Christine O. Gregoire **Theodore R. Kulongoski** **Arnold Schwarzenegger**

Janet Napolitano **Bill Richardson**

WESTERN REGIONAL CLIMATE ACTION INITIATIVE

WHEREAS, western states are experiencing the effects of a hotter, drier climate, including prolonged droughts, excessive heat waves, reduced snow packs, increased snowmelts, decreased spring runoffs, altered precipitation patterns, more severe forest and rangeland fires, widespread forest diseases, and other serious impacts; and

WHEREAS, scientific consensus has developed that increasing emissions of human-caused greenhouse cases (GHGs), including carbon dioxide, methane and other GHGs, that are released into the atmosphere are affecting the Earth's climate; and

WHEREAS, the Western Governors Association (WGA) has declared that climate change could have severe economic and environmental impacts on the Western States in coming decades; and

WHEREAS, the WGA also has declared that action is needed to reduce GHG emissions and that many of these actions can have significant economic and environmental benefits for the Western States, including increased energy efficiency, increased renewable energy generation, improved air quality, cost savings, job growth, increased state revenues, and reduced water pollution; and

WHEREAS, we support the development of national, regional, tribal, state and local programs to reduce GHG emissions; and

WHEREAS, we support national, regional, tribal, state and local level policies on global climate change that are consistent with efforts to develop cost-effective alternative energy sources and more efficient use of energy; and

WHEREAS, we recognize the need for collaboration among states to develop climate change policies that provide consistent approaches to recognize and give credit for actions to reduce GHG emissions; and

WHEREAS, we have already adopted or committed to adopt clean tailpipe standards for passenger vehicles that will result in major reductions in GHG emissions and other pollutants; and

WHEREAS, we support market-based policies to reduce GHG emissions in the most cost-effective manner; and

WHEREAS, we have set goals to significantly reduce GHG emissions from our respective states; and

WHEREAS, we welcome expanding the partners to this initiative to other states, tribes, Canadian provinces and Mexican states and offer monitoring status to any state, tribe or province interested in observing the initiative;

NOW, THEREFORE, we, the undersigned Governors, jointly establish the Western Regional Climate Action Initiative and agree to collaborate in identifying, evaluating and implementing ways to reduce GHG emissions in our states collectively and to achieve related co-benefits. This collaboration shall include, but is not limited to:

- Setting an overall regional goal, within six months of the effective date of this initiative, to reduce emissions from our states collectively, consistent with state-by-state goals;

- Developing, within eighteen months of the effective date of this agreement, a design for a regional market-based multi-sector mechanism, such as a load-based cap and trade program, to achieve the regional GHG reduction goal; and

- Participating in a multi-state GHG registry to enable tracking, management, and crediting for entities that reduce GHG emissions, consistent with state GHG reporting mechanisms and requirements.

In addition, we commit to continue our independent and collaborative efforts to reduce GHG emissions through:

- Promoting the development and use of clean and renewable energy within the region;

- Increasing the efficiency of energy use within our jurisdictions;

- Advocating regional and national climate policies that reflect the needs and interests of western states, tribes and provinces; and

- Identifying measures in our states, tribes and provinces to adapt to the impacts of climate change.

We will direct our staffs and the appropriate state agencies to meet as soon as is practicable to develop a work plan to move forward with this initiative.

DONE, in five (5) duplicate originals, this 26th day of February, 2007, in Washington, D.C.

Governor Christine O. Gregoire
State of Washington

Governor Theodore R. Kulongoski
State of Oregon

Governor Janet Napolitano
State of Arizona

Governor Bill Richardson
State of New Mexico

Governor Arnold Schwarzenegger
State of California

Western Climate Initiative

Western Climate Initiative Update

August 27, 2007

On February 26, 2007, Governors Gregoire (WA), Kulongoski (OR), Napolitano (AZ), Richardson (NM) and Schwarzenegger (CA) signed an agreement establishing the Western Climate Initiative (WCI). The purpose of the initiative is to collaborate in identifying, evaluating and implementing ways to reduce GHG emissions and to achieve related co-benefits.

Since February, Premier Gordon Campbell of British Columbia, Utah Governor Jon Huntsman, and Premier Gary Doer of Manitoba have joined the Initiative as full partners.

Currently the following jurisdictions are participating as official observers: the U.S. States of Colorado, Kansas, Nevada, and Wyoming; the Canadian Provinces of Ontario, Quebec, and Saskatchewan; and the Mexican State of Sonora.

On August 22, 2007, the WCI partners released their regional goal to collectively reduce emissions, consistent with previously established state and provincial goals. Details on the WCI regional goal (to reduce emissions 15% below 2005 levels by 2020) can be found at www.westernclimateinitiative.org.

By August 2008, the partners will design a regional market-based multi-sector mechanism, such as a load-based cap and trade program, to help achieve the goal. Each of the partners has joined the newly formed GHG registry (The Climate Registry). The Climate Registry is expected to be operational by January, 2008. More information about The Climate Registry can be found at www.theclimateregistry.org.

Five WCI subcommittees have recently been established to work on various aspects of the regional program. The five subcommittees are: Reporting, Scope, Electricity, Allocations, and Offsets. Staff from WCI states and provinces will serve on the subcommittees. The subcommittee chairs will establish a process for obtaining input from technical experts and stakeholders.

It is the intention of the Governors and the Premiers to expand the partners in the initiative to include other states, tribes, and provinces who share their commitment to aggressively address climate change.

New partners are invited to sign the February 26, 2007 agreement, committing to the goals of the initiative. As stated in the agreement, it is expected that any state or province wishing to become a partner will have set a goal to significantly reduce GHG emissions and committed to adopt clean tailpipe standards for passenger vehicles, in addition to committing to the overall goals of the initiative.

The partners have also offered observer status to states, tribes, or provinces that are interested in pursuing greenhouse gas reductions.

Each of the WCI partners will separately conduct stakeholder outreach and involvement with interested parties in their jurisdictions. In addition, the partners will collectively host periodic conference calls and provide written updates on the progress of the initiative. Documents will be posted to the WCI website as they become available.

For more information, please contact:

Arizona:	Lori Faeth (lfaeth@az.gov) Steve Owens (Owens.Stephen@azdeq.gov) – WCI Co-Chair
California:	Brian Prusnek (brian.prusnek@gov.ca.gov) Michael Gibbs (mgibbs@calepa.ca.gov)
New Mexico:	Sarah Cottrell (sarah.cottrell@state.nm.us) Jim Norton (jim.norton@state.nm.us)
Oregon:	David Van't Hof (david.vanthof@state.or.us)
Utah:	Dianne Nielson (dnielson@utah.gov)
Washington:	Janice Adair (jada461@ecy.wa.gov) – WCI Chair Tony Usibelli (tonyu@cted.wa.gov)
British Columbia:	Warren Bell (warren.bell@gov.bc.ca)
Manitoba:	Jane Gray (jane.gray@gov.mb.ca)

Facilitators:

Patrick Cummins	Western Governors' Association	(pcummins@westgov.org)
Tom Peterson	Center for Climate Strategies	(tdp1@mac.com)

Western Climate Initiative

www.westernclimateinitiative.org

Western Climate Initiative

Statement of Regional Goal

August 22, 2007

1. Regional Goals. The Western Climate Initiative (WCI) regional greenhouse gas emission reduction goal is an aggregate reduction of 15% below 2005 levels by 2020.

- This regional, economy-wide goal is consistent with the emission goals of WCI partners and does not replace the partners' existing goals.

- The WCI partners acknowledge that new entrants and updates to data may result in some incremental changes to the regional goal.

- The metrics for establishing this goal are documented in Attachment A.

The WCI partners commit to do their share to reduce regional GHG emissions sufficient over the long term to significantly lower the risk of dangerous threats to the climate. Current science suggests that this will require worldwide reductions between 50% and 85% in carbon dioxide emissions from current levels by 2050.[1]

2. New Entrants. The WCI encourages participation by additional US states, tribes, Canadian provinces, and Mexican states that are making comparable efforts to combat climate change. In determining whether the new entrant is undertaking comparable efforts to meet the challenge of climate change, the partners shall consider whether the proposed new entrant:

a. Has adopted an economy-wide greenhouse gas reduction goal. The goal shall reflect a level of effort that is consistent with that of the WCI partners;

[1] IPCC Fourth Assessment Report, Working Group III, Mitigation of Climate Change

b. Has developed or is developing a comprehensive multi-sector climate action plan to achieve the goal;

c. Has committed to adopt greenhouse gas tailpipe standards for passenger vehicles; and

d. Is participating in The Climate Registry.

When deciding whether to accept a new entrant, the partners may consider other factors they deem appropriate. The partners will establish a decision-making process on adopting new entrants.

3. Coverage of Actions in the Goal. Emissions reduction activities by which partners achieve the regional reduction goal should be comprehensive and economy-wide, including:

a. Regional multi-sector market-based mechanisms;

b. Actions in all sectors, including but not limited to: stationary sources, energy supply, residential, commercial, industrial, transportation, waste management, agriculture, and forestry; and

c. Reduction in emission of any GHG reported to the UN Framework Convention on Climate Change by the USEPA and Environment Canada, i.e., carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6).

4. Reporting Requirements. Each partner will update the other WCI partners on their climate action plan and GHG emissions inventories every two years to ensure that actions are underway at levels consistent with full achievement of the 2020 goal.

Attachment A: Metrics used to Establish WCI Regional Goal

The WCI aggregate greenhouse gas emission reduction goal of 15% below 2005 levels by 2020 is based on:

- The aggregation of GHG emissions and emissions goals of WCI partners that have thus far established a 2020 goal (Arizona, British Columbia, California, New Mexico, Oregon, and Washington) and Manitoba's short-term goal, as shown in the Table 1 below.

- Currently available state or provincial emissions inventories. Some of these inventories are currently under revision, and the values shown in Table 2 below will be periodically updated. While further changes to specific emissions estimates are likely, the aggregate regional emission reduction goal for the current partners is unlikely to deviate substantially from 15% below 2005 levels by 2020.

- Gross emissions estimates, across all sectors, for the six greenhouse gases reported to the UN Framework Convention on Climate Change by the USEPA in the U.S. Greenhouse Gas Inventory and by Environment Canada in the Canada National Inventory Report: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). These estimates are presented in terms of CO_2 equivalence (CO_2e), which indicates the relative contribution of each gas to global average radiative forcing on a 100-year Global Warming Potential (GWP) weighted basis. Gross emissions estimates do not include changes in biological carbon stocks due to agriculture, forestry, and land use change. In addition, GHG emissions associated with international aviation and international bunker fuels are generally excluded.

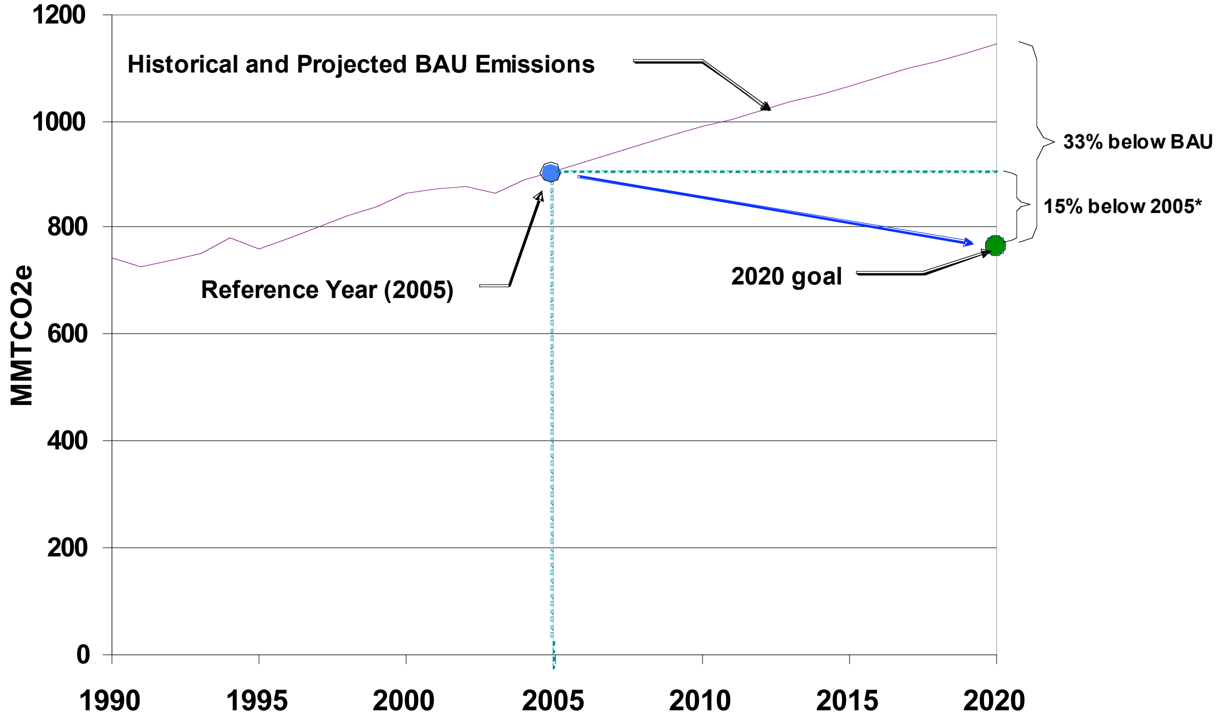
- Consumption-based (or "load-based") emissions estimates for the electricity sector, except where such estimates are currently unavailable, in which case production-based estimates are used (British Columbia). Consumption-based estimates reflect the emissions associated with generating the electricity delivered to consumers in each state or province whether the electricity was generated in state/province or out of state/province. Considerable work is currently underway to further develop and improve consumption-based estimates.

Table 1. State and Provincial Goals for GHG Reductions

	Short Term (2010-12)	Medium Term (2020)	Long Term (2040-50)
Arizona	not established	2000 levels by 2020	50% below 2000 by 2040
British Columbia	not established	33% below 2007 by 2020	not established
California	2000 levels by 2010	1990 levels by 2020	80% below 1990 by 2050
Manitoba	6% below 1990	6% below 1990[2]	not established
New Mexico	2000 levels by 2012	10% below 2000 by 2020	75% below 2000 by 2050
Oregon	arrest emissions growth	10% below 1990 by 2020	>75% below 1990 by 2050
Utah	Will set goals by June 2008		
Washington	not established	1990 levels by 2020	50% below 1990 by 2050

[2] Manitoba has not yet established a formal goal for 2020, but expects to meet or do better than its short term goal.

WCI Partner GHG Emissions and Regional Goal[3]



BAU = Business-as-usual (projections).

The arrow shown is purely directional: it illustrates the where regional emissions will need to be by 2020 rather than the specific path emissions are expected to follow during the 2007-2020 period.

* See footnote c in the Table 2 below.

[3] Note that this chart does not include Manitoba emissions, which will be added when 2020 projections are available.

Table 2 compiles and compares WCI partner goals for the year 2020, and indicates the relative percentage emissions reduction below historical (1990, 2000, and 2005) or projected (business-as-usual or "BAU" in 2020) levels that these goals imply. Also shown are the absolute emission reductions below projected BAU levels in 2020 in million metric tons of CO2 equivalents (MMtCO2e) that are needed to meet these goals. The final column indicates how fast greenhouse gas emissions would be expected to grow from 1990 to 2020 were no action taken to reduce them. The final row shows the aggregate result for the WCI partners that have established 2020 goals (percents are based on total emissions for the partners shown). As illustrated, the compilation of partner goals represents an aggregate 16% reduction below 2005 levels by 2020. This figure has been rounded to 15% for the regional goal, as stated above.

Table 2. Summary Compilation and Comparison of 2020 goals (Estimates as of July 2007[a])

	Goals					1990-2020 BAU growth
	Relative to 1990	Relative to 2000	Relative to 2005	Relative to 2020 BAU[b]	Absolute Reductions from BAU (MMtCO2e)	
Arizona	35%	0%	-11%	-45%	72	144%
British Columbia	-9%	-27%	-30%	-46%	40	69%
California	0%	-10%	-14%	-28%	170	40%
Manitoba	-6%	-16%	-17%	TBD	TBD	TBD
New Mexico	14%	-10%	-14%	-31%	28	65%
Oregon	-10%	-29%	-32%	-44%	40	61%
Washington	0%	-16%	-11%	-28%	33	40%
Total	**2%**	**-12%**	**-16%**[c]	**-33%**[d]	**383**[d]	**54%**[d]

[a] Methodologies for estimating electricity emissions may not be fully comparable. State electricity emissions estimates used to develop the figures shown above are consumption-based (i.e. "load-based"); methodologies for consumption-based electricity emissions vary among states. Provincial electricity emission estimates are currently available only on a production basis.

[b] Current BAU forecasts (2020 estimates) may not be fully comparable. Two factors, in particular, may need to be further examined with respect to assessing comparability of effort: a) underlying socioeconomic projections, most notably population and economic activity; and, b) the extent to which emission reduction actions are included in BAU projections.

[c] The WCI goal of 15% below 2005 levels reflects a rounding of this figure, which may change slightly as partner states and provinces continue to refine their GHG inventories.

[d] These totals do not include Manitoba emissions, since projections are not currently available.

References for GHG emissions estimates:

Arizona: "Climate Change Action Plan", Arizona Climate Change Advisory Group, August 2006. http://www.azclimatechange.gov/

British Columbia: Historical emissions from Environment Canada, "National Inventory Report: 1990 - 2005", http://www.ec.gc.ca/pdb/ghg/inventory_report/2005_report/toc_e.cfm; projections from BC Ministry of Environment calculations based on Natural Resources Canada and Simon Fraser University estimates.

California: "Inventory of California Greenhouse Gas Emissions and Sinks: 1990 to 2004", Staff Final Report, December 2006, CEC-600-2006-013-SF, http://www.climatechange.ca.gov/policies/greenhouse_gas_inventory/index.html

Manitoba: Historical emissions from Environment Canada, "National Inventory Report: 1990 - 2005", http://www.ec.gc.ca/pdb/ghg/inventory_report/2005_report/toc_e.cfm

New Mexico: "Final Report", New Mexico Climate Change Advisory Group, December 2006, http://www.nmclimatechange.us

Oregon: "Oregon Strategy for Greenhouse Gas Reductions", Governor's Advisory Group on Global Warming, December 2004, http://www.oregon.gov/ENERGY/GBLWRM/Strategy.shtml, with subsequent revisions yet to be published.

Washington: "Greenhouse Gas Inventory and Reference Case Projections", Washington State Climate Advisory Team, April 2007 Draft, with subsequent revisions yet to be published. http://www.ecy.wa.gov/climatechange/cat_documents.htm

References for GHG emissions goals:

Arizona: "Climate Change Action" Governor Janet Napolitano's Executive Order 2006-13, September 8, 2006 http://www.governor.state.az.us/dms/upload/EO_2006-13_090806.pdf

British Columbia: "Speech from the Throne" February 13, 2007 http://www.leg.bc.ca/38th3rd/4-8-38-3.htm

California: Governor Arnold Schwarzenegger's Executive Order S-3-05 and AB32 legislation, http://www.climatechange.ca.gov/

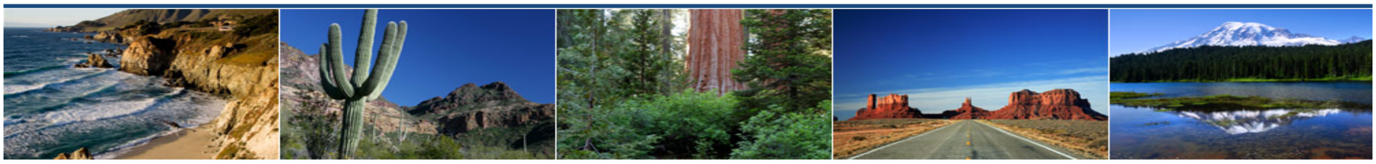
Manitoba: "Kyoto and Beyond", Province of Manitoba Climate Change Action Plan, 2002, http://www.gov.mb.ca/est/climatechange/pdfs/final-mccap-sep-16-02.pdf

New Mexico: "Climate Change and Greenhouse Gas Reduction",.Governor Bill Richardson's Executive Order 2005-033, June 9, 2005, http://www.governor.state.nm.us/2005orders.php

Oregon: Enrolled House Bill 3543, signed into law on August 7, 2007 by Governor Ted Kulongoski, http://www.leg.state.or.us/07reg/measpdf/hb3500.dir/hb3543.en.pdf

Washington: Governor Christine Gregoire's Executive Order 07-02, February 7, 2007, http://www.governor.wa.gov/execorders/eo_07-02.pdf and Engrossed Substitute Senate Bill (ESSB) 6001, http://www.leg.wa.gov/pub/billinfo/2007-08/Pdf/Bill%20Reports/Senate%20Final/6001-S.FBR.pdf

Western Climate Initiative



October 29, 2007

TO: All Interested Parties

The Western Climate Initiative (WCI) Partners are pleased to release the attached work plan of WCI activities through August 2008. As directed by our Governors and Premiers (http://www.westernclimateinitiative.org/ewebeditpro/items/O104F12775.pdf), this work plan describes our process for developing design recommendations for a proposed cap-and-trade program, as one element of our collaboration to identify, evaluate, and implement ways to reduce GHG emissions and to achieve related co-benefits.

The WCI Partners encourage stakeholder and public participation, and toward that end have included a description of the proposed stakeholder process in the work plan. This process includes three workshops, planned for January, May, and July 2008, as well as regular conference calls and other activities. These activities will supplement the outreach being conducted individually by each of the states and provinces.

Included in the attached work plan is a list of program design questions and issues on which we are particularly interested in receiving input at this time. The WCI Partners request that you submit input regarding these questions and issues by November 30, 2007. Instructions for submitting comments are posted on the WCI website: www.westernclimateinitiative.org.

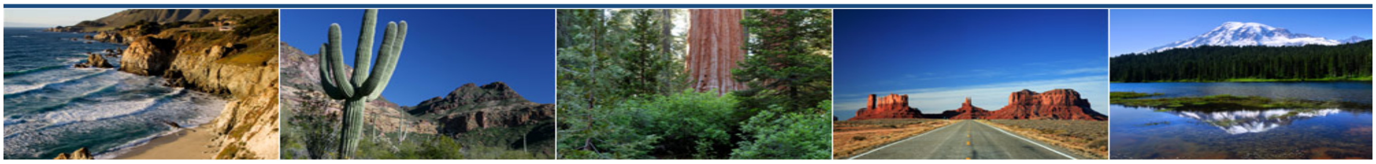
Throughout our work, the WCI Partners will solicit written input, including feedback on preliminary materials as they are developed. Comments and input will be posted to our website. Input is welcome at any time on issues related to the WCI.

The WCI Partners appreciate your interest and involvement in this initiative. We look forward to working with all stakeholders to achieve WCI's objectives.

Sincerely,

Janice Adair, Special Assistant	Steve Owens, Director
Washington Department of Ecology	Arizona Department of Environmental Quality
Chair, Western Climate Initiative	Co-Chair, Western Climate Initiative

Western Climate Initiative



WESTERN CLIMATE INITIATIVE

WORK PLAN
October 2007 - August 2008

October 29, 2007

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I. INTRODUCTION

This document presents the plan for the Western Climate Initiative (WCI) activities through August 2008.

- Section II presents a brief summary of the WCI and its objectives.
- Section III presents the design principles adopted by the WCI Partners to guide the development of recommendations for a cap-and-trade program.
- Section IV presents the process for involving stakeholders and the public in the WCI deliberations.
- Section V presents a summary of the overall timeline and milestones for developing the program design recommendations.
- Section VI presents design questions and issues on which public input is solicited at this time. Please note that input on additional questions and issues will be solicited during the development of the program recommendations and that input is welcome at any time on issues related to the WCI.
- Section VII describes the subcommittees created by the WCI Partners.
- Section VIII presents the work plans for each of the subcommittees.

II. BACKGROUND

On February 26, 2007, Governors Gregoire (WA), Kulongoski (OR), Napolitano (AZ), Richardson (NM) and Schwarzenegger (CA) signed an agreement establishing the Western Climate Initiative (WCI). The purpose of the initiative is to collaborate in identifying, evaluating and implementing ways to reduce GHG emissions and to achieve related co-benefits.

Since February, Premier Gordon Campbell of British Columbia, Utah Governor Jon Huntsman, and Premier Gary Doer of Manitoba have all joined the Initiative as full Partners.

It is the intention of the Governors and the Premiers to expand the Partners in the initiative to include other states, tribes, and provinces who share their commitment to aggressively address climate change.

Currently the following jurisdictions are participating as official observers: the U.S. States of Alaska, Colorado, Idaho, Kansas, Nevada, and Wyoming; the Canadian Provinces of Ontario, Quebec, and Saskatchewan; and the Mexican State of Sonora.

On August 22, 2007, the WCI Partners released their regional goal to collectively reduce emissions, consistent with previously established state and provincial goals. Details on the WCI regional goal (to reduce emissions 15% below 2005 levels by 2020) can be found at www.westernclimateinitiative.org.

Each of the Partners has joined the newly formed GHG registry (The Climate Registry). The Climate Registry builds on the existing California Climate Action Registry and will begin accepting data in early 2008. More information about The Climate Registry can be found at www.theclimateregistry.org. The Climate Registry will play an important role in establishing an accurate reporting mechanism and accounting infrastructure on which to base the WCI cap-and-trade program.

Five WCI subcommittees have recently been established to work on various aspects of the regional program. The five subcommittees are: Reporting, Scope, Electricity, Allocations, and Offsets. Staff from WCI states and provinces serve on the subcommittees, and each subcommittee will obtain input from technical experts and stakeholders.

Each of the WCI Partners will separately conduct stakeholder outreach and involvement with interested parties in their jurisdictions. In addition, the Partners will collectively host periodic conference calls, provide written updates on the progress of the initiative, and conduct other communications and outreach activities.

By August 2008, the Western Climate Initiative Partners will develop design recommendations for a regional cap-and-trade program to:

1. Reduce greenhouse gas emissions in each Partner jurisdiction; and
2. Help achieve the Partners' overall greenhouse gas emissions reduction goals.

III. DESIGN PRINCIPLES FOR A REGIONAL CAP AND TRADE PROGRAM

To attain the Western Climate Initiative's greenhouse gas reduction goal, the members are committed to designing a system that:

1. Is equitable, administratively simple for government and private participants, minimizes administrative costs, and has a clear compliance path;
2. Maximizes total benefits throughout the region, including reducing air pollutants, diversifying energy sources, and advancing economic, environmental, and public health objectives, while also avoiding localized or disproportionate environmental or economic impacts;
3. Requires all reductions to be real, surplus/additional, verifiable, permanent, and enforceable;
4. Stimulates investment, especially in low carbon technologies, and rewards innovations that will lead to long-term permanent greenhouse gas reductions;
5. Covers as many sources as is practical, while encouraging pollution reductions beyond the capped sources and sectors;
6. Provides appropriate recognition and incentives for early emissions reductions;
7. Assures a transparent and robust accounting system that will measure and report emissions rigorously and consistently across all sectors and throughout the region;
8. Minimizes the potential for leakage; and
9. Facilitates linkage to similarly rigorous regional and international greenhouse gas reduction markets and encourages other states, provinces, and countries to join the market.

IV. COMMUNICATIONS AND STAKEHOLDER OUTREACH

The Western Climate Initiative Partners are committed to maintaining an open and transparent process that integrates public participation and stakeholder input. Therefore, the WCI Partners will conduct a regional communications and stakeholder outreach process during the design phase to:

1. Supplement the individual state and province communication and outreach efforts.
2. Inform the public and stakeholders of the WCI Partners' deliberations, and draft and final work products.
3. Provide a mechanism for subcommittees to obtain timely input from the public and stakeholders on key design elements of the regional cap-and-trade initiative to support their deliberations and recommendations.
4. Establish opportunities for the public and stakeholders to communicate through oral and/or written comments to the WCI Partners prior to key decision points in the process, including integration of design elements from subcommittees into the final program design.
5. Maintain an ongoing dialogue between WCI Partners and stakeholders in the process.

The WCI Partners will carry out the following actions.

1. Website. The WCI Partners have established a Western Climate Initiative website at www.westernclimateinitiative.org. The website will serve as the primary vehicle for the WCI Partners to make their draft and final work products available for public review and comment. In addition, the WCI Partners intend to post the written comments received from members of the public and stakeholders on the website.
2. Listserv. The WCI Partners have established a regional Listserv to which members of the public and stakeholders may subscribe by visiting the WCI website (www.westernclimateinitiative.org). Subscribers to the regional Listserv will receive email notifications when new content is added to the website, including the availability of draft and final work products, as well as notifications of public information sessions.
3. Public Information Sessions. In addition to making draft and final work products available on the WCI website, the WCI Partners will hold public meetings by teleconference and in-person, as follows:
   - Teleconferences. The purpose of the teleconferences is to provide information to interested members of the public and stakeholders. The WCI Partners will hold periodic teleconferences to relate the subject of their ongoing deliberations on areas of focus in the initiative. In general, these teleconferences will occur shortly after the periodic meetings of the WCI Partners, though additional teleconferences will be held as necessary. Call information will be posted on the website and notifications will be sent vial the Listserv. The current schedule for WCI teleconferences is as follows:
     - Thursday, October 31, 2007 at 2 pm PDT / 3 pm MDT
     - Thursday, December 6, 2007 at 2 pm PST / 3 pm MST
     - Thursday, March 6, 2008 at 2 pm PST / 3 pm MST

- Workshops. The WCI Partners will conduct public workshops at various locations in the WCI region beginning in January 2008. Workshops will be webcast.
    - At the first session (early January), the subcommittees will present the status of their deliberations, including identifying the major options that are under consideration and the pros and cons of the alternatives. Public input on the options will be solicited.
    - The second workshop will occur in May 2008. At the second session, the subcommittees will present their recommendations on key elements of the regional cap-and-trade program. Public input on the recommendations will be solicited.
    - The third workshop will occur in July 2008. At the third session, the Partners will present the preferred fully integrated plan that is being considered. Public input on the proposed plan will be solicited.
    - Interested members of the public and stakeholders will have the opportunity to provide oral comments at public information sessions. Participants will be encouraged to submit written comments to supplement oral comments. Comments that are submitted in electronic format will be posted to the WCI website.

(Note: The dates for teleconferences and in-person meetings are subject to change, and any changes will be promptly posted on the WCI website and sent out on the WCI listserv.)

- Public Input to Subcommittee Deliberations. The purpose of this activity is to provide a mechanism by which the subcommittees can solicit stakeholder and public input. As necessary, each subcommittee will prepare written requests for input that will be posted on the website and announced via the Listserv. Written input will be received, reviewed, and posted on the website.
- State and Provincial Stakeholder Processes. This section describes communication and outreach that the WCI Partners will undertake together at the regional level. These regional communications are intended to supplement and not replace individual state and provincial communications and do not supplant any public comment periods required in connection with the adoption of laws and regulations in specific Partner jurisdictions.

The WCI Partners will revisit this Communications Plan from time to time and consider appropriate revisions to the plan based on comments received by interested members of the public and stakeholders, or on their own initiative.

V. TIMELINE AND MILESTONES

October 2007	Release work plan and major design issues for review and comment • Subcommittees identify specific issues on which input is sought
November 2007	Initial written stakeholder feedback on work plan and major design issues requested by November 30.
January 2008	Subcommittees describe major options under consideration • Workshop to discuss options with interested stakeholders
May 2008	Subcommittee recommendations on key elements of regional cap-and-trade program • Workshop to discuss subcommittee recommendations
July 2008	Proposed design of regional cap-and-trade program • Workshop to discuss proposed design
August 2008	Partners release design recommendations for a regional cap-and-trade program

VI. DESIGN QUESTIONS FOR STAKEHOLDER REVIEW & COMMENT

The WCI Partners are broadly framing their discussions around the following set of design questions and seek input from stakeholders and interested members of the public to guide the development of the program.

Program Scope and Timing

A. What sectors and gases should be covered by the cap-and-trade program, and within each covered sector, what point of regulation is most appropriate?

1. Electricity:
   - (a) At the generator level?
   - (b) At the retail provider level?
   - (c) A "first seller"[1] approach (covering both emissions that occur inside the jurisdiction as well as the emissions attributable to the electricity generated outside the jurisdiction)?
   - (d) A generator-retail provider hybrid approach?
   - (e) Other?
   - (f) For all of the above, which gases should be considered for the electricity sector?

2. Others sectors: Referring to Table 1 in the work plan (see page 18), are the options shown properly defined? Should additional options be added? What combination of options should be considered?

B. Should all sectors/gases be covered by the program on the same launch date, or should sectors/gases be added over time, and why?

Setting Cap Level(s), Scheduling Reductions & Distributing Allowances

A. What factors should be considered in determining the relative role of the cap-and-trade program as compared with complementary policies in reaching regional emission reduction goals?

B. How should the initial emissions cap(s) for the cap-and-trade program be established at the regional, state and provincial and/or sectoral levels, and what schedule of reductions should be set?

C. What are the key objectives that WCI Partners should address through allowance distribution (e.g., cost minimization, equity, technology incentives, etc.)?

D. How should the allowances be distributed (e.g. auction or free allocation), and should the distribution process be common to all Partners?

[1] For discussion of the first seller, retail provider, and other electricity sector scope options see http://www.climatechange.ca.gov/documents/2007-06-29_MAC_FINAL_REPORT.PDF

E. How should recognition and incentives for early emission reductions be provided?

Offsets

A. What roles and key objectives, if any, should an offsets mechanism play in WCI?

B. How should a WCI offset mechanism be designed?

1. How should greenhouse gas offsets be defined for use within the WCI cap and trade system?

2. How should the WCI design principles that reductions be real, surplus/additional, verifiable, permanent, and enforceable be translated into practice?

3. What approaches should be used to develop project baselines and monitoring methodologies?

4. Should there be limits on the extent to which offsets can be used to meet compliance obligations? Should such limits change over time?

5. What issues should be considered in determining issues such as project start dates, offset expiration, and project crediting periods?

6. What project types and locations should be eligible, and on what basis should eligibility be determined? Should offsets from other programs be eligible (e.g. Clean Development Mechanism, Regional Greenhouse Gas Initiative)?

C. How should the WCI administer an offset mechanism? Are there useful models and protocols to follow?

Other Flexibility and Cost-Containment Mechanisms

A. What should the length of the compliance periods be, and why?

B. What are the pros and cons of allowance banking?

C. What are the pros and cons of allowance borrowing?

D. Should the program include other cost-containment mechanisms such as a safety valve, allowance price cap, or other instruments? If so, how should these be designed?

Emissions and Allowance Data, Monitoring, Reporting and Tracking

A. What are the best sources of data to use in establishing emission baselines?

B. Should mandatory emissions reporting precede establishment of an emissions baseline in one or more of the sectors to be covered by the program?

C. How should emissions, allowances, and offsets be measured, monitored, reported and/or tracked by the program?

D. Are there additional objectives for a reporting systems beyond assessing compliance with the cap-and-trade program, and if so, what should they be?

E. What are the best ways to assure consistency in reporting throughout the WCI? How should mandatory reporting under the WCI be best integrated with The Climate Registry?

Miscellaneous Issues

A. How should the cap-and-trade program be designed to enhance the benefits from complementary policies in the Partner jurisdictions?

B. How should the WCI ensure compliance with program goals? What non-compliance penalties would be appropriate for entities that are covered under the cap?

C. Should the WCI partners establish regional organization(s) to coordinate aspects of program implementation, and if so, what aspects?

D. Which design elements should be common, and which should be allowed to vary, across WCI partner jurisdictions?

E. How should the program be designed to facilitate linkage with other trading systems outside the WCI region (e.g. EU Emission Trading System, Regional Greenhouse Gas Initiative)?

F. Are there additional issues that should be considered to ensure that the cap-and-trade system conforms to the WCI principles?

VII. SUBCOMMITTEES

In order to carry out their mission, the Partners have established five subcommittees which are briefly described below. Section VIII of this work plan provides a more detailed description of the subcommittee work plans.

Reporting Subcommittee. The mission of the Reporting Subcommittee is to identify and/or develop a consistent mechanism for mandatory reporting of GHG emissions that will provide the measurement and accounting structure for the regional cap-and-trade program to be developed and implemented by the WCI. The Reporting Subcommittee is chaired by Jim Norton of the State of New Mexico.

Scope Subcommittee. The Scope Subcommittee will recommend the scope and points of regulation for the cap-and-trade program, with the exception of the electricity sector which is being assessed by the Electricity Subcommittee. The Scope Committee is chaired by Michael Gibbs of the State of California.

Electricity Subcommittee. The Electricity Subcommittee will recommend the scope and point of regulation for the electric sector. The Electricity Subcommittee is chaired by David Van't Hof of the State of Oregon.

Allocations Subcommittee. The Allocations Subcommittee will recommend options for establishing emissions allowance budgets in each Partner jurisdiction, as well as how to distribute allowances within Partner jurisdictions among covered sectors and sources within each sector. The Allocations Subcommittee is chaired by Steve Owens of the State of Arizona.

Offsets Subcommittee. The Offsets Subcommittee will make recommendations on the inclusion, design, scope and operation of the greenhouse gas offset system as an element of the cap-and-trade program. The Offsets Subcommittee is chaired by Tim Lesiuk of the Province of British Columbia.

In general, the Subcommittees will carry out the following tasks:

- *Information Gathering and Learning*. Each Subcommittee will take primary responsibility for gathering information and learning about the Subcommittee's areas of focus.
- *Identify Policy Questions*. The Subcommittees will collectively identify the relevant policy questions that should be assessed in order to develop design recommendations for the cap-and-trade program.
- *Evaluate Policy Options.* Each Subcommittee will evaluate potential approaches for within the Subcommittee's area of focus. The Subcommittees will present these potential options together with an explanation of the benefits and challenges associated with each approach.
- *Propose Policy Decisions*. The Subcommittees will make policy recommendations within their focus areas for consideration by the Partners.

Based on the work of the subcommittees, the Partners will develop a proposal containing all key elements of a regional cap-and-trade program for review and comment prior to reaching final agreement on the recommendations for program design.

VIII. SUBCOMMITTEE WORK PLANS

A) Reporting Subcommittee

i. Mission

The mission of the Reporting Subcommittee is to identify and/or develop a consistent mechanism for mandatory reporting of GHG emissions that will provide the measurement and accounting structure for the regional cap-and-trade program to be developed and implemented by the WCI. This reporting mechanism will be consistent with the protocols of The Climate Registry (TCR) and utilize TCR to the maximum extent possible. It will also echo or align with existing or emerging reporting systems within partner jurisdictions to the greatest degree possible. It is anticipated that this reporting mechanism will form the basis of regulations to be adopted or updated by all partner jurisdictions with respect to the reporting of GHG emissions.

In developing this mechanism, the subcommittee will likely need to design a reporting system that balances multiple objectives, consistent with the design principles laid out in Section II, and reflects key decisions of other subcommittees.

The subcommittee may consider a phased-in approach for reporting that mirrors any phase-in that may be employed for including sectors and sources under the cap or as part of an offset provision, so that the reporting system may encompass additional sectors, sources, or GHGs over time.

ii. Tasks

Task 1: Identify the roles, objectives and principles that will guide design of the reporting mechanism.

The subcommittee will need to consider the full range of potential roles and objectives for reporting within the WCI program. While the primary objective is to provide the measurement and accounting system for emissions that will allow partner jurisdictions to assess the compliance of sectors and sources under the cap within their regions, there are other possible roles for a reporting system that should be considered. These include gathering data that could be used to assess early reductions, preparing sectors and sources that are not initially covered by the program for eventual inclusion, informing decisions about expansion of the program or the allocation of allowances, monitoring offset project performance, etc. Early decisions from other subcommittees will be critical to identifying additional objectives.

The subcommittee will also need to identify what principles will be employed in balancing multiple objectives. In addition to the overall design principles in Section II above, the subcommittee will need to consider factors such as the availability of credible quantification approaches for any given sector or source, the reporting burden associated with including a given sector or source, tradeoffs between the cost and rigor associated with employing a given quantification approach, etc.

Task 2: Identify and assess existing reporting systems that can inform development of a WCI reporting mechanism.

A number of credible reporting systems exist, both within the WCI region and outside, that can be drawn upon in developing a uniform WCI reporting mechanism. The subcommittee will identify and assess these systems, comparing them on the basis of a range of key design decisions. This process will both inform how the key objectives identified in task 1 can be met and identify those sources and sectors for which reliable quantification and reporting exists, and those for which the subcommittee would need to develop such guidance. The analysis will focus at a minimum on existing and emerging systems within the WCI region, but may also examine reporting systems in other regions and nations. One key output of this task will be a comparison matrix that summarizes the key features of existing reporting systems.

Task 3: Ensure that the WCI reporting mechanism aligns with existing and emerging mandatory GHG reporting rules and The Climate Registry.

Of particular importance will be identifying how the WCI reporting mechanism can be aligned with existing reporting systems and ongoing rulemaking processes in the WCI region. The strategy developed in this task will also identify options for how updates to the WCI reporting mechanism (if a phase-in is employed) are expected to be rolled out and incorporated by partner jurisdictions.

Task 4: Frame key elements of a WCI mandatory GHG reporting mechanism and identify options for sectors and sources that could be included.

This task will center on developing an outline for a reporting mechanism that includes a range of options as to key reporting parameters. These options will be based on existing reporting programs assessed in Task 2 and objectives identified in Task1. The outline will also include a list of proposed sources and sectors for which reliable and practicable quantification guidance exists and which should be included in the reporting mechanism, based on input from other subcommittees.

Task 5: Consider whether a model rule should be developed, and if so, what it should include and what its development schedule should be.

Based on input from other subcommittees and feedback from stakeholders on the outline, the subcommittee will consider the development of a model rule that includes at a minimum, all sources and sectors to be included in the initial phase of a WCI cap. Any such model rule will utilize TCR to the greatest extent possible and will align with existing and emerging reporting programs to the greatest degree possible. It may also include reporting provisions developed by the Offset Subcommittee around offset projects and other sectors and sources that are identified for eventual inclusion in the WCI program, to the extent that reliable methodologies are identified. Any draft model rule developed will be refined based on stakeholder feedback, as appropriate.

Task 6: Identify expected updates to the WCI reporting mechanism.

Based on input from the Scope Subcommittee and any concrete plans for expansion of the WRI program, the Reporting Subcommittee will develop a plan for updating its reporting mechanism over time. This will involve identifying and prioritizing additional sectors/sources for inclusion in the mechanism, as well as a process for developing reliable reporting methodologies where none exist. The subcommittee will also work to develop a schedule for the development of these updates.

iii. Coordination with Other Subcommittees

Reporting of GHG emissions and reductions will ultimately form the basis for evaluating progress toward meeting WCI goals and compliance for covered sources. Key input from the Scope Subcommittee and the Electricity Subcommittee will be necessary to achieve this goal. The reporting rule could also be designed to collect data for the purposes of monitoring offset projects or informing other aspects of the WCI program, such as offset baselines, expansion of the cap, allocation of allowances etc. Accordingly, the Reporting Subcommittee will have to coordinate closely with the other subcommittees and require their input, almost immediately.

Areas for coordination include:

- Scope: The Scope Subcommittee will need to provide guidance on gases and sectors covered (including thresholds) and points of regulation, and coordinate with the Reporting Subcommittee on developing a schedule for including sectors/sources where credible quantification methodologies are not readily available.
- Offsets: Offset reporting rules and eligibility requirements will need to be propagated to WCI partners, perhaps as a component of the reporting mechanism; reporting in some sectors might also be included in an initial model rule in order to inform baseline development for future offset development.
- Allocations: The emissions reporting mechanism, as well as future transaction processing systems, will need to be closely aligned to ensure reconciliation of emissions and allowances in determining compliance of covered sources.
- Electricity: The Electricity Subcommittee will need to provide direction to the Reporting Subcommittee on the nature and details of an approach for capturing emissions from this sector both within the WCI region and outside.

B) Scope Subcommittee

i. Mission

The mission of the Scope Subcommittee is to recommend the scope of a proposed cap and trade program. The scope must be defined so that the following are clear:

- The sectors that fall under the cap.
- The emissions sources that fall under the cap.
- The greenhouses gases that fall under the cap.
- The point(s) of regulation where the cap would be enforced.

From the scope definition, any entity or facility must be able to tell whether it has a compliance obligation under the cap, and which of its emissions are subject to the obligation.

To make this recommendation, the subcommittee must balance multiple objectives, consistent with the design principles presented above.

The subcommittee acknowledges that phasing over time may be considered, so that the program scope can encompass additional sectors, sources, or GHGs over time.

The subcommittee will examine all sectors, sources, and GHGs with the exception of the electric sector (which is being addressed in a separate subcommittee). "Sector" refers to all elements of the economy, including residential, commercial, industrial, transportation, forestry, waste management, agriculture, and others. Sources refer to the activities that create emissions, including fuel combustion, process emissions, and fugitive emissions. GHGs refer to the full set of Kyoto gases, including carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6).

ii. Tasks

Task 0: Emissions Inventory Dataset

The purpose of this task is to develop an emissions inventory dataset that the subcommittee can use in its assessment of the implications of including/excluding sectors, sources, and GHGs from the proposed scope. To support the Scope Subcommittee's deliberations, the subcommittee directs that the data include the following:

- Geography: The data are required for the WCI partner and observer states and provinces. To put the region into context, the other states and provinces in the west should be included. If possible, the states and provinces in the Western Electric Coordinating Council would be appropriate to cover, in part to be consistent with the Electricity Subcommittee work.[2] As a reference, the national totals for the United States, Canada, and Mexico would also be valuable.
- Time Period: The data should be summarized for a range of years, such as 1990-2020.
- Sectors: The data should divide the emissions into major sectors that can be considered as options for coverage.
- GHGs: The data should summarize each of the six Kyoto GHGs.

[2] The WECC includes: British Columbia; Alberta; Washington; Oregon; California; Idaho; Utah; Nevada; Arizona; New Mexico; Colorado; Wyoming; Montana; and Baja California.

The level of detail and the categories included will be driven by the available data. The data, including both emissions totals and estimates of the number of entities with potential compliance obligations, will facilitate the Scope Subcommittee's initial deliberation regarding the implications of alternative scope definitions.

Additional detail may be needed to focus on specific alternatives. For example, we may want to collect additional detailed data on emissions from industrial natural gas consumption to set a size or emissions cut off for inclusion in the scope.

Task 1: Initial Options for Consideration

The purpose of this task is to define a short list of major options that will be considered. While there is a very broad range of possibilities, several realities narrow the field, including (*inter alia)*:

- The significance of sectors/sources in the overall inventory (regionally, and within individual states/provinces);
- The inability to measure/monitor emissions adequately to support inclusion in a cap and trade program (e.g., some fugitive emissions and certain process emissions);
- The existence of reasonable points of regulation capable of addressing the sector/sources;
- The existence or expectation of other regulatory approaches for the source/sector.

There are multiple resources available to use for this task, including the Market Advisory Committee (MAC) Report from California,[3] U.S. EPA Guidance on the design of cap and trade programs,[4] the Nicholas Institute report on reporting thresholds for greenhouse gas emission regulation,[5] and many academic and related reports.

The output from this task will be a set of three to five major options that will be evaluated more thoroughly. Table 1 provides an initial list of options for program elements that can be used to initiate the Scope Subcommittee's discussions. This list was developed based on a review of background material regarding the design of cap-and-trade types of programs for greenhouse gases. The list includes most, if not all, of the major program elements that have been discussed in recent years.

Each of the options in Table 1 defines a set of sources and GHGs that may be considered for coverage. Some of the elements can be combined into a program that covers multiple elements, while others are mutually exclusive and cannot be combined. In all cases, the consideration of options for covering the electric sector is deferred to the Electricity Subcommittee.

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[3] *Recommendations for Designing a Greenhouse Gas Cap-and-Trade System for California*, Recommendations of the Market Advisory Committee to the Air Resources Board, available at: http://www.climatechange.ca.gov/documents/index.html.
[4] *Tools of the Trade: A Guide To Designing and Operating a Cap and Trade Program For Pollution Control*, U.S. Environmental Protection Agency, available at: http://www.epa.gov/airmarkets/resource/cap-trade-resource.html.
[5] *Size Thresholds for Greenhouse Gas Regulation: Who Would be Affected by a 10,000-ton CO2 Emissions Rule?*, the Nicholas Institute for Environmental Policy Solutions, Duke University, available at: http://www.nicholas.duke.edu/institute/knowledge-energy.html.

Table 1 represents a starting point for discussion. Additional options may be defined and considered as part of the subcommittee deliberations, and through public input and comment.

Task 2: Description of Each Major Option

The purpose of this task is to prepare detailed descriptions that flesh out each of the major options being considered. The descriptions would include:

- General description of the option, including the sectors, sources, and GHGs covered, and the point(s) of regulation.
- Estimate of the portion of the total emission inventory included, with estimates for each state and the region as a whole.
- Estimate of the number of entities expected to have compliance obligations, by state and for the region as a whole. If possible these data should be estimated by sector.
- Assessment of the potential interactions with other regulatory initiatives or programs, including other initiatives reducing GHG emissions.
- Administrative complexity and burden.

The output from this task will be a detailed description of each major option, which will be released for public review and comment.

Task 3: Option Evaluation

The purpose of this task is to evaluate each of the major options using the detailed descriptions. The program design principles will be the starting point for the evaluation criteria to use. Additional criteria may be identified by the subcommittee and may come from public input and comment. Prior to evaluating the options, the subcommittee will produce a public review draft of the evaluation criteria for review and comment.

This evaluation will consider whether there is flexibility for states/provinces to vary in their implementation of the option. This evaluation will identify those aspects for which flexibility is possible, and those aspects for which identical implementation is necessary.

The output of this task will be a summary evaluation of the pros and cons of each of the major options, which will be released for public review and comment.

Task 4: Option Recommendation

The purpose of this task is to develop a consensus recommendation from the Scope Subcommittee. The draft of the recommendation will be presented for public review and input, including the factors that were important in making the decision.

iii. Coordination with Other Subcommittees

There are several key points where the Scope Subcommittee will need to coordinate with the other subcommittees:

- The Scope Subcommittee's assessment of which sources can be measured/monitored adequately for purposes of inclusion in a cap and trade program should be consistent with the Reporting Subcommittee's findings on which sources can report emissions.
- Prior to making a recommendation, we will review the Scope Subcommittee's major options with the Electricity Subcommittee to identify any inconsistencies or conflicts.
- The Offsets and Allocations Subcommittees require an understanding of the major options under consideration by this subcommittee.

Table 1: Initial Program Design Elements for Public Comment and Discussion

Elements	Sectors[1]	Sources	GHGs	Comments
A. Large stationary combustion sources regulated at the point of emission.	All large stationary sources, including oil refining and other industrial facilities.	Fossil fuel combustion in stationary equipment only.	CO_2 only. Could be expanded to other combustion related GHGs (N_2O and CH_4).	This is a downstream option, similar to traditional pollution control programs. Typically an emissions threshold is used to exclude small sources.
B. Liquid fuels (**i.e., transportation fuels)** regulated upstream where they enter into commerce (i.e., upstream at the "terminal rack" or the point of refining or import of refined products).	This can be focused on transport sectors, including fossil fuels used in some or all of: on-road vehicles; off-road vehicles; air; marine, rail.	Liquid fossil fuel combustion.	Addresses CO_2 emissions. (Indirectly affects N_2O and CH_4 emissions from fuel combustion.)	Upstream approach to capture the transport sector. Note: some liquid fuels are used both in transport and stationary sources. Note also: gaseous fuels and electricity also used in transport.
C. Residential and commercial natural gas combustion regulated at the local distribution company (LDC).	Residential and commercial customers of LDCs.	Natural gas combustion only.	CO_2 only. (Indirectly affects N_2O and CH_4 emissions from natural gas combustion.)	This is a midstream option for covering residential and commercial combustion sites that are too small to be considered large stationary combustion sources.
D. Industrial process and waste management emissions regulated at the point of emission.	Specifically defined industrial processes, such as oil refining, cement production, aluminum smelting, adipic acid production, nitric acid production, lime production, natural gas transmission and distribution, wastewater treatment; landfill operations; others.	Specific industrial processes.	GHG relevant to each industrial and waste management process.	Downstream option to cover process emissions that can be measured or computed reliably. Wide variety of facility types.
E. Fossil fuel industry regulated at the "facility" level, such as a production field, pipeline, coal mine, or other.	Oil and gas exploration, production, gathering, and processing. Coal mining.	Fugitive and vented emissions. May include emissions from flaring if not covered elsewhere.	CO_2, CH_4	Includes exploration activities, oil and gas production wells, gathering pipelines, gas processing plants and related facilities (such as dehydrators), coal mine ventilation, coal processing.

Elements	Sectors[1]	Sources	GHGs	Comments
F. Fossil carbon content of fuels regulated at the appropriate upstream or midstream choke point for the fuel.	All sectors that use fuels with fossil carbon.	Fossil fuel combustion.	CO_2 only. (Indirectly affects N_2O and CH_4 emissions from fossil fuel combustion.)	"Choke point" option, primarily considered upstream, to cover all fossil carbon emissions.
G. Passenger cars and light duty trucks regulated at the manufacturer sales level.	Transportation sector, covering passenger cars and light duty trucks.	All GHGs from the use of the relevant vehicles, including fuel combustion and refrigerant fugitive emissions.	CO_2, CH_4; N_2O, HFCs	Tradable emission caps associated with the vehicles sold by the manufacturer. May be incompatible with the vehicle emissions intensity standards adopted by CA and others. Requires estimates of vehicle emissions when sold.
H. Large transportation fleets regulated at the fleet management level.	Transportation.	Fossil fuel combustion from fleet vehicles (could be defined as on-road only).	CO_2 only. Could be expanded to other combustion related GHGs (N_2O and CH_4).	This is a focused downstream transport sector option, treating "fleets" like large stationary sources.
I. Agriculture emissions regulated at the producer or "farm" level.	All agricultural sectors.	Livestock, soils (does not include fuel combustion emissions)	CO_2; CH_4; N_2O	Most emissions are diffuse and not conducive to measurement and quantification at the farm level.
J. Forestry and land use change emissions regulated at the land owner level.	Forested lands owned privately and publicly (could be segmented by ownership).	Change in carbon stock on the land.	CO_2	Requires protocols to measure changes in carbon stock relative to baseline conditions over time.
K. Production of high GWP gases regulated at the point of production.	Chemical manufacturing, particularly HCFC-22 production.	Fugitive process emissions.	High GWP gases	Small number of production facilities nationally and internationally.
1. Under all options, the Electricity Subcommittee is assessing how best to cover the electric sector.				

C) Electricity Subcommittee

i. Mission

The mission of the WCI Electricity Subcommittee is to recommend a point of regulation, a market-based compliance mechanism design, and an accounting structure to incorporate the electricity sector into a proposed cap-and-trade program.

ii. Tasks

The Electricity Subcommittee proposes to take on the following tasks:

1. Recommend whether and how an electricity sector market mechanism should include greenhouse gases beyond CO_2.
2. Gather and share information for each partner jurisdiction on (a) historical and projected future sales and emissions from the electricity sector within the partner jurisdiction, (b) historical and projected future electricity imports into the partner jurisdiction, and (c) available data concerning the emissions and ownership attributes of the imported electricity.
3. Establish criteria, evaluate, and propose cap-and-trade compliance option(s), including the point of regulation and compliance structure (e.g., first-seller, hybrid load/source, load based, etc.). Options would focus on structures that maximize coverage of emissions attributable to electricity consumed in the partner jurisdictions, facilitate end-use energy efficiency, and meet other criteria determined by the group.
4. Based on the compliance structures evaluated, develop a consistent regional inventory methodology for CO_2 emissions from the generation of electricity that does not lead to double counting of emissions (e.g. overlapping claims) and provides a robust baseline for a cap-and-trade system.
5. Propose detailed design elements specific to an electricity sector cap-and-trade structure, including those design elements that should be consistent across states and provinces.

iii. Emissions Scope

Electricity sector emissions are tentatively defined as the greenhouse gas emissions from all generating plants that serve WCI Partners, including generation outside the borders of the WCI Partners that serve end users in WCI states and provinces.

iv. Coordination with Other Subcommittees

This committee will work closely with the Scope Sub-Committee, but as a starting point for the work of this committee we will assume the Scope Sub-Committee will not recommend upstream regulation at the point of entry of fossil fuels into the WCI region. However, this possibility is recognized. For example, the WCI Partners might choose to regulate upstream CO_2 and methane emissions from facilities that provide fuel for generating plants (e.g., coal mines and liquefied natural gas import facilities).

Close coordination with the Allocation Sub-Committee will also be needed. An electric cap-and-trade design proposal, the potential allocation of free allowances and the potential distribution of revenues from allowance auctions could affect the distribution of benefits and costs among the WCI Partners if such a system were implemented. Also, allocation decisions could affect the program's ability to accomplish end-use energy efficiency, a key element in reducing greenhouse gas emissions from the electric sector.

Finally, the accounting structures and methodologies evaluated (proposed), as well as cap-and-trade designs, will have numerous implications for the Reporting Committee.

<u>D)</u> ***<u>Allocations Subcommittee</u>***

i. Mission

The mission of the WCI Allocation Subcommittee is:

1. To recommend a methodology for determining the number of allowances to be apportioned, either individually to each WCI partner and thereby establishing each Partner's overall emissions allowance budget for the WCI program, or regionally for the WCI region overall; and
2. To determine whether to recommend that the Partners establish a common method for distributing the budgeted emissions allowances (a) among covered sectors; and (b) within each sector to covered entities. If a common allowance distribution method is recommended, the Subcommittee will recommend a distribution method or methods for consideration by the WCI Partners.

ii. Tasks

To accomplish its mission, the Subcommittee proposes to take on the following tasks:

1. Identify the Subcommittee's preliminary information needs.
2. Before deliberating on potential options for establishing the budgeted allowances (for either the WCI region overall or each individual Partner), and recommending whether and how to distribute allowances within covered sectors and entities, the Subcommittee will develop recommended design principles to guide the Subcommittee in its deliberations.
3. Determine whether an allowance budget should be established for each WCI Partner individually or whether a regional allowance budget should be set for the WCI region overall with allowances allocated to sectors within the region.
4. Develop and recommend a methodology for determining the amount of overall allowances to be apportioned either regionally or to each WCI Partner's allowance budget.
5. Determine whether and what to recommend concerning how individual allowance budgets should be divided among individual sectors within the WCI region or each Partner jurisdiction (i.e. establish specific allowance budgets for each sector within each the WCI region overall or each Partner jurisdiction.
6. Determine whether and what to recommend concerning how allowances are distributed, either by each Partner throughits allowance budget(s) or regionally by sector within the WCI region overall, including:
    - Examine existing approaches and evaluate, at a minimum, the following options: distribution by:
        - free allocation;
        - auction; and
        - a hybrid of free allocation and auction.

- If a free allocation methodology is recommended in whole or in part:
    - Recommend the parties to whom the allowances will be allocated (i.e., emitters only, consumers, product generators/producers, and/or governmental entities);
    - Recommend a formula for calculating the allowances to be allocated to each covered entity, considering:
        - The factors on which the allocation of allowances should be based (i.e., emissions, fuel or other input, product output and/or some other benchmark); and
        - The baseline for the allocations (i.e., based on a single year emissions, an average of multiple years' emissions, or the maximum emissions over a period of years) and whether the baseline should be updated periodically.
- If an auction is recommended, in whole or in part:
    - Recommend the percentage of allowances to be auctioned;
    - Recommend criteria/parameters for uses of the funds generated by the auctions; and
    - Recommend such other auction design parameters as the Subcommittee deems appropriate, for example a reserve price, specific timing of auctions and/or eligibility for participation in the auctions, etc.

7. Determine whether the method used for allocating allowances (i.e. free, auction or hybrid) should be the same for all sectors or may/should vary by sector.

8. Determine whether the amount of allowances allocated to each sector and/or WCI Partner should decline, and if so, at what rate and pace.

9. Determine whether and what to recommend concerning how appropriate recognition and incentives for early emissions reductions can/should be considered in distributing allowances.

10. Determine whether banking of allowances should be permitted, and if so, the criteria and condition for banking, including:
    - The length of time for which allowances may be banked; and
    - The amount of allowances that may be banked;

11. Determine whether borrowing of allowances should be permitted, and if so, the criteria and condition for borrowing, including:
    - The length of time for which allowances may be borrowed;
    - The amount of allowances that may be borrowed; and
    - The rate of repayment of borrowed allowances (i.e., 2 for 1)

iii. Working Process

General Approach

- Subcommittee members and technical staff will develop one or more working documents to frame and evaluate various options for apportioning Partner allowance budgets and allocating emissions among covered sectors and entities within Partner jurisdictions.
- A plan for soliciting input from stakeholders will be developed in connection with the pending discussion on stakeholder involvement by the committee as a whole.
- The subcommittee will forward one or more straw proposals and will include an evaluation of the preferred and other options for the WCI Partners to consider.

iv. Gathering Information Gathering and Support Resources

- Data. Regarding apportionment to each state, and after conferral with the Scope Subcommittee, the baseline emissions for all Partners from the proposed sectors to be developed with the data group. A series of allocation algorithms will allow members to look at the allocations in various ways.
- Expertise. The group will generate a list of useful experts to offer presentations on a bi-weekly basis (as needed). Include discussions with people with expertise in other emissions trading systems: for example, the U.S. EPA Acid Rain Program, the Northeast NOx Emissions Trading Program, the Irish program,, the UK Emissions Trading Scheme and also their auction experience, RGGI, the EU/ETS.
- Consultants. The subcommittee will identify projects and consultants that it may need to perform its missions and develop a proposed subcommittee budget that identifies the potential costs for this assistance.

v. Coordination with Other Subcommittees

- The Allocations Subcommittee will need to work closely with the Scope Subcommittee, to settle on the sectors among which reduction targets will be set based on which sectors are included in the program.
- The Allocations Subcommittee will also need also need to work jointly with the Electricity Subcommittee.

E) Offsets Subcommittee

i. Mission

The mission of the WCI Offsets Subcommittee is to make recommendations on whether to include a greenhouse gas offset mechanism as an element of the Western Climate Initiative cap and trade system, and, if so, on the design, scope and operation of such a mechanism.

ii. Tasks

Task 1: Role and objectives of a WCI offset mechanism

This task involves the development of clear definitions of an offset, the role of a WCI offset mechanism, and the objectives that will guide its design in the overall WCI cap-and-trade system.

The subcommittee will examine a number of potential roles an offset mechanism could play in the WCI including economic, environmental and social aspects of a cap and trade system that may influence or be influenced by an associated offset mechanism. Potential roles may include:

- Encouraging emission reductions and other benefits across the economy
- Distributing economic and environmental benefits of emission reductions across the economy
- Enabling the Partners to achieve more aggressive reduction targets than would otherwise be technologically or economically possible at capped entities alone
- Containing overall costs and competitiveness concerns for emitters and WCI partners
- Maintaining or enhancing the environmental integrity of the regional cap and trade system.

The subcommittee will also review and determine design objectives that should guide the development of a potential WCI offset mechanism and may include:

- Spurring innovation outside the regulated sectors
- Providing incentive for partnership in the WCI
- Enhancing market liquidity
- Minimizing administrative complexity, fees and transaction costs (managing barriers to entry)
- Providing environmental and social co-benefits
- Ensuring transparency
- Avoiding unintended outcomes, including negative interaction with current and future government policies

As part of this task, the subcommittee will also outline broad options that could frame the overall role and contribution of offsets to meeting compliance obligations and containing overall costs, including whether and what types of quantitative limits might be considered.

Task 2: Core design elements of a WCI offset mechanism

This task involves the development of specific technical criteria and/or requirements for projects that may be eligible in the WCI offset mechanism, and to translate into practice the WCI design principle that reductions be real, surplus/additional, verifiable, permanent, and enforceable.

The subcommittee will review potential design elements and optional aspects of those design elements including:

- Components to ensure reductions are real
- Ways to show projects or actions satisfy the principles of being surplus to other requirements and additional/incremental
- Methods to measure quantify and report emission reductions (baseline and monitoring methodologies)
- How to establish the boundary of a project and ways to account for leakage or increases in emissions outside the boundary
- How long carbon must be stored, biologically or geologically, to be considered permanent, and what tools and procedures should be used to address the loss of stored carbon from offset projects
- Ways to simplify accounting and use comparable accounting approaches across project types
- Ways to provide adequate assurance that project activities and emissions reductions or removals are taking place as claimed (validation and verification)

The subcommittee has anticipated some of the basic design criteria that will need to be reviewed and will seek input on additional design criteria as required and considered.

Task 3: Offset eligibility and fungibility

This task involves the development of any specific criteria and/or requirements that will determine the offset project types and locations, and, if relevant, other existing tradable emission commodities from other regional or international programs that would be eligible within the overall system.

The subcommittee will review a) offset project types and locations (WCI region, North America, global) and b) existing tradable emissions commodities with respect to the robustness of quantification and verification protocols, environmental integrity (permanence, leakage, incrementality/additionality), potential interaction with existing and future policies and regulations, and ability to contribute to WCI goals and principles. As part of this review, the subcommittee will examine the eligibility decisions taken in other mandatory compliance jurisdictions and their rationale. The subcommittee will also review options for eligible project start dates, and the crediting periods over which the project developers can expect to benefit from offset revenues.

Decision options may include one or more of the following:

- Determination of offset type (or commodity) eligibility subject to the availability of sufficiently robust quantification and verification protocols.
- Specification of the process by which the adequacy of protocols is determined, i.e. by the WCI itself or by other programs or standards (see also Task 4).

- Preferences and/or restrictions on eligible project and commodity types and/or locations, based on goals, principles and design elements (as developed in the Tasks 1 and 2), in addition to the robustness of protocols. (The subcommittee may also consider the possibility of rewarding or discounting specific project types or locations)
- Determination of eligible project starting date, i.e. the earliest date at which the implementation of a project activity could begin (or have begun) in order to qualify.
- Establishment of offset crediting periods, specifying the time period over which project emission reductions would be verified and/or certified, and, if relevant, offset credit expiration dates

Task 4: Offset program structure and authority

This task involves the development of operational guidelines and recommended program structure and authority to oversee and manage an offset mechanism, if and as appropriate depending on the recommendations developed above regarding the extent to which the WCI should administer its own offset program or to otherwise develop specific (e.g. minimum) criteria.

The subcommittee may consider, among other issues:

- Procedures for project validation and verification, approval of validators/verifiers, and whether appropriate and sufficient protocols are currently available.
- The process for registering and/or certifying offsets, issuing credits and maintaining transaction records
- How initial and ongoing operational questions, such as adequacy of project documentation, certification or accreditation of operational entities would be addressed and decided, including which activities should be left to third parties or other institutions.
- The institutional requirements related to the above tasks, and how that influences the path forward

iii. Coordination with other subcommittees

The Offsets Subcommittee will:

- Coordinate with the Reporting Subcommittee in the development of validation, verification and reporting requirements for the offset mechanism;
- Reflect the recommendations of the Scope Subcommittee in the definition of offset mechanism boundaries and in determining eligible project types;
- Ensure the recommendations of the Scope, Allocation and Electricity Subcommittees do not lead to double counting, gaming or perverse incentives when implemented in coordination with the offset mechanism (or vice-versa).

October 29, 2007 Work Plan October 2007 – August 2008

List of Commenters

Acequia la Rosa de Castilla

3E Strategies, Arizona PIRG, BC Sustainable Energy Association, Climate Protection Campaign, Climate Solutions, Coalition for Clean Affordable Energy, David Suzuki Foundation, Earth Ministry of Washington, Ecumenical Ministries of Oregon, Environmental Defense, Environmental Defence Canada, Environmental Entrepreneurs/Pacific Northwest Chapter, Environment Arizona, Environment California, Environment New Mexico, Environment Oregon, Grand Canyon Trust, National Wildlife Federation, Natural Resources Defense Council, New Energy Economy, New Mexico Council of Churches, Oregon Environmental Council, Pembina Institute for Appropriate Development, Physicians for Social Responsibility, New Mexico, Renewable Northwest Project, Sightline, Union of Concerned Scientists, Utah Clean Energy, Utah Physicians for a Healthy Environment, Wasatch Clean Air Coalition, Washington Environmental Council, West Coast Environmental Law, Western Environmental Law Center, Western Resource Advocates

Alcoa, Inc.

American Forest Resource Council

APX, Inc.

Arizona Public Service Company

Association of Washington Businesses

Avista Corporation

Calpine Corporation

Center for Resource Solutions

Citizens Utility Board of Oregon

ConocoPhillips EcoSecurities

El Paso Pipeline Group

Energy Producers and Users Coalition; Cogeneration Association of California

Environmental Defense

Evergreen Energy, Inc.

Fenn, Colin R.

FPL Environmental Services

Franklin, Naomi

Goldman Sachs

Havatone

Industrial Customers of Northwest Utilities

Kretschmar, Brian

Morgan Stanley Capital Group, Inc.

Natural Resources Defense Council

Northwest Pulp and Paper Association

NW Natural

Oregon Business Association

Oregon Forest Industries Council

Oregon Municipal Electric Utilities Association

Oregon Rural Electric Cooperative Association

Oregon Small Woodlands Association

Oregon Wild

Pacific Forest Trust

Pacific Gas and Electric Company

PacifiCorp

Point Carbon

Port of Portland

Portland General Electric

Public Utility District No. 1 of Chelan County

Puget Sound Energy

Renewable Energy Marketing Association

Renewable Northwest Project

Rogel, Ty

Salt River Project

Seattle City Light

Sempra Energy

Sherback, Harvey

Sightline Institute

Snohomish County Public Utility District #1

Solid Waste Industry for Climate Solutions

Southern California Edison

Sutherland, Doug, Commissioner of Public Lands (Washington)

The Business Council for Sustainable Energy

The Climate Protection Campaign

The Climate Trust

The Independent Petroleum Association of Mountain States

The Nature Conservancy of Arizona, The Nature Conservancy of California, The Nature Conservancy of New Mexico, The Nature Conservancy of Oregon, The Nature Conservancy of Utah, The Nature Conservancy of Washington

Thermografix Consulting Corporation

TransAlta

Tri-State Generation and Transmission Association, Inc.

Tuscon Electric Power Company

U.S. Department of Agriculture, Forest Service

Union of Concerned Scientists

Van Horn Consulting

Washington Forest Protection Association

Washington Public Utility Districts Association

WEST Associates

Western Forestry Leadership Coalition

Western Power Trading Forum

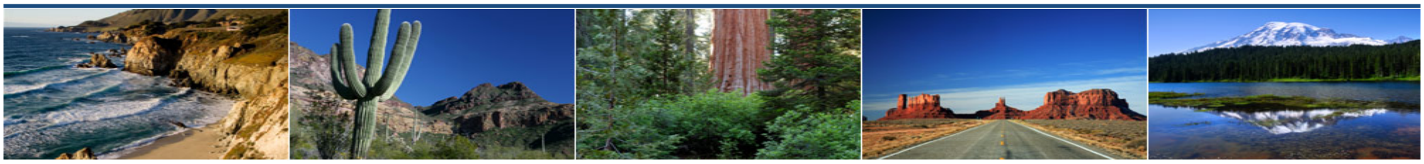
Western Resource Advocates

Western States Petroleum Association

Weyerhaeuser Company

XTO Energy

Western Climate Initiative



Allocations Subcommittee

Stakeholder Discussion Document

The WCI Allocations Subcommittee is studying the program design options governing the apportionment of allowances among the participating states and provinces, or Partners, and the distribution of allowances to covered sectors and entities. In addition, the committee is considering options for accomplishing the WCI mandate to “provide appropriate recognition and incentives for early emissions reductions.” The Allocations Subcommittee will consider additional program design requirements after guidance is received from other subcommittees on key questions currently under consideration.

The Allocations Subcommittee seeks to recommend a program design that maximizes program simplicity, minimizes unfair competition among covered industries across the region, provides for state and provincial flexibility, promotes consistent regional program standards and methods, recognizes early emissions reduction actions, maximizes the program’s GHG reduction potential and avoids undue economic impacts on consumers and industries. Some of these goals are potentially in conflict therefore the Subcommittee seeks recommendations that achieve the best balance between them.

The Allocations Subcommittee seeks Partner, observer, stakeholder and public input regarding these options. The issues and questions identified below identify several advantages and disadvantages for each option. The Subcommittee welcomes comment on these questions including additional advantages and disadvantages and other options not identified here. Commenters are encouraged to fully discuss the reasoning behind each response.

1. ***Apportionment of Allowances –*** Apportionment means the subdivision of the regional cap and trade emissions cap among the participating jurisdictions[1]. The question here is whether each Partner should be authorized to distribute allowances equal to that Partner's share of the regional cap, or, whether a regional entity should distribute allowances on behalf of all the Partners without apportioning the regional cap among them.

   a. ***Should allowances be distributed centrally, without apportionment to Partners?***

Advantages
• Reduces the need for a framework to prevent "over allocation" by Partners
• Reduces disputes between Partners over apportionment 'amounts'
• Partners establish regional and possibly sector 'cap(s)', but individual Partner 'caps' are not required
• Centralized distribution increases administrative efficiency
• Ensures equity among same-industry competitors throughout region

Disadvantages
• All Partners must agree on distribution method(s), including allocation among sectors (if required)
• Could require 'regional entity' to assume greater authority
• If allowances are sold, Partners would not have unilateral authority over the sale, and sale proceeds would go to Partners indirectly

   b. ***Or, should allowances be apportioned to, and distributed by Partners individually?***

Advantages
• Partners are free to choose the degree of distribution consistency across the region
• Allows a more conventional role for the regional organization
• Partners receive allowance sale proceeds directly

Disadvantages
• Increases the risk that inconsistent distribution methods create an unfair competitive situation among covered entities across the region
• Decentralized distribution is administratively inefficient
• Partners must agree on the basis of apportionment and potentially individual Partner 'caps'

   c. ***Or, should some combination of centralized distribution and apportionment be pursued?***

   d. ***ISSUE: The Allocations Subcommittee recognizes that centralized distribution will require more intensive cooperation and a different approach to the exercise of provincial, state and tribal authority. Comments, observations and recommendations are being sought to assist the committee with mechanisms for design and implementation of a regional allocation system.***

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[1] Each of the WCI states and provinces has adopted (or is adopting) an economy wide goal for reducing its greenhouse gas emissions. The cap-and-trade program is expected to be one of the policies used by the states and provinces to achieve their regional and individual economy-wide goals. Given that only a portion of total emissions will be covered by the cap-and-trade program, a method is required to set the cap-and-trade program cap either regionally or for each state and province.

2. ***Distribution of Allowances –*** Distribution or allocation of allowances means the process by which emissions allowances are distributed for use by covered sources under an emissions cap and trade system. The question here is to what degree distribution by the Partners should be made uniform, or standardized, among participating jurisdictions.

   a. ***Assuming allowances are distributed by Partners, should distribution methods be standardized?***

Advantages
• Reduces the need for a framework to prevent "over allocation" by Partners
• Promotes equity among same-industry competitors throughout region
• Promotes consistency among sectors throughout the region
• Promotes greater consistency among the standards and rules applied across the region

Disadvantages
• Partners must agree on distribution methods
• Partners will find it more difficult to tailor distribution methods to accommodate unique circumstances within their internal sectors
• Standardized distribution requires all Partners to secure legislative or other approvals without allowance for dissimilar results

   b. ***Assuming allowances are distributed by Partners, should distribution methods be left to each jurisdiction to decide?***

Advantages
• Partners are free to establish individual distribution methods, allowing legislatures to adopt dissimilar programs and allowing state or province-specific issues to be individually addressed
• The regional program can be enacted without the Partners agreeing on distribution methods

Disadvantages
• Increases the risk that inconsistent distribution methods create an unfair competitive situation among covered entities across the region
• Increases the risk that individual Partner distribution decisions will seek a competitive advantage for particular industries or sectors
• May require creation of regional entity with authority to approve or deny Partner distribution plans to enforce minimum standards of consistency or as a check against the concern raised immediately above

   c. ***Or, should some flexibility be allowed within prescribed limits beyond which all Partners must adopt the same distribution system?***

   d. ***ISSUE: The Allocations Subcommittee recognizes that there are many more detailed questions concerning the distribution of allowances than are asked here. The subcommittee anticipates seeking comment on these questions at a later time.***

   e. ***ISSUE: The Allocations Subcommittee recognizes the special challenges associated with the development of a regional system that could successfully merge into a future national program, and the additional complications of developing a single regional program that can accomplish this in two nations. The subcommittee seeks comments on how to ensure that the proposed and potential future programs will function well together.***

3. ***Allocation Methods –*** There are multiple ways allowances can be distributed or allocated for use by covered sources. The question here is whether and to what degree allowances should be distributed directly to covered sources free of charge.

   a. ***Assuming there is centralized distribution or at least partial standardization of decentralized distribution, should some of the allowances be distributed directly to covered entities free-of-charge?***

Advantages
• Covered entities with fixed contracts or which are otherwise unable to pass-through the allowance cost would be protected from economic hardship
• Covered entities that are price-regulated would be able to comply without seeking to pass the allowance cost along to the consumer

Disadvantages
• Partners need to develop a basis for free distribution, i.e. 'grandfathering', 'benchmarking', etc.
• Partners may need to provide some reserve or other mechanism to accommodate free distribution for new sources to avoid discouraging investment in new plants
• Many existing covered entities may reap a financial benefit without an associated benefit to consumers or GHG reductions

   b. ***Assuming there is centralized distribution or at least partial standardization of decentralized distribution, should some or all of the allowances be auctioned or otherwise sold?***

Advantages
• All covered entities compete equally for allowances
• Reduced risk of financial windfall for covered entities
• Program design is simplified
• Revenues from the auction or sale are controlled by the state or province and can be used to mitigate any financial impact of the program on consumers. Revenues can also finance investment in complimentary GHG reduction measures, research and development of promising technologies or fund other GHG mitigation or adaptation measures.

Disadvantages
• Covered entities with fixed contracts or which are otherwise unable to pass-through the allowance cost may be exposed to economic hardship

   c. ***Should the allowance distribution system have the capacity to change over the life of the program through phasing in particular distribution methods or using different distribution bases?***

   d. ***Should the Partners place restrictions on the use of revenues from auctioned allowances?***

4. ***Early Actions –*** Any cap and trade system implemented by the WCI Partners will take some time to develop, approve and implement. Sources may see a benefit in delaying investments in GHG emission reductions until the program is underway in order to take full advantage of program incentives or credits. WCI Partners wish to recognize early actions through program design and implementation. The question here is how should the cap and trade program either encourage or hold-harmless emission reductions efforts that occur prior to the start of the program. Of course, all qualifying early actions would have to be quantifiable, verifiable, enforceable and permanent.

    a. ***The WCI Design Principles state that the program will "provide appropriate recognition and incentives for early emissions reductions." Should the program accomplish this:***

        i. ***Through the selection of benchmarking and program start dates?***

        ii. ***Through special allocations of allowances?***
            1. ***Drawn from within the cap?***
            2. ***Drawn from outside the cap?***

        iii. ***Through auctioning of allowances?***

        iv. ***By other means?***

Selection of benchmarking and program start dates
• Careful selection of these dates could hold those undertaking early actions harmless, and could offer incentives to undertake these reductions in advance of the program start.

Auctioning of allowances
• If all covered entities are required to purchase allowances from the market, those undertaking early emissions reductions will avoid the need to purchase those allowances. The avoidance of this cost is an economic incentive equal to the one that exists after the program begins.

Special allocations of allowances
• Special allocations of allowances can create a financial incentive if the distribution to those undertaking early reductions occurs over and above that which otherwise occurs after the program begins. • Such special allocations can be created through an allowance set-aside under the cap, or allowances can be made available to early actors over and above the cap (as has been done by RGGI).

January 2, 2008 Allocations Subcommittee Stakeholder Discussion Document

List of Commenters

Alcoa, Inc.

American Trucking Association

Arizona Public Service Company

BC Forest Industry Working Group on Climate Change

Boise Cascade

BP America, Inc.

Business Council for Sustainable Energy

Business Council of British Columbia

California Council for Environmental and Economic Balance

California Public Utilities Commission Division of Ratepayer Advocates

Canadian Lime Institute

Center for Resource Solutions

Dynergy

El Paso Pipeline Group

Energy Producers and Users Coalition and the Cogeneration Association of California

Global Green USA

Jeld-Wen, Inc.

Johnson, Kenneth C.

Landau Associates

League of Women Voters of Washington, Energy and Climate Portfolio

The Nature Conservancy

Northern California Power Agency

Oregon Municipal Electric Utilities Association

Pacific Gas and Electric Company

PacifiCorp

PNGC Power

Public Power Council

Puget Sound Energy

Renewable Energy Marketing Association

Seattle City Light

Sightline Institute

Snohomish County Public Utility District

Southern California Edison Company

Southern California Public Power Authority

Southwest Public Service

Sustainable Energy Advantage and THR Associates

Terasen Gas

Tucson Electric Power

Union of Concerned Scientists

Washington Public Utilities Districts Association

Waste Management, Inc.

WEST Associates

West Linn Paper Company

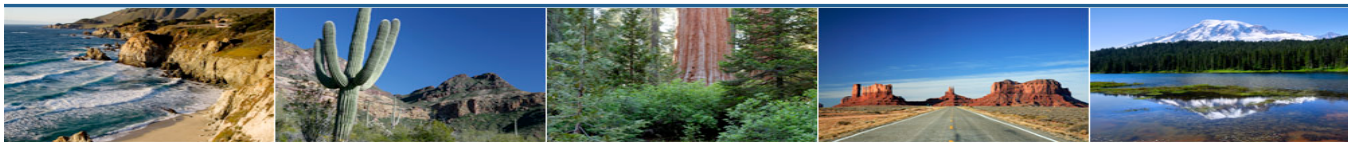
Western Climate Advocates Network

Western Power Trading Forum

Western States Petroleum Association

Weyerhaeuser

Western Climate Initiative



WCI ELECTRICITY SUBCOMMITTEE

<u>Update on Subcommittee Activities and Request for Stakeholder Input</u>
January 2, 2007

To: All Interested Parties

The Electricity Subcommittee of the Western Climate Initiative is pleased to provide this update on its activities and progress to date. The Subcommittee will be taking questions and comments on specific topics at the regional stakeholder meeting on January 10, 2008.

<u>Goals and Activities</u>

The WCI Work Plan issued October 29, 2007 calls on the Electricity Subcommittee to make recommendations to the WCI Partners on the scope and point of regulation for the electricity sector portion of a regional cap-and-trade program. To that end, the Subcommittee has undertaken the following tasks:

(1) <u>Data collection</u>. The Subcommittee has been working to assemble as much available data on electricity generation, sales and "imports" into WCI jurisdictions as possible.

(2) <u>Consideration of emissions scope</u>. The Subcommittee is considering whether and how to cover sulfur hexafluoride (SF_6) emissions from the electric sector along with carbon dioxide (CO_2).

(3) <u>Consideration of point of regulation</u>. The Subcommittee has collected information on the various electricity sector options for point of regulation, including for the following:

(a) Pure Load-based.

(b) Pure Generator-based.

(c) Hybrid system covering both generators and retail providers within the WCI jurisdiction.

(d) Hybrid system covering the “first seller” of “first deliverer” of electricity into WCI Partner jurisdictions.

The attached point of regulation table summarizes the information gathered by the Subcommittee on each of the options under consideration. Please note that table seeks to capture the arguments of both those in favor and those against a particular option. The statements in the table therefore do not represent the conclusions of the Subcommittee as a whole.

Stakeholder Input

The Subcommittee is seeking stakeholder input on the point of regulation table. Specifically, the Subcommittee seeks comments on whether the table is complete in its explication of benefits and challenges associated with each potential approach. The Subcommittee also seeks stakeholder input concerning what overall approach is best for the WCI electricity sector.

Timing for Input

The Subcommittee will receive input from stakeholders during its breakout session on January 10 in Portland, Oregon. In addition, the Subcommittee welcomes written input on the options presented in the table, and requests that input no later than January 22, 2008. Please be careful to submit comments to the attention of the WCI Electricity Subcommittee.

On behalf of the members of the Western Climate Initiative Electricity Subcommittee, we thank you for your interest in our Initiative and very much look forward to your input.

Sincerely,

/s/

David Van’t Hof
Oregon Governor’s
Chair, WCI Electricity Subcommittee

ELECTRICITY SUBCOMMITTEE

SUMMARY TABLE COMPARING DIFFERENT
APPROACHES TO ELECTRIC SECTOR CAP-AND-TRADE
(DRAFT 1/2/07)

Load-Based Approaches		**Generator-Based**	**Hybrid Approaches**	
Allowance Trading	**CO2 Reduction Credit Trading**		**Load-Generator Hybrid**	**First Seller (or Deliverer)**
1. Description of Approaches				
A load-based cap-and-trade program puts the compliance obligation on the retail electricity provider. The retail providers are required to hold sufficient allowances to cover the emissions attributable to the electricity delivered by the RP to its retail customers. *It does not cover exports and may or may not cover self-generation.*	*A load-based CO2 crediting program that does not cap emissions, but rather credits emissions reductions at generating plants in the western interconnect region. Retail providers are then required to retire a certain number of the credits, thereby achieving reductions compared to base year emissions.*	*A generator-based cap-and-trade program places the compliance obligation on the generator of the electricity and the source of emissions. Generators must hold sufficient allowances to cover all of the emissions measured and monitored at each facility.* *It covers all generation within the jurisdiction, including self-generation; it does not cover imports. No jurisdiction over generators on tribal lands.*	*A load-generator hybrid cap-and-trade program combines the key features of the load-based and generator-based cap-and-trade programs. It places the compliance obligation on the generators in the jurisdiction and on the load-serving entities for power originating outside the jurisdiction. Both the generators and retail providers are required to hold sufficient allowances to cover the emissions measured at the stack in the case of the generators, and attributed to the electricity imported in the case of the retail providers.*	*A First Seller cap-and-trade program places the compliance obligation on the first entity to sell electricity in the jurisdiction, whether the electricity was generated inside or outside the jurisdiction. This is either the generator who generates the electricity in the WCI state or province, or the entity selling the electricity brought into the WCI jurisdiction from outside the state or province. The First Seller is required to hold sufficient allowances to cover the emissions measured at the stack in the case of generators, or attributed to the electricity in the case of first sellers.*
2. Where have these approaches been implemented or designed?				
No load-based cap-and-trade programs have been implemented, but designs have been developed in Oregon and California. A description of	*Functions very much like mandatory renewable portfolio standard with renewable energy credit trading.* *A description of this approach is*	*Generator-based cap-and-trade programs have been used to reduce sulfur dioxide and nitrogen oxides emissions from power plants nationally, in the*	*No load-generator hybrid has been implemented, though the RGGI states are exploring ways to implement a load-based program to cover imports*	*The First Seller concept was introduced by the California Market Advisory Committee in its report issued in the spring of 2007. California PUC staff has*

Load-Based Approaches		Generator-Based	Hybrid Approaches	
Allowance Trading	**CO2 Reduction Credit Trading**		**Load-Generator Hybrid**	**First Seller (or Deliverer)**
Oregon's design may be found at: *http://www.oregon.gov/ENERGY/GBLWRM/docs/CATF_Proposal.pdf*	*available* *http://www.westernclimateinitiative.org/ewebeditpro/items/O104F14498.pdf*	*Northeast states, and in Ontario. The EU ETS is the first generator-based cap-and-trade program to be implemented for* CO_2*, and RGGI will be the second such program. Information on RGGI is available at www.rggi.org.*	*alongside a generator-based program.*	*been further refining the concept, and has introduced the term "deliverer" as more accurate and descriptive. A copy of the MAC report is available at:* *http://www.climatechange.ca.gov/documents/2007-06-29_MAC_FINAL_REPORT.PDF*
3. What do proponents consider are the key advantages of each program approach? What disadvantages have been noted for each approach?				
Advantages: ▪ Covers all power delivered through the retail provider including both in-jurisdiction generation and imported power ▪ Retail providers are often in the best position to make investments in energy efficiency, with or without a trading component. ▪ Energy regulatory structure exists for oversight in most states. ▪ Some have suggested that retail providers are regulated to keep prices no higher than necessary, unlike merchant generators, whose prices are set by the market. ▪ A successful WCI load-based program could influence a future federal program.		***Advantages:*** ▪ This approach is relatively proven through experience ▪ Emissions inventory structure exists, and emissions can be measured and tracked with high confidence and transparency. No need for default emissions values. ▪ Generators may be in the best position to make technology changes or upgrades to address	***Advantages:*** ▪ Seeks to cover the gaps of both the generator and load-based approaches by placing point of regulation on both generator emissions and emissions from imports at the retail provider level. This allows each state to account for as many emissions as possible within the sector. ▪ Advantage over a pure load-based approach is that it addresses in-state generation more completely and can cover exports. ▪ Advantage over a pure generator-based approach is that it covers imports. ▪ Provisions for generator-based emissions in a hybrid approach could ease transition to a source-based national program, and facilitate linkage to other programs (e.g., RGGI, EU ETS)	

Load-Based Approaches		Generator-Based	Hybrid Approaches	
Allowance Trading	CO2 Reduction Credit Trading		Load-Generator Hybrid	First Seller (or Deliverer)
	Advantages: ▪ May not require emissions attribute tracking ▪ Similar to renewable energy credit trading	carbon emissions. ▪ Easily linked to other existing programs in the U.S. and internationally. ▪ Clear state or provincial-wide emissions baseline to protect sources in the event of a federal program.		
Disadvantages: ▪ Does not cover electricity generated within a jurisdiction for out-of-jurisdiction consumption ▪ Not likely to be adopted on national level, making transition to federal program tricky ▪ Some international programs may not consider load-based reductions the equivalent of generator-based reductions ▪ Some regulatory gaps may exist with retail providers not under PUC jurisdiction		***Disadvantages:*** ▪ Only covers in-state or in-province emissions from power generation; imports not covered, including “imports” from tribal lands. ▪ If not auctioned, free allowances to the generator may not stimulate end-use energy efficiency and may also create windfall profit opportunities.	***Disadvantages****:* ▪ Complexity: design of the program requires both a generator-based component and an imports component. ▪ In regional context, special care is needed to avoid double-counting of emissions from capped jurisdictions.	

Load-Based Approaches		Generator-Based	Hybrid Approaches	
Allowance Trading	**CO2 Reduction Credit Trading**		**Load-Generator Hybrid**	**First Seller (or Deliverer)**
***Disadvantages**:* ▪ Difficult to accurately track emissions associated with power delivered from out-of-jurisdiction sources and from purchases from power pools or short-term transactions. Default values may create distortions.	***Disadvantages**:* ▪ Does not cap emissions *per se*; regulator must adjust credit retirement requirements to ensure overall reductions ▪ Need to have regional authority create and issue credits or states would have to agree how to allocate CO2RCs to generators outside WCI jurisdictions, making state-by-state adoption more difficult ▪ Potentially large transfer of wealth to generating plants outside region; approaches to deal with this are complicated			***Disadvantages**:* ▪ A potential gap exists in the first seller approach where the federal government is the first seller.

<table>
<tr><th colspan="2">Load-Based Approaches</th><th rowspan="2">Generator-Based</th><th colspan="2">Hybrid Approaches</th></tr>
<tr><th>Allowance Trading</th><th>CO2 Reduction Credit Trading</th><th>Load-Generator Hybrid</th><th>First Seller (or Deliverer)</th></tr>
<tr><td colspan="5">4. What specific factors can affect the relative cost-effectiveness of each approach (i.e., lowest reduction cost at lowest price to consumer)?</td></tr>
<tr><td colspan="2">▪ <u>Regulatory oversight</u>: Most retail provider electricity rates regulated under utility commissions in states and provinces
▪ <u>Regulatory incentives</u>: Retail providers have a direct incentive to invest in energy efficiency and non-fossil generation
▪ <u>Regulatory barriers</u>: interconnection charges, stand-by rate barriers, etc.</td><td rowspan="2">▪ <u>Distribution of allowances</u>: Electricity prices for wholesale power from merchant plants are not regulated. Free allowances would not lower wholesale prices paid by retail providers; however if allowances are auctioned, energy efficiency investments administered by utility (or other entity) could lower costs
▪ <u>Generator-based incentives</u>: to invest in technology changes or upgrades
▪ <u>Administrative costs</u>: may be comparatively lower than other approaches due to existing monitoring and reporting requirements</td><td colspan="2" rowspan="2">▪ <u>Regulatory oversight</u>: Most retail provider electricity rates regulated under utility commissions in states and provinces
▪ <u>Incentives</u>: placed both at the generator level and at the LSEs or first seller (deliverer) level.
▪ <u>Administrative costs</u>: Trading administrator would need to administer the program for both generator-based and load-based entities</td></tr>
<tr><td>▪ <u>Perverse incentives</u>: For wholesale power purchases assigned non-specific emission rates, plants supplying this power may face incorrect incentives</td><td></td></tr>
</table>

<table>
<tr><th colspan="2">Load-Based Approaches</th><th rowspan="2">Generator-Based</th><th colspan="2">Hybrid Approaches</th></tr>
<tr><th>Allowance Trading</th><th>CO2 Reduction Credit Trading</th><th>Load-Generator Hybrid</th><th>First Seller (or Deliverer)</th></tr>
<tr><td colspan="5">5. Will the model effectively cover emissions associated with all of the power consumed in the WCI jurisdictions (i.e., generated and imported)?</td></tr>
<tr><td colspan="2">▪ Would cover electricity sold in WCI jurisdictions by retail providers.</td><td rowspan="2">▪ Would cover generation in the WCI jurisdictions.
▪ Gaps in coverage include: emissions attributable to electricity generated outside WCI jurisdictions and imported to serve WCI load.
▪ May lead to incremental increases in imported electricity above current levels (i.e. leakage).</td><td rowspan="2">▪ Would cover electricity sold in WCI jurisdictions by retail providers and cover generation in the WCI jurisdiction.
▪ Gaps in coverage include: emissions that are “shuffled” to serve load outside the WCI jurisdiction. Similar to load-based system except that in-jurisdiction generation issues should be resolved.</td><td rowspan="2">▪ Would cover electricity sold in WCI jurisdictions by regulated first sellers and cover generation in the WCI jurisdiction.
▪ Gaps in coverage include: emissions attributable to power sold and delivered by the U.S. federal government (e.g., BPA, WAPA) and, for the states, by foreign government-owned corporations (e.g., Powerex, Comisión Federal de Electricidad).</td></tr>
<tr><td>▪ Gaps in coverage include: non-specific generation in WCI jurisdictions; generation in WCI jurisdictions that serves load outside WCI jurisdictions; and emissions that are “shuffled” to serve load outside the WCI jurisdiction.</td><td>▪ Does not cap emissions per se; requires periodic adjustment to account for growth in electricity demand WECC-wide</td></tr>
<tr><td colspan="5">6. How would the model position WCI jurisdictions and their sources when national programs emerge in the United States and/or Canada?</td></tr>
<tr><td colspan="2">▪ Load-based model for the electricity sector is not transferable to other sectors.
▪ No federal proposals follow the load-based approach, though this could change.</td><td>▪ Generator-based model is transferable to other sectors.
▪ Most federal proposals focus on emitters (generators), though this could change.</td><td colspan="2">▪ Covering all power delivered through the retail provider allows coverage of both native generation and imported power.
▪ The two-component model makes keeping the generator-based component and phasing out the load-based component in the future a viable option.</td></tr>
</table>

Load-Based Approaches		Generator-Based	Hybrid Approaches	
Allowance Trading	**CO2 Reduction Credit Trading**		**Load-Generator Hybrid**	**First Seller (or Deliverer)**
7. Does the model present specific issues related to the allocation of emissions allowances?				
▪ Energy regulatory agency can prevent a regulated entity from charging for an allowance that it receives at no charge; allocations at no charge to regulated entities therefore possible without charge to consumers.				
▪ No need to auction to prevent windfalls to regulated retail providers, though other reasons to auction may exist.	▪ Proposal suggests that some credits could be sold to prevent transfer of wealth to generators outside WCI	▪ Auction of allowances may be required for those suppliers whose rates are not regulated to prevent increased revenues associated with "free" allowances. ▪ In lieu of auction, a direct allocation to energy efficiency providers or consumers is possible to prevent windfall. ▪ In the case of an auction, long-term electricity power purchase agreements may not allow generator to pass on cost of allowances to power purchaser.	▪ Need to devise allocation method that addresses both generators and retail providers.	
8. Does the model have implications for linking with other programs in North America and internationally?				
▪ Not clear whether load-based allowances or credits would be transferable or valid in other markets. ▪ The lack of transparency between emissions and compliance points may be a challenge.		▪ EU ETS follows emissions source model for all sectors. ▪ RGGI follows emissions source approach.	▪ Generator-based component very similar to existing programs. Load-based component could be seen as additional to what other systems provide. ▪ Load-based allowances may not be transferable or valid in other markets	

<table>
<tr><th colspan="2">Load-Based Approaches</th><th rowspan="2">Generator-Based</th><th colspan="2">Hybrid Approaches</th></tr>
<tr><th>Allowance Trading</th><th>CO2 Reduction Credit Trading</th><th>Load-Generator Hybrid</th><th>First Seller (or Deliverer)</th></tr>
<tr><td colspan="5">9. What are the key practical challenges specific to design and implementation of each model?</td></tr>
<tr><td colspan="2">▪ Price of carbon not included in market price – retail providers must track prices and allowances separately which could increase cost and administrative burden. NOTE: this is not necessarily true[1]
▪ New system required to track and report emissions and trades
▪ Need to distinguish co-generation emissions for electricity versus thermal load</td><td rowspan="2">▪ Most design issues have been covered in existing programs as to emissions sources.
▪ Emissions associated with imports and leakage are still being addressed by RGGI.</td><td rowspan="2">▪ Same issues presented by load-based system.
▪ Need to integrate the generator-based program with the load-based component.
▪ Legal challenges may be most difficult in order to treat power equally between two completely separate components.
▪ New system required to track and report emissions and trades</td><td rowspan="2">▪ Need to understand who are the first sellers for each jurisdiction that can be regulated, and what impacts result from not being able to regulate some first sellers.
▪ Unique legal issues may apply since this would include a new class of regulated entities (power brokers and marketers).
▪ Existing administrative requirements to collect and maintain tracking systems may need to be revised</td></tr>
<tr><td>▪ Tracking emissions associated with non-specific wholesale purchases in a timely, accurate, transparent fashion
▪ Administrative determination of default emission factors</td><td>▪ Regional entity required to issue and allocate credits
▪ May have to rely on federal data reporting requirements and federal quality control, unless WCI jurisdictions imposed reporting requirements on generators as a condition to getting CO2RCs.</td></tr>
</table>

[1] The 'challenge' embodied in this item comes down to the fact that retail providers would have to evaluate 2 factors when selecting bids: the cost and the allowance, in addition to the other performance elements of a proposed resource. The greater the number of factors, the more complications in the selection. While this may not be a top issue at the moment, we should identify it so that all are aware of the issues.

10. What crosscutting considerations need to be addressed under any cap & trade approach?
▪ Emissions tracking - need system and improved reporting ▪ Linkages to other programs ▪ Leakage and contract shuffling issues ▪ Legal issues affecting interstate or international trade and commerce ▪ Interchangeability and transparency of discrete state/provincial program elements and allowances structure, i.e. what is the impact on costs and trading if states have differing targets, hence difference costs of producing allowances ▪ Allowance verification and compliance protocols among partner programs ▪ Use of allowance revenues ▪ Addressing the potential for program redundancy and double counting with related regulatory programs ▪ Inclusion of electricity transmission line losses is a cross-cutting issue.

January 2, 2008 Electricity Subcommittee Update on Subcommittee Activities and Request for Stakeholder Input

List of Commenters

American Trucking Association

Arizona Electric Power Cooperative, Inc.

Arizona Public Service Company

BC Forest Industry Working Group on Climate Change

Business Council of British Columbia

California Municipal Utilities Association

California Public Utilities Commission Division of Ratepayer Advocates

Cement Association of Canada

Center for Resource Solutions

Clark Public Utilities

Energy Producers and Users Coalition; Cogeneration Association of California

Johnson, Kenneth C.

Longview Fibre Paper and Packaging, Inc.

Morgan Stanley Capital Group, Inc.

Natural Resources Defense Council and Union of Concerned Scientists

Northern California Power Agency

Oregon Business Association

Oregon Municipal Electric Utilities Association

Pacific Gas and Electric Company

PacifiCorp

PNGC Power

Public Power Council

Public Utility District No. 1 of Chelan County

Puget Sound Energy

Renewable Energy Marketers Association

Salt River Project

Sierra Club and Sierra Club of Canada

Sightline Institute

Snohomish County Public Utility District #1

Southern California Edison Company

Southern California Public Power Authority

Southwest Public Service

Tucson Electric Power Company

United States Environmental Protection Agency Office of Atmospheric Programs

Washington Public Utility Districts Association

WEST Associates

West Linn Paper Company

Western Climate Advocates Network

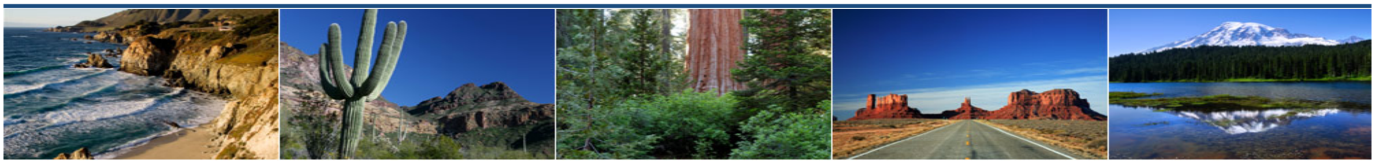
Western Power Trading Forum

Western Resource Advocates

Western States Petroleum Association

Weyerhaeuser Company

Western Climate Initiative



Scope Subcommittee

January 2, 2008

Summary of Major Design Options Under Consideration

This paper presents the major design options under consideration by the Scope Subcommittee. The mission of the Scope Subcommittee is to recommend the scope of a proposed cap-and-trade program, defining:

- The sectors that fall under the cap-and-trade program.
- The emissions sources that fall under the cap-and-trade program.
- The greenhouse gases that fall under the cap-and-trade program.
- The point(s) of regulation where the cap-and-trade program would be enforced.

To develop options for the program scope, the Scope Subcommittee defined individual design elements for consideration. The list of the design elements was released for public review and comment as part of the WCI work plan (see www.westernclimateinitiative.org).

The Scope Subcommittee is assessing the feasibility of including the design elements as part of the program scope. A brief description of each of the design elements is presented below, starting on page 4. While each of the design elements remains under consideration, the subcommittee's preliminary analysis has been used to identify design elements that appear to be feasible to include in a cap-and-trade program in the near term. These design elements include:

- Electric sector, as defined by the Electricity Subcommittee;[1]
- Large stationary combustion sources;
- Liquid transportation fuels;
- Residential and commercial natural gas combustion;
- Residential and commercial stationary combustion of fuel oil and other liquid fuels;
- Industrial process and waste management emissions; and
- Fossil carbon content of fuels.

While the subcommittee's preliminary analysis indicates that these elements are feasible to include in the program, we note that significant administrative and potential emissions leakage issues remain to be assessed. Additionally, options for phasing in and combining the elements

[1] The Electric Subcommittee is assessing how best to include the electric sector in the program. The major options under consideration by the Electric Subcommittee are reported separately.

must be considered. These issues are being examined through the subcommittee's continuing analysis and assessment.

Combinations of the feasible design elements are presented as five major design options below. These options indicate how the elements could be combined to create a cap-and-trade program with varying levels of coverage. Option 1, with the narrowest scope, would cover the electric sector, large fossil fuel stationary combustion sources, and large industrial process emissions. Option 3 has a significantly broader scope by also including liquid transportation fuels and fossil fuel stationary combustion in the residential and commercial sectors. Option 5 represents an alternative approach, focusing on the fossil carbon content of all fuels.

The subcommittee's preliminary analysis has indicated that several design elements are not likely to be feasible to be included under the cap in a cap-and-trade program in the near term. The factors indicating that these elements are not good candidates for inclusion under the cap-and-trade program are: inability to measure or calculate emissions reliably at the entity level; administrative challenges due to the large number of regulated entities; and significant vulnerability to emissions leakage. These design elements include:

- emission sources at fossil fuel production facilities for which it is difficult to measure or calculate emissions at the entity level;
- passenger cars, light duty trucks and medium duty vehicles regulated at the manufacturer;
- large transportation fleets;
- agriculture emissions and sinks;
- forestry emissions and sinks; and
- high-GWP gases regulated at the point of manufacture.

While the sectors and sources included in these design elements may ultimately not be recommended for inclusion under the cap of a cap-and-trade program, these sectors and sources may be appropriate for inclusion in an offset program, or may be addressed through other policies or measures.

By releasing this preliminary list of major design options, the Scope Subcommittee solicits public comments on these materials. Comments would be particularly appreciated on the following:

1. Feasibility: Do you agree with the subcommittee's assessment of the design elements that are feasible for inclusion in a cap-and-trade program? If not, what would you change?
2. Options: Do you agree with the range of options presented by the subcommittee? If not, what options would you add or delete?
3. Thresholds: What thresholds (e.g., tons of emissions per year) are appropriate to use to define the entities with regulatory obligations under each of the design elements?
4. Phasing: Which design elements, if any, should be phased in over time?

Major Scope Options Under Consideration as of December 2007 – For Public Review and Comment

Option 1	Option 2	Option 3	Option 4	Option 5
Electric Sector[1]	Electric Sector[1]	Electric Sector[1]	Electric Sector[1]	
A. Large stationary combustion sources	A. Large stationary combustion sources	A. Large stationary combustion sources	A. Large stationary combustion sources	
		B. Liquid transportation fuels	B. Liquid transportation fuels	
	C. Residential and commercial natural gas combustion	C. Residential and commercial natural gas combustion		
	C1. Residential and commercial stationary combustion of fuel oil and other liquid fuels	C1. Residential and commercial stationary combustion of fuel oil and other liquid fuels		
D. Industrial process and waste management emissions	D. Industrial process and waste management emissions	D. Industrial process and waste management emissions	D. Industrial process and waste management emissions	D. Industrial process and waste management emissions
				F. Fossil carbon content of fuels
1. The electric sector would be covered in a manner defined by the Electric Subcommittee.				

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A. Large Stationary Combustion Sources

1. Description

1.1 Sectors

This sector includes all large stationary combustion sources, including oil refining, cement manufacturing (including clinker production), pulp and paper manufacturing, hydrogen production, and other large combustion sources. Electric power generation is included in the Electric Sector, and is not included in this design element. An annual emissions threshold may be used to define the combustion sources considered "large." Various thresholds have been defined in other programs (such as mandatory greenhouse gas reporting programs). A threshold has not yet been selected for this design element, and is under consideration.

1.2 Emissions Sources

Fossil fuel combustion in stationary equipment only.

1.3 Greenhouse Gases

All six Kyoto gases are included. However, CO_2 comprises the overwhelming majority of the total emissions in this sector (close to 100%).

1.4 Point of Regulation

The point of regulation is the facility where the combustion emissions occur.

2. Emissions and Entity Data

Among the WCI partner states and provinces, fossil fuel combustion at industrial facilities (not including electric power generation) accounted for about 110 MMT of CO_2e in 2005, or about 11% of total gross emissions. This percentage varies from about 4% to 15% across the states and provinces.

The total number of entities that would be covered in this sector depends on whether, and at what level, an annual emissions threshold is set. Table 1 summarizes the emissions for the WCI partners.

3. Emissions at the Entity Level

Greenhouse gas emissions from fossil fuel combustion at large stationary sources can be measured or calculated with an adequate level of precision to support inclusion in a cap-and-trade program. Fuel-based calculations can generally be used to quantify CO_2 emissions, which comprise nearly 100% of the emissions for this sector. Alternatively, continuous emissions monitors (CEMs) can be used to measure emissions.

4. Administration

This sector does not pose significant administrative challenges. Regulatory agencies are able to identify most if not all the entities in this sector with compliance obligations because the facilities typically have other air emission compliance requirements. The covered entities should also have the capability to know their compliance obligations and understand the applicable requirements. The emissions from this sector are reasonably well known, so that an acceptable emission baseline can be developed.

5. Leakage Issues

Vulnerability to significant leakage varies among the facilities that would be covered under this sector. Some facilities require close proximity to their markets, so that significant leakage to locations outside the WCI region is not expected. However, others (such as the cement industry and the pulp and paper industry), may be vulnerable to leakage as their products are traded as commodities internationally. The vulnerability to leakage needs to be assessed individually for each industry.

Table 1: Summary of Stationary Combustion Source Emissions

State/Province	2005 Emissions (MMT CO_2e)	Percent of 2005 Gross Emissions
Arizona	5.2	5%
California (2004)	69.8	14%
New Mexico	3.2	4%
Oregon (2004)	7.5	11%
Utah	6.5	9%
Washington	11.0	12%
British Columbia	5.8	9%
Manitoba	1.4	7%
Total WCI Partners	**110.3**	**11%**

MMT = million metric tons

Percent of gross emissions calculated for each state/province. Estimates do not apply an emissions threshold for potentially covered entities.

Preliminary estimates, subject to review and revision.

B. Liquid Transportation Fuels

1. Description

This design element covers CO_2 emissions from the combustion of liquid transportation fuels. The point of regulation being examined is the point at which the fuels enter into commerce in the individual WCI states and provinces. As described below, this point may vary among the states and provinces.

1.1 Sectors

This design element focuses on liquid fossil fuels used in the transportation sector, including but not limited to gasoline, distillate fuels (diesel, etc.), jet fuel, aviation gas, and LPG. The liquid fuels used for stationary combustion by residential, commercial, and industrial customers are described separately. Nevertheless, the manner in which liquid fuels could be covered for these other customers is closely related to how they could be covered for transportation uses. Fuel use in the electricity sector is also not covered in this design element.

1.2 Emissions Sources

The emission source is the combustion of liquid fossil fuels in mobile sources. These sources include on-road and off-road vehicles, including: passenger cars; trucks; rail; marine vessels; and aircraft. Off-road equipment, such as farm equipment and construction equipment could also be included.

1.3 Greenhouse Gases

Carbon dioxide is the dominant GHG produced in this element, accounting for on the order of 97% of emissions from these sources. Nitrous oxide (N_2O) and methane (CH_4) are also emitted.

1.4 Point of Regulation

It is generally considered impractical to define the point of regulation for transportation emissions at the point of emission, which would be the individual vehicle owner. Rather, the point of regulation under consideration for this element is the point at which transportation fuels enter into commerce in the individual states and provinces. In selecting this point of regulation, consideration is being given to the fact that most jurisdictions have a mechanism for tracking the sale of transportation fuels for other purposes. Building on the existing fuel tracking procedures in each jurisdiction is expected to simplify program design and implementation requirements.

For some jurisdictions, the point at which liquid fuels are tracked is the fuel distribution terminal, often referred to as the terminal rack. For example, in the United States, federal excise taxes on transportation fuels are collected at the terminal rack. Some states rely on this terminal-rack based tracking system to collect state taxes, thereby providing the capability to track fuel flows into the state.

Some jurisdictions (e.g., Oregon) track gasoline deliveries to retailers for tax purposes. For these jurisdictions, the preferred point of regulation may be the licensed fuel wholesalers that are already required to report the quantity of fuel delivered.

Using this approach, the compliance obligation would be to hold emission allowances to cover the fossil carbon content of the fuel that is entering into commerce in the individual states and provinces. The regulated entity would be the party that enters the fuel into commerce in the state or province, such as the owner of the fuel dispensed at the terminal rack, or the licensed fuel wholesaler that dispenses fuel to retail locations.

2. Emissions and Entity Data

The transportation sector is the largest or second largest source of GHG emissions for each of the WCI partners. The emissions estimate for 2005 is about 353 MMT CO_2e, accounting for about 36% of total gross emissions among the WCI partners. The percentage of total gross emissions varies among the partners from about 21% to 46%. Table 2 summarizes the emissions estimates for the WCI partners.

The total number of entities with a compliance obligation depends on the point of regulation. If terminal racks are the point of regulation for most jurisdictions, the total number of terminals and refineries (where the racks are located) is on the order of about 200 for the WCI partners (see Table 2). If wholesalers are the point of regulation, the number of entities will be larger. For example, Oregon licenses about 160 motor vehicle fuel dealers. The appropriate point of regulation and the number of entities is under investigation.

3. Emissions at the Entity Level

As described above, the point of regulation under consideration is the point at which liquid transportation fuels enter into commerce in the individual states and provinces. At this point, the regulated entity cannot measure or calculate actual GHG emissions from fuel combustion. Rather, the entity can calculate potential CO_2 emissions based on the fossil carbon content of the fuel and the quantity of the fuel. Virtually all the carbon in the fuel is converted to CO_2, so that the carbon content of the fuel is an accurate predictor of CO_2 emissions.

Several issues need to be addressed in order to use this calculation of potential emissions:

- <u>Variations in fossil carbon content</u>: Currently, the fossil carbon content of liquid transportation fuels is well known. However, in the future, fuels may include varying levels of non-fossil carbon components (e.g., in response to low carbon fuel standards). Consequently, the fossil carbon component of the fuel may need to be verified at the point of regulation, or may need to be provided to the point of regulation by the fuel producer. The mechanism required to make this fossil carbon content determination remains to be determined.
- <u>Fuel use for non-combustion purposes</u>: The emission calculation presumes that all the fuel delivered will be combusted. Some fuels may be used to produce products (such as plastics) that sequester carbon. While this eventuality may be unlikely for transportation fuels, the issue remains to be assessed.

Notably, this method of calculating emissions is a proxy only for the CO_2 emissions that occur when the fuel is combusted. The calculation does not include N_2O and CH_4 emissions, although those emissions would also be expected to occur during combustion along with the CO_2 emissions. Additionally, the method does not include the GHG emissions associated with producing the fuel. Rather, this method covers emissions associated with fuel use, but not fuel production. Emissions associated with fuel production (e.g., emissions at the refinery) would be covered separately as stationary combustion or process emissions from the facilities involved in producing the fuel in the WCI states and provinces.

4. Administration

By leveraging existing fuel tracking procedures in states and provinces, the administrative challenges for this design element can be minimized. However, the tracking capabilities of each state and province remain to be examined in detail to assess the comprehensiveness of the existing tracking capabilities. Insofar as the existing procedures provide incomplete coverage of the fuels, additional tracking capabilities may be required.

The potential challenges associated with verifying the fossil and non-fossil carbon components of transportation fuels at the proposed point of regulation remain to be examined.

5. Leakage Issues

The potential for emission leakage is significant for components of the transportation sector:

- Marine: Ocean-going vessels can obtain fuel outside the WCI partner jurisdictions.
- Aviation: Airline operations are particularly sensitive to fuel costs. Opportunities to obtain fuel outside the WCI partner jurisdictions may be significant.

Gasoline use in passenger cars, light duty trucks, and medium duty vehicles is less vulnerable to leakage, as motorists typically obtain fuel in close proximity to their residences and places of employment. On-road gasoline use accounts for about two-thirds of the total emissions from this sector, making it the largest portion of emissions.

Long-haul trucking may also be vulnerable to leakage if trucks can operate within WCI jurisdictions with fuel obtained from outside the WCI jurisdictions. However, the International Fuel Tax Agreement (IFTA) requires diesel trucks operating in multiple jurisdictions to calculate fuels consumed in each state and province based on the miles traveled in each state/province. All the WCI partners are parties to the IFTA.[2] Consequently, the IFTA data could be used to compute a compliance obligation for diesel trucks that operate in multiple jurisdictions, thereby avoiding leakage.[3]

These differences in leakage potential may indicate that the program should consider focusing coverage on the portion of transportation fuels that are least subject to leakage.

Table 2: Summary of Liquid Transportation Fuel CO_2 Emissions

State/Province	2005 Emissions (MMT CO_2e)	Percent of 2005 Gross Emissions	# Entities	
			Terminals	Refineries
Arizona	39.3	39%	10	--
California (2004)	182.0	37%	84	20
New Mexico	15.6	21%	16	3
Oregon (2004)	23.2	34%	10	1
Utah	17.4	25%	7	5
Washington	43.1	46%	25	5
British Columbia	25.4	39%	3	2
Manitoba	7.4	36%	1	--
Total WCI Partners	**353.4**	**36%**	**156**	**36**

MMT = million metric tons
Percent of gross emissions calculated for each state/province.
Preliminary estimates, subject to review and revision.

[2] The 48 contiguous states of the United States and 10 Canadian provinces are parties to IFTA. Yukon Territory, Northwest Territory, Nunavut, and the District of Columbia are not parties to IFTA.

[3] IFTA covers diesel trucks with the following characteristics: (a) has three or more axles; or (b) has two axles and a gross vehicle or registered gross vehicle weight of more than 26,000 pounds or 11,797 kilograms; or (c) is used in a combination that has a combined or registered gross vehicle weight of more than 26,000 pounds or 11,797 kilograms. Recreational vehicles are not covered.

C. Residential and Commercial Natural Gas Consumption

1. Description

Under this element, the carbon dioxide emissions associated with residential and commercial combustion of natural gas would be covered. The point of regulation is the local natural gas distribution company (LDC). The LDCs would be required to hold allowances to cover the carbon dioxide emissions associated with the ultimate combustion of the natural gas they sell to their residential and commercial customers, based on the carbon content and volume of the fuel they sell.

LDCs also deliver gas to large industrial and electric utility customers. They would not be required to hold allowances for emissions associated with those deliveries. The expectation is that those emissions would be covered at the source, as described in separate design elements.

1.1 Sectors

The sector covered is part of residential and commercial stationary combustion.

1.2 Emissions Sources

The emissions sources are residential and commercial natural gas combustors, such as boilers and furnaces.

1.3 Greenhouse Gases

The greenhouse gas covered is carbon dioxide. Other combustion-related greenhouse gases would also be affected (e.g., nitrous oxide and methane). However, the other emissions are not addressed explicitly through this design element.

1.4 Point of Regulation

The entities with compliance obligations are local natural gas distribution companies (LDCs). LDCs are typically private companies regulated by state and provincial utility commissions or similar boards. Some LDCs may be municipal utilities. All LDCs, regardless of size or volume of gas delivered, could be included in this program element.

2. Emissions and Entity Data

Based on the information collected to date, there are about 55 LDCs in the WCI partner states and provinces; and about 155 total if WCI observers are included. The CO_2 emissions associated with the natural gas these LDCs distributed in 2005 to residential and commercial customers is 138.7 MMT for the U.S. partners and is currently being estimated for the Canadian partners. Table 3 summarizes this data and the data on the numbers of LDCs.

3. Emissions at the Entity Level

Calculating emissions associated with residential and commercial combustion would be straightforward for LDCs. LDCs already account for the volumes of natural gas they sell by customer class. The LDCs would need to apply the appropriate carbon content factor to these gas volumes to calculate their compliance obligation. The LDC would exclude from this calculation any natural gas that is sold to an entity that has a separate compliance obligation under the program, such as an industrial source that is regulated directly.

4. Administration

Covering LDCs in a cap-and-trade program does not pose unusually significant administrative challenges. LDCs are already subject to economic regulation by the state public utilities commissions in the United States and by provincial authorities in Canada. Thus, a state or provincial regulatory agency can identify all the entities with compliance obligations. The LDCs would have the capability to know that they have compliance obligations and understand their compliance requirements. The number of entities appears manageable. However, there are a number of small LDCs in Kansas (a WCI observer state). An annual emissions threshold, for example 10,000 tons of CO_2, could be used to exclude small LDCs.

5. Leakage Issues

LDCs themselves would not be subject to emission leakage issues. The LDCs are regulated monopolies with defined service territories.

LDC customers may vary with regard to leakage vulnerabilities. Most residential and commercial natural gas customers do not have high greenhouse gas emissions intensities. Consequently internalizing the cost of the carbon content of natural gas into natural gas prices (as would be expected) would not significantly affect the competitiveness of most customers.

However, there are two circumstances of note. First, increased natural gas prices could adversely affect low income residential customers. Assistance programs for low income customers, provided by many LDCs in the United States, could be a mechanism for addressing this impact. Second, there may be some individual large volume gas customers for which carbon emissions are significant. If these customers face competition from regions that do not limit greenhouse gas emissions, they may vulnerable to emissions leakage. The circumstances of these customers would be similar to large stationary source emissions sources that would be covered directly. The number of customers for which this is an issue, and the potential impacts on these customers, remain to be identified.

Table 3: Summary of Residential and Commercial Natural Gas CO_2 Emissions

State/Province	2005 Emissions (MMT CO_2e)	Percent of 2005 Gross Emissions	# LDCs
Arizona	4.0	4%	8
California (2004)	42.9	9%	11
New Mexico	3.4	6%	19
Oregon (2004)	4.0	6%	3
Utah	5.5	8%	2
Washington	7.4	8%	7
British Columbia			4
Manitoba			1
Total WCI Partners	**67.5**	**8%**	**55**
MMT = million metric tons Percent of gross emissions calculated for each state/province. Emissions data currently being developed for provinces. Preliminary estimates, subject to review and revision.			

C1: Residential and Commercial Stationary Combustion of Fuel Oil and Other Liquid Fuels

1. Description

This design element covers CO_2 emissions from the stationary combustion of fuel oil and other liquid fuels in the residential and commercial sector. The point of regulation being examined is the point at which the fuels enter into commerce in the individual WCI states and provinces. As described below, this point may vary among the states and provinces.

1.1 Sectors

This design element focuses on liquid fossil fuels used for stationary combustion by residential and commercial customers. The fuels include heating oil, propane and liquefied petroleum gas (LPG). The liquid fuels used in the transportation sector are described separately. Nevertheless, the manner in which liquid fuels could be covered for transportation uses is closely related to how they could be covered for these residential and commercial uses. Fuel use in the electricity sector is also not covered in this design element.

1.2 Emissions Sources

The emission source is the combustion of liquid fossil fuels in stationary source equipment, such as furnaces and boilers.

1.3 Greenhouse Gases

Carbon dioxide is the dominant GHG produced in this element, accounting for on the order of 99% of emissions from these sources. Nitrous oxide (N_2O) and methane (CH_4) are also emitted.

1.4 Point of Regulation

It is generally considered impractical to define the point of regulation for residential and commercial stationary fuel combustion emissions at the point of emission, which would be the individual building owner. Rather, the point of regulation under consideration for this element is the point at which the relevant fuels enter into commerce in the individual states and provinces. In selecting this point of regulation, consideration is being given to the fact that some jurisdictions have a mechanism for tracking the sale of these fuels for other purposes. Building on the existing fuel tracking procedures in each jurisdiction is expected to simplify program design and implementation requirements.

For some jurisdictions, the point at which liquid fuels are tracked is the fuel distribution terminal, often referred to as the terminal rack. For example, in the United States, federal excise taxes on liquid fuels are collected at the terminal rack. Some states rely on this terminal-rack based tracking system to collect state taxes, thereby providing the capability to track fuel flows into the state.

Some jurisdictions track fuel deliveries to retailers for tax purposes. For these jurisdictions, the preferred point of regulation may be the licensed fuel wholesalers that are already required to report the quantity of fuel delivered.

Using this approach, the compliance obligation would be to hold emission allowances to cover the fossil carbon content of the fuel that is entering into commerce in the individual states and provinces. The regulated entity would be the party that enters the fuel into commerce in the state or province, such as the owner of the fuel dispensed at the terminal rack, or the licensed fuel wholesaler that dispenses fuel to retail locations.

2. *Emissions and Entity Data*

The stationary combustion of liquid fossil fuels in the residential and commercial sectors accounts for a small portion of overall GHG emissions within the WCI partners jurisdictions. Although incomplete data are currently available, these sources appear to account for less than 1% of total emissions in 2005 (see Table 4).

The total number of entities with a compliance obligation depends on the point of regulation. If terminal racks are the point of regulation for most jurisdictions, the total number of terminals and refineries (where the racks are located) is on the order of about 200 for the WCI partners (see Table 4). If wholesalers are the point of regulation, the number of entities will be larger. The compliance obligation for these fuels would likely be closely coordinated with the compliance obligation for the carbon content of liquid transportation fuels, which is described separately.

3. *Emissions at the Entity Level*

As described above, the point of regulation under consideration is the point at which liquid fuels enter into commerce in the individual states and provinces. At this point, the regulated entity cannot measure or calculate actual GHG emissions from fuel combustion. Rather, the entity can calculate potential CO_2 emissions based on the fossil carbon content of the fuel and the quantity of the fuel. Virtually all the carbon in the fuel is converted to CO_2, so that the carbon content of the fuel is an accurate predictor of CO_2 emissions.

Several issues need to be addressed in order to use this calculation of potential emissions:

- Variations in fossil carbon content: Currently, the fossil carbon content of liquid fuels is well known. However, in the future, fuels may include varying levels of non-fossil carbon components (e.g., in response to low carbon fuel standards). Consequently, the fossil carbon component of the fuel may need to be verified at the point of regulation, or may need to be provided to the point of regulation by the fuel producer. The mechanism required to make this fossil carbon content determination remains to be determined.
- Fuel use for non-combustion purposes: The emission calculation presumes that all the fuel delivered will be combusted. Some fuels may be used to produce products (such as plastics) that sequester carbon. While this eventuality may be unlikely for these fuels, the issue remains to be assessed.

Notably, this method of calculating emissions is a proxy only for the CO_2 emissions that occur when the fuel is combusted. The calculation does not include N_2O and CH_4 emissions, although those emissions would also be expected to occur during combustion along with the CO_2 emissions. Additionally, the method does not include the GHG emissions associated with producing the fuel. Rather, this method covers emissions associated with fuel use, but not fuel production. Emissions associated with fuel production (e.g., emissions at the refinery) would be covered separately as stationary combustion or process emissions from the facilities involved in producing the fuel in the WCI states and provinces.

4. *Administration*

By leveraging existing fuel tracking procedures in states and provinces, the administrative challenges for this design element can be minimized. However, the tracking capabilities of each state and province remain to be examined in detail to assess the comprehensiveness of the existing tracking capabilities. Insofar as the existing procedures provide incomplete coverage of the fuels, additional tracking capabilities may be required. As discussed above, the tracking of these fuels would be coordinated closely with the tracking of transportation fuels.

The potential challenges associated with verifying the fossil and non-fossil carbon components of fuels at the proposed point of regulation remain to be examined.

5. Leakage Issues

Fuel oil customers may vary with regard to leakage vulnerabilities. Most residential and commercial fuel oil customers do not have high greenhouse gas emissions intensities. Consequently internalizing the cost of the carbon content of fuel oil into fuel oil prices (as would be expected) would not significantly affect the competitiveness of most customers.

However, there are two circumstances of note. First, increased fuel prices could adversely affect low-income residential customers. Assistance programs for low-income customers could be a mechanism for addressing this impact. Second, there may be some individual commercial customers for which carbon emissions are significant. If these customers face competition from regions that do not limit greenhouse gas emissions, they may vulnerable to emissions leakage. The circumstances of these customers would be similar to large stationary source emissions sources that would be covered directly. The number of customers for which this may be an issue, and the potential impacts on these customers, remain to be identified.

Table 4: Summary of CO_2 Emissions from Residential and Commercial Stationary Combustion of Fuel Oil and Other Liquid Fuels

State/Province	2005 Emissions (MMT CO_2e)	Percent of 2005 Gross Emissions	# Entities	
			Terminals	**Refineries**
Arizona	0.7	0.7%	10	--
California (2004)	1.0	0.2%	84	20
New Mexico	1.2	1.6%	16	3
Oregon (2004)	0.8	1.2%	10	1
Utah	0.4	0.6%	7	5
Washington	1.4	1.5%	25	5
British Columbia	(NA)	(NA)	3	2
Manitoba	(NA)	(NA)	1	--
Total WCI Partners	5.6	0.6%	**156**	**36**

MMT = million metric tons
Percent of gross emissions calculated for each state/province.
NA = Data not available. Emissions data currently being developed.
Preliminary estimates, subject to review and revision.

D. Industrial Process and Waste Management Emissions

1. Description

This element includes industrial process and waste management emissions regulated at the point of emission.

1.1 Sectors

This sector includes specifically identified industrial processes and waste management activities, such as oil refining, cement production, aluminum smelting, iron and steel production, adipic acid production, nitric acid production, lime production, pulp and paper manufacturing, sawmill kilns, agricultural chemical manufacturing, plastics manufacturing, natural gas transmission and distribution, magnesium smelters and casters, mineral production, silicon chip manufacturing, ammonia production, wastewater treatment facilities; landfill operations, wastewater treatment from food processing; and others. An annual emissions threshold may be used to define the facilities included in the program. This threshold has not been established, and is under consideration. Process emissions from the Electric Sector are included in the Electric Sector, and are not included here.

1.2 Emissions Sources

The emission sources included are process emissions from stationary sources. Process emissions include emissions from chemical, biological, and other non-combustion processes. The emissions may be deliberate (e.g., vented), fugitive (e.g., leaked), or accidental. Fossil fuel combustion emissions are not included in this design element, and are covered in a separate description.

1.3 Greenhouse Gases

All six Kyoto greenhouse gases are included.

1.4 Point of Regulation

The point of regulation is the facility where the emissions occur.

2. Emissions and Entity Data

Among the WCI partner states and provinces, process emissions accounted for about 75 MMT of CO_2e in 2005, or about 8% of total gross emissions. This percentage varies from about 4% to 12% across the states and provinces.

The total number of entities that would be covered in this sector depends on whether, and at what level, an annual emissions threshold is set. The potential number of entities with compliance obligations is currently being assessed. Table 5 summarizes the emissions for the WCI partners.

3. Emissions at the Entity Level

The ability to measure or calculate emissions reliably and precisely at the entity level must be assessed for each of the industrial process and waste management sources in the WCI region. This assessment must examine:

- Is there an existing measurement or calculation protocol or method for the source?
- Is a new protocol or method required?
- What greenhouse gases can be measured or calculated reliably and precisely?

- Are there technical barriers to the entities being able to measure/calculate their emissions with sufficient precision to be covered by the cap-and-trade program? If there are barriers, which sources cannot be included, and how does their exclusion affect the emissions covered?

There are numerous industrial processes that emit greenhouse gases, and the answers to these questions will vary widely among the processes. For example, a protocol has been developed to calculate process emissions from cement manufacturing. Also, emissions of N_2O from nitric acid production can be monitored accurately using measurement devices in the process vent. Alternatively, process emissions at refineries are themselves diverse. Some refinery process emissions may be amenable to measurement or calculation, while others (such as fugitive emissions) may not be suitable for inclusion. This element could cover only those emissions that can be measured or calculated adequately. If needed, processes could be added to the program as methods or protocols are developed over time.

4. Administration

The primary administrative challenge associated with this sector is the inability to measure or calculate emissions precisely from some sources. Most of the large facilities that fall under this design element would already have compliance obligations under other regulatory programs. Consequently, the entities are well known and would be in a position to understand their compliance obligations under a cap-and-trade program. As discussed above, the use of an annual emissions threshold would reduce the number of entities with compliance obligations.

5. Leakage Issues

Vulnerability to leakage varies among the facilities that would be covered under this sector. Some facilities require close proximity to their markets, so that significant leakage to locations outside the WCI region is not expected. However, others (such as the cement industry), may be vulnerable to leakage as their products are traded as commodities internationally. The vulnerability to leakage needs to be assessed individually for each industry.

Table 5: Summary of Industrial Process and Waste Management Emissions

	2005 Emissions (MMT CO_2e)		
State/Province	**Processes**	**Waste Management**	**Percent of 2005 Gross Emissions**
Arizona	4.5	2.1	7%
California (2004)	29.8	9.4	8%
New Mexico	1.5	1.4	4%
Oregon (2004)	3.3	1.9	8%
Utah	3.6	2.0	8%
Washington	3.0	2.4	6%
British Columbia	3.1	5.1	12%
Manitoba	0.4	1.0	7%
Total WCI Partners	**49.2**	**25.4**	**8%**

MMT = million metric tons
Percent of gross emissions calculated for each state/province.
Preliminary estimates, subject to review and revision.

E. Fossil Fuel Industry

The Fossil Fuel Industry encompasses oil and gas exploration, production, and processing, and coal mining. This design element includes a broad set of facilities and activities with diverse emissions sources. Some of the emissions sources included here are also part of other design elements (e.g., stationary combustion sources and process emissions). However, the sources are described here to provide a comprehensive description of emissions from this industry.

1.1 Sectors

The Fossil Fuel Industry can be categorized into the following sectors:

- Oil Production: Oil production covers exploration, drilling, production, and transportation of crude oil by pipeline to terminals or refineries. Facilities include well fields, pipelines, and tank batteries. Ships used to transport crude oil are included in the transportation sector. The output of this process is crude oil.
- Natural Gas Production and Processing: Natural gas production and processing covers exploration, production, and treatment of natural gas. Facilities include well fields, pipelines, and processing equipment. The output of this process is natural gas that meets specifications required for injection into natural gas transmission and distribution pipelines.
- Coal Mining: Coal mining covers mine development and operations, including surface mining (i.e., open pit mining) and underground mining. Coal processing facilities are considered a stationary source, and coal transport (e.g., by train) is considered part of the transportation sector.

Oil and gas are often produced from the same wells. In these cases, the distinction between oil production facilities and natural gas production facilities is not meaningful. Additionally, condensate and other liquids are often produced with oil and/or natural gas. The oil and natural gas production and processing facilities listed above encompass the production and processing of these liquids.

Methane recovered from coal seams (often referred to as “coalbed methane”) can also be used to produce pipeline quality natural gas. Coalbed methane production and treatment is included in this design element as part of natural gas production.

Pipelines of various types are also used to transport crude oil, liquid products, and gas. Pipelines are included in this design element, including: gathering lines; crude oil and liquid products pipelines that run to refineries, terminals, and tanks; and gas pipelines that connect to transmission lines. Natural gas transmission and distribution pipelines are not included in this design element.[4] Similarly, refineries and the transport of refined products to market are not included in this design element.[5]

1.2 Emissions Sources

The Fossil Fuel Industry includes a diverse set of greenhouse gas emissions sources. Many of the sources are specialized pieces of equipment found only in this industry. The major emission sources in oil and gas production and processing are listed in Table 6. As shown in the table, the emissions sources can be categorized into six types:

[4] Natural gas transmission and distribution pipelines are considered stationary sources with combustion emissions (i.e., from compressors) and process emissions (i.e., gas venting and fugitive emissions).

[5] Refineries are considered a stationary source with combustion emissions and process emissions. The transport of refined products to market is considered part of the transportation sector.

- Stationary combustion includes all types of fossil fuel combustion, including flaring.
- Process vents include equipment that is designed to vent emissions as part of its normal operation. Amine treatment as part of acid gas removal is an example of a process with this type of venting.
- Maintenance venting includes emissions that occur during scheduled maintenance activities.
- Non-routine venting occurs periodically, often for safety reasons.
- Other venting is associated with specific activities or pieces of equipment, some of which are designed to vent as part of normal operation (e.g., pneumatic devices and chemical injection pumps).
- Fugitive emissions occur from unintended leaks from equipment components.

The relative importance of each of the sources depends on site-specific equipment requirements, operations, and configurations.

The source of coal mining emissions is primarily due to the release of methane from the coal and surrounding strata due to mining activities. In underground mines, methane can create an explosive hazard, so it is removed through a ventilation system. Methane concentrations in ventilation system emissions are typically less than 1%, and consequently the methane is nearly always emitted to the atmosphere. In some mines, a degasification system is used to withdraw methane prior to mining due to large quantities of methane occurring in the coal and surrounding strata. The methane collected by the degasification system may be recovered and used for fuel in some cases.

In surface mining, the methane associated with the coal is emitted directly to the atmosphere as the coal is uncovered. For both underground coal and surface-mined coal, some methane remains in the coal after it is mined. This methane is released subsequently during processing, transport, and storage.

Finally, methane is also emitted from closed or abandoned underground mines. Although mining is no longer active, closed mines can release methane from vents, fissures, or boreholes.

This list of emissions sources for the Fossil Fuel Industry includes only those sources that produce emissions during the production and processing of the fuel (oil, gas, and coal). When the resulting products are combusted (i.e., when refined oil products and natural gas are used as fuel by others), they also produce emissions (primarily carbon dioxide). The emissions from fuel combusted by others are not included in this design element.

1.3 Greenhouse Gases

The predominant GHGs emitted from the Fossil Fuel Industry are:

- Carbon dioxide (CO_2): CO_2 is released from fossil fuel combustion at oil and gas production and processing facilities. This combustion includes emissions from flaring (see Table 6). Also, CO_2 is often mixed with natural gas as it is produced from underground formations, particularly from coalbed methane sources. During gas processing, this CO_2 is typically separated from the natural gas and vented.[6]
- Methane (CH_4): Methane is typically released due to venting and leaks during oil and natural gas production and processing (methane is the primary component of natural gas). Methane is also released from coal mines.

[6] In some cases, CO_2 separated from natural gas is captured and re-injected or used for other purposes.

- Nitrous oxide (N_2O): N_2O emissions are primarily associated with fuel combustion. N_2O emissions are typically a very small portion of total GHG emissions from the Fossil Fuel Industry.

The largest GHG emissions from the Fossil Fuel Industry are CO_2 from combustion of fuel and CO_2 separated from the raw gas stream.

1.4 Point of Regulation

The point of regulation currently under consideration is the facility where the emissions occur. As discussed above, oil and gas production facilities include a diverse set of equipment, processes, and activities. These facilities may also cover large geographic areas, encompassing well fields, pipelines, and tank batteries. Ownership and operational control may be divided among multiple entities as the oil and gas is produced and processed.

2. Emissions and Entity Data

Among the WCI partner states and provinces, Fossil Fuel Industry emissions accounted for about 45 million metric tons (MMT) of CO_2e in 2005, or about 5% of total gross emissions from the WCI partners. However, for New Mexico and British Columbia, emissions from the Fossil Fuel Industry are a larger portion of total gross emissions, accounting for about 26% and 22% respectively of their gross emissions in 2005. Table 7 summarizes the emissions estimates for each province and state.

Although significant improvements have been made in the ability to calculate GHG emissions from the fossil fuel industry, considerable uncertainty remains in national and state/provincial emission inventory estimates. Emissions factors for some types of emissions, such as fugitive emissions, continue to have broad ranges of uncertainty. Additionally, some activity data, such as the quantities of gas flared or vented, are not well measured or reported in some circumstances. Various efforts are ongoing to continue to improve emissions estimates for this industry.

The number of operating oil and gas wells is on the order of 65,000 and 45,000 respectively for the WCI partners (see Table 8). Typically, a small number of well field operators account for a large portion of operating wells and oil and gas production. For example, within the United States in 2005, the top 50 operators account for 77% of oil production and 72% of natural gas production.[7] In British Columbia, five operators account for about 80% of natural gas production, and in New Mexico 20 operators account for about 80% of natural gas production. Similarly, in California, 30 operators account for more than 90% of oil and gas production. Consequently, if a size threshold were adopted for participation in a cap-and-trade program, a large portion of total production could be covered while keeping the number of oil and gas field operators with a regulatory obligation manageable. Assessments of size threshold options and the number of entities covered remains ongoing.

The number of coal mines operating in the WCI jurisdictions is on the order of 29, including 14 underground and 15 surface mines (see Table 8).

3. Emissions at the Entity Level

The ability to measure or calculate emissions reliably and precisely at the facility or entity level varies depending on the activities performed and equipment used at the facility and the manner

[7] U.S. Energy Information Agency, "Operator Information by Size Class" available at: http://tonto.eia.doe.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_m.htm.

in which data are collected and verified. For oil and gas production and processing emissions, several resources have been developed to assist in estimating emissions:

- The American Petroleum Institute's *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil & Gas Industry*[8] promotes consistency in estimating petroleum company's GHG emissions and provides recommendations on ways to improve and streamline GHG emissions estimates among existing methodologies.
- The International Petroleum Industry Environmental Conservation Association (IPIECA), International Association of Oil and Gas Producers (OGP) and API also prepared the *Petroleum Industry Guidelines for Reporting Greenhouse Gas Emissions*[9], a consistent global framework for accounting and reporting of GHG emissions by the industry sector.
- The World Business Council for Sustainable Development (WBCSD) and World Resources Institute (WRI) have developed *The Greenhouse Gas Protocol: a Corporate Accounting and Reporting Standard*[10], a common framework for defining the boundaries of reporting emissions.
- The New Mexico Environment Department, California Air Resources Board, and California Climate Action Registry, in cooperation with the Western Regional Air Partnership, have begun a joint initiative to develop a registry reporting protocol specific to the upstream oil and gas industry sector (i.e., production) and natural gas processing. This protocol, in combination with protocols already developed or soon to be completed for petroleum refining and natural gas transmission and distribution, will provide a basis for accelerated adoption of a complete oil and gas sector protocol by The Climate Registry. The protocol will not be likely to be completed until mid 2009.

While these resources have improved (and are continuing to work to improve) the consistency of emissions calculations and methods, the accuracy of entity-specific emissions calculations remains an issue of concern for certain sources at oil and gas production and processing facilities. Emissions calculations for metered fuel use and process vents amenable to measurement are expected to be as precise as the estimates performed for similar emissions from other stationary sources. However, emissions calculations for unmetered gas use (either flared or vented) and leaks pose challenges. The use of average or representative emissions factors for some sources (such as fugitive emissions) does not enable site-specific conditions to be reflected, and does not allow for improved operation and maintenance to be reflected in reduced emissions estimates.

Based on the information reviewed to date, only a portion of the sources at oil and gas production and processing facilities will likely be feasible to include in a cap-and-trade program at this time. Improved methodologies may enable additional sources to be included in the future. The identification and assessment of those sources remains ongoing.

The ability of individual coal mines to calculate or measure emissions accurately varies. Surface mined coal does not provide an opportunity to measure emissions, although those emissions are typically low. Emissions from underground coal mining can be estimated from

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[8] *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil & Gas Industry,* American Petroleum Institute (API), Washington, DC, February 2004, available at http://ghg.api.org.

[9] *Petroleum Industry Guidelines for Reporting Greenhouse Gas Emissions*, International Petroleum Industry Environmental Conservation Association (IPIECA), London, United Kingdom, December 2003.

[10] *The Greenhouse Gas Protocol: a corporate accounting and reporting standard*, World Business Council for Sustainable Development (WBCSD) and World Resources Institute (WRI), Washington, DC, January 2004, available at http://www.ipieca.org/reporting/ghg.html.

methane concentrations in ventilation air. Additionally, methane collected in degasification systems (prior to mining) is typically quantified.

Emissions from coal mines emitting over 100,000 metric tons CO_2e in Canada report their emissions federally. [11] The Environment Canada National Inventory Report contains data on fugitive emissions from coal mining, but the data for British Columbia is confidential due to the low number of market participants in the province (four). [12]

The ability to calculate emissions precisely from underground coal mining remains under review.

4. Administration

The primary administrative challenge associated with this sector is the inability of entities to measure or calculate emissions precisely from some sources. The entities that own or operate facilities that fall under this design element would already have compliance obligations under other regulatory programs. Consequently, the entities are well known and would be in a position to understand their compliance obligations under a cap-and-trade program.

The number of entities in the oil and gas production and processing industry could be large. Complex ownership and operating arrangements are also typically encountered. As discussed above, the use of a size or annual emissions threshold would reduce the number of entities with compliance obligations.

5. Leakage Issues

Oil, gas, and coal mining activities are undertaken at the locations of the resources themselves. Consequently, the operations cannot relocate to avoid participation in a cap-and-trade program. However, the companies that operate these facilities compete for investment resources. Increased cost or regulatory burdens have the potential to shift investment and production from WCI jurisdictions to other regions. Over time, therefore, production activities could shift to locations without GHG emissions limits, so that no net emission reduction is achieved. The significance of this vulnerability to emissions leakage remains under review.

[11] *Facility GHG Reporting,* Environment Canada, Ottawa, Canada, available at http://www.ec.gc.ca/pdb/ghg/facility_e.cfm.

[12] *National Inventory Report, 1990-2005: Greenhouse Gas Sources and Sinks in Canada*, Table A11-20: 1990-2005 GHG Emission Summary for British Columbia, Environment Canada, Ottawa, Canada, April 2007, available at http://www.ec.gc.ca/pdb/ghg/.

Table 6: Major Greenhouse Gas Emissions Sources from Oil and Gas Production and Processing

Equipment*	Emissions Type
Boilers/steam generators	Stationary combustion
Heaters/treaters	Stationary combustion
Compressors (internal combustion engines and turbines)	Stationary combustion
Flares	Stationary combustion
Incinerators	Stationary combustion
Gas sweetening processes	Process vent
Gas dehydration	Process vent
Vessel blowdowns	Maintenance venting
Well workovers	Maintenance venting
Compressor starts	Maintenance venting
Compressor blowdowns	Maintenance venting
Gathering pipeline blowdowns	Maintenance venting
Pressure relief valves	Non-routine venting
Well tests and blowdowns (when not flared)	Non-routine venting
Emergency shutdown/emergency safety blowdown	Non-routine venting
Tanks	Other venting
Pneumatic devices	Other venting
Chemical injection pumps	Other venting
Well drilling and testing	Other venting
Leaks from equipment components	Fugitive emissions

* Mobil sources are also used in oil and gas production fields (e.g., supply boats, barges, trucks, and aircraft). Mobil sources are not included in this design element.

Table 7: Summary of Fossil Fuel Industry Greenhouse Gas Emissions

State/Province	2005 Emissions (MMT CO_2e)	Percent of 2005 Gross Emissions
Arizona	0.6	1%
California (2004)	4.6	1%
New Mexico	19.5	27%
Oregon (2004)	0.7	1%
Utah	4.1	6%
Washington	0.9	1%
British Columbia	14.3	22%
Manitoba	0.6	3%
Total WCI Partners	**45.4**	**5%**

MMT = million metric tons
Percent of gross emissions calculated for each state/province.
Preliminary estimates, subject to review and revision.

Table 8: Oil Wells, Gas Wells, and Coal Mines

State/Province	Oil Wells (2004)	Gas Wells (2004)	Coal Mines (2005)	
			Surface	Underground
Arizona	20	8	2	0
California	45,515	3,362	0	0
New Mexico	14,928	33,029	3	1
Oregon	0	16	0	0
Utah	2,180	3,936	0	13
Washington	0	0	1	0
British Columbia	1,107	4,385	8	1
Manitoba	1,474	--	0	0
Total WCI Partners	**65,224**	**44,736**	14	15

U.S. data from Energy Information Administration (http://www.eia.doe.gov).

British Columbia oil and gas well data from "Annual Drilling & Production Statistics in British Columbia (1995-2005)" (http://www.em.gov.bc.ca/Subwebs/oilandgas/stat/annual.htm).

British Columbia coal mine data from "British Columbia Operating Coal Mines 2005" (http://www.em.gov.bc.ca/Mining/MiningStats/34coalcomlist99.htm).

Manitoba data for oil wells capable of production, from "Manitoba Petroleum Statistics" (http://www.gov.mb.ca/iedm/petroleum/stats/index.html).

Preliminary estimates, subject to review and revision.

F. Fossil Carbon Content of Fuels

1. Description

1.1 Sectors

This design element covers CO_2 emissions from fossil fuel combustion throughout the economy, including: the electricity sector, transportation fuels, residential and commercial stationary combustion, and industrial stationary combustion.

1.2 Emissions Sources

This design element covers fossil fuel combustion throughout the economy. The fuels include coal, oil, natural gas, and other fossil fuels (such as propane).

1.3 Greenhouse Gases

This design element would cover CO_2 emissions. Other greenhouse gases associated with fuel combustion (nitrous oxide and methane) would be affected, but not covered explicitly. CO_2 emissions are estimated to account for more than 98% of the GHG emissions from fossil fuel combustion.

1.4 Point of Regulation

For some sectors, such as large industrial sources, GHG emissions can be tracked at the point of combustion. For other sectors, such as transportation, it is generally considered impractical to define the point of regulation at the point of emission, which would be the individual vehicle owner. The point of regulation under consideration for this element is to cover all fossil fuels at an appropriate point in their distribution and use. The appropriate point will vary depending on the fuel:

- Liquid Fuels: The preferred point of regulation for liquid fuels (gasoline, diesel, propane) will likely be the point at which these fuels enter into commerce in the individual states and provinces. In examining this point of regulation, consideration is being given to the fact that most jurisdictions have an existing mechanism for tracking the sale of liquid fuels. The manner in which jurisdictions track fuel distribution and sales varies, so that the preferred point of regulation may also vary among jurisdictions. Some states track fuel deliveries through licensed wholesalers. Other states track fuel dispensed from terminals and refineries. Care is needed to ensure that the tracking systems are comprehensive and compatible. Because these tracking systems have generally been developed to support tax collection, building on the existing fuel tracking procedures in each jurisdiction is expected to simplify program design and implementation requirements.

- Natural Gas: The preferred point of regulation for natural gas will likely be a combination of entities. For residential and commercial customers (and some industrial customers), natural gas is delivered by local distribution companies (LDCs). The LDCs are in a position to track and report natural gas delivered to these customers. Some large natural gas users (e.g., some industrial customers) purchase natural gas directly, bypassing the LDCs. The point of regulation for direct purchasers of natural gas would be the direct purchasers themselves. Coordination would be required to ensure the combined set of entities cover natural gas use comprehensively, and without duplication, in each jurisdiction.

- Coal: In most jurisdictions, coal is typically combusted in facilities that are known to regulatory agencies for other environmental control purposes. The preferred point of regulation would likely be the individual facilities that combust coal.

2. Emissions and Entity Data

CO_2 emissions from fossil fuel combustion are the largest component of GHG emissions for each of the WCI partners. The emissions estimate for 2005 is about 780 MMT CO_2e, accounting for about 80% of total gross emissions among the WCI partners. The percentage of total gross emissions varies among the partners from about 55% to 87%. Table 9 summarizes the emissions estimates for the WCI partners.

The number of entities with regulatory obligations under this design element is being assessed. The number of LDCs in the WCI partner states is shown in Table 10, along with the number of refineries and liquid fuel terminals. The number of licensed fuel wholesalers is expected to be larger than the number of terminals. For example, Oregon licenses about 160 motor vehicle fuel dealers. The number of entities that purchase natural gas directly or combust coal remains to be identified, but is expected to be a manageable number for administrative purposes.

3. Emissions at the Entity Level

As described above, the points of regulation under consideration for natural gas and liquid fuels do not coincide with their emissions points. LDCs and fuel distributors (whether at terminals or wholesalers) cannot measure or calculate actual GHG emissions from fuel combustion. Rather, the entity can calculate potential CO_2 emissions based on the fossil carbon content of the fuel and the quantity of the fuel. Virtually all the carbon in the fuel is converted to CO_2, so that the carbon content of the fuel is an accurate predictor of CO_2 emissions.

Several issues need to be addressed in order to use this calculation of potential emissions:

- Variations in fossil carbon content: Currently, the fossil carbon content of liquid fuels and natural gas is well known. However, in the future, fuels may include varying levels of non-fossil carbon components (e.g., in response to low carbon fuel standards). Consequently, the fossil carbon component of the fuel may need to be verified at the point of regulation, or may need to be provided to the point of regulation by the fuel producer. The mechanism required to make this fossil carbon content determination remains to be determined.
- Fuel use for non-combustion purposes: The emission calculation presumes that all the fuel delivered will be combusted. Some fuels may be used to produce products (such as plastics) that sequester carbon. A mechanism is needed to account for this carbon sequestration at the point of use of the fuel.

Notably, this method of calculating emissions is a proxy only for the CO_2 emissions that occur when the fuel is combusted. The calculation does not include N_2O and CH_4 emissions, although those emissions would also be expected to occur during combustion along with the CO_2 emissions. Additionally, the method does not include the GHG emissions associated with producing the fuel. Rather, this method covers emissions associated with fuel use, but not fuel production. Emissions associated with fuel production would be covered separately as emissions from the facilities involved in producing the fuel.

For direct purchasers of natural gas and for coal combustion facilities, the entity would also be capable of measuring or calculating CO_2 emissions. Facilities could use fuel consumption data along with the carbon content of the fuel. Alternatively, some facilities may find it advantageous to measure emissions directly.

4. Administration

This sector does not pose significant administrative challenges. Regulatory agencies are able to identify most if not all the entities in this sector with compliance obligations because the entities typically have other regulatory requirements. LDCs are already subject to economic regulation by the state public utilities commissions in the United States and by provincial authorities in Canada. Thus, a state or provincial regulatory agency can identify all the entities with compliance obligations. Large industrial purchasers of natural gas and coal combustors typically have other air emission compliance requirements, and consequently are known to regulators.

By leveraging existing liquid fuel tracking procedures in states and provinces, the administrative challenges for these fuels can be minimized. However, the tracking capabilities of each state and province remain to be examined in detail to assess the comprehensiveness of the existing tracking capabilities. Insofar as the existing procedures provide incomplete coverage of the fuels, additional tracking capabilities may be required.

The covered entities should also have the capability to know their compliance obligations and understand the applicable requirements. The emissions from this sector are reasonably well known, so that an acceptable emission baseline can be developed.

5. Leakage Issues

This design element covers a very broad set of sectors throughout the economy. Significant vulnerabilities to leakage exist in specific components of fossil fuel use.

- Electric Sector: This design element covers the combustion at fossil fuel power plants either directly (e.g., as direct natural gas purchasers and coal combustion facilities) or indirectly through the inclusion of natural gas LDCs and oil distributors. Because emissions leakage associated with electricity imports from jurisdictions without GHG emissions caps can be significant, such leakage would need to be addressed as part of this approach.
- Transportation fuels: The potential for emission leakage is significant for components of the transportation sector:
  - *Marine:* Ocean-going vessels can easily obtain fuel outside the WCI partner jurisdictions.
  - *Aviation:* Airline operations are particularly sensitive to fuel costs. Opportunities to obtain fuel outside the WCI partner jurisdictions may be significant.

  Gasoline use in passenger cars, light duty trucks, and medium duty vehicles is less vulnerable to leakage, as motorists typically obtain fuel in close proximity to their residences and places of employment.

  Long-haul trucking may also be vulnerable to leakage if trucks can operate within WCI jurisdictions with fuel obtained from outside the WCI jurisdictions. However, the International Fuel Tax Agreement (IFTA) requires diesel trucks operating in multiple jurisdictions to calculate fuels consumed in each state and province based on the miles traveled in each state/province. All the WCI partners are parties to the IFTA.[13] Consequently, the IFTA data could be used to compute a compliance obligation for diesel trucks that operate in multiple jurisdictions, thereby avoiding leakage.[14]

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[13] The 48 contiguous states of the United States and 10 Canadian provinces are parties to IFTA. Yukon Territory, Northwest Territory, Nunavut, and the District of Columbia are not parties to IFTA.

[14] IFTA covers diesel trucks with the following characteristics: (a) has three or more axles; or (b) has two axles and a gross vehicle or registered gross vehicle weight of more than 26,000 pounds or 11,797 kilograms; or (c) is used in a combination that has a combined or registered gross vehicle weight of more than 26,000 pounds or 11,797 kilograms. Recreational vehicles are not covered.

- Industrial Facilities: Vulnerability to leakage varies among the industrial facilities that would be covered under this sector. Some facilities require close proximity to their markets, so that significant leakage to locations outside the WCI region is not expected. However, others (such as the cement industry and the pulp and paper industry), may be vulnerable to leakage as their products are traded as commodities internationally. The vulnerability to leakage needs to be assessed individually for each industry.

Table 9: Summary of CO_2 Emissions from Fossil Fuel Combustion

State/Province	2005 Emissions (MMT CO_2e)	Percent of 2005 Gross Emissions
Arizona	86.6	87%
California (2004)	410.7	85%
New Mexico	43.9	60%
Oregon (2004)	56.0	83%
Utah	54.0	78%
Washington	80.5	86%
British Columbia	39.1	59%
Manitoba	11.1	55%
Total WCI Partners	**781.9**	**80%**

MMT = million metric tons
Percent of gross emissions calculated for each state/province.
Preliminary estimates, subject to review and revision.

Table 10: Summary of Number of Potentially Regulated Entities for Fossil Fuels

State/Province	# LDCs (Natural Gas)	# Liquid Fuel Entities	
		Terminals	Refineries
Arizona	8	10	--
California	11	84	20
New Mexico	19	16	3
Oregon	3	10	1
Utah	2	7	5
Washington	7	25	5
British Columbia	4	3	2
Manitoba	1	1	--
Total WCI Partners	**55**	**156**	**36**

Data for direct purchasers of natural gas and for coal combustors are under development.
Preliminary estimates, subject to review and revision.

G. Passenger Cars, Light Duty Trucks and Medium Duty Vehicles

1. Description

This design element covers emissions from passenger cars, light duty trucks and medium duty vehicles. These emissions could be covered through several different approaches. This design element focuses on vehicle manufacturers as one option for covering these emissions.

1.1 Sectors

The sector covered is the light and medium duty vehicle portion of the transportation sector (cars and trucks less than 14,000 pounds gross vehicle weight rating).

1.2 Emissions Sources

Emission sources include all emissions during the operation of passenger cars, light duty trucks and medium duty vehicles, including: fuel combustion; refrigerant emissions; and evaporative emissions. Emissions associated with producing the vehicles or producing the fuel used by the vehicles are not included in this design element.

1.3 Greenhouse Gases

All six Kyoto gases are included. The primary gases associated with vehicle operations are CO_2, CH_4, N_2O, and high GWP gases (refrigerants).

1.4 Point of Regulation

It is generally considered impractical to define the point of regulation for passenger cars, light duty trucks and medium duty vehicles at the point of emission, which would be the individual vehicle owner. Rather, the point of regulation under consideration for this element is the vehicle manufacturer. In considering this point of regulation, the vehicle manufacturer would be assigned responsibility for the expected emissions associated with their new vehicles that are sold in each jurisdiction, or alternatively, for vehicles *delivered for sale* in a jurisdiction. This regulatory obligation could take various forms, including:

- Fleet Requirement: Under this approach, a maximum fleet average emission rate would be defined for each year. The actual fleet average for each manufacturer would be calculated each year based on the new vehicles sold (or delivered for sale) by that manufacturer in that year. Manufacturers would be required to hold allowances for emissions that exceed the fleet average maximum, and could earn credits for attaining average fleet emissions below the maximum. Whether and how these emission allowances and credits could be traded with other components within of a cap-and-trade system remain to be assessed.

- Lifetime Emissions: Under this approach, each manufacturer would be responsible for the expected lifetime emissions associated with its new vehicles sold (or delivered for sale) each year. The manufacturer would be required to hold emission allowances equal to the expected lifetime emissions from the new cars sold in that year.

2. Emissions and Entity Data

The transportation sector is the largest or second largest source of GHG emissions for each of the WCI partners. Table 11 summarizes the emissions estimates for the WCI partners. The total number of entities with compliance obligations is the number of vehicle manufacturers that sell vehicles in the WCI states and provinces. There are approximately 40 manufacturers that sell vehicles in these jurisdictions.

3. Emissions at the Entity Level

As described above, the point of regulation under consideration is the sale of new passenger cars, light duty trucks and medium duty vehicles by manufacturers. At this point, the regulated entity (the manufacturer) cannot measure or calculate actual GHG emissions from vehicle use. Rather, the entity can calculate potential emissions based on the expected operating characteristics of the vehicles sold, including the number of years the vehicles remain in use. These emissions estimates depend, in part, on how owners maintain and use their vehicles (e.g., vehicle miles traveled annually). Additionally, actual emissions will depend on fuel characteristics, including the availability and use of fuels with non-fossil carbon components.

To carry out the necessary emission calculations, the emissions rate associated with each model sold would need to be certified (e.g., emissions per mile traveled). Vehicle testing procedures have been developed to support requirements such as the California vehicle emissions regulations that focus on fleet average emissions. Additional data are required to calculate expected lifetime emissions. Consequently, lifetime emission estimates made at the time of sale by the manufacturers will necessarily have additional uncertainty, which may be a barrier to using the lifetime emissions approach.

4. Administration

There are roughly 40 manufacturers of passenger cars and light duty trucks worldwide. Therefore, the number of entities does not pose an administrative challenge. The manufacturers have the capability to know their compliance obligations and understand the applicable requirements. The potential need to track nearly new vehicles that are registered in the state or province needs to be assessed. For example, to avoid the program requirements, a new vehicle could be sold and registered in a non-WCI jurisdiction and then moved to a WCI jurisdiction and registered. Vehicles with fewer than 15,000 miles (for example) that are registered for the first time in a WCI jurisdiction could be counted as a newly sold vehicle for purposes of the program. Whether this tracking of nearly new vehicles would be needed, and how it would be administered remains to be considered.

In addition to administrative issues, potential legal issues also remain to be examined. The WCI jurisdictions must assess whether they have an adequate regulatory basis for requiring reporting and participation by vehicle manufacturers. If needed, jurisdictions could consider regulating (via permit) automobile manufacturers as “Indirect Sources” of air pollution (for example, Oregon’s regulations at OAR 340-254-0030).

5. Leakage Issues

The sale of new passenger cars and light duty trucks is not particularly vulnerable to leakage because consumers purchase vehicles primarily for local transportation purposes. Concerns have been raised regarding impacts on the rate of turnover of the vehicle fleet. Higher vehicle prices may slow the rate of vehicle replacement, leading to vehicles with higher emissions remaining on the road longer than would otherwise be the case. This impact can be assessed for alternative program designs.

Table 11: Summary of CO_2 Emissions from On-Road Gasoline Combustion

State/Province	2005 Emissions (MMT CO_2e)	Percent of 2005 Gross Emissions
Arizona	25.3	25%
California (2004)	142.3	29%
New Mexico	9.3	13%
Oregon (2004)	13.1	19%
Utah	9.8	14%
Washington	23.5	25%
British Columbia	10.5	16%
Manitoba	3.0	15%
Total WCI Partners	**236.9**	**24%**

MMT = million metric tons
Percent of gross emissions calculated for each state/province.
NA = Not Available. Emissions data currently being developed.
Preliminary estimates, subject to review and revision.

H. Large Transportation Fleets

1. Description

This design element covers large transportation fleets. The point of regulation would be entities (e.g., companies, local governments, transit agencies, etc.) that operate fleets of motor vehicles or boats. A key issue in this sector is what constitutes a "fleet" of vehicles or boats. Thresholds in both quantitative (e.g., number of vehicles or boats) and qualitative (e.g. types of vehicles or boats) terms may be applied to limit the scope of regulation within this sector.

1.1 Sectors

Large Transportation Fleets regulated at the fleet management level.

1.2 Emissions Sources

Fossil fuel combustion from fleet vehicles and boats.

1.3 Greenhouse Gases

Carbon dioxide is the dominant GHG produced in this element, accounting for on the order of 97% of emissions from these sources. Nitrous oxide (N_2O) and methane (CH_4) are also emitted.

1.4 Point of Regulation

The point of regulation for this option would be the entity that owns and operates the vehicles that are to be regulated. This entity would be required to hold allowances equal to the emissions of the fleet vehicles. Issues around leased vehicles would need to be clarified.

A threshold for inclusion in the sector would seem to be a practical necessity. Possible thresholds include number of vehicles or boats, combined fleet vehicle miles traveled, total fuel use, or other metrics. However, it may be most appropriate to set an emissions threshold for including fleets in the cap-and-trade program.

Other factors may play into the definition of a "fleet" for the purposes of compliance. Types of vehicles (commercial, off-road, on-road, marine, weights of vehicles, etc.) may be one factor. Geographic range, or the geographic location of a centralized operations base, may also play into a definition of what constitutes a fleet for inclusion in such a program. Inclusion of ferry and other boat fleets (such as those operated by Washington State Ferries, the BC Ferry Corporation and marine barge operations) should be considered under this design element due to the amount of associated emissions.

2. Emissions and Entity Data

Data collection and analysis are underway to estimate the number of fleets at various threshold levels and the portion of emissions that the fleets may represent. Initial indications are that there may be on the order of 10,000 vehicle fleets in the WCI partner states and provinces that each have 10 or more vehicles. However, this is a very preliminary figure.

3. Emissions at the Entity Level

Most fleet management systems would capture the relevant data necessary for estimating emissions from fleet vehicles. Emissions could be estimated from odometer readings, fuel use, and other factors. Protocols for estimating these emissions exist. However, fleet data have been suspect in terms of data reliability and verifiability. The margins of error associated with these data should be considered.

Currently, the fossil carbon content of liquid transportation fuels is well known. However, in the future, fuels may include varying levels of non-fossil carbon components (e.g., in response to low carbon fuel standards). Consequently, the fossil carbon component of the fuel may need to be verified at the point of regulation, or may need to be provided to the point of regulation by the fuel producer. The mechanism required to make this fossil carbon content determination remains to be determined.

If N_2O and CH_4 were included in the cap and trade program for this sector then estimating emissions for these gases may be subject to a wide margin of uncertainty because emission rates depend on vehicle characteristics and maintenance conditions. National and international standard N_2O and CH_4 emission factors for different fuels could be used as a proxy for more precise estimations.

4. Administration

The ability to administer a cap and trade program in the fleet sector is largely a function of how fleets are defined. If the threshold for inclusion (by whatever metric) is low enough to include the numerous family-run or other similar small business operations in trucking, retail, and urban delivery, then the ability for these entities to understand and administer their obligations is questionable. Conversely, the largest fleet operations – especially in trucking, ferries and businesses like rental fleets – are likely well positioned from both an administrative and data perspective to deal with the regulatory burden. Steps may need to be taken, however, to ensure that fleets do not sub-divide their structures to potentially avoid regulation by falling under whatever threshold is put in place.

5. Leakage Issues

There are components of the large fleet sector for which there may be a high level of leakage from any attempt to regulate the large fleet sector. Medium- to large-scale fleets in the goods delivery sector have the ability to locate themselves in any number of locations so long as they have at least some reasonable level of proximity to the markets they operate in. Thus it is possible that in response to any cap-and-trade regime in WCI states and provinces that trucking fleets (in particular) may relocate to the borders of adjoining states and provinces not subject to the cap-and-trade regime.

However, the International Fuel Tax Agreement (IFTA) requires diesel trucks operating in multiple jurisdictions to calculate fuels consumed in each state and province based on the miles traveled in each state/province. All the WCI partners are parties to the IFTA.[15] Consequently, the IFTA data could be used to compute a compliance obligation for fleet operators of diesel trucks that operate in multiple jurisdictions, thereby avoiding leakage.[16]

Leakage is less of an issue for fleets that must serve specific areas. These fleets may include municipal and state/province government vehicles, as well as electric and gas utility trucks. Similarly, leakage would not apply to ferry fleets, and likely not to marine barge and other localized marine fleets.

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[15] The 48 contiguous states of the United States and 10 Canadian provinces are parties to IFTA. Yukon Territory, Northwest Territory, Nunavut, and the District of Columbia are not parties to IFTA.

[16] IFTA covers diesel trucks with the following characteristics: (a) has three or more axles; or (b) has two axles and a gross vehicle or registered gross vehicle weight of more than 26,000 pounds or 11,797 kilograms; or (c) is used in a combination that has a combined or registered gross vehicle weight of more than 26,000 pounds or 11,797 kilograms. Recreational vehicles are not covered.

Smaller fleets serving specific urban markets are less likely to be able to relocate to avoid regulation. However, as previously noted, the administrative feasibility of regulating the smaller fleets is in question.

I. Agriculture Emissions

1. Description

1.1 Sectors

This design element covers the agricultural sector, which includes a diverse set of production activities, including: crop production; livestock production; grazing lands; and other activities. Agriculture can serve as a sink (i.e., can remove carbon dioxide from the atmosphere) or as a source of emissions. Not included in this design element is forestry, although agriculture and forestry are often interrelated because land can change from one use to the other and back.

1.2 Emissions Sources

Given the diversity of agricultural activities, there are a large number of sources of emissions, including:

- methane and nitrous oxide (N_2O) emissions from livestock manure management;
- N_2O emissions from soils due to fertilizer use, legume production, and increased microbial activity associated with liming;
- methane emissions from livestock digestive processes, rice cultivation; and cultivation of other wetland crops;
- methane emissions from the conversion of lands from trees or grasses to annual cropland; and
- carbon dioxide (CO_2) emissions from the use of lime.

In addition to these sources, agricultural lands can emit CO_2 or act as a sink for CO_2 in a given year by changing the carbon stock on the agricultural land. Carbon stock is the carbon contained in biomass, including above and below ground biomass, at a specific point in time. If the carbon stock increases from one year to the next, the agricultural land acted as a sink, and accumulated carbon by removing it from the atmosphere. If the carbon stock decreases, the land released carbon.

Practices that can increase carbon stock (i.e., remove CO_2 from the atmosphere) include reduced tillage, use of cover crops, favorable crop rotations, changing from row crops to permanent pasture or other perennial crops, and increasing productivity of plants on pasturelands.

Emissions due to fertilizer production and fuel use in farm equipment are not included as sources in this sector.

1.3 Greenhouse Gases

N_2O and methane are the primary GHG emitted in the agriculture sector. CO_2 emissions and sinks also occur.

1.4 Point of Regulation

The point of regulation for agriculture is the land owner. The land owner typically has control over how the lands are managed, including the type and level of agricultural production that takes place. Consequently, the land owner has the most influence over the activities that lead to emissions (or sinks) on his/her agricultural lands.

Notably, some agriculture lands are leased to others who use the land for production purposes. For example, grazing lands are often leased to livestock owners, so that the land owner does not necessarily have a comprehensive inventory of the livestock grazing taking place. Federal and state governments are significant leasers of grazing lands, for example accounting for approximately 33% of grazing and range lands in the United States.

2. Emissions and Entity Data

Among the WCI partner states and provinces, agriculture emissions accounted for about 58 MMT of CO_2e in 2005, or about 6% of total gross emissions. This percentage is less than 10% for all the partners, with the exception of Manitoba, which reports agriculture emissions accounting for 30% of gross emissions in 2005. Table 12 summarizes the emissions for the WCI partners.

The total number of entities that would be covered in this sector depends on whether, and at what level, an annual emissions threshold is set. In the livestock sector, confined animal operations (CAOs) typically have the highest concentration of animals and manure that can lead to emissions. As shown in Table 12, the number of CAOs totals more than 18,000 among the WCI partners. Also shown in the table is the number of farms with harvested cropland, an indication that nitrogen fertilizers may be used. The total number of farms with harvested cropland is on the order of 150,000 among the WCI partners.

3. Emissions at the Entity Level

Precise direct measurement of agriculture GHG emissions at the entity level is not currently practical. Emissions estimates are typically made using emissions factors associated with various types of management practices. However, site-specific conditions and individual management practices can have a significant impact on emissions so that actual entity-level emissions can vary substantially from the estimates based on representative emissions factors.

For example, N_2O emissions from soils are the largest component of agriculture GHG emissions. Emission factors for N_2O from soils have very large ranges and uncertainties due to the highly variable rate of emissions spatially and temporally across soil conditions and seasons. Perhaps most importantly, the N_2O emissions factors cannot currently estimate with precision the changes in emissions that may result from changes in practices at the entity level.

Similarly, although emissions factors for livestock emissions, manure management emissions, and rice cultivation emissions are available, they do not easily incorporate site-specific practices that can affect emissions rates.

Emissions or removals of CO_2 can be inferred from changes in carbon stocks. For example, soil carbon stocks can be measured by using soil samples. Together with a properly designed survey, such samples can result in estimates of soil carbon content with high levels of accuracy and precision. However, because the increases or decreases in carbon stocks are small relative to the amount of carbon in the soil, changes can best be estimated by performing surveys spaced a number of years apart. In most circumstances, a five year interval between measurements is likely to be the shortest interval that would result in reliable estimates of changes in soil carbon.

Emissions modeling, combined with field measurements, can be used to better estimate emissions and sinks from agricultural activities. However, the use of these models is generally beyond what can reasonably be expected from most producers.

4. Administration

If individual agricultural land owners are required to hold allowances or report on emissions and emission reductions, a very large number of entities would be involved. As shown in Table 12, many thousands of entities would have compliance obligations. Moreover, as suggested above, tools to measure many agricultural emissions are in early stages of development, and current estimates can have large uncertainties. The wide variety of mechanisms that result in emissions or emission reductions, together with the difficulties of obtaining reliable estimates in many cases would pose a significant challenge. Additionally, as mentioned above, many land owners lease their land to others for grazing or other agricultural purposes. Consequently, the land owner may not have adequate information to perform a reasonable emissions calculation. When combined, these factors pose very significant administrative challenges.

5. Leakage Issues

The agriculture sector is highly vulnerable to emission leakage. The market for agriculture products is international in scope, and highly competitive. If compliance requirements in the WCI region reduce production, production could increase in another region. The shift in production location may result in no net change in emissions overall. Consequently, particular care must be taken as it relates to imposing reporting or other compliance requirements within this sector.

Table 12: Summary of Agriculture Emissions

State/Province	2005 Emissions (MMT CO_2e)	Percent of 2005 Gross Emissions	CAO Operations[a]	Harvested Cropland[b]
Arizona	4.7	5%	547	3,139
California (2004)	23.5	5%	4,815	54,115
New Mexico	6.2	9%	857	7,204
Oregon (2004)	4.9	7%	3,682	23,013
Utah	4.2	6%	1,862	9,661
Washington	5.6	6%	3,043	21,802
British Columbia	2.6	4%	2,000[c]	14,484
Manitoba	6.1	30%	1,439[c]	16,660
Total WCI Partners	**57.7**	**6%**	**18,245**	**150,078**

a. Confined animal operations, including dairy operations, beef cattle operations, and hog farms. Does not including grazing operations (i.e., non-confined).

b. Entities reporting harvested cropland.

c. Does not include beef cattle operations.

MMT = million metric tons

Percent of gross emissions calculated for each state/province.

Preliminary estimates, subject to review and revision.

J. Forestry and Land-Use Change

1. Description

Forestry and land-use change encompass the suite of human activities and naturally occurring processes and events that result in changes in forest cover and/or changes to the amount of carbon stocks on forest lands. Forestry can serve as a sink (i.e., can remove carbon dioxide from the atmosphere) or as a source of emissions.

1.1 Sectors

The forestry sector refers to lands that support, or can support, a given tree canopy cover and that allow for management of one or more forest resources, including timber, fish and wildlife, biodiversity, water quality, recreation, aesthetics and other public benefits.[17] Forest lands are owned by federal, state, provincial, and municipal governments, companies, individuals, and non-governmental organizations. Forest lands can serve multiple purposes, including supply of wood and fiber, recreation, habitat, scenic enhancement, water quality, preservation of carbon stocks, and other purposes.

Land-use change refers to the conversion of land from one purpose to another. Forest land may be converted to other uses through deforestation or, for example, to residential use. Land that was not in forest cover may become forest land (i.e., through reforestation or afforestation). Agriculture and forestry are often interrelated because land frequently changes from one use to the other and back.

This design element does not include the processing of timber into products, or the use of forest biomass for energy production. The long-term fate of harvested wood products could be included as part of this design element, but doing so is challenging, particularly at the land owner level.

1.2 Emissions Sources and Sinks

The extent to which forest lands emit greenhouse gases (primarily CO_2) or act as a sink for CO_2 in a given year is measured in terms of the change in carbon stock on the forest land. Carbon stock is the carbon contained in forest biomass, including above and below ground biomass, at a specific point in time. If the carbon stock increases from one year to the next, the forest land acted as a sink, and accumulated carbon by removing it from the atmosphere. If the carbon stock decreases, the forest land released carbon.

Carbon stocks on forest lands can increase or decrease through both natural events and human intervention. Natural fire cycles affect the carbon stock on forest lands. Human activities can affect the fire cycle, however. Forest management for commercial or noncommercial harvest of biomass can also affect carbon stocks. If the amount of biomass that grows is the same as the amount of biomass removed for products or energy, the managed forest is presumed to result in no net emissions from changes in carbon stocks. In the event of forest fires, insect and disease, or unsustainable harvesting practices, forests can act as significant carbon sources.

Land-use change can also result in emissions or a sink. Land that changes from non-forest cover to forest cover will show an increase in carbon stock, and consequently is a sink over the

[17] A tree canopy cover of 10% is used to define forest land by the California Climate Action Registry (see *Forest Sector Protocol*, Version 2.1, The California Climate Action Registry, September 2007, available at: http://www.climateregistry.org/PROTOCOLS/FP/). Other percentages are also used, such as 25% in British Columbia and other Canadian provinces.

long term. Land that is converted from forest cover to another use, such as agriculture, will show a reduction in carbon stock, and consequently is an emission source.

While the overall impact of human activities and natural events and processes can be assessed as changes in carbon stock, the specific activities and events that result in emissions include:

- immediate release from burning of biomass (including in forest fires);
- residual release from biomass decay;
- soil carbon releases due to soil disturbance;
- decay of harvested wood products; and
- decay of standing timber (from insect and disease or general decline).

Finally, it should be noted that long-lived wood products, such as furniture and building materials, also represent a carbon pool. The carbon in these products was removed from the atmosphere through forest management. Methods for accounting for the wood product carbon pool have been developed for national and state/province level inventories. However, accounting methods are not available for application at the land owner level. Consequently, incorporating the carbon pool from long-lived wood products into a cap-and-trade program at the land-owner level would be very challenging at this time.

1.3 Greenhouse Gases

The predominant greenhouse gas affected by forestry and land-use change is CO_2. However, biomass combustion (e.g., due to forest fires) also results in nitrous oxide (N_2O) emissions. Forests can also act as either sources or sinks for methane. The N_2O and methane emissions are very small compared to the CO_2 emissions and sinks.

1.4 Point of Regulation

The point of regulation for forestry and land-use change is the land owner. The land owner typically has control over how the forest lands are managed, within the applicable regulatory framework of the jurisdiction in which the lands are located. Consequently, the land owner has the most influence over changes in carbon stock on his/her forest lands.

As discussed below, governments are large owners of forest lands. Companies and individuals own smaller parcels, although some individual private holdings are significant. A threshold of parcel size may be used to limit the coverage of the large numbers of owners of small amounts of forest lands.

2. Emissions and Entity Data

Among the WCI partners and provinces, forestry and land use change have been estimated to be an overall sink for GHG emissions. As shown in Table 13, the sink was on the order of 11% of gross emissions in 2005. The size of the sink varies significantly across states and provinces, with the forestry sink being sizable compared to gross emissions from some jurisdictions. Of note is that although forestry and land use currently are a sink, some analysts have estimated that the forest sector could be a much larger sink than is currently the case. Consequently, forestry provides an opportunity to increase the sequestration of carbon.

Governments are significant owners of forest lands in the WCI states and provinces. For example, the provincial government of British Columbia owns 95% of forested land in the province. Most of remainder of the forest land is owned by a small number of forestry companies, and many small land owners. In California, the federal government owns approximately 52% of forest lands, and provincial/local governments own about 3%. The remainder of the forest land (45%) is privately owned. Similarly, in Washington, approximately 57% of forest lands are publicly owned, with 43% privately owned. Table 13 lists the portion of forest land that is publicly owned in each WCI partner jurisdiction.

The land owners that convert forest lands to other uses (such as urban development) are not typically the large government land owners. Rather, owners of smaller parcels are involved in converting forest land to other uses, an activity that typically results in net emissions. Many thousands of land owners in the WCI region play a role in conversion of forest lands to other uses.

3. Emissions at the Entity Level

Protocols on how to perform forest carbon modeling are well established (IPCC Good Practice Guidance[18], 2006 IPCC Inventory Guidelines[19]) as are international reporting mechanisms (UNFCCC, Kyoto Protocol[20]). While the models have degrees of uncertainty (particularly due to the quality and consistency of input inventory data and growth and yield curves), they are internationally accepted and used. These approaches are typically used at the government level for national and state/province inventories.

Protocols have also been developed for measuring changes in carbon stock at the land owner or entity level.[21] To apply these methods, landowners would be required to conduct periodic inventories to determine their carbon stock over time. As these methods typically rely on characterizations of samples of areas within forest lands, and are measuring biological activities, the resulting emission/sink estimates are generally considered to be less precise than emissions calculations for fossil fuel combustion emissions.

Notably, the extent to which a given parcel of forest land is a source or a sink in a given year depends, in part, on previous years and future years. For example, the natural fire cycle may reduce the carbon stock on certain forest lands in a given year. In that year, the land is an emissions source. In subsequent years, the carbon stock may increase, indicating that the forest is a sink. Over time, the forest may be carbon neutral, so that it is neither a source nor a sink. This time-dependent nature of carbon stocks on forest lands would need to be addressed in the estimating procedure at the individual land owner level under a cap-and-trade program.

4. Administration

As described above, governments typically own a large portion of forest lands. Nevertheless, there are many owners of large land holdings (including those engaged in commercial harvesting) and a very large number of owners of smaller land parcels. Many of the forest land owners are not typically covered by existing air quality regulations, although those involved in commercial harvesting may be regulated under other programs. Identifying all the relevant land owners could be a significant administrative challenge unless smaller parcels were excluded from the program.

The ability to measure emissions from all relevant land owners also presents a challenge. Specialized expertise is required to measure carbon stock changes at the entity level using

[18] http://www.ipcc-nggip.iges.or.jp/public/gpglulucf/gpglulucf.htm

[19] http://www.ipcc-nggip.iges.or.jp/public/2006gl/index.htm

[20] http://unfccc.int/kyoto_protocol/items/2830.php

[21] See, for example, *Forest Sector Protocol*, Version 2.1, The California Climate Action Registry, September 2007, available at: http://www.climateregistry.org/PROTOCOLS/FP/.

existing protocols. Ensuring the availability of this expertise to all relevant land owners could also present a significant challenge.

Given these administrative challenges, a less than fully comprehensive approach to covering forestry and land-use change within a cap-and-trade program may need to be considered. For example, the cap-and-trade program could focus solely on land conversion, from forest cover to other uses, and from other uses to forest cover. Other policy measures and approaches (outside of the cap-and-trade program) could be used to address the other aspects of the forestry and land-use change sector. The portion of emissions/sinks that could be addressed with a cap-and-trade program by such an approach remains to be assessed.

5. Leakage Issues

Important components of the forestry sector are highly vulnerable to emission leakage. The market for wood products is international in scope, and highly competitive. In response to reduced commercial forest production in one region, production could increase in another region. The shift in harvest location may result in no net change in emissions overall. Consequently, particular care must be taken as it relates to requirements for emission measurement or other requirements for the commercial forest products portion of the sector.

Land conversion, from forest lands to urban development for example, may be vulnerable to leakage if alternative locations for development are available. However, given the size of WCI jurisdictions, such leakage has the potential to be small. Perhaps more important is the potential for increased costs to affect the rate of forest conversion. If significant costs are imposed to prepare emission inventories for forest lands, owners of small parcels may find it advantageous to convert their land to other uses so as to avoid the emission inventory requirement. This potential impact must be considered carefully to assess potential negative impacts of including forest lands under a cap-and-trade program.

Table 13: Summary of Forestry Emissions (Sinks)

State/Province	**2005 Emissions (MMT CO_2e)**	**Percent of 2005 Gross Emissions**	**Portion of Forest Land Publicly Owned**
Arizona	(6.7)	-7%	59%
California (2004)	(4.7)	-1%	55%
New Mexico	(20.9)	-29%	62%
Oregon	--[a]	--[a]	63%
Utah	(13.0)	-19%	82%
Washington	(39.1)	-42%	57%
British Columbia	(25.3)	-39%	97%
Manitoba	--[a]	--[a]	94%
Total WCI Partners	(109.8)	-11%	**--**

a. Data remaining under investigation.
MMT = million metric tons
Percent of gross emissions calculated for each state/province.
Preliminary estimates, subject to review and revision.

K. High GWP Gases

1. Description

Hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6) are potent greenhouse gases, some of which persist in the atmosphere for thousands of years. These gases, referred to as high global warming potential (GWP) gases are from 650-23,900 times more potent than CO_2 in terms of their capabilities to trap heat in the atmosphere over a 100-year period. Also, because they remain in the atmosphere almost indefinitely, atmospheric concentrations of these gases will increase as long as emissions continue.

1.1 Sectors

High GWP gases are used by and emitted from a wide variety of activities and equipment. The overwhelming majority of the use and emissions of these gases are associated with their use as substitutes for ozone depleting substances that have been phased out. Consequently, these gases are used are as refrigerants in residential, commercial and industrial equipment, as well as aerosol propellants and solvents.[22] High GWP gases are also used in semiconductor manufacturing, magnesium production, and other miscellaneous applications. SF_6 is used in electric power transmission and distribution systems. Emissions of SF_6 from these sources are included in the electric sector, and are not included here.

In some cases, high GWP gases are produced as byproducts of industrial processes. For example, CF_4 and C_2F_6 are produced during aluminum smelting. These process-related emissions are not included in this design element, but rather are included under industrial process emissions.

1.2 Emissions Sources

High GWP gases are emitted in several ways. When used as refrigerants, these gases may leak during normal equipment operation, or may be released as a result of equipment failure. Additionally, during equipment servicing or disposal the refrigerants may be deliberately or inadvertently released. It is currently best practice to collect and recover refrigerants during servicing and disposal so as to prevent emissions (capture and recycling is required in some jurisdictions). However, consumers can purchase cans of refrigerant to recharge their automobile air conditioners. Emissions may result from these consumer maintenance activities, and residual amounts of refrigerant in the cans are also typically emitted.

The semiconductor manufacturing industry uses high GWP gases in plasma etching and in cleaning chemical vapor deposition tool chambers. These processes use the gases to selectively create circuitry patterns and remove deposited materials.[23] The high GWP gases are vented as part of this process. In some cases, the gases may be captured and recycled to prevent emissions. The magnesium metal production and casting industry uses sulfur hexafluoride (SF_6) as a cover gas to prevent the rapid oxidation of molten magnesium in the presence of air. The SF_6 is emitted as part of this process.

1.3 Greenhouse Gases

The high GWP gases include hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6).

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[22] For more information see: *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 –2005*, U.S. Environmental Protection Agency, Washington, D.C., 2007, p. 4-44, available at: http://epa.gov/climatechange/emissions/usinventoryreport.html.

[23] For more information, see: http://www.epa.gov/highgwp/sources.html.

1.4 Point of Regulation

It is generally considered impractical to define the point of regulation for high GWP gases as the point of emission for the majority of the high GWP emissions sources. In particular, emissions from leaks and servicing of residential, commercial, and industrial refrigeration and air conditioning equipment would be the responsibility of the equipment owners and servicing companies. In most cases these emissions cannot be measured directly, and the equipment owners and service personnel are not in a position to calculate and report the emissions as part of a cap and trade system. Similarly, the users of aerosol products are not in a position to calculate and be responsible for the emissions associated with their product usage.

Consequently, the approach under consideration is to hold the manufacturers of the high GWP gases responsible for the emissions. In nearly all cases, all the gases produced will eventually be emitted. The gases are rarely converted to other substances or destroyed. Consequently, the quantity of gas manufactured is a reasonable estimate of the expected emissions. The gas manufacturer would be required to hold allowances to cover the total production and sale of high GWP gases each year.

In taking this approach, the program would cover the emission of newly manufactured high GWP gases. This approach does not cover the high GWP gases that are already stored in equipment, and are vulnerable to release.

As an alternative to placing the point of regulation on the manufacturers, it could be placed at the point where the gases enter into commerce in each state or province. This approach would require comprehensive tracking of the distribution and sale of these gases within each jurisdiction, for example through the licensing of dealers.

The use of high GWP gases in industrial applications, such as semiconductor manufacturing and magnesium manufacturing, could be addressed differently. The entity responsible for the emissions (i.e., the facility) could be defined as the point of regulation. The quantity of gas used and emitted could be tracked, and the entity would be required to hold emission allowances.

2. Emissions and Entity Data

Among the WCI partner jurisdictions, the high GWP gases are a relatively minor portion of total gross emissions, accounting for about 3% of total emissions in 2005. However, these emissions are expected to grow faster than total emissions through 2020. Table 14 summarizes the emissions estimates for 2005.

High GWP gases are produced by a small number of chemical manufacturing companies internationally. For example, *Chemical Market Reporter* identifies nine companies producing fluorocarbon gases (HFCs) in the United States at 14 plants. Only one plant is located in a WCI partner state, accounting for less than 10% of total production capacity.

3. Emissions at the Entity Level

As described above, one point of regulation under consideration is at the gas manufacturer. At this point, the regulated entity (the manufacturer) cannot measure or calculate actual GHG emissions. Rather, the entity can calculate potential emissions based on the expected release over time of the total amount of the gas produced. The manufacturer would calculate its emissions responsibility as the quantity of gas produced times the appropriate GWP for the gas.

If the point of regulation is at the industrial facility that uses and emits the gas, the calculation would be similar. The total amount of gas used and emitted would be multiplied by the appropriate GWP. Any destruction or conversion of the gas in the industrial process could be accounted for at the facility level.

4. Administration

The relatively small number of manufacturers of high GWP gases would make administration at the manufacturer level tractable. However, as discussed above, nearly all the manufacturers and their plants are not located in WCI jurisdictions. Consequently, WCI states and provinces would not be in a position to regulate their production or sales of these gases.

The alternative approach of setting the point of regulation at the point where the gases enter into commerce in each state and province would be more administratively challenging. A system of licensing and tracking of the sales of the gases does not currently exist, and would need to be created.

Assigning the point of regulation to industrial facilities that use the gases, such as semiconductor manufacturing and magnesium manufacturing, is administratively feasible. There are a relatively small number of facilities, each of which could be tracked. The covered entities should have the capability to know their compliance obligations and understand the applicable requirements. However, it should be noted that these facilities account for a very small portion of the total emissions from this sector.

5. Leakage Issues

Vulnerability to emissions leakage is an important consideration for this design element. High GWP gases are produced and traded internationally. Actions that increase production costs in the U.S. and Canada could shift production elsewhere, resulting in no change in actual emissions. To address this leakage potential, imports of the gases would also need to be covered, which is beyond the jurisdiction of states and provinces. The potential impacts associated with covering industrial facilities should also be examined. For example, semiconductor production could also shift elsewhere, resulting in no change in actual emissions.

Table 14: Summary of High GWP Gas Emissions

State/Province	**2005 Emissions (MMT CO_2e)**	**Percent of 2005 Gross Emissions**
Arizona	3.7	4%
California (2004)	14.8	3%
New Mexico	1.1	1%
Oregon (2004)	2.1	3%
Utah	2.0	3%
Washington	2.1	2%
British Columbia	0.0	0%
Manitoba	0.0	0%
Total WCI Partners	**25.8**	**3%**

NA = Data not available. Data currently being developed.
MMT = million metric tons
Percent of gross emissions calculated for each state/province.
Preliminary estimates, subject to review and revision.

January 2, 2008 Scope Subcommittee Summary of Major Design Options Under Consideration

List of Commenters

1000 Friends of Oregon

Alcoa, Inc.

American Automotive Leasing Association

American Forest & Paper Association

American Trucking Association

Arizona Public Service Company

BC Forest Industry Working Group on Climate Change

Boise Cascade

Business Council of British Columbia

California Council for Environmental and Economic Balance

California Municipal Utilities Association

Canadian Lime Institute

Canadian Parks and Wilderness Society

Cement Association of Canada

Center for Resource Solutions

Chevron Corporation

City of Phoenix Office of Environmental Programs

Climate Solutions, Environment Washington, Environmental Defense, National Wildlife Federation, Natural Resources Defense Council, New Mexico Conference of Churches, Oregon Environmental Council, Oregon Interfaith Power and Light, The Pembina Institute, Sightline Institute, Western Environmental Law Center, Western Resource Advocates

El Paso Pipeline Group

JACO Environmental

National Lime Association

National Wildlife Federation

The Nature Conservancy

Pacific Gas and Electric Company

PNGC Power

Portland Cement Association

Puget Sound Energy

Semiconductor Industry Association

Sempra Energy

Sierra Club of Canada

Sightline Institute

Southern California Edison Company

Terasen Gas

Tucson Electric Power

Union of Concerned Scientists

Washington Forest Protection Association

Washington Public Utility Districts Association

Waste Management, Inc.

WEST Associates

West Linn Paper

Western Power Trading Forum

Weyerhaeuser

Western Climate Initiative

Western Climate Initiative
Scope Subcommittee
Stakeholder Conference Call
8:30 AM Pacific Time   February 12, 2008

Call in Number: 1.800.868.1837; Participant Code: 659 537#
To ask a question, press *1

8:30 Introductions

8:40 Transportation Fuels

The subcommittee would like to understand the comments received regarding the inclusion of transportation fuels in the scope of the WCI cap-and-trade program. Many comments were received supporting the inclusion of transportation fuels. We would like to discuss the following issues:

1. How does the inclusion of transportation fuels affect other sources in the cap-and-trade program, and the development of a market for allowances?
2. Should alternate strategies be used to reduce emissions from transportation through 2020 rather than including transportation fuels in a cap-and-trade program? How do the alternate strategies compare in terms of cost and environmental effectiveness? Are some strategies complementary to including transportation fuels in a cap-and-trade program?
3. Comments were received suggesting that transportation fuels be phased in to a cap-and-trade program in the future. Does phasing create risks, such as increasing uncertainty or volatility in the allowance market? What are the benefits of phasing?
4. What are the pros and cons of allowing flexibility among the WCI states and provinces regarding the inclusion of transportation fuels in the cap-and-trade program?
5. If transportation fuels are included in the scope, how will the transportation fuels industry comply with the cap? What are the implications of the cost of carbon allowances being substantially passed through to consumers? Should the potential impacts on low income consumers be addressed, and if so how?

9:20 Natural Gas

The subcommittee would like to understand the comments received regarding the inclusion of residential and commercial natural gas combustion by placing the regulatory obligation at the local distribution company. We would like to discuss the following issues:

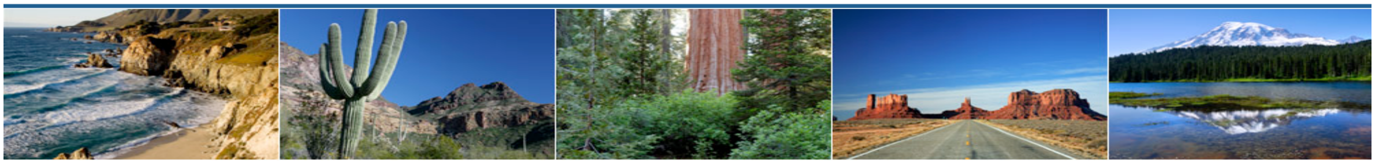
1. Should alternate strategies be used to reduce emissions from residential and commercial natural gas combustion through 2020 rather than including them in a cap-and-trade program? How do the alternate strategies compare in terms of cost and environmental effectiveness? Are some strategies complementary to including these emissions in a cap-and-trade program?
2. If these emissions are included in the scope, how will the LDCs comply with the cap? What are the implications of the cost of carbon allowances being substantially passed

through to consumers? Should the potential impacts on low income consumers be addressed, and if so how?

9:40 Open Discussion on All Scope Topics

The subcommittee invites participants to ask questions and make additional comments.

Western Climate Initiative



WCI Reporting Subcommittee
1/3/08

Summary of Major Options for a GHG Reporting System to Support the WCI Program

Background

A robust and credible reporting system will be the backbone of the WCI program. This system will need to ensure that emissions are quantified and reported in an accurate and transparent manner. It will allow regulators in the participating jurisdictions to assess compliance of regulated sources, measure progress against state, provincial and regional targets and generate public trust in this progress. Additionally, market participants of all stripes will rely on the reporting system and the data it generates to make decisions on which significant transactions will be based. Confidence in the reporting system will be critical to the success of the WCI program.

Starting Assumptions

The WCI is fortunate in that several GHG reporting systems exist that can inform the design of and perhaps even underpin the reporting system it will require. The Reporting Subcommittee has assessed many of these systems and anticipates that the reporting system it ultimately recommends will attempt to establish as much consistency with as many of them as the details and rigor of the WCI program allow. Many of the details of the WCI reporting system however will necessarily depend on decisions currently being considered by other Subcommittees.

This reality aside, the WCI partners are unanimous in their view that the reporting component of the program should rely as heavily as possible upon the infrastructure currently under design by The Climate Registry (the TCR). The TCR is a nonprofit corporation that is a collaborative effort between U.S. states, Canadian provinces and Mexican states to establish a common infrastructure for measuring and reporting GHG emissions. All of the WCI partners are members of the governing board of the TCR. The objective of the TCR is to provide a common set of tools for the measurement and reporting of GHG emissions that can support a broad range of state or provincial policies.

In the first phase of its development, the TCR is designing a voluntary entity wide GHG reporting program. This program can be conceptualized of as consisting of three major components: 1) entity reporting specifications, 2) quantification methodologies and 3) reporting services and systems. The reporting specifications dictate all parameters specific to the TCR program--what must be reported, how an entity is defined for reporting purposes, the sources and gases it must report, the frequency of reporting and verification, etc. The quantification methodologies dictate how emissions from specific sources are measured or calculated. Finally, the TCR's services and systems will provide assistance to reporters, support verification, and collect, store and make data available to the public.

A WCI reporting system could rely heavily on the TCR's quantification methodologies and its services and systems. Doing so should reduce the costs of implementation for partners, ease the reporting burden on regulated entities, and ensure the basic consistency both between data collected within the WCI region and data collected in other regions that also rely on the TCR. However, the WCI will necessarily need to develop its own reporting specifications, consistent with the scope of the sources and gases it regulates and other program parameters. Figure 1 and Table 1 illustrate how the WCI could rely on the TCR to provide major components of its reporting system.

<u>Major Options for a Reporting System</u>

Beyond the WCI's intention to rely on TCR infrastructure to the maximum extent possible, the Reporting Subcommittee has identified several major options for the design and implementation of a reporting system that it is actively considering. These are summarized below.

The WCI Reporting Subcommittee welcomes partner, observer, and stakeholder input regarding these options. Specifically, the Subcommittee seeks input regarding additional advantages or disadvantages concerning the options below and any recommendation that the commenting party may have for choosing between the options. In addition, the Subcommittee welcomes any suggestions parties may as to whether additional major options should be considered, and if so what they are.

1. Breadth/Scope of Reporting

a. Should reporting be required only for sectors/sources included within the cap?

Advantages
▪ Ease of start up, could be put in place relatively quickly
▪ Necessary reporting methodologies likely available "off the shelf"

Disadvantages
▪ Limited data utility: supports compliance only

b. Or, should reporting be required for sectors/sources not included in the cap-and-trade program (e.g., ones that are likely to be phased in over time)?

Advantages	Disadvantages
▪ Could support expansion of cap to additional sectors/sources (both by collecting data that could inform decisions about expansion and through regulatory assimilation of reporters)	▪ Increased reporting burden
▪ Potential to stimulate voluntary reductions outside of cap through measurement and public reporting	▪ May require development or refinement of reporting approaches that do not yet exist or are not yet robust enough
▪ Data collection could support development of sectoral baselines for offsets	
▪ System could serve to aggregate top down inventories of partner jurisdictions for a regional top down inventory	

2. Initiation of Reporting

a. Should mandatory reporting begin before cap and trade commences?

Advantages	Disadvantages
▪ Bottom-up data could be used to "true-up" baselines otherwise established with top-down data only	▪ Likely to delay start of cap
▪ Sector/source data could inform allocation decisions (minimizing initial risk of over-allocating sources)	
▪ Would allow reporters time to put measurement and management systems in place	
▪ Could promote voluntary early reductions (especially if coupled with a mechanism for incentivizing early action)	

b. Or should mandatory reporting begin only with the start of the cap's first compliance period?

Advantages	Disadvantages
▪ Could initiate cap more quickly	▪ First compliance period of cap may be a de facto "training wheels" period that may be accompanied by greater market volatility
▪ Minimizes pre-cap compliance burden	

3. Coordination Among Partner Jurisdictions on Reporting

a. Should WCI develop a single WCI reporting rule that stipulates all reporting specifications?

Advantages	Disadvantages
▪ Maximizes harmonization of reporting systems across WCI jurisdictions and consistency of data collected there from	▪ Adoption of a single reporting rule in all WCI jurisdictions, without significant modification may prove difficult
▪ Easy adoption of reporting rules for jurisdictions that do not already have reporting rules in place	▪ Could create challenges for WCI jurisdictions that already have reporting rules in place
▪ Easier to update or modify reporting rules through a unitary reporting rule	
▪ Minimizes compliance burden for entities operating sources in multiple WCI jurisdictions	

b. Or should individual WCI jurisdictions have loosely coordinated rules possessing common core elements? If so, what aspects should the common core elements cover or include?

Advantages	Disadvantages
▪ Would require less modification of existing rules in WCI jurisdictions that have adopted or are developing reporting systems	▪ Partners put in position of assessing whether one another's reporting rules comply with minimum standards
▪ Identifying the minimum required common elements for reporting rules for partner jurisdictions would require less time and resources than development of a detailed model reporting rule	▪ Partners might be need to develop quantification methods for sources and sectors for which methods do not yet exist (either in TCR guidance or in other existing mandatory reporting systems)

4. Data Management and TCR Interaction

a. Should WCI require that all capped sources report directly to and verify through the TCR?

Advantages
▪ Maintaining a single central data collection system and database through the TCR more efficient and less resource intensive than maintaining multiple partner-specific systems
▪ Minimizes the reporting burden on entities that operate regulated sources within multiple jurisdictions (i.e. reporting to a single system)
▪ Would ensure consistency across jurisdictions in the way that data quality is verified
▪ Greater ease of start-up as TCR is already in process of developing a data collection system and verification system

Disadvantages
▪ May present a legal question for some jurisdiction as to whether sources can be mandated to report to a non-profit third party
▪ Could create the appearance that partner jurisdictions are ceding compliance authority (though could be mitigated by allowing partners "first touch" such that data is not released by TCR until partner provides approval)

b. Or should sources report to and verify at the level of the individual jurisdiction (with data then uploaded to the TCR or otherwise shared centrally)

Advantages
▪ Would allow jurisdictions that have already have data collection and verification systems in place to continue to rely on those systems
▪ GHG reporting and verification in some jurisdictions might simply be "piggy-backed" on existing air pollution data collection efforts

Disadvantages
▪ WCI would have to articulate minimum data handling and verification standards
▪ Partners and TCR would have to invest significant resources in data exchange capabilities
▪ "Versioning" problem would be significant where updates to partner data collection systems would create ongoing data exchange challenges
▪ Standards for data verification could vary significantly

5. *Verification*

a. Should WCI require third party verification?

Advantages	Disadvantages
▪ Consistent with international practice	▪ Might require additional layer of data quality assurance than is already required by some jurisdictions
▪ Could rely on TCR third party verification system that is already under development	▪ Stakeholder perception that costs of verification high
▪ Efficient approach for large number of diverse source types	
▪ Could allow entities that operate regulated sources in multiple WCI jurisdictions to use a single verifier, reducing costs	

b. Or should WCI allow multiple approaches to ensuring data quality (other than third party verification)?

Advantages	Disadvantages
▪ Greater flexibility for partners to rely on existing data quality assurance approaches	▪ Nearly impossible to maintain and implement consistent standards for data quality
▪ Could streamline quality assurance process for sources reporting both GHG and other air pollution data	▪ Increased costs for entities operating regulated sources in more than one WCI jurisdiction

6. *Administrative Costs & Fees*

a. Should states and provinces mandate that fees go directly to TCR and TCR administers the reporting database?

Advantages	Disadvantages
▪ Consistent fee structure across states and provinces.	▪ States and provinces may not have authority to require fees to be paid to a third party without new legislation.
▪ Fewer transaction steps should allow lower transaction costs.	▪ States and provinces will not have fee revenue to support their reporting efforts.
▪ TCR would more directly manage its own financial health.	

Advantages	Disadvantages
	▪ There may need to be a different fee structure for entities that report only within partner jurisdictions instead of entity-wide with TCR.

b. Or should states and provinces collect fees and contract with TCR to administer the reporting database?

Advantages	Disadvantages
▪ States and provinces could use a portion of the fees to administer their reporting efforts	▪ TCR may not be assured of adequate funding to administer the database.
	▪ More transaction steps may result in higher transaction costs.

7. *Mandatory Federal Greenhouse Gas Reporting*

On December 18, 2007, Congress adopted an omnibus appropriations bill that directed the U.S. Environmental Protection Agency to develop and publish a rule requiring mandatory reporting of greenhouse gas emissions above appropriate thresholds in all sectors of the economy. The Agency is publish a draft rule within nine months, and a final rule within 18 months, and is to determine appropriate thresholds, frequency of reporting, and reporting of emissions resulting from upstream production and downstream sources to the extent it deems appropriate. Similarly on December 8, 2007, Canadian Environment Minister John Baird announced that firms in Canada's major industrial sectors (emitting above set thresholds) will be required to report their 2006 greenhouse gas emissions by May 31, 2008 to enable the Government to develop its industrial air emissions regulations.

How should WCI states/provinces and The Climate Registry incorporate and interface with this development and new Canadian Federal GHG reporting requirements in designing and implementing their GHG reporting program?

Appendix: Figures and Tables

Figure 1. WCI Interaction with TCR Reporting System Components

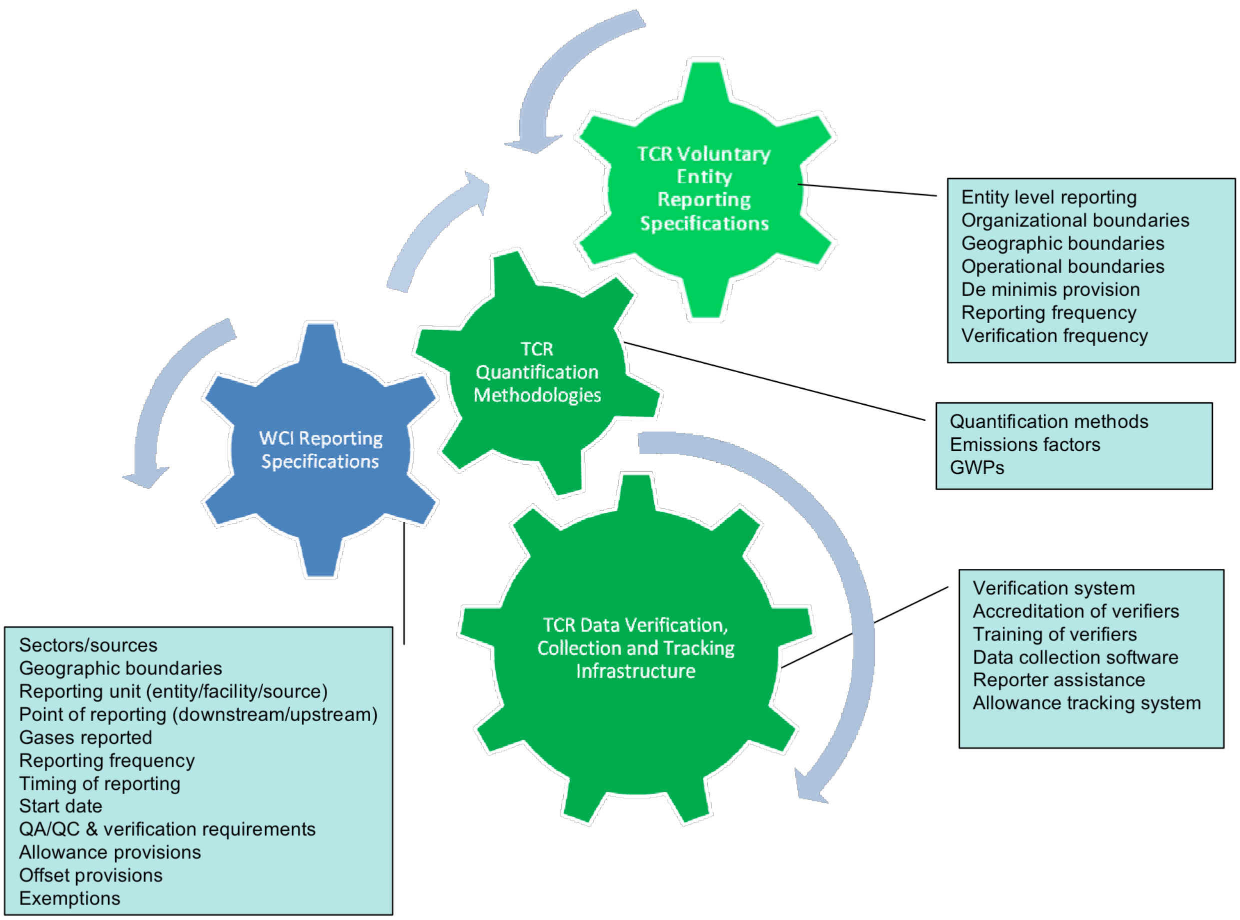


Table 1. WCI Reporting: Potential Relationship with *The Climate Registry*

Reporting / Data Tracking Feature	Where Specified*		Where Provided	
	WCI	TCR	WCI	TCR
Fundamental Parameters/Specifications				
Sectors / Sources (organizational and operational boundaries)	√			
Geographic Boundaries	√			
Start Date	√			
Reporting Unit (entity / facility / source)	√			
Point of Reporting (at source / upstream / downstream)	√			
Gases	√			
Reporting Frequency	√			
Timing of Reporting	√			
3rd Party Verification	√			
Verification Frequency	√			
Allowance Provisions	√			
Offsets Provisions	√			
Exemptions/De Minimis Provisions	√			
Implementation Parameters/Quantification				
GWPs		√		
Emission Factors		√		
Quantification Methodologies		√		
Services/Systems				
Data Quality Control (QA/QC)				√
Assistance to Reporters				√
Accreditation of Verifiers				√
Training of Verifiers				√
Data Collection Software & System				√
Allowance Tracking				√
Offsets Tracking				√

** WCI- or state-/provincially-specified for sources within WCI program. TCR specifies the same features for its entity wide reporting program and may eventually for non-WCI jurisdictions.*

January 3, 2008 Summary of Major Options for a GHG Reporting System to Support the WCI Program

List of Commenters

Alcoa, Inc.

American Forest & Paper Association

American Trucking Association

APX, Inc.

Arizona Public Service Company

BC Forest Industry Working Group on Climate Change

BP America, Inc.

Business Council of British Columbia

California Council for Environmental and Economic Balance

Cement Association of Canada

Cement Association of Canada

City of Seattle

Climate Solutions

El Paso Pipeline Group

Jeld-Wen, Inc.

League of Women Voters of Washington, Energy and Climate Portfolio

Northern California Power Agency

Oregon Municipal Electric Utilities Association

Pacific Gas and Electric Company

PacifiCorp

Pembina Institute

PNGC Power

Public Power Council

Ruud, Dean

Salt River Project

Southern California Edison Company

Terasen Gas

Washington Forest Protection Association

Waste Management, Inc.

WEST Associates

West Linn Paper Company

Western Climate Advocates Network

Western Power Trading Forum

Western States Petroleum Association

Weyerhaeuser Company

January 4, 2008 General Comments

List of Commenters

Alternative Hybrid Locomotive Technologies

Chinle School District #24

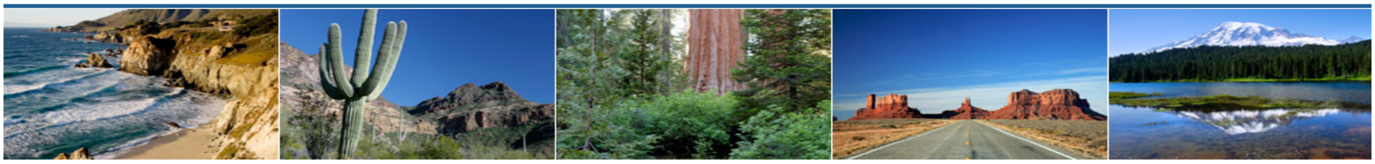
Industrial Customers of Northwest Utilities

Krahn, Peter K.

Oregon Rural Electric Cooperatives Association

Tacoma Power

Western Climate Initiative



WCI Offsets Subcommittee

Summary of Major Options for a GHG Offsets System to Support the WCI Program

January 3, 2008

Background

The Western Climate Initiative Offsets Subcommittee is examining the potential design, scope and operation of a greenhouse gas offset mechanism as an element of the WCI cap-and-trade system. The Subcommittee will develop recommendations within each of the four task areas in its workplan[1]: the role and objectives of a WCI offset mechanism, the core design elements of a WCI offset mechanism, offset eligibility and fungibility, and offset program structure and authority. While work on each of these tasks continues, the Offsets Subcommittee has identified a set of critical path questions – the Major Options listed below -- that will inform the extent and direction of further analysis and recommendations.

The Offsets Subcommittee seeks Partner, observer, stakeholder and public input on these options. This document identifies several advantages and disadvantages for each option. The Subcommittee recognizes that this list is not exhaustive, and that many of the pros and cons may be lessened – or enhanced – depending on how an offset mechanism is designed and implemented in practice. Therefore, the Subcommittee welcomes input on additional advantages and disadvantages, and on how some of the advantages shown can be maximized, or disadvantages minimized, in the design of an effective offsets mechanism.
Commenters are encouraged to fully discuss the reasoning behind each response.

[1] The Workplan for the WCI subcommittees was released to the public on October 29th, 2007 and is available at: http://www.westernclimateinitiative.org/ewebeditpro/items/O104F13792.pdf

1. Should the WCI allow offsets as a compliance mechanism?

Advantages	Disadvantages
▪ Achieves a given emissions goal at lower overall cost (economic efficiency); provides lower cost compliance options for capped sources ▪ By reducing program costs, can enable establishment of a lower cap than might otherwise be possible	▪ Poses a risk to environmental integrity of the cap, if issues surrounding additionality, permanence, leakage, quantification or verification are not adequately dealt with.
▪ Can spur technology development and innovation in sectors, sources, and locations not included in the cap-and-trade program ▪ Can provide environmental and social co-benefits, such as reduced air pollution, habitat preservation, or job creation, in sectors/sources not included in the cap-and-trade program	▪ Reduces incentive for investment and innovation in lower-emitting technologies by sources and sectors included in the cap-and-trade program ▪ Reduces any associated co-benefits in these sources and sectors
▪ Sends a carbon market signal to emissions sources or sectors that might be otherwise difficult – with emissions too small, disperse, uncertain, or episodic -- to include in a cap-and-trade program ▪ Enables participation of, and new revenues sources and business opportunities for, sectors/sources and locations not included in the cap-and-trade program	▪ May create a barrier to later inclusion of sectors/sources in cap-and-trade systems or conflict with alternative policy instruments (e.g. standards or incentives) in sectors/sources where offsets are allowed, if these issues are not adequately addressed in program design ▪ May be perceived as inequitable to the extent that some emission sources benefit from offset revenue while sources covered by the cap-and-trade system face compliance costs
▪ May be less costly per ton of GHG reduced than other mechanisms (e.g. regulation or incentives) for achieving reductions at sources/sectors not included in the cap-and-trade program, as a result of market forces	▪ May be more costly per ton of GHG reduced than other mechanisms where the cost of implementing offset projects is significantly lower than the market price of offsets
▪ Builds capacity and expertise within the region	▪ Can create administrative complexity and costs, and decisions would be needed on rules and procedures
	▪ May create challenges in sectors/sources not included in the cap-and-trade program where existing incentives and regulations differ significantly between jurisdictions, if these issues are not adequately addressed in program design

2. Location

The WCI is considering the implications of restricting the eligibility of offsets on a geographical basis. Such restrictions could limit some of the disadvantages noted above. At the same time, the WCI recognizes that such restrictions may affect the liquidity of the market and increase compliance costs.

a. Should the WCI allow offsets (only)* from projects located within its Partner jurisdictions?

Advantages	Disadvantages
▪ Enables financial flows and reductions/removals to remain within the region; concentrates other benefits of offset market to the region listed above (co-benefits, innovation); may be easier to ensure credibility and environmental integrity of offsets outside the WCI region (see list of potential disadvantages of allowing offsets from outside the WCI under question 2b below)	▪ Could lead to increased compliance costs, less stringent cap for sources/sectors in the cap-and-trade system, greater price uncertainty, reduced prospects for linkage (see list of potential advantages of allowing offsets from outside the WCI under 2b below)
▪ Could provide a competitive edge for the region, assuming other jurisdictions eventually adopt cap-and-trade programs with a role for offsets	▪ May be questioned by industry (with operations both within and outside the WCI) or by other jurisdictions
▪ May provide leverage to encourage other jurisdictions to join	

* - Note that all options are still under consideration, including the possibility of not allowing offsets from within the region, thus "only" is shown in parenthesis. The subcommittee recognizes that questions 1, 2a, and 2b are somewhat overlapping.

b. Should the WCI allow offsets from projects located outside the WCI (either in the rest of North America or internationally)?

Advantages	Disadvantages
▪ Enables access to a much larger and well established offset market, providing liquidity and offset availability, which may be important in achieving economic efficiency benefits or setting a more ambitious cap level ▪ Could reduce price uncertainty due to the magnitude of potential supply	▪ Could lead to financial flows out of the region and foregone benefits to local projects ▪ May be more difficult to ensure credibility and environmental integrity of offsets outside the WCI region
▪ Can provide support to, and increase prospects for linkage with, other regional or international climate agreements	▪ May raise concerns about consistency or rules and procedures with a WCI offsets program if created
▪ May require less administrative effort for offsets that have undergone adequately rigorous certification processes	▪ May increase complexity and costs of administration, or risk environmental integrity, for offsets that have not undergone certification processes that are adequately rigorous
▪ Can support adoption of low-carbon technologies, technology transfer, and sustainable development benefits to developing countries	▪ May not yield anticipated technology transfer and sustainable development benefits unless additional criteria are applied

3. *Quantitative Limits on the Use of Offsets.*

a. Should there be quantitative limits on the use of offsets (perhaps based on their location) to meet compliance obligations?

Advantages	Disadvantages
▪ Moderates some of the potential disadvantages of offsets (see section 1) ▪ May increase the extent of emission-reducing investments made by sources/sectors included in the cap-and-trade program	▪ Reduces ability to utilize lower-cost compliance options, and thereby could increase compliance costs ▪ Reduces the market signal to, and potential ancillary benefits from sectors, sources and locations not included in the cap-and-trade program. ▪ May result in setting a less stringent cap for the cap-and-trade program, given the higher overall program costs that offset limits might imply
▪ Can be relaxed if compliance costs are considered to be too burdensome	▪ May constrain development of a robust offset market (e.g., due to investment uncertainties) and create liquidity concerns
▪	▪ Differing limits based on location would increase administrative complexity

In relation to the quantitative limits, the WCI is also considering: how such limits might change over time; how such limits might vary based on the price of allowances; and whether offsets might be discounted (such that a ton of emission reductions from an offset might count as less than a ton towards compliance obligations, based on their location, project type, or other factors), among other possibilities.

4. *Eligible offset project types within WCI*

a. ***Should the WCI decide by August 2008 upon an initial list of approved project types, possibly including approved baseline and monitoring methodologies, prior cap-and-trade design?*** If offsets are allowed (see question 1 above), the WCI would likely establish a process and criteria for approving project types and methodologies on an ongoing basis. The question here is whether time is sufficient and benefits are significant enough to warrant establishing an initial set of approved project types (and perhaps including methodologies) prior to the WCI design to be issued in August 2008.

Advantages	Disadvantages
▪ Quantification methods exist for a number of project types, and have been approved for use in a number of systems (e.g., RGGI, CDM)	▪ Requires assessment of the availability of sufficiently robust quantification methods to ensure that offsets from a given project type are real surplus/additional, verifiable, permanent, and enforceable
▪ Sends an early signal and provides added certainty to potential offset sources and investors	

b. Should the WCI allow offsets from sources capped and regulated by the cap-and-trade system or from indirect emission reductions in sectors covered by the cap-and-trade system?

Advantages	Disadvantages
▪ Increases liquidity	▪ More administratively burdensome than treatment under the cap
▪ To maintain environmental integrity (and avoid double counting) allowances can be set aside or retired for offsets from capped sources	▪ Requires maintaining set asides or determining which allowances to retire, which can increase complexity of the system
▪ Enables additional (double) crediting for specific project types, where an added incentive for specific project types or technologies is desired	▪ Creates potential for double counting from simultaneously generating both an offset and a freed up allowance
▪ Can be allowed (as early action credit) until caps take effect	▪ Offsets from sources/sectors included in the cap-and-trade system are excluded by some other trading systems (e.g. RGGI)
▪ Indirect emissions reduction projects represent a potentially significant area of interest and potential (demand-side electricity efficiency, renewable electricity, biofuels, transit, cement use, etc.)	▪ Other mechanisms such as allowance allocation can be used to support indirect emission reduction opportunities

.

5. Linkage with, and use of allowances from, other emission trading systems

The WCI is initially discussing the question of linkage within the Offset Subcommittee, with the recognition that it raises a number of questions distinct from the offsets-specific issues noted above. Input from multiple subcommittees is anticipated. Potential linkage with other systems will have implications with respect to offsets, both directly (by enabling access to offset commodities within other systems) and indirectly (since allowances may be internally fungible with offsets in other systems).

a. Bilateral linkage: Should the WCI link directly with other, rigorous cap-and-trade programs and allow fungibility of allowances among the two (or more) systems?

Advantages	Disadvantages
▪ Encourages harmonization among regional, national, and/or international systems and prepares for a potential future global market	▪ May limit or complicate WCI design choices; linkage will be challenging where cap-and-trade systems differ significantly in terms of cap stringency and basis (e.g., absolute vs. intensity-based), borrowing, penalties for non-compliance, offset limitations, monitoring protocols, and other key features. ▪ Would be undermined by price caps or floors unless harmonized
▪ Increases market liquidity and overall cost-effectiveness across the linked systems ▪ Affords a highly credible, low-transaction cost alternative to project-based offsets, where allowances are not over-allocated in other programs, ▪ May reduce WCI compliance costs if allowances in other systems trade at a lower price	▪ Could position WCI as a "price-taker", subject to prices based on other systems' supply-demand relationships, especially if linked systems are larger (e.g. EU Emissions Trading System); ▪ May increase WCI compliance costs if allowances in other systems trade at a higher price
	▪ Differences in allocation levels and modes among systems may create equity and competitiveness concerns

b. Unilateral linkage: Should the WCI allow the use of allowances from other, similarly rigorous cap-and-trade programs to be used as a compliance mechanism by capped sources in the WCI?

Advantages	Disadvantages
▪ May reduce WCI compliance costs if allowances in other systems trade at a lower price ▪ Increases liquidity; enables access to larger market	▪ Requires assessment to establish that allowances from other systems have sufficient rigor

January 4, 2008 Summary of Major Options for a GHG Offsets System to Support the WCI Program

List of Commenters

American Trucking Association

APX, Inc.

Arizona Public Service Company

BC Forest Industry Working Group on Climate Change

BP America, Inc.

Business Council for Sustainable Energy

Business Council of British Columbia

California Council for Environmental and Economic Balance

California Public Utilities Commission Division of Ratepayer Advocates

Canadian Lime Institute

Canadian Parks and Wilderness Society

Carbon Offset Providers Coalition

Center for Resource Solutions

Climate Solutions

The Climate Trust

Defenders of Wildlife

Dynegy

EcoSecurities

Jeld-Wen, Inc.

Joanneum Research

League of Women Voters of Washington, Energy and Climate Portfolio

Morgan Stanley Capital Group, Inc.

Natsource, LLC

Northwest Natural Resource Group

Oregon Municipal Electric Utilities Association

Pacific Forest Trust

Pacific Gas and Electric Company

PacifiCorp

PNGC Power

Public Power Council

Public Utility District No. 1 of Chelan County

Salt River Project

Santa Cruz County, Arizona

Seattle City Light

Semiconductor Industry Association

Shell Energy North America

Sierra Club of Canada

Southern California Edison Company

Terasen Gas

The Nature Conservancy

Tucson Electric Power Company

Union of Concerned Scientists

Washington Forest Protection Association

Waste Management, Inc.

WEST Associates

West Linn Paper Company

Western Climate Advocates Network

Western Power Trading Forum

Western States Petroleum Association

Weyerhaeuser Company

Western Climate Initiative

Approaches to Covering Electricity Emissions

Electricity Subcommittee
David Van’t Hof, Chair

Regional Stakeholders’ Meeting
January 10, 2008

Electricity Subcommittee Tasks

- Recommend emissions scope (CO_2, N_2O, SF_6)
- Gather data on electricity sales, emissions, imports, etc.
- Evaluate options for point of compliance--maximize coverage, energy efficiency and meet other criteria determined important.
- Recommend point of regulation.
- Recommend method for establishing baseline emissions.

Stakeholder Input on Work Plan

- More than 85 sets of written comments were received on the work plan; on website
- Comments ranged from principles for the design of a regional program, to specific design choices for the electricity sector

Stakeholder Input on Work Plan

Commenters included:

- Coalition of 34 Environmental and Energy NGOs
- Avista Corporation
- Business Council for Sustainable Energy (BSCE)
- Center for Resource Solutions
- Citizens Utility Board of Oregon
- Energy Producers and Users Coalition of CA
- Industrial Customers of Northwest Utilities
- Morgan Stanley
- The Nature Conservancy
- Pacificorp
- Puget Sound Energy
- Renewable Energy Marketing Association
- Sightline
- Washington Public Utilities Association

Stakeholder Input on Work Plan

- Last week, released table of possible approaches to covering the sector
- Subcommittee seeks comments on advantages and disadvantages of each approach today, and in writing by January 22nd.

Options for Covering Electricity

- Load-based--
  - *Option 1: Load-based Cap Approach*. Retail electricity providers are required to surrender enough allowances to cover emissions attributable to electricity delivered from whatever source.
  - *Option 2: CO_2 Reduction Credits Approach*. Establish baselines for all generators in the western grid; issue CO_2RCs for reductions from baselines. Require retail providers to hold and retire CO_2RCs to accomplish reductions from sector.

Options for Covering Electricity

- Generator-based--fossil-fuel burning electricity generators surrender allowances to cover emissions.

Options for Covering Electricity

- Hybrid load-generator approaches--
  - “First seller” approach: compliance obligation on the entity that “first sells” electricity in the jurisdiction, i.e., the in-state generators and in-state sellers of electricity.
  - Other “Hybrid”: Generators as to in-state generation and retail providers as to imported electricity.

Emissions Coverage Under Options

Load-based Cap	Load-based CO2RCs	Generator-based	Hybrid of load & generator	"First Seller" Hybrid
Covers all electricity delivered in-jurisdiction through retail provider.	Covers all electricity consumed by achieving reductions anywhere in western grid.	Covers all in-jurisdiction emissions from electricity generation.	Cover in-jurisdiction generators; cover imports through retail providers	Covers all electricity at point of first sale (generators & first importer)
Not exports; may not cover self-generation. Contract shuffling.	Not exports; may not cover self-generation.	Not imports; not tribal or federal generators. "Leakage"	Covers imports, exports, generation	May not cover where federal gov't is first seller

Advantages

<table>
<tr><th>Load-based Cap</th><th>Load-based CO_2RCs</th><th>Generator-based</th><th>Hybrid of load & generator</th><th>“First Seller”</th></tr>
<tr><td colspan="2">• Covers all power through retail provider
• RP in best position to invest in EE
• Regulatory structure exists
• Successful load-based program could influence future federal program</td><td>• Well proven through experience
• Emissions monitoring and reporting structure in place
• Generators in best position to make plant upgrades & add technology
• Easily linked to other existing source-based programs
• Establishes clear emissions baselines for future federal program</td><td colspan="2">• Hybrid options have the broadest emissions coverage of the options.
• Advantage over load-based system is that it covers in-state generation more completely & covers exports
• Advantage over generator-based system is that it covers imports.
• Provisions for generator-based component could ease transition to national generator-based program.</td></tr>
</table>

Disadvantages

<table>
<tr><th>Load-based</th><th>Load-based CO_2RCs</th><th>Generator</th><th>Hybrid of load & generator</th><th>“First Seller”</th></tr>
<tr><td colspan="2" rowspan="2">

- Difficult to track power from outside jurisdiction, from power pools & short-term transactions (May not need tracking with CO_2RCs)
- Does not cover in-jurisdiction power sold & delivered outside (Exports).
- Not proposed in any national legislation, making transition to national program an issue
- International systems may not recognize load-based reductions

</td><td rowspan="2">

- Only covers in-jurisdiction emissions from power generation; imports not covered, including “imports” from tribal lands.
- If not auctioned, free allowances to the generator may not stimulate end-use energy efficiency and may also create windfall profit opportunities.

</td><td colspan="2">

- Complexity: design of the program requires both a generator-based component and an imports component.
- In regional context, special care is needed to avoid double-counting of emissions from capped jurisdictions

</td></tr>
<tr><td></td><td>

- May not cover federal first sellers

</td></tr>
</table>

Key Practical Challenges

Load-based Cap	Load-based CO_2RCs	Generator-based	Hybrid of load & generator	"First Seller"
• Tracking emissions with power sales • Assigning default emission rates • New system required to track emissions and trades • Need to distinguish cogen emissions between steam and electricity	• May need to track emissions and sales • New system required to issue and track CO_2RCs	• Most implementation issues have been addressed in existing programs • Emissions associated with imports and leakage are still being addressed by RGGI.	• Same challenges as load-based. • Need to integrate generator and load-based components. • Need to treat imports and in-jurisdiction generation similarly • New system needed to track on load-side	• Need to identify first sellers • Need to address any gaps in jurisdiction over some first sellers • Need to consider legal authority to regulate first sellers • Need to develop first-seller based tracking system

Stakeholder Feedback Needed

- Are we considering the right set of options?
- Are there additional advantages and disadvantages that should be considered for the approaches outlined?
- What approach will best serve the WCI region, and why?

Subcommittee's Next Steps

- Review and Consider Stakeholder Comments
- Subcommittee Deliberation
- Recommendation to Partners
- Incorporation in the Overall Proposals

Western Climate Initiative

Offset Mechanism Design Issues

Offsets Subcommittee
Tim Lesiuk, Province of British Columbia

January 10, 2008

Portland, Oregon

Overview

- Offsets Subcommittee
  - Mission
  - Members
  - Work Plan
  - Work Plan Comments
- Major Options
  - Offset Mechanism
  - Location
  - Quantitative limits
  - Project Types
  - Linkages

Offsets Subcommittee

- Mission
- Members
- Work Plan
- Work Plan Comments

Mission

- Recommend whether to include a greenhouse gas offset mechanism as an element of the Western Climate Initiative cap and trade system, and if so,
- Recommend design, scope and operation of such a mechanism.

Members

Affiliation	Member	Affiliation	Member
Arizona	Ed Ranger	Manitoba	Juliane Schaible
British Columbia	Tim Lesiuk	Manitoba	Neil Cunningham
British Columbia	Rachel Boston	Nevada	Ryan McGinness
British Columbia	Dale Draper	New Mexico	Jim Norton
British Columbia	Dennis Paradine	Ontario	John Hutchison
California	Kristin Ralff-Douglas	Oregon	Phil Carver
California	Kevin Kennedy	Oregon	Bill Drumheller
California	Fereidun Feizollahi	Saskatchewan	Howard Loseth
California	Stephen Shelby	Utah	Colleen Delaney
California	Brieanne Douke	Washington	Spencer Reeder
Colorado	Kate Fay	Washington	Greg Nothstein
Manitoba	Jane Gray	Wyoming	Kelly Bott

Workplan

- Task 1: Role of an offset mechanism
  - Identified in workplan
  - Comments received
- Task 2: Core design elements
  - Identified in workplan
  - Comments received
- Task 3: Project eligibility and fungibility
  - Released prior to workshop
  - Comments requested
- Task 4: Mechanism structure and authority
  - Pending outcome of Tasks 1, 2, and 3

Workplan Comments

- Support for offsets as a compliance mechanism
  - suggestion of a limited or short-term role
- Broad support for a wide variety of project types
- General interest in limiting transaction costs
- No clear opinion on quantitative limits for offsets
- Simple and robust approach to determining “real” and “surplus / additional”
- Mixed support for offsets from outside the WCI jurisdictions
- Suggestions of specific models and resources for how WCI could administer an offset mechanism

Major Options

- Offset Mechanism
- Location
- Quantitative limits
- Project Types
- Linkages

Offset Mechanism

- Should the WCI allow offsets as a compliance mechanism?

Location

- Should the WCI only allow offsets from projects located within the Partners' jurisdictions?
- Should the WCI allow offsets from projects located outside the Partners' jurisdictions?

Quantitative Limits

- Should there be quantitative limits on the use of offsets to meet compliance obligations?

Project Types

- Should the WCI decide upon an initial list of approved project types prior to cap-and-trade design?
- Should the WCI allow offsets from sources capped and regulated by the cap-and-trade system or from indirect emission reductions in sectors covered by the cap-and-trade system?

Linkages

- Should the WCI link directly with other, similarly rigorous cap-and-trade programs and allow fungibility of allowances among the systems?
- Should the WCI allow the use of allowances from other, similarly rigorous cap-and-trade programs to be used as a compliance mechanism by capped sources in the WCI?

Western Climate Initiative

Regional Stakeholder's Workshop

January 10, 2008

Portland, Oregon

Overview

Western Regional Climate Action Initiative (WCI)

- Collaboration of Western states, provinces and Mexican states to reduce greenhouse gas emissions in our region
- Partners include
  - Washington, Oregon, California, Arizona, New Mexico, Utah, Manitoba, British Columbia, and as of today, Montana
- Observers include
  - Kansas, Wyoming, Nevada, Colorado, Alaska, Idaho, Quebec, Saskatchewan, Ontario and the Mexican states of Sonora and Tamaulipas

Collaboration is to include

- Setting a regional goal consistent with each partner's reduction goal
- Joining a multi-state registry to track, manage and credit entities with reductions
- Developing a design for a regional market-based multi-sector mechanism, such as a load-based cap and trade program.

Western Climate Initiative Status

Achieved two of the three directives:

- A regional goal has been established
  - 15% below 2005 by 2020
- All partners and observers have joined The Climate Registry
  - Consistent, verifiable reporting of emissions

Progress on design work

- 5 subcommittees underway
  - Scope
  - Allocations
  - Electricity
  - Offsets
  - Reporting
- Preliminary design anticipated Spring, 2008
- Completed design by August 26, 2008

How WCI Works

- Monthly all-partner staff working sessions in person
- Bi-weekly teleconferences of partners/observers and of subcommittee chairs
- Subcommittees engage in technical details to generate recommendations for partners
- Consensus decision making
- Technical support provided by partner agency staff, Pew Center on Climate Change, World Resources Institute, New America Foundation and The Center for Climate Strategies
- Western Governors Association provides project management support

What we expect to deliver

- Memorandum of Agreement
  – Recommended design elements
    - Substantive Agreement
    - Process to get rest of agreement
    - States/provinces will use results for legislative authority to implement
  – Further regional collaboration for ghg reductions

Western Climate Initiative (WCI) Stakeholder Outreach – Initial Plans

- Regional outreach and communication
  - Work plan and other documents submitted for public review and comment
  - Regional teleconferences after each WCI work session
  - Regional face-to-face workshops scheduled *to date*
    - January 10, 2008 (Portland): Discuss major options under consideration (350+ registered attendees)
    - May 2008: Discuss initial subcommittee recommendations
    - July 2008: Discuss proposed design
  - WCI list serve
  - Website

- State/Provincial outreach and communication

Questions?

Western Climate Initiative

Scope Design Issues

Scope Subcommittee
Michael Gibbs, Cal/EPA

January 10, 2008
Portland, Oregon

Overview

- Scope Subcommittee
  - Mission
  - Members
  - Work Plan
  - Work Plan Comments
- Major Options
  - Design Elements
  - Major Options
  - Questions

Mission

- Recommend the scope of a proposed cap and trade program:
  - The sectors that fall under the cap.
  - The emissions sources that fall under the cap.
  - The greenhouses gases that fall under the cap.
  - The point(s) of regulation where the cap would be enforced.
- Electric Sector evaluated by the Electricity Subcommittee.

Mission (Continued)

- The Subcommittee must balance multiple objectives, consistent with the WCI design principles.
  - …administratively simple …
  - …minimizes administrative costs…
  - …covers as many sources as is practical…
  - …minimizes the potential for leakage…
  - …facilitates linkage…

Members

Affiliation	Name	Affiliation	Name	Affiliation	Name
Arizona	Eric Massey	Colorado	Ginny Brannon	Ontario	Sheri Beaton
Arizona	Lee Alter	Manitoba	Jane Gray	Ontario	Suzanne Brooks
British Columbia	Dale Draper	Manitoba	Neil Cunningham	Ontario	Tom Markowitz
British Columbia	Dennis Paradine	Nevada	Colleen Cripps	Oregon	Bill Drumheller
British Columbia	Kelvin Hicke	Nevada	Sig Jaunarajs	Oregon	Phil Carver
British Columbia	Laura Lapp	New Mexico	Sandra Ely	Quebec	Michel Lesueur
British Columbia	Lee Thiessen	New Mexico	Sarah Cottrell	Saskatchewan	Howard Loseth
British Columbia	Paul Flanagan	Ontario	Cheryl O'Donnell	Utah	Glade Sowards
British Columbia	Rachel Boston	Ontario	David Coates	Washington	Spencer Reeder
California	Fereidun Feizollahi	Ontario	John Hutchison	Washington	Stu Clark
California	Lucille VanOmmering	Ontario	Ray Rivers	Wyoming	Paige Smith
California	Michael Gibbs	Ontario	Seema Khanna		

Work Plan

- Task 0: Emissions Inventory
- Task 1: Initial Options
- Task 2: Description of Major Options
- Task 3: Option Evaluation
- Task 4: Option Recommendation

Work Plan (Continued)

- Task 0: Emissions Inventory
  - Preliminary and ongoing
- Task 1: Initial Options
  - Listed in Work Plan
  - Comments requested
- Task 2: Description of Major Options
  - Released prior to the Workshop
  - Comments requested
- Task 3: Option Evaluation
- Task 4: Option Recommendation

Work Plan Comments

- Alcoa
- American Forest Resource Council
- Arizona Public Service Company
- Avista
- Business Council for Sustainable Energy
- Center for Resource Solutions
- Citizens Public Utility Board of Oregon
- Climate Protection Campaign
- ConocoPhillips
- Environmental Defense Fund
- Florida Power & Light
- Industrial Customers of Northwest Utilities
- Morgan Stanley
- Natural Resources Defense Council
- Northwest Pulp and Paper Association
- NW Natural
- Oregon Wild
- Pacificorp
- Pacific Forest Trust
- Portland General Electric
- Puget Sound Energy
- Salt River Project
- Seattle City Light
- Sempra Energy
- Snohomish County PUD #1
- TransAlta
- Washington Public Utilities Association
- WEST Associates
- Western Power Trading Forum
- Western Regional NGOs

Work Plan Comments (Continued)

	NGO	Utility	Other	Total
Business	6	9	3	18
Citizen Group	1			1
Environmental	6			6
Municipal Utility	1	3		4
Other	1			1
Total	**15**	**12**	**3**	**30**

Work Plan Comments (Continued)

- What sectors should be included?

	Economy Wide	Other	Total
Business	10	4	14
Citizen		1	1
Environmental	3		3
Municipal Utility	2		2
Grand Total	**15**	**5**	**20**

Work Plan Comments (Continued)

- What Gases:
  - All 6 Kyoto gases: 9 comments.
- Should “thresholds” be used?
  - Yes: 5 comments.
- List of the Design Elements:
  - No comments (to date).

Major Options

- Design Elements
- Major Options
  - Combinations of Design Elements
- Questions

Design Elements

- Design Elements A through K
  - Description
  - Emissions and Entity Data
  - Emissions at the Entity Level
  - Administration
  - Leakage Issues
- Working Draft – solicit comments

Design Elements

A. Large stationary combustion sources

B. Liquid transportation fuels

C. Residential and commercial natural gas combustion

C1. Residential and commercial fuel oil and other fuel combustion

D. Industrial process and waste management emissions

E. Fossil fuel industry

F. Fossil carbon content of fuels

G. Passenger cars and light duty trucks

H. Large transportation fleets

I. Agriculture emissions

J. Forestry and land use change

K. Production of high GWP gases

Major Options

	Options				
Design Elements	**1**	**2**	**3**	**4**	**5**
Electric Sector	X	X	X	X	
A. Large stationary combustion sources	X	X	X	X	
B. Liquid transportation fuels			X	X	
C. Residential and commercial natural gas combustion		X	X		
C1. Residential and commercial stationary combustion of fuel oil and other liquid fuels		X	X		
D. Industrial process and waste management emissions	X	X	X	X	X
F. Fossil carbon content of fuels					X

Major Options (Continued)

- Design Elements not in the options:
  E. Fossil Fuel Industry (oil and natural gas production; natural gas processing)
  G. Passenger Cars, Light Duty Trucks and Medium Duty Vehicles (manufacturers)
  H. Large Transportation Fleets
  I. Agriculture Emissions
  J. Forestry and Land Use Change
  K. Production of High GWP Gases

Questions

- Feasibility: Subcommittee’s assessment of the design elements that are feasible.
- Options: The range of options presented.
- Thresholds: What thresholds (e.g., tons of emissions per year) are appropriate to use.
- Phasing: Which design elements, if any, should be phased in over time.

Questions?

Short Break

Western Climate Initiative

Allocations Design Issues

Allocations Subcommittee
Steve Owens, Chair

January 10, 2008
Portland, Oregon

Mission

The mission of the WCI Allocation Subcommittee is:

- To recommend a methodology for determining the number of allowances to be apportioned, either individually to each WCI partner and thereby establishing each Partner's overall emissions allowance budget for the WCI program, or regionally for the WCI region overall; and

- To determine whether to recommend that the Partners establish a common method for distributing the budgeted emissions allowances (a) among covered sectors; and (b) within each sector to covered entities.

  If a common allowance distribution method is recommended, the Subcommittee will recommend a distribution method or methods for consideration by the WCI Partners.

- WCI Work Plan, 10/29/07

Subcommittee Members

- **<u>Arizona</u>**: Steve Owens, Patrick Cunningham, Ira Domsky, Lee Alter
- **<u>California</u>**: Belinda Chen, Fereidun Feizollahi, Kevin Kennedy, Steve Roscow
- **<u>Colorado</u>**: Ginny Bannon
- **<u>Nevada</u>**: Colleen Cripps, Leo Drozdoff
- **<u>New Mexico</u>**: Sandra Ely, Mary Uhl
- **<u>Oregon</u>**: Phil Carver
- **<u>Utah</u>**: Colleen Delaney
- **<u>Wyoming</u>**: Brian Bohlmann
- **<u>British Columbia</u>**: Warren Bell, Rachel Boston, Kel Hicke, Laura Lapp
- **<u>Ontario</u>**: Jennifer Backler, David Coates, John Hutchinson, Seema Khanna, Tom Markowitz, Ray Rivers
- **<u>Quebec</u>**: Michel Lesueur
- **<u>Saskatchewan</u>**: Howard Loseth

Commenters as of November 30, 2007

This summary of public comments was assembled from the subset of all comments that were identified as related to the Allocation Subcommittee. This summary reflects comments received as of November 30, 2007.

Commenters

Comments were received from the 17 organizations listed in Table 1.

Table 1: List of Allocation Commenters

Commenter	Category	Type
Advocate Design Matrix	Unknown	Unknown
Alcoa	Mining	Business
APX	Env Services	Business
Arizona Public Service Company	Utility	Business
Avista	Utility	Business
Business Council for Sustainable Energy	NGO	Business
Center for Resource Solutions	NGO	Other
Citizens Public Utility Board of Oregon	NGO	Citizen
Environmental Defense Fund	NGO	Environmental
Industrial Customers of Northwest Utilities	NGO	Business
Morgan Stanley	Financial Institution	Business
Pacificorp	Utility	Business
Portland General Electric	Utility	Business
Puget Sound Energy	Utility	Business
Renewable Energy Marketing Assoc	Trade Association	Business
The Climate Protection Campaign	NGO	Environmental
Western Regional NGOs	NGO	Environmental

Summary of Comments Received as of November 30, 2007

The following is a brief summary of the responses to allocation-related questions in the work plan released on October 31, 2007.

- Distribution: Eight commenters recommend that allowances should be distributed free of charge while four supported their sale by auction. Several comments supported use of both methods.
- Early Action Incentives: Five commenters supported the use of rewards or incentives to recognize or encourage GHG reduction investments before the program starts. One commenter opposed the use of incentives and one expressed limited support.
- Banking and Borrowing: Seven commenters supported the use of allowance banking while two supported limits on banking. No commenters opposed banking of allowances. Support for borrowing was less strong with four in favor, one opposed and four supporting limited borrowing.
- Safety Valve: Five commenters supported the use of some form of safety valve mechanism, and two were opposed.
- Other Issues: A handful of other comments were received on issues such as regional apportionment and point of regulation. Three commenters supported the use of new source allowance set-asides.

Question #1

Apportionment of Allowances

- Apportionment means the subdivision of the regional cap and trade emissions cap among the participating jurisdictions.
- Should each Partner should be authorized to distribute allowances equal to that Partner's share of the regional cap, or, should a regional entity distribute allowances on behalf of all the Partners without apportioning the regional cap among them?

Question #1

a. Should allowances be distributed centrally, without apportionment to Partners?

Advantages
• Reduces the need for a framework to prevent "over allocation" by Partners
• Reduces disputes between Partners over apportionment 'amounts'
• Partners establish regional and possibly sector 'cap(s)', but individual Partner 'caps' are not required
• Centralized distribution increases administrative efficiency
• Ensures equity among same-industry competitors throughout region

Disadvantages
• All Partners must agree on distribution method(s), including allocation among sectors (if required)
• Could require 'regional entity' to assume greater authority
• If allowances are sold, Partners would not have unilateral authority over the sale, and sale proceeds would go to Partners indirectly

Question #1

b. Or, should allowances be apportioned to, and distributed by Partners individually?

Advantages
• Partners are free to choose the degree of distribution consistency across the region
• Allows a more conventional role for the regional organization
• Partners receive allowance sale proceeds directly

Disadvantages
• Increases the risk that inconsistent distribution methods create an unfair competitive situation among covered entities across the region
• Decentralized distribution is administratively inefficient
• Partners must agree on the basis of apportionment and potentially individual Partner 'caps'

Question #1

c. Or, should some combination of centralized distribution and apportionment be pursued?

d. ISSUE: The Allocations Subcommittee recognizes that centralized distribution will require more intensive cooperation and a different approach to the exercise of provincial, state and tribal authority. Comments, observations and recommendations are being sought to assist the committee with mechanisms for design and implementation of a regional allocation system.

Question #2

Distribution of Allowances

- Distribution or allocation of allowances means the process by which emissions allowances are distributed for use by covered sources under an emissions cap and trade system.

- To what degree should distribution by the Partners be made uniform, or standardized, among participating jurisdictions?

Allocations Subcommittee Question #2

a. Assuming allowances are distributed by Partners, should distribution methods be standardized?

Advantages
• Reduces the need for a framework to prevent "over allocation" by Partners
• Promotes equity among same-industry competitors throughout region
• Promotes consistency among sectors throughout the region
• Promotes greater consistency among the standards and rules applied across the region

Disadvantages
• Partners must agree on distribution methods
• Partners will find it more difficult to tailor distribution methods to accommodate unique circumstances within their internal sectors
• Standardized distribution requires all Partners to secure legislative or other approvals without allowance for dissimilar results

Question #2

b. Assuming allowances are distributed by Partners, should distribution methods be left to each jurisdiction to decide?

Advantages
• Partners are free to establish individual distribution methods, allowing legislatures to adopt dissimilar programs and allowing state or province-specific issues to be individually addressed
• The regional program can be enacted without the Partners agreeing on distribution methods

Disadvantages
• Increases the risk that inconsistent distribution methods create an unfair competitive situation among covered entities across the region
• Increases the risk that individual Partner distribution decisions will seek a competitive advantage for particular industries or sectors
• May require creation of regional entity with authority to approve or deny Partner distribution plans to enforce minimum standards of consistency or as a check against the concern raised immediately above

Question #2

c. ***Or, should some flexibility be allowed within prescribed limits beyond which all Partners must adopt the same distribution system?***

d. ISSUE: The Allocations Subcommittee recognizes that there are many more detailed questions concerning the distribution of allowances than are asked here. The subcommittee anticipates seeking comment on these questions at a later time.

e. ISSUE: The Allocations Subcommittee recognizes the special challenges associated with the development of a regional system that could successfully merge into a future national program, and the additional complications of developing a single regional program that can accomplish this in two nations. The subcommittee seeks comments on how to ensure that the proposed and potential future programs will function well together.

Question #3

Allocation Methods

- There are multiple ways allowances can be distributed or allocated for use by covered sources.

- Whether and to what degree should allowances be distributed directly to covered sources free of charge?

Question #3

a. Assuming there is centralized distribution or at least partial standardization of decentralized distribution, should some of the allowances be distributed directly to covered entities free-of-charge?

Advantages
• Covered entities with fixed contracts or which are otherwise unable to pass-through the allowance cost would be protected from economic hardship
• Covered entities that are price-regulated would be able to comply without seeking to pass the allowance cost along to the consumer

Disadvantages
• Partners need to develop a basis for free distribution, i.e. 'grandfathering', 'benchmarking', etc.
• Partners may need to provide some reserve or other mechanism to accommodate free distribution for new sources to avoid discouraging investment in new plants
• Many existing covered entities may reap a financial benefit without an associated benefit to consumers or GHG reductions

Question #3

b. Assuming there is centralized distribution or at least partial standardization of decentralized distribution, should some or all of the allowances be auctioned or otherwise sold?

Advantages
• All covered entities compete equally for allowances
• Reduced risk of financial windfall for covered entities
• Program design is simplified
• Revenues from the auction or sale are controlled by the state or province and can be used to mitigate any financial impact of the program on consumers. Revenues can also finance investment in complementary GHG reduction measures, research and development of promising technologies or fund other GHG mitigation or adaptation measures.

Disadvantages
• Covered entities with fixed contracts or which are otherwise unable to pass-through the allowance cost may be exposed to economic hardship

Question #3

c. Should the allowance distribution system have the capacity to change over the life of the program through phasing in particular distribution methods or using different distribution bases?

d. Should the Partners place restrictions on the use of revenues from auctioned allowances?

Question #4

Early Actions

- **WCI cap and trade design principle:**

  "Provide appropriate recognition and incentives for early emissions reductions"

- **How should the cap and trade program either encourage or hold-harmless emission reductions efforts that occur prior to the start of the program?**

  Qualifying early actions would have to be quantifiable, verifiable, enforceable and permanent.

Question #4

a. ***The WCI Design Principles state that the program will "provide appropriate recognition and incentives for early emissions reductions." Should the program accomplish this:***

   i. ***Through the selection of benchmarking and program start dates?***

Selection of benchmarking and program start dates
• Careful selection of these dates could hold those undertaking early actions harmless, and could offer incentives to undertake these reductions in advance of the program start.

Question #4

ii. Through special allocations of allowances?

1. ***Drawn from within the cap?***

2. ***Drawn from outside the cap?***

Special allocations of allowances
• Special allocations of allowances can create a financial incentive if the distribution to those undertaking early reductions occurs over and above that which otherwise occurs after the program begins. • Such special allocations can be created through an allowance set-aside under the cap, or allowances can be made available to early actors over and above the cap (as has been done by RGGI).

Question #4

iii. Through auctioning of allowances?

Auctioning of allowances
• If all covered entities are required to purchase allowances from the market, those undertaking early emissions reductions will avoid the need to purchase those allowances. The avoidance of this cost is an economic incentive equal to the one that exists after the program begins.

iv. By other means?

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Questions?

Western Climate Initiative

Lunch

Breakout Sessions Begin at 2:00 p.m. Pacific.

Breakout Webinar Access information at www.westernclimateinitiative.org

Plenary Session will reconvene at 3:45 p.m.

Western Climate Initiative

Public Comment Session Underway

Western Climate Initiative

Suggestions for Future Meetings?

Meeting Adjourned

Thank you for Participating!

Western Climate Initiative

GHG Reporting Design Options

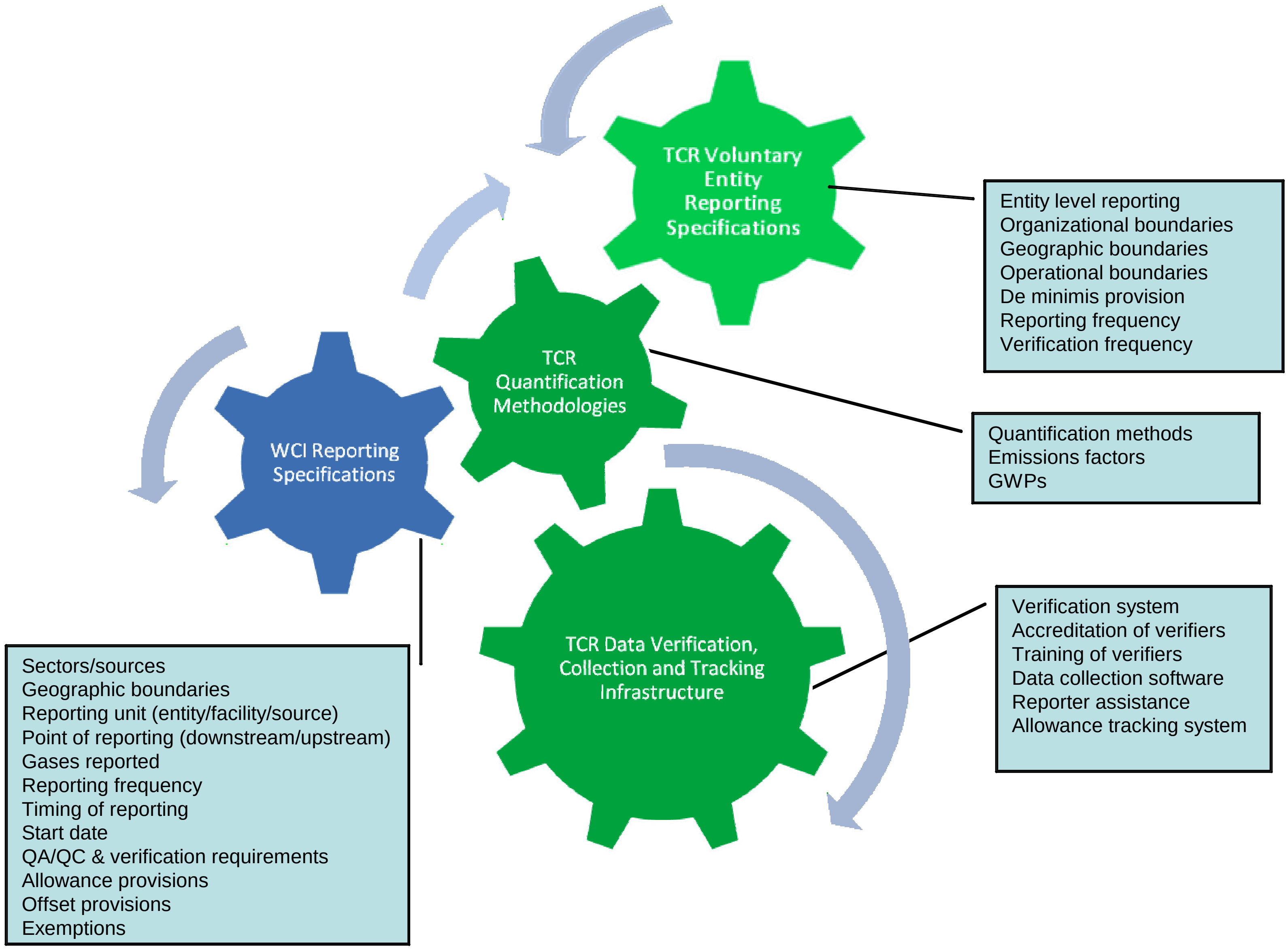
Reporting Subcommittee
Jim Norton, Chair

January 10, 2008
Portland, Oregon

Key Points

- Key Principles
  - Maximum consistency in quantification and reporting, for sources and for states/provinces
  - Maximum reliance on The Climate Registry (TCR)
- WCI & TCR - Form will follow function…
  - Key WCI decisions impacting reporting remain TBD
  - Anticipate a set of WCI Reporting Specifications
  - Expect to employ TCR quantification protocols and reporting systems and services
- A Moving Target
  - From multiple registry efforts to a unified effort – The Climate Registry
  - From little federal activity to recent federal actions regarding GHG reporting in US and Canada

WCI Interaction with TCR Reporting System Components



Reporting Design Option Issues

1. Breadth/Scope of Coverage
2. Initiation of Reporting
3. Coordination Among Partner Jurisdictions on Reporting
4. Data Management and TCR Interaction
5. Verification
6. Administrative Costs & Fees
7. Mandatory Federal GHG Reporting

1. Breadth/Scope of Coverage

a. Should reporting be required only for sectors/sources included within the cap?

b. Or should reporting be required for sectors/sources not included in the cap-and-trade program (e.g., ones that are likely to be phased in over time)?

2. Initiation of Reporting

a. Should mandatory reporting begin before cap-and-trade commences?

b. Or begin only with the start of the cap’s first compliance period?

3. Coordination Among Partner Jurisdictions

a. Should WCI develop a single WCI reporting rule that stipulates all reporting specifications?

b. Or should individual WCI jurisdictions have loosely coordinated rules possessing common core elements? If so, what aspects should the common core elements cover or include?

4. Data Management and TCR Interaction

a. Should WCI require that all capped sources report directly to and verify through the TCR?

b. Or should sources report to and verify at the level of the individual jurisdiction (with data then uploaded to the TCR or otherwise shared centrally)?

5. Verification

a. Should WCI require third party verification?

b. Or should WCI allow multiple approaches to ensuring data quality (other than third party verification)?

6. Administrative Costs & Fees

a. Should states and provinces mandate that fees go directly to TCR, and TCR administers the reporting database?

b. Or should states and provinces collect fees and contract with TCR to administer the reporting database?

7. Mandatory Federal GHG Reporting

In December, Congress directed EPA to adopt a mandatory GHG reporting rule within 18 months, and Canada's federal government required firms in major industrial sectors to report 2006 GHG emissions by May 31, 2008.

a. How should WCI states/provinces and TCR incorporate and interface with these developments in designing and implementing their GHG reporting program?

Overview of Comments to Date

- Mandatory reporting before baseline establishment
  - Divided opinion
  - Possibly for sectors where good historical data not available
- Tracking of allowances and offsets
  - TCR would need system for issuing certificates, tracking transactions, RECs, etc.
  - Western Regional Energy Generator Information System (WREGIS) suggested for electric power sector, possibly expand to other sectors
- Integration of WCI reporting with TCR
  - Several opposed to use of TCR
  - Protocols lacking and/or undesirable for land use, ag, forestry (esp. managed forests)
  - Some felt there was Insufficient stakeholder input to TCR design
  - Some complaints based on assumption WCI reporting will follow all of TCR voluntary reporting protocol

Possible Next Steps

- Receive and digest stakeholder comments on options questions.
- Written comments requested by Feb 1
- WCI determines key precursor elements including the scope by end of February 08
- Subcommittee recommends reporting options to WCI partners in March 08
- Input from stakeholders at meeting in May 08 or earlier
- Proceed to develop draft GHG Reporting program per WCI partners direction.
- Input from stakeholders at meeting in July 08
- Final mandatory reporting program released in August 08

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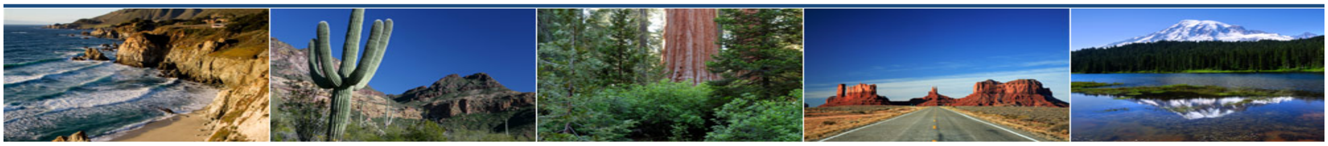

January 24, 2008

Dear WCI Stakeholders:

On behalf of all the WCI partners, we'd like to thank those of you who were able to participate in our first regional face-to-face stakeholder meeting in Portland on January 10. We had about 300 people attend in person and almost 200 participate via the webinar.

At the end of the meeting, we committed to let you know about future opportunities for stakeholder involvement in WCI. Attached you will find a detailed schedule of future calls and meetings. In addition, each state and province will continue their own stakeholder processes.

As you will see in the schedule, the WCI will continue to post draft documents on our website for public review and comment. Currently, each subcommittee has posted its Major Options paper, which outlines the various options they are considering. Please provide comments on the options papers through the website by February 1.

In March, the subcommittees will post for public review and comment their initial draft design recommendation(s). Each subcommittee will then schedule a stakeholder call to discuss their initial draft. The Offsets Subcommittee will use a stakeholder workshop in Vancouver on March 26 as the primary opportunity for input on its preliminary recommendations. The Offsets Subcommittee plans to release discussion drafts prior to the workshop.

In May, we will release the final draft recommendations from each subcommittee and the results of our economic analysis. There will be a face to face stakeholder meeting to discuss these documents in Salt Lake City on May 21.

The WCI partners will take the comments received on the final drafts and work on final recommendations in June and July. Draft final recommendations for the design of a regional cap-and-trade program will be made available in mid-July and a face-to-face stakeholder meeting will be scheduled in late-July. Comments on the final draft will be incorporated into the design recommendations to be released in August 2008.

We look forward to your continued involvement in this important project. Please do not hesitate to contact any of the WCI Partners with questions about our work or the stakeholder involvement process.

Sincerely,

Janice Adair, Washington	Steve Owens, Arizona
WCI Chair	WCI Co-Chair

WCI Process and Timeline for Public Review and Comment on Work Products and Draft Recommendations

Process and Timeline

Comments Due on Options Papers	Feb 1
▪ Options papers are available at www.westernclimateinitiative.org	

Stakeholder Calls to Review Comments on Options Papers

- All calls will be held at 8:30 am PST / 9:30 am MST
- Call-in numbers for all calls: 1-800 868-1837 (toll free)
  1-404-920-6440 (alternate - direct dial)
  Public Participant Code: 659 537#
- Schedule
  - Electricity — Mon, Feb 11
  - Scope — Tues, Feb 12
  - Allocations — Wed, Feb 13
  - Offsets — Thur, Feb 14
  - Reporting — Fri, Feb 15

Economic Analysis and Modeling	
▪ Study begins	Mid-February
▪ Stakeholder involvement (dates and process TBD)	March - May
Scope and Electricity Preliminary Recommendations	
▪ Subcommittee drafts released for review and comment	Wk of Mar 3
▪ Stakeholder call to discuss drafts	Wk of Mar 10
▪ Written comments due	Mon, Mar 17
Allocations and Reporting Preliminary Recommendations	
▪ Subcommittee drafts released for review and comment	Wk of Mar 31
▪ Stakeholder call to discuss drafts	Wk of Apr 7
▪ Written comments due	Wed, April 16
Offsets Subcommittee	
▪ Public Workshop on Options - Vancouver (Discussion drafts will be available prior to workshop.)	March 26
Subcommittee Recommendations & Economic Analysis Released	Wk of May 5
WCI Stakeholder Meeting – Salt Lake City	May 21
Draft final recommendations released for review and comment	Mid-July
WCI Stakeholder Meeting	Late July
WCI Announcement of Program Design and Next Steps	August 2008

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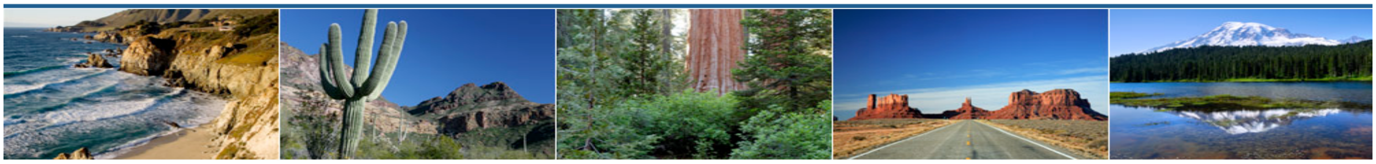

Draft Electricity Point of Regulation Recommendations for Public Review and Comment

March 3, 2008

To: All Interested Parties

This memorandum presents the WCI draft recommendation for the electricity point of regulation for the WCI cap-and-trade program. The recommendation is based on the WCI's analysis and assessment of the various approaches to covering the electricity sector released in table format in January 2008.[1] The WCI has taken into account all stakeholder comments received in writing, as well as the oral comments received at the January 10, 2008 stakeholder meeting and the February 11, 2008 stakeholder conference call.

Background

As set out in the "Update on Subcommittee Activities and Request for Stakeholder Input" released by the Electricity Subcommittee on January 2, 2008, the Electricity Subcommittee has considered several potential approaches to covering the electricity sector, including:

(1) Pure load-based approach that places the point of compliance on retail providers within WCI and requires tracking of emissions attributes;

(2) Pure generator-based approach that places the compliance obligation on fossil-fuel-fired generators in WCI;

(3) The CO_2 Reduction Credits (CO_2RCs) approach to reducing emissions in the western interconnect area by placing a requirement to purchase and retire CO_2RCs on retail electricity providers in WCI;

(4) A load-generator hybrid approach that combines the generator-based and load-based approaches to cover both emissions attributable to electricity delivered inside and outside of WCI; and

[1] The approaches table is available online at: http://www.westernclimateinitiative.org/ewebeditpro/items/O104F14577.PDF

(5) A “deliverer” or “first seller” approach that places the point of regulation on the first entity to deliver electricity in a WCI jurisdiction.

The benefits and challenges associated with each approach are detailed in the Subcommittee’s “Summary Table Comparing Different Approaches to Electric Sector Cap-and-Trade”.

<u>The Preliminary Draft Approach</u>

After careful consideration of the Subcommittee’s recommendation, as well as the many stakeholder comments received by the Electricity Subcommittee, the Partners reached the following preliminary points of agreement:

The Partners agree:

- The point of regulation for the electricity sector should maximize coverage and minimize emissions leakage.
- A generator-based approach to covering the electricity sector is the preferable option.
- The generator-based option will be most effective with universal participation throughout WECC.[2]
- A proposal to bring in additional generators serving the western interconnect will be developed with a date certain by which those other jurisdictions will join the WCI. If the additional WECC jurisdictions do not join by that date, then the WCI will continue to develop the first-jurisdictional deliverer approach described below.
- That because not all generators serving the western interconnect are currently within the WCI, additional measures are needed to maximize coverage and minimize leakage.
- That the first jurisdictional deliverer approach should address the coverage and leakage issues during the transition to full WECC participation in the WCI:
    - The first jurisdictional deliverer approach covers all emissions generated in WCI; and,
    - All emissions attributable to electricity delivered in WCI but generated outside WCI.

[2] The Western Electricity Coordinating Council (WECC) region encompasses the interconnected power grid of the Western states, provinces, tribes, and a small part of Mexico (i.e., the “western interconnect”).

- To explore additional complementary measures to reduce leakage.

- That the point of regulation does not dictate the method of allocation and the partners are continuing to work on the allocation issue.

The Electricity Subcommittee is now in the process of working through questions raised by the Partners, including how additional generation in the WECC can be brought into the WCI, and how the first jurisdictional deliverer approach would actually be implemented in Partner jurisdictions. The Partners are eager to get stakeholder input on this draft point of regulation for the electricity sector.

Descriptions of the Approaches

The "first jurisdictional deliverer" and "generator-based" approaches are described below. The Electricity Subcommittee will work to provide more detail on these approaches, and to address any concerns or issues raised by individual partners and stakeholders.

The "Generator-based" Approach

- Each WCI partner would implement a set of requirements that apply to fossil-fuel electric generators (i.e. sources) in their jurisdiction.

- Generators would be required to measure, monitor and report emissions.

- At the end of each compliance period, generators would be required to "cover" all of their emissions with emissions allowances issued by the state or province.

- Leakage and coverage issues would be addressed if all jurisdictions in the WECC became trading partners in the WCI.

- Leakage and coverage challenges could be overcome through a "Generator-Plus" model in which imports are addressed through complementary measures.

The "First Jurisdictional Deliverer" Approach

- The point of regulation is on the first entity that the WCI partner has jurisdiction over that delivers power onto the WCI grid at a designated point of delivery

- First jurisdictional deliverers are (a) the fossil-fuel generators in the WCI jurisdictions and (b) the first party to deliver electricity generated outside the WCI region over whom the WCI Partner may assert jurisdiction.

- An importing deliverer could be an independent energy producer, a retail provider, a power marketer, or a power broker.

- For multi-jurisdictional utilities (spanning in and out of the WCI region) a load-based approach to cover non-WCI power imported over their power lines into their WCI service areas could be used.

- In the case of deliveries by Federal entities -- such as the Bonneville Power Administration (BPA) and the Western Area Power Administration (WAPA) -- the first jurisdictional entity may be a retail provider.

- WCI partners would have the option of phasing-in this approach over time, beginning with the fossil-fuel generators in the WCI jurisdiction.

- Tracking will be needed to account for greenhouse gas emissions resulting from power imports and exports among WCI jurisdictions and imports from non-WCI areas.

- Power generated outside WCI states and provinces that is "wheeled through," but not delivered, to the WCI would be exempt from coverage.

The Other Approaches

In reaching the preliminary draft electricity point of regulation, the Partners necessarily had to set aside consideration of the other approaches to the electricity sector. Each of these approaches is listed below, together with some of the reasons given by one or more of the Partners for not selecting the approach:

(1) A pure load-based approach was removed for consideration because, among other reasons, it would require a complex emissions attribute tracking system, would not cover exported electricity; presented potential jurisdictional hurdles, and could be difficult to harmonize with a potential generator-based national cap-and-trade program.

(2) A load-generator hybrid approach was removed from consideration after, the Subcommittee determined it could modify the original "deliverer" or "first seller" approach into the first jurisdictional deliverer approach and meet WCI's needs with a less-complicated administrative structure than that of the load-generator hybrid.

(3) The CO_2 Reduction Credits (CO_2RCs) approach was removed from consideration because it requires the periodic adjustment of the reduction requirement imposed on retail providers depending on load growth in the West; it is complex and difficult to understand; and because it presented issues with harmonizing to a potential generator-national program.

It bears noting that this discussion is meant to give you a sense of the chief reasons for not recommending each approach. The explanations are not complete and are not all shared by all Partners.

Next Steps

The Partners have directed the Electricity Subcommittee to gather stakeholder input on the draft electricity point of regulation, and to develop more detailed assessment of how to add more generation from the WECC into the WCI as well as how the first jurisdictional deliverer approach would be implemented in individual jurisdictions.

To that end, there will be a stakeholder conference call on Tuesday, March 11, 2008 from 10:30 to 12:00 noon Pacific Standard Time. During that call, questions will be taken on the draft point of regulation. Written comments are also encouraged, and the Partners are suggesting that these comments be forwarded via the website no later than Monday, March 17, 2008.

On behalf of the WCI Electricity Subcommittee and all of the WCI Partners, I thank you for your continued interest in the Western Climate Initiative and the Electricity Subcommittee's work.

Sincerely,

/s/

David Van't Hof
Oregon Governor's Office, and
Chair, Electricity Subcommittee

March 3, 2008 Draft Electricity Point of Regulation Recommendations for Public Review and Comment

List of Commenters

Air Transport Association

Alcoa, Inc.

Avista Corporation

BC Spaces for Nature

California Public Utilities Commission Division of Ratepayer Advocates

City of Seattle

Clark Public Utilities

Energy Producers and Users Coalition and the Cogeneration Association of California

Grant County Public Utility District

Gregory, L. Jay

Industrial Customers of Northwest Utilities

Modesto Irrigation District

Morgan Stanley Capital Group, Inc.

Northern California Power Agency

Northwest Pulp and Paper Association

Oregon Municipal Electric Utilities Association

Oregon Public Utility Commission

PacifiCorp

PNGC Power

Portland General Electric

Public Power Council

Puget Sound Energy

Reliant Energy, Inc.

Salt River Project

Sierra Club of Canada

Snohomish County Public Utility District #1

Southern California Public Power Authority

Spectra Energy Transmission

Tacoma Public Utilities

Tucson Electric Power Company

Washington Public Utility Districts Association

Waste Management, Inc.

WEST Associates

Western Climate Advocates Network

Western Power Trading Forum

Western Resource Advocates

Western States Petroleum Association

Weyerhaeuser Company

Scope Subcommittee

March 3, 2008[1]

Summary of Major Design Options Under Consideration

This paper presents the major design options under consideration by the Scope Subcommittee. The mission of the Scope Subcommittee is to recommend the scope of a proposed cap-and-trade program, defining:

- The sectors that fall under the cap-and-trade program.
- The emissions sources that fall under the cap-and-trade program.
- The greenhouse gases that fall under the cap-and-trade program.
- The point(s) of regulation where the cap-and-trade program would be enforced.

To develop options for the program scope, the Scope Subcommittee defined individual design elements for consideration. The list of the design elements was released for public review and comment as part of the WCI work plan (see www.westernclimateinitiative.org).

The Scope Subcommittee is assessing the feasibility of including the design elements as part of the program scope. A brief description of each of the design elements is presented below, starting on page 4. While each of the design elements remains under consideration, the subcommittee's preliminary analysis has been used to identify design elements that appear to be feasible to include in a cap-and-trade program in the near term. These design elements include:

- Electric sector, as defined by the Electricity Subcommittee;[2]
- Large stationary combustion sources;
- Liquid transportation fuels;
- Residential and commercial natural gas combustion;
- Residential and commercial stationary combustion of fuel oil and other liquid fuels;
- Industrial process and waste management emissions; and
- Fossil carbon content of fuels.

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[1] The paper was originally released on January 2, 2008. This revised version incorporates updated emissions data and data for Montana. The discussion of the options remains unchanged.

[2] The Electric Subcommittee is assessing how best to include the electric sector in the program. The major options under consideration by the Electric Subcommittee are reported separately.

While the subcommittee's preliminary analysis indicates that these elements are feasible to include in the program, we note that significant administrative and potential emissions leakage issues remain to be assessed. Additionally, options for phasing in and combining the elements must be considered. These issues are being examined through the subcommittee's continuing analysis and assessment.

Combinations of the feasible design elements are presented as five major design options below. These options indicate how the elements could be combined to create a cap-and-trade program with varying levels of coverage. Option 1, with the narrowest scope, would cover the electric sector, large fossil fuel stationary combustion sources, and large industrial process emissions. Option 3 has a significantly broader scope by also including liquid transportation fuels and fossil fuel stationary combustion in the residential and commercial sectors. Option 5 represents an alternative approach, focusing on the fossil carbon content of all fuels.

The subcommittee's preliminary analysis has indicated that several design elements are not likely to be feasible to be included under the cap in a cap-and-trade program in the near term. The factors indicating that these elements are not good candidates for inclusion under the cap-and-trade program are: inability to measure or calculate emissions reliably at the entity level; administrative challenges due to the large number of regulated entities; and significant vulnerability to emissions leakage. These design elements include:

- emission sources at fossil fuel production facilities for which it is difficult to measure or calculate emissions at the entity level;
- passenger cars, light duty trucks and medium duty vehicles regulated at the manufacturer;
- large transportation fleets;
- agriculture emissions and sinks;
- forestry emissions and sinks; and
- high-GWP gases regulated at the point of manufacture.

While the sectors and sources included in these design elements may ultimately not be recommended for inclusion under the cap of a cap-and-trade program, these sectors and sources may be appropriate for inclusion in an offset program, or may be addressed through other policies or measures.

By releasing this preliminary list of major design options, the Scope Subcommittee solicits public comments on these materials. Comments would be particularly appreciated on the following:

1. Feasibility: Do you agree with the subcommittee's assessment of the design elements that are feasible for inclusion in a cap-and-trade program? If not, what would you change?
2. Options: Do you agree with the range of options presented by the subcommittee? If not, what options would you add or delete?
3. Thresholds: What thresholds (e.g., tons of emissions per year) are appropriate to use to define the entities with regulatory obligations under each of the design elements?
4. Phasing: Which design elements, if any, should be phased in over time?

Major Scope Options Under Consideration as of December 2007 – For Public Review and Comment

Option 1	Option 2	Option 3	Option 4	Option 5
Electric Sector[1]	Electric Sector[1]	Electric Sector[1]	Electric Sector[1]	
A. Large stationary combustion sources	A. Large stationary combustion sources	A. Large stationary combustion sources	A. Large stationary combustion sources	
		B. Liquid transportation fuels	B. Liquid transportation fuels	
	C. Residential and commercial natural gas combustion	C. Residential and commercial natural gas combustion		
	C1. Residential and commercial stationary combustion of fuel oil and other liquid fuels	C1. Residential and commercial stationary combustion of fuel oil and other liquid fuels		
D. Industrial and waste management process and fugitive emissions	D. Industrial and waste management process and fugitive emissions	D. Industrial and waste management process and fugitive emissions	D. Industrial and waste management process and fugitive emissions	D. Industrial and waste management process and fugitive emissions
				F. Fossil carbon content of fuels
1. The electric sector would be covered in a manner defined by the Electric Subcommittee.				

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A. Large Stationary Combustion Sources

1. Description

1.1 Sectors

This sector includes all large stationary combustion sources, including oil refining, cement manufacturing (including clinker production), pulp and paper manufacturing, hydrogen production, and other large combustion sources. Electric power generation is included in the Electric Sector, and is not included in this design element. An annual emissions threshold may be used to define the combustion sources considered “large.” Various thresholds have been defined in other programs (such as mandatory greenhouse gas reporting programs). A threshold has not yet been selected for this design element, and is under consideration.

1.2 Emissions Sources

Fossil fuel combustion in stationary equipment only.

1.3 Greenhouse Gases

All six Kyoto gases are included. However, CO_2 comprises the overwhelming majority of the total emissions in this sector (close to 100%).

1.4 Point of Regulation

The point of regulation is the facility where the combustion emissions occur.

2. Emissions and Entity Data

Among the WCI partner states and provinces, fossil fuel combustion at industrial facilities (not including electric power generation) accounted for about 130 MMT of CO_2e in 2005, or about 13% of total gross emissions. This percentage varies from about 4% to 23% across the states and provinces.

The total number of entities that would be covered in this sector depends on whether, and at what level, an annual emissions threshold is set. Table 1 summarizes the emissions for the WCI partners.

3. Emissions at the Entity Level

Greenhouse gas emissions from fossil fuel combustion at large stationary sources can be measured or calculated with an adequate level of precision to support inclusion in a cap-and-trade program. Fuel-based calculations can generally be used to quantify CO_2 emissions, which comprise nearly 100% of the emissions for this sector. Alternatively, continuous emissions monitors (CEMs) can be used to measure emissions.

4. Administration

This sector does not pose significant administrative challenges. Regulatory agencies are able to identify most if not all the entities in this sector with compliance obligations because the facilities typically have other air emission compliance requirements. The covered entities should also have the capability to know their compliance obligations and understand the applicable requirements. The emissions from this sector are reasonably well known, so that an acceptable emission baseline can be developed.

5. Leakage Issues

Vulnerability to significant leakage varies among the facilities that would be covered under this sector. Some facilities require close proximity to their markets, so that significant leakage to locations outside the WCI region is not expected. However, others (such as the cement industry and the pulp and paper industry), may be vulnerable to leakage as their products are traded as commodities internationally. The vulnerability to leakage needs to be assessed individually for each industry.

Table 1: Summary of Stationary Combustion Source Emissions

State/Province	2005 Emissions (MMT CO_2e)	Percent of 2005 Gross Emissions
Arizona	5.2	5%
California (2004)	79.0	16%
Montana	2.8	8%
New Mexico	3.2	4%
Oregon (2004)	6.2	9%
Utah	6.5	9%
Washington	11.0	12%
British Columbia	14.9	23%
Manitoba	1.4	7%
Total WCI Partners	**130.2**	**13%**

MMT = million metric tons

Percent of gross emissions calculated for each state/province. Estimates do not apply an emissions threshold for potentially covered entities.

Preliminary estimates, subject to review and revision.

B. Liquid Transportation Fuels

1. Description

This design element covers CO_2 emissions from the combustion of liquid transportation fuels. The point of regulation being examined is the point at which the fuels enter into commerce in the individual WCI states and provinces. As described below, this point may vary among the states and provinces.

1.1 Sectors

This design element focuses on liquid fossil fuels used in the transportation sector, including but not limited to gasoline, distillate fuels (diesel, etc.), jet fuel, aviation gas, and LPG. The liquid fuels used for stationary combustion by residential, commercial, and industrial customers are described separately. Nevertheless, the manner in which liquid fuels could be covered for these other customers is closely related to how they could be covered for transportation uses. Fuel use in the electricity sector is also not covered in this design element.

1.2 Emissions Sources

The emission source is the combustion of liquid fossil fuels in mobile sources. These sources include on-road and off-road vehicles, including: passenger cars; trucks; rail; marine vessels; and aircraft. Off-road equipment, such as farm equipment and construction equipment could also be included.

1.3 Greenhouse Gases

Carbon dioxide is the dominant GHG produced in this element, accounting for on the order of 97% of emissions from these sources. Nitrous oxide (N_2O) and methane (CH_4) are also emitted.

1.4 Point of Regulation

It is generally considered impractical to define the point of regulation for transportation emissions at the point of emission, which would be the individual vehicle owner. Rather, the point of regulation under consideration for this element is the point at which transportation fuels enter into commerce in the individual states and provinces. In selecting this point of regulation, consideration is being given to the fact that most jurisdictions have a mechanism for tracking the sale of transportation fuels for other purposes. Building on the existing fuel tracking procedures in each jurisdiction is expected to simplify program design and implementation requirements.

For some jurisdictions, the point at which liquid fuels are tracked is the fuel distribution terminal, often referred to as the terminal rack. For example, in the United States, federal excise taxes on transportation fuels are collected at the terminal rack. Some states rely on this terminal-rack based tracking system to collect state taxes, thereby providing the capability to track fuel flows into the state.

Some jurisdictions (e.g., Oregon) track gasoline deliveries to retailers for tax purposes. For these jurisdictions, the preferred point of regulation may be the licensed fuel wholesalers that are already required to report the quantity of fuel delivered.

Using this approach, the compliance obligation would be to hold emission allowances to cover the fossil carbon content of the fuel that is entering into commerce in the individual states and provinces. The regulated entity would be the party that enters the fuel into commerce in the state or province, such as the owner of the fuel dispensed at the terminal rack, or the licensed fuel wholesaler that dispenses fuel to retail locations.

2. Emissions and Entity Data

The transportation sector is one of the largest sources of GHG emissions for each of the WCI partners. The emissions estimate for 2005 is about 353 MMT CO_2e, accounting for about 35% of total gross emissions among the WCI partners. The percentage of total gross emissions varies among the partners from about 21% to 45%. Table 2 summarizes the emissions estimates for the WCI partners.

The total number of entities with a compliance obligation depends on the point of regulation. If terminal racks are the point of regulation for most jurisdictions, the total number of terminals and refineries (where the racks are located) is on the order of about 210 for the WCI partners (see Table 2). If wholesalers are the point of regulation, the number of entities will be larger. For example, Oregon licenses about 160 motor vehicle fuel dealers. The appropriate point of regulation and the number of entities is under investigation.

3. Emissions at the Entity Level

As described above, the point of regulation under consideration is the point at which liquid transportation fuels enter into commerce in the individual states and provinces. At this point, the regulated entity cannot measure or calculate actual GHG emissions from fuel combustion. Rather, the entity can calculate potential CO_2 emissions based on the fossil carbon content of the fuel and the quantity of the fuel. Virtually all the carbon in the fuel is converted to CO_2, so that the carbon content of the fuel is an accurate predictor of CO_2 emissions.

Several issues need to be addressed in order to use this calculation of potential emissions:

- Variations in fossil carbon content: Currently, the fossil carbon content of liquid transportation fuels is well known. However, in the future, fuels may include varying levels of non-fossil carbon components (e.g., in response to low carbon fuel standards). Consequently, the fossil carbon component of the fuel may need to be verified at the point of regulation, or may need to be provided to the point of regulation by the fuel producer. The mechanism required to make this fossil carbon content determination remains to be determined.
- Fuel use for non-combustion purposes: The emission calculation presumes that all the fuel delivered will be combusted. Some fuels may be used to produce products (such as plastics) that sequester carbon. While this eventuality may be unlikely for transportation fuels, the issue remains to be assessed.

Notably, this method of calculating emissions is a proxy only for the CO_2 emissions that occur when the fuel is combusted. The calculation does not include N_2O and CH_4 emissions, although those emissions would also be expected to occur during combustion along with the CO_2 emissions. Additionally, the method does not include the GHG emissions associated with producing the fuel. Rather, this method covers emissions associated with fuel use, but not fuel production. Emissions associated with fuel production (e.g., emissions at the refinery) would be covered separately as stationary combustion or process emissions from the facilities involved in producing the fuel in the WCI states and provinces.

4. Administration

By leveraging existing fuel tracking procedures in states and provinces, the administrative challenges for this design element can be minimized. However, the tracking capabilities of each state and province remain to be examined in detail to assess the comprehensiveness of the existing tracking capabilities. Insofar as the existing procedures provide incomplete coverage of the fuels, additional tracking capabilities may be required.

The potential challenges associated with verifying the fossil and non-fossil carbon components of transportation fuels at the proposed point of regulation remain to be examined.

5. Leakage Issues

The potential for emission leakage is significant for components of the transportation sector:

- Marine: Ocean-going vessels can obtain fuel outside the WCI partner jurisdictions.
- Aviation: Airline operations are particularly sensitive to fuel costs. Opportunities to obtain fuel outside the WCI partner jurisdictions may be significant.

Gasoline use in passenger cars, light duty trucks, and medium duty vehicles is less vulnerable to leakage, as motorists typically obtain fuel in close proximity to their residences and places of employment. On-road gasoline use accounts for about two-thirds of the total emissions from this sector, making it the largest portion of emissions.

Long-haul trucking may also be vulnerable to leakage if trucks can operate within WCI jurisdictions with fuel obtained from outside the WCI jurisdictions. However, the International Fuel Tax Agreement (IFTA) requires diesel trucks operating in multiple jurisdictions to calculate fuels consumed in each state and province based on the miles traveled in each state/province. All the WCI partners are parties to the IFTA.[3] Consequently, the IFTA data could be used to compute a compliance obligation for diesel trucks that operate in multiple jurisdictions, thereby avoiding leakage.[4]

These differences in leakage potential may indicate that the program should consider focusing coverage on the portion of transportation fuels that are least subject to leakage.

[3] The 48 contiguous states of the United States and 10 Canadian provinces are parties to IFTA. Yukon Territory, Northwest Territory, Nunavut, and the District of Columbia are not parties to IFTA.

[4] IFTA covers diesel trucks with the following characteristics: (a) has three or more axles; or (b) has two axles and a gross vehicle or registered gross vehicle weight of more than 26,000 pounds or 11,797 kilograms; or (c) is used in a combination that has a combined or registered gross vehicle weight of more than 26,000 pounds or 11,797 kilograms. Recreational vehicles are not covered.

Table 2: Summary of Liquid Transportation Fuel CO_2 Emissions and Entity Counts

State/Province	2005 Emissions (MMT CO_2e)	Percent of 2005 Gross Emissions	# Entities	
			Terminals	Refineries
Arizona	38.2	38%	13	--
California (2004)	177.7	37%	84	20
Montana	7.7	21%	13	4
New Mexico	15.1	21%	16	3
Oregon (2004)	23.3	34%	10	1
Utah	16.3	24%	7	5
Washington	43.1	45%	25	5
British Columbia	24.3	37%	3	2
Manitoba	7.1	35%	1	--
Total WCI Partners	**352.8**	**35%**	**172**	**40**

MMT = million metric tons
Percent of gross emissions calculated for each state/province.
Preliminary estimates, subject to review and revision.

C. Residential and Commercial Natural Gas Consumption

1. Description

Under this element, the carbon dioxide emissions associated with residential and commercial combustion of natural gas would be covered. The point of regulation is the local natural gas distribution company (LDC). The LDCs would be required to hold allowances to cover the carbon dioxide emissions associated with the ultimate combustion of the natural gas they sell to their residential and commercial customers, based on the carbon content and volume of the fuel they sell.

LDCs also deliver gas to large industrial and electric utility customers. They would not be required to hold allowances for emissions associated with those deliveries. The expectation is that those emissions would be covered at the source, as described in separate design elements.

1.1 Sectors

The sector covered is part of residential and commercial stationary combustion.

1.2 Emissions Sources

The emissions sources are residential and commercial natural gas combustors, such as boilers and furnaces.

1.3 Greenhouse Gases

The greenhouse gas covered is carbon dioxide. Other combustion-related greenhouse gases would also be affected (e.g., nitrous oxide and methane). However, the other emissions are not addressed explicitly through this design element.

1.4 Point of Regulation

The entities with compliance obligations are local natural gas distribution companies (LDCs). LDCs are typically private companies regulated by state and provincial utility commissions or similar boards. Some LDCs may be municipal utilities. All LDCs, regardless of size or volume of gas delivered, could be included in this program element.

2. Emissions and Entity Data

Based on the information collected to date, there are about 60 LDCs in the WCI partner states and provinces; and about 155 total if WCI observers are included. The CO_2 emissions associated with the natural gas these LDCs distributed in 2005 to residential and commercial customers is 72 MMT for the U.S. partners. Table 3 summarizes this data and the data on the numbers of LDCs.

3. Emissions at the Entity Level

Calculating emissions associated with residential and commercial combustion would be straightforward for LDCs. LDCs already account for the volumes of natural gas they sell by customer class. The LDCs would need to apply the appropriate carbon content factor to these gas volumes to calculate their compliance obligation. The LDC would exclude from this calculation any natural gas that is sold to an entity that has a separate compliance obligation under the program, such as an industrial source that is regulated directly.

4. Administration

Covering LDCs in a cap-and-trade program does not pose unusually significant administrative challenges. LDCs are already subject to economic regulation by the state public utilities commissions in the United States and by provincial authorities in Canada. Thus, a state or provincial regulatory agency can identify all the entities with compliance obligations. The LDCs would have the capability to know that they have compliance obligations and understand their compliance requirements. The number of entities appears manageable. However, there are a number of small LDCs in Kansas (a WCI observer state). An annual emissions threshold, for example 10,000 tons of CO_2, could be used to exclude small LDCs.

5. Leakage Issues

LDCs themselves would not be subject to emission leakage issues. The LDCs are regulated monopolies with defined service territories. LDC customers may vary with regard to leakage vulnerabilities. Most residential and commercial natural gas customers do not have high greenhouse gas emissions intensities. Consequently internalizing the cost of the carbon content of natural gas into natural gas prices (as would be expected) would not significantly affect the competitiveness of most customers.

However, there are two circumstances of note. First, increased natural gas prices could adversely affect low income residential customers. Assistance programs for low income customers, provided by many LDCs in the United States, could be a mechanism for addressing this impact. Second, there may be some individual large volume gas customers for which carbon emissions are significant. If these customers face competition from regions that do not limit greenhouse gas emissions, they may vulnerable to emissions leakage. The circumstances of these customers would be similar to large stationary source emissions sources that would be covered directly. The number of customers for which this is an issue, and the potential impacts on these customers, remain to be identified.

Table 3: Summary of Residential and Commercial Natural Gas CO_2 Emissions and Number of LDCs

State/Province	2005 Emissions (MMT CO_2e)	Percent of 2005 Gross Emissions	# LDCs
Arizona	3.8	4%	8
California (2004)	38.9	8%	11
Montana	1.8	5%	5
New Mexico	3.1	4%	19
Oregon (2004)	3.5	5%	3
Utah	5.2	7%	2
Washington	6.7	7%	7
British Columbia	6.5	10%	4
Manitoba	2.3	11%	1
Total WCI Partners	**71.7**	**7%**	**60**
MMT = million metric tons Percent of gross emissions calculated for each state/province. Emissions data currently being developed for provinces. Preliminary estimates, subject to review and revision.			

C1: Residential and Commercial Stationary Combustion of Fuel Oil and Other Liquid Fuels

1. Description

This design element covers CO_2 emissions from the stationary combustion of fuel oil and other liquid fuels in the residential and commercial sector. The point of regulation being examined is the point at which the fuels enter into commerce in the individual WCI states and provinces. As described below, this point may vary among the states and provinces.

1.1 Sectors

This design element focuses on liquid fossil fuels used for stationary combustion by residential and commercial customers. The fuels include heating oil, propane and liquefied petroleum gas (LPG). The liquid fuels used in the transportation sector are described separately. Nevertheless, the manner in which liquid fuels could be covered for transportation uses is closely related to how they could be covered for these residential and commercial uses. Fuel use in the electricity sector is also not covered in this design element.

1.2 Emissions Sources

The emission source is the combustion of liquid fossil fuels in stationary source equipment, such as furnaces and boilers.

1.3 Greenhouse Gases

Carbon dioxide is the dominant GHG produced in this element, accounting for on the order of 99% of emissions from these sources. Nitrous oxide (N_2O) and methane (CH_4) are also emitted.

1.4 Point of Regulation

It is generally considered impractical to define the point of regulation for residential and commercial stationary fuel combustion emissions at the point of emission, which would be the individual building owner. Rather, the point of regulation under consideration for this element is the point at which the relevant fuels enter into commerce in the individual states and provinces. In selecting this point of regulation, consideration is being given to the fact that some jurisdictions have a mechanism for tracking the sale of these fuels for other purposes. Building on the existing fuel tracking procedures in each jurisdiction is expected to simplify program design and implementation requirements.

For some jurisdictions, the point at which liquid fuels are tracked is the fuel distribution terminal, often referred to as the terminal rack. For example, in the United States, federal excise taxes on liquid fuels are collected at the terminal rack. Some states rely on this terminal-rack based tracking system to collect state taxes, thereby providing the capability to track fuel flows into the state.

Some jurisdictions track fuel deliveries to retailers for tax purposes. For these jurisdictions, the preferred point of regulation may be the licensed fuel wholesalers that are already required to report the quantity of fuel delivered.

Using this approach, the compliance obligation would be to hold emission allowances to cover the fossil carbon content of the fuel that is entering into commerce in the individual states and provinces. The regulated entity would be the party that enters the fuel into commerce in the state or province, such as the owner of the fuel dispensed at the terminal rack, or the licensed fuel wholesaler that dispenses fuel to retail locations.

2. Emissions and Entity Data

The stationary combustion of liquid fossil fuels in the residential and commercial sectors accounts for a small portion of overall GHG emissions within the WCI partners jurisdictions. Although incomplete data are currently available, these sources appear to account for less than 1% of total emissions in 2005 (see Table 4).

The total number of entities with a compliance obligation depends on the point of regulation. If terminal racks are the point of regulation for most jurisdictions, the total number of terminals and refineries (where the racks are located) is on the order of about 210 for the WCI partners (see Table 4). If wholesalers are the point of regulation, the number of entities will be larger. The compliance obligation for these fuels would likely be closely coordinated with the compliance obligation for the carbon content of liquid transportation fuels, which is described separately.

3. Emissions at the Entity Level

As described above, the point of regulation under consideration is the point at which liquid fuels enter into commerce in the individual states and provinces. At this point, the regulated entity cannot measure or calculate actual GHG emissions from fuel combustion. Rather, the entity can calculate potential CO_2 emissions based on the fossil carbon content of the fuel and the quantity of the fuel. Virtually all the carbon in the fuel is converted to CO_2, so that the carbon content of the fuel is an accurate predictor of CO_2 emissions.

Several issues need to be addressed in order to use this calculation of potential emissions:

- <u>Variations in fossil carbon content</u>: Currently, the fossil carbon content of liquid fuels is well known. However, in the future, fuels may include varying levels of non-fossil carbon components (e.g., in response to low carbon fuel standards). Consequently, the fossil carbon component of the fuel may need to be verified at the point of regulation, or may need to be provided to the point of regulation by the fuel producer. The mechanism required to make this fossil carbon content determination remains to be determined.

- <u>Fuel use for non-combustion purposes</u>: The emission calculation presumes that all the fuel delivered will be combusted. Some fuels may be used to produce products (such as plastics) that sequester carbon. While this eventuality may be unlikely for these fuels, the issue remains to be assessed.

Notably, this method of calculating emissions is a proxy only for the CO_2 emissions that occur when the fuel is combusted. The calculation does not include N_2O and CH_4 emissions, although those emissions would also be expected to occur during combustion along with the CO_2 emissions. Additionally, the method does not include the GHG emissions associated with producing the fuel. Rather, this method covers emissions associated with fuel use, but not fuel production. Emissions associated with fuel production (e.g., emissions at the refinery) would be covered separately as stationary combustion or process emissions from the facilities involved in producing the fuel in the WCI states and provinces.

4. Administration

By leveraging existing fuel tracking procedures in states and provinces, the administrative challenges for this design element can be minimized. However, the tracking capabilities of each state and province remain to be examined in detail to assess the comprehensiveness of the existing tracking capabilities. Insofar as the existing procedures provide incomplete coverage of the fuels, additional tracking capabilities may be required. As discussed above, the tracking of these fuels would be coordinated closely with the tracking of transportation fuels.

The potential challenges associated with verifying the fossil and non-fossil carbon components of fuels at the proposed point of regulation remain to be examined.

5. Leakage Issues

Fuel oil customers may vary with regard to leakage vulnerabilities. Most residential and commercial fuel oil customers do not have high greenhouse gas emissions intensities. Consequently internalizing the cost of the carbon content of fuel oil into fuel oil prices (as would be expected) would not significantly affect the competitiveness of most customers.

However, there are two circumstances of note. First, increased fuel prices could adversely affect low-income residential customers. Assistance programs for low-income customers could be a mechanism for addressing this impact. Second, there may be some individual commercial customers for which carbon emissions are significant. If these customers face competition from regions that do not limit greenhouse gas emissions, they may vulnerable to emissions leakage. The circumstances of these customers would be similar to large stationary source emissions sources that would be covered directly. The number of customers for which this may be an issue, and the potential impacts on these customers, remain to be identified.

Table 4: Summary of CO_2 Emissions from Residential and Commercial Stationary Combustion of Fuel Oil and Other Liquid Fuels

State/Province	2005 Emissions (MMT CO_2e)	Percent of 2005 Gross Emissions	# Entities	
			Terminals	Refineries
Arizona	0.7	0.7%	13	--
California (2004)	2.4	0.5%	84	20
Montana	0.4	1.1%	13	4
New Mexico	1.2	1.6%	16	3
Oregon (2004)	0.9	1.3%	10	1
Utah	0.4	0.6%	7	5
Washington	1.4	1.5%	25	5
British Columbia	0.9	1.3%	3	2
Manitoba	0.2	0.9%	1	--
Total WCI Partners	**8.6**	**0.8%**	**172**	**40**

MMT = million metric tons
Percent of gross emissions calculated for each state/province.
NA = Data not available. Emissions data currently being developed.
Preliminary estimates, subject to review and revision.

D. Industrial and Waste Management Process and Fugitive Emissions

1. Description

This element includes industrial and waste management process and fugitive emissions regulated at the point of emission.

1.1 Sectors

This sector includes specifically identified industrial processes and waste management activities, such as oil refining, cement production, aluminum smelting, iron and steel production, adipic acid production, nitric acid production, lime production, pulp and paper manufacturing, sawmill kilns, agricultural chemical manufacturing, plastics manufacturing, natural gas transmission and distribution, magnesium smelters and casters, mineral production, silicon chip manufacturing, ammonia production, wastewater treatment facilities; landfill operations, wastewater treatment from food processing; and others. An annual emissions threshold may be used to define the facilities included in the program. This threshold has not been established, and is under consideration. Process emissions from the Electric Sector are included in the Electric Sector, and are not included here.

1.2 Emissions Sources

The emission sources included are process emissions from stationary sources. Process emissions include emissions from chemical, biological, and other non-combustion processes. The emissions may be deliberate (e.g., vented), fugitive (e.g., leaked), or accidental. Fossil fuel combustion emissions are not included in this design element, and are covered in a separate description.

1.3 Greenhouse Gases

All six Kyoto greenhouse gases are included.

1.4 Point of Regulation

The point of regulation is the facility where the emissions occur.

2. Emissions and Entity Data

Among the WCI partner states and provinces, process emissions accounted for about 70 MMT of CO_2e in 2005, or about 7% of total gross emissions. This percentage varies from about 4% to 12% across the states and provinces.

The total number of entities that would be covered in this sector depends on whether, and at what level, an annual emissions threshold is set. The potential number of entities with compliance obligations is currently being assessed. Table 5 summarizes the emissions for the WCI partners.

3. Emissions at the Entity Level

The ability to measure or calculate emissions reliably and precisely at the entity level must be assessed for each of the industrial process and waste management sources in the WCI region. This assessment must examine:

- Is there an existing measurement or calculation protocol or method for the source?
- Is a new protocol or method required?

- What greenhouse gases can be measured or calculated reliably and precisely?
- Are there technical barriers to the entities being able to measure/calculate their emissions with sufficient precision to be covered by the cap-and-trade program? If there are barriers, which sources cannot be included, and how does their exclusion affect the emissions covered?

There are numerous industrial processes that emit greenhouse gases, and the answers to these questions will vary widely among the processes. For example, a protocol has been developed to calculate process emissions from cement manufacturing. Also, emissions of N_2O from nitric acid production can be monitored accurately using measurement devices in the process vent. Alternatively, process emissions at refineries are themselves diverse. Some refinery process emissions may be amenable to measurement or calculation, while others (such as fugitive emissions) may not be suitable for inclusion. This element could cover only those emissions that can be measured or calculated adequately. If needed, processes could be added to the program as methods or protocols are developed over time.

4. Administration

The primary administrative challenge associated with this sector is the inability to measure or calculate emissions precisely from some sources. Most of the large facilities that fall under this design element would already have compliance obligations under other regulatory programs. Consequently, the entities are well known and would be in a position to understand their compliance obligations under a cap-and-trade program. As discussed above, the use of an annual emissions threshold would reduce the number of entities with compliance obligations.

5. Leakage Issues

Vulnerability to leakage varies among the facilities that would be covered under this sector. Some facilities require close proximity to their markets, so that significant leakage to locations outside the WCI region is not expected. However, others (such as the cement industry), may be vulnerable to leakage as their products are traded as commodities internationally. The vulnerability to leakage needs to be assessed individually for each industry.

Table 5: Summary of Industrial and Waste Management Emissions Process and Fugitive Emissions

State/Province	2005 Emissions (MMT CO_2e) Industrial Processes	Waste Management	Percent of 2005 Gross Emissions	Entity Count Industrial Facilities	Landfills
Arizona	4.5	2.1	7%	53	32
California (2004)	24.1	9.4	7%	451	372
Montana	0.9	0.3	3%	12	5
New Mexico	1.6	1.4	4%	17	9
Oregon (2004)	3.4	1.9	8%	37	117
Utah	3.7	2.0	8%	26	31
Washington	3.3	2.4	6%	39	11
British Columbia	3.1	5.1	12%	16	NA
Manitoba	0.4	1.0	7%	3	NA
Total WCI Partners	**45.0**	**25.6**	**7%**	**654**	**577**

MMT = million metric tons
Percent of gross emissions calculated for each state/province.
NA = Data not available. Emissions data currently being developed.
Preliminary estimates, subject to review and revision.

E. Fossil Fuel Production and Processing

1. Description

Fossil Fuel Production and Processing encompasses oil and gas exploration, production, and processing, and coal mining. This design element includes a broad set of facilities and activities with diverse emissions sources. Some of the emissions sources included here are also part of other design elements (e.g., stationary combustion sources and process emissions). However, the sources are described here to provide a comprehensive description of emissions from this industry.

1.1 Sectors

The Fossil Fuel Production and Processing Sector can be categorized into the following components:

- Oil Production: Oil production covers exploration, drilling, production, and transportation of crude oil by pipeline to terminals or refineries. Facilities include well fields, pipelines, and tank batteries. Ships used to transport crude oil are included in the transportation sector. The output of this process is crude oil.
- Natural Gas Production and Processing: Natural gas production and processing covers exploration, production, and treatment of natural gas. Facilities include well fields, pipelines, and processing equipment. The output of this process is natural gas that meets specifications required for injection into natural gas transmission and distribution pipelines.
- Coal Mining: Coal mining covers mine development and operations, including surface mining (i.e., open pit mining) and underground mining. Coal processing facilities are considered a stationary source, and coal transport (e.g., by train) is considered part of the transportation sector.

Oil and gas are often produced from the same wells. In these cases, the distinction between oil production facilities and natural gas production facilities is not meaningful. Additionally, condensate and other liquids are often produced with oil and/or natural gas. The oil and natural gas production and processing facilities listed above encompass the production and processing of these liquids.

Methane recovered from coal seams (often referred to as "coalbed methane") can also be used to produce pipeline quality natural gas. Coalbed methane production and treatment is included in this design element as part of natural gas production.

Pipelines of various types are also used to transport crude oil, liquid products, and gas. Pipelines are included in this design element, including: gathering lines; crude oil and liquid products pipelines that run to refineries, terminals, and tanks; and gas pipelines that connect to transmission lines. Natural gas transmission and distribution pipelines are not included in this design element.[5] Similarly, refineries and the transport of refined products to market are not included in this design element.[6]

[5] Natural gas transmission and distribution pipelines are considered stationary sources with combustion emissions (i.e., from compressors) and process emissions (i.e., gas venting and fugitive emissions).

[6] Refineries are considered a stationary source with combustion emissions and process emissions. The transport of refined products to market is considered part of the transportation sector.

1.2 Emissions Sources

The Fossil Fuel Production and Processing Sector includes a diverse set of greenhouse gas emissions sources. Many of the sources are specialized pieces of equipment found only in this industry. The major emission sources in oil and gas production and processing are listed in Table 6. As shown in the table, the emissions sources can be categorized into six types:

- Stationary combustion includes all types of fossil fuel combustion, including flaring.
- Process vents include equipment that is designed to vent emissions as part of its normal operation. Amine treatment as part of acid gas removal is an example of a process with this type of venting.
- Maintenance venting includes emissions that occur during scheduled maintenance activities.
- Non-routine venting occurs periodically, often for safety reasons.
- Other venting is associated with specific activities or pieces of equipment, some of which are designed to vent as part of normal operation (e.g., pneumatic devices and chemical injection pumps).
- Fugitive emissions occur from unintended leaks from equipment components.

The relative importance of each of the sources depends on site-specific equipment requirements, operations, and configurations.

The source of coal mining emissions is primarily due to the release of methane from the coal and surrounding strata due to mining activities. In underground mines, methane can create an explosive hazard, so it is removed through a ventilation system. Methane concentrations in ventilation system emissions are typically less than 1%, and consequently the methane is nearly always emitted to the atmosphere. In some mines, a degasification system is used to withdraw methane prior to mining due to large quantities of methane occurring in the coal and surrounding strata. The methane collected by the degasification system may be recovered and used for fuel in some cases.

In surface mining, the methane associated with the coal is emitted directly to the atmosphere as the coal is uncovered. For both underground coal and surface-mined coal, some methane remains in the coal after it is mined. This methane is released subsequently during processing, transport, and storage.

Finally, methane is also emitted from closed or abandoned underground mines. Although mining is no longer active, closed mines can release methane from vents, fissures, or boreholes.

This list of emissions sources for Fossil Fuel Production and Processing includes only those sources that produce emissions during the production and processing of the fuel (oil, gas, and coal). When the resulting products are combusted (i.e., when refined oil products and natural gas are used as fuel by others), they also produce emissions (primarily carbon dioxide). The emissions from fuel combusted by others are not included in this design element.

1.3 Greenhouse Gases

The predominant GHGs emitted from Fossil Fuel Production and Processing are:

- Carbon dioxide (CO_2): CO_2 is released from fossil fuel combustion at oil and gas production and processing facilities. This combustion includes emissions from flaring (see Table 6). Also, CO_2 is often mixed with natural gas as it is produced from underground formations, particularly from coalbed methane sources. During gas processing, this CO_2 is typically separated from the natural gas and vented.[7]

- Methane (CH_4): Methane is typically released due to venting and leaks during oil and natural gas production and processing (methane is the primary component of natural gas). Methane is also released from coal mines.
- Nitrous oxide (N_2O): N_2O emissions are primarily associated with fuel combustion. N_2O emissions are typically a very small portion of total GHG emissions from Fossil Fuel Production and Processing.

The largest GHG emissions from Fossil Fuel Production and Processing are CO_2 from combustion of fuel and CO_2 separated from the raw gas stream.

1.4 Point of Regulation

The point of regulation currently under consideration is the facility where the emissions occur. As discussed above, oil and gas production facilities include a diverse set of equipment, processes, and activities. These facilities may also cover large geographic areas, encompassing well fields, pipelines, and tank batteries. Ownership and operational control may be divided among multiple entities as the oil and gas is produced and processed.

2. Emissions and Entity Data

Among the WCI partner states and provinces, Fossil Fuel Production and Processing emissions accounted for nearly 45 million metric tons (MMT) of CO_2e in 2005, or about 4% of total gross emissions from the WCI partners. However, for New Mexico and British Columbia, emissions from the Fossil Fuel Production and Processing Sector are a larger portion of total gross emissions, accounting for about 27% and 22% respectively of their gross emissions in 2005. Table 7 summarizes the emissions estimates for each province and state.

Although significant improvements have been made in the ability to calculate GHG emissions from Fossil Fuel Production and Processing, considerable uncertainty remains in national and state/provincial emission inventory estimates. Emissions factors for some types of emissions, such as fugitive emissions, continue to have broad ranges of uncertainty. Additionally, some activity data, such as the quantities of gas flared or vented, are not well measured or reported in some circumstances. Various efforts are ongoing to continue to improve emissions estimates for this industry.

The number of operating oil and gas wells is on the order of 70,000 and 50,000 respectively for the WCI partners (see Table 8). Typically, a small number of well field operators account for a large portion of operating wells and oil and gas production. For example, within the United States in 2005, the top 50 operators account for 77% of oil production and 72% of natural gas production.[8] In British Columbia, five operators account for about 80% of natural gas production, and in New Mexico 20 operators account for about 80% of natural gas production. Similarly, in California, 30 operators account for more than 90% of oil and gas production. Consequently, if a size threshold were adopted for participation in a cap-and-trade program, a large portion of total production could be covered while keeping the number of oil and gas field operators with a regulatory obligation manageable. Assessments of size threshold options and the number of entities covered remains ongoing.

[7] In some cases, CO_2 separated from natural gas is captured and re-injected or used for other purposes.

[8] U.S. Energy Information Agency, “Operator Information by Size Class” available at: http://tonto.eia.doe.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_m.htm.

The number of coal mines operating in the WCI jurisdictions is on the order of 35, including 19 underground and 16 surface mines (see Table 8).

3. Emissions at the Entity Level

The ability to measure or calculate emissions reliably and precisely at the facility or entity level varies depending on the activities performed and equipment used at the facility and the manner in which data are collected and verified. For oil and gas production and processing emissions, several resources have been developed to assist in estimating emissions:

- The American Petroleum Institute's *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil & Gas Industry*[9] promotes consistency in estimating petroleum company's GHG emissions and provides recommendations on ways to improve and streamline GHG emissions estimates among existing methodologies.
- The International Petroleum Industry Environmental Conservation Association (IPIECA), International Association of Oil and Gas Producers (OGP) and API also prepared the *Petroleum Industry Guidelines for Reporting Greenhouse Gas Emissions*[10], a consistent global framework for accounting and reporting of GHG emissions by the industry sector.
- The World Business Council for Sustainable Development (WBCSD) and World Resources Institute (WRI) have developed *The Greenhouse Gas Protocol: a Corporate Accounting and Reporting Standard*[11], a common framework for defining the boundaries of reporting emissions.
- The New Mexico Environment Department, California Air Resources Board, and California Climate Action Registry, in cooperation with the Western Regional Air Partnership, have begun a joint initiative to develop a registry reporting protocol specific to the upstream oil and gas industry sector (i.e., production) and natural gas processing. This protocol, in combination with protocols already developed or soon to be completed for petroleum refining and natural gas transmission and distribution, will provide a basis for accelerated adoption of a complete oil and gas sector protocol by The Climate Registry. The protocol will not be likely to be completed until mid 2009.

While these resources have improved (and are continuing to work to improve) the consistency of emissions calculations and methods, the accuracy of entity-specific emissions calculations remains an issue of concern for certain sources at oil and gas production and processing facilities. Emissions calculations for metered fuel use and process vents amenable to measurement are expected to be as precise as the estimates performed for similar emissions from other stationary sources. However, emissions calculations for unmetered gas use (either flared or vented) and leaks pose challenges. The use of average or representative emissions factors for some sources (such as fugitive emissions) does not enable site-specific conditions to be reflected, and does not allow for improved operation and maintenance to be reflected in reduced emissions estimates.

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[9] *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil & Gas Industry,* American Petroleum Institute (API), Washington, DC, February 2004, available at http://ghg.api.org.

[10] *Petroleum Industry Guidelines for Reporting Greenhouse Gas Emissions*, International Petroleum Industry Environmental Conservation Association (IPIECA), London, United Kingdom, December 2003.

[11] *The Greenhouse Gas Protocol: a corporate accounting and reporting standard*, World Business Council for Sustainable Development (WBCSD) and World Resources Institute (WRI), Washington, DC, January 2004, available at http://www.ipieca.org/reporting/ghg.html.

Based on the information reviewed to date, only a portion of the sources at oil and gas production and processing facilities will likely be feasible to include in a cap-and-trade program at this time. Improved methodologies may enable additional sources to be included in the future. The identification and assessment of those sources remains ongoing.

The ability of individual coal mines to calculate or measure emissions accurately varies. Surface mined coal does not provide an opportunity to measure emissions, although those emissions are typically low. Emissions from underground coal mining can be estimated from methane concentrations in ventilation air. Additionally, methane collected in degasification systems (prior to mining) is typically quantified.

Emissions from coal mines emitting over 100,000 metric tons CO_2e in Canada report their emissions federally.[12] The Environment Canada National Inventory Report contains data on fugitive emissions from coal mining, but the data for British Columbia is confidential due to the low number of market participants in the province (four).[13]

The ability to calculate emissions precisely from underground coal mining remains under review.

4. Administration

The primary administrative challenge associated with this sector is the inability of entities to measure or calculate emissions precisely from some sources. The entities that own or operate facilities that fall under this design element would already have compliance obligations under other regulatory programs. Consequently, the entities are well known and would be in a position to understand their compliance obligations under a cap-and-trade program.

The number of entities in the oil and gas production and processing industry could be large. Complex ownership and operating arrangements are also typically encountered. As discussed above, the use of a size or annual emissions threshold would reduce the number of entities with compliance obligations.

5. Leakage Issues

Oil, gas, and coal mining activities are undertaken at the locations of the resources themselves. Consequently, the operations cannot relocate to avoid participation in a cap-and-trade program. However, the companies that operate these facilities compete for investment resources. Increased cost or regulatory burdens have the potential to shift investment and production from WCI jurisdictions to other regions. Over time, therefore, production activities could shift to locations without GHG emissions limits, so that no net emission reduction is achieved. The significance of this vulnerability to emissions leakage remains under review.

[12] *Facility GHG Reporting,* Environment Canada, Ottawa, Canada, available at http://www.ec.gc.ca/pdb/ghg/facility_e.cfm.

[13] *National Inventory Report, 1990-2005: Greenhouse Gas Sources and Sinks in Canada*, Table A11-20: 1990-2005 GHG Emission Summary for British Columbia, Environment Canada, Ottawa, Canada, April 2007, available at http://www.ec.gc.ca/pdb/ghg/.

Table 6: Major Greenhouse Gas Emissions Sources from Oil and Gas Production and Processing

Equipment*	Emissions Type
Boilers/steam generators	Stationary combustion
Heaters/treaters	Stationary combustion
Compressors (internal combustion engines and turbines)	Stationary combustion
Flares	Stationary combustion
Incinerators	Stationary combustion
Gas sweetening processes	Process vent
Gas dehydration	Process vent
Vessel blowdowns	Maintenance venting
Well workovers	Maintenance venting
Compressor starts	Maintenance venting
Compressor blowdowns	Maintenance venting
Gathering pipeline blowdowns	Maintenance venting
Pressure relief valves	Non-routine venting
Well tests and blowdowns (when not flared)	Non-routine venting
Emergency shutdown/emergency safety blowdown	Non-routine venting
Tanks	Other venting
Pneumatic devices	Other venting
Chemical injection pumps	Other venting
Well drilling and testing	Other venting
Leaks from equipment components	Fugitive emissions
* Mobil sources are also used in oil and gas production fields (e.g., supply boats, barges, trucks, and aircraft). Mobil sources are not included in this design element.	

Table 7: Summary of Fossil Fuel Production and Processing Greenhouse Gas Emissions

State/Province	2005 Emissions (MMT CO_2e)	Percent of 2005 Gross Emissions
Arizona	0.6	1%
California (2004)	5.6	1%
Montana	5.0	13%
New Mexico	19.5	27%
Oregon (2004)	0.7	1%
Utah	4.1	6%
Washington	0.9	1%
British Columbia	6.1[a]	22%
Manitoba	0.6	3%
Total WCI Partners	**43.1**	**4%**

MMT = million metric tons
Percent of gross emissions calculated for each state/province.
Preliminary estimates, subject to review and revision.
a. This figure for British Columbia is under joint review by provincial and federal officials and may be revised.

Table 8: Oil Wells, Gas Wells, and Coal Mines

State/Province	Oil Wells (2004)	Gas Wells (2004)	Coal Mines (2005)	
			Surface	Underground
Arizona	20	8	2	0
California	45,515	3,362	0	0
Montana	3,765	5,356	5	1
New Mexico	14,928	33,029	3	1
Oregon	0	16	0	0
Utah	2,180	3,936	0	13
Washington	0	0	1	0
British Columbia	1,107	4,385	8	1
Manitoba	1,474	--	0	0
Total WCI Partners	**68,989**	**50,092**	**19**	**16**

U.S. data from Energy Information Administration (http://www.eia.doe.gov).
British Columbia oil and gas well data from "Annual Drilling & Production Statistics in British Columbia (1995-2005)" (http://www.em.gov.bc.ca/Subwebs/oilandgas/stat/annual.htm).
British Columbia coal mine data from "British Columbia Operating Coal Mines 2005" (http://www.em.gov.bc.ca/Mining/MiningStats/34coalcomlist99.htm).
Manitoba data for oil wells capable of production, from "Manitoba Petroleum Statistics" (http://www.gov.mb.ca/iedm/petroleum/stats/index.html).
Preliminary estimates, subject to review and revision.

F. Fossil Carbon Content of Fuels

1. Description

1.1 Sectors

This design element covers CO_2 emissions from fossil fuel combustion throughout the economy, including: the electricity sector, transportation fuels, residential and commercial stationary combustion, and industrial stationary combustion.

1.2 Emissions Sources

This design element covers fossil fuel combustion throughout the economy. The fuels include coal, oil, natural gas, and other fossil fuels (such as propane).

1.3 Greenhouse Gases

This design element would cover CO_2 emissions. Other greenhouse gases associated with fuel combustion (nitrous oxide and methane) would be affected, but not covered explicitly. CO_2 emissions are estimated to account for more than 98% of the GHG emissions from fossil fuel combustion.

1.4 Point of Regulation

For some sectors, such as large industrial sources, GHG emissions can be tracked at the point of combustion. For other sectors, such as transportation, it is generally considered impractical to define the point of regulation at the point of emission, which would be the individual vehicle owner. The point of regulation under consideration for this element is to cover all fossil fuels at an appropriate point in their distribution and use. The appropriate point will vary depending on the fuel:

- Liquid Fuels: The preferred point of regulation for liquid fuels (gasoline, diesel, propane) will likely be the point at which these fuels enter into commerce in the individual states and provinces. In examining this point of regulation, consideration is being given to the fact that most jurisdictions have an existing mechanism for tracking the sale of liquid fuels. The manner in which jurisdictions track fuel distribution and sales varies, so that the preferred point of regulation may also vary among jurisdictions. Some states track fuel deliveries through licensed wholesalers. Other states track fuel dispensed from terminals and refineries. Care is needed to ensure that the tracking systems are comprehensive and compatible. Because these tracking systems have generally been developed to support tax collection, building on the existing fuel tracking procedures in each jurisdiction is expected to simplify program design and implementation requirements.
- Natural Gas: The preferred point of regulation for natural gas will likely be a combination of entities. For residential and commercial customers (and some industrial customers), natural gas is delivered by local distribution companies (LDCs). The LDCs are in a position to track and report natural gas delivered to these customers. Some large natural gas users (e.g., some industrial customers) purchase natural gas directly, bypassing the LDCs. The point of regulation for direct purchasers of natural gas would be the direct purchasers themselves. Coordination would be required to ensure the combined set of entities cover natural gas use comprehensively, and without duplication, in each jurisdiction. Another option for covering natural gas would be at the pipeline.
- Coal: In most jurisdictions, coal is typically combusted in facilities that are known to regulatory agencies for other environmental control purposes. The preferred point of regulation would likely be the individual facilities that combust coal.

2. Emissions and Entity Data

CO_2 emissions from fossil fuel combustion are the largest component of GHG emissions for each of the WCI partners. The emissions estimate for 2005 is about 820 MMT CO_2e, accounting for about 81% of total gross emissions among the WCI partners. The percentage of total gross emissions varies among the partners from about 55% to 87%. Table 9 summarizes the emissions estimates for the WCI partners.

The number of entities with regulatory obligations under this design element is being assessed. The number of pipelines and LDCs in the WCI partner states is shown in Table 10, along with the number of refineries and liquid fuel terminals. The number of licensed fuel wholesalers is expected to be larger than the number of terminals. For example, Oregon licenses about 160 motor vehicle fuel dealers. The number of entities that purchase natural gas directly or combust coal remains to be identified, but is expected to be a manageable number for administrative purposes.

3. Emissions at the Entity Level

As described above, the points of regulation under consideration for natural gas and liquid fuels do not coincide with their emissions points. LDCs and fuel distributors (whether at terminals or wholesalers) cannot measure or calculate actual GHG emissions from fuel combustion. Rather, the entity can calculate potential CO_2 emissions based on the fossil carbon content of the fuel and the quantity of the fuel. Virtually all the carbon in the fuel is converted to CO_2, so that the carbon content of the fuel is an accurate predictor of CO_2 emissions.

Several issues need to be addressed in order to use this calculation of potential emissions:

- Variations in fossil carbon content: Currently, the fossil carbon content of liquid fuels and natural gas is well known. However, in the future, fuels may include varying levels of non-fossil carbon components (e.g., in response to low carbon fuel standards). Consequently, the fossil carbon component of the fuel may need to be verified at the point of regulation, or may need to be provided to the point of regulation by the fuel producer. The mechanism required to make this fossil carbon content determination remains to be determined.
- Fuel use for non-combustion purposes: The emission calculation presumes that all the fuel delivered will be combusted. Some fuels may be used to produce products (such as plastics) that sequester carbon. A mechanism is needed to account for this carbon sequestration at the point of use of the fuel.

Notably, this method of calculating emissions is a proxy only for the CO_2 emissions that occur when the fuel is combusted. The calculation does not include N_2O and CH_4 emissions, although those emissions would also be expected to occur during combustion along with the CO_2 emissions. Additionally, the method does not include the GHG emissions associated with producing the fuel. Rather, this method covers emissions associated with fuel use, but not fuel production. Emissions associated with fuel production would be covered separately as emissions from the facilities involved in producing the fuel.

For direct purchasers of natural gas and for coal combustion facilities, the entity would also be capable of measuring or calculating CO_2 emissions. Facilities could use fuel consumption data along with the carbon content of the fuel. Alternatively, some facilities may find it advantageous to measure emissions directly.

4. Administration

This sector does not pose significant administrative challenges. Regulatory agencies are able to identify most if not all the entities in this sector with compliance obligations because the entities typically have other regulatory requirements. LDCs are already subject to economic regulation by the state public utilities commissions in the United States and by provincial authorities in Canada. Thus, a state or provincial regulatory agency can identify all the entities with compliance obligations. Large industrial purchasers of natural gas and coal combustors typically have other air emission compliance requirements, and consequently are known to regulators.

By leveraging existing liquid fuel tracking procedures in states and provinces, the administrative challenges for these fuels can be minimized. However, the tracking capabilities of each state and province remain to be examined in detail to assess the comprehensiveness of the existing tracking capabilities. Insofar as the existing procedures provide incomplete coverage of the fuels, additional tracking capabilities may be required.

The covered entities should also have the capability to know their compliance obligations and understand the applicable requirements. The emissions from this sector are reasonably well known, so that an acceptable emission baseline can be developed.

5. Leakage Issues

This design element covers a very broad set of sectors throughout the economy. Significant vulnerabilities to leakage exist in specific components of fossil fuel use.

- Electric Sector: This design element covers the combustion at fossil fuel power plants either directly (e.g., as direct natural gas purchasers and coal combustion facilities) or indirectly through the inclusion of natural gas LDCs and oil distributors. Because emissions leakage associated with electricity imports from jurisdictions without GHG emissions caps can be significant, such leakage would need to be addressed as part of this approach.

- Transportation fuels: The potential for emission leakage is significant for components of the transportation sector:

    - *Marine:* Ocean-going vessels can easily obtain fuel outside the WCI partner jurisdictions.

    - *Aviation:* Airline operations are particularly sensitive to fuel costs. Opportunities to obtain fuel outside the WCI partner jurisdictions may be significant.

    Gasoline use in passenger cars, light duty trucks, and medium duty vehicles is less vulnerable to leakage, as motorists typically obtain fuel in close proximity to their residences and places of employment.

    Long-haul trucking may also be vulnerable to leakage if trucks can operate within WCI jurisdictions with fuel obtained from outside the WCI jurisdictions. However, the International Fuel Tax Agreement (IFTA) requires diesel trucks operating in multiple jurisdictions to calculate fuels consumed in each state and province based on the miles traveled in each state/province. All the WCI partners are parties to the IFTA.[14]

[14] The 48 contiguous states of the United States and 10 Canadian provinces are parties to IFTA. Yukon Territory, Northwest Territory, Nunavut, and the District of Columbia are not parties to IFTA.

Consequently, the IFTA data could be used to compute a compliance obligation for diesel trucks that operate in multiple jurisdictions, thereby avoiding leakage.[15]

- Industrial Facilities: Vulnerability to leakage varies among the industrial facilities that would be covered under this sector. Some facilities require close proximity to their markets, so that significant leakage to locations outside the WCI region is not expected. However, others (such as the cement industry and the pulp and paper industry), may be vulnerable to leakage as their products are traded as commodities internationally. The vulnerability to leakage needs to be assessed individually for each industry.

Table 9: Summary of CO_2 Emissions from Fossil Fuel Combustion

State/Province	2005 Emissions (MMT CO_2e)	Percent of 2005 Gross Emissions
Arizona	86.6	87%
California (2004)	416.2	86%
Montana	22.6	61%
New Mexico	43.9	60%
Oregon (2004)	57.7	83%
Utah	54.0	78%
Washington	81.0	85%
British Columbia	46.9	71%
Manitoba	11.4	55%
Total WCI Partners	**820.1**	**81%**

MMT = million metric tons
Percent of gross emissions calculated for each state/province.
Preliminary estimates, subject to review and revision.

[15] IFTA covers diesel trucks with the following characteristics: (a) has three or more axles; or (b) has two axles and a gross vehicle or registered gross vehicle weight of more than 26,000 pounds or 11,797 kilograms; or (c) is used in a combination that has a combined or registered gross vehicle weight of more than 26,000 pounds or 11,797 kilograms. Recreational vehicles are not covered.

Table 10: Summary of Number of Potentially Regulated Entities for Fossil Fuels

	Natural Gas			Petroleum	
	Pipelines			# Liquid Fuel Entities	
State/Province	**Interstate**	**Intrastate**	**# LDCs**	**Terminals**	**Refineries**
Arizona	4		8	13	--
California	6	3	11	84	20
Montana	2	2	5	13	4
New Mexico	8	4	19	16	3
Oregon	3	-	3	10	1
Utah	4	-	2	7	5
Washington	2	1	7	25	5
British Columbia	2	2	4	3	2
Manitoba	1	-	1	1	--
Total WCI Partners	**32**	**12**	**60**	**172**	**40**
Data for direct purchasers of natural gas and for coal combustors are under development. Preliminary estimates, subject to review and revision.					

G. Passenger Cars, Light Duty Trucks and Medium Duty Vehicles

1. Description

This design element covers emissions from passenger cars, light duty trucks and medium duty vehicles. These emissions could be covered through several different approaches. This design element focuses on vehicle manufacturers as one option for covering these emissions.

1.1 Sectors

The sector covered is the light and medium duty vehicle portion of the transportation sector (cars and trucks less than 14,000 pounds gross vehicle weight rating).

1.2 Emissions Sources

Emission sources include all emissions during the operation of passenger cars, light duty trucks and medium duty vehicles, including: fuel combustion; refrigerant emissions; and evaporative emissions. Emissions associated with producing the vehicles or producing the fuel used by the vehicles are not included in this design element.

1.3 Greenhouse Gases

All six Kyoto gases are included. The primary gases associated with vehicle operations are CO_2, CH_4, N_2O, and high GWP gases (refrigerants).

1.4 Point of Regulation

It is generally considered impractical to define the point of regulation for passenger cars, light duty trucks and medium duty vehicles at the point of emission, which would be the individual vehicle owner. Rather, the point of regulation under consideration for this element is the vehicle manufacturer. In considering this point of regulation, the vehicle manufacturer would be assigned responsibility for the expected emissions associated with their new vehicles that are sold in each jurisdiction, or alternatively, for vehicles *delivered for sale* in a jurisdiction. This regulatory obligation could take various forms, including:

- <u>Fleet Requirement</u>: Under this approach, a maximum fleet average emission rate would be defined for each year. The actual fleet average for each manufacturer would be calculated each year based on the new vehicles sold (or delivered for sale) by that manufacturer in that year. Manufacturers would be required to hold allowances for emissions that exceed the fleet average maximum, and could earn credits for attaining average fleet emissions below the maximum. Whether and how these emission allowances and credits could be traded with other components within of a cap-and-trade system remain to be assessed.
- <u>Lifetime Emissions</u>: Under this approach, each manufacturer would be responsible for the expected lifetime emissions associated with its new vehicles sold (or delivered for sale) each year. The manufacturer would be required to hold emission allowances equal to the expected lifetime emissions from the new cars sold in that year.

2. Emissions and Entity Data

The transportation sector is one of the largest sources of GHG emissions for each of the WCI partners. Table 11 summarizes the emissions estimates for the WCI partners. The total number of entities with compliance obligations is the number of vehicle manufacturers that sell vehicles in the WCI states and provinces. There are approximately 40 manufacturers that sell vehicles in these jurisdictions.

3. Emissions at the Entity Level

As described above, the point of regulation under consideration is the sale of new passenger cars, light duty trucks and medium duty vehicles by manufacturers. At this point, the regulated entity (the manufacturer) cannot measure or calculate actual GHG emissions from vehicle use. Rather, the entity can calculate potential emissions based on the expected operating characteristics of the vehicles sold, including the number of years the vehicles remain in use. These emissions estimates depend, in part, on how owners maintain and use their vehicles (e.g., vehicle miles traveled annually). Additionally, actual emissions will depend on fuel characteristics, including the availability and use of fuels with non-fossil carbon components.

To carry out the necessary emission calculations, the emissions rate associated with each model sold would need to be certified (e.g., emissions per mile traveled). Vehicle testing procedures have been developed to support requirements such as the California vehicle emissions regulations that focus on fleet average emissions. Additional data are required to calculate expected lifetime emissions. Consequently, lifetime emission estimates made at the time of sale by the manufacturers will necessarily have additional uncertainty, which may be a barrier to using the lifetime emissions approach.

4. Administration

There are roughly 40 manufacturers of passenger cars and light duty trucks worldwide. Therefore, the number of entities does not pose an administrative challenge. The manufacturers have the capability to know their compliance obligations and understand the applicable requirements. The potential need to track nearly new vehicles that are registered in the state or province needs to be assessed. For example, to avoid the program requirements, a new vehicle could be sold and registered in a non-WCI jurisdiction and then moved to a WCI jurisdiction and registered. Vehicles with fewer than 15,000 miles (for example) that are registered for the first time in a WCI jurisdiction could be counted as a newly sold vehicle for purposes of the program. Whether this tracking of nearly new vehicles would be needed, and how it would be administered remains to be considered.

In addition to administrative issues, potential legal issues also remain to be examined. The WCI jurisdictions must assess whether they have an adequate regulatory basis for requiring reporting and participation by vehicle manufacturers. If needed, jurisdictions could consider regulating (via permit) automobile manufacturers as “Indirect Sources” of air pollution (for example, Oregon’s regulations at OAR 340-254-0030).

5. Leakage Issues

The sale of new passenger cars and light duty trucks is not particularly vulnerable to leakage because consumers purchase vehicles primarily for local transportation purposes. Concerns have been raised regarding impacts on the rate of turnover of the vehicle fleet. Higher vehicle prices may slow the rate of vehicle replacement, leading to vehicles with higher emissions remaining on the road longer than would otherwise be the case. This impact can be assessed for alternative program designs.

Table 11: Summary of CO_2 Emissions from On-Road Gasoline Combustion

State/Province	2005 Emissions (MMT CO_2e)	Percent of 2005 Gross Emissions
Arizona	24.4	24%
California (2004)	138.1	28%
Montana	4.1	11%
New Mexico	8.9	12%
Oregon (2004)	13.1	19%
Utah	8.8	13%
Washington	23.5	25%
British Columbia	10.5	16%
Manitoba	2.9	14%
Total WCI Partners	**234.2**	**23%**

MMT = million metric tons
Percent of gross emissions calculated for each state/province.
NA = Not Available. Emissions data currently being developed.
Preliminary estimates, subject to review and revision.

H. Large Transportation Fleets

1. Description

This design element covers large transportation fleets. The point of regulation would be entities (e.g., companies, local governments, transit agencies, etc.) that operate fleets of motor vehicles or boats. A key issue in this sector is what constitutes a "fleet" of vehicles or boats. Thresholds in both quantitative (e.g., number of vehicles or boats) and qualitative (e.g. types of vehicles or boats) terms may be applied to limit the scope of regulation within this sector.

1.1 Sectors

Large Transportation Fleets regulated at the fleet management level.

1.2 Emissions Sources

Fossil fuel combustion from fleet vehicles and boats.

1.3 Greenhouse Gases

Carbon dioxide is the dominant GHG produced in this element, accounting for on the order of 97% of emissions from these sources. Nitrous oxide (N_2O) and methane (CH_4) are also emitted.

1.4 Point of Regulation

The point of regulation for this option would be the entity that owns and operates the vehicles that are to be regulated. This entity would be required to hold allowances equal to the emissions of the fleet vehicles. Issues around leased vehicles would need to be clarified.

A threshold for inclusion in the sector would seem to be a practical necessity. Possible thresholds include number of vehicles or boats, combined fleet vehicle miles traveled, total fuel use, or other metrics. However, it may be most appropriate to set an emissions threshold for including fleets in the cap-and-trade program.

Other factors may play into the definition of a "fleet" for the purposes of compliance. Types of vehicles (commercial, off-road, on-road, marine, weights of vehicles, etc.) may be one factor. Geographic range, or the geographic location of a centralized operations base, may also play into a definition of what constitutes a fleet for inclusion in such a program. Inclusion of ferry and other boat fleets (such as those operated by Washington State Ferries, the BC Ferry Corporation and marine barge operations) should be considered under this design element due to the amount of associated emissions.

2. Emissions and Entity Data

Data collection and analysis are underway to estimate the number of fleets at various threshold levels and the portion of emissions that the fleets may represent. Initial indications are that there may be on the order of 10,000 vehicle fleets in the WCI partner states and provinces that each have 10 or more vehicles. However, this is a very preliminary figure.

3. Emissions at the Entity Level

Most fleet management systems would capture the relevant data necessary for estimating emissions from fleet vehicles. Emissions could be estimated from odometer readings, fuel use, and other factors. Protocols for estimating these emissions exist. However, fleet data have been suspect in terms of data reliability and verifiability. The margins of error associated with these data should be considered.

Currently, the fossil carbon content of liquid transportation fuels is well known. However, in the future, fuels may include varying levels of non-fossil carbon components (e.g., in response to low carbon fuel standards). Consequently, the fossil carbon component of the fuel may need to be verified at the point of regulation, or may need to be provided to the point of regulation by the fuel producer. The mechanism required to make this fossil carbon content determination remains to be determined.

If N_2O and CH_4 were included in the cap and trade program for this sector then estimating emissions for these gases may be subject to a wide margin of uncertainty because emission rates depend on vehicle characteristics and maintenance conditions. National and international standard N_2O and CH_4 emission factors for different fuels could be used as a proxy for more precise estimations.

4. Administration

The ability to administer a cap and trade program in the fleet sector is largely a function of how fleets are defined. If the threshold for inclusion (by whatever metric) is low enough to include the numerous family-run or other similar small business operations in trucking, retail, and urban delivery, then the ability for these entities to understand and administer their obligations is questionable. Conversely, the largest fleet operations – especially in trucking, ferries and businesses like rental fleets – are likely well positioned from both an administrative and data perspective to deal with the regulatory burden. Steps may need to be taken, however, to ensure that fleets do not sub-divide their structures to potentially avoid regulation by falling under whatever threshold is put in place.

5. Leakage Issues

There are components of the large fleet sector for which there may be a high level of leakage from any attempt to regulate the large fleet sector. Medium- to large-scale fleets in the goods delivery sector have the ability to locate themselves in any number of locations so long as they have at least some reasonable level of proximity to the markets they operate in. Thus it is possible that in response to any cap-and-trade regime in WCI states and provinces that trucking fleets (in particular) may relocate to the borders of adjoining states and provinces not subject to the cap-and-trade regime.

However, the International Fuel Tax Agreement (IFTA) requires diesel trucks operating in multiple jurisdictions to calculate fuels consumed in each state and province based on the miles traveled in each state/province. All the WCI partners are parties to the IFTA.[16] Consequently, the IFTA data could be used to compute a compliance obligation for fleet operators of diesel trucks that operate in multiple jurisdictions, thereby avoiding leakage.[17]

Leakage is less of an issue for fleets that must serve specific areas. These fleets may include municipal and state/province government vehicles, as well as electric and gas utility trucks. Similarly, leakage would not apply to ferry fleets, and likely not to marine barge and other localized marine fleets.

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[16] The 48 contiguous states of the United States and 10 Canadian provinces are parties to IFTA. Yukon Territory, Northwest Territory, Nunavut, and the District of Columbia are not parties to IFTA.

[17] IFTA covers diesel trucks with the following characteristics: (a) has three or more axles; or (b) has two axles and a gross vehicle or registered gross vehicle weight of more than 26,000 pounds or 11,797 kilograms; or (c) is used in a combination that has a combined or registered gross vehicle weight of more than 26,000 pounds or 11,797 kilograms. Recreational vehicles are not covered.

Smaller fleets serving specific urban markets are less likely to be able to relocate to avoid regulation. However, as previously noted, the administrative feasibility of regulating the smaller fleets is in question.

I. Agriculture Emissions

1. Description

1.1 Sectors

This design element covers the agricultural sector, which includes a diverse set of production activities, including: crop production; livestock production; grazing lands; and other activities. Agriculture can serve as a sink (i.e., can remove carbon dioxide from the atmosphere) or as a source of emissions. Not included in this design element is forestry, although agriculture and forestry are often interrelated because land can change from one use to the other and back.

1.2 Emissions Sources

Given the diversity of agricultural activities, there are a large number of sources of emissions, including:

- methane and nitrous oxide (N_2O) emissions from livestock manure management;
- N_2O emissions from soils due to fertilizer use, legume production, and increased microbial activity associated with liming;
- methane emissions from livestock digestive processes, rice cultivation; and cultivation of other wetland crops;
- methane emissions from the conversion of lands from trees or grasses to annual cropland; and
- carbon dioxide (CO_2) emissions from the use of lime.

In addition to these sources, agricultural lands can emit CO_2 or act as a sink for CO_2 in a given year by changing the carbon stock on the agricultural land. Carbon stock is the carbon contained in biomass, including above and below ground biomass, at a specific point in time. If the carbon stock increases from one year to the next, the agricultural land acted as a sink, and accumulated carbon by removing it from the atmosphere. If the carbon stock decreases, the land released carbon.

Practices that can increase carbon stock (i.e., remove CO_2 from the atmosphere) include reduced tillage, use of cover crops, favorable crop rotations, changing from row crops to permanent pasture or other perennial crops, and increasing productivity of plants on pasturelands.

Emissions due to fertilizer production and fuel use in farm equipment are not included as sources in this sector.

1.3 Greenhouse Gases

N_2O and methane are the primary GHG emitted in the agriculture sector. CO_2 emissions and sinks also occur.

1.4 Point of Regulation

The point of regulation for agriculture is the land owner. The land owner typically has control over how the lands are managed, including the type and level of agricultural production that takes place. Consequently, the land owner has the most influence over the activities that lead to emissions (or sinks) on his/her agricultural lands.

Notably, some agriculture lands are leased to others who use the land for production purposes. For example, grazing lands are often leased to livestock owners, so that the land owner does not necessarily have a comprehensive inventory of the livestock grazing taking place. Federal and state governments are significant leasers of grazing lands, for example accounting for approximately 33% of grazing and range lands in the United States.

2. Emissions and Entity Data

Among the WCI partner states and provinces, agriculture emissions accounted for about 65 MMT of CO_2e in 2005, or about 6% of total gross emissions. This percentage is less than 10% for all the partners, with the exception of Montana and Manitoba, which report agriculture emissions accounting for 21% and 30% of gross emissions in 2005, respectively. Table 12 summarizes the emissions for the WCI partners.

The total number of entities that would be covered in this sector depends on whether, and at what level, an annual emissions threshold is set. In the livestock sector, confined animal operations (CAOs) typically have the highest concentration of animals and manure that can lead to emissions. As shown in Table 12, the number of CAOs totals nearly 20,000 among the WCI partners. Also shown in the table is the number of farms with harvested cropland, an indication that nitrogen fertilizers may be used. The total number of farms with harvested cropland is on the order of 150,000 among the WCI partners.

3. Emissions at the Entity Level

Precise direct measurement of agriculture GHG emissions at the entity level is not currently practical. Emissions estimates are typically made using emissions factors associated with various types of management practices. However, site-specific conditions and individual management practices can have a significant impact on emissions so that actual entity-level emissions can vary substantially from the estimates based on representative emissions factors.

For example, N_2O emissions from soils are the largest component of agriculture GHG emissions. Emission factors for N_2O from soils have very large ranges and uncertainties due to the highly variable rate of emissions spatially and temporally across soil conditions and seasons. Perhaps most importantly, the N_2O emissions factors cannot currently estimate with precision the changes in emissions that may result from changes in practices at the entity level.

Similarly, although emissions factors for livestock emissions, manure management emissions, and rice cultivation emissions are available, they do not easily incorporate site-specific practices that can affect emissions rates.

Emissions or removals of CO_2 can be inferred from changes in carbon stocks. For example, soil carbon stocks can be measured by using soil samples. Together with a properly designed survey, such samples can result in estimates of soil carbon content with high levels of accuracy and precision. However, because the increases or decreases in carbon stocks are small relative to the amount of carbon in the soil, changes can best be estimated by performing surveys spaced a number of years apart. In most circumstances, a five year interval between measurements is likely to be the shortest interval that would result in reliable estimates of changes in soil carbon.

Emissions modeling, combined with field measurements, can be used to better estimate emissions and sinks from agricultural activities. However, the use of these models is generally beyond what can reasonably be expected from most producers.

4. Administration

If individual agricultural land owners are required to hold allowances or report on emissions and emission reductions, a very large number of entities would be involved. As shown in Table 12, many thousands of entities would have compliance obligations. Moreover, as suggested above, tools to measure many agricultural emissions are in early stages of development, and current estimates can have large uncertainties. The wide variety of mechanisms that result in emissions or emission reductions, together with the difficulties of obtaining reliable estimates in many cases would pose a significant challenge. Additionally, as mentioned above, many land owners lease their land to others for grazing or other agricultural purposes. Consequently, the land owner may not have adequate information to perform a reasonable emissions calculation. When combined, these factors pose very significant administrative challenges.

5. Leakage Issues

The agriculture sector is highly vulnerable to emission leakage. The market for agriculture products is international in scope, and highly competitive. If compliance requirements in the WCI region reduce production, production could increase in another region. The shift in production location may result in no net change in emissions overall. Consequently, particular care must be taken as it relates to imposing reporting or other compliance requirements within this sector.

Table 12: Summary of Agriculture Emissions

State/Province	2005 Emissions (MMT CO_2e)	Percent of 2005 Gross Emissions	CAO Operations[a]	Harvested Cropland[b]
Arizona	4.7	5%	547	3,139
California (2004)	23.3	5%	4,815	54,115
Montana	7.9	21%	1,554	16,543
New Mexico	6.2	8%	857	7,204
Oregon (2004)	5.1	7%	3,682	23,013
Utah	4.2	6%	1,862	9,661
Washington	5.4	6%	3,043	21,802
British Columbia	2.6	4%	2,000[c]	14,484
Manitoba	6.1	30%	1,439[c]	16,660
Total WCI Partners	**65.5**	**6%**	**19,799**	**166,621**

a. Confined animal operations, including dairy operations, beef cattle operations, and hog farms. Does not including grazing operations (i.e., non-confined).

b. Entities reporting harvested cropland.

c. Does not include beef cattle operations.

MMT = million metric tons

Percent of gross emissions calculated for each state/province.

Preliminary estimates, subject to review and revision.

J. Forestry and Land-Use Change

1. Description

Forestry and land-use change encompass the suite of human activities and naturally occurring processes and events that result in changes in forest cover and/or changes to the amount of carbon stocks on forest lands. Forestry can serve as a sink (i.e., can remove carbon dioxide from the atmosphere) or as a source of emissions.

1.1 Sectors

The forestry sector refers to lands that support, or can support, a given tree canopy cover and that allow for management of one or more forest resources, including timber, fish and wildlife, biodiversity, water quality, recreation, aesthetics and other public benefits.[18] Forest lands are owned by federal, state, provincial, and municipal governments, companies, individuals, and non-governmental organizations. Forest lands can serve multiple purposes, including supply of wood and fiber, recreation, habitat, scenic enhancement, water quality, preservation of carbon stocks, and other purposes.

Land-use change refers to the conversion of land from one purpose to another. Forest land may be converted to other uses through deforestation or, for example, to residential use. Land that was not in forest cover may become forest land (i.e., through reforestation or afforestation). Agriculture and forestry are often interrelated because land frequently changes from one use to the other and back.

This design element does not include the processing of timber into products, or the use of forest biomass for energy production. The long-term fate of harvested wood products could be included as part of this design element, but doing so is challenging, particularly at the land owner level.

1.2 Emissions Sources and Sinks

The extent to which forest lands emit greenhouse gases (primarily CO_2) or act as a sink for CO_2 in a given year is measured in terms of the change in carbon stock on the forest land. Carbon stock is the carbon contained in forest biomass, including above and below ground biomass, at a specific point in time. If the carbon stock increases from one year to the next, the forest land acted as a sink, and accumulated carbon by removing it from the atmosphere. If the carbon stock decreases, the forest land released carbon.

Carbon stocks on forest lands can increase or decrease through both natural events and human intervention. Natural fire cycles affect the carbon stock on forest lands. Human activities can affect the fire cycle, however. Forest management for commercial or noncommercial harvest of biomass can also affect carbon stocks. If the amount of biomass that grows is the same as the amount of biomass removed for products or energy, the managed forest is presumed to result in no net emissions from changes in carbon stocks. In the event of forest fires, insect and disease, or unsustainable harvesting practices, forests can act as significant carbon sources.

Land-use change can also result in emissions or a sink. Land that changes from non-forest cover to forest cover will show an increase in carbon stock, and consequently is a sink over the

[18] A tree canopy cover of 10% is used to define forest land by the California Climate Action Registry (see *Forest Sector Protocol*, Version 2.1, The California Climate Action Registry, September 2007, available at: http://www.climateregistry.org/PROTOCOLS/FP/). Other percentages are also used, such as 25% in British Columbia and other Canadian provinces.

long term. Land that is converted from forest cover to another use, such as agriculture, will show a reduction in carbon stock, and consequently is an emission source.

While the overall impact of human activities and natural events and processes can be assessed as changes in carbon stock, the specific activities and events that result in emissions include:

- immediate release from burning of biomass (including in forest fires);
- residual release from biomass decay;
- soil carbon releases due to soil disturbance;
- decay of harvested wood products; and
- decay of standing timber (from insect and disease or general decline).

Finally, it should be noted that long-lived wood products, such as furniture and building materials, also represent a carbon pool. The carbon in these products was removed from the atmosphere through forest management. Methods for accounting for the wood product carbon pool have been developed for national and state/province level inventories. However, accounting methods are not available for application at the land owner level. Consequently, incorporating the carbon pool from long-lived wood products into a cap-and-trade program at the land-owner level would be very challenging at this time.

1.3 Greenhouse Gases

The predominant greenhouse gas affected by forestry and land-use change is CO_2. However, biomass combustion (e.g., due to forest fires) also results in nitrous oxide (N_2O) emissions. Forests can also act as either sources or sinks for methane. The N_2O and methane emissions are very small compared to the CO_2 emissions and sinks.

1.4 Point of Regulation

The point of regulation for forestry and land-use change is the land owner. The land owner typically has control over how the forest lands are managed, within the applicable regulatory framework of the jurisdiction in which the lands are located. Consequently, the land owner has the most influence over changes in carbon stock on his/her forest lands.

As discussed below, governments are large owners of forest lands. Companies and individuals own smaller parcels, although some individual private holdings are significant. A threshold of parcel size may be used to limit the coverage of the large numbers of owners of small amounts of forest lands.

2. Emissions and Entity Data

Among the WCI partners and provinces, forestry and land use change have been estimated to be an overall sink for GHG emissions. As shown in Table 13, the sink was on the order of 11% of gross emissions in 2005. The size of the sink varies significantly across states and provinces, with the forestry sink being sizable compared to gross emissions from some jurisdictions. Of note is that although forestry and land use currently are a sink, some analysts have estimated that the forest sector could be a much larger sink than is currently the case. Consequently, forestry provides an opportunity to increase the sequestration of carbon.

Governments are significant owners of forest lands in the WCI states and provinces. For example, the provincial government of British Columbia owns 95% of forested land in the province. Most of remainder of the forest land is owned by a small number of forestry companies, and many small land owners. In California, the federal government owns approximately 52% of forest lands, and provincial/local governments own about 3%. The remainder of the forest land (45%) is privately owned. Similarly, in Washington, approximately 57% of forest lands are publicly owned, with 43% privately owned. Table 13lists the portion of forest land that is publicly owned in each WCI partner jurisdiction.

The land owners that convert forest lands to other uses (such as urban development) are not typically the large government land owners. Rather, owners of smaller parcels are involved in converting forest land to other uses, an activity that typically results in net emissions. Many thousands of land owners in the WCI region play a role in conversion of forest lands to other uses.

3. Emissions at the Entity Level

Protocols on how to perform forest carbon modeling are well established (IPCC Good Practice Guidance[19], 2006 IPCC Inventory Guidelines[20]) as are international reporting mechanisms (UNFCCC, Kyoto Protocol[21]). While the models have degrees of uncertainty (particularly due to the quality and consistency of input inventory data and growth and yield curves), they are internationally accepted and used. These approaches are typically used at the government level for national and state/province inventories.

Protocols have also been developed for measuring changes in carbon stock at the land owner or entity level.[22] To apply these methods, landowners would be required to conduct periodic inventories to determine their carbon stock over time. As these methods typically rely on characterizations of samples of areas within forest lands, and are measuring biological activities, the resulting emission/sink estimates are generally considered to be less precise than emissions calculations for fossil fuel combustion emissions.

Notably, the extent to which a given parcel of forest land is a source or a sink in a given year depends, in part, on previous years and future years. For example, the natural fire cycle may reduce the carbon stock on certain forest lands in a given year. In that year, the land is an emissions source. In subsequent years, the carbon stock may increase, indicating that the forest is a sink. Over time, the forest may be carbon neutral, so that it is neither a source nor a sink. This time-dependent nature of carbon stocks on forest lands would need to be addressed in the estimating procedure at the individual land owner level under a cap-and-trade program.

4. Administration

As described above, governments typically own a large portion of forest lands. Nevertheless, there are many owners of large land holdings (including those engaged in commercial harvesting) and a very large number of owners of smaller land parcels. Many of the forest land owners are not typically covered by existing air quality regulations, although those involved in commercial harvesting may be regulated under other programs. Identifying all the relevant land owners could be a significant administrative challenge unless smaller parcels were excluded from the program.

The ability to measure emissions from all relevant land owners also presents a challenge. Specialized expertise is required to measure carbon stock changes at the entity level using

[19] http://www.ipcc-nggip.iges.or.jp/public/gpglulucf/gpglulucf.htm

[20] http://www.ipcc-nggip.iges.or.jp/public/2006gl/index.htm

[21] http://unfccc.int/kyoto_protocol/items/2830.php

[22] See, for example, *Forest Sector Protocol*, Version 2.1, The California Climate Action Registry, September 2007, available at: http://www.climateregistry.org/PROTOCOLS/FP/.

existing protocols. Ensuring the availability of this expertise to all relevant land owners could also present a significant challenge.

Given these administrative challenges, a less than fully comprehensive approach to covering forestry and land-use change within a cap-and-trade program may need to be considered. For example, the cap-and-trade program could focus solely on land conversion, from forest cover to other uses, and from other uses to forest cover. Other policy measures and approaches (outside of the cap-and-trade program) could be used to address the other aspects of the forestry and land-use change sector. The portion of emissions/sinks that could be addressed with a cap-and-trade program by such an approach remains to be assessed.

5. Leakage Issues

Important components of the forestry sector are highly vulnerable to emission leakage. The market for wood products is international in scope, and highly competitive. In response to reduced commercial forest production in one region, production could increase in another region. The shift in harvest location may result in no net change in emissions overall. Consequently, particular care must be taken as it relates to requirements for emission measurement or other requirements for the commercial forest products portion of the sector.

Land conversion, from forest lands to urban development for example, may be vulnerable to leakage if alternative locations for development are available. However, given the size of WCI jurisdictions, such leakage has the potential to be small. Perhaps more important is the potential for increased costs to affect the rate of forest conversion. If significant costs are imposed to prepare emission inventories for forest lands, owners of small parcels may find it advantageous to convert their land to other uses so as to avoid the emission inventory requirement. This potential impact must be considered carefully to assess potential negative impacts of including forest lands under a cap-and-trade program.

Table 13: Summary of Forestry Emissions (Sinks)

State/Province	2005 Emissions (MMT CO_2e)	Percent of 2005 Gross Emissions	Portion of Forest Land Publicly Owned
Arizona	(1.3)	-1%	59%
California (2004)	(4.7)	-1%	55%
Montana	(23.1)	-62%	74%
New Mexico	(20.9)	-29%	62%
Oregon	--[a]	--[a]	63%
Utah	(12.3)	-18%	82%
Washington	(28.6)	-30%	57%
British Columbia	(25.3)	-38%	97%
Manitoba	--[a]	--[a]	94%
Total WCI Partners	(116.2)	-11%	**--**

a. Data remaining under investigation.
MMT = million metric tons
Percent of gross emissions calculated for each state/province.
Preliminary estimates, subject to review and revision.

K. High GWP Gases

1. Description

Hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6) are potent greenhouse gases, some of which persist in the atmosphere for thousands of years. These gases, referred to as high global warming potential (GWP) gases are from 650-23,900 times more potent than CO_2 in terms of their capabilities to trap heat in the atmosphere over a 100-year period. Also, because they remain in the atmosphere almost indefinitely, atmospheric concentrations of these gases will increase as long as emissions continue.

1.1 Sectors

High GWP gases are used by and emitted from a wide variety of activities and equipment. The overwhelming majority of the use and emissions of these gases are associated with their use as substitutes for ozone depleting substances that have been phased out. Consequently, these gases are used are as refrigerants in residential, commercial and industrial equipment, as well as aerosol propellants and solvents.[23] High GWP gases are also used in semiconductor manufacturing, magnesium production, and other miscellaneous applications. SF_6 is used in electric power transmission and distribution systems. Emissions of SF_6 from these sources are included in the electric sector, and are not included here.

In some cases, high GWP gases are produced as byproducts of industrial processes. For example, CF_4 and C_2F_6 are produced during aluminum smelting. These process-related emissions are not included in this design element, but rather are included under industrial process emissions.

1.2 Emissions Sources

High GWP gases are emitted in several ways. When used as refrigerants, these gases may leak during normal equipment operation, or may be released as a result of equipment failure. Additionally, during equipment servicing or disposal the refrigerants may be deliberately or inadvertently released. It is currently best practice to collect and recover refrigerants during servicing and disposal so as to prevent emissions (capture and recycling is required in some jurisdictions). However, consumers can purchase cans of refrigerant to recharge their automobile air conditioners. Emissions may result from these consumer maintenance activities, and residual amounts of refrigerant in the cans are also typically emitted.

The semiconductor manufacturing industry uses high GWP gases in plasma etching and in cleaning chemical vapor deposition tool chambers. These processes use the gases to selectively create circuitry patterns and remove deposited materials.[24] The high GWP gases are vented as part of this process. In some cases, the gases may be captured and recycled to prevent emissions. The magnesium metal production and casting industry uses sulfur hexafluoride (SF_6) as a cover gas to prevent the rapid oxidation of molten magnesium in the presence of air. The SF_6 is emitted as part of this process.

1.3 Greenhouse Gases

The high GWP gases include hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6).

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[23] For more information see: *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 –2005*, U.S. Environmental Protection Agency, Washington, D.C., 2007, p. 4-44, available at: http://epa.gov/climatechange/emissions/usinventoryreport.html.

[24] For more information, see: http://www.epa.gov/highgwp/sources.html.

1.4 Point of Regulation

It is generally considered impractical to define the point of regulation for high GWP gases as the point of emission for the majority of the high GWP emissions sources. In particular, emissions from leaks and servicing of residential, commercial, and industrial refrigeration and air conditioning equipment would be the responsibility of the equipment owners and servicing companies. In most cases these emissions cannot be measured directly, and the equipment owners and service personnel are not in a position to calculate and report the emissions as part of a cap and trade system. Similarly, the users of aerosol products are not in a position to calculate and be responsible for the emissions associated with their product usage.

Consequently, the approach under consideration is to hold the manufacturers of the high GWP gases responsible for the emissions. In nearly all cases, all the gases produced will eventually be emitted. The gases are rarely converted to other substances or destroyed. Consequently, the quantity of gas manufactured is a reasonable estimate of the expected emissions. The gas manufacturer would be required to hold allowances to cover the total production and sale of high GWP gases each year.

In taking this approach, the program would cover the emission of newly manufactured high GWP gases. This approach does not cover the high GWP gases that are already stored in equipment, and are vulnerable to release.

As an alternative to placing the point of regulation on the manufacturers, it could be placed at the point where the gases enter into commerce in each state or province. This approach would require comprehensive tracking of the distribution and sale of these gases within each jurisdiction, for example through the licensing of dealers.

The use of high GWP gases in industrial applications, such as semiconductor manufacturing and magnesium manufacturing, could be addressed differently. The entity responsible for the emissions (i.e., the facility) could be defined as the point of regulation. The quantity of gas used and emitted could be tracked, and the entity would be required to hold emission allowances.

2. Emissions and Entity Data

Among the WCI partner jurisdictions, the high GWP gases are a relatively minor portion of total gross emissions, accounting for about 3% of total emissions in 2005. However, these emissions are expected to grow faster than total emissions through 2020. Table 14 summarizes the emissions estimates for 2005.

High GWP gases are produced by a small number of chemical manufacturing companies internationally. For example, *Chemical Market Reporter* identifies nine companies producing fluorocarbon gases (HFCs) in the United States at 14 plants. Only one plant is located in a WCI partner state, accounting for less than 10% of total production capacity.

3. Emissions at the Entity Level

As described above, one point of regulation under consideration is at the gas manufacturer. At this point, the regulated entity (the manufacturer) cannot measure or calculate actual GHG emissions. Rather, the entity can calculate potential emissions based on the expected release over time of the total amount of the gas produced. The manufacturer would calculate its emissions responsibility as the quantity of gas produced times the appropriate GWP for the gas.

If the point of regulation is at the industrial facility that uses and emits the gas, the calculation would be similar. The total amount of gas used and emitted would be multiplied by the appropriate GWP. Any destruction or conversion of the gas in the industrial process could be accounted for at the facility level.

4. Administration

The relatively small number of manufacturers of high GWP gases would make administration at the manufacturer level tractable. However, as discussed above, nearly all the manufacturers and their plants are not located in WCI jurisdictions. Consequently, WCI states and provinces would not be in a position to regulate their production or sales of these gases.

The alternative approach of setting the point of regulation at the point where the gases enter into commerce in each state and province would be more administratively challenging. A system of licensing and tracking of the sales of the gases does not currently exist, and would need to be created.

Assigning the point of regulation to industrial facilities that use the gases, such as semiconductor manufacturing and magnesium manufacturing, is administratively feasible. There are a relatively small number of facilities, each of which could be tracked. The covered entities should have the capability to know their compliance obligations and understand the applicable requirements. However, it should be noted that these facilities account for a very small portion of the total emissions from this sector.

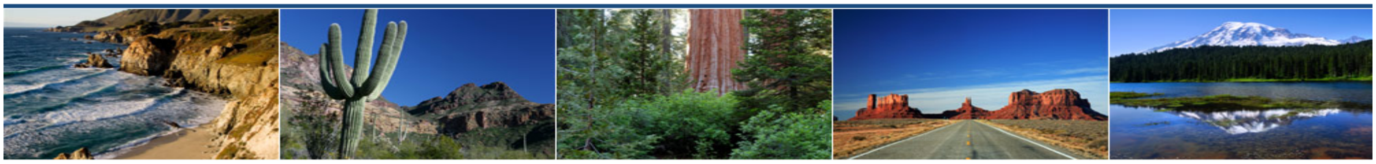
5. Leakage Issues

Vulnerability to emissions leakage is an important consideration for this design element. High GWP gases are produced and traded internationally. Actions that increase production costs in the U.S. and Canada could shift production elsewhere, resulting in no change in actual emissions. To address this leakage potential, imports of the gases would also need to be covered, which is beyond the jurisdiction of states and provinces. The potential impacts associated with covering industrial facilities should also be examined. For example, semiconductor production could also shift elsewhere, resulting in no change in actual emissions.

Table 14: Summary of High GWP Gas Emissions

State/Province	2005 Emissions (MMT CO_2e)	Percent of 2005 Gross Emissions
Arizona	3.7	4%
California (2004)	15.9	3%
Montana	0.4	1%
New Mexico	1.2	2%
Oregon (2004)	2.4	4%
Utah	2.1	3%
Washington	2.4	3%
British Columbia	0.6	1%
Manitoba	0.0	0%
Total WCI Partners	**28.7**	**3%**

NA = Data not available. Data currently being developed.
MMT = million metric tons
Percent of gross emissions calculated for each state/province.
Preliminary estimates, subject to review and revision.



Western Climate Initiative
Draft Program Scope Recommendations

1. Introduction

This paper presents the WCI draft recommendation for the scope and point of regulation for the WCI cap-and-trade program. The recommendation is based on the WCI's analysis and assessment of the Major Options paper it released in January 2008. The WCI developed and applied evaluation criteria to these major options. It also took into account stakeholder comments received in writing by February 1, 2008, as well as comments at the January 10, 2008 stakeholder meeting and the February 12, 2008 stakeholder conference call on scope issues. Other key inputs include data collection and deliberations by the WCI, including: emissions inventory data; estimates of the potential number entities with regulatory obligations; an assessment of the feasibility of covering liquid fuels; a discussion of phasing; a review of emissions thresholds (including those used in other air emission programs); a review of non-combustion emissions sources; and briefings on two sectors--(a) oil and gas production and processing and (b) agriculture and forestry and land-use change.

This document is organized as follows.

- Section 2 defines scope and point of regulation.
- Section 3 summarizes the design elements that were considered for inclusion in the WCI cap and trade program.
- Section 4 evaluates the design elements, taking into account the WCI design principles and the Scope Subcommittee evaluation criteria, as well as consideration of phasing and thresholds. It describes the design elements that are recommended for inclusion, as well as those that are not.
- Section 5 defines and evaluates the major options, which are combinations of the design elements. It describes the evaluation criteria, linkage with the electricity sector recommendation, and the WCI scope recommendation.
- Section 6 discusses issues that remain under consideration, and how each has the potential to affect the final recommendation. These items include legal questions, economic impacts, and alternative policies that may be preferable or complementary to cap and trade for particular sectors or subsectors.

Appendix A is a summary of the Scope Subcommittee's current understanding of process emissions that can be calculated or measured at the entity level. Appendix B is a summary of information collected regarding potential points of regulation for liquid transportation fuels. Appendix C is the Major Options paper that the Scope Subcommittee released in early January 2008.

2. The Definition of Scope and Point of Regulation

The scope defines the GHG emissions that are included in the cap and trade program, including:

- The sectors that fall under the cap.
- The emissions sources that fall under the cap.
- The greenhouses gases that fall under the cap.
- The point(s) of regulation where the cap would be enforced.

From the scope definition, any entity or facility must be able to tell whether it has a compliance obligation under the cap, and which of its emissions are subject to the obligation.

The "point of regulation" is the portion of the scope definition that identifies the entities that have the obligation to surrender GHG emission allowances to cover GHG emissions. Several terms are used to describe the point of regulation:

- Downstream, at the point of emission: The point of regulation can be placed where the GHGs are emitted, such as where coal is combusted. This point of regulation is typically referred to as "downstream." Examples of downstream points of regulation include: (a) stationary source combustion of coal, natural gas, and oil; and (b) process and fugitive emissions from industrial facilities.
- Upstream, where carbon enters the economy: The point of regulation can be placed at the point where carbon enters into the economy. This point is typically referred to as "upstream." Examples of upstream points of regulation for fossil fuels include: (a) where natural gas is processed and upgraded to pipeline quality; (b) where oil products are refined or imported; and (c) where coal is mined. For some high global warming potential (GWP) gases (such as sulfur hexafluoride, SF_6), an upstream point of regulation may be the point at which the gas is manufactured.
- Midstream: The point of regulation can be placed at a point between the upstream and downstream. This point is typically referred to as midstream. Midstream points for fossil fuel may include where the fuel is distributed, examples including: (a) natural gas transmission pipelines; (b) natural gas local distribution companies (LDCs); and (c) gasoline and diesel terminal racks, fuel distributors or wholesalers.

Figure 1 illustrates the upstream-downstream continuum for points of regulation for the major fossil fuels. The left side of the figure shows the upstream portion of the continuum, where fuels are extracted. As you move to the right in the figure, you move toward the downstream point of emission. Not shown in the figure are two potential points of regulation that are outside the flow of fuels: load serving entities (LSEs) that deliver electricity to customers; and vehicle manufacturers. These two entities could also be considered as points of regulation.

As discussed below, considerations in selecting the points of regulation include the comprehensiveness of the coverage of the cap, the administrative feasibility of imposing the regulatory obligation, and the ability of the regulated entities to calculate or measure emissions.

Among the options that may be considered are combinations of upstream, downstream, and midstream points of regulation. For example, multiple points of regulation may be appropriate for covering emissions of natural gas combustion. For large stationary sources of natural gas combustion, such as power plants and industrial facilities, the preferred point of regulation may be at the point of emission. In this case, the regulatory obligation would be on the facility.

For residential and commercial buildings that use natural gas, it is generally considered infeasible to put the point of regulation on the homeowner or the building owner. Rather, the point of regulation could be moved toward the upstream to cover these emissions, such as to the local distribution company. A hybrid approach of downstream and midstream points of regulation would need to be coordinated carefully to ensure that natural gas emissions were not regulated twice. As shown in Figure 2, some large stationary sources purchase natural gas from LDCs. The point of regulation for the natural gas consumed by these sources would need to be either the facility, or the LDC, but not both.

Figure 1: The upstream/downstream continuum for fossil fuels

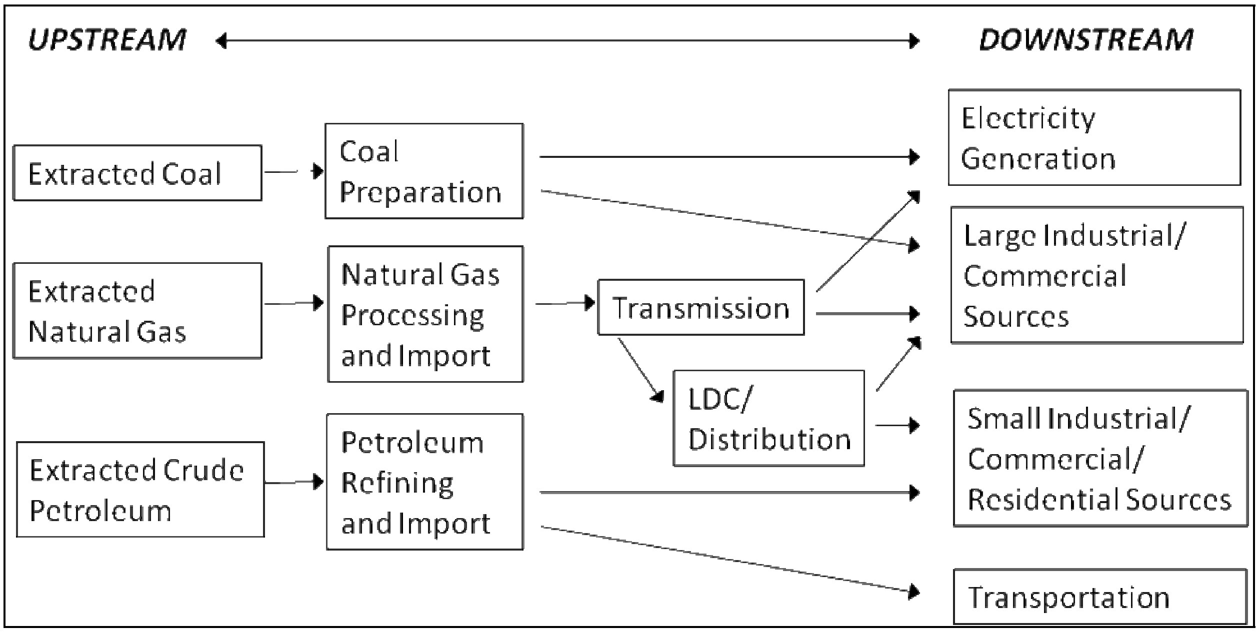
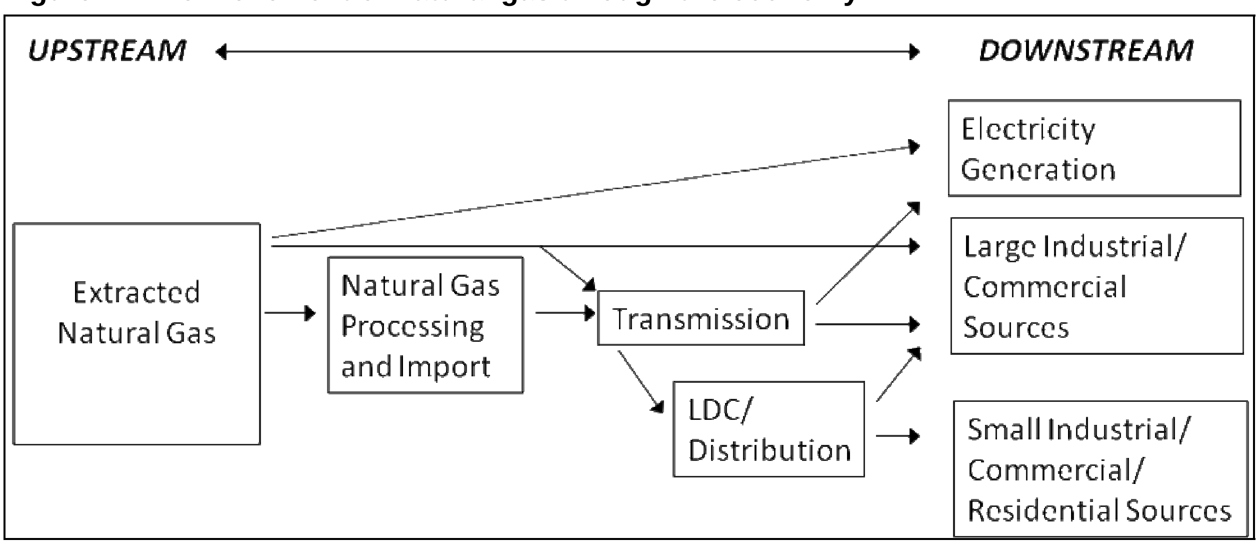


Figure 2: The movement of natural gas through the economy



To define the scope and points of regulation for the WCI cap-and-trade program, particular attention is focused on identifying points of regulation that can be used by states and provinces.

In some cases, upstream points of regulation (e.g., natural gas processing facilities) fall outside the jurisdiction of the WCI states and provinces. Consequently, in some cases the furthest upstream point of regulation that may be considered is the point at which the fuel enters into the economy of the state or province. Within the framework of Figure 1, these points of regulation may be considered midstream.

3. The Scope Design Elements

To develop options for the program scope, the emissions inventory was divided into individual "design elements" for consideration. Each design element includes a specific set of sources, and a designation for the point of regulation. The options for the cap-and-trade program scope (discussed in Section 5) are then assembled from the individual design elements.

Table 1 presents a summary of the design elements considered. This list of the design elements was released for public review and comment as part of the WCI work plan (released October 2007). In response to comment and discussion, design element C was divided into two pieces, one for residential and commercial natural gas combustion and one for residential and commercial combustion of liquid fossil fuels. The electric sector is not included among the design elements, as that sector is being addressed by the Electricity Subcommittee.

As shown in the table, each design element covers a portion of the overall emissions inventory. As discussed below in Section 5, the emissions that would be included in a cap-and trade program would be less than the estimates in the table for two reasons. First, the WCI expects that thresholds will be applied to exempt small sources from some sectors. The amount by which thresholds will reduce coverage depends on the levels of the thresholds. Second, within design elements D and E, there are sources for which emissions cannot be measured or calculated with sufficient precision at the entity level. These sources will be excluded from coverage, further reducing the portion of total emissions covered by the options.

In addition to defining the emissions, the design element also identifies the point of regulation. The WCI recognizes that some of the design elements overlap, so that some emission sources can be covered by more than one design element. However, the recommended program scope combines the design elements so that no double counting or overlap occurs.

More detailed descriptions of the design elements were provided in the WCI Major Options paper for the Scope Subcommittee (released January 2008), and included as Appendix C. The descriptions in the appendix include the following for each design element:

- a description, including the sectors, sources, GHGs, and points of regulation;
- data on the emissions from the design element, and the number of entities that would be covered;
- an assessment of the ability to calculate or measure emissions at the entity level;
- the administrative feasibility of including the design element; and
- an examination of the potential risk of leakage.

Table 1: Summary of Design Elements

Design Element	Description	Estimated emissions (million metric tons) (% of WCI gross emissions)	Number of entities with a compliance obligation in the WCI region	Comments
A. Large Stationary Combustion Sources	Large combustion sources regulated at the industrial facilities.[1] All 6 Kyoto gases included, but mostly CO_2.	127 MMT CO_2e[2] 13% of WCI gross emissions	Number of entities depends on threshold adopted.	There are no significant administrative challenges. Vulnerability to leakage varies by industry.
B. Liquid Transportation Fuels	CO_2 emissions from the combustion of liquid transportation fuels regulated at the point where the fuels enter into commerce in each state or province. The point of regulation may vary among the states and provinces.	356 MMT CO_2e 36% of total WCI gross emissions	Depends on the point of regulation.	There are administrative challenges to identifying appropriate points of regulation by state and province. Gasoline use is generally not vulnerable to leakage, but any long-haul trucking that is not covered by the International Fuel Tax Agreement, aviation and marine transportation are.
C. Residential and Commercial Natural Gas Consumption	CO_2 emissions from with residential and commercial combustion of natural gas regulated at the Local Distribution Company (LDC).	70 MMT CO_2e 7% of total WCI gross emissions	There are about 60 LDCs.	There are no significant administrative challenges. Vulnerability to leakage may be an issue for some commercial customers.

[1] Electric power generation is included in the electric sector, being evaluated by the Electricity Subcommittee. Electric power generation is not included in this design element. Fuel combustion for cogeneration of heat and electricity may be covered in this design element, depending on emissions thresholds for coverage that are adopted.

[2] CO_2e - carbon dioxide equivalent

Design Element	Description	Estimated emissions (million metric tons) (% of WCI gross emissions)	Number of entities with a compliance obligation in the WCI region	Comments
C1: Residential and Commercial Stationary Combustion of Liquid Fuels	CO_2 emissions from the stationary combustion of heating oil and propane in the residential and commercial sector regulated at the point at which the fuels enter into commerce in each state or province.	Less than 1% of GHG emissions within the WCI region	As with B, the total number of entities with a compliance obligation depends on the point of regulation.	Though a small portion of emissions, coverage would help avoid creating inappropriate incentives for fuel switching to petroleum products. The administrative challenges for this element may be addressed as part of design element B. Leakage is not likely to be an issue for residential customers so long as competing heating fuels are covered, and may be an issue for some commercial customers.
D. Process and Fugitive Emissions from Industrial and Waste Management Sources	Process and fugitive emissions regulated at the point of emission.[3]	44 MMT of CO_2e 5% of total gross WCI emissions		The administrative challenge is being examined on a process-by-process basis. The primary need is to develop adequate protocols for certain sources prior to inclusion (see Appendix A). Vulnerability to leakage varies by industry.
E. Fossil Fuel Production and Processing	Oil and gas exploration, production, and processing, and coal mining and preparation, a broad set of facilities and activities with diverse emissions sources, including stationary combustion, venting and fugitive emissions. The point of regulation is at the facility where the emissions occur.	38 MMT CO_2e 4% of total gross WCI emissions	About 65,000 operating oil wells; 45,000 operating gas wells. A small number of operators account for 80-90% of oil and gas production. The number of operating coal mines is about 29.	Only a portion of the sources at oil and gas production and processing facilities will likely be feasible to include in a cap-and-trade program at this time. Leakage risk is relatively low because these activities are undertaken at the locations of the resources themselves, although the companies that operate these facilities do compete with entities outside the WCI region.

[3] Fugitive emissions include emissions from equipment leaks, pipeline leaks, and storage losses. Process emissions include planned and unplanned venting, accidental discharges, and related emissions. Together, process and fugitive emissions include all non-combustion emissions from industrial and waste management sources.

Design Element	Description	Estimated emissions (million metric tons) (% of WCI gross emissions)	Number of entities with a compliance obligation in the WCI region	Comments
F. Fossil carbon content of fuels regulated at the appropriate point for each fuel	CO_2 emissions from fossil fuel combustion throughout the economy. The fuels include coal, oil, natural gas, and other fossil fuels (such as propane). The points of regulation would be upstream or midstream for liquid fuels, downstream for coal, and at the pipelines or LDC/purchaser for natural gas.	797 MMT CO_2e 82% of total gross WCI emissions	There are 60 LDCs, 208 refineries and liquid fuel terminals, 109 natural gas pipelines.	This element does not pose significant administrative challenges. Significant vulnerabilities to leakage exist in specific components of fossil fuel use, especially marine transport, aviation, and energy-intensive industries.
G. Passenger cars and light duty trucks regulated at the manufacturer sales level.	Includes emissions during the operation of passenger cars, light duty trucks and medium duty vehicles, including: fuel combustion; refrigerant emissions; and evaporative emissions.	242 MMT CO_2e 25% of total gross WCI emissions	There are approximately 40 manufacturers that sell vehicles in the WCI region.	The potential need to track nearly new vehicles that are registered in the state or province needs to be assessed. Potential legal issues also remain to be examined. Light duty vehicle sales are not particularly vulnerable to leakage, but requirements can affect the rate of turnover of the vehicle fleet.
H. Large transportation fleets	Includes emissions from fuel used by entities (e.g., companies, local governments, transit agencies, etc.) that operate fleets of motor vehicles or boats.	Total emissions covered depend on the emissions threshold that may be adopted. Preliminary estimates show emissions are less than 4% of total WCI gross emissions.	About 10,000 vehicle fleets in the WCI partner states and provinces each have 10 or more vehicles.	Administrative feasibility is largely a function of how fleets are defined. The risk of leakage is significant for those fleets with flexibility as to their location; the risk is low for fleets that must serve specific areas.

Design Element	Description	Estimated emissions (million metric tons) (% of WCI gross emissions)	Number of entities with a compliance obligation in the WCI region	Comments
I. Agriculture emissions	Covers the agricultural sector, including a diverse set of production activities, including crop production; livestock production; and grazing lands. Agriculture can serve as a sink or as a source of emissions.	58 MMT CO_2e 6% of total WCI gross emissions.	>18,000 confined animal operations (CAOs) among the WCI partners. The total number of farms with harvested cropland is about 150,000.	Precise direct measurement of agriculture GHG emissions at the entity level is not currently practical, so that covering this sector poses very significant administrative challenges. The agriculture sector is highly vulnerable to emission leakage. The market for agriculture products is international in scope, and highly competitive.
J. Forestry and land-use change	Covers human activities and naturally occurring processes that result in changes in forest cover and/or carbon stocks on forest lands. Emissions would be regulated at the land owner level. Forestry and land-use change can serve as a sink or as a source of emissions.	Net sink: 10% of WCI gross emissions.	Governments are significant forest land owners in WCI. Most remaining forest land is owned by a small number of forestry companies, and tens of thousands of small land owners.	Identifying all the relevant land owners and measuring their net emissions or sequestration would be a significant administrative challenge. Important components of the forestry sector are highly vulnerable to emission leakage. Compliance and measurement costs could drive small landowners to convert their land to other uses. Land-use change could be handled separately from forestry, but still poses significant administrative challenges.

Design Element	Description	Estimated emissions (million metric tons) (% of WCI gross emissions)	Number of entities with a compliance obligation in the WCI region	Comments
K. Production of high-GWP gases	Covers HFCs, PFCs, SF_6 regulated at the point of production.	28 MMT 3% of gross WCI emissions	A small number of chemical companies produce these gases internationally. Nine companies produce HFCs in the U.S. at 14 plants. One plant is located in a WCI partner state, accounting for <10% of total U.S. production capacity.	Administration at the manufacturer would be tractable, but nearly all the manufacturers and their plants are not located in WCI jurisdictions. Administration at the point where the gases enter into commerce in each state and province would be more challenging. Regulating industrial facilities that use the gases is administratively feasible. Vulnerability to emissions leakage is significant as these gases are produced and traded internationally. Covering industrial facilities could also lead to leakage.

4. Evaluation of the Scope Design Elements

4.1 Design Principles and Criteria

The WCI recommendation for the scope of the cap-and-trade program is guided by the WCI Design Principles, listed below in Exhibit 1. Consistent with these design principles, the WCI has adopted the following additional criteria for evaluating whether individual design elements are appropriate for consideration within the program scope:

- The design element includes a meaningful portion of the GHG inventory within the WCI region.
- Emissions can be accurately and cost-effectively measured or calculated and reported by the entities.
- It is administratively feasible (considering the number of entities and other factors).
- There is an acceptable risk of leakage (taking into consideration alternative approaches for reducing emissions from the sources within the design element).

Table 2 presents the results of applying these criteria to the design elements, based on the information presented in Appendix C. As shown in the table, most of the design elements were found to have meaningful portions of the emissions inventory within the WCI region. For three design elements the WCI found that emissions cannot currently be accurately and cost-effectively measured or calculated at the entity level in a manner that is consistent with the implementation of a cap-and-trade program. These are: agriculture, forestry and land-use change, and passenger cars and light duty trucks (regulated at the manufacturer level). Additionally, the ability to measure or calculate emissions varies within two of the design elements: industrial and waste management process and fugitive emissions; and the fossil fuel production and processing industry. For these two design elements, Appendix A lists the emissions for which the WCI has identified emission calculation protocols that can be applied at the entity level.

The administrative feasibility of the design elements was evaluated primarily on the basis of (1) the number of entities that would have a regulatory obligation; and (2) the capacity of the regulated entities to undertake the steps needed to participate in the program. Two design elements (agriculture and forestry and land-use change) appear to have the potential to cover such a large number of entities so as to make it very challenging to administer a program that includes these design elements. Additionally, the number of transportation fleets that could be covered would also be very large, depending on the level of the emissions threshold adopted.[4] Indications are that covering transportation fuels at the point at which the fuels enter the economy is administratively feasible, although the precise approach remains under investigation.

Finally, the risk of emission leakage was assessed.[5] The WCI recognizes that varying levels of risk of leakage apply to many entities depending on the markets in which they operate. Table 2 identifies several design elements for which the WCI finds that there is substantial risk of leakage. Additionally, the risk varies within several design elements. Opportunities to mitigate

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[4] Emission thresholds are discussion in Section 4.3.

[5] Emission leakage refers to emission sources relocating outside the region in order to avoid emissions regulations, such as a cap-and-trade program. The relocation of sources is called leakage because the emissions “leak” out of the region in response to efforts to reduce emissions.

these risks will be assessed, in part, through the design of allowance allocation mechanisms. Consequently, mitigating leakage is not discussed further in this paper.

Exhibit 1: WCI Design Principles for a Regional Cap-and-Trade Program

To attain the Western Climate Initiative's greenhouse gas reduction goal, the members are committed to designing a system that

1. Is equitable, administratively simple for government and private participants, minimizes administrative costs, and has a clear compliance path;
2. Maximizes total benefits throughout the region, including reducing air pollutants, diversifying energy sources, and advancing economic, environmental, and public health objectives, while also avoiding localized or disproportionate environmental or economic impacts;
3. Requires all reductions to be real, surplus/additional, verifiable, permanent, and enforceable;
4. Stimulates investment, especially in low carbon technologies, and rewards innovations that will lead to long-term permanent greenhouse gas reductions;
5. Covers as many sources as is practical, while encouraging pollution reductions beyond the capped sources and sectors;
6. Provides appropriate recognition and incentives for early emissions reductions;
7. Assures a transparent and robust accounting system that will measure and report emissions rigorously and consistently across all sectors and throughout the region;
8. Minimizes the potential for leakage; and
9. Facilitates linkage to similarly rigorous regional and international greenhouse gas reduction markets and encourages other states, provinces, and countries to join the market.

Source: WCI Work Plan, October 29, 2007.

4.2 Considerations for Phasing

Phasing refers to adjusting the scope of the program over time to "phase in" some aspect of the program scope. Phasing could be applied to any aspect of the Scope definition, including: a design element; the sources included; the gases included; and the threshold(s) applied. Phasing would be defined in terms of:

- the specific aspect of the scope being phased in (e.g., a specific emissions source);
- the timing of the phase in (e.g., number of years); and
- any conditions associated with the phase in (e.g., the adoption of an emissions calculation protocol).

Table 2: Evaluation of Design Elements

Design Elements	Meaningful Portion of Emissions	Measure/Calculate Emissions by the Entity	Administratively Feasible	Acceptable Risk of Leakage
Electric Sector – Not Evaluated Here	--	--	--	--
A. Large stationary combustion sources at the point of combustion.	Yes	Yes	Yes	Generally Yes (some exceptions)
B. Liquid transportation fuels regulated where they enter into commerce in the state/province.	Yes	Yes	Yes, Method Under Evaluation	Generally Yes (some exceptions)
C. Residential and commercial natural gas combustion regulated at the LDC.	Yes	Yes	Yes	Yes
C1. Residential and commercial fuel oil and other fuel combustion regulated where they enter into commerce in the state/province.	No	Yes	Under Evaluation Probably Yes	Yes
D. Process and fugitive emissions from industrial and waste management sources regulated at the point of emission.	Yes	Varies, depending on source	Yes	Varies, depending on industry
E. Fossil fuel production and processing regulated at the facility level, such as the oil and gas field, gas processing plant, coal mine.	Yes	Varies, depending on source	Yes	Yes
F. Fossil carbon content of fuels regulated at an appropriate point for each fuel.	Yes	Yes	Under Evaluation Probably Yes	Generally Yes (some exceptions)
G. Passenger cars and light duty trucks regulated at the manufacturer level.	Yes	No	Yes	Yes
H. Large transportation fleets regulated at the fleet management level.	No	Yes	Probably No	Probably Yes
I. Agriculture emissions regulated at the producer or farm level.	Yes	No	No	Varies (mostly no)
J. Forestry and land-use change emissions regulated at the land owner level.	Yes	No (Possibly yes for some land-use change)	No	No (Possibly for some land-use change)
K. Production of high GWP gases regulated at the point of production.	Varies	Yes	Yes	No

The WCI identified several conditions that warrant the consideration of phasing:

1. Measurement/Calculation Protocol: No protocol currently exists for measuring or calculating emissions at the entity level. However, it is feasible to develop a protocol and the WCI can direct the development or recognition of a protocol in a timely manner. Phasing the coverage would enable the source to be included after the protocol becomes available.
2. Identification of Regulated Entities: The entities that will be regulated have not been well identified to date (e.g., they are not currently in other regulatory programs). It is expected that the regulated entities will be identified in the near future, for example through mandatory reporting requirements. Phasing the coverage would enable the source to be included after the regulated entities were well identified.
3. Emissions Data: Emissions data are not readily available for a source. It is expected that mandatory emissions reporting will provide emissions data in the near future. Phasing coverage would enable the source to be included after the emissions data become available.
4. Statutory Authority: Time is required to obtain statutory authority required to regulate certain sources. Phasing would enable the source to be included after the statutory authority was put in place.
5. Economic Impact: Phasing reduces costs and/or improves market development and price stability.

The WCI notes that the need for phasing depends, in part, on the start date for the program.

4.3 Considerations for Setting Emissions Thresholds

Emission thresholds can be used to define the minimum size of entities that would be covered under the cap-and-trade program. By using emissions thresholds the program can focus on those entities that have large emissions, while exempting small emitters that do not contribute significantly to total emissions in a sector or category. Also, with thresholds the program can reduce substantially the number of entities that would be regulated, thereby reducing the administrative cost of the program.

To assess potential emission thresholds, the WCI reviewed thresholds used in other GHG related programs, and assessed the sizes of entities that may be covered in the WCI region. Table 3 lists the thresholds used in the programs reviewed. As shown in the table, a variety of thresholds have been used. In several GHG emission reporting programs, reporting is triggered by a reporting requirement for conventional air pollutants.

The recently promulgated reporting rule in California uses several thresholds, including specific thresholds for electric power generators, and a separate threshold of 25,000 tons per year of CO_2e for other stationary combustion sources. Canada's and Wisconsin's reporting programs use a threshold of 100,000 tons per year of CO_2e. Canada's threshold is currently being revised to what may be a substantially lower limit.

The WCI reviewed the European Union Emissions Trading Scheme (EU ETS) and the Regional Greenhouse Gas Initiative (RGGI). RGGI covers the electricity sector only, and uses a single threshold for power plants. As shown in the table, the EU ETS uses industry-specific thresholds, generally linked to production capacity.

Table 3: Examples of Thresholds in GHG Related Programs

Program	Threshold
Mandatory GHG Emissions Reporting Programs	
California	Electricity: ≥2,500 Metric Tons of CO_2e and ≥1 MW nameplate capacity Stationary Combustion: ≥25,000 Metric Tons of CO_2e All cement plants and refineries
Connecticut	Title V Major Sources: Municipal Waste Combustors, capacity >35 Mg/day HAPs: 10 tons per year of one HAP or 25 tons per year combined 100 tons per year of any regulated air pollutant In serious ozone nonattainment areas: 50 tons per year VOCs or NO_x In severe ozone nonattainment areas: 25 tons per year VOCs or NO_x
Maine	Sources that emit or are licensed to emit: CO: 75 tons per year SO_2: 40 tons per year VOC or NO_x: 25 tons per year PM10 or PM2.5: 15 tons per year Pb: 0.1 tons per year NH3: 50 tons per year Any electric power & transmission facility emitting any amount SF_6 Any GHG-manufacturing facility emitting any amount of GHG
New Jersey	Title V major sources: 25 tons per year VOCs or NO_x 100 tons per year CO, SO_2, TSP, PM2.5, PM10, or NH_3 5 tons per year Pb
New Mexico	Electricity: 25 MW nameplate capacity Major Title V sources (as defined by the Agency) All cement plants and refineries
Wisconsin	100,000 tons per year of GHGs
Canada	100,000 tons per year of GHGs. Currently being revised – substantially lower thresholds may be adopted.
GHG Emissions Control Programs	
European Union Emissions Trading Scheme (EU ETS)	Electricity: 20 MW nameplate capacity All oil refineries, coke production, pulp production Pig iron or steel: >2.5 metric tons per hour capacity Cement: >500 metric tons per day of clinker production capacity Lime: >50 metric tons per day of production capacity Glass: >20 metric tons per day of production capacity Ceramic Products: >50 metric ton per day of capacity or kiln capacity >4 cubic meters with setting density >300 kg per cubic meter
Regional Greenhouse Gas Initiative (RGGI)	Electricity: 25 MW nameplate capacity

Based on this review, the WCI found that thresholds have been used in both reporting programs and emission control programs for GHGs. The WCI recommends that thresholds be considered for defining the scope of the cap-and-trade program. However, there is not yet a single threshold that has become widely accepted and criteria for selecting thresholds are to be developed. The thresholds need to be set based on the specific conditions found among the sources within the WCI region, discussed further in Section 5.

4.4 Design Elements Recommended for Consideration

Based on the application of the design principles and evaluation criteria presented above, the WCI has identified the following design elements as feasible for including in a cap-and-trade program within the timeframe contemplated for WCI: [6]

A. Large stationary combustion sources;

B. Liquid transportation fuels;

C. Residential and commercial natural gas combustion;

C1. Residential and commercial stationary combustion of fuel oil and other liquid fuels;

D. Process and fugitive emissions from industrial and waste management sources;

E. Fossil fuel production and processing; and

F. Fossil carbon content of fuels.

The WCI recognizes that the point of regulation for liquid fuels remains to be identified precisely. However, indications are that there are acceptable options for including this design element in an administratively feasible manner within each of the WCI jurisdictions. Appendix B presents the information reviewed on the potential points of regulation for liquid fuels.

Similarly, the WCI acknowledges that there is a subset of industrial, waste management, and fossil fuel industry emissions that may be challenging to develop adequate measurement protocols for use at the entity level. As presented in Appendix A, emissions protocols are not currently available for non-combustion emissions sources of emissions from oil and gas production, for example. The WCI recommends that those sources for which adequate protocols are available – or which can be developed in a timely manner – be considered for inclusion in the program at the outset, and that additional sources be phased in as emissions protocols are adopted. The WCI also recommends that high priority be placed on the development of suitable protocols for the fossil fuel production and processing sources, so that these sources can be included in the program from its initiation.

As described below in Section 5, these design elements were combined into major options for consideration.

4.5 Design Elements Not Recommended for Consideration

Based on the application of the design principles and evaluation criteria presented above, the WCI recommends against including for consideration the following design elements for a cap-and-trade program within the timeframe contemplated for WCI:

G. Passenger cars and light duty trucks regulated at the manufacturer level: Annual emissions cannot be calculated precisely by the manufacturer.

[6] The Electricity Subcommittee is assessing how best to include the electric sector in the program. The recommendations by the Electricity Subcommittee are reported separately.

H. Large transportation fleets regulated at the fleet management level: Not a meaningful portion of total emissions and likely to be administratively challenging due to the number of entities.

I. Agriculture emissions regulated at the producer or farm level: Emissions cannot be calculated or measured precisely and cost-effectively at the point of regulation, and likely to be administratively challenging due to the number of entities.

J. Forestry and land-use change emissions regulated at the land owner level: Emissions cannot be calculated or measured precisely and cost-effectively at the point of regulation, and likely to be administratively challenging due to the number of entities. Although land-use change emissions can be measured, incorporation would be administratively challenging due to the number of entities at the point of regulation.

K. Production of high GWP gases regulated at the point of production: Most of the points of regulation fall outside the jurisdiction of the WCI states and provinces.

These design elements are not considered in the major options discussed in the next section.

5. Evaluation of the Major Options

5.1 Definition of the Major Options

The WCI used the seven design elements considered feasible for inclusion in the cap-and-trade program to create five major options, shown in Table 4. These options indicate how the elements could be combined to create a cap-and-trade program with varying levels of coverage. Option 1, with the narrowest scope, would cover the electric sector, large fossil fuel stationary combustion sources, and large industrial process emissions. Option 3 has a significantly broader scope by also including liquid transportation fuels and fossil fuel stationary combustion in the residential and commercial sectors. Option 5 represents an alternative approach, focusing on the fossil carbon content of all fuels.

The coverage estimates shown in the table are likely to be biased upward for two reasons. First, the WCI expects that thresholds will be applied to exempt small sources from some sectors. The amount by which thresholds will reduce coverage depends on the levels of the thresholds. Second, within design elements D and E, there are sources for which emissions cannot be measured or calculated with sufficient precision at the entity level. These sources will be excluded from coverage, further reducing the portion of total emissions covered by the options.

As shown in the table, Option 1 covers less than 50% of the total emissions inventory in the WCI states and provinces. Because transportation fuels are a large portion of total emissions, their inclusion would increase coverage substantially. .

5.2 Evaluation Criteria and Recommendation

The criteria for evaluating among the major options include the design principles (above, in Exhibit 1), and the following:

- Breadth of coverage: Include as many sources as is practical to cover as much of the emissions inventory as possible.
- Market characteristics:
  - Include a sufficient number of market participants to create a vital and efficient market.
  - Include diverse market participants to create a vital and efficient market.

Table 4: Major Options Considered

Design Elements	Options 1	2	3	4	5
Electric Sector	X	X	X	X	
A. Large stationary combustion sources	X	X	X	X	
B. Liquid transportation fuels			X	X	
C. Residential and commercial natural gas combustion		X	X		
C1. Residential and commercial stationary combustion of fuel oil and other liquid fuels		X	X		
D. Industrial process and waste management emissions	X	X	X	X	X
E. Fossil fuel production and processing	X	X	X	X	X
F. Fossil carbon content of fuels					X
Portion of WCI Emissions Inventory Included*	~47%	~54%	~90%	~83%	~90%
* Portion of WCI Emissions Inventory calculated using the 2005 emissions inventory for the WCI partners. Estimates are approximate, and assume 100% coverage in each of the design elements. The use of emissions thresholds will reduce the portion of emissions covered. Additionally, some sources within design elements D and E cannot be measured or calculated adequately for inclusion in a cap-and-trade program at this time. These sources may need to be phased in over time as methods are developed.					

- Economic Impacts: Include those sources that benefit from the efficiencies of a cap-and-trade program so as to minimize economic impacts across the entire economy.

These criteria, along with the WCI Design Principles, generally indicate that a more comprehensive scope is preferred. This preference is balanced against potential opportunities to use alternative policy mechanisms to reduce emissions from sources with less overall economic impact than would be experienced using a cap-and-trade program. Given these considerations, the WCI recommends the following:

- Base Program: The WCI recommends that Option 1 be implemented by all WCI partners as a base program from the start of the cap-and-trade program. In making this recommendation, the WCI is separately recommending an approach for the electric sector that is consistent with the structure of Option 1. Additionally, as discussed above, WCI recommends that high priority be placed on developing emissions protocols for the fossil fuel production and processing sector so that as much of this sector as possible can be included in the cap-and-trade program from the start of the program.
- Transportation Fuels: Emissions from transportation fuels (design element B) are the single largest source in the region (about 36% of total emissions), and must be addressed through an effective combination of near-term and long-term policies. WCI members thus express strong interest in including transportation fuels within the cap and trade program. However, prior to recommending how best to reduce emissions in this sector, analyses of the economic impacts of various options for including transportation fuels in the program will be examined, including the potential effectiveness of alternative policies for reducing these emissions. Options to be considered include the potential to phase in transportation fuels in a later stage of the program, and special consideration for low-income populations and for rural communities most adversely impacted by consequent price change in the sector. It is anticipated that a decision on how to

address transportation fuels will be informed by economic modeling and additional analysis over the course of Spring 2008.

- Residential and Commercial Fuel Combustion: Emissions from residential and commercial combustion, including natural gas, fuel oil and other liquid fuels, while collectively only about 8% of emissions in the region, could be usefully addressed through an effective combination of near-term and long-term policies. WCI members thus express interest in including these sectors within the cap-and-trade program. However, as with transportation fuels, prior to recommending how best to reduce emissions in this sector, analyses of the economic impacts of various options for including these fuels in the program will be examined, including the potential effectiveness of alternative policies for reducing these emissions. Options to be considered include the potential to phase in these fuels in a later stage of the program, and special consideration for low-income populations and for rural communities most adversely impacted by consequent price change in the sector. It is anticipated that a decision on how to address these fuels will be informed by economic modeling and additional analysis over the course of Spring 2008.
- Thresholds: The WCI recommends that thresholds be adopted to exempt small sources from the cap-and-trade program, while ensuring that the overall coverage of emissions remains high. The WCI has not yet set emissions thresholds, and is continuing its assessment of threshold values.
- Phasing: The WCI has discussed the potential need to phase in sources to the program over time. The WCI recommends that the base program (Option 1) be implemented in its entirety from the start of the program. However, the WCI acknowledges that phasing may be required for other sources given the additional complexities of their points of regulation, the organizational capabilities of the potentially regulated entities, and related issues.

In the event that only the base program is implemented throughout the WCI states and provinces (Option 1), the program will cover less than 50% of the emissions in the region. Aggressive and effective policies will be needed in the sectors outside the cap-and-trade program to ensure that the overall regional emissions goal will be achieved. In the event that a broader program is adopted, including transportation fuels and residential/commercial fuel combustion (Option 3), the coverage may exceed 80% of the regional emissions.

In all cases, complementary policies that work in conjunction with the cap-and-trade program will be needed to motivate investments in improved efficiency and other measures to reduce emissions. The WCI recommends that a full set of complementary policies be examined as part of the analyses supporting the design of the cap-and-trade program.

6. Issues Under Review

This draft recommendation is based on the information and analysis the WCI has done to date. However, a number of issues remain under consideration. These considerations may affect the final recommendation in August 2008.

6.1 Legal Issues

A number of legal issues may affect the scope recommendation. Among these issues is the potential need for additional statutory authority in some jurisdictions to authorize the implementation of the cap-and-trade program with the proposed scope. In addition, legal issues may arise regarding the mechanics of implementation and enforcement. These considerations may affect the final recommendation in August 2008.

6.2 Economic Impacts Analysis

WCI is conducting economic analyses of the major options under consideration for the cap-and-trade program. These analyses will be used to evaluate alternative design decisions, including cost containment mechanisms, offsets and allowance allocation. If the economic analysis indicates that including a certain industry in the scope would result in economic impacts or leakage that cannot be adequately mitigated through cost containment mechanisms of other design features, the WCI could revisit the decision to include that industry in the scope of the program. Similarly, if the economic analysis indicates that including a particular sector does not achieve significant emission reductions and leads to unacceptable price impacts that cannot be adequately mitigated through cost containment mechanisms, the WCI could decide to exclude that sector.

6.3 Analysis of Alternative and Complementary policies

WCI will examine the potential role of policies other than cap and trade in meeting its GHG targets. The results of this examination could affect decisions about the program scope. The analysis of some of these policies could indicate that they complement the scope of the cap-and-trade program. For example, demand-side energy efficiency programs can complement and reduce the cost of cap-and-trade programs by reducing market barriers to adoption of cost-effective technologies and practices. Similarly, vehicle performance standards may complement, and reduce the cost of complying with, the fuels portion of a cap-and-trade program.

Alternatively, analysis may indicate that there are policies for particular sectors that may be preferable to a cap-and-trade program. For example, analysis may indicate that a low-carbon fuel standard is preferred to including liquid transportation fuels in the cap-and-trade program. Similarly, natural gas equipment efficiency standards and energy efficiency programs may be preferred to including residential and commercial natural gas combustion in the cap-and-trade program.

Appendix A: Process and Fugitive Emissions

The WCI has adopted the position that to be included in the cap-and-trade program, a recognized protocol must be available for calculating or measuring emissions from the sources in the design elements, including in design element D, Process and Fugitive Emissions from Industrial and Waste Management Sources, and design element E, Fossil Fuel Production and Processing. Consequently, to assess the feasibility of including the sources in design elements D and E, the Scope Subcommittee reviewed the major sources of emissions in this design element, and identified available emission calculation and measurement protocols. The subcommittee's review is presented in the tables below.

The list of sources in design elements D and E was developed based on a review of national emission inventory guidelines. For each source, the subcommittee identified whether the source exists within the WCI partner states and provinces. For those sources within the WCI, the subcommittee identified whether The Climate Registry (TCR) includes the source in its General Reporting Protocol (GRP).[7] As shown in Table A-1, 11 industrial sources are included in the TCR GRP. For the sources not included in the TCR GRP, the subcommittee reviewed other reporting protocols, including mandatory reporting programs. The most comprehensive materials, the Intergovernmental Panel on Climate Change (IPCC) reporting guidelines, were examined to assess whether the guidelines could be applied at the entity level with sufficient precision to be adequate to support inclusion in a cap-and-trade program.[8] Four IPCC methods appear to be adequate, although additional review is recommended. Also shown in the table, the adequacy of several IPCC methods for use in a cap-and-trade program remains uncertain and will be further assessed.

Based on this assessment, the subcommittee recommends that the industrial sources included in the TCR GRP and for which the IPCC (or other) methods are adequate, or are in the near future deemed adequate based on expert review, be included within the design element D.

A similar assessment was conducted for the waste management process and fugitive emissions. As shown in Table A-2, these emissions sources do not have specific protocols in the TCR GRP. A review of the IPCC guidelines, and information from other programs, leads the subcommittee to conclude that adequate protocols are not available for these sources at this time. Based on this assessment, the subcommittee recommends that the waste management process and fugitive emissions not be included in design element D until adequate emissions reporting protocols are available.

Finally, the subcommittee reviewed protocols for sources in the fossil fuel production and processing sector. This sector includes a diverse set of emissions sources, including fuel combustion, equipment venting, and fugitive emissions. As shown in Table A-3, protocols are under development for several key sources in the oil and natural gas industries. The subcommittee recommends a high priority be assigned to completing these protocols so that these sources can be included in the cap-and-trade program.

[7] The Climate Registry GRP is available at: http://www.theclimateregistry.org/crdocuments.html.

[8] The 2006 Intergovernmental Panel on Climate Change (IPCC) Guidelines for National Greenhouse Gas Inventories are available at: http://www.ipcc-nggip.iges.or.jp/public/2006gl/.

Table A-1: Industrial Process and Fugitive Emissions Sources

Source	Source In WCI?	Protocol?	Adequate for C&T?	Comments
Adipic Acid Production	Yes	TCR GRP	Yes	
Aluminum Production	Yes	TCR GRP	Yes	Based on anode carbon consumption and PFCs from anode effects.
Ammonia Manufacture	Yes	TCR GRP	Yes	Based on carbon in feedstock use (typically natural gas). The EU program categorizes the source category as "Fertilizers and Ammonia Manufacture"
Cement Manufacture	Yes	TCR GRP	Yes	
Electric Transmission and Distribution (SF6)	Yes	TCR GRP	Yes	Mass balance approach.
Iron and Steel	Yes	TCR GRP	Yes	Carbon in coke consumption plus other fluxes used.
Lime Manufacture	Yes	TCR GRP	Yes	
Nitric Acid Production	Yes	TCR GRP	Yes	Factors reflect control system in place.
Pulp and Paper Production	Yes	TCR GRP	Yes	Stoichiometric approach based on carbonate used.
Semiconductor Manufacture	Yes	TCR GRP	Yes	Plant-specific parameters used in U.S. EPA Program.
HFC-22 Production	??	TCR GRP	Yes	
Magnesium Production and Processing (foundries, smelters and casting facilities)	Yes	US EPA Program, IPCC	Yes	US EPA Program detailed reporting method at: http://www.epa.gov/highgwp/magnesium-sf6/resources.html IPCC reporting protocol at: http://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/3_Volume3/V3_4_Ch4_Metal_Industry.pdf
Ferroalloy Production	Yes	IPCC	Yes	US EPA emissions inventory report calculates carbon in coke consumption (which varies by alloy produced). IPCC protocol at: http://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/3_Volume3/V3_4_Ch4_Metal_Industry.pdf
Lead Production	Yes	IPCC	Yes	US EPA emissions inventory report calculates using C content of coke and other reductants. IPCC protocol at: http://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/3_Volume3/V3_4_Ch4_Metal_Industry.pdf
Limestone and Dolomite Use	Yes	IPCC	Yes	US EPA emissions inventory report uses a stoichiometric emissions factor times use in a broad range of applications. IPCC protocol at: http://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/3_Volume3/V3_2_Ch2_Mineral_Industry.pdf
Petrochemical Production	Yes	IPCC	Possibly	Carbon in feedstock use (natural gas). IPCC protocol at: http://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/3_Volume3/V3_3_Ch3_Chemical_Industry.pdf

Source	Source In WCI?	Protocol?	Adequate for C&T?	Comments
Phosphoric Acid Production	Yes		Probably	US EPA emissions inventory report uses a stoichiometric emissions factor multiplied by production (emissions factor varies with rock characteristics). Adequate protocol could be developed as needed.
Soda Ash Manufacture and Consumption	Observer State	IPCC	Possibly	US EPA emissions inventory report uses a stoichiometric emissions factor multiplied by production. IPCC Tier 3 protocol at: http://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/3_Volume3/V3_2_Ch2_Mineral_Industry.pdf
Silicon Carbide Consumption	No			
Silicon Carbide Production	No	IPCC		IPCC protocol at: http://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/3_Volume3/V3_3_Ch3_Chemical_Industry.pdf
Titanium Dioxide Production	No	IPCC		IPCC protocol at: http://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/3_Volume3/V3_3_Ch3_Chemical_Industry.pdf
Zinc Production	Yes	IPCC	Possibly	US EPA emissions inventory report calculates carbon in coke consumption (which varies by process type). IPCC protocol at: http://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/3_Volume3/V3_4_Ch4_Metal_Industry.pdf

Table A-2: Waste Management Emissions Sources

Source	Source In WCI?	Protocol?	Adequate for C&T?	Comments
Municipal Landfills (methane emissions)	Yes	US EPA Program IPCC	No	US EPA Climate Leaders method for estimating methane emissions (uses first order decay model and default parameters -- see http://www.epa.gov/stateply/documents/resources/protocol-solid_waste_landfill.pdf). Does not capture site specific conditions well, although site specific conditions can be modeled (using precipitation, organic content of waste, depth of landfill, etc) and emissions can be calculated.
Municipal Wastewater Treatment	Yes	IPCC	No	IPCC methods rely on approximate methane conversion factors that do not consider site-specific conditions.
Industrial Wastewater	Yes	IPCC	No	IPCC methods rely on approximate methane conversion factors that do not consider site-specific conditions.

Table A-3: Fossil Fuel Production and Processing Emissions Sources

Source and Gases	Source In WCI?	Protocol?	Adequate for C&T?	Comments
Coal Mine Fugitive Emissions (Active mines); Methane	Yes	IPCC	Probably for underground/shaft mines	IPCC Tier 3 recommends using ventilation emissions measurements and degasification production data. Continuous emissions monitoring systems (CEMS) may capture underground mine coal methane emissions.
Coal Mine Fugitive Emissions (Abandoned); Methane	Yes		Probably Not	US emissions inventory report uses a decline curve representation of emissions over time.
Petroleum Systems-Refineries and Processing Facilities; CO_2; Methane; High GWP gases	Yes	CA Reporting Rule	Yes	California Reporting Rule includes a method for measuring or calculating emissions (supporting data may not be available for non-CA refineries).
Hydrogen Production; CO_2; Methane; High GWP gases	Yes	CA Reporting Rule	Yes	Hydrogen plants often at refineries, but some are independent of refineries. California Reporting Rule includes a method for hydrogen plants.
Natural Gas Distribution Systems; Methane	Yes	In Process IPCC	TBD	California Climate Action Registry Protocol under development. US EPA Natural Gas Star Program also has a method.
Natural Gas Transmission Systems Methane	Yes	In Process IPCC	TBD	California Climate Action Registry CCAR Protocol under development. US EPA Natural Gas Star Program also has a method.
Oil and Gas Production and Processing CO_2; Methane	Yes	In Process IPCC	TBD	Western Regional Air Partnership (WRAP) developing a protocol through the “Oil & Gas Exploration & Production and Natural Gas Gathering & Processing GHG Accounting Protocol Project” (see http://www.wrapair.org/WRAP/ClimateChange/GHGProtocol/)
TBD = To Be Determined.				

Appendix B: Points of Regulation for Liquid Transportation Fuels

1. What are the liquid fuels that might be covered?

If any emissions associated with liquid fossil fuels in larger emitters were picked up at the point of combustion, the other possible sectors to regulate would be transportation fuel, liquid fuels for residential/commercial use, and liquid fuel in small industrial applications. Biofuels and other non-petroleum fuels would either not be covered or given some credit for their lower life-cycle GHG emissions. Non-fuel uses of petroleum (e.g., for chemicals) would not be covered.

2. How significant a fraction of the emissions are they?

It depends on which emissions are covered: Transport only (gasoline, diesel, aviation fuel, marine and locomotive diesel, residual oil for ships)? Transport, residential and commercial combustion (propane, heating oil)? Off-road diesel?

Based on EIA data:

- Oil comprises 53% of total WCI CO_2 from fossil fuel combustion. Oil use for transportation is 49% of total CO_2 from fossil fuel. This means that 4% of the CO_2 emissions from oil is not related to oil used for transportation.
- Residential sector oil use is <0.2% of total fossil fuel CO_2 and about 0.3% of CO_2 from oil combustion.
- Commercial sector oil use is about 1% of total fossil fuel CO_2 and about 1.6% of CO_2 from oil combustion. This is probably mostly from larger institutional facilities and may include some diesel fuel for on-site generation.
- Propane for residential sector use is about 0.5% of total fossil fuel CO_2 and about 0.9% of CO_2 from oil combustion.

EIA Data on WCI Residential & Commercial Fuel/Emission Shares

	% WCI CO_2 From Oil	% of total WCI CO_2 from Fossil Fuels
Residential Oil	0.3%	<0.2%
Commercial Oil	1.6%	1%
Residential Propane	0.9%	0.5%

CO_2 emissions from liquid fuels in the residential/commercial sectors are very small, especially compared to the large numbers of facilities represented. Thus one is unlikely to achieve significant GHG reductions from regulating this sector. However, one would not want to create an incentive to switch to non-regulated fuels by regulating other fuels (e.g. natural gas) but not liquid fuels.

The remaining 2.8 percent of liquid fuels is used in industrial and farm equipment.

3. What are the options for point of regulation?

This depends, in part, on which sectors are regulated.

- *Regulation at the refinery/importer*

  Regulation at the refinery is challenging because a significant fraction of WCI's liquid fuel use comes from refineries that are outside of WCI. Appendix B1 shows the estimated supply/demand balance for fuel products (gasoline, jet and distillate) in each of the WCI states and provinces. [9] Utah is close to balanced in supply and demand. Washington is long, as is Montana. California appears balanced, but there are a lot of imports into and exports out of California (see notes on the Appendix B1 table). Arizona, Oregon, and the two Canadian provinces are very short product with none (or minimal) instate or in-province production. New Mexico is somewhat short.

  Utah's situation is probably the most balanced of the states, but Holly Corporation (which has a refinery in Utah) announced plans to construct a 300 mile pipeline to move product from Utah refineries to Las Vegas, beginning in 2009 or 2010. So Utah may wind up exporting more of its product (and possibly expanding refineries) through that pipeline. In other words, the situation may change in the future and whatever system is put in place must recognize, and be designed to cover, changing balances in the future.

  There are 34 refineries in the WCI region.

  One could cover the bulk of the importers with a similarly small number of entities, but there may be many very small importers. In combination with the refinery approach, this would require tracking all the pipelines that move products into and out of the WCI states. Volumes (by product grade and owner of shipment) moved in or out via pipeline are documented at the receiving terminals. One would also need to track waterborne imports and exports. The railcar volumes that move into the region are primarily ethanol, with much smaller gasoline volumes. Railcar movements should also be trackable, but further analysis is needed to determine the exact mechanism. The truck movements in and out are likely small, and may net out. These may need to be ignored in an "upstream model", but would be captured automatically in the state tax or EIA model described below.

  On net, the WCI states and provinces are importing product from non-WCI states or provinces to meet demand of roughly 340 TBD, or 12 percent of demand. If the intent is only to get the net balance right, one possibility is to ignore the flows and cover the refineries for all of the product they move, plus the importers.

- *Regulation at the transportation level: pipeline, truck, barge or rail car.*

  Regulation at the transportation level would be quite complicated due to the multiple potential paths, the difficulty of determining where the product is going for which application, and the high potential for double-counting.

- *Regulation at the terminal.*

  The point with the smallest number of regulated points and best connection to end users is probably the petroleum distribution terminal, a facility designed to receive, store and distribute fuel to others. A terminal rack is an industry's point of distribution to its local distributors, wholesalers (including marketers) and certain bulk end users. There are

[9] This estimate is rough. The state demand numbers come from the EIA for the US and the Canada Energy Statistics website for Canada (www.statcan.ca). The supply estimates come from Oil and Gas Journal refinery capacities, estimated utilization based on actual history, and yield estimates for each state based on an assessment of typical yield of the different products for the types of refineries in each state.

legitimate concerns about double-counting at this level but they are probably addressable. Some states collect their fuel taxes on distributors at the terminal rack, so the distinction between the terminal and wholesaler/distributor is fuzzy.

- *Regulation at the wholesale or distribution level*

  At the wholesale level, there starts to be a differentiation between transportation fuels and fuels for stationary applications. The number of regulated entities also increases from tens per state to hundreds per state. There is overlap between distribution terminals, wholesalers, distributors, and retailers that creates some difficulty identifying where some of the entities fall.

- *Regulation at the blender*

  Fuel blenders prepare fuels for final sale, blending in oxygenates and other additives for compliance with fuel standards.

- *Regulation at the prime supplier*

  The EIA tracks fuel data from each prime supplier, which EIA defines as "a firm that produces, imports, or transports any of the selected petroleum products across State boundaries and local marketing areas and sells the product to local distributors, local retailers, or end users." They were selected due to their small number and the relative size of their sales volumes. The Prime Supplier can be producing product in the state itself, or importing or transporting product into the state. There are 185 prime suppliers in the U.S.

Appendix B2 presents publicly available sources of data on fuel flows.

4. What data do we have available from which states and provinces and at what point of regulation?

There are already existing data on sales of most of the transportation fuels in all of the participating states at both the refineries and some combination of terminal racks, wholesalers and distributors. While there are still some definitional questions, it appears that gasoline, aviation fuel, jet fuel and on-road diesel are tracked in all the WCI states and BC. At least some jurisdictions also track off-road diesel fuel. While regulating at the distributor level entails regulating more entities, it appears that in many cases most of the data are already being collected for tax collection purposes. It should be relatively easy to expand these programs to track off-road diesel fuel and even fuel sales for stationary applications, if desired.

The table below summarizes how each jurisdiction collects fuel taxes.

BC collects volume information for tax purposes at the terminal and first fuel importer level. Currently only some of the states seem to have volumetric data at this level. Some of the available U.S. terminal volume data are from environmental permits and are not highly accurate.

WCI State/ Province	Fuels Covered Under Tax Data Collection					Where Tax is Collected	How Many Entities Report	Comments
	Motor Gasoline	On-Road Diesel	Off-Road Diesel	Jet Fuel	Aviation Fuel			
Arizona	X	X		X	X	Rack Suppliers[1]	117*	Exports not taxed; imports are taxed (truck, rail)
California	X	X		X	X	Rack Suppliers	117	Exports not taxed; believe imports are taxed (truck, rail)
Montana	X	X		X	X	Last sale between distributor[2] and final destination	75	Exports not taxed; believe imports are taxed (truck, rail)
New Mexico	X	X		X	X	First receiver[3] from product terminal.	170	For gasoline only, first receiver can pass on tax obligation to next wholesaler. The next wholesaler is then responsible for tax obligation
Oregon	X	X		X	X	Gasoline: First receiver from product terminals Diesel: Retailers	150	Exports not taxed; believe imports are taxed (truck, rail)
Utah	X	X	X	X	X	Gasoline: First receiver from terminal; Diesel - rack suppliers. Imports taxed for both.	127	Jet and aviation fuel taxed in the same manner as gasoline.
Washington	X	X	X	X	X	Rack Suppliers and any imports.	215	Exports not taxed; imports are taxed (truck, rail)
British Columbia	X	X	X	X	X	Importer[4] or manufacturer pays a "security" that is equal to the tax	100	The "security" is passed through the supply chain in the price until the consumer finally actually pays the tax at the retail station.

*Assumed similar to CA until confirmed from AZ source.

[1] A company that owns product and sells that product at the terminal rack.

[2] A middleman that purchases products for resale to other wholesalers, jobbers and/or retail stations. A distributor may sell to another distributor.

[3] The company that first lifts the product from the terminal rack. A distributor could be a first receiver if it buys at the terminal rack, however if they buy from another distributor they are not a first receiver. Another example is service stations that send their own trucks to lift product from the rack. A third example is a service station who receives product directly from a rack supplier.

[4] A company that crosses state lines to deliver product in another state.

5. What data could be made available from which states and at what point of regulation?

It may be that entities are reporting some or all of this information to the federal government, and states could require them to report the same information to the states. For example, EIA Form 782C is submitted by Prime Suppliers to report statewide sales of all petroleum products. This form is submitted monthly by the Prime Suppliers to EIA. The supplier is required to put in one aggregate number for total sales for each product in a given state for each month. It is not clear whether this form and its submissions are "audit-tested", as there is no apparent obligation to provide supporting data, nor any process to match sales to any production or inventory data. In addition, WCI needs to check with EIA to verify that all parties are required to fill out these forms.

There are other existing sources of data (for example, NM and AZ have data on volumes of product moved through terminals from their air quality agency); however none seem to provide complete and/or reliable data on volumetric throughput. It is possible to establish new reporting requirements but not clear how difficult that would be in each jurisdiction.

6. What is the potential for double-counting for different points of regulation? How could the potential for double-counting be addressed?

The potential for double-counting seems lowest at the beginning (refinery) and end (retail) of the supply chain and highest in the middle (transportation and distribution) where there is potential for multiple levels of delivery and receipt. Double counting can be addressed through careful tracking, but it does create an extra level of administration.

7. What are the leakage issues?

The potential for emission leakage is significant for components of the transportation sector:

- *Marine:* Ocean-going vessels can easily obtain fuel outside the WCI partner jurisdictions.
- *Aviation:* Airline operations are particularly sensitive to fuel costs. Opportunities to obtain fuel outside the WCI partner jurisdictions may be significant.

Gasoline use in passenger cars, light duty trucks, and medium duty vehicles is less vulnerable to leakage, as motorists typically obtain fuel in close proximity to their residences and places of employment.

Long-haul trucking may also be vulnerable to leakage if trucks can operate within WCI jurisdictions with fuel obtained from outside the WCI jurisdictions. However, the International Fuel Tax Agreement (IFTA) requires diesel trucks operating in multiple jurisdictions to calculate fuels consumed in each state and province based on the miles traveled in each state/province.

8. Ease of Administration by Partner

Based on discussions in each WCI jurisdiction of the liquid fuels scope and point of regulation issues and data availability, and some other information sources, our preliminary assessment is that it appears that the following points of regulation would be the most straightforward to administer by the following partners:

AZ: Terminal Rack Suppliers

BC: Terminal Rack

CA: Point of final blending

MT: Distributor/wholesaler

NM: Distributor: First Receiver

OR: Distributor: First Receiver

UT: Refinery

WA: Terminal Rack

It is possible that each jurisdiction could cover liquid fuels differently, but WCI would need to ensure no double counting between jurisdictions.

9. Number and characteristics of regulated entities

Regulating at the refinery/importer or at the terminal involves regulating tens of entities, whereas regulating at the distributors/wholesalers would involve hundreds. Some argue that it's not a matter of the number of entities but rather their capability to participate effectively in an allowance market. Unlike larger corporations which own the stationary sources typically subject to regulatory requirements, distributors and wholesalers may not have the institutional resources to fold such a compliance mechanism into their standard operations. However, they could contract with outside experts to fulfill this function.

10. Challenge of including liquid fuels at any point of regulation

A problem with covering oil upstream is that the only compliance options available to regulated entities are buying allowances, selling or blending non-fossil fuels, or reducing fuel sales. Since the liquid fuels cap would be just one part of an economy-wide cap and trade program, regulated entities could buy allowances from other covered sectors. A low carbon fuel standard would be a possible alternative to including liquid fuels in the cap and trade program.

Appendix B1

Estimated State Supply/Demand Balances (Approximations)

State/ Province	Refinery Capacity (TBD)	Refinery Throughput 2006 (TBD)	G+D+J Yield (%)	G+D+J Yield (TBD)	Demands (EIA, Canada) (TBD)	Net Long vs (Short) (TBD)	Supply and Demand Comments
Arizona	0	0		0	260.8	(260.8)	Receives all product from California plus pipeline deliveries from Texas
California	1,983	1,804.6	90	1,624.2	1,590.7	33.5	California appears on net slightly long, but the balance is not as obvious as shown. California imports about 60 TBD ethanol by rail, 120 TBD gasoline (most from the Gulf Coast; some from Washington), 70 TBD jet fuel, and about 30 TBD distillate. They export to Arizona and Nevada about 145 TBD gasoline, 70 TBD jet, and about 90 TBD distillate. They also export about 30 TBD gasoline to Oregon, and some distillate overseas (10 TBD). None of the imports or exports are included in the numbers shown, which are instate production and in state sales (ethanol is part of the in state gasoline sales)
Montana	187	170.3	86	146.4	81.1	65.3	Montana exports gasoline to Idaho, Wyoming, Washington & Oregon
New Mexico	104.6	95.2	80	76.1	102.5	(26.4)	New Mexico's shortfall is made up from imports from Texas (primarily)
Oregon	0	0.0		0.0	170.3	(170.3)	Receives all product from 1) Washington (most); 2) California; 3) pipeline from Montana and Utah and 4) imports
Utah	173.9	158.2	85	134.5	131.6	2.9	This shows Utah at over 95% coverage, but Utah does export via Chevron pipeline to Idaho and Washington/Oregon some volume of product; my guess is that they are also getting some imports into the region.
Washington	634.9	577.8	86	496.9	311.6	185.3	All product from in state refineries plus minor import from Montana and Utah

Estimated State Supply/Demand Balances (Approximations)

State/ Province	Refinery Capacity (TBD)	Refinery Throughput 2006 (TBD)	G+D+J Yield (%)	G+D+J Yield (TBD)	Demands (EIA, Canada) (TBD)	Net Long vs (Short) (TBD)	Supply and Demand Comments
British Columbia	65.2	59.3	78	46.3	167.3	(121.0)	British Columbia may be getting a limited supply from Washington to make up their shortfall, and also Alberta; Manitoba is also likely getting product from Alberta
Manitoba	0	0	0	0.0	47.1	(47.1)	
Summary	**3148.8**	**2865.4**	**505.0**	**2524.4**	**2863**	**(338.6)**	

Notes: G=gasoline; D=Diesel; J=Jet fuel

State	Prime Supplier Sales Volume (TBD), 2006				
	Motor Gasoline	Aviation Gasoline	Kerosene-type Jet Fuel	Distillate and Kerosene	Total
New Mexico	62.8	0.2	5.4	34.1	**102.5**
Montana	42.8	0.3	2.4	35.6	**81.1**
Utah	71.7	0.3	17.5	42.1	**131.6**
Arizona	176.9	0.6	17.8	65.5	**260.8**
California	1,049.6	1.7	245.9	293.5	**1,590.7**
Oregon	102.7	0.3	13.3	54.0	**170.3**
Washington	187.1	0.6	43.0	80.9	**311.6**

Province	Domestic Sales (TBD), 2006					
	Motor Gasoline	Aviation Turbo Fuel	Diesel Fuel Oil	Light Fuel Oil	Stove and Kerosene	Total
Manitoba	25.8	3.8	17.2	0.2	0.1	**47.1**
British Columbia	78.9	26.4	58.5	3.2	0.2	**167.3**

Sources:

EIA Petroleum Navigator: http://tonto.eia.doe.gov/dnav/pet/pet_cons_prim_a_EPM0_P00_Mgalpd_a.htm

Statistics Canada Energy Statistics Handbook: http://www.statcan.ca/english/freepub/57-601-XIE/57-601-XIE2007002.pdf

1 cubic meter =6.28981077 barrels (http://www.onlineconversion.com/volume.htm)

State	Prime Supplier Sales Volume (MGD), 2006				
	Motor Gasoline	Aviation Gasoline	Kerosene-type Jet Fuel	Distillate and Kerosene	Total
New Mexico	2,637.5	7.3	228.4	1,430.9	**4,304.1**
Montana	1,798.4	11.1	101.4	1,495.4	**3,406.3**
Utah	3,012.9	12.3	733.6	1,767.8	**5,526.6**
Arizona	7,428.5	24.8	749.2	2,752.8	**10,955.3**
California	44,084.5	70.1	10,326.0	12,328.8	**66,809.4**
Oregon	4,314.4	11.9	559.4	2,266.6	**7,152.3**
Washington	7,860.1	26.5	1,803.9	3,396.2	**13,086.7**

Province	Domestic Sales (TCM), 2006					
	Motor Gasoline	Aviation Turbo Fuel	Diesel Fuel Oil	Light Fuel Oil	Stove and Kerosene	Total
Manitoba	1,496.1	218.1	1,000.4	11.1	6.2	**2,731.9**
British Columbia	4,581.0	1,531.9	3,396.0	187.2	12.8	**9,708.9**

Sources:

EIA Petroleum Navigator: http://tonto.eia.doe.gov/dnav/pet/pet_cons_prim_a_EPM0_P00_Mgalpd_a.htm

Statistics Canada Energy Statistics Handbook: http://www.statcan.ca/english/freepub/57-601-XIE/57-601-XIE2007002.pdf

Appendix B2
Publicly Available Sources of Data on Fuel Flows

Arizona – Online listings:

Diesel consumption on road: http://www.azcommerce.com/doclib/ENERGY/Onroaddiesel.PDF

Sales of all types of fuel for consumption in Arizona:
http://www.azcommerce.com/doclib/energy/petrosales.pdf

British Columbia - Email for queries on fuel volume information **-** FuelTax@gov.bc.ca

Contacts: Michael Rensing, BC Ministry of Energy, Mines and Petroleum Resources; and Hugh Hughson, BC Ministry of Small Business and Revenue

California – Contact: Lynn Garcia, California Dept of Revenue**-** Fuels Tax unit
http://www.boe.ca.gov/sptaxprog/spftrpts.htm

Monthly Motor Vehicle Fuel Distributions Report. 10 yr diesel and jet fuel report.

PIIRA requires petroleum products refiners, marketers, storers, importers and exporters to file reports. For instance, refiners must submit monthly fuel use and sales reports, and weekly production and storage information. The information is aggregated for public release to protect proprietary data. Each type of company must file one or more reporting forms to the Energy Commission on a weekly, monthly, and annual basis. Some of these companies must also submit copies of certain forms they submit to the federal Energy Information Administration (EIA). Refineries are required to send copies of their weekly EIA-800 and monthly EIA-810 Refinery Reports to the Energy Commission. Major marketers who currently file the monthly EIA-782B report are required to submit a CEC-782B to the Energy Commission. The Retail Fuel Outlet Survey (CEC A15) form must be filed annually by each retail fuel outlet in California. More information is here: http://www.energy.ca.gov/oil/piira/index.html

Montana – Vanessa L Olson, Compliance Specialist – Supervisor, Fuel Tax Management & Analysis Bureau, Montana Department of Transportation

New Mexico – Theresa Smith, New Mexico Fuels Tax Unit.
http://www.tax.state.nm.us/pubs/TaxreseStat/vol_val.htm

Mineral extraction - Oil and Gas Volumes and Values by County - Jan 1999 through Dec 2003

List of company by company volumes provided by email

Utah – Utah Dept of Revenue Tax Unit, Kyle Boyer, kboyer@utah.gov

http://www.tax.utah.gov/esu/misc/index.html *All in gallons*

Oregon – Fuels Tax Unit, Department of Revenue

http://www.oregon.gov/ODOT/CS/FTG/tdreports.shtml#BM1

Oregon quarterly data for gallonage for roadway and aviation gasoline and jet fuel

Washington – Ann Diaz, State Department of Licensing, ADIAZ@DOL.WA.GOV

Data provided by email. Fuel tax is collected when fuel leaves the rack, or is imported or produced in Washington.

Appendix C: Major Options Paper

Attached separately is the Major Options Paper released by the WCI Scope Subcommittee in January 2008 and revised in March 2008.

March 5, 2008 Draft Program Scope Recommendations

List of Commenters

Air Transport Association

Alcoa, Inc.

Antupit, Stephen

Avista Corporation

Chevron

City of Portland Office of Public Utilities

City of Seattle

City of Seattle

Clark Public Utilities

Climate Solutions

El Paso Pipeline Group and El Paso Pipeline Partners

Friedman, Lee

Grant County Public Utility District

Hurley, Peter

Independent Energy Producers Association

Industrial Customers of Northwest Utilities

Modesto Irrigation District

National Lime Federation

National Wildlife Federation

The Nature Conservancy

Northern California Power Agency

Northwest Pulp and Paper Association

Northwest Pulp and Paper Association

Oregon Municipal Electric Utilities Association

Oregon Public Utility Commission

Oregon Wild

Pacific Forest Trust

Pacific Gas and Electric Company

Pembina Institute

PNGC Power

Portland General Electric

Public Power Council

Public Utility District No. 1 of Chelan County

Puget Sound Energy

Sempra Energy

Sightline Institute

Snohomish County Public Utility District #1

Southern California Edison Company

Tucson Electric Power Company

Union of Concerned Scientists and Environment California

Washington Public Utility Districts Association

Waste Management, Inc.

WEST Associates

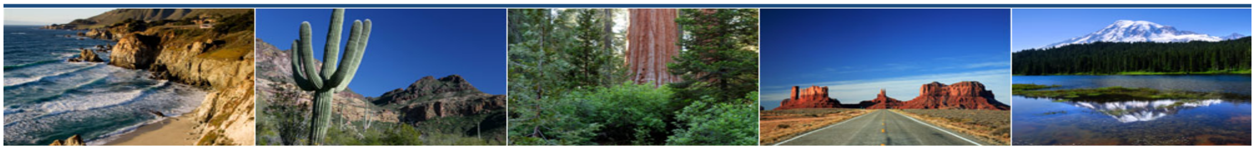
Western Climate Advocates Network

Western Power Trading Forum

Western States Petroleum Association

Weyerhaeuser Company

Western Climate Initiative



WCI Economic Analysis
Scope of Work

Task 1 – Kickoff Meeting and Project Management

The purposes of this task are to: (1) review and finalize the technical approach for this project; and (2) manage this project throughout its period of performance. The contractor shall participate in a kickoff meeting with WCI representatives to: review the activities that will be conducted; develop a schedule of conference calls and meetings; and establish deadlines for interim and final products. The contractor shall prepare a memo summarizing the kickoff meeting decisions for WCI review.

To manage the project, the contractor shall participate in weekly conference calls with WCI representatives to review progress and gain feedback on various deliverables. The contractor shall prepare a monthly status report summarizing activities performed, progress on deliverables, budget expended, and budget remaining.

<u>Deliverables</u>: (1) Kickoff Meeting; (2) Weekly conference calls; (3) Monthly status reports.

Task 2 – Assemble Data and Prepare Modeling Tools to Support Phase 1 Analysis

The purpose of this task is to assemble the data and prepare the modeling tools needed to support the Phase 1 analysis through the May 2008 WCI public workshop. The Phase 1 analysis will use the standard model data and additional data that are readily available and easily inputted, and consequently is designed to require a minimum of customization of the model and its data. Under the guidance of WCI, the contractor shall incorporate selected complementary policies into the model that are likely to have a large impact on GHG emissions and/or program costs (e.g., tailpipe standards, low carbon fuel standard, demand-side management, renewable portfolio standard, travel demand management).

The contractor shall assemble the data necessary and prepare the ENERGY 2020 model to support the Phase 1 analysis. The contractor shall prepare an Assumptions Book as the key document for managing the process of choosing and recording inputs and data sources. The Assumptions Book will be a living document that evolves over the course of the project under the direction of WCI.

The contractor shall use ENERGY 2020 to generate reference case forecasts out to 2030, combining historic data, a macroeconomic forecast, a simulation of energy demand and supply, and other model inputs. The contractor shall provide outputs at the regional and partner levels that include GHG emissions, energy production and consumption, and other outputs as agreed to with WCI.

<u>Deliverables</u>: (1) Briefing on ENERGY 2020; (2) Draft Assumptions Book; (3) Memo describing the complementary policies incorporated into the model; (4) Reference case forecasts summarized in PowerPoint and data tables.

Task 3 – Perform Phase 1 Analysis to Support Program Design

The purpose of this task is to perform the Phase 1 analysis to support WCI program design deliberations through the May 2008 stakeholder meeting. The contractor shall simulate and analyze various cap-and-trade program designs, as directed by WCI. The contractor shall assist and advise WCI in thinking through which designs to model.

Each model run will generate:

- Costs, savings, and allowance prices.
- Industry-specific impacts including impacts on emission leakage, and output; along with fuel prices, fuel consumption, electricity prices, production, and generation mix.

Deliverables: (1) List of analyses being performed and standard outputs; (2) Results for each analysis conveyed by PowerPoint presentations, tables, and interpretation.

Task 4 – Assemble Data and Prepare Modeling Tools to Support Phase 2 Analysis

The purpose of this task is to assemble the data and prepare the modeling tools needed to support the Phase 2 analysis through the August 2008 release of the WCI program design. The Phase 2 analysis will include refined model inputs and specifications that enable partner-specific conditions to be reflected.

The contractor shall refine the data and assumptions assembled under Task 2 by incorporating selected partner-specific inputs and additional complementary policies, under the guidance of WCI. In consultation with WCI partners, the contractor shall incorporate high-impact GHG mitigation policies that partners have adopted or are considering, especially those likely to reduce energy demand and/or promote non-emitting energy sources. The contractor shall consult with WCI partners and adjust data inputs and parameters to ensure that all parties view the revised reference cases and policy specifications as reasonable.

The contractor shall perform this task in parallel with Tasks 2 and 3 so that the Phase 2 analysis can be presented at the July WCI stakeholder meeting.

Deliverables: (1) Revised Assumptions Book; (2) Memo describing the selected state-specific inputs and complementary policies incorporated into the model; (3) Refined reference case forecasts summarized in PowerPoint and data tables. (4) Paper describing the data, assumptions, and model tools.

Task 5 – Perform Phase 2 Analysis to Support Program Design

The purpose of this task is to perform the Phase 2 analysis through the August 2008 release of the WCI program design, with particular emphasis on the July 2008 stakeholder meeting. The contractor shall simulate and analyze various cap-and-trade program designs, as directed by WCI. The contractor shall assist and advise WCI in thinking through which designs to model.

Each model run will generate:

- Costs, savings, and allowance prices.
- Industry-specific impacts including impacts on emission leakage, and output; along with fuel prices, fuel consumption, electricity prices, production, and generation mix.

Deliverables: (1) List of analyses being performed and standard outputs; (2) Results for each analysis conveyed by PowerPoint presentations, tables, and interpretation; (3) Summary Paper presenting the results.

Task 6 – Stakeholder Process Support

The purpose of this task is to support the WCI stakeholder process for this economic modeling project. The contractor shall provide the following support:

- Prepare and present summaries of the methods, data, and results at two stakeholder meetings, in May and July 2008. Prepare draft presentations for WCI review. Incorporate WCI comments prior to delivering the presentations.
- Prepare for, present to, and participate in stakeholder conference calls dedicated to economic analysis and modeling.
- Prepare summary responses to summaries of comments received from stakeholders on economic analysis and modeling issues.

Deliverables: (1) Presentations to two stakeholder meetings; (2) Participation in stakeholder conference calls; (3) Review and response to summaries of stakeholder comments as prepared by WCI.

Schedule of Stakeholder Events

Event	Date
Stakeholder Conference Call: Present an overview of the economic modeling activities. Present a detailed description of Energy 2020	Friday, March 28, 2008
Stakeholder Conference Call: Present the *Assumptions Book* listing all the model inputs.	Monday, April 14, 2008
Stakeholder Conference Call: Preview of initial model results, including reference scenarios.	Monday, May 12, 2008
Stakeholder Workshop, Salt Lake City: Present model results, including reference scenarios.	Wednesday, May 21, 2008
Stakeholder Conference Call: Present revised *Assumptions Book* with updated model inputs for Phase 2 analysis, and reflecting stakeholder comments.	Monday, June 9, 2008
Stakeholder Conference Call: Present initial Phase 2 results using updated model inputs and reflecting stakeholder comments.	Monday, July 21, 2008
Stakeholder Workshop, (location to be determined): Present Phase 2 model results.	Tuesday, July 29, 2008

Stakeholder comments will be solicited throughout the process.

Western Climate Initiative

Economic Modeling and Analysis to Support the Western Climate Initiative

Economic Modeling Team

March 28, 2008

Objective

- Support WCI in the development of a regional, multi-sector cap-and-trade program to reduce greenhouse gas (GHG) emissions.
  - Program Scope
  - Allowance Allocations
  - Stringency
  - Flexible Compliance Mechanisms

Objective (continued)

- Outcomes of interest
  - Economy-wide costs and savings
  - Cap-and-trade program outcomes
    - Allowances prices, allowance trading
  - Emissions
    - Sources within the cap-and-trade program
    - All sources economy wide
  - Sector impacts

Approach

- Energy 2020 -- Integrated model of the economy and energy for Canada and the U.S.
- Focus on design decisions
  – Alternative program designs
  – Sensitivity of the outcomes to assumptions and inputs:
    - Fuel prices, availability and cost of relevant technologies, growth rates, others
- Build on the body of previous work

Approach (continued)

- Statement of Work – WCI website
  - Open process: all data and assumptions
- Seven Stakeholder Events (so far)
  - Five conference calls
  - Two workshops (May, July)
- Written Comments
  - Timely
  - Accepted throughout

Approach (continued)

- Phase 1:
  - Initial results using aggregate data
  - Exercise the model
  - Engage stakeholders
- Phase 2:
  - Customize the model
  - Detailed analyses
  - Engage stakeholders

Events

Event	Date
Stakeholder Conference Call: Present an overview of the economic modeling activities. Present a detailed description of Energy 2020	Friday, March 28, 2008
Stakeholder Conference Call: Present the *Assumptions Book* listing all the model inputs.	Monday, April 14, 2008
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Stakeholder Workshop (location to be determined): Present Phase 2 model results.	Tuesday, July 29, 2008

Comments and Questions Regarding the Proposed Process

Climate Change Modeling Using ENERGY 2020

Presented to

Western Climate Initiative Stakeholders

March 28, 2008

ENERGY 2020 Applied in the U.S.

- Illinois – Governor's Climate Change Advisory Group
  - Target - reduce emissions to 1990 level by 2020
  - Policies in all sectors including cap-and-trade & links to regional trading systems.
  - Economic impacts analyzed in conjunction with a macro-economic model
  - http://www.epa.state.il.us/air/climatechange/documents/index.html
- Wisconsin – Global Warming Task Force
  - Up to 30 GHG mitigation policies being analyzed in 10-12 portfolios
  - Scenarios include cap-and-trade variations and sensitivity analyses on the Reference Case forecast
  - Integrated emission/economic modeling with REMI
  - http://dnr.wi.gov/environmentprotect/gtfgw/AG_t.html
- California – Adaptation of ENERGY 2020 for CARB Policy Analysis
  - Customized version of ENERGY 2020 that will be used by the California Air Resources Board for the analysis and development of multi-sector climate change response policies and programs

ENERGY 2020 is used extensively in Canada

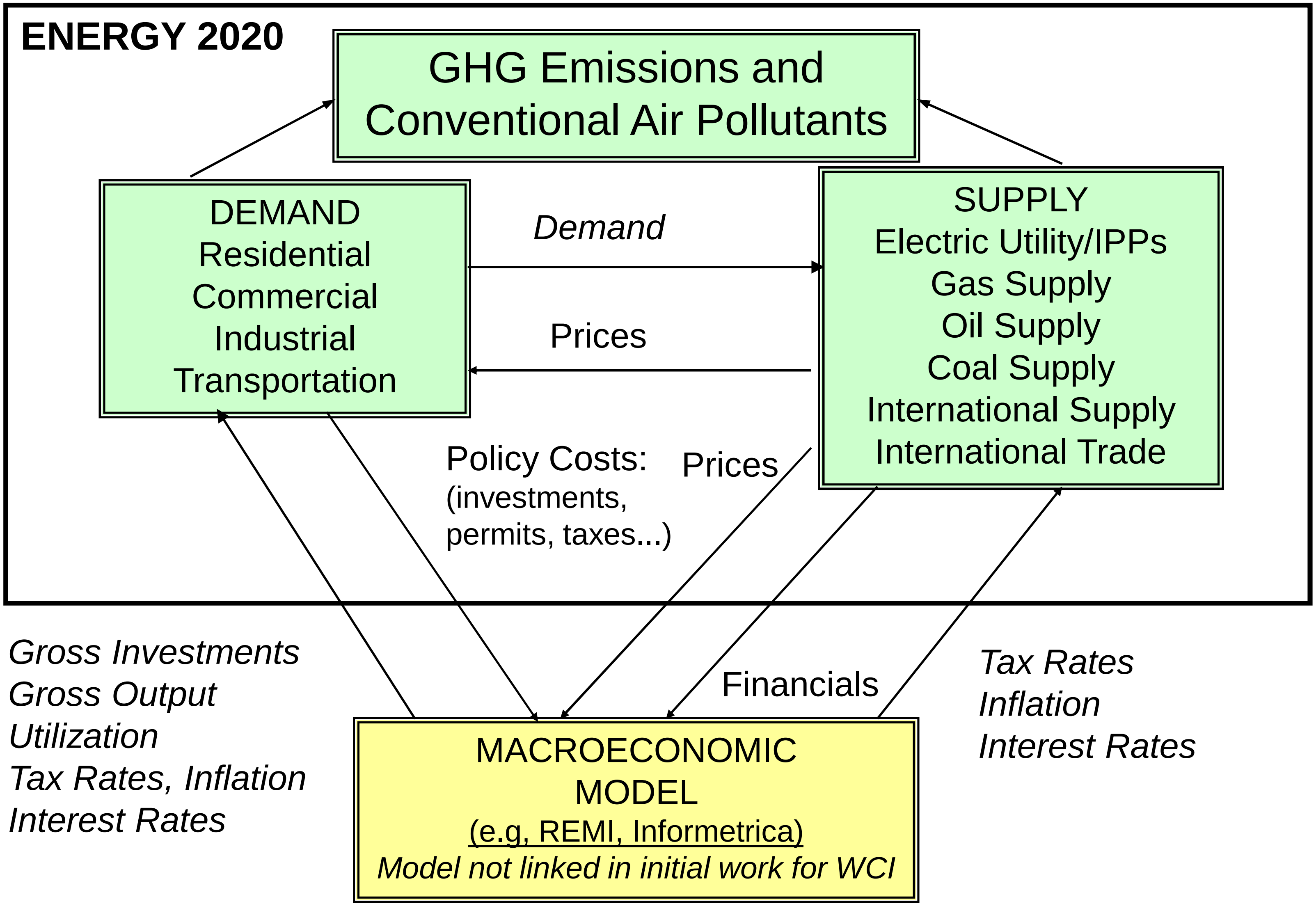
- Environment Canada – “Turning the Corner” - Multi-Sector Climate Change Policy Modeling:
  - Analyzing GHG emissions for reference case and policy scenarios
  - Modeling federal and provincial level emissions and emission policies
  - Macroeconomic impacts of policies (relative to the reference case)
  - Analysis extends to 2050
  - http://www.ec.gc.ca/default.asp?lang=En&n=75038EBC-1 (esp. Chap. 5)
- NRTEE (National Round Table on the Environment and the Economy - Canada)
  - Long-Term Energy and Climate Change Strategy to reduce GHG emissions by 60% below 1990 levels by 2050
  - Measures included energy efficiency across all sectors, renewable fuels for transportation and electric generation, restructuring industrial and urban mix, and carbon capture and sequestration.
  - http://www.nrtee-trnee.ca/eng/publications/wedge-advisory-note/ecc-wedge-advisory-note-eng.pdf
- Additional work for Environment Canada and Ontario

ENERGY 2020 Model Overview

Overview of ENERGY 2020

- Integrated North American economy, energy and emissions model
- Includes all U.S. States and Canadian Provinces
- Energy demand end-use sector disaggregation
- Energy supply for electricity, oil, gas, coal, renewables,
- Separate outputs can be provided for each type of air emission:
  - Greenhouse Gas (CO2, N2O, CH4, SF6, HFC, PFC)
  - Conventional Pollutants (SOx, NOx, VOC, CO, PMT, PM10, PM2.5)
- Model can be extended out to 2050

Model Structure & Relationships



Major Model Inputs

- Historical Data
  - Energy demand, supply, prices, and emissions by state/province
  - Unit-by-unit generator data
- Projected Economic Activity (from a macro-economic forecast)
  - GDP, Gross output by sector, personal Income
- Projected Fuel Prices
  - World oil prices, US natural gas and coal prices
  - Biomass, ethanol, biodiesel prices
- Projected Technology Cost and Performance
  - Power generation, vehicles, etc.
  - End-use and energy efficiency, including potential for improvements
- Availability and Cost of Offsets

Major Model Outputs

- Emissions – GHG and conventional air pollutants
  - With market-clearing allowance price for GHG cap-and-trade program
  - GHG offset prices and quantities used
- Power Sector
  - Demand, generation, capacity, wholesale prices, LSE revenues and rates
- Fuel use and market shares
  - Oil, natural gas, coal, gasoline, diesel, ethanol, biodiesel, etc.
- Levels of Energy Efficiency
- All outputs broken out by states/province and by economic sector

Modeling Principles

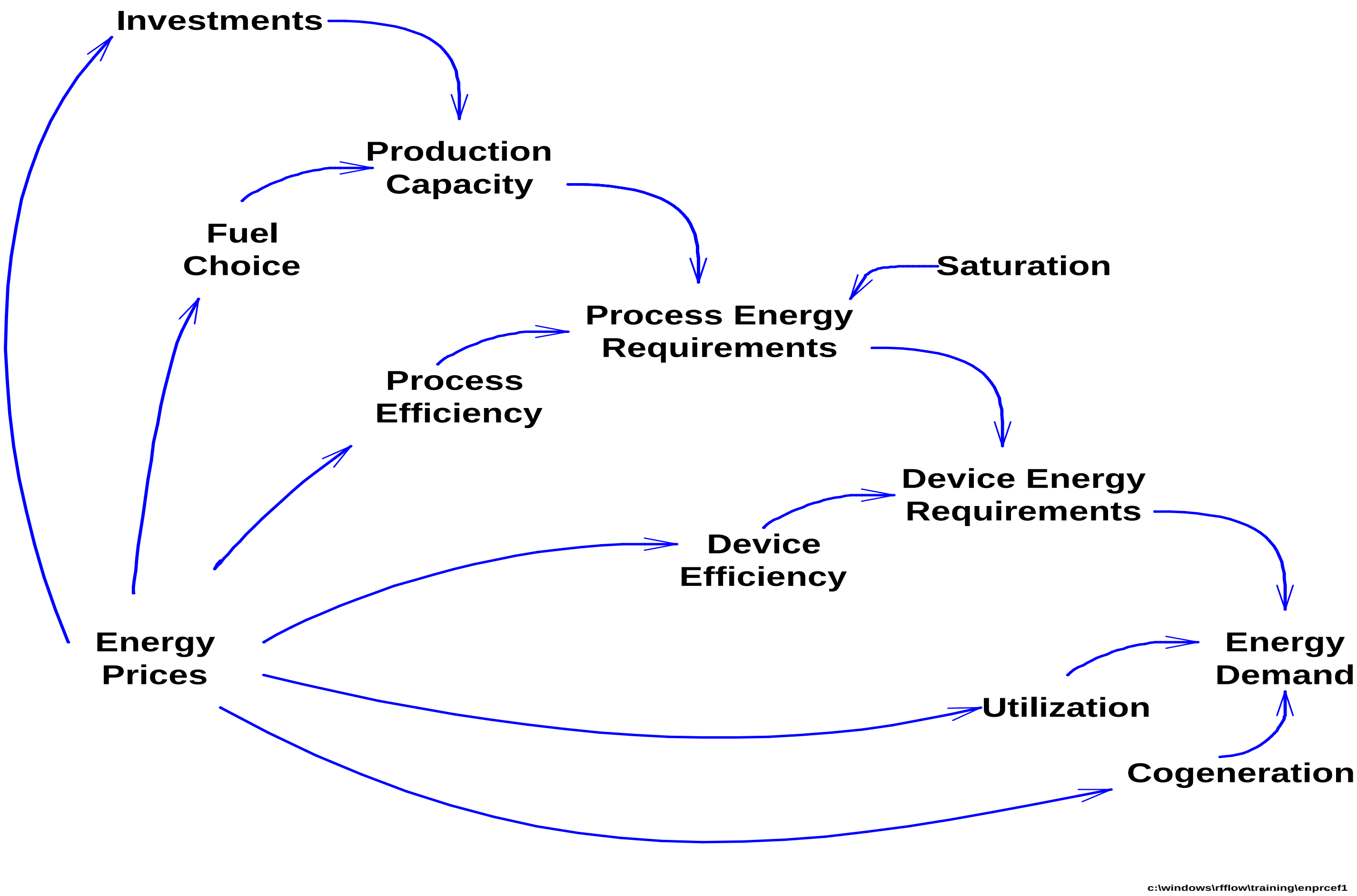
- Key Decisions are Endogenous
- Stocks and Flows
- Marginal Decisions
- Causality vs. Correlation
- Actual vs. Optimal Decisions
- Dynamically describes the behavior of both energy suppliers and consumers for all fuels and for all end-uses

What makes ENERGY 2020 Different?

- Not Optimization
  - Models behavior based on past experience, not optimal solution
- Not Classical Econometrics
  - Enables modeling of unprecedented actions and events
- Uses Qualitative Choice Theory
  - Recognizes price and non-price elements of decisions, market imperfections, time delays, etc.
  - "Maximizes utility" within constraints of imperfect market
  - Simulates actual, as opposed to assumed, responses
  - e.g. choice of vehicle considers non-price factors of style, comfort, space, safety, affordability, and reliability in addition to vehicle efficiency or lowest operating cost.
- Decisions are endogenous to the model
- Capable of flexible policy analysis and multiple scenarios

Demand Overview

Energy Demand Structure



Energy Demand Determination

- Energy is a “derived demand”
  - Users want “energy services” not “energy.” Energy demand is driven by several discrete choices:
  - Choice of fuel
  - Choice of energy conversion process
  - Choice of energy device
  - Choice of utilization level
  - Examples
- Fuel and Technology Market Shares
  - ENERGY 2020 simulates decisions on fuel, process, device, and utilization
- Stock and Flow Accounting
  - Simulates capital stocks by vintage over time
- Conversion of energy service requirements into actual energy demand
  - Simulates utilization of capital stocks

Demand – Sectors & End Uses

- Detailed model of sectors:
  - Residential – 3 structure types
  - Commercial/Institutional – 14 sub-sectors
  - Industrial – 39 sub-sectors (including construction, agriculture & forestry)
  - Transportation – separates passenger, freight & off-road
- End Uses:
  - Specific to each sector
  - Separates “substitutable” loads (multiple fuel choices) from “non-substitutable” (electric only).
  - Transportation divided into 7 “modes” as well as by vehicle classes within passenger and freight.

Demand – Sectors & End Uses (cont.)

Residential	Commercial	Transportation	Other
1. Single Family 2. Multi Family 3. Other Residential	1. Transportation Services 2. Pipelines 3. Communication 4. Electric Utilities 5. Gas Utilities 6. Water & Other Utilities 7. Wholesale 8. Retail 9. FIRE (Finance, Insurance, & Real Estate) 10. Offices - Business Services 11. Education 12. Health & Social 13. Food, Lodging, Recreation 14. Government	1. Passenger 2. Freight 3. Off Road	1. Misc. & Street Lighting 2. Electric Resale 3. Utility Electric 4. Generation 5. Industry Electric 6. Generation 7. Steam Generation 8. Solid Waste 9. Waste Water 10. Incineration 11. Land Use

Demand – Sectors & End Uses (cont.)

Industrial Sectors		
1. Food & Tobacco 2. Textiles 3. Apparel 4. Lumber 5. Furniture 6. Paper 7. Printing 8. Chemicals 9. Petroleum Products 10. Rubber 11. Leather 12. Cement 13. Glass	14. Lime & Gypsum 15. Other Non-Metallic 16. Iron & Steel 17. Aluminium 18. Other Nonferrous 19. Fabricated Metals 20. Machines 21. Computers 22. Electric 23. Equipment 24. Transport Equipment 25. Other Manufacturing 26. Metal Mining	27. Non-metal 28. Mining 29. Light Oil Mining 30. Heavy Oil Mining 31. Frontier Oil Mining 32. Oil Sands In-Situ 33. Oil Sands Mining 34. Oil Sands Upgraders 35. Gas Mining 36. Coal Mining 37. Construction 38. Forestry 39. Agriculture

Demand – Sectors & End Uses (cont.)

Residential	Commercial	Industrial	Transportation
1. Space heating	1. Space heating	1. Process heat	1. Highway (automobile & trucks)
2. Water heating	2. Water heating	2. Electric motors	2. Buses
3. Lighting	3. Lighting	3. Other substitutable [c]	3. Trains
4. Air conditioning	4. Air conditioning	4. Miscellaneous [d]	4. Planes
5. Refrigeration	5. Refrigeration		5. Marine
6. Other substitutable [a]	6. Other substitutable [a]		6. Others (electric vehicles, fuel cells and ethanol)
7. Other non-substitutable [b]	7. Other non-substitutable [b]		

a *an aggregate category to include cooking and drying end-use services*

b *represents miscellaneous electric appliances*

c *hot water or drying that is not part of the primary-process heat*

d *lighting and electrochemical process*

Supply Overview

Electricity Supply

- Functional Divisions
  - Distribution
  - Transmission
  - Marketing
  - Generation
- Capacity Expansion
  - developed endogenously to maintain a reserve margin target
  - committed capacity can be specified exogenously
- Generation and Fuel Use
- Electricity Prices
- Emissions

Other Supplies

- Extensive choice of fuel types
  - 33 fuels/sources can be modeled
  - Sub-sector detail will depend on available time and resources
- Oil production (6 sub-sectors including non-conventional)
- Gas production
- Coal Mining
- Combined Heat & Power & Steam Production
- Ethanol Production
- Renewables

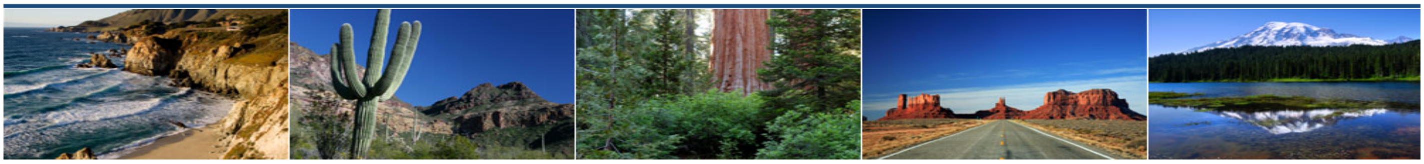
Modeling of Complementary Policies

- Flexibility in ENERGY 2020 allows modeling of a broad range of policies, e.g.,
  - DSM policies
  - Building codes
  - Efficiency standards for vehicles, appliances, etc.
  - Renewable portfolio standards
  - Low-carbon fuel standard
  - Carbon capture and sequestration
  - GHG offsets

Inputs and Assumptions

- An "Assumptions Book" catalogs key inputs and assumptions
  - This book is a "living document" that evolves over the course of the project
  - The current Assumptions Book will be available on the WCI website as it evolves
- WCI will seek stakeholder comment on the Assumptions Book inputs and assumptions
  - The Assumptions Book will be the topic of the stakeholder conference call on April 14, 2008
  - Comments on the Assumptions Book will be welcome throughout the process

Western Climate Initiative



Draft Allocations Design Recommendations

April 2, 2008

I. Introduction

As stated in the WCI Work Plan, the WCI Allocations Subcommittee was established to:

1. Recommend a methodology for determining the number of allowances to be apportioned, either individually to each WCI partner and thereby establishing each Partner's overall emissions allowance budget for the WCI program, or regionally for the WCI region overall; and

2. Determine whether to recommend that the Partners establish a common method for distributing the budgeted emissions allowances (a) among covered sectors; and (b) within each sector to covered entities. If a common allowance distribution method is recommended, the Subcommittee will recommend a distribution method or methods for consideration by the WCI Partners.

To accomplish this mission, the WCI Work Plan directed the Allocations Subcommittee to:

- Develop design principles to guide the Subcommittee's deliberations;
- Determine whether an allowance budget should be established (a) for each Partner or (b) for the region, with subsequent allocation to sectors within the region;
- Develop a methodology for determining the amount of overall allowances;
- Determine whether and what to recommend concerning how allowances are divided among economic sectors;
- Determine whether and what to recommend concerning how allowances are distributed (i.e., by free allocation, auction, or a hybrid of these two);
- Address specific issues identified in the Work Plan related to free allocations (if recommended) and auctions (if recommended);
- Determine whether the method for allocating allowances (i.e., free allocation, auction, or hybrid) should be the same for all sectors or may/should vary by sector;
- Determine whether the amount of allowances should decline, and if so, at what rate;
- Determine whether and what to recommend concerning how appropriate recognition and incentives for early emission reductions can/should be considered in distributing allowances;

- Determine whether banking of allowances should be permitted, and if so, the criteria and condition for banking (e.g., the length of time and amount of allowances that may be banked); and
- Determine whether borrowing of allowances should be permitted, and if so, the criteria and condition for borrowing (e.g., the length of time and amount of allowances that may be borrowed and the rate of repayment of borrowed allowances).

Pursuant to the WCI Work Plan, the Allocations Subcommittee established the following design principles to guide its deliberations. These design principles were identified in the Allocations Stakeholder Discussion Document (January 2, 2008):

- Maximize program simplicity,
- Minimize unfair competition among covered industries across the region,
- Provide for state and provincial flexibility,
- Promote consistent regional program standards and methods,
- Provide appropriate recognition and incentives for early emissions reductions,
- Maximize the program's GHG reduction potential, and
- Avoid undue economic impacts on consumers and industries.

In the Stakeholder Discussion Document, the Allocations Subcommittee recognized that some of these principles are potentially in conflict. The Subcommittee therefore sought stakeholder comments on how, among other things, to achieve the best balance between them and carefully considered the range of stakeholder perspectives in developing its recommendations.

The draft Allocations Design recommendations set forth herein take into account the above design principles, as well as the draft WCI recommendations on Scope and Electricity, public comments received on the WCI Work Plan (October 29, 2007) and the Allocations Stakeholder Discussion Document (January 2, 2008), and information gathered during conference calls and in-person meetings, including a conference call with stakeholders.

The Partners have agreed upon the draft Allocations Design recommendations set forth below. These draft recommendations are a first step for inclusion of allowance allocations in the overall cap and trade design. The Partners will continue to work on various allocations issues and will have additional recommendations after further deliberations and public input.

For example, the Partners will evaluate how to monitor the market and protect against manipulation.

In addition, while the Partners have agreed that a minimum amount of allowances should be auctioned, a number of issues related to the auction remain to be addressed. The Partners will take into account the RGGI and European experiences with auctions. RGGI has a complete auction design (based on a comprehensive study) and is planning its first auction for later this year. Some of the issues to be considered include who will administer the auction; the frequency of the auctions; the procedure for establishing the price of allowances sold at auction; use of auction proceeds; who may participate in the auction; and how to monitor the auction market and protect against market manipulation, among other questions. The Partners also will consider whether there should be a safety valve.

II. Draft Allocations Design Recommendations

The Partners agree to the following draft Allocations Design recommendations:

Regional Cap and Allowance Budgets:
The WCI will establish a regional cap that will decline over time, and each Partner will have an allowance budget within the cap. The emissions from any given Partner could be greater or less than its allowance budget depending on the extent of inter-jurisdictional allowance trading.

The regional cap will be equal to the sum of the Partner allowance budgets. Reductions achieved by the cap plus reductions from uncapped sources resulting from complementary measures should achieve the WCI regional goal of a 15% reduction below 2005 levels by 2020.

The initial regional cap and Partner allowance budgets will be set through 2020. The regional cap and each Partner's allowance budget will not be adjusted except as necessary to account for changes in WCI membership, sectors added to the cap, errors discovered in data used to determine the cap or the Partner budgets, which may become apparent after the start of mandatory reporting, or errors that resulted in either under-allocation or over-allocation of allowances. Such adjustments will take effect at a regionally-coordinated and designated time, such as the beginning of the relevant compliance period.

Distribution of Allowances by Partners:
Once the allowance budget has been established for each Partner, allowances will be issued by each Partner rather than issued by a regional organization. Through mutual reciprocal recognition by the Partners, allowances will be of equivalent use and value throughout the WCI region, regardless of which Partner issues the allowances.

Establishment of Cap and Trade Partner Budgets:
Each Partner's allowance budget will be established in a transparent manner that is consistent with the emission reductions that the WCI must realize from the sources covered by the cap and trade program in order to achieve the WCI economy-wide emissions reduction goal.

The Partners will develop a methodology for calculating the Partner allowance budgets. The methodology should set the Partner allowance budgets at the levels needed to achieve the WCI economy-wide emissions reduction goal.

The WCI seeks comments from stakeholders on the methodology for establishing Partners' allowance budgets and the factors to be included in the methodology.

Partners' Initial Allowance Budgets:
The Partners recognize the potential conflict between the need to begin the cap and trade program as soon as possible to bring about reductions in GHG emissions and the need for accurate data on which to base the calculation of allowances for the regional cap and individual

Partner budgets. Substantial emissions data is already available due to reporting under existing regulatory requirements for other pollutants and energy consumption, as well as the GHG emissions inventories and forecasts compiled by the Partners, but data from mandatory reporting of GHG emissions may be necessary for more precise allocations of allowances. With this in mind, the calculation of the regional cap and the Partner allowance budgets for the initial years of the cap and trade program will recognize potential concerns about data accuracy and be adjusted in ensuing years as necessary if mandatory reporting reveals significant data errors.

Partner Discretion to Issue Allowances:

Each Partner initially will have flexibility to issue, beyond the minimum percentage auction amount discussed below and subject to the sector-specific assessments discussed below, its remaining allowances as it sees fit, including (i) auctioning more than the minimum amount of allowances; (ii) issuing some or all of the remaining allowances for free; (iii) holding some or all of the remaining allowances within a compliance period; and/or (iv) retiring some or all of the remaining allowances.

Each Partner initially will have discretion to issue allowances differently to different sectors within its jurisdiction. Each Partner may decide how and to whom to issue the allowances in its allowance budget, subject to the minimum auction requirement and the sector-specific assessments of competition outlined below.

While each Partner initially will have flexibility in how it allocates the allowances beyond the minimum auction amount, each Partner will be required to advise the other WCI Partners at the beginning of the relevant compliance period how it intends to allocate the remaining allowances, so that the WCI can make public the Partners' plans in a coordinated fashion. This procedure will help reduce the potential for adverse impacts on auction prices by preventing allowances from being "dumped" into the market unexpectedly.

Any Partner that has chosen to hold allowances must allocate or retire those allowances by the end of the applicable compliance period. A Partner will not be able to hold allowances beyond the end of the compliance period. These requirements will help reduce market instability by providing more certainty about the volume of allowances available during a compliance period.

The Partners will continue to examine the impacts of Partners utilizing different approaches to allocate allowances to the same sectors and seek comments from stakeholders on this issue.

The Partners also will continue to consider the impacts of Partners making different use of auction proceeds and seek comments from stakeholders on this issue.

While the Partners initially will have flexibility to issue allowances, the WCI will seek to achieve standardized distribution of allowances over time to the extent possible.

- ***Sector-Specific Assessment of Competition Among WCI Jurisdictions*:**
  While the Partners initially will have significant flexibility in issuing allowances, a diverse array of allocation procedures could yield significant cost differentials among competing firms or industries among WCI jurisdictions. There may be cases where it is necessary to assess whether allocations to a particular sector should be treated uniformly

by all Partners in the WCI region to address competition among entities within the WCI region. This potential could be minimized through a continued dialogue among the Partners and harmonization of allocation procedures and the use of auction proceeds where appropriate. The Partners believe that only a few sectors face significant risks of unfair competition from differing allocation methods among the WCI Partners, and a harmonized approach would be limited to carbon-intensive industries facing significant competition among WCI jurisdictions. For such cases, a case-by-case sector-specific analysis will be conducted jointly by the WCI Partners to determine whether consistent allocation is needed to address such disparities within the WCI. This approach will provide for sufficient standardization for an efficient cap and trade program while providing the Partners flexibility to address their individual priorities.

- ***Sector-Specific Assessment of Competition with Non-WCI Jurisdictions*:**
  While the Partners initially will have significant flexibility in issuing allowances, a diverse array of allocation procedures could yield significant cost differentials among competing firms or industries within the WCI and those outside the WCI, resulting in leakage outside the WCI region. There may be cases where it is necessary to assess whether allocations to a particular sector should be treated uniformly by all Partners in the WCI region to address competition and leakage from entities outside the WCI region. This potential can be minimized through a continued dialogue among the Partners and harmonization of allocation procedures and the use of auction proceeds where appropriate. The Partners believe that leakage of this type is likely an issue only for bulk commodity sectors with high GHG emissions per unit of output that face significant non-WCI competition, and a harmonized approach would be limited to carbon-intensive industries facing significant competition outside the WCI region. For such cases, a sector-specific analysis will be conducted jointly by the WCI Partners to determine whether consistent allocation is needed to address non-WCI region leakage. This approach will provide for sufficient standardization for an efficient cap and trade program while providing the Partners flexibility to address their individual priorities.

Minimum Auction Percentage:

Each Partner will auction a minimum percentage between 25% and 75% of its allowance budget through a coordinated regional auction process by which each Partner will auction allowances throughout the WCI region and receive the proceeds of the auction.

The Partners will determine a specific minimum percentage auction amount. The WCI seeks comments from stakeholders on this question.

Because multiple Partners would be simultaneously auctioning allowances through a single pool, the auction could result in Partners auctioning or selling some of their allowances to entities in other jurisdictions. This outcome is fully consistent with the concept of regional trading and the importance of allowances having equivalent use/value for compliance purposes throughout the WCI region.

Phased Increase of Auctioning:
Greater emphasis could be given to free allocation in the early years of the program (and more to auctions in later years) as a means of mitigating business and consumer cost impacts and providing transition assistance, in addition to utilizing auction proceeds for these purposes. Some Partners may choose to provide more time for an allowance market to develop before capped entities must purchase larger portions of their allowances in an auction.

The minimum percentage of allowances to be auctioned should be increased over time, potentially to 100%. Even before such an increase, each Partner will have discretion to auction a greater portion of its allowances at the program outset or gradually over time as it sees fit.

Credits for Early Reductions:
Each Partner will have discretion to give credit for early actions, but any credit for early action must come from within the cap and will come out of the individual Partner's allowance budget. Early action credits will not be added to or be on top of the amount of allowances in each Partner's allowance budget.

Banking:
Purchasers and covered entities will be allowed to bank allowances without restrictions on the amount of allowances that may be banked or for how long.

Borrowing:
Borrowing of allowances from future compliance periods will not be allowed.

Compliance Periods:
The compliance periods will be three years long.

Multi-year compliance periods will provide covered entities with flexibility for compliance and in planning for (or responding to) large and unexpected changes in the allowance market or in other markets, such as energy markets, which may affect allowance prices, as well as programmatic flexibility for the WCI, to for example, ensure a steadily declining cap. The Partners note that three years is the length of the compliance periods chosen by RGGI.

Initial Compliance Period:
To accommodate start-up issues both from the covered entity standpoint and the regulatory standpoint, the initial compliance period will include special rules, such as a two-year period, or other measures to assist in the transition into a cap and trade system, while maintaining the integrity of the cap and value of the allowances.

Regional Organization:
Although allowances will be issued by each Partner, the Partners will create a regional entity (similar to RGGI, Inc.), to coordinate the regional auction of allowances, track emissions and allowances, monitor and report on market activity, and other activities. The regional organization also could be the forum through which each Partner updates the other Partners every two years on its progress toward achieving the regional goal and the Partners' individual goals.

There may also be a need to resolve other coordination issues, such as competitiveness and leakage issues resulting from potentially divergent allocation procedures among the WCI Partners. Such issues could be resolved through this regional organization or some other forum.

New Partners:
Allowances for new Partners will be in addition to the existing allowance budgets for current Partners. The regional cap will be expanded to accommodate emissions from the new Partner.

Once the cap and trade program has been instituted, new Partners will come into the cap and trade program at a regionally-coordinated and designated time, such as the beginning of the relevant compliance period.

Timelines for Partner Activities:
The Partners will develop a schedule for various WCI efforts, including launching the cap and trade program, establishing emissions baselines and Partner allowance budgets, undertaking any case-by-case discussions on competition or leakage issues which may affect Partner allocation plans and other various allocation-related efforts.

April 3, 2008 Draft Allocations Design Recommendations

List of Commenters

Alcoa, Inc.

American Forest & Paper Association

Arizona Public Service

Associated Oregon Industries

Avista Corporation

Barclays Capital

BC Forest Industry Working Group on Climate Change

BP America, Inc.

Business Council for Sustainable Energy

California Budget Project, Children's Action Alliance of Arizona, New Mexico Voices for Children, Oregon Center for Public Policy, Voices for Utah Children, Washington State Budget & Policy Center

California Public Utilities Commission Division of Ratepayer Advocates

Calpine Corporation

Canadian Association of Petroleum Producers

Cement Association of Canada

Chevron

Climate Protection Campaign

Climate Solutions

ConocoPhillips

del Moral, Sara

Energy Producers and Users Coalition, the Cogeneration Association of California, and the Cogeneration Coalition of Washington

Entegra Power Group

Fitzgerald, Timothy

Grant County Public Utility District

Independent Energy Producers Association

Industrial Customers of Northwest Utilities

Interfaith Power and Light

International Climate Change Partnership

The Nature Conservancy

New Mexico Conference of Churches, New Mexico Public Regulation Commission, and Western Resource Advocates

Northern California Power Agency

Northwest Pulp & Paper Association

Oregon Public Utilities Commission

Pacific Gas and Electric Company

PacifiCorp

PNGC Power

Port of Portland

Portland General Electric

Public Power Council

Public Utility District No. 2 of Grant County, Washington (GCPUD)

Puget Sound Energy

Renewable Energy Marketers Association

Salt River Project

Sempra Energy

Sierra Club of Canada

Sightline Institute

Snohomish County Public Utility District #1

Southern California Edison Company

Southern California Public Power Authority

State of New Mexico Taxation and Revenue Department

Tacoma Public Utilities

Tucson Electric Power Company

Van Horn Consulting

Washington Public Utility Districts Association

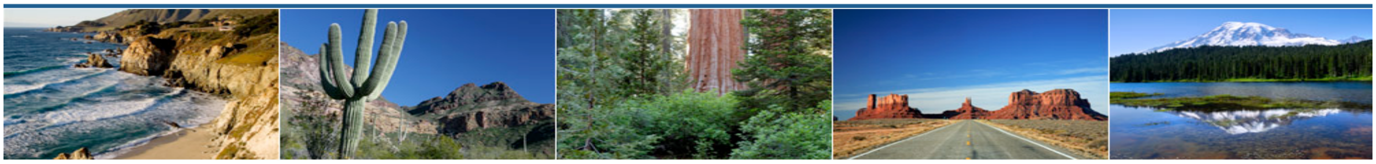
Washington Public Utility Districts Association, the Northern California Power Agency, the Northwest Public Power Association, and the Golden State Power Cooperative

WEST Associates

Western Power Trading Forum

Weyerhaeuser

Western Climate Initiative



Western Climate Initiative

Draft Offsets Design Recommendations

April 3, 2008

I. Introduction

The Offsets Subcommittee is examining the potential design, scope, and operation of a greenhouse gas offset program for the Western Climate Initiative (WCI) cap and trade system. The Subcommittee is developing draft recommendations within each of the four task areas identified in the Offsets section of the WCI Workplan released in October, 2007:

1. the role and objectives of a WCI offset program,
2. the core design elements of a WCI offset program,
3. offset eligibility and fungibility, and
4. offset program structure and authority.

In preparing these draft recommendations, the Subcommittee took into account the draft recommendations of other WCI subcommittees, public comments received on the WCI Work Plan (October 29, 2007) and the Summary of Major Options for a GHG Offsets System (January 3, 2008), and information gathered and discussed by the Subcommittee during several conference calls and in-person meetings, including the workshop on Designing an Offsets Program for the WCI (March 26, 2008).

The Subcommittee's draft recommendations are a first step for inclusion of offsets in the overall cap and trade design and are intended to solicit stakeholder input before the Subcommittee takes its draft recommendations to the Partners. The Subcommittee will continue its work and intends to have additional draft recommendations after further deliberations, public input, and interaction with other WCI subcommittees. The Subcommittee is particularly interested in stakeholder comments on how to implement, or alternatives to, the draft recommendations described below.

II. Evaluation Criteria

Based on overall WCI design principles, the Subcommittee identified the following criteria to guide the evaluation of offset program design options:

Administratively simple and cost effective,

Operationally straightforward for participants,

Ensures integrity of emission reductions,

Adds to economic efficiency of the cap and trade system,

Stimulates innovation and provides co-benefits,

Enhances transparency and minimizes uncertainty, and

Facilitates linkage with other programs.

III. Draft recommendations

Based on the guidance provided by the overall WCI design principles and feedback from stakeholders, the Subcommittee recommends that a greenhouse gas offset program be an element of the WCI cap and trade design to facilitate the achievement of WCI Partners' emission reduction goals.

Role of the Offset Program

A primary role of the offset program could be to reduce the overall compliance costs for the cap-and-trade system, by enabling the offset market to deliver lower-cost emission reduction options than are available in the sectors/sources included in the cap-and-trade system. In addition, by lowering overall costs, an offset program could support a more aggressive reduction cap than might otherwise be feasible for the cap and trade system. Another role could be to encourage innovation, co-benefits, greenhouse gas emission reductions from sources not covered by the cap and trade system and removals by sinks.

Offset project types and protocols

The WCI should:

- aim to develop an initial set of eligible project types and approved protocols prior to cap and trade program launch;
- provide a process to review and approve other project types and related protocols proposed by project developers;
- use protocols that are standardized to the extent possible; and,
- make use of, and adapt if needed, existing protocols as appropriate.

Offset projects approved through the WCI offsets program

In addition to those offset projects approved within its jurisdictions, the WCI should consider approving offset projects located throughout Canada, the United States, and Mexico, where such projects would be subject to comparably rigorous oversight, validation, verification and enforcement as those located within the WCI jurisdictions and would not undermine the ability for the WCI to link to other trading systems.

The WCI should consider a method that gives priority to offset projects located within WCI jurisdictions. The method should also consider other roles of the offset system.

Tradable units from government regulated GHG emission trading systems

The WCI should consider allowing for compliance purposes by individual regulated entities the use of tradable units (offsets and allowances) from other government regulated GHG emission trading systems that are recognized by the WCI as meeting similarly rigorous criteria for environmental integrity.

The WCI should ensure accounting systems are in place to prevent using tradable units more than once for compliance.

Limits

To ensure that meaningful emission reductions take place within the sources covered by the cap-and-trade system, the WCI should limit the use of offsets and non-WCI tradable units for compliance by individual regulated entities. The Subcommittee will consider making a specific draft recommendation to the WCI based on further analysis and considering the level of the cap set for the cap and trade system.

Offset program administrative structure and function

The WCI should use an administrative structure for the offset program that combines optimal aspects of jurisdiction-by-jurisdiction, public-private partnership, and centralized regional approaches and may draw from existing programs.

A regional organization should:

- coordinate review and adoption of protocols;
- coordinate review and issuing of offsets;
- provide the criteria and means to accredit service providers to deliver validation and verification services.

The subcommittee recognizes that each jurisdiction may need to retain regulatory authority for offset protocol and project approval, issuing offsets and enforcement.

The WCI should select or develop a centralized offset registry and ensure integration with the emissions reporting and allowance tracking system of the cap and trade system. Public-private partners could be involved in the registration and tracking of WCI offsets.

April 4, 2008, Draft Offsets Design Recommendations

List of Commenters

Alcoa, Inc.

APX Inc.

Associated Oregon Industries

Avista Corporation

BC Forest Industry Working Group on Climate Change

Business Council for Sustainable Energy

California Climate Action Registry

California Council for Environmental and Economic Balance

Calpine Corporation

Camco International Group

Canadian Parks and Wilderness Society

Climate Trust

EcoSecurities

EPCOR Utilities, Inc.

Independent Energy Producers Association

Industrial Customers of Northwest Utilities

Industry Provincial Offsets Working Group

International Climate Change Partnership

Lane Climate Change/Peak Oil Coalition

Morgan Stanley Capital Group, Inc.

National Carbon Offset Coalition

The Nature Conservancy

Navajo Refining Company, LLC

Northwest Pulp and Paper Association

Oregon Department of Agriculture

Oregon Municipal Electric Utilities Association

Pacific Gas and Electric Company

PacifiCorp

Pembina Institute

Port of Portland

Public Utility District No. 1 of Chelan County

Salt River Project

The Sierra Club and the Sierra Club of Canada

Sightline Institute

Soil Carbon Coalition

Tuscon Electric Power Company

Washington Forest Protection Association

Waste Management, Inc.

WEST Associates

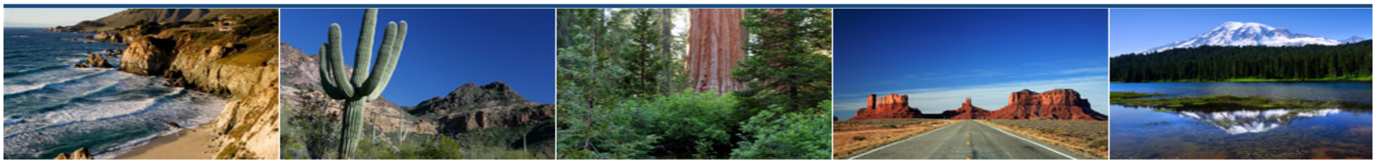
Western Climate Advocates Network

Western Forestry Leadership Coalition

Western States Petroleum Association

Weyerhauser

Western Climate Initiative



Western Climate Initiative
Draft Program Reporting Recommendations

1. Introduction

This paper presents the WCI draft recommendation for the greenhouse gas (GHG) emissions reporting system to support the WCI cap-and-trade program. The recommendation is based on the WCI's analysis and assessment of the Reporting Major Options paper it released in January 2008, entitled "Summary of Major Options for a GHG Reporting System to Support the WCI Program". The WCI evaluated these major options in light of general WCI design principles and needs and capabilities of individual Partner jurisdictions. It also took into account stakeholder comments received in writing by February 1, 2008, as well as comments at the January 10, 2008 stakeholder meeting and the February 15, 2008 stakeholder conference call on reporting issues.

The WCI welcomes stakeholder input regarding these recommendations. A stakeholder call to discuss this draft will be scheduled for the week of April 7, 2008. Written comments may be submitted through the WCI web site and are due by Wednesday, April 16, 2008.

Background

A robust and credible reporting system will be the backbone of the WCI program. This system will need to ensure that emissions are quantified and reported in an accurate and transparent manner. It will allow regulators in the participating jurisdictions to assess compliance of regulated sources, measure progress against state, provincial and regional targets and generate public trust in this progress. Additionally, market participants of all stripes will rely on the reporting system and the data it generates to make decisions on which significant transactions will be based. Confidence in the reporting system will be critical to the success of the WCI program.

WCI Design Principles Relevant to Reporting

Several of the WCI Design Principles outlined in the October 29, 2007 WCI Work Plan are especially relevant to reporting and were given serious consideration in development of the recommendations in this paper (shown in bold below).

1. ***Is equitable, administratively simple for government and private participants, minimizes administrative costs, and has a clear compliance path;***

2. **Maximizes total benefits throughout the region, including reducing air pollutants, diversifying energy sources, and advancing economic, environmental, and public health objectives, while also avoiding localized or disproportionate environmental or economic impacts;**
3. **Requires all reductions to be real, surplus/additional, verifiable, permanent, and enforceable;**
4. **Stimulates investment, especially in low carbon technologies, and rewards innovations that will lead to long-term permanent greenhouse gas reductions;**
5. ***Covers as many sources as is practical, while encouraging pollution reductions beyond the capped sources and sectors;***
6. ***Provides appropriate recognition and incentives for early emissions reductions;***
7. ***Assures a transparent and robust accounting system that will measure and report emissions rigorously and consistently across all sectors and throughout the region;***
8. **Minimizes the potential for leakage; and**
9. ***Facilitates linkage to similarly rigorous regional and international greenhouse gas reduction markets and encourages other states, provinces, and countries to join the market.***

Starting Assumptions

The WCI is fortunate in that several GHG reporting systems exist that can inform the design of and perhaps even underpin the reporting system it will require. The Reporting Subcommittee has assessed many of these systems and anticipates that the reporting system it ultimately recommends will attempt to establish as much consistency with as many of them as the details and rigor of the WCI program allow. Many of the details of the WCI reporting system however will necessarily depend on other decisions still being considered by the Partners.

This reality aside, the WCI partners are unanimous in their view that the reporting component of the program should rely as heavily as possible upon the infrastructure currently under design by The Climate Registry (TCR). The TCR is a nonprofit corporation that is a collaborative effort between U.S. states, Canadian provinces and Mexican states to establish a common infrastructure for measuring and reporting GHG emissions. All of the WCI partners are members of the governing board of the TCR. The objective of the TCR is to provide a common set of tools for the measurement and reporting of GHG emissions that can support a broad range of state or provincial policies.

TCR's mission includes not only the establishment and operation of a voluntary GHG emissions registry, but also providing support for mandatory GHG reporting programs that may differ from the voluntary registry. In the first phase of its development, the TCR is designing a voluntary entity wide GHG reporting program. This program can be conceptualized of as consisting of three major components: 1) entity reporting specifications, 2) quantification methodologies and 3) reporting services and systems. The reporting specifications dictate all parameters specific to the TCR voluntary reporting program--what must be reported, how an entity is defined for reporting purposes, the sources and gases it must report, the frequency of reporting and verification, etc. The quantification methodologies dictate how emissions from specific sources are measured or calculated. Finally, the TCR’s services and systems will provide assistance to reporters, support verification, and collect, store and make data available to the public. In its second phase of development, the TCR will develop systems for the support of reporting mandated by its Partner jurisdictions and regional organizations of which the Partners are members.

A WCI reporting system could rely heavily on the TCR's quantification methodologies and its services and systems (components 2 and 3 listed above). Doing so should reduce the costs of implementation for partners, ease the reporting burden on regulated entities, and ensure the basic consistency both between data collected within the WCI region and data collected in other regions that also rely on the TCR. However, the WCI will necessarily need to develop its own reporting specifications (component 1 listed above), consistent with the scope of the sources and gases it regulates and other program parameters. The WCI reporting specifications will necessarily differ from the reporting specifications of TCR's voluntary registry. In the Appendix, Figure 1 and Table 1 illustrate how the WCI could rely on the TCR to provide major components of its reporting system.

2. Recommendations

Beyond the WCI's intention to rely on TCR infrastructure to the maximum extent possible, the January 2008 Major Options paper identified several issues crucial in the design and implementation of a reporting system. For most of these, two alternative approaches were offered for stakeholder comment. This paper presents, for each of these issues, the alternatives presented in the Major Options paper, the WCI recommendation, a discussion of stakeholder comments, and other considerations taken into account by WCI in making its recommendations.

Data reporting is essentially a support or enabling function to serve the other components of the WCI program. Final decisions on the WCI reporting system will therefore necessarily depend on the final decisions regarding scope, electricity, allocations, and offsets.

Breadth/Scope of Reporting

The alternatives presented in the Reporting Major Options paper were:

a. Should reporting be required only for sectors/sources included within the cap?
b. Or, should reporting be required for sectors/sources not included in the cap-and-trade program (e.g., ones that are likely to be phased in over time)?

Stakeholder Comments: Commenters mostly favored Option (b), allowing for reporting of sources and sectors not included in the cap-and-trade program. Commenters noted that this option allows for more accurate accounting across all sectors, provides a better basis for allocations, and provides for more comprehensive public information. Some commenters favoring this option urged that a reasonable threshold for reporting be set to relieve burdens for small operations. One commenter favoring Option (a) suggested that non-capped sources could be eligible for offsets.

WCI Recommendation: ***Include capped sectors in reporting and certain non-capped sectors that may be phased in later (will have to determine which ones, and lower thresholds may apply).***

WCI Considerations: WCI recommends Option (b), with some rewording for greater clarity. In particular, rewording was intended to indicate that reporting may be required not only for sources in some sectors outside the cap, but also for some sources that are within a capped sector but below the threshold for the cap-and-trade program. WCI Partners believe that the advantages of this option greatly outweigh the disadvantages. The Draft Program Scope Recommendations paper (March 3, 2008) identifies several conditions that warrant the consideration of phasing of sectors/sources into the cap-and-trade program, including the need to obtain emissions data for sources under consideration for future inclusion. Uniform mandatory reporting will be needed to obtain such data. WCI is also considering whether emissions reporting from additional sources/sectors might be needed in the future for such purposes as improving regional GHG emissions inventories, evaluating the effectiveness of emissions reduction strategies that are complementary to the cap-and-trade system, and determining whether there is shifting of emissions to sub-threshold sources. WCI's first priority is establishment of reporting for sources/sectors under the cap and for those under consideration for coming under the cap.

Initiation of Reporting

The alternatives presented in the Reporting Major Options paper were:

a. Should mandatory reporting begin before cap and trade commences?
b. Or should mandatory reporting begin only with the start of the cap's first compliance period?

Stakeholder Comments: Commenters overwhelming favored Option (a), beginning mandatory reporting before cap-and-trade commences. Several commenters pointed to the need for accurate data as a basis for allocations, citing the EU experience in which an excess of allocations was distributed. Commenters also noted that preliminary reporting data could be useful in setting the threshold for capped sources. Others suggested that a period of reporting prior to setting the cap and trading would allow for a 'shake-out' period to ensure the proper functioning of the system, and one commenter suggested that a period of voluntary reporting prior to cap-and-trade could serve as a training period.

WCI Recommendation: ***Begin reporting before cap-and-trade commences. Strive to avoid reporting-related delays to the start of the cap-and-trade program.***

WCI Considerations: WCI recommends Option (a), with the addition of language to clarify that initiation of cap-and-trade should not be delayed until all sources and sectors can be included in the reporting program. WCI recognizes the lesson learned from the EU program, which is that accurate emissions data are necessary for setting allocation levels. The electricity generation sector and possibly other sources may have sufficiently high-quality emissions data to support their early inclusion in the cap-and-trade program, while inclusion of other sectors might be delayed pending collection of high quality emissions data. Pending final decisions on scope, point of regulation for the electricity sector, and emissions quantification issues, WCI reporting should begin as soon as possible not only for sources and sectors initially included in the cap-and-trade program, but also for others that might potentially be included later.

Coordination Among Partner Jurisdictions on Reporting

The alternatives presented in the Reporting Major Options paper were:

a. Should WCI develop a single WCI reporting rule that stipulates all reporting specifications?
b. Or should individual WCI jurisdictions have loosely coordinated rules possessing common core elements? If so, what aspects should the common core elements cover or include?

Stakeholder Comments: Commenters overwhelmingly recommended Option (a), the development of a single reporting rule for WCI (i.e., a model rule to be adopted by each jurisdiction). These commenters pointed to the advantages of consistency in providing administrative effectiveness and cost efficiency. They said that lack of consistency would increase gaming of the system, lead to errors in reporting, and make reporting and verification more costly for reporters. Commenters favoring Option (b) cited the advantages of continuity with existing state/provincial reporting programs, and noted that this option would likely face fewer legal and technical challenges. One commenter favored a hybrid system, with a single uniform rule but allowing Partners to supplement this core with additional reporting they thought useful.

WCI Recommendation: ***Develop essential requirements for a model WCI reporting rule by the end of 2008. Incorporate consideration for jurisdictions that already have reporting rules adopted or in process.***

WCI Considerations: WCI agrees with stakeholders regarding the value of uniformity and consistency in reporting, and recommends Option (a). Wording was slightly changed ("essential" rather than "minimum") to avoid any implication that the rule should not be comprehensive and specific. WCI also recognizes that several Partner jurisdictions have already adopted or are in the process of adopting their own reporting rules. Consequently, development of the model WCI reporting rule should not be *de novo*, but should take into account existing reporting rules, seek to retain common elements where possible, and minimize disruption of existing programs where possible. Inclusion of 'bridge' and 'glide path' provisions could provide for a smooth transition from disparate jurisdictional rules to eventual harmonization. The model rule should also allow for some flexibility in reporting, particularly for sources not in the cap or under consideration for inclusion in the cap, and could allow jurisdictions to go beyond the essential reporting requirements. Higher-tier quantification methods are likely to be required for sources under the cap or under consideration for inclusion in the cap. Stakeholders should be involved in development of the model rule.

Data Management and TCR Interaction

The alternatives presented in the Reporting Major Options paper were:

a. Should WCI require that all capped sources report directly to and verify through the TCR?
b. Or should sources report to and verify at the level of the individual jurisdiction (with data then uploaded to the TCR or otherwise shared centrally)

Stakeholder Comments: Commenters were divided on this question, and several recommended neither of the options presented. Commenters favoring Option (a) cited the advantage of simplified reporting for companies with facilities in multiple WCI jurisdictions. Commenters favoring Option (b) pointed to the advantages of coupling greenhouse gas reporting with other pollutant discharge reporting which is made directly to the state or provincial jurisdictions. Some commenters noted that Partners might face legal issues if they were to require reporting directly to an entity other than the state or province. Some commenters suggested a hybrid system where the reporter had the option of reporting to the state/province or to TCR. Some commenters recommended that TCR not be used at all, on the grounds that reporting to TCR would trigger a requirement to report all North American emissions (which is incorrect, as explained below).

WCI Recommendation: ***Sources will report either (a) directly to jurisdictions (which would then upload the data to TCR's central repository), or (b) through the TCR's program framework (which would then download the data to the necessary jurisdiction(s)).***

WCI Considerations: WCI recommends a hybrid approach, in which individual jurisdictions would have the option of requiring reporting directly to TCR or requiring reporting to the jurisdiction for later upload to TCR. Verification issues are addressed below, so the option language referring to verification was removed. Some Partners believe that direct reporting to TCR will be sufficient for their mandatory reporting, while other Partners believe they will face legal difficulties in requiring reporting to an outside entity, even one such as TCR of which the Partner is a member. Some Partners believe it is essential that they get the 'first touch' of the data. WCI notes that Partners will continue to evaluate TCR support of mandatory reporting to determine that it is the best value for the expense. WCI would particularly emphasize that use of TCR to support mandatory reporting would <u>not</u> thereby require sources to report all North American emissions. Although WCI's design of its mandatory reporting program might draw upon some elements of TCR's reporting requirements, WCI would not cede authority over reporting requirements to those in TCR's General Reporting Protocol for Voluntary Reporting (GRP), nor will the GRP supersede WCI reporting requirements. WCI does intend to rely on TCR's quantification methodologies and reporting tools and database(s). WCI will also seek to minimize the imposition of additional burdens on sources that voluntarily report their entity-wide North American emissions to TCR.

Verification

The alternatives presented in the Reporting Major Options paper were:

a. Should WCI require third party verification?
b. Or should WCI allow multiple approaches to ensuring data quality (other than third party verification)?

Stakeholder Comments: A majority of commenters favored Option (b), allowing multiple approaches to ensuring data quality. Many who expressed this view cited concerns over the potential costs of third party verification. Others, particularly in the electricity generation sector, thought that third party verification would not be needed for emissions measured by continuous emissions monitors and/or other federally approved methods subject to existing compliance monitoring. Commenters favoring third party verification (i.e., Option (a)) cited the need for consistency and credibility of emissions data, especially in a program where emissions relate directly to financial obligations and benefits.

WCI Recommendation: ***WCI will establish essential quality assurance elements for reported data that will be consistent across jurisdictions. Each jurisdiction will have an oversight mechanism to ensure compliance with the reporting requirements. As part of this mechanism, each jurisdiction will establish procedures to ensure that the quality assurance elements are met, which could include requiring 3rd party verification, rigorous compliance audits or other appropriate approaches.***

WCI Considerations: WCI's recommendation is similar to Option (b), but is substantially modified to ensure that consistent standards of data quality are maintained across jurisdictions. WCI recognizes stakeholder concerns regarding the costs and burdens of third party verification. WCI also recognizes the advantages of combining greenhouse gas reporting with existing air pollutant reporting, particularly for the many sources operating in only a single jurisdiction. Partners also believe that they, rather than a third party, should ultimately be responsible for accuracy of the data. Some WCI Partners may wish to delegate or contract out verification activities, while others may want to perform this function themselves. To allow this flexibility while at the same time ensuring consistency, WCI will establish uniform quality assurance elements required for all jurisdictions. Depending on the verification approach used by a jurisdiction, there may be fees/costs associated with verification.

Administrative Costs & Fees

The alternatives presented in the Reporting Major Options paper were:
a. Should states and provinces mandate that fees go directly to TCR and TCR administers the reporting database?
b. Or should states and provinces collect fees and contract with TCR to administer the reporting database?

Stakeholder Comments: Most commenters choosing either option preferred Option (a), where fees would go directly to TCR. Those favoring Option (a) thought this would avoid administrative complexity. One commenter favoring Option (a) noted that implementation might require enabling legislation, and suggested that Option (b) could be used in the interim. Several commenters did not choose either of the options presented, but recommended that fees should be paid to the entity where data are reported, whether TCR or the WCI partner jurisdiction. Several commenters said that fees should only be used to support the costs of the program and should not be diverted to state/provincial general funds. State/provincial jurisdictions were also asked to exercise oversight of TCR to ensure that fees were reasonable.

WCI Recommendation: ***Jurisdictions will collect fees from sources reporting directly to them and contract with TCR to administer the program. Jurisdictions may also accept data directly from TCR if they choose to do so; entities that report through TCR may have to pay an additional fee if one is required by the jurisdiction(s).***

WCI Considerations: WCI recommends a modified hybrid approach, with fees going to the TCR or the Partner jurisdiction depending on which entity is the direct recipient of data reported from the source. In addition, some Partner jurisdictions may want to charge a registration or other fee to sources reporting directly to TCR. Other Partner jurisdictions may not wish to charge a fee at all, but to cover fees themselves for reporters. Although WCI would like to have complete uniformity regarding fee payments, some jurisdictions may have legal issues in requiring the payment of fees to an entity other than the jurisdiction itself. With agreement of their jurisdiction, sources voluntarily reporting their entity-wide North American emissions to TCR should not have any additional fees imposed, unless an additional fee is required by a Partner jurisdiction.

Mandatory Federal Greenhouse Gas Reporting

The question presented in the Major Options paper concerned how WCI states/provinces and The Climate Registry should incorporate and interface with the new Congressional mandate for US EPA to develop an economy-wide GHG reporting rule and new Canadian Federal GHG reporting requirements in designing and implementing the WCI GHG reporting program?

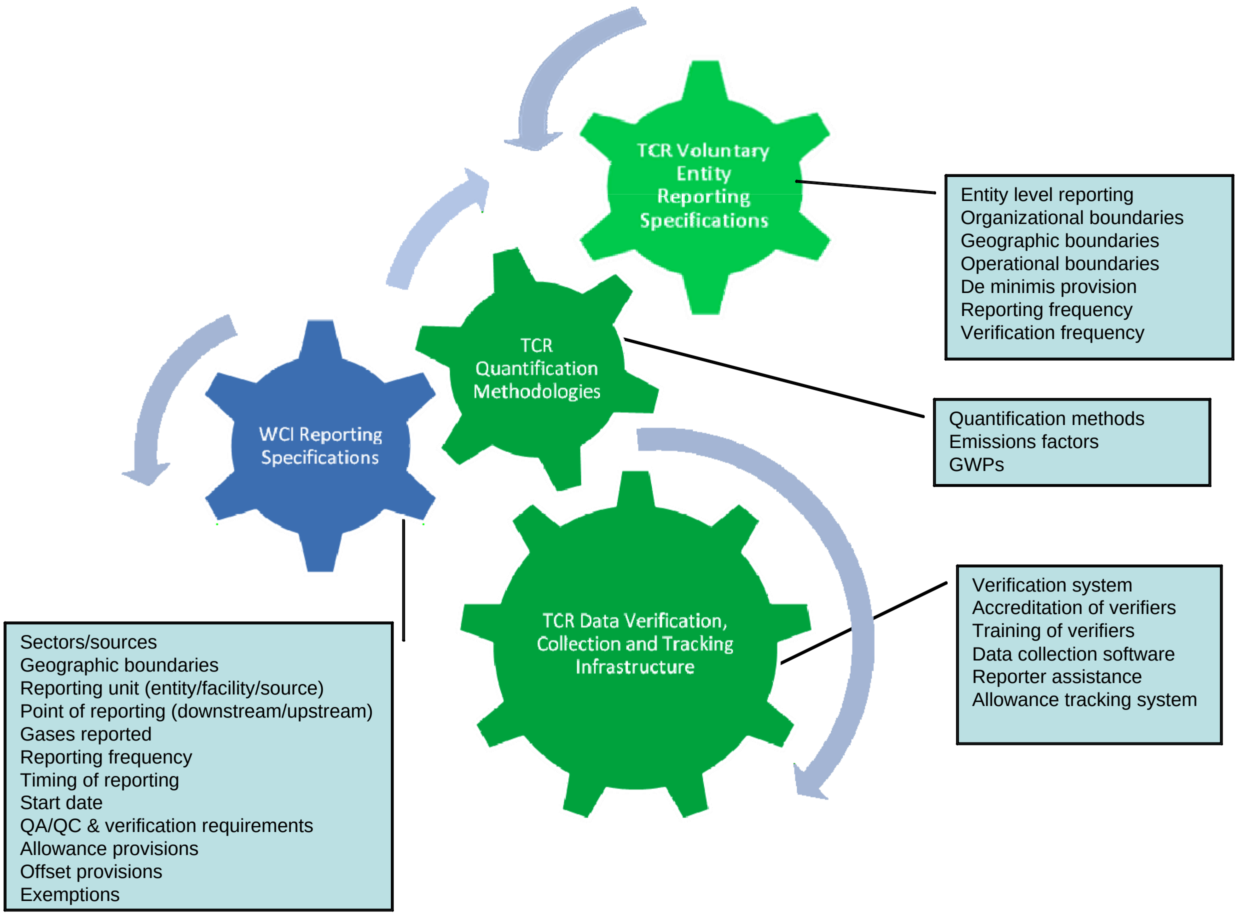
Stakeholder Comments: Commenters overwhelmingly called for consistency and single (i.e., one-time) reporting. Commenters varied in their assumptions or preferences for priority of federal versus WCI reporting. Some called for WCI to follow development of the US federal program and strive for consistency with it, while others said that WCI and TCR should seek to influence and guide development of the US federal program. Several commenters urged that WCI strive for consistency with the Canadian federal program, which has already established some GHG reporting requirements.

WCI Recommendation: ***Get involved in federal GHG reporting program development in the U.S. and Canada to ensure that federal reporting programs are harmonized with the jurisdictions' interests to the greatest extent possible.***

WCI Considerations: WCI strongly agrees with stakeholders on the advantages of a single, unified reporting system. Since the US federal reporting system is in the early stages of development, there is considerable opportunity for WCI to influence the development of that system. WCI will seek a dialogue with US EPA officials involved in developing their program. Other regional programs (RGGI, Midwest Greenhouse Gas Accord) should also be at the table. Given that a Canadian federal system exists and a new more detailed system is under development, WCI reporting should initially seek to minimize differences with the Canadian system to the extent possible, and later work cooperatively to harmonize the rules. Many issues need to be addressed, including preemption, so it is difficult to specify at this time precisely how harmonization among the different jurisdictions' reporting systems will occur.

Appendix: Figures and Tables

Figure 1. WCI Interaction with TCR Reporting System Components*



* The requirements for allowance and offset tracking and trading systems are being considered by other WCI Subcommittees, and decisions are still pending on whether these systems might be provided by TCR or other parties.

Table 1. WCI Reporting: Potential Relationship with *The Climate Registry*

Reporting / Data Tracking Feature	Where Specified[1]		Where Provided	
	WCI	TCR	WCI	TCR
Fundamental Parameters/Specifications				
Sectors / Sources (organizational and operational boundaries)	√			
Geographic Boundaries	√			
Start Date	√			
Reporting Unit (entity / facility / source)	√			
Point of Reporting (at source / upstream / downstream)	√			
Gases	√			
Reporting Frequency	√			
Timing of Reporting	√			
3rd Party Verification	√			
Verification Frequency	√			
Allowance Provisions	√			
Offsets Provisions	√			
Exemptions/De Minimis Provisions	√			
Implementation Parameters/Quantification				
GWPs		√		
Emission Factors		√		
Quantification Methodologies		√		
Services/Systems				
Data Quality Control (QA/QC)				√
Assistance to Reporters				√
Accreditation of Verifiers				√
Training of Verifiers				√
Data Collection Software & System				√
Allowance Tracking[2]				TBD
Offsets Tracking[2]				TBD

[1] *WCI- or state-/provincially-specified for sources within WCI program. TCR specifies the same features for its entity wide reporting program and may eventually for non-WCI jurisdictions.*

[2] *Decisions pending on whether these databases will reside in TCR or elsewhere.*

April 3, 2008 Draft Program Reporting Recommendations

List of Commenters

Alcoa, Inc.

APX, Inc.

Associated Oregon Industries

BC Forest Industry Working Group on Climate Change

BP America, Inc.

City of Seattle

First Environment, Inc.

Independent Energy Producers Association

Industrial Customers of Northwest Utilities

Navajo Refining Company, LLC

Northwest Pulp and Paper Association

PNGC Power

Port of Portland

Puget Sound Energy

Salt River Project

Southern California Edison Company

Waste Management, Inc.

Western Climate Advocates Network

WEST Associates

Western States Petroleum Association

April 8, 2008 Economic Analysis and Modeling Support to the Western Climate Initiative, ENERGY 2020 Model Inputs and Assumptions, April 8, 2008 (Revision Date)

List of Commenters

Independent energy Producers Association

Pacific Power, Puget Sound Energy, Rocky Mountain Power, Portland General Electric

Public Utility District No.1 of Chelan County

Reliant Energy

Salt River Project

Sightline Institute (two comments)

Southern California Edison Company

Tucson Electric Power Company

WEST Associates

Western States Petroleum Association

Economic Analysis and Modeling Support to the Western Climate Initiative

ENERGY 2020 Model Inputs and Assumptions

April 8, 2008
(revision date)

Prepared for:
Western Governor's Association

ICF INTERNATIONAL

Prepared By:
ICF Consulting Canada, Inc.
277 Wellington St. W.
Suite 808
Toronto, ON M5V 3E4

Contact:
Glen Wood
T: (416) 341-8952
F: (416) 341-0383

PLEASE NOTE:

This report outlines the assumptions and data inputs used in developing a Reference Case for the Western Governor's Association, in support of the Western Climate Initiative.

The development of the Reference Case is on-going and as such this is a living document that will evolve as the model is reviewed and refined.

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Acronyms & Definitions

AEO	Annual Energy Outlook (published by EIA)
ARB	California Air Resources Board
BPA	Bonneville Power Administration
Btu	British Thermal Units
CAC	Criteria Air Contaminants (SOx, NOx, PM, etc.)
CFL	Compact Fluorescent Light bulb
CHP	Combined Heat and Power
CO_2e	Carbon Dioxide equivalent
GDP	Gross Domestic Product
GO	Gross Output
GWP	Global Warming Potential
DG	Distributed Generation
EIA	Energy Information Administration
EPACT	Energy Policy Act of 2005
ESCO	Energy Service Company
GHG	Greenhouse Gas
IECC	International Energy Conservation Code
IGCC	Integrated Gasification Combined Cycle
kW	Kilowatt
kWh	Kilowatt-hour
Mt	Mega tonne
MW	Megawatt
MWe	Megawatt electric
MTCE	Megatonnes Carbon Equivalent (also as Mt CO_2e)
NOx	Nitrogen Oxides
OGCC	Oil/Gas Combined Cycle Turbine
OGCT	Oil/Gas Combustion Turbine
OGST	Oil/Gas Steam Turbine
PC	Pulverized Coal
REMI	Regional Economic Models, Inc.
RECS	Renewable Energy Certificates
Rest of US	Balance of systems in US
SOx	Sulphur Oxides (including sulphur dioxide)
USEPA	United States Environmental Protection Agency
W	Watt
WCI	Western Climate Initiative

1 Background and Project Scope

The Western Climate Initiative (WCI) has retained ICF International and its partner Systematic Solutions Inc., to assist in modeling a cap-and-trade system for the western US and Canada. The Scope of Work for the modeling is posted on the WCI website.[1] The WCI envisions a trading program that may ultimately link with other similarly rigorous programs.

The ICF Team has offered a suite of models that represent the state-of-the-art to support the WCI in this plan; starting with ENERGY 2020. This report outlines the assumptions and data inputs used in developing the Reference Case which will be used as a reference point and a base for evaluating proposed policy changes.

This report is organized as follows. Section 2 describes the analytic approach used by ENERGY 2020 and the characteristics of the model. Section 3 describes the model inputs. A more detailed explanation of the ENERGY 2020 model is included as Appendix A.

2 Analytic Approach

This project uses ENERGY 2020 to model the likely business-as-usual outlook and the impact of potential GHG reduction policies for the states and province partners in the WCI[2] as well as surrounding states and provinces.

ENERGY 2020 is an integrated multi-region energy model that provides complete and detailed, all-fuel demand and supply sector simulations. The model can be used in regulated as well as deregulated and transitioning environments. Greenhouse Gas (GHG) and Criteria Air Contaminant (CAC) pollution emissions and costs, including allowances and trading, are endogenously determined, thereby allowing assessment of environmental risk and co-benefit impacts.

The basic implementation of ENERGY 2020 for North America contains a user-defined level of aggregation down to the 10 provincial and 50 state (and sub-

[1] See http://www.westernclimateinitiative.org/ewebeditpro/items/O104F16124.pdf

[2] Arizona, California, Montana, New Mexico, Oregon, Utah, Washington, British Columbia and Manitoba.

state) level. ENERGY 2020 contains historical information on all electric generating units in the US and Canada (data for Mexico can be incorporated as needed). ENERGY 2020 is parameterized with local data for each region/state/province as well as all the associated energy suppliers it simulates. Thus, it captures the unique characteristics (physical, institutional and cultural) that affect how people make choices and use energy. Collections of state and provincial models are currently validated from 1986 to the latest quarterly numbers.[3]

ENERGY 2020 can be linked to a detailed macroeconomic model to determine the economic impacts of energy/environmental policy and the energy and environmental impacts of national economic policy. For US regional and state level analyses, the REMI macroeconomic model is regularly linked to ENERGY 2020.[4] The Informetrica macroeconomic model is linked to ENERGY 2020 for Canadian national and provincial efforts.[5] The REMI and Informetrica macroeconomic models include inter-state/provincial, US and world trade flows, price and investment dynamics, and simulate the real-time impact of energy and environmental concerns on the economy and vice versa.

The structure of the model is well tested and has been used to simulate not only US and Canadian energy and environmental dynamics, but also those of several countries in South America, Western, Central, and Eastern Europe. These efforts include strategic and tactical analyses for both planning and energy industry restructuring/deregulation. In the 1990's, the US EPA made ENERGY 2020 available to interested states to analyze emissions, energy, and economic impacts of state-level climate change initiatives Further, the model has been used successfully for deregulation analyses in all the US states and Canadian provinces. Many US and Canadian energy suppliers use the model for the analysis of combined electricity and gas deregulation dynamics.[6]

The default model simulates demand by three residential categories (single family, multi-family, and agriculture/rural), over 40 NAICS commercial and industrial categories, and three transportation services (passenger, freight, and off-road). There are approximately six end-uses per category and six

[3] Energy supplier data comes from FERC and US DOE for the US and Statistics Canada. US and Canadian fuel and demand data come from the US Department of Energy and Natural Resources Canada, respectively. US and Canadian pollution data come from US EPA and Environment Canada, respectively.

[4] Regional Economic Models, Inc. www.remi.com

[5] Informetrica Limited www.informetrica.ca

[6] ENERGY 2020 is the only model known to have simulated and predicted the dynamics that occurred in the UK electric deregulation. These include gaming, market consolidation and re-regulation dynamics.

technology/mode families per end-use.[7] Currently the technology families correspond to six fuels groups (oil, gas, coal, electric, solar and biomass) and 30 detailed fuel products. The transportation sector contain 45 modes including various types of automobile, truck, off-road, bus, train, plane, marine and alternative-fuel vehicles. More end-uses, technologies, and modes can be added as data allow. For all end-uses and fuels, the model is parameterized based on historical, locale-specific data. The load duration curves are dynamically built up from the individual end-uses to capture changing conditions under consumer choice and combined gas/electric programs.

Each energy demand sector includes cogeneration, self-generation, and distributed generation simulation, including mobile-generation, micro-turbines, and fuel-cells. Fuel-switching responses are rigorously determined. The technology families (which can be split, as an option, to portray specific technology dynamics) are aggregates that, within the model, change building shell, economic-process and device efficiency and capital costs as price or other information that the decision makers see, change. ENERGY 2020 utilizes the historical and forecast data developed for each technology family to parameterize and disaggregate the model.

The supply portion of the model includes endogenous detailed electric supply simulation of capacity expansion/construction, rates/prices, load shape variation due to weather, and changes in regulation.[8] The model dispatches plants according to the specified rules whether they are optimal or heuristic and simulates transmission constraints when determining dispatch.[9] A sophisticated dispatch routine selects critical hours along seasonal load duration curves as a way to provide a quick but accurate determination of system generation. Peak and base hydro usage is explicitly modeled to capture hydro-plant impacts on the electric system.

[7] End-uses include Process Heat, Space Heating, Water Heating, Other Substitutable, Refrigeration, Lighting, Air Conditioning, Motors, and Other Non-Substitutable (Miscellaneous). Detailed modes include: small auto, large auto, light truck, medium-weight truck, heavy-weight truck, bus, freight train, commuter train, airplane, and marine. Each mode type can be characterized by gasoline, diesel, electric, ethanol, NG, propane, fuel-cell, or hybrid vehicles.

[8] ENERGY 2020 includes a complete, but aggregate representation of the electric transmission system. Electric transmission data is provided by FERC, the Department of Energy, and the National Electric Reliability Council. The dispatch technologies in the basic model include: Oil/Gas Combustion turbine, Oil/Gas Combined Cycle, Oil/Gas Combined Cycle with CCS, Oil/Gas Steam Turbine, Coal Steam Turbine, Advanced Coal, Coal with CCS, Nuclear, Baseload Hydro, Peaking Hydro, Small Hydro, Wind, Solar, Wave, Geothermal, Fuel-cells, Flow-Battery Storage, Pumped Hydro, Biomass, Landfill Gas, Trash, and Biogas.

[9] A 110 node transmission system is used in the default model, but a full AC load-flow bus representation model has also been interfaced with ENERGY 2020.

ENERGY 2020 supply sectors include electricity, oil, natural gas, refined petroleum products, ethanol, land-fill gas, and coal supply. Energy used in primary production and emissions associated with primary production and its distribution is included in the model. The supply sectors included in a particular implementation of ENERGY 2020 will depend on the characteristics of the area being simulated and the problem being addressed. If the full supply sector is not needed, then a simplified simulation determines delivered-product prices.

The ENERGY 2020 model includes pollution accounting for both combustion (by fuel, end-use, and sector) and non-combustion, and non-energy (by economic activity) for SO_2, NO_2, N_2O, CO, CO_2, CH_4, PM_T, $PM_{2.5}$, PM_5, PM_{10}, VOC, CF_4, C_2F_6, SF_6, and HFC at the state and provincial level by economic sector. Other (gaseous, liquid, and solid) pollutants can be added as desired. Pollution does not need to be determined directly by coefficients but can recognize the accumulation of capital investments that result in pollution emission with usage. National and international allowance trading is also included. Plant dispatch can consider emission restrictions.

The model captures the feedback among energy consumers, energy suppliers, and the economy using Qualitative Choice Theory and co-integration.[10] For example, a change in price affects demand that then affects future supply and price. Increased economic activity increases demand; increased demand increases the investment in new supplies. The new investment affects the economy and energy prices. The energy prices also affect the economy.

Finally, the system includes confidence and validity testing software that places uncertainty bounds on simulation results, quantifies confidence intervals, and ranks the contributions to uncertainty in future conditions. This feature can be used to limit data efforts to information most important to the analysis.

In order to assess the potential impacts of proposed policy options, a b*usiness-as-usual* scenario is developed as a point of reference. This "Reference Case" represents a scenario that is viewed as a reasonable expectation of how the economy, energy use and emissions might develop over time.

Part of the nature of developing a Reference Case is the need to address inherently uncertain issues that can have significant impacts on future energy use and emissions. No forecast is going to be "right" or "accurate" in that no one

[10] The model has used the work of Daniel McFadden and Clive Granger since its inception in the late 1970's.

can tell today how some of the key underlying issues may develop. Given the level of uncertainty involved in any projection of a possible future, caution should be used in applying a high level of precision to the modeling results. Understanding the Reference Case, however, is useful for providing an underlying structure against which to model proposed policies, and in determining directionality and cause and effect.

Numerous assumptions are required to perform an analysis of this type across a range of topic areas, including economic developments, fuel and electric markets, and regulatory structures. Projected outcomes are only as good as the input assumptions upon which they are based, with more rigorous assumptions leading to a more rigorous analysis. The inputs and assumptions described in this document were developed to provide an initial representation of the activities and structures underlying energy use and greenhouse gas emissions in the WCI region. These inputs and assumptions will be updated as the project progresses.

3 Reference Case Inputs

ENERGY 2020 derives energy demands, such as the demand for electricity based on economic activity and device efficiency. The following sections provide a brief overview of the data inputs and assumptions as well as the sources of data used in the Reference Case.

As a multi-sector analytical tool, ENERGY 2020 requires data and assumptions covering a broad range of economic sectors and their interactions. In most cases, the necessary data – both historical and projected – is available from the federal government (EIA, EPA, etc.). In past analyses, ENERGY 2020 has relied heavily on these federal sources to populate and calibrate the model. In developing the model used for the WCI partners a considerable amount of state-specific information is being developed and will be used where possible.

The following sections provide an overview of the data and assumptions that will be required to perform the multi-sector analysis, and list the data sources that have been used to populate ENERGY 2020 to this point. It is expected that this data will change as the model is reviewed and evolves to incorporate more detailed data specific to the WCI region.

Data[11] inputs for ENERGY 2020 will be required in five areas:

1. Population and economic
2. Fuel prices
3. Energy use and consumption
4. Emissions and air regulations
5. Electricity generation capacity and operation

The sections below list the key data elements required in each of these areas, along with the sources that have been used to supply this data for other analyses. Appendix B lists a number of default data sources used by the model. The sections that follow provide a more specific description of the data used for this project including state-specific data used in place of national sources.

ENERGY2020 requires both historical data and projections to calibrate and generate forward-looking projections. Historical data will be required from a base year (1985) to the last historic year (2005). Projections for the period to be

[11] "Data" here refers to both historical data and assumptions and projections of future inputs.

modeled (e.g. through 2030) will be gathered where possible to provide points of comparison and check the reasonableness of the projection.

The implementation of ENERGY 2020 for the WCI project includes the geographic areas of Arizona, California, Montana, New Mexico, Oregon, Utah, Washington, British Columbia and Manitoba. Interactions between these states and provinces are modeled, particularly with respect to electricity generation. To ensure consistency the assumptions used within the WCI region are applied to other states to the extent possible.

3.1 *Population and Economic Data*

Demographic and economic data is required to generate demands for services. The historic data for the US states was obtained from the US Bureau of Economic Analysis (BEA). For the Canadian provinces, historic data is from Statistics Canada's CANSIM database while the forecast is provided by Informetrica. Default economic forecasts for US states are being developed.

The following data sources are currently being used in the model:

Description of Data/Input	Sources Used/Available
Total population, historical and growth over time	US Census Bureau Statistics Canada/Informetrica
Population by housing type (single-family, multi-family, etc.)	US Census Bureau Statistics Canada/Informetrica
Households by housing type (single-family, multi-family, etc.)	US Census Bureau Statistics Canada/Informetrica
Personal income	US Bureau of Economic Analysis EDRAM for California Statistics Canada/Informetrica
Employment by sector	US Bureau of Economic Analysis Statistics Canada/Informetrica

Summary information for each WCI partner will be provided for review as the project proceeds.

3.2 *Price data*

Energy prices can play a significant role in end user decisions on equipment, capital and operating decisions. Fuel costs can be critical in determining the costs of electric dispatch, as well as input costs of some industrial processes and home heating. ENERGY2020 calculates future electric prices based in part on these fuel costs.

Energy prices are largely determined by international markets, although domestic demand, such as electric sector demand for natural gas can influence prices. As a result, fuel prices are treated by the model as an exogenous input.

The default energy price forecast for the US is based on the Energy Information Administration's Annual Energy Outlook Reference Case forecast for 2007 to 2030. For Canada, the National Energy Board's price forecast is used.

Biomass prices in the model are based on research completed for a previous project, shown in the table below. Unlike other fuels, biomass prices are significantly influenced by local cost and supply issues.

Biomass Cost *(per MMBtu in 2006$)*	
Residential	$11.53
Commercial	$10.09
Industrial	$10.06

- Power prices are calculated endogenously by the model based on generation costs and dispatch. While, the model calculates retail electricity prices, actual consumer prices may differ as a result of political, regulatory or market influences. The model can be calibrated to actual prices, within reasonable parameters, for the historic period.
- Given the limited time available the project is not intended to model the different regulatory regimes among the partner jurisdictions to reflect actual retail prices delivered in each market. The intent of the modeling is rather to show relative changes in electricity prices as a result of the proposed policies.

3.3 *Historic Energy Consumption Data*

ENERGY 2020 models energy use at the end-use level within each economic sector based on the existing physical stock and the efficiency of that stock. The database of device efficiencies reflects both the average efficiency of energy use for current stocks and the efficiency/energy alternatives available to consumers at the margin. Technology and efficiency choices are modeled based on past experience with consumer choice rather than on a purely economic evaluation.

Historic energy use and consumption data used in the model is derived from the federal Energy Information Administration (EIA) State Energy Data (SEDS) database. Where state-specific data was available, this data was used to replace national data sources.

Default sectoral and end-use data as well as energy intensities are based on the Residential Energy Consumption Survey (RECS), Commercial Energy Consumption Survey (CECS) and Manufacturers Consumption Energy Survey (MECS).

Description of Data/Input	Sources Used/Available
Residential Data - Household income by housing type - No. of people per household - End-use consumption data, including fuels used for space and water heating, air conditioning, etc.	2001 EIA Residential Energy Consumption Survey (RECS), by Census Region and Division (2005 RECS in process) http://www.eia.doe.gov/emeu/recs/contents.html For Canada – NRCan OEE Database
Commercial Data - Floor area by sub-sector - End-use consumption data, including fuels used for space and water heating and energy intensities	2003 EIA Commercial Buildings Energy Consumption Survey (CBECS), by Census Region and Division (2007 CBECS underway) http://www.eia.doe.gov/emeu/cbecs/contents.html For Canada – NRCan OEE Database
Industrial/Manufacturing Data - Energy use by fuel for each sub-sector and end-use	2002 EIA Manufacturing Energy Consumption Survey (MECS), by Census Region (2006 MECS underway) http://www.eia.doe.gov/emeu/mecs/contents.html For Canada – NRCan OEE Database
State/Provincial Energy Data: - Energy consumption and expenditures by sector and energy source	2004 EIA State Energy Data System (SEDS) http://www.eia.doe.gov/emeu/states/_seds.html For Canada – NRCan OEE Database and CANSIM

Household data for the WCI region was gathered from the US Census Bureau supplemented by data from the EIA's State data on Prices and Expenditures.

3.4 *Historic Emission Data*

3.4.1 Emissions and Air Regulations

Historic GHG emissions are based on the Canadian national inventory published by Environment Canada and the US GHG emissions inventory as published by the EPA[12]. More specific state and provincial inventories will be sought from WCI partners. ENERGY 2020 is calibrated using historic information on all of the major greenhouse gas emissions including:

- Carbon dioxide (CO_2),
- Nitrous oxide (N_2O),
- Methane (CH_4),
- Sulphur hexafluoride (SF_6),
- Hydrofluorocarbons (HFCs) and
- Perfluorocarbons (PFCs).

GHG emissions are presented in CO_2 equivalent (CO_2e) terms. The global warming potentials used to convert the different greenhouse gas emissions into CO_2e terms are provided in Appendix I.

Input	Sources Used/Available
Emissions by sector, end-use, fuel and GHG	US EPA http://www.epa.gov/climatechange/emissions/usinventoryreport.html Environment Canada http://www.ec.gc.ca/pdb/ghg/inventory_e.cfm

3.4.2 Emission Factors

Emission factors for most fuels are based on values used by ICF in developing national and state inventories. For the transportation sector however, the emission factors for CH_4 and N_20 pollutants were adapted from the Canadian National Inventory Report.[13] ENERGY 2020 calculates GHG emissions at the point of combustion for most fuels. Upstream emissions from extraction and processing are captured as part of those respective economic sectors.

[12] EPA website: http://www.epa.gov/climatechange/emissions/usinventoryreport.html

[13] Environment Canada. National Inventory Report 1990-2005, Greenhouse Gas Sources and Sinks in Canada, April 2007. (Annex 12 Emission Factors)

Emissions associated with the use of biomass as a fuel are deemed to be biogenic and therefore not contribute to global warming. As a result, the model assumes no GHG emissions are created from the use of biomass.

Emissions from ethanol and other biofuels represent an exception from a modeling perspective. In order to capture the emissions associated with their production and distribution, the model applies full cycle emission factors for these fuels. While the combustion of ethanol and biodiesel are not deemed to result in any anthropogenic emissions, the model uses an emission factor to recognize upstream emissions.

The full-cycle emission factor used in the model for each biofuels type are shown in the table below[14]:

Corn Ethanol	76 gCO2-e / MJ
Cellulosic Ethanol	14 gCO2-e / MJ
Biodiesel	30 gCO2-e / MJ

When these fuels are used in combination with other fuels, for example in a mix of gasoline and ethanol, the emissions associated with gasoline combustion are reported as part of total gasoline-related emissions.

3.5 *Electricity Sector Data*

3.5.1 Generation Data

The electricity sector differs from other sectors in the extent to which emissions associated with power use within the state may result from emissions outside the WCI as power is imported from or exported to other areas.

ENERGY 2020 contains information on every generating unit in the state or province, as well as in neighboring jurisdictions which may supply power to the state. The model tracks and uses the following information for each generating unit:

[14] Alexander Farrell, UC Berkeley and Daniel Sperling, UC Davis, A Low-Carbon Fuel Standard for California Part 1: Technical Analysis May 29, 2007 Table 2-3 http://www.energy.ca.gov/low_carbon_fuel_standard/UC-1000-2007-002-PT1.PDF

- Historic Peak Capacity (MW);
- Historic generation levels (GWh);
- Type of fuel used;
- Heat rate;
- Historic annual fuel use (PJ);
- Emissions by pollutant type;
- O&M costs;
- Capacity factors;
- Emission rates;
- Outage rates;
- State or Province;
- Physical location (latitude and longitude);
- Ownership information;
- Plant type (Hydraulic, Coal, Combined Cycle Turbine, etc.)

The data on existing and committed generating units in the US was obtained from the National Electric Energy Data System (NEEDS) 2006 database and reconciled with a list of plants from BPA. The database of plants in Canada was developed based on the Canadian IPM module, modified and updated based on information from Statistics Canada, Environment Canada and the National Energy Board.

3.5.2 Electricity Generation Capacity and Operation Data

ENERGY 2020 will be populated with data describing the type, operation and performance of every generating unit in the western US and the two Canadian provinces. In order to improve model performance, some smaller units with common characteristics may be combined (i.e., wind units at the same site, or small hydraulic units). In addition to plant-level data, the table below includes other inputs necessary to describe the electric system, including transmission capability.

Input	Sources Used/Available
Plant type	FERC reports for US Statistics Canada for Canada
Plant capacity	FERC reports for US Statistics Canada for Canada
Plant historical generation	FERC reports for US Statistics Canada for Canada Total generation output by plant type for California from CEC

Input	Sources Used/Available
Plant fuel type	FERC reports for US Statistics Canada for Canada
Plant Heat Rate	FERC reports for US Statistics Canada for Canada
Plant fuel consumption	FERC reports for US Statistics Canada for Canada
Plant emissions by pollutant	EPA or Environment Canada
Plant costs (operation and maintenance, variable and fixed)	FERC reports for US Statistics Canada for Canada
Plant historical capacity factor	FERC reports for US Statistics Canada for Canada
Plant availability (outages)	FERC reports for US Statistics Canada for Canada
Plant owner and location	FERC reports for US Statistics Canada for Canada
Planned capacity additions and retirements	California Public Utility Commission GHG Modeling process (E3)
Transmission Capability	NERC

This data has been compared to generation data provided as part of modeling for the California Public Utilities Commission.[15]

The resulting list of generating units was matched to emission data from the EPA in order to calculate emission rates. The resulting emission rates for the targeted GHG emissions were then reviewed for reasonableness based on plant type and capacity factors, etc.

Historic generation by plant type will be calibrated with historic generation data available from the EIA.

3.5.3 Transmission Structure and Dispatch

Power flows between neighboring US states are modeled within ENERGY 2020 based on existing transmission capabilities and interconnections as obtained from NERC reports. Appendix C describes the inter-regional transmission capabilities between model regions (or nodes) as well as the maximum capacity limit of each transmission path used in the model. Interconnection capacities

[15] www.ethree.com/cpuc_ghg_model.html

used in the model were based on the IPM Model 2006[16] updated to reflect changes in the region based on past work for past clients.

Generation is dispatched at the node level for a set of sample hours in each season. Each node is economically dispatched, selecting lowest cost generation first with the resulting clearing price determining the generation price for that node as described in Appendix A. As part of the calculation the model can utilize resources from a neighboring node within the constraints of the transfer capacity between nodes. The transfer of energy between nodes is subject to a 1% loss to represent additional transmission losses.

3.5.4 Planned Capacity Changes

As part of the modeling process, ENERGY 2020 builds new capacity endogenously as needed to meet capacity and reserve requirements. At any given time, however, plans may already be in place to build, re-furbish, upgrade or retire generation facilities. These plans must be incorporated into the model in order to reflect decisions and commitments that have already been made. Of necessity, some decisions had to be made on which planned projects and which scheduled plant retirements to incorporate in the model based on best judgment. As part of the process of developing the Reference Case, WCI partners will be asked to provide information on known new capacity commitments and planned retirements in their respective jurisdictions.

ENERGY 2020 can determine the need for new generation based on a pre-determined reserve requirement. Normally, this determination is based on the highest level of demand for power and the available capacity at the time of that peak. Some types of generation, such as wind or some types of hydro-electric generation however, may not be available at the time of the peak. For modeling purposes the model assumes that only 15% of installed wind capacity is available at the time of the peak.

[16] Table 3.5 of section 3 of the documentation for the EPA Base Case 2006 (v3.0) posted on the EPA website: http://epa.gov/airmarkets/progsregs/epa-ipm/index.html#docs

3.5.5 New Generation Characteristics

The costs and characteristics of new generation are based on information developed as part of the GHG modeling process for the California Public Utility Commission[17] and are shown in Appendix F.

3.5.6 Industrial Generation and Co-generation

ENERGY 2020 models both utility generation, which supplies the power grid, and industrial generation which supplies a particular end user. Industrial generation is defined as power generation that is within the industrial end user's facility and is not used to supply power to the grid. Industrial generation, as defined in ENERGY 2020, could also be referred to as self-generation or load displacement generation. Industrial generation may be supplied by any of the fuels listed below:

- Biomass
- Coal
- LPG
- Oil
- Solar
- Steam

Co-generation, or combined heat and power facilities, simultaneously generate electricity and supply a heat load. ENERGY 2020 recognizes that co-generation may occur either as industrial generation or as utility generation and may use any of a number of fuels.

- Within the power sector, these plants are treated as 'must run' units, meaning that they will always operate when available. Power from these units contributes to overall electricity supply. Heat from these units may be captured as part of a separate steam supply system, however, limited data is available regarding overall US steam demand.
- Within the industrial sector, co-generation capacity will run based on heating requirements. Heat produced from co-generation is used to meet industrial heat requirements based on a co-generation heat rate. Co-generated electricity is used to meet industrial power requirements, reducing net demand from the grid.

[17] www.ethree.com/cpuc_ghg_model.html.

Where the heat contribution of co-generation is significant, the preferred modeling approach is to include these units in the industrial sector.

The databases used to represent electricity generation often include all significant generators, including both utility and industrial boilers and generators. By contrast, reported electricity consumption information tends to be based on metered electricity sales, and as such are net of self generation. Total electricity consumption and generation will generally be slightly higher than reported electricity sales. It is therefore important in calibrating the model with historic electricity consumption that existing generation used as industrial or self-generation be appropriately identified.

3.6 *Transportation*

ENERGY 2020 models passenger, freight and off road transportation separately, based on different underlying drivers. Passenger and freight transportation are modeled by mode and vehicle type. Changes in transportation demand, in terms of passenger miles traveled and ton-miles of freight, are calibrated for the historic period.

The bulk of existing and forecast passenger transportation is attributable to personal vehicles. The model does not currently assume any changes in the CAFÉ Standard, however, this will be modified as the requirements of *Energy Independence and Security Act of 2007* are incorporated into the model (see section 4.8).

Off road transportation energy use is modeled in ENERGY 2020 based on drivers including Agriculture, Forestry and Construction activity.

3.7 *Built Environment*

Several of the jurisdictions involved in the WCI have had a long history of promoting energy efficiency and demand side management for electricity and natural gas energy use. As a result, average appliance and equipment efficiencies are expected to be higher than for the US and Canada as a whole. As part of Tasks 4 and 5 we will attempt to gather information on current levels of equipment efficiency and the state of the market for efficiency technologies. This information will then be used to adjust end-use data within the model to reflect current levels of efficiency and market saturations.

The Reference Case does not assume any increase in equipment or appliance efficiency other than the improvements due to the *Energy Independence and Security Act of 2007*, as noted in section 4.8.

3.8 *Programs/Policies Incorporated in Reference Case*

As this assumptions document is further refined and developed, a table listing the specific laws and regulations included in the Reference Case will be inserted here.

Of particular importance, the *Energy Independence and Security Act of 2007* was passed into law in early January 2008. The following assumptions will be used to model the Act in the Reference Case:

- Transportation: The current marginal vehicle efficiency for passenger cars and light trucks will be incrementally increased by a fixed percentage each year starting in 2011 to reach the mandated fleet efficiency in 2020.
- Renewable Fuels: The model will assume that each of the US states will continue to use the same relative volume of the renewable fuels produced nationally (as per the schedules outlined in the Act) as are currently consumed in the state.
- Residential Boilers and Furnace Fans: Savings estimates developed by the ACEEE for each state will be used to model this portion of the Act, using only the benefits realized by upgrades to the residential energy boilers, leaving out any energy benefits associated with reduced electricity consumption by furnace fans.
- Walk-In Coolers and Walk-In Freezers: Savings estimates developed by the ACEEE for each state will be used to model this portion of the Act.
- Electric Motor Efficiency Standards: The model will utilize the ACEEE savings projections, pro-rated to California's relative industrial electricity sales.
- External Power Supply Efficiency Standard: savings estimates developed by the ACEEE for each state will be used to model this portion of the Act.
- Energy Efficient Light Bulbs: Information will be collected on existing market shares for efficient lighting in the WCI region in order to estimate the impact of this aspect of the Act. The base assumptions are that

general service lighting accounts for about 90% of residential lighting, 10% of commercial lighting and 5% of industrial lighting.

- Metal Halide Lamp Fixtures: The model assumes that 15% of commercial lighting and 60% of industrial lighting now use metal halide fixtures. For new installations the model assumes that 80% of this market would use pulse start ballasts.

The model will also include regulations affecting the power sector which have been approved but have not yet come into effect. Such regulations may be significant to the extent that they influence dispatch decisions which in turn will affect CO_2 emissions.

A listing of future legislation/regulation changes to be included in the modeling is currently being compiled and will be provided in subsequent versions of this report.

Appendix A: The Energy 2020 Model

The Model – ENERGY 2020

ENERGY 2020 is an integrated multi-region, multi-sector energy analysis system that simulates the supply, price and demand for all fuels. It is a causal and descriptive model, which dynamically describes the behavior of both energy suppliers and consumers for all fuels and for all end-uses. It simulates the physical and economic flows of energy users and suppliers. It simulates how they make decisions and how those decisions causally translate to energy-use and emissions.

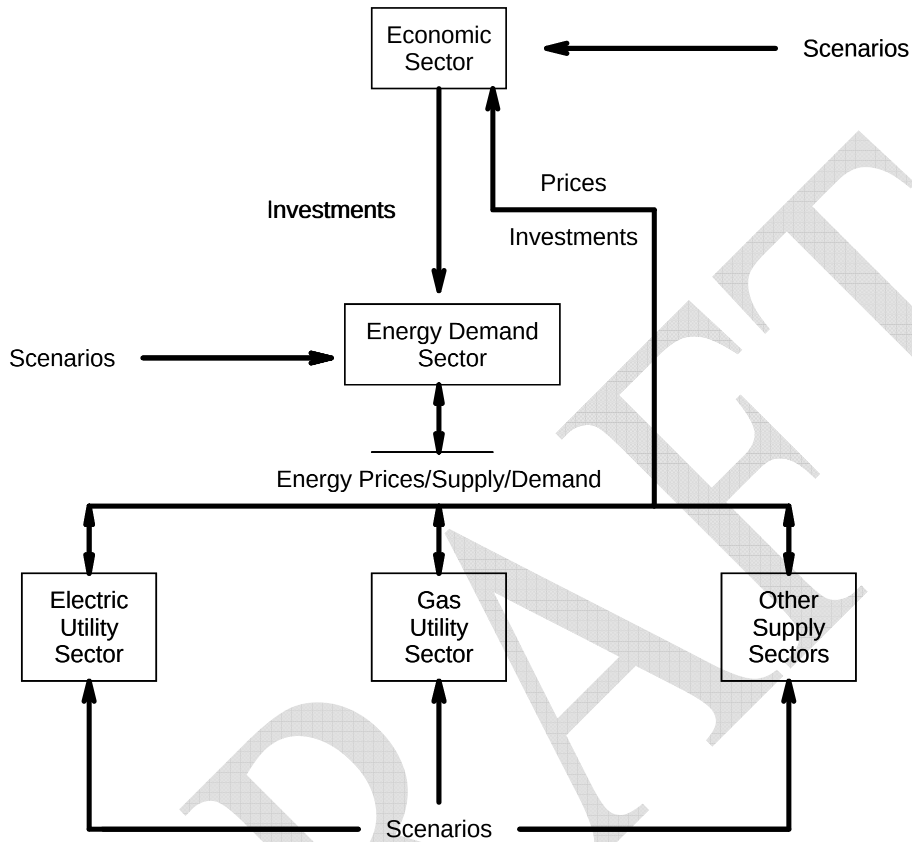
ENERGY 2020 is an outgrowth of the FOSSIL2/IDEAS model developed for the US Department of Energy (DOE) and used for all national energy policy since the Carter administration.[18] This early version of ENERGY 2020 was developed in 1978 at Dartmouth College for the DOE's Office of Policy Planning and Analysis.

Model Overview:

The basic structure of ENERGY 2020 is provided in Figure A-1. Energy Demand sector interacts with the Energy Supply sector to determine equilibrium levels of demand and energy prices. Energy Demand is driven by the Economy sector, which in turn provides inputs to the Economy sector in terms of investments in energy using equipment and processes and energy prices. The model has a simplified Economy sector to capture the linkages between the energy system and the macro-economy. However, the model is best run with full integration with a macroeconomic model such as REMI. Given the modular nature of ENERGY 2020, additional sectors or modules from other, non-ENERGY 2020 related, models (macroeconomic, supply such as oil, gas, renewables etc.) can be incorporated directly into the ENERGY 2020 framework.

[18] FOSSIL2 was the original version but was renamed to IDEAS a few years ago to reflect its evolutionary development since its original construction.

Figure A-1: ENERGY 2020 Overview



Energy Demand:

The demand sector of the model represents the geographic area by disaggregating the four economic sectors into subsectors based on energy services. As many or as few subsectors can be incorporated as required. Multiple technologies, multiple end-uses and multiple fuels are detailed. The level of detail that can be incorporated is of course subject to the data availability. The four economic sectors are:

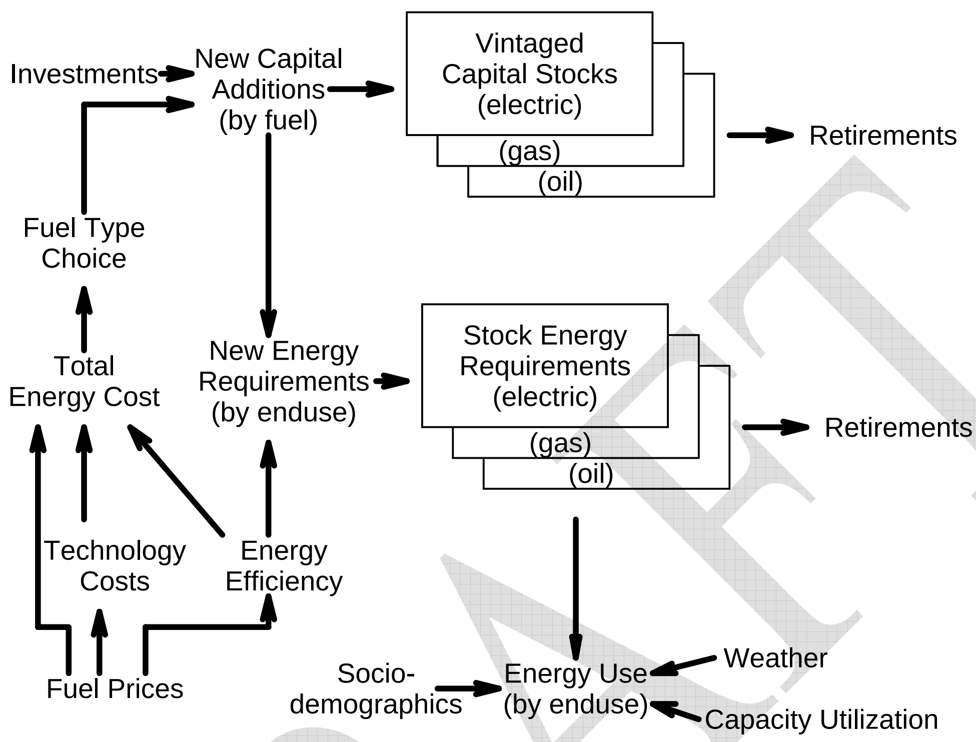
- Residential sector which includes three classes, single family, multifamily and rural/agricultural with 8 end-uses including space heating, water heating, lighting, cooling, refrigeration, other substitutable, and other non-substitutable.

- Commercial sector which is aggregated into one class and end-uses including space heating, water heating, cooling, lighting, other substitutable, other non-substitutable.
- Industrial sector which includes 10 (23 for US) 2-digit SIC categories and is further broken down into process heat, motors, lighting, miscellaneous as the end uses.
- Transportation sector which includes several modes of transportation including automobile, truck, bus, train, plane, marine and electric vehicles. Also, each of the residential, commercial and industrial sectors has separate transportation demands.

For each of the end-uses, up to six fuels are modeled, for example, the residential space heating has the choice of a gas, oil, coal, electric, solar and biomass space heating technologies. Added end-uses, technologies and modes can be added as data allow. For all end-uses and fuels, the model is parameterized based on historical locale-specific data. The load duration curves are dynamically built up from the individual end-uses to capture changing condition under consumer choice and combined gas/electric programs.

A few basic concepts are crucial to an understanding of how the model simulates the energy system. These concepts including, the capital stock driver, the modeling of energy efficiency through trade-off curves, the fuel market share calculation, utilization multipliers and the cogeneration module are discussed below in abbreviated form. Figure A-2 (Demand Overview) illustrates the demand sector interactions.

Figure A-2: Demand Overview



Energy Demand as a Function of Capital Stock:

The model assumes that energy demand is a consequence of using capital stock in the production of output. For example, the industrial sector produces goods in factories, which require energy for production; the commercial sector requires buildings to provide services; and the residential sector needs housing to provide sustained labor services. The occupants of these buildings require energy for heating, cooling, and electromechanical (appliance) uses.

The amount of energy used in any end-use is based on the concept of energy efficiencies. For example, the energy efficiency of a house along with the conversion efficiency of the furnace determines how much energy the house uses to provide the desired warmth. The energy efficiency of the house is called the capital stock energy or process efficiency. This efficiency is primarily technological (e.g. insulation levels) but can also be associated with control or life-style changes (e.g. less household energy use because both spouses work outside the home.) The furnace efficiency is called the device or thermal efficiency. Thermal efficiency is associated with air conditioning, electromotive devices, furnaces and appliances.

The model simulates investment in energy using capital (buildings and equipment) from installation to retirement through three age classes or vintages. This capital represents embodied energy requirements that will result in a specified energy demand as the capital is utilized, until it is retired or modified.

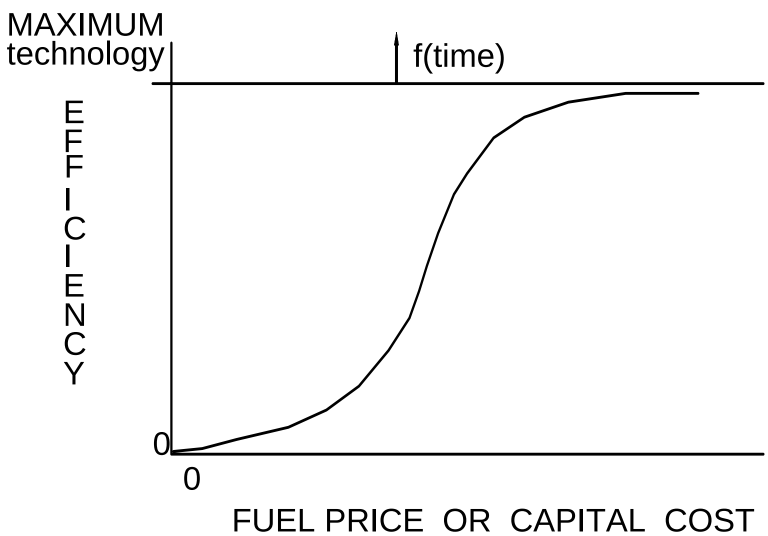
The size and efficiency of the capital stock, and hence energy demands, change over time as consumers make new investments and retire old equipment. Consumers determine which fuel and technology to use for new investments based on perceptions of cost and utility. Marginal trade-offs between changing fuel costs and efficiency determine the capital cost of the chosen technology. These trade-offs are dependent on perceived energy prices, capital costs, operating costs, risk, access to capital, regulations and other imperfect information.

The model formulates the energy demand equation causally. Rather than using price elasticities to determine how demand reacts to changes in price, the model explicitly identifies the multiple ways price changes influence the relative economics of alternative technologies and behaviors, which in turn determine consumers' demand. In this sense, price elasticities are outputs, not inputs, of the model. The model accurately recognizes that price responses vary over time, and depend upon factors such as the rate of investment, age and efficiency of the capital stock, and the relative prices of alternative technologies.

Device and Process Energy Efficiency:

The energy requirement embodied in the capital stock can be changed only by new investments, retirements, or by retrofitting. The efficiency with which the capital uses energy has a limit determined by technological or physical constraints. The trade-off between efficiency and other factors (such as capital costs) is depicted in Figure A-3 (Efficiency/Capital Cost Trade-Off). The efficiency of the new capital purchased depends on the consumer's perception of this trade-off. For example, as fuel prices increase, the efficiency consumers choose for a new furnace is increased despite higher capital costs. The amount of the increase in efficiency depends on the perceived price increase and its relevance to the consumer's cash flow.

Figure A-3: Efficiency/Capital Cost Trade-Off



The standard the model efficiency trade-off curves are called consumer-preference curves because they are estimated using cross-sectional (historical) data showing the decisions consumers made based on their perception of a choice's value. Many planners are now interested in measure-by-measure or least-cost curves which use engineering calculations and discount rates to show how consumers should respond to changing energy prices. Another analysis focuses on the technical/price differences in alternative technologies and the incentives needed to increase the market-share or market penetration of a specific technology. This perspective on the choice process uses market share curves. The model allows the user to select any of these three types of curves to represent the way consumers make their choices. Shared savings, rebate, subsidy programs, etc. can be tested using any of the curves.

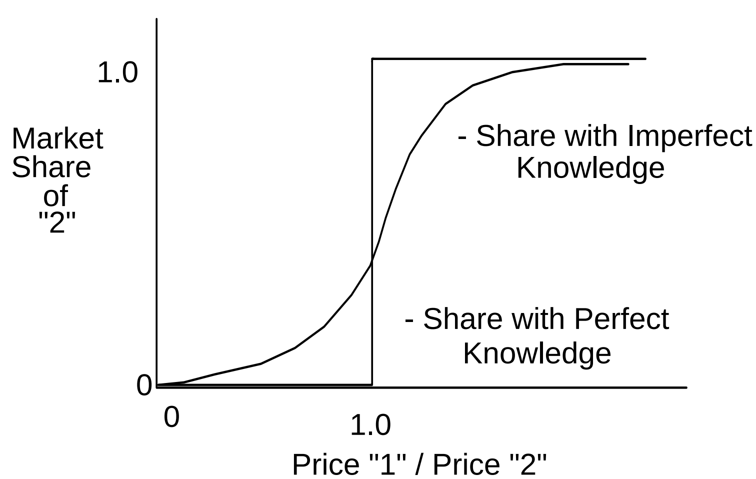
Cumulative investments determine the average "embodied" efficiency. The efficiency of new investments versus the average efficiency of existing equipment is one measure of the gap between realized and potential conservation savings.

The model uses saturation rates for devices to represent the amount of energy services necessary to produce a given level of output. Saturation rates may change over time to reflect changes in standard of living or technological improvements. For example, air conditioning has historically increased with rising disposable incomes. These rates can be specified exogenously or can be defined in relation to other variables within the model (such as disposable income).

The Market Share Calculation:

Not all investment funds are allocated to the least expensive energy option. Uncertainty, regional variations, and limited knowledge make the perceived price a distribution. The investments allocated to any technology are then proportional to the fraction of times one technology is perceived as less expensive (has a higher perceived value) than all others. This process is shown graphically in Figure A-4 (Market Share Dynamics).

Figure A-4: Market Share Dynamics



Short Term Budget Responses:

A short-term, temporary response to budget constraints is included in the model. Customers reduce usage of energy if they notice a significant increase in their energy bills. The customers' budgets are limited and energy use must be reduced to keep expenditures within those limits. These cutbacks are temporary behavioral reactions to changes in price, and will phase out as budgets adjust and efficiency improvements (true conservation) are implemented. This causes the initial response to changing prices to be more exaggerated than the long-term response, a phenomenon called "take-back" in studies of consumer behavior.

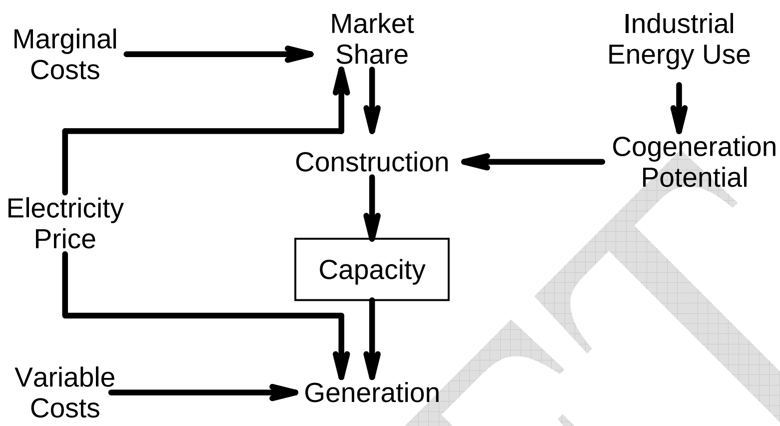
Accounting for Fungible Demand:

Some furnaces and processes can use multiple fuels. That is, they can switch almost instantaneously between, for example, gas and oil or coal and biomass as prices or the market dictates. Energy demand that is affected by this short-term fuel switching phenomena is called fungible demand. The model explicitly simulates this market share behavior.

Modeling Cogeneration:

Most energy users meet their electricity requirements through purchases from a utility. Some users (industrial and commercial) can, however, convert some of their own waste heat into usable electricity when economics warrant such action. Other users (residential and commercial) can purchase self-generation energy sources such as gas turbines, diesel-generators or fuel cells. Figure A-5 shows a simplified overview of the cogeneration structure.

Figure A-5: Cogeneration Concepts



In the model all energy used for heating is a candidate for cogeneration. The cost of cogeneration is the fixed capital cost of the investment plus the variable fuel costs (net of efficiency gains). This cogeneration cost is estimated for all technologies and compared to the price of electricity. The marginal market share for each cogeneration technology is based on this comparison.

Cogeneration is restricted to consumers who directly produce part of their own electricity requirement. Companies which generate power primarily for resale to the electric utility, are considered independent power producers and are model in the electric supply model.

Energy Supply:

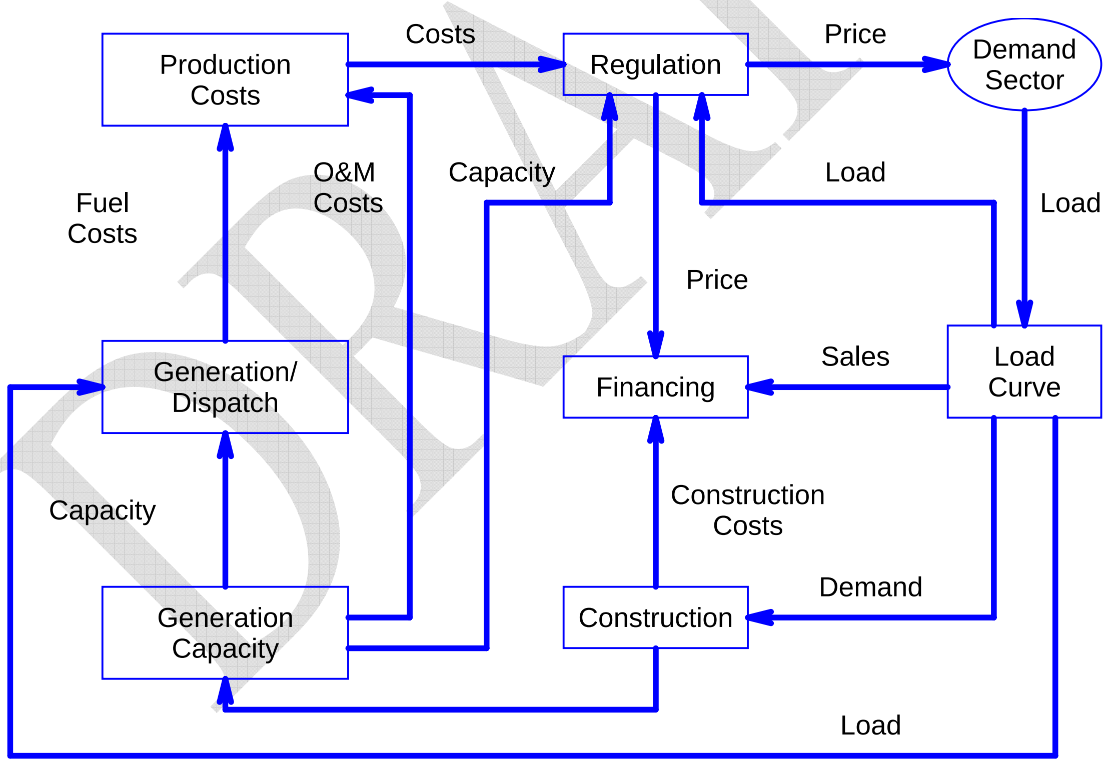
For electric and gas utilities (separate or combined), ENERGY 2020 internally and self-consistently simulates sales, load (by end-use, time-of-use, and class), production (across thirty-six dispatch types), demand-side management (by technology), forecasting, capacity expansion (new generation, independent power producers, purchases, and DSM), all important financial variables, and rates (by class, end-use, and time-of-use.)

The version currently used in this analysis only has the electricity utility sector (a full fledged natural gas utility sector for Canada is currently unavailable in the model, only a simplified natural gas supply function is used to calculate the supply price response).

With the inclusion of the electric utility sector, the generic supply model turns over the calculation of electricity prices to that sector. The model endogenously simulates the forecasting of capacity needs, as well as the planning, construction, operation and retirement of generating plants and transmission facilities. Each step is financed in the model by revenues, debt, and the sale of stock. The simulated utility, like its real world counterpart, pays taxes and generates a complete set of accounting books. In ENERGY 2020, the regulatory function is modeled as a part of the utility sector. The regulator sets the allowed rate of return, divides revenue responsibility among customer classes, approves rate base, revenues and expenses, and sets fuel adjustment charges.

The interactions in the electric utility sector are summarized in Figure A-6

Figure A-6: Electric Utility Structure Overview



Expansion Planning:

The utility sector endogenously forecasts future demand for electricity. From the forecast it projects the future capacity required meeting future demand by taking into account retirements and plants already under construction. If future electricity requirements, including reserves, are forecasted to exceed available capacity (using seasonal ratings), then construction of additional capacity is initiated. The model can also make a decision to build new capacity on an economic basis where that is appropriate. .

If additional capacity is needed to meet forecasted needs, the basic capacity expansion module in ENERGY 2020 determines whether base or peaking capacity is required. The model determines the maximum number of hours that new peaking capacity can be economically operated, before it would be less expensive to construct and operate base load capacity instead. If the forecasted peaking capacity would operate more than that economic maximum, base loads units are initiated, otherwise peaking units are initiated. Any plant type including geothermal, wind, biomass and storage can be considered.

New plants, of a pre-specified minimum size, are initiated when the reserve margin would be violated if the plants were not built or if base load capacity is inadequate to serve base load energy needs at the end of the forecast period. The model does allow the minimum reserve margin to be temporarily violated at the peak if new base load capacity is scheduled to be available within the year. Peaking units are allowed to serve more than the "maximum economical" number of hours until base load capacity comes on-line.

Minimum plant size is exogenous. The mix of new base load plants (i.e. alternative coal technologies, hydro, or nuclear) is user-specified in the standard ENERGY 2020 configuration. The model also evaluates the financial implications of new construction, including total construction costs, cost schedules, and AFUDC/CWIP. The gross rate on AFUDC equals the weighted average cost of capital. The actual construction progress and financial impacts are simulated on a year by year basis.

ENERGY 2020 can also be configured to consider intermediate load units, firm purchases contracts, external sales, independent power producers, and demand-side options. These options can be "optionally" selected based on endogenous least-cost analysis or can be chosen by user-specified criteria to meet. A detailed automatic Integrated Resource Planning module that would endogenously choose (with user control) from DSM measures utility and non-utility generation and purchase alternatives using linear programming techniques is now being offered as an enhancement.

Financing:

The ENERGY 2020 utility finance subsector simulates the activities of a utility's finance department. It forecasts funding requirements and follows corporate policies for obtaining new funds. The model simulates borrowing and issuing of stock, and can repurchase stock or make investments if it has excess cash. Cash flows are explicitly modeled, as are any decision that affects them. Coverage ratios, intermediate- and long-term debt limits, capitalization, rates of return, new stock issues, bond financing, and short-term investments are endogenously calculated. The model keeps track of gross, net, and tax assets. It also calculates the depreciation values used for the income statement and tax obligations.

Regulation:

The utility sector sets electricity prices according to regulatory requirements. The regulatory procedures use allowed rate-of-return and test year cost and demands to determine allowed revenues. Electricity prices are calculated from peak-demand fractions by allocation of costs. Any other allocation scheme can also be considered. The regulatory subsector of ENERGY 2020 automatically factors in a wide variety of regulatory policies and options. More importantly, the model can be readily modified to consider a wide spectrum of scenarios.

The regulatory process revolves around a test year, usually one year forward, when proposed rates will go into effect. The utility sector forecasts test year sales and peak demands by season and customer class, just as it does to determine capacity needs. These test year demand estimates are used to allocate responsibility for system peak, and therefore, generation capacity costs.

Fuel costs for the test year are estimated by dispatching the plants that will be available in the test year, using the dispatching routine explained below. Fuel costs and operating and maintenance costs are adjusted for expected inflation, and these costs are factored into the electricity rates using forecasted sales.

ENERGY 2020 calculates the utility rate-base according to a detailed conventional rate making formula. The model allows the user to adjust allowable costs, and has been used extensively to evaluate alternative rate-base scenarios for individual plants, including allowing return of, but no return on investment, and partial disallowment of construction and interest costs.

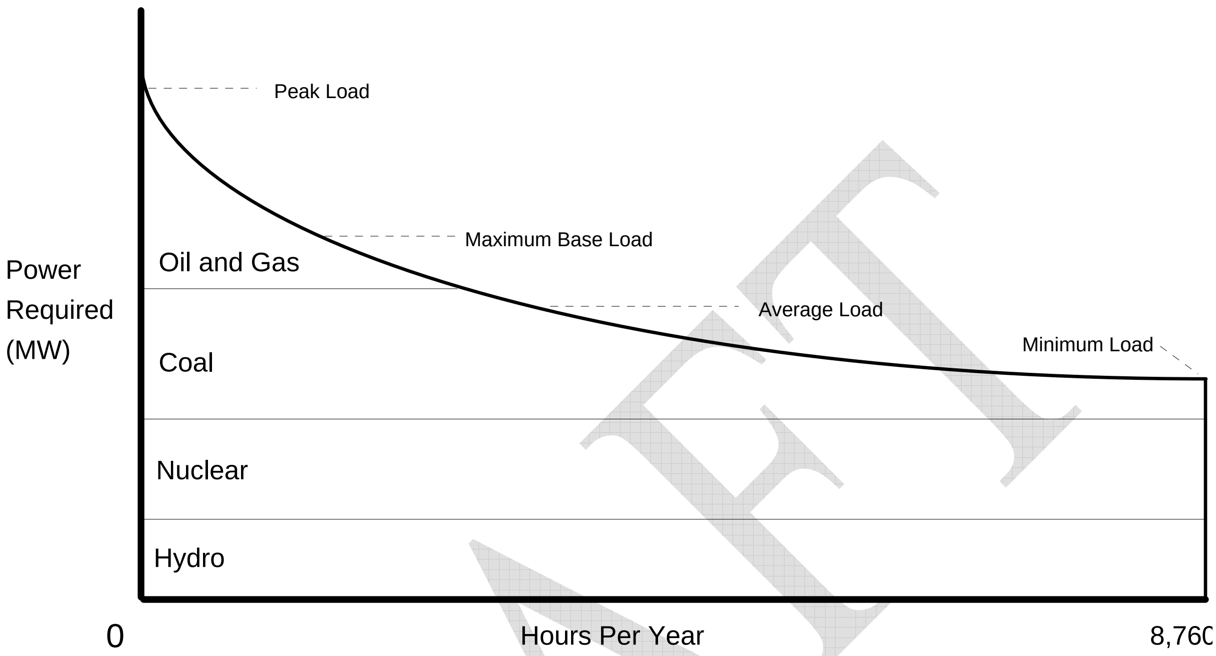
The ENERGY 2020 system also includes estimation of avoided costs, which determines when the utility may be required to purchase third party power. Environmental constraints, such as air pollution restrictions, can also be included in the model. If ENERGY 2020 is configured as a regional or state-wide system, municipal utilities, with their unique tax and rate structures, are incorporated. Similarly, regional or power pool interchange is also recognized by ENERGY 2020. As with the other sectors of ENERGY 2020, the regulatory subsector is flexible enough to accommodate any existing or hypothetical circumstance.

Operations:

Each end-use in ENERGY 2020 has a related set of load shape factors. Typically, these factors define the relationship between peak, minimum and average load for each season. These factors when combined with the weather-adjusted energy demand by end-use and corrected for cogeneration, resale, and load management programs, form the basis of the approximated system load duration curve. Alternatively, unit hourly loads for each end-use for three days per month (average weekday, weekend and peak weekday) are used.

The standard ENERGY 2020 production subsector uses an advanced de-rating or chronological method to estimate the seasonal or hourly dispatch of plants. It purchases power externally when economic or necessary. Plant availability and generation for coal, nuclear, hydroelectric, oil and gas are currently considered, as well as pumped storage, firm purchases, interruptible load, and fuel switching and qualified facilities. Figure A-7 also shows a typical plant dispatch schedule.

Figure A-7: Generation from the Load Curve



The ENERGY 2020 system estimates conventional fuel costs based on the unit dispatch, heat rates, and fuel prices (from the supply sector.) Nuclear fuel costs are capitalized and depreciated throughout the re-fuelling cycle. Nuclear fuel expenses also include fuel disposal costs.

ENERGY 2020 explicitly models the costs of maintaining the transmission and distribution (T&D) system. New facility investments are scheduled and incurred endogenously. In addition, the user can specify the decision rules that dictate T&D expenditures. ENERGY 2020 also explicitly models both fixed and variable operation and maintenance costs, power pool interchanges, nuclear decommissioning costs, plant capital additions, plant cancellations, and general administration costs.

Model Applications:

The structure of the model is well tested and has been used to simulate not only US and the Canada energy and environmental dynamics but also those of several countries in Western, Central and Eastern Europe. Current efforts include strategic and tactical analyses for South America deregulation. In the

1990s, the US EPA made ENERGY 2020 available to interested states to analyze emissions, energy, and economic impacts of state-level climate change initiatives. Further, the model has been used successfully for deregulation analyses in over 50 energy suppliers and in all the US states and Canadian provinces. Several US and Canadian energy suppliers currently use the model for the analysis of combined electricity and gas deregulation dynamics.[19] The model contains confidence and validity packages that allow it to determine how to take maximal advantage of RTO rules. The ISO NE used the model to find "gaps" in its rules and to develop more efficient market conditions. The model was used for the CAPX/ISO to model to show, before the fact, many of the "games" played in the California market.

[19] Energy 2020 is the only model known to have simulated and predicted the dynamics that occurred in the UK electric deregulation. These include gaming, market consolidation and re-regulation dynamics.

Appendix B: Data Sources

Historical Energy Prices and Demands
Historic energy prices and demands are from *State Energy Data 2000*, Integrated Energy Statistics Divisions of the Office of Energy Markets and End Use, Energy Information Administration, USDOE. This document provides annual time series estimates of State-level energy consumption, prices, and expenditures by major economic sectors. In 2000, *State Energy Data 2000* is EIA's replacement of two former reports: State Energy Data Report (SEDR) and State Energy Price and Expenditure Report (SEPER). Tables by major economic sector can be found at: http://www.eia.doe.gov/emeu/states/_states.html. New tables by energy source can be found at: http://www.eia.doe.gov/emeu/states/multi_states.html.

Future Energy Prices
To estimate future energy prices, we apply the forecasted price growth rates in the High Price Case from the *Annual Energy Outlook (AEO) 2007* to the prices from the last historical year (obtained from *State Energy Data*). The Annual Energy Outlook 2007 presents a forecast and analysis of US energy supply, demand, and prices through 2030. http://www.eia.doe.gov/oiaf/aeo/supplement/index.html

Note that there is a gap between the most recently reported historical year of data and the first forecast year. We resolve this by including one year's worth of price data from the AEO of the previous year.

Future Energy Demands
Future energy demands are computed by the model, but the model can calibrate to future energy demands if desired. In this case we use the forecasted energy demands from the Annual Energy Outlook.

Device Energy Efficiency Standards
Device efficiency standards come mainly from the *Energy Policy Act of 1992*, with some efficiencies coming from other selected sources.
http://energy.navy.mil/publications/law_us/92epact/hr776toc.htm

Device Capital Cost, Efficiency, and Device Lifetimes; Cogeneration Capital Costs, Heat Rates and Parameters
The values all come from ARC 80 with the exception of some end uses which come from other selected sources. *Annual Report to Congress, 1980: Volume 3*. Energy Information Administration, USDOE, Report #: DOE/EIA-0173(80)/3.

End-Use Load Shapes
The end use load shapes were extracted from 1995 NEPOOL published reports.

Industrial Energy Splits, Industrial End Use Splits and Commercial End-Use Splits
The energy that we obtain from *State Energy Data 2000* is a total value that needs to be split among different industries and/or uses (end use demands, cogeneration demands, feedstock demands). We obtain the splits among industries and uses from the *1998 Manufacturing Energy Consumption Survey*, Energy Information Administration, USDOE. The Manufacturing Energy Consumption Survey is conducted every five years and provides detailed data on energy consumption in the manufacturing sector.
http://www.eia.doe.gov/emeu/mecs/contents.html

Residential Devices Saturations and Market Shares
Residential devices saturations and market shares are obtained from the *2001 Residential Energy Consumption Survey*, Energy Information Administration, USDOE.
http://www.eia.doe.gov/emeu/recs/contents.html

Inflation Rate
Historical inflation rates are calculated from the consumer price index reported by the Bureau of Labor. Projections for inflation from 2004 through 2030 are calculated from the consumer price index projections of the *Annual Energy Outlook 2007*, Energy Information Administration, USDOE. http://www.eia.doe.gov/oiaf/aeo/index.html.

Fuel Choice Variance Factors, Return on Investment, and Maximum Process Efficiency Multiplier
The fuel choice variance factors, return on investment and maximum process efficiency multiplier variables come from projections obtained from the DEMAND81 energy model. Backus, George A. 1981. DEMAND81: National Energy Policy Model. Four Volumes. AFC 7-10. School of Industrial Engineering. Purdue University. West Lafayette, Indiana.

Process Capital Costs
The data was developed from the US I/O Tables by REMI in $1987

Residential Energy Usage Per Appliance
The average usage per appliance comes from *NEPOOL April 1994 Forecast for Massachusetts*. The miscellaneous end use category is computed by adding the residential energy for all miscellaneous end uses and dividing by the number of households.

Number of Households
The number of households comes from the United States Census 2000, US Census Bureau. http://www.census.gov/main/www/cen2000.html.

Appendix C: Inter-Regional Transmission Capacity in Energy 2020

Region From	Region To	Capacity Limit (MW)
Alberta	British Columbia	1,000
British Columbia	Alberta	1,200
Allston, OR	Olympia, WA	4,200
Olympia, WA	Allston, OR	4,200
Allston, OR	Williamet, OR	4,120
Williamet, OR	Allston, OR	4,120
Arizona	LADWP, CA	1,229
LADWP, CA	Arizona	1,229
Arizona	New Mexico	2,500
New Mexico	Arizona	2,500
Arizona	Pace, UT	600
Pace, UT	Arizona	600
Arizona	San Diego & Imperial Valley, CA	1,133
San Diego & Imperial Valley, CA	Arizona	1,133
Arizona	Southern California	2,150
Southern California	Arizona	2,150
Arizona	WAPA L.C. (AZ,NM)	9,999
WAPA L.C. (AZ,NM)	Arizona	9,999
British Columbia	North Puget, WA	2,850
North Puget, WA	British Columbia	2,000
British Columbia	Spokane, WA	200
Spokane, WA	British Columbia	200
British Columbia	West Kootenay, BC	9,999
West Kootenay, BC	British Columbia	9,999
Bonanza, UT	Bridger, WY	300
Bridger, WY	Bonanza, UT	300
Bonanza, UT	Pace, UT	785
Pace, UT	Bonanza, UT	400
Bonanza, UT	WAPA R.M., CO	650
WAPA R.M., CO	Bonanza, UT	650
Bridger, WY	Eastern Idaho	2,200
Eastern Idaho	Bridger, WY	600
Bridger, WY	WAPA R.M., CO	1,450
WAPA R.M., CO	Bridger, WY	1,450
Bridger, WY	Wyoming R.M.	400
Wyoming R.M.	Bridger, WY	400
Bridger, WY	Yellowtail, MT	625
Yellowtail, MT	Bridger, WY	400
Brownlee, ID	Lower Columbia (WA,OR)	50
Lower Columbia (WA,OR)	Brownlee, ID	50
Brownlee, ID	McNary, WA	300
McNary, WA	Brownlee, ID	300
Brownlee, ID	Oxbow, OR	1,700

Region From	Region To	Capacity Limit (MW)
Oxbow, OR	Brownlee, ID	1,700
Brownlee, ID	Southern Idaho	1,850
Southern Idaho	Brownlee, ID	1,850
Coulee, WA	Grant County, WA	2,396
Grant County, WA	Coulee, WA	2,396
Coulee, WA	Mid Columbia (WA,OR)	1,844
Mid Columbia (WA,OR)	Coulee, WA	1,844
Coulee, WA	North Puget, WA	1,451
North Puget, WA	Coulee, WA	1,451
Coulee, WA	Olympia, WA	126
Olympia, WA	Coulee, WA	126
Coulee, WA	Seattle South, WA	5,275
Seattle South, WA	Coulee, WA	5,275
Coulee, WA	Spokane, WA	1,140
Spokane, WA	Coulee, WA	1,140
Eastern Idaho	Garrison, MT	224
Garrison, MT	Eastern Idaho	337
Eastern Idaho	Idaho	400
Idaho	Eastern Idaho	270
Eastern Idaho	Pace, UT	400
Pace, UT	Eastern Idaho	630
Eastern Idaho	Southern Idaho	2,557
Southern Idaho	Eastern Idaho	2,557
Garrison, MT	WAPA U.M., MT	200
WAPA U.M., MT	Garrison, MT	200
Garrison, MT	Western, MT	2,200
Western, MT	Garrison, MT	2,200
Garrison, MT	Yellowtail, MT	2,573
Yellowtail, MT	Garrison, MT	2,573
Idaho	Ogden, UT	9,999
Ogden, UT	Idaho	9,999
Idaho	Pace, UT	9,999
Pace, UT	Idaho	9,999
Idaho	Wyoming R.M.	9,999
Wyoming R.M.	Idaho	9,999
LADWP, CA	Lower Columbia (WA,OR)	3,100
Lower Columbia (WA,OR)	LADWP, CA	3,100
LADWP, CA	Pace, UT	1,400
Pace, UT	LADWP, CA	1,200
LADWP, CA	Sierra, NV	235

Region From	Region To	Capacity Limit (MW)
Sierra, NV	LADWP, CA	235
LADWP, CA	Southern Nevada	1,841
Southern Nevada	LADWP, CA	1,841
LADWP, CA	Southern California	9,999
Southern California	LADWP, CA	9,999
LADWP, CA	WAPA L.C. (AZ,NM)	1,231
WAPA L.C. (AZ,NM)	LADWP, CA	1,231
Lower Columbia (WA,OR)	Malin, OR	1,708
Malin, OR	Lower Columbia (WA,OR)	1,708
Lower Columbia (WA,OR)	McNary, WA	1,948
McNary, WA	Lower Columbia (WA,OR)	1,948
Lower Columbia (WA,OR)	Mid Columbia (WA,OR)	5,277
Mid Columbia (WA,OR)	Lower Columbia (WA,OR)	5,277
Lower Columbia (WA,OR)	Slatt, OR	3,031
Slatt, OR	Lower Columbia (WA,OR)	3,031
Lower Columbia (WA,OR)	Williamet, OR	3,334
Williamet, OR	Lower Columbia (WA,OR)	3,334
Lower Granite Dam, WA	Mid Columbia (WA,OR)	5,560
Mid Columbia (WA,OR)	Lower Granite Dam, WA	5,560
Lower Granite Dam, WA	Spokane, WA	1,155
Spokane, WA	Lower Granite Dam, WA	1,155
Malin, OR	PG and E, CA	4,800
PG and E, CA	Malin, OR	4,800
Malin, OR	Sierra, NV	300
Sierra, NV	Malin, OR	300
Malin, OR	Southern Idaho	1,500
Southern Idaho	Malin, OR	1,500
Malin, OR	Southern Oregon	4,782
Southern Oregon	Malin, OR	4,782
McNary, WA	Mid Columbia (WA,OR)	2,000
Mid Columbia (WA,OR)	McNary, WA	2,000
McNary, WA	Slatt, OR	2,854
Slatt, OR	McNary, WA	2,854
McNary, WA	Williamet, OR	227
Williamet, OR	McNary, WA	227
Baja, Mexico	San Diego & Imperial Valley, CA	800
San Diego & Imperial Valley, CA	Baja, Mexico	800
Mid Columbia (WA,OR)	Oxbow, OR	400
Oxbow, OR	Mid Columbia (WA,OR)	400
Mid Columbia (WA,OR)	Seattle South, WA	3,700

Region From	Region To	Capacity Limit (MW)
Seattle South, WA	Mid Columbia (WA,OR)	3,700
Mid Columbia (WA,OR)	Slatt, OR	4,100
Slatt, OR	Mid Columbia (WA,OR)	4,100
Mid Columbia (WA,OR)	Spokane, WA	273
Spokane, WA	Mid Columbia (WA,OR)	273
Mid Columbia (WA,OR)	Williamet, OR	2,600
Williamet, OR	Mid Columbia (WA,OR)	2,600
N. King, WA	Seattle South, WA	526
Seattle South, WA	N. King, WA	526
New Mexico	PS Colorado	558
PS Colorado	New Mexico	558
New Mexico	WAPA L.C. (AZ,NM)	817
WAPA L.C. (AZ,NM)	New Mexico	817
New Mexico	WAPA R.M., CO	690
WAPA R.M., CO	New Mexico	690
North Puget, WA	Seattle North, WA	3,000
Seattle North, WA	North Puget, WA	3,000
North Puget, WA	Seattle South, WA	3,000
Seattle South, WA	North Puget, WA	3,000
Ogden, UT	Pace, UT	9,999
Pace, UT	Ogden, UT	9,999
Olympia, WA	Seattle South, WA	4,500
Seattle South, WA	Olympia, WA	4,500
OVERTHRS, WY	Wyoming R.M.	9,999
Wyoming R.M.	OVERTHRS, WY	9,999
Oxbow, OR	Southern Idaho	90
Southern Idaho	Oxbow, OR	50
Oxbow, OR	Spokane, WA	450
Spokane, WA	Oxbow, OR	300
Pace, UT	Scenic SW, UT	300
Scenic SW, UT	Pace, UT	300
Pace, UT	Sierra, NV	205
Sierra, NV	Pace, UT	205
Pace, UT	Station Load, WY	9,999
Station Load, WY	Pace, UT	9,999
Pace, UT	WAPA L.C. (AZ,NM)	265
WAPA L.C. (AZ,NM)	Pace, UT	265
Pace, UT	Wyoming R.M.	9,999
Wyoming R.M.	Pace, UT	9,999
PG and E, CA	Sierra, NV	160

Region From	Region To	Capacity Limit (MW)
Sierra, NV	PG and E, CA	150
PG and E, CA	Southern Oregon	30
Southern Oregon	PG and E, CA	80
PG and E, CA	Southern California	3,400
Southern California	PG and E, CA	3,000
PS Colorado	WAPA R.M., CO	9,999
WAPA R.M., CO	PS Colorado	9,999
Southern California Edison	Southern California	200
Southern California	Southern California Edison	200
Scenic SW, UT	Southern Nevada	300
Southern Nevada	Scenic SW, UT	300
Scenic SW, UT	St. George, UT	9,999
St. George, UT	Scenic SW, UT	9,999
Scenic SW, UT	Station Load, WY	26
Station Load, WY	Scenic SW, UT	26
San Diego & Imperial Valley, CA	Southern California	5,000
Southern California	San Diego & Imperial Valley, CA	5,000
Seattle North, WA	Seattle South, WA	1,690
Seattle South, WA	Seattle North, WA	1,690
Sierra, NV	Southern Idaho	262
Southern Idaho	Sierra, NV	500
Sierra, NV	Southern California	17
Southern California	Sierra, NV	17
Southern Oregon	Williamet, OR	4,495
Williamet, OR	Southern Oregon	4,495
Southern Nevada	Southern California	2,754
Southern California	Southern Nevada	2,754
Southern Nevada	WAPA L.C. (AZ,NM)	4,554
WAPA L.C. (AZ,NM)	Southern Nevada	4,554
Southern California	WAPA L.C. (AZ,NM)	1,140
WAPA L.C. (AZ,NM)	Southern California	1,140
Spokane, WA	West Kootenay, BC	200
West Kootenay, BC	Spokane, WA	200
Spokane, WA	Western, MT	6,500
Western, MT	Spokane, WA	6,500
Station Load, WY	Wyoming R.M.	9,999
Wyoming R.M.	Station Load, WY	9,999
WAPA L.C. (AZ,NM)	WAPA R.M., CO	485
WAPA R.M., CO	WAPA L.C. (AZ,NM)	485
WAPA U.M., MT	Yellowtail, MT	390

Region From	Region To	Capacity Limit (MW)
Yellowtail, MT	WAPA U.M., MT	390

Appendix D: Data Sets Used in ENERGY 2020

This Appendix describes the initial "set" definitions for ENERGY 2020 used for this project. The "sets" are the dimensions of the variables (sometimes called indexes) which delineate the scope and detail of the model. For example, the time frame set could be defined as a base year 1990 and every 5 years.

Time Frame

The initial historical year for calibration is 1990.
The end year of the analysis is 2030.
The last historic year of data will be 2005.
All data sets include annual data for each year of history and the forecast.

For some data sets, the period covered by actual data will depend on available data (e.g., emissions).

Geographical Areas

Each area in the model will represent a state or a province (no sub-state break-outs).
The model will provide separate results for the WCI partners, the surrounding Region, the rest of the US and Canada.

The States and Provinces included in the "WCI Region" for modeling purposes include:

- Arizona
- California
- Montana
- New Mexico
- Oregon
- Utah
- Washington
- British Columbia
- Manitoba

Generating Units

The list of units is based on the NEEDS database for the US plus a similar database for the units in Canada. Within the Region and the rest of the US, some of the smaller plants may be aggregated by plant type in order to allow the expedite model operation. With that aggregation, the model will likely end up with approximately 3000 units/plants.

Electric Companies

The model currently represent seven utilities within California including: PG&E, SCE, SDG&E, LADWP, SMUD, Other North and Other South. In the broader western region, the model currently assumes that each state has a single aggregate electric company. The exception to this is BPA.

Sectors and Classes

The energy demand portion of the model will simulate residential, commercial, industrial, and transportation demands. There will be an electric sales class for each sector.

Emission Only Sectors

Several sectors generate emissions, but do not have full energy demand simulations in the model. These include solid waste, waste water, incineration, and land use. It may be possible to develop a full energy demand simulation for one or more of these.

Offsets

Possible offset categories, if broken out as a set, could include:

- Sequestration
- Landfill Gas Capture
- Agricultural Methane
- Energy Efficiency (for each sector)

Pollutants

The model currently has the capability to cover 15 pollutants, although the final set will depend on the WCI partner's requirements and available data. The GHG pollutants include Carbon Dioxide, Methane, Nitrous Oxide, Sulfur-Hexafluoride, Perfluorocarbon, and Hydrofluorocarbon. The criteria air pollutants include Sulfur Dioxide, Nitrogen Oxides, Total Particulate Matter, Volatile Organic Compounds, Carbon Monoxide, Particulate Matter 2.5, Particulate Matter 10, Mercury, and Ozone.

Fuels

There are currently two sets of fuels in the model. The largest category contains 33 fuels (shown below). The second category is the list of technologies which the energy demand sectors choose from. This smaller set contains only the basic types of fuels (Electricity, Natural Gas, Oil, LPG, Biomass, Solar). The aggregate category oil is later broken out into the different types of oil (LFO, HFO, petroleum coke, etc.).

Entire List of Fuels

- Asphalt
- Aviation Fuel
- Biomass
- Coal
- Coke
- Coke Oven Gas
- Diesel
- Electric
- Ethanol
- Geothermal
- Heavy Fuel Oil
- Hydro
- Hydrogen
- Kerosene
- Landfill Gases
- Light Fuel Oil
- LPG
- Lubricants
- Motor Gasoline
- Naphtha Specialties
- Natural Gas
- Nuclear
- Oil, Unspecified
- Other Non-Energy Products
- Petrochemical Feedstocks
- Petroleum Coke
- Solar
- Steam
- Still Gas
- Wave
- Wind
- Unknown 1
- Unknown 2

Electric Generation Plants Types

The electric generation plant types are used to hold the data for future generic plants which the model will construct endogenously. The list currently includes:

- Gas/Oil Peaking
- Gas/Oil Combined Cycle
- Gas/Oil Steam
- Coal
- Coal Advanced
- Coal with CCS
- Gas CC with CCS
- Nuclear
- Base Hydro
- Peak Hydro
- Other Generation
- Biomass
- Landfill Gas
- Wind
- Solar
- Fuel Cells
- Pumped Hydro
- Small Hydro
- Wave
- Geothermal
- Other Storage
- Biogas
- Trash

Residential Sectors

The residential sector is split into housing types:

- Single Family
- Multi-Family
- Other Residential

Commercial Sectors

- Transportation Services
- Pipelines
- Communication
- Electric Utilities
- Gas Utilities
- Water & Other Utilities
- Wholesale
- Retail
- FIRE
- Offices - Business Services
- Education
- Health & Social
- Food, Lodging, Recreation
- Government

Industrial Sectors

- Food & Tobacco
- Textiles
- Apparel
- Lumber
- Furniture
- Pulp & Paper Mills
- Converted Paper
- Printing
- Petrochemicals
- Industrial Gas
- Other Chemicals
- Fertilizers
- Petroleum Products
- Rubber
- Leather
- Cement
- Glass
- Lime & Gypsum
- Other Non-Metallic
- Iron & Steel
- Aluminum
- Other Nonferrous
- Fabricated Metals
- Machines
- Computers
- Electric Equipment
- Transport Equipment
- Other Manufacturing
- Iron Ore Mining
- Other Metal Mining
- Non-metal Mining
- Light Oil Mining
- Heavy Oil Mining
- Frontier Oil Mining
- Oil Sands In-Situ
- Oil Sands Mining
- Oil Sands Upgraders
- Gas Mining
- Coal Mining
- Construction
- Forestry
- Agriculture

Transportation Sectors

- Passenger
- Freight
- Off Road

Miscellaneous Sectors

- Misc. & Street Lighting
- Electric Resale
- Utility Electric Generation
- Industry Electric Generation
- Steam Generation
- Solid Waste
- Waste Water
- Incineration
- Land Use

Residential End-Uses

- Space Heating
- Water Heating
- Other Substitutable
- Refrigeration
- Lighting
- Air Conditioning
- Other Non-Substitutable

Commercial End-Uses

- Space Heating
- Water Heating
- Other Substitutable
- Refrigeration
- Lighting
- Air Conditioning
- Other Non-Substitutable

Industrial End-uses

- Process Heat
- Electric Motors
- Other Substitutable
- Miscellaneous

Transportation End-Uses

- Ground
- Air/Water

Residential, Commercial, and Industrial Technology Types

Each technology type has its own trade-off curve which determines the efficiency and the capital cost of the technology type. These curves allow the model to contain many different technologies within these broad types.

- Electric
- Gas
- Coal
- Oil
- Biomass
- Solar
- LPG
- Steam

Transportation Technology Types

Several technology types are provided for transportation, and each of these contains a trade-off curve which allows the model to simulate even more individual technologies.

- Plug-in Hybrids
- Light Gasoline
- Light Diesel
- Light Propane
- Light CNG
- Light Electric (Plug-in)
- Light Ethanol
- Light Hybrid Gasoline
- Light Hybrid Diesel
- Light Fuel Cell Gasoline
- Light Fuel Cell CNG
- Light Fuel Cell Hydrogen
- Medium Gasoline
- Medium Diesel
- Medium Propane
- Medium CNG
- Medium Ethanol
- Medium Hybrid Gasoline
- Medium Hybrid Diesel
- Medium Fuel Cell Gasoline
- Medium Fuel Cell CNG
- Medium Fuel Cell Hydrogen
- Heavy Gasoline
- Heavy Diesel
- Heavy Propane
- Heavy CNG
- Heavy Ethanol
- Heavy Hybrid Gasoline
- Heavy Hybrid Diesel
- Heavy Fuel Cell Gasoline
- Heavy Fuel Cell CNG
- Heavy Fuel Cell Hydrogen
- Motorcycle
- Bus Gasoline
- Bus Diesel
- Bus Propane
- Bus CNG
- Bus Fuel Cell Gasoline
- Bus Fuel Cell Hydrogen
- Bus Fuel Cell Ethanol
- Train
- Plane
- Marine
- Off Road

Prices

Delivered energy prices are presented for the following fuels:

- Residential Electricity
- Residential Natural Gas
- Residential Coal
- Residential Oil
- Residential Biomass
- Residential LPG
- Residential Steam
- Commercial Electricity
- Commercial Natural Gas
- Commercial Coal
- Commercial Oil
- Commercial Biomass
- Commercial LPG
- Commercial Steam
- Industrial Electricity
- Industrial Natural Gas
  Industrial Coal
- Industrial Oil
- Industrial Biomass
- Industrial LPG
- Industrial Steam
- Gasoline
- Diesel
- Aviation Fuel
- Transportation HFO
- Transportation Natural Gas
- Transportation LPG
- Electric Utility Residual Oil
- Electric Utility Distillate Oil
- Electric Utility Natural Gas
- Electric Utility Coal
- Electric Utility Nuclear
- Electric Utility Biomass
- Ethanol
- Hydrogen

Electric Load Segments

The model dispatches for 6 different hour types (high peak, low peak, high intermediate, low intermediate, high base load, low base load) for each of the four seasons.

Appendix F: New Generation Performance and Cost Assumptions

Table 1A. Input Values to Busbar Energy Costs - California Resources (2008 $)

Resource Technology	2020 Overnight Capital Cost ($/kW) ($/kW)		Fixed O&M Cost ($/kW-year)		Variable O&M Cost ($/MWh)		Capacity Factor	Nominal Heat Rate (Btu/kWh)
	Low (if range)	High (if range)	Low (if range)	High (if range)	Low (if range)	High (if range)		
Biogas	$3,065		$139		1.20		80%	13,648
Biomass	$4,484		$65		1.20		80%	8,911
Geothermal	$3,339	$8,131	$157	$226	1.20		90%	n/a
Hydro - Small	$2,539	$5,170	$14	$31	0.94	1.81	25% - 65%	n/a
Solar - Thermal	$3,235		$64		1.20		37% - 40%	n/a
Wind	$1,962		$37		1.20		27% - 40%	n/a
Coal ST	$2,479		$33		1.20		85%	8,844
Coal IGCC	$2,866		$47		1.20		85%	8,309
Coal IGCC with CCS	$4,101		$55		1.20		85%	9,713
Gas CCCT	$1,054		$14		1.20		90%	6,917
Gas CT	$807		$15		1.20		5%	10,807
Hydro - Large	$1,486	$2,193	$9	$13	0.63	0.89	12% - 57%	n/a
Nuclear	$3,999		$83		1.20		85%	10,400

Table 1B. Input Values to Busbar Energy Costs - Rest of WECC Resources (2008 $)

Resource Technology	2020 Overnight Capital Cost ($/kW) ($/kW)		Fixed O&M Cost ($/kW-year)		Variable O&M Cost ($/MWh)		Capacity Factor	Nominal Heat Rate (Btu/kWh)
	Low (if range)	High (if range)	Low (if range)	High (if range)	Low (if range)	High (if range)		
Biogas	$2,350	$2,835	$107	$128	0.92	1.11	80%	13,648
Biomass	$3,438	$4,148	$50	$60	0.92	1.11	80%	8,911
Geothermal	$1,582	$19,451	$157	$226	0.96	1.11	90%	n/a
Hydro - Small	$1,758	$4,782	$11	$28	0.71	1.69	22% - 65%	n/a
Solar - Thermal	$2,588	$2,939	$51	$58	0.96	1.09	36% - 39%	n/a
Wind	$1,504	$1,815	$28	$34	0.92	1.11	27% - 40%	n/a
Coal ST	$1,901	$2,293	$26	$31	0.92	1.11	85%	8,844
Coal IGCC	$2,197	$2,651	$36	$43	0.92	1.11	85%	8,309
Coal IGCC with CCS	$3,144	$3,794	$42	$51	0.92	1.11	85%	9,713
Gas CCCT	$808	$975	$11	$13	0.92	1.11	90%	6,917
Gas CT	$619	$747	$11	$14	0.92	1.11	5%	10,807
Hydro - Large	$1,122	$2,031	$5	$11	0.41	0.78	15% - 65%	n/a
Nuclear	$3,066	$3,699	$63	$76	0.92	1.11	85%	10,400

Source: Energy and Environmental Economics, Inc., CPUC GHG Modeling - Generation Costs, www.ethree.com/cpuc_ghg_model.html

Appendix G: Global Warming Potential

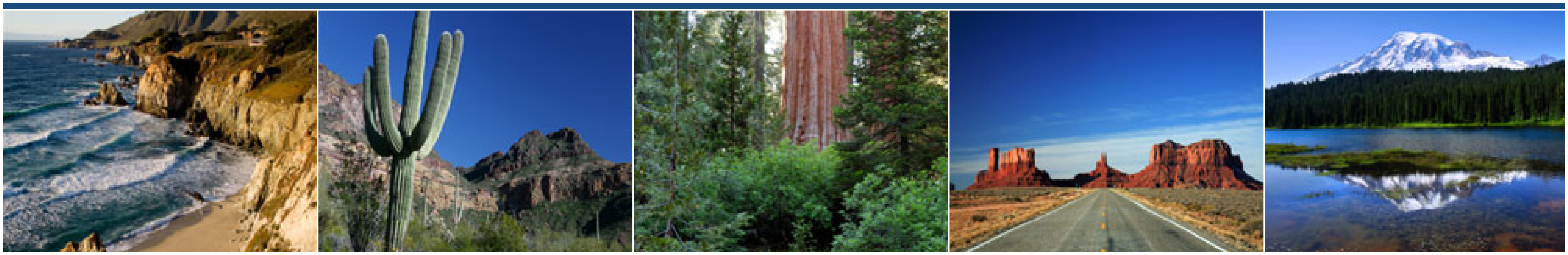
ENERGY 2020 models emissions of each of the six greenhouse gases reported under the Kyoto protocol. These emissions are then translated into equivalent quantities of CO_2 emissions (CO_2e) based on the global warming potential of each of the gases.

The Global Warming Potential (GWP) values used in ENERGY 2020 are shown in the table below.

Greenhouse Gas	Global Warming Potential
Carbon Dioxide (CO2)	1
Methane (CH4)	21
Nitrous Oxide (N2O)	310
Sulphur Hexafluoride (SF6)	23,900
Perfluorocarbons (PFC)	7,000
Hydrofluorocarbons (HFC)	1,300

These values are consistent with the Global Warming Potential values used in the 1996 Second Assessment Report based on 100-year warming potential for the individual gases. In the case of HFCs and PFCs the GWP values used in the model are based on an estimated average GWP for these gases.

Western Climate Initiative



Preliminary Phase 1 Modeling Results

Presented to

Western Climate Initiative Stakeholders

May 12, 2008

Topics

- Phase 1 Challenges
- Preliminary Results
- Example Model Outputs
- Status of Assumptions Book

Phase 1 Challenges

- Reference case
  - Aim for “reasonable closeness” to 9 partners’ 2005 inventories
  - Incorporate 2007 national energy bill (EISA) and existing renewable portfolio standards
- Complementary policies
  - CA car standards, VMT reduction
  - Energy efficiency programs (electric & gas utilities, LPG, heating oil)
- Cap-and-trade scenarios
  - First-jurisdictional deliverer (proxy with WECC-wide cap)
  - Proper treatment of tribal power plants

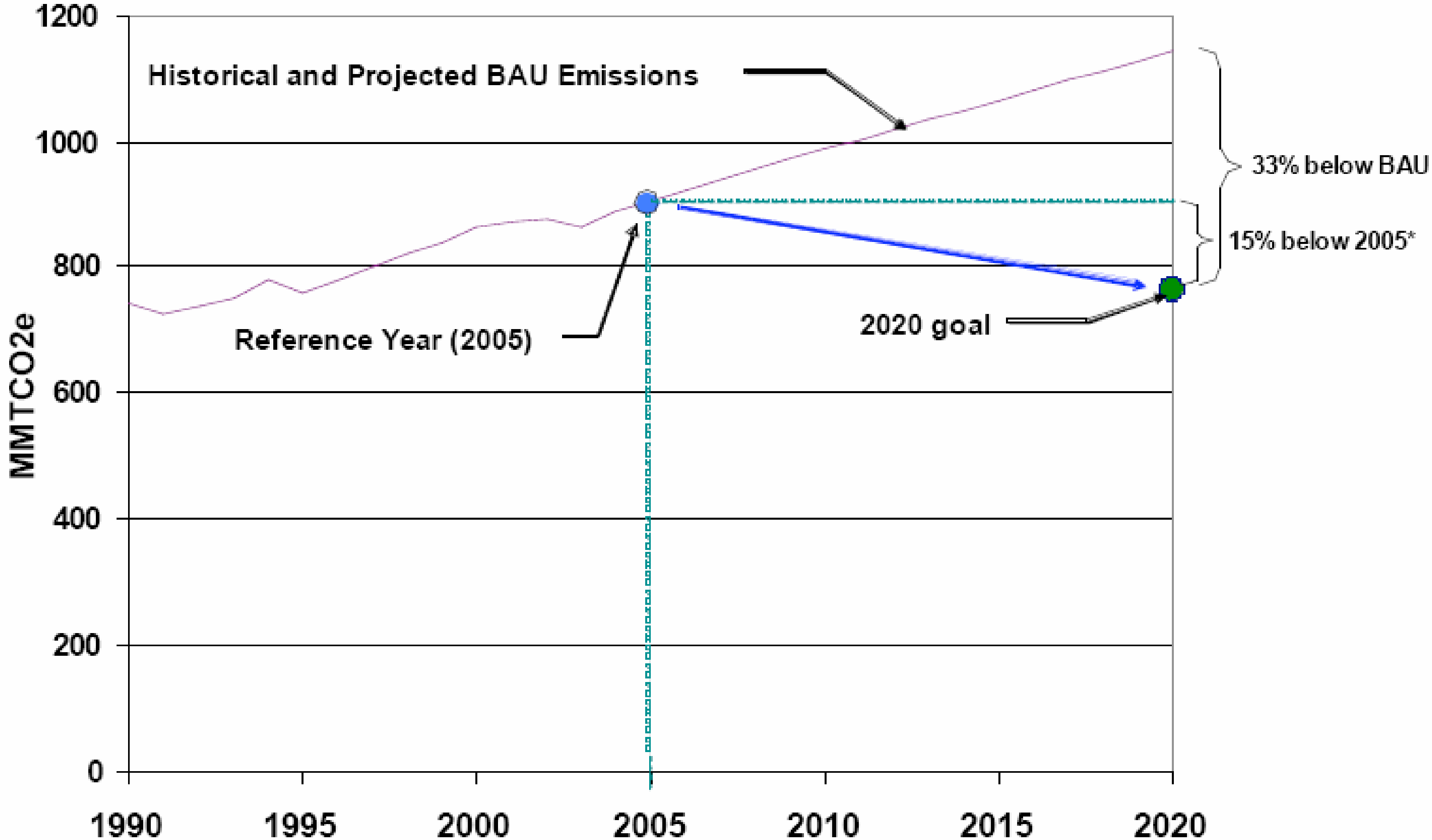
Status

- Model simulation of 2005 inventories align reasonably well (not perfectly) with WCI partners' 2005 inventories.
- Preliminary results for Reference Case projections are plausible and lower than partners' projections.
- Complementary Policies model run produces plausible results.
- Cap-and-trade model runs are in progress
- Manitoba and Quebec not yet modeled

WCI Partner Data

- WCI compiled GHG inventories and forecasts in August 2007
- The forecasts suggested aggregate growth of >25% in emissions from 2005-2020
- Reducing emissions to 15% below 2005 levels would thus require a 33% reduction from BAU ("Business As Usual" or "Reference Case")
- See graph on next slide

WCI Partner GHG Emissions and Regional Goal[3]



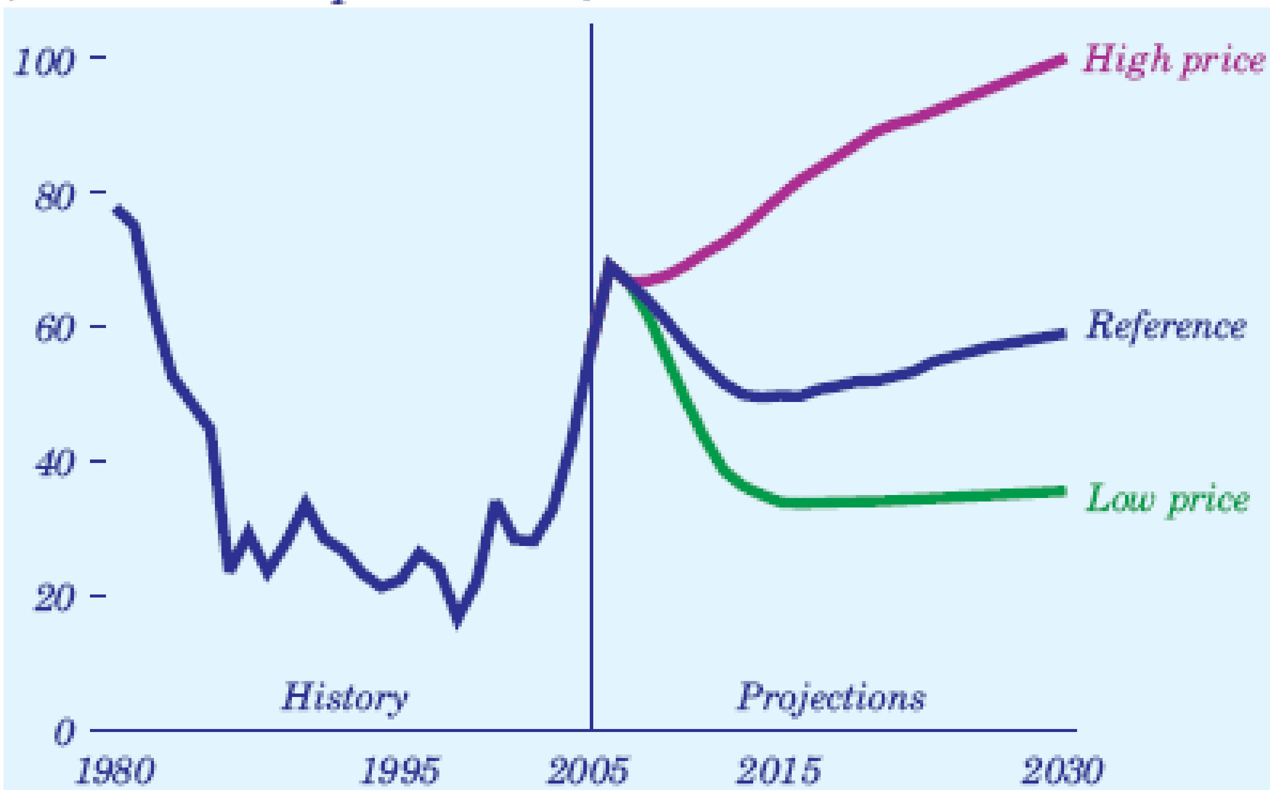
ENERGY 2020 Reference Case

- The model can simulate the partner inventories for 2005 reasonably well
- GHG emissions in 2020 in the Reference Case are significantly lower. Why?
  - Partner forecasts are ~1 to 5 years old
  - Energy prices are projected to be higher
  - Reference Case includes EISA and state RPS's
  - Reference Case assumes no new conventional coal plants (beyond "committed coal plants")
  - Not using partner-specific population growth rates in Phase 1 modeling

AEO 2007: World Price Projection

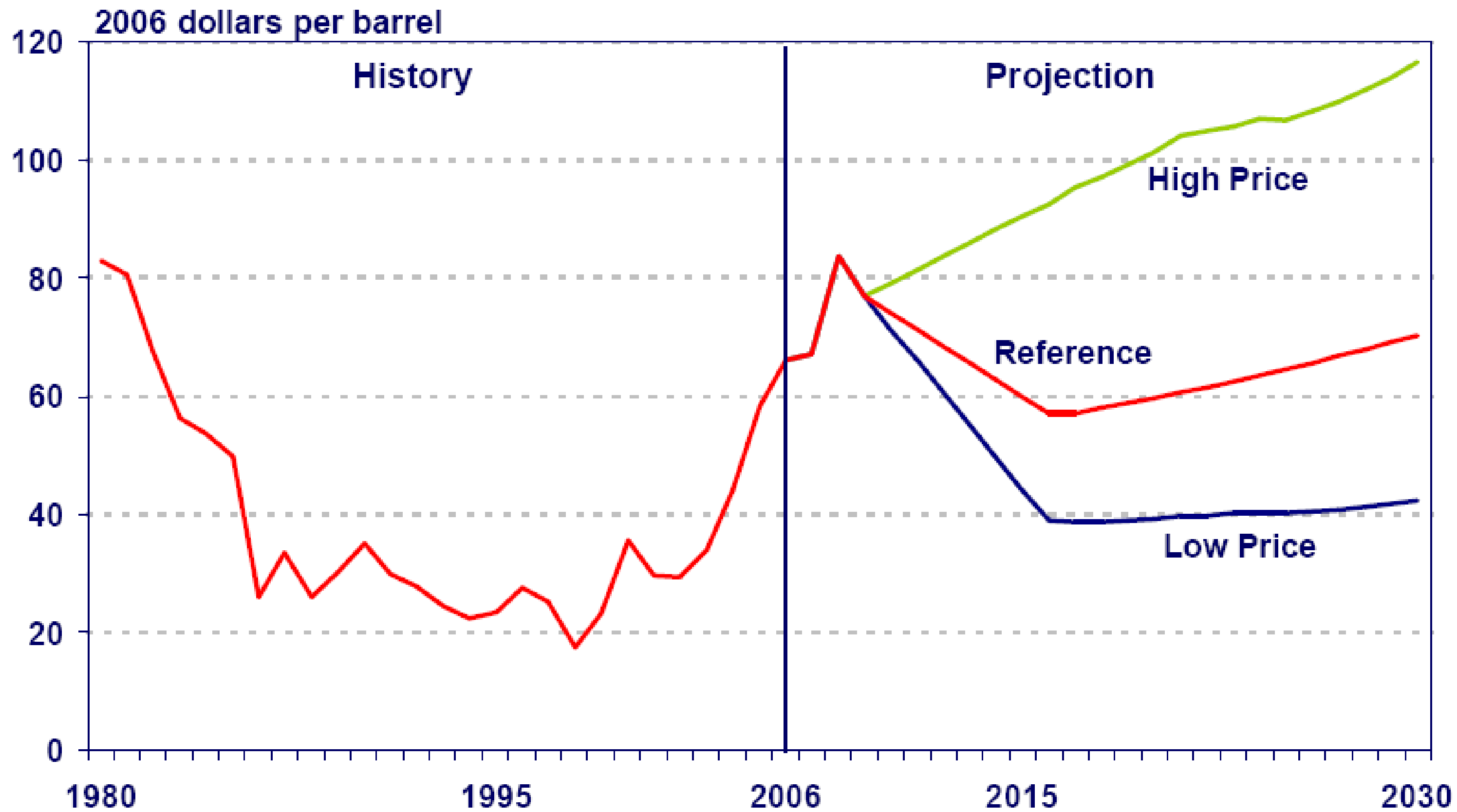
Oil Price Cases Show Uncertainty in Prospects for World Oil Markets

Figure 29. World oil prices, 1980-2030 (2005 dollars per barrel)



AEO 2008: World Price Projection

Figure 2. World oil prices are higher in all *AEO2008* cases.

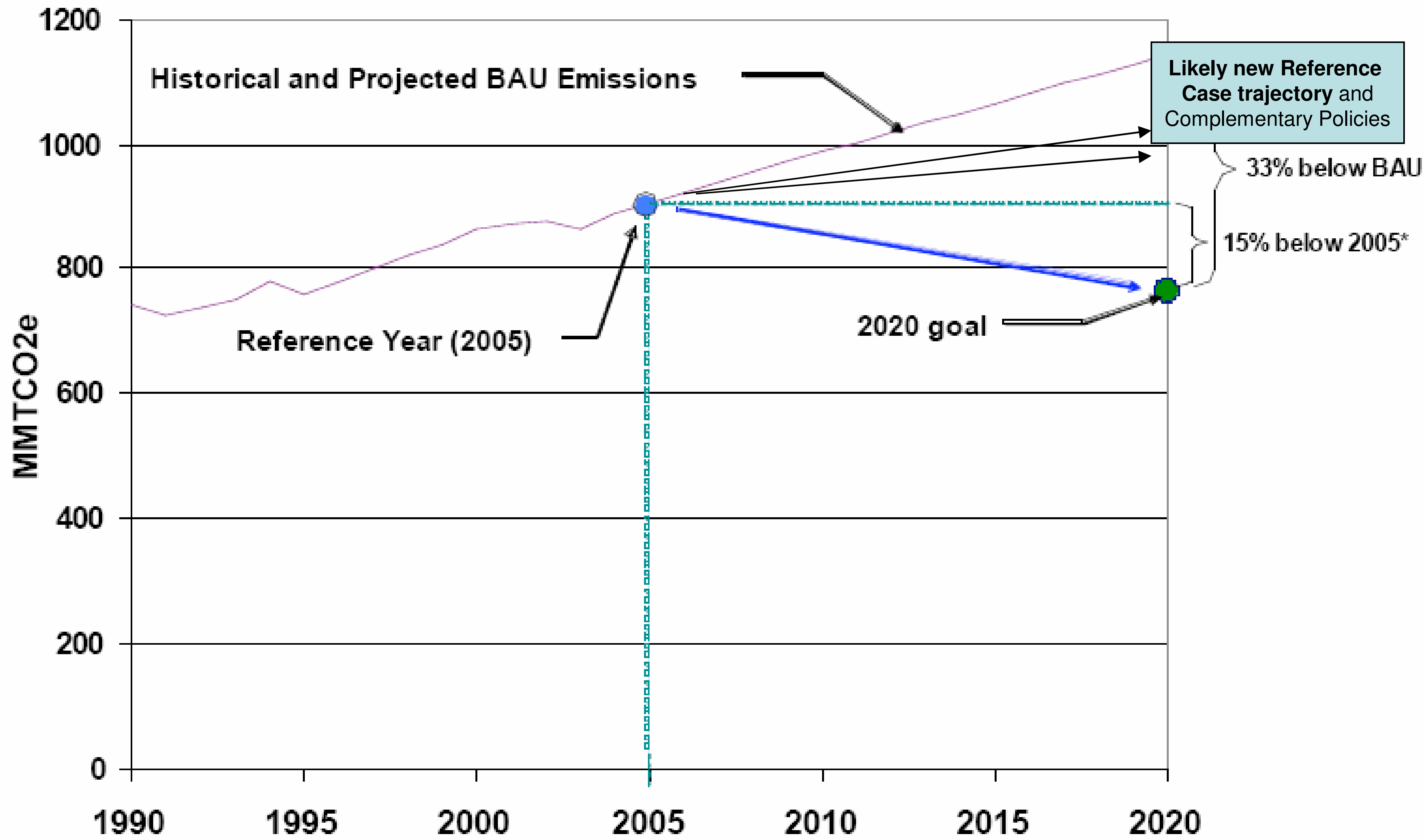


Comparison of AEO 2007 vs. 2008

		AEO 2007		AEO 2008	
	2005	2020	% Incr	2020	% Incr
Total CO2 Emissions (MMT)	5982	6944	16%	6384	7%
Ave Annual Growth 2005-2030					
Energy Consumption			1.2%		0.7%
Economic Growth			2.9%		2.4%

- Significant decreases in projected CO2: 16% vs. 7%
- Energy consumption grows more slowly
- Economy grows more slowly
- All projections are from AEO “mid-price” cases, Table 18.

WCI Partner GHG Emissions and Regional Goal[3]



ENERGY 2020 Reference Case and Complementary Policies

- Graph illustrates likely trajectories of Reference Case and Complementary Policies model run
- Reference Case reflects
  - Higher energy prices
  - EISA 2007: Stronger CAFÉ standards, biofuel mandate, efficiency standards, current state RPS's
  - Assumption of no new conventional coal plants (beyond "committed coal plants")

Model Run: Complementary Policies Only

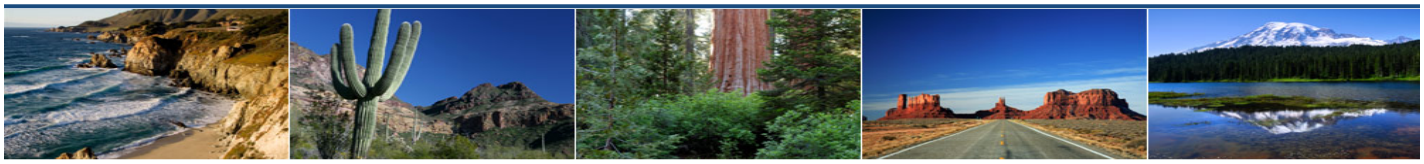
- Rationale for model run
- Includes three WCI-wide policies:
  - CA car standards (and assumes that there will be a "Part 2" to these standards per California ARB)
  - Total VMT reduced below levels in 2020 Reference Case
  - Aggressive energy efficiency programs that annually reduce demand below the annual percentage growth rate in the Reference Case for electricity, natural gas, LPG, and heating oil

Example Model Outputs

- Emissions – GHG and conventional air pollutants
  - With market-clearing allowance price for GHG cap-and-trade program
  - GHG offset prices and quantities used
- Power Sector
  - Demand, generation, capacity, wholesale prices, retail electric rates
- Fuel use and market shares
  - Oil, natural gas, coal, gasoline, diesel, ethanol, biodiesel, etc.
- Levels of Energy Efficiency
- Examples of model output
  - http://www.epa.state.il.us/air/climatechange/documents/07-09-06/modeling-of-policy-proposals.ppt (Illinois)
  - http://dnr.wi.gov/environmentprotect/gtfgw/documents/reference_case_outputs_20080416.pdf (Wisconsin)

Status of Assumptions Book

- We are processing input from April 14 stakeholder call and from emails
- We will post a new version prior to June 9 stakeholder call



Western Climate Initiative

Draft Design Recommendations on Elements of the Cap-and-Trade Program

May 16, 2008

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Introduction

The Western Climate Initiative (WCI) began in February 2007 when the Governors of Arizona, California, New Mexico, Oregon, and Washington agreed to:

- join The Climate Registry;
- develop a regional greenhouse gas reduction goal consistent with their state goals; and
- design a multi-sector market-based mechanism by August 2008 to help meet the greenhouse gas reduction goal.

The five Governors invited other states, provinces and tribes to join the WCI or to participate as observers. Since the initial signing, the Premiers of British Columbia, Manitoba, and Quebec and the Governors of Montana and Utah have joined the Initiative. The states of Alaska, Colorado, Idaho, Kansas, Nevada and Wyoming participate as observers, as do the provinces of Ontario and Saskatchewan and the Mexican border states of Baja California, Chihuahua, Coahuila, Nuevo Leon, Sonora, and Tamaulipas.

The WCI Partners issued their regional greenhouse gas reduction goal on August 22, 2007 (see: http://www.westernclimateinitiative.org/ewebeditpro/items/O104F13006.pdf). The regional goal is a 15 percent reduction from 2005 levels by 2020. This regional, economy-wide goal is consistent with the state and provincial goals of the WCI Partners and does not replace the Partners' existing goals. The WCI Partners also re-committed to do their share to reduce regional GHG emissions sufficiently over the long term to significantly lower the risk of dangerous threats to the climate. Current science suggests that this will require worldwide reductions in carbon dioxide emissions of 50 percent to 85 percent below current levels by 2050.

On October 29, 2007, the WCI Partners released their Work Plan of WCI activities through August 2008 for public review and comment. Comments on the Work Plan were requested and more than 100 organizations and individuals submitted comments. As directed by the Governors and Premiers, the Work Plan describes the process for developing design recommendations for a proposed cap-and-trade program as one element of the WCI's effort to identify, evaluate, and implement ways to reduce greenhouse gas (GHG) emissions and achieve related co-benefits.

Developing Design Recommendations for a Cap-and-Trade Program – The Process

Five WCI subcommittees (each chaired by one of the Partners) are working toward a cap-and-trade program design that all Partners can embrace and implement. The five subcommittees and their purposes are:

- **Reporting:** Recommend the reporting system needed to support the WCI program.
- **Electricity:** Define the point of regulation for the electricity industry.
- **Scope:** Identify the other sectors and sources to include in the cap-and-trade program in addition to the electricity sector.
- **Allocations:** Specify how to distribute emission allowances.
- **Offsets:** Examine whether and how emission offset projects should be included.

Each subcommittee is comprised of staff from partner and observer jurisdictions, and each has support from various consultants working under contract to WCI. The subcommittees meet regularly by conference call and at times hold face-to-face meetings.

All subcommittees have incorporated stakeholder involvement and feedback to help design the program. The stakeholder process includes three workshops. The first was held in Portland on January 10, 2008 and was attended by more than 300 people with another 200 people participating via Webinar. Before the workshop, each of the five subcommittees released for public review and comment papers describing the major options under consideration. After the workshop, each subcommittee held a conference call to get extra stakeholder input and answer questions.

Information about the WCI is regularly updated on the WCI website. The website is also the portal through which stakeholders and the public can submit comments to the Partners and sign up for the WCI listserv (www.westernclimateinitiative.org).

Outreach during March – August 2008

The WCI outreach activities described below supplement the individual outreach conducted by each of the partner states and provinces.

Activity	Date
Scope of Work for Economic Analysis ▪ See http://www.westernclimateinitiative.org/Economic_Analysis.cfm for stakeholder involvement opportunities .	March 3, 2008
Initial Draft Design Recommendations Released	
▪ Scope and Electricity	March 5
▪ Offsets, Allocations, and Reporting	April 3
▪ Offsets Workshop in Vancouver, BC	March 26
Stakeholder Workshop in Salt Lake City to discuss draft subcommittee recommendations	May 21
Draft Program Design Recommendations for public review and comment	Mid-July
Stakeholder Workshop in San Diego	July 29
WCI Program Design Recommendations released	Early September 2008

As called for in the WCI agreement, the WCI Partners are working diligently toward a set of recommendations for the design of a regional cap-and-trade program. The Partners will complete their work on this first phase of the regional program by the end of August and will release their report in early September. The report will also describe next steps, including the expected timelines and critical paths for states and provinces to implement the program.

Draft Recommendations on Elements of the Cap-and-Trade Program

The draft recommendations that follow were developed collaboratively by the WCI Partners. As WCI continues to refine and assess these draft recommendations, it welcomes stakeholder feedback on all the concepts presented in this document. **Comments on this document should be submitted to the WCI website by June 6.**

The goal is to present the draft recommendations for a preferred, fully-integrated program at the July 29 stakeholder workshop in San Diego. Between now and then work will continue to create a program design that helps achieve GHG reduction goals fairly and effectively.

The WCI Partners stress that as they continue to evaluate the scope and design of the cap-and-trade program, they will carefully examine economic impacts, including the impact on consumers and businesses in each jurisdiction. The WCI will model the economic impacts for all sectors that may be included to ensure that the program is cost-effective and fair to consumers and businesses while also meeting the environmental objective.

Also, WCI recognizes that policies that complement the cap-and-trade program will be needed to motivate investments in improved efficiency and other measures to reduce emissions. The WCI will examine a full set of complementary policies as part of the analyses supporting implementation of the cap-and-trade program.

Finally, it is important to point out that the programs developed through this regional initiative will ultimately be implemented through laws, regulations, and policies at the state and provincial level. A high degree of regional consistency is important for the success of the program, but the WCI Partners are diverse geographically, economically, and demographically, and each state and province has unique factors that it will have to address when implementing this program.

Therefore, the WCI Partners are focused on developing a program that builds on the strength of consistent regional approaches, while at the same time understanding that each Partner must have the flexibility to implement the program in a way that addresses the unique characteristics of their jurisdiction.

Draft Recommendations

The WCI Partner states and provinces are pleased to present these draft recommendations on the regional cap-and-trade program for ongoing review and comment by stakeholders and the public. The recommendations focus on the following:

- Reporting
- Scope
- Electricity
- Allocations
- Offsets
- Regional Organization

Reporting

A robust and credible reporting system will be the backbone of the WCI cap-and-trade program. This system must ensure that emissions are quantified and reported accurately and transparently. This will allow regulators in participating jurisdictions to assess compliance of regulated sources, measure progress against state, provincial and regional targets, and generate public trust in this progress. Also, all market participants will rely on the reporting system to make decisions that will be the basis for transactions. Confidence in the reporting system will be critical to the success of the WCI program.

The WCI is fortunate that several GHG reporting systems exist that can inform the design of and perhaps even underpin the WCI reporting system. The Reporting Subcommittee has assessed many of these systems and anticipates that the WCI reporting system will be as consistent as possible with existing systems.

The WCI Partners unanimously agree that the WCI reporting system should rely heavily on the infrastructure that The Climate Registry (TCR) is designing. TCR is a collaboration between U.S. states, Canadian provinces and Mexican states to establish a common infrastructure for measuring and reporting GHG emissions. TCR's objective is to provide a common set of tools that will support a broad range of state and provincial policies. All of the WCI Partners are members of the Board of Directors of TCR.

Draft Recommendations for Reporting

- Breadth/Scope of Reporting
  The WCI recommends that reporting requirements apply to the capped sectors and to certain non-capped sectors that may be phased in later (will have to determine which sectors - lower thresholds may apply).

- Initiation of Reporting
  The WCI recommends that reporting start before cap-and-trade commences in order to avoid reporting-related delays to the start of the cap-and-trade program.

- Coordination Among Partner Jurisdictions
  The WCI recommends developing essential requirements for a model WCI reporting rule by the end of 2008 and will incorporate consideration for jurisdictions that already have reporting rules adopted or in process.

- Data Management and TCR Interaction
  The WCI recommends sources report either (a) directly to jurisdictions (which would then upload the data to TCR's central repository), or (b) through TCR's program framework (which would then download the data to the necessary jurisdiction(s)).

- Verification
  The WCI recommends establishing essential quality assurance elements for reported data. These elements will be consistent across jurisdictions. Each jurisdiction will have an oversight mechanism to ensure compliance with the reporting requirements. As part of this mechanism, each jurisdiction will establish procedures to ensure that the quality assurance elements are met. This could include requiring third-party verification, rigorous compliance audits or other appropriate approaches.

- Administrative Costs & Fees
  The WCI recognizes that jurisdictions may collect fees from sources that report directly to them and contract with TCR to administer the program. Jurisdictions may also accept data directly from TCR if they choose to do so; entities that report through TCR may have to pay an additional fee if one is required by the jurisdiction(s).

- Mandatory Federal Greenhouse Gas Reporting
  The WCI recommends getting involved in federal GHG reporting program development in the U.S. and Canada to ensure that federal reporting programs are harmonized with the jurisdictions' interests to the greatest extent possible.

Summary of Major Comments Received to Date on Reporting Recommendations

Stakeholders have expressed general agreement with the WCI Design Principles relevant to reporting. Stakeholders want a reporting system that is fair, easy to manage, and not costly for reporters or Partner jurisdictions. Stakeholders generally support a transparent and robust accounting system for consistent and accurate reporting of emissions across sectors and jurisdictions. WCI's efforts to harmonize WCI reporting and future federal greenhouse gas reporting are also supported.

Most stakeholders agree that reporting should not be limited to sectors and sources within the cap, but should also include sectors that are likely to be phased in to the market system later. Opinion is divided on whether reporting should extend beyond this scope to sources that are not likely to be in the cap-and-trade system.

Stakeholders overwhelmingly support the idea of beginning reporting before cap-and-trade commences. Many commenters cited the need for WCI to have accurately measured emissions as a basis for allocating allowances.

Commenters generally support development of a single WCI reporting rule, citing the advantages of administrative simplicity and cost effectiveness. Stakeholders are concerned that a lack of consistency would undermine confidence in the use of reported data in a market system. For some commenters, however, continuity with existing jurisdictional reporting systems was a higher priority, and these commenters favored more loosely coordinated rules with common core elements.

Stakeholder opinion remains divided on whether reporting should made directly to The Climate Registry (TCR) or to the Partner jurisdictions for upload to TCR. In part, this disagreement may reflect the different interests of reporters with sources in multiple jurisdictions versus those with sources in only a single jurisdiction. Multi-jurisdictional reporters tend to favor direct reporting to TCR for the simplicity of one-stop reporting, while single-jurisdiction reporters tend to favor combining greenhouse gas emissions reporting with their existing air pollutant reporting directly to the jurisdictions.

Stakeholders also differ on whether third-party verification should be required, either WCI-wide or as an option for individual jurisdictions. Supporters generally see third-party verification as essential to ensuring the accuracy and consistency of data that will be converted to financial credits or liabilities, and point to corporate financial audits as an appropriate analogy. Others see third-party verification as redundant to the jurisdictional compliance and enforcement provisions that will be applicable to reported data. This latter view is held most strongly by electricity generation commenters, who cite their existing requirements for continuous emissions monitoring of carbon dioxide from power plants. Reducing uncertainty over verification costs may help to resolve this issue.

Commenters are divided on whether reporting fees should go directly to TCR or to Partner jurisdictions which would then contract with TCR for its data management services. This issue is related to the question of where the data should be reported, and similar considerations are raised on either side. Some commenters are also concerned that governmental accountability for funds will be lacking or diminished if fees go directly to a non-profit entity.

Design of the reporting system will continue beyond the September 2008 announcement of WCI Program Design. Completion of the essential requirements for GHG reporting rules is scheduled for December 2008. During this period, the Reporting Subcommittee will develop more specific proposals and will seek stakeholder comment. Greater specificity may help to resolve some stakeholder concerns. Comment will be sought on key issues including:

- Emissions quantification methodologies for specific sectors and source types;
- Design of the reporting system, including the user interface and the relationship to TCR's mandatory reporting support function;
- Thresholds for reporting;
- Operational boundaries for reporting;
- Verification and/or other quality assurance requirements; and
- Other details in the essential requirements for Partner GHG emissions reporting rules.

Scope

Scope defines the GHG emissions that are included in the cap-and-trade program, including:

- The sectors that fall under the cap.
- The emissions sources that fall under the cap.
- The greenhouses gases that fall under the cap.
- The point(s) of regulation where the cap would be enforced.

From the scope definition, any entity or facility must be able to tell whether it has a compliance obligation under the cap, and which of its emissions are subject to the obligation. The "point of regulation" is the portion of the scope definition that identifies the entities that have the obligation to surrender GHG emission allowances to cover GHG emissions.

The draft recommendations are based on the WCI's analysis and assessment of the Major Options released in January 2008. The WCI developed and applied evaluation criteria to the major options, taking into account stakeholder comments received in writing and during conference calls.

Draft Recommendations for Scope

- Industrial and Commercial Sources
  The WCI recommends a base program from the start of the cap-and-trade program that includes the electricity sector, large stationary combustion sources, industrial process and waste management emissions, and fossil fuel production and processing. (Please see Electricity section for information on recommended approaches for that sector.) All six GHGs are recommended for inclusion.

  The WCI recommends that high priority be placed on developing GHG reporting protocols for the fossil fuel production and processing sector so that as much of this sector as possible can be included in the cap-and-trade program from the start.

- Transportation Fuels
  Emissions from transportation fuels are the single largest source in the region (about 36 percent of total emissions), and must be addressed through an effective combination of near-term and long-term policies. Most Partners have a strong interest in including transportation fuels in the cap-and-trade program. However, before recommending how best to reduce emissions in this sector, analyses of the economic impacts of various options for including transportation fuels in the program will be examined, including the potential effectiveness of alternative policies for reducing these emissions. Options to be considered include the potential to phase in transportation fuels in a later stage of the program, other fiscal measures to regulate this sector, and special consideration for low-income populations and other communities most adversely impacted by consequent price change in the sector. It is anticipated that a decision on how to address transportation fuels will be informed by economic modeling and additional analysis in the coming months.

- Residential and Commercial Fuel Combustion
  The WCI recommends including residential and commercial fuel combustion in the cap-and-trade program and acknowledges that individual jurisdictions may instead utilize comparable

fiscal measures, such as British Columbia's carbon tax, to regulate these sectors. The WCI is also considering whether to include these emissions within the program beginning with the first or second compliance period. The point of regulation for including the emissions from this fuel use would be at the point where these fuels are distributed, including: local distribution companies for natural gas; an appropriate upstream point for propane (LPG), such as refineries and wholesalers; and fuel oil distribution points (which may vary among partner jurisdictions).

- Thresholds
  The WCI recommends using an emission threshold to define the facilities that would have a regulatory compliance obligation under the cap-and-trade program. The WCI recommends setting the threshold so that at least 90 percent of non-power plant stationary source fuel combustion emissions WCI-wide are covered by the program. Based on an initial review of available data, the WCI believes that a threshold within the range of 10,000 to 25,000 metric tons of CO_2e per year per facility may achieve this objective and to assure consistent coverage of facilities within industries and across jurisdictions. The WCI is continuing to evaluate this threshold range, and is examining whether categories of facilities should be included or excluded from coverage regardless of their annual emissions rate. WCI is still considering whether, and at what level, to apply thresholds to electricity sector entities that have compliance obligations.

- Future Program Expansion
  The WCI recommends that the scope of the cap-and-trade program be capable of expanding over time. Possible factors for bringing in additional sources into the program include:

  - Advancements in monitoring technologies, procedures, and/or protocols which would enable the cost-effective inclusion of additional sources and types of greenhouse gas emissions, or smaller-sized sources within currently covered categories, particularly if mandatory reporting data show these sources to be larger contributors than expected;
  - Sources or sectors whose exclusion from the program leads to emissions leakage or competitiveness issues;
  - Resolution of legal or administrative issues that had precluded the inclusion of a source or sector; and
  - Addition of new jurisdictions to the cap-and-trade program.

  Sources that are considered as viable offset projects at the start of the cap-and-trade program may become part of the program at a future date.

Summary of Major Comments Received to Date on Scope Recommendations

The WCI Scope Subcommittee has received public comment at in-person meetings, on conference calls for stakeholders, and in written form. These public comments responded to the options papers released by the WCI in January 2008 and the draft recommendations released in March 2008.

The WCI received written comments from 38 organizations in response to the major options paper, and from 43 organizations in response to the draft recommendations. Many of these organizations represented multiple entities, including businesses and non-profits. Stakeholders also provided comments at teleconferences on February 12 and March 11, 2008 and at the public workshop in Portland on January 10, 2008. The subcommittee requested and received comments on a large number of topics, including sector coverage, point of regulation, thresholds for inclusion of specific sources, greenhouse gas coverage, phasing of source inclusion, coverage of transportation fuels and residential and commercial natural gas, as well as specific concerns for various industries, sectors and sources.

In general, most comments supported a broad coverage of sources under a cap-and-trade program with a point of regulation as close to the point of emissions as possible. Stakeholders asked the subcommittee to include as many sources as administratively and technically possible in order to increase the availability of low-cost emission reductions and to lower the total cost of the cap-and-trade program. Comments also addressed the following:

- Many comments emphasized the importance of available and correct quantification methods in order to include a source in the program, and of reliable data for the design and operation of the program. These comments focused on a desire to avoid double counting emission reductions and to ensure the integrity of a trading system.
- Comments also reflected a desire for certainty about which sources would be included, especially if the program phased in new sources over time.
- Some comments asked for further analysis of outstanding issues such as the inclusion of transportation fuels and commercial and residential natural gas, and suggested varying approaches for these sources. These issues, particularly the inclusion of transportation fuels, received substantial attention. One-third of the comments received after the release of the major options paper related to the issues of transportation fuels.
- Many comments expressed concern that sources not covered under a cap-and-trade program remain responsible for the emission reductions necessary to achieve the regional greenhouse gas emissions target.

The subcommittee remains interested in receiving stakeholder comments. The subcommittee's recommendations include a number of topics that will require further consideration, including transportation fuels and emission source thresholds. The subcommittee has carefully reviewed and considered stakeholder comments in order to formulate the draft recommendations contained in this document.

Electricity

Draft Recommendations for Electricity

- Point of Regulation and Coverage
  The WCI recommends a point of regulation for the electricity sector that maximizes coverage and minimizes emissions leakage.

    - A generator-based approach to covering the electricity sector is preferable.
    - The generator-based option will be most effective with universal participation throughout the Western interconnect.
    - A proposal to bring in additional generators serving the Western interconnect will be developed, including a date by which those other jurisdictions will join the WCI. If the additional Western Electric Coordinating Council (WECC) jurisdictions do not join by that date, the WCI will continue to develop the first jurisdictional deliverer approach described below.
    - Because not all generators serving the western interconnect are currently within the WCI, additional measures are needed to maximize coverage and minimize leakage.
    - The first jurisdictional deliverer approach should address the coverage and leakage issues during the transition to full WECC participation in the WCI:
        - The first jurisdictional deliverer approach covers all emissions generated in WCI and all emissions attributable to electricity delivered in WCI but generated outside WCI.

- Leakage
  The WCI recommends exploring additional complementary measures to reduce leakage.

- Allocation in the Electricity Sector
  The point of regulation does not dictate the method of allocation, and the Partners are continuing to work on the allocation issue.

The Electricity Subcommittee is now in the process of working through questions raised by the Partners, including how additional generation in the WECC can be brought into the WCI, and how the first jurisdictional deliverer approach would actually be implemented in Partner jurisdictions.

Summary of Major Comments Received to Date on Electricity Recommendations

To date, the WCI Electricity Subcommittee has received more than 100 comments from more than 60 parties, or coalitions of parties. The comments have come from utilities, trade groups, environmental NGOs (non-governmental organizations), religious institutions, and public interest groups interested in social justice.

Some commenters have noted that a federal approach would be preferable to WCI because leakage would be reduced. Others have called for no action by the WCI because a federal approach may eventually appear. Initially, the subcommittee suggested five options for the point of regulation for electricity. Each option had some support from at least a portion of those who commented, while many parties have requested that WCI not make a final decision until economic modeling is completed. However, consensus seems to have emerged around two approaches: generator-based and first jurisdictional deliverer (FJD).

Many commenters have called for a generator-based approach if all WECC jurisdictions participate in the WCI. Some commenters have argued that additional measures beyond a generator-based approach would be necessary to prevent contract shuffling and windfalls to electricity importers. Parties have suggested that the additional measures could include complementary measures, a load-generator hybrid, and FJD.
Some commenters have advocated starting with a generator-based approach and eventually shifting to FJD. Others have called for optional phasing in of FJD. Still others have advocated using FJD as the starting point. Some parties are concerned about the tracking necessary for load-based approaches and FJD, and they are worried that either method may have high administrative costs. Commenters have also expressed concern about the potential for gaming the system under the hybrid approaches. Some commenters are concerned about grid stability with any approach. The WCI Partners are still assessing the public comments and other analyses to determine the appropriate point of regulation for this sector within the regional program.

Many parties have commented on allowance allocation in the electricity sector. Requests have run the gamut from advocating for 100 percent auctioning to promoting 100 percent free allocation. Many parties have called for auctioning with auction revenues used for the benefit of consumers by giving the auction proceeds to rate-regulated entities or directly to consumers. Many commenters have worried about competitive impacts to businesses in the WCI under designs that include auctions. Some parties have requested that one or more economic sectors be exempted from auctioning. Parties have advocated allocation protocols based upon historical emissions, load, or output singularly or in combination. Similarly, commenters have advocated for apportionment among Partners based upon Partner targets, averaging of Partner targets, historical emissions, load, output, population, and GDP (gross domestic product), singularly or in combination.

Many parties have commented that combined heat and power (CHP) facilities should be covered under a separate sector and given credit for lower emissions. Other parties have noted that if a CHP facility produces fewer emissions, it should do well if it is regulated under the electricity sector like other generators. Some parties have called for unique treatment for their particular situations, while other commenters have requested even treatment for all entities across the sector. Parties have also called for a set-aside of allowances for the voluntary renewables market to ensure that market's viability.

Allocations

Draft Recommendations for Allocations

- Regional Cap and Allowance Budgets
  The WCI recommends establishing a regional cap that will decline over time, and each Partner will have an allowance budget within the cap. Actual emissions from any given Partner could be greater or less than its allowance budget, depending on the extent of inter-jurisdictional allowance trading.

  The regional cap will be equal to the sum of the Partner allowance budgets. Reductions achieved by the cap plus reductions from uncapped sources resulting from complementary measures should achieve the WCI regional goal of a 15 percent reduction below 2005 levels by 2020.

  The initial regional cap and Partner allowance budgets will be set through 2020. The regional cap and each Partner's allowance budget will not be adjusted except as necessary to account for changes in WCI membership, sectors added to the cap, errors discovered in data used to determine the cap or the Partner budgets, which may become apparent after the start of mandatory reporting, or errors that resulted in either under-allocation or over-allocation of allowances. Such adjustments will take effect at a regionally coordinated and designated time, such as the beginning of the relevant compliance period.

- Distribution of Allowances by Partners
  The WCI recommends that once the allowance budget has been established for each Partner, allowances will be issued by each Partner rather than issued by a regional organization. Allowances will be of equivalent use and value throughout the WCI region, regardless of which Partner issues the allowances.

- Establishment of Cap-and-Trade Partner Budgets
  The WCI recommends that each Partner's allowance budget will be established in a transparent manner. This will be consistent with the emission reductions that the WCI must realize from the sources covered by the cap-and-trade program in order to achieve the WCI economy-wide emissions reduction goal.

  The Partners will develop a methodology for calculating the Partner allowance budgets. The methodology should set the Partner allowance budgets at the levels needed to achieve the WCI economy-wide emissions reduction goal.

  The WCI seeks comments from stakeholders on the methodology for establishing Partners' allowance budgets and the factors to be included in the methodology.

- Partners' Initial Allowance Budgets
  The WCI recognizes the potential conflict between the need to begin the cap-and-trade program as soon as possible to reduce GHG emissions, and the need for accurate data to calculate allowances for the regional cap and individual Partner budgets. Substantial emissions data is already available due to reporting under existing regulatory requirements for other pollutants and energy consumption, as well as the GHG emissions inventories and forecasts compiled by the Partners, but data from mandatory reporting of GHG emissions may be necessary for more precise allocations of allowances. With this in mind, the calculation of the regional cap and the Partner allowance budgets for the initial years of the cap-and-trade program will recognize potential concerns about data accuracy and will be adjusted in ensuing years as necessary if mandatory reporting reveals significant data errors.

- Partner Discretion to Issue Allowances
  The WCI recommends each Partner initially have flexibility to issue, beyond the minimum percentage auction amount discussed below and subject to the sector-specific assessments discussed below, its remaining allowances as it sees fit, including:
    - auctioning more than the minimum amount of allowances;
    - issuing some or all of the remaining allowances for free;
    - holding some or all of the remaining allowances within a compliance period; and/or
    - retiring some or all of the remaining allowances.

  The WCI recommends each Partner initially have discretion to issue allowances differently to different sectors within its jurisdiction. Each Partner may decide how and to whom to issue the allowances in its allowance budget, subject to the minimum auction requirement and the sector-specific assessments of competition outlined below.

  While each Partner initially will have flexibility in how it allocates the allowances beyond the minimum auction amount, at the beginning of the relevant compliance period, each Partner will be required to advise the other WCI Partners how it intends to allocate the remaining allowances, so that the WCI can make the Partners' plans public in a coordinated fashion. This procedure will help reduce the potential for adverse impacts on auction prices by preventing allowances from being "dumped" into the market unexpectedly.

  Any Partner that chooses to hold allowances must allocate or retire those allowances by the end of the applicable compliance period. A Partner will not be able to hold allowances beyond the end of the compliance period. These requirements will help reduce market instability by providing more certainty about the volume of allowances available during a compliance period.

  The Partners will continue to examine the impacts of Partners using different approaches to allocate allowances to the same sectors and will seek comments from stakeholders on this issue.

  The Partners also will continue to consider the impacts of Partners making different use of auction proceeds and will seek comments from stakeholders on this issue.

  While the Partners initially will have flexibility to issue allowances, over time, the WCI will seek to standardize distribution of allowances as much as possible.

    - *Sector-Specific Assessment of Competition Among WCI Jurisdictions*:
      While the Partners initially will have significant flexibility in issuing allowances, a diverse array of allocation procedures could yield significant cost differentials among competing firms or industries among WCI jurisdictions. There may be cases where it is necessary to assess whether allocations to a particular sector should be treated uniformly by all Partners in the WCI region to address competition among entities within the WCI region. This potential could be minimized through a continued dialogue among the Partners and harmonization of allocation procedures and the use of auction proceeds where appropriate.

      The Partners believe that only a few sectors face significant risks of unfair competition from differing allocation methods among the WCI Partners, and a harmonized approach would be limited to carbon-intensive industries facing significant competition among WCI jurisdictions. For such cases, a case-by-case sector-specific analysis will be conducted jointly by the WCI Partners to determine whether consistent allocation is needed to address such disparities within the WCI. This approach will provide for an efficient cap-and-trade program while providing the Partners flexibility to address their individual priorities.

  - *Sector-Specific Assessment of Competition with Non-WCI Jurisdictions*:
    While the Partners initially will have significant flexibility in issuing allowances, a diverse array of allocation procedures could yield significant cost differentials among competing firms or industries within the WCI and those outside the WCI, resulting in leakage outside the WCI region. There may be cases where it is necessary to assess whether allocations to a particular sector should be treated uniformly by all Partners in the WCI region to address competition and leakage from entities outside the WCI region. This potential can be minimized through a continued dialogue among the Partners and harmonization of allocation procedures and the use of auction proceeds where appropriate.

    The Partners believe that leakage of this type is likely an issue only for bulk commodity sectors with high GHG emissions per unit of output that face significant non-WCI competition, and a harmonized approach would be limited to carbon-intensive industries facing significant competition outside the WCI region. For such cases, a sector-specific analysis will be conducted jointly by the WCI Partners to determine whether consistent allocation is needed to address non-WCI region leakage. This approach will provide for sufficient standardization for an efficient cap-and-trade program while providing the Partners flexibility to address their individual priorities.

- Minimum Auction Percentage
  The WCI recommends each Partner auction a minimum percentage, between 25 percent and 75 percent, of its allowance budget through a coordinated regional auction process. Each Partner will auction allowances throughout the WCI region and will receive the proceeds of the auction.

  The Partners will determine a specific minimum percentage auction amount. The WCI seeks comments from stakeholders on this question.

  Because multiple Partners would be simultaneously auctioning allowances through a single pool, the auction could result in Partners auctioning or selling some of their allowances to entities in other jurisdictions. This outcome is fully consistent with the concept of regional trading and the importance of allowances having equivalent use/value for compliance purposes throughout the WCI region.

- Phased Increase of Auctioning
  Greater emphasis could be given to free allocation in the early years of the program (and more to auctions in later years) as a means to mitigate business and consumer cost impacts and to provide transition assistance, in addition to using auction proceeds for these purposes. Some Partners may choose to provide more time for an allowance market to develop before capped entities must purchase larger portions of their allowances in an auction.

The minimum percentage of allowances to be auctioned should be increased over time, potentially to 100 percent. Even before such an increase, each Partner will have discretion to auction more than the minimum percentage of its allowances as it sees fit.

- Credits for Early Reductions
  The WCI recommends each Partner have discretion to give credit for early actions, but any credit for early action must come from within the cap and will come out of the individual Partner's allowance budget. Early action credits will not be added to or be on top of the amount of allowances in each Partner's allowance budget.

- Banking
  The WCI recommends purchasers and covered entities be allowed to bank allowances, without restrictions on the amount of allowances that may be banked or on how long they may be banked.

- Borrowing
  The WCI recommends that borrowing of allowances from future compliance periods not be allowed.

- Compliance Periods
  The WCI recommends the compliance periods be three years long.

  Multi-year compliance periods will provide covered entities with flexibility for compliance and in planning for (or responding to) large and unexpected changes in the allowance market or in other markets, such as energy markets, which may affect allowance prices. They also will provide programmatic flexibility for the WCI—for example, to ensure a steadily declining cap. The Partners note that three years is the length of the compliance periods chosen by the Regional Greenhouse Gas Initiative (RGGI).

- Initial Compliance Period
  To accommodate start-up issues, both from the covered entity standpoint and the regulatory standpoint, the WCI recommends that the initial compliance period include special rules, such as a two-year period, or other measures to assist in the transition into a cap-and-trade system, while maintaining the integrity of the cap and value of the allowances.

- New Partners
  The WCI recommends allowances for new Partners be in addition to the existing allowance budgets for current Partners. The regional cap will be expanded to accommodate emissions from the new Partner.

  Once the cap-and-trade program has been instituted, new Partners will come into the cap-and-trade program at a regionally coordinated and designated time, such as the beginning of the relevant compliance period.

- Timelines for Partner Activities
  The Partners will develop a schedule for various WCI efforts, including launching the cap-and-trade program, establishing emissions baselines and Partner allowance budgets, undertaking any case-by-case discussions on competition or leakage issues which may affect Partner allocation plans and other various allocation-related efforts.

Summary of Major Comments Received to Date on Allocations Recommendations

The WCI Allocations Subcommittee issued its Draft Design Recommendations for public comment on April 2, 2008. Fifty-six (56) comments were received from stakeholders by the April 16, 2008 deadline, with an additional five (5) comments received after the deadline. The subcommittee is still reviewing the comments and has not yet determined whether any of the draft allocations recommendations should be modified in light of the comments.

A diverse group of stakeholders provided comments on the draft allocations recommendations, including industry/trade associations (15), utilities (13), NGOs (11), government agencies (3), private citizens (2), and miscellaneous business entities (12). Nineteen (19) of the comments came from stakeholders with multi-state operations or interests; the remainder came as follows: Washington (10), California (9), Oregon (5), British Columbia (4), Arizona (4), Canada (3) and New Mexico (2).

Not surprisingly, the commenters provided a wide diversity of comments on the draft recommendations, with little consensus on several key issues. For example, comments on the WCI's draft recommendations regarding the regional cap and the Partner allowance budgets included the following divergent perspectives:

- The allowance budgets should be based on load or output.
- The allowance budgets should be based on historical emissions.
- The allowance budgets should be based on the state and provincial goals.
- Partner budgets should be identical to Partner commitment to the regional goal.
- Budgets should not be determined until accurate data are available.
- Budgets should include some set aside (3-5 percent) of allowances for new entrants.

Similarly, while some commenters called for free allocation of allowances to utilities, others argued for auctioning a significant percentage of the allowances. A number of commenters (e.g., NGOs) called for 100 percent auctioning, while others (e.g., utilities) argued that only a very small percentage (5 percent or less) of allowances should be auctioned, if at all.

There also were differences of opinion about the degree of flexibility that Partners should have to allocate allowances. Some who opposed flexibility expressed concern that the lack of uniformity could result in leakage. To minimize potential for leakage, one commenter suggested adopting consistent rules for reporting, tracking and compliance obligations. Another suggested distributing allowances to a third party.

There was a general level of support expressed for the WCI's draft recommendation regarding credits for early reductions, but a few commenters preferred that credits come from outside each Partner's allowance budget.

By the same token, more commenters than not supported the WCI's draft recommendations to allow unlimited banking but prohibit borrowing of allowances. Commenters supported the recommended three-year compliance periods by a wide margin. And to the extent that comment was received on the desirability of a regional organization, it was well received.

Finally, some commenters offered advice on topics not directly addressed in the draft allocations recommendations, including the following:

- Develop an independent Market Oversight Committee to develop best practices to guard against market manipulation, hold down consumer costs and avoid burdens on state economies.
- Consider more practical alternatives to address hoarding of allowances.
- Have a cost containment mechanism
- Have a safety valve.
- Do not have a safety valve.
- Have a price ceiling for allowances for a defined period.
- Allow only emitters to participate in auctions.
- Allow anyone to purchase allowances at auctions.

The WCI appreciates the range of ideas and perspectives expressed in the comments and will give them serious consideration as we move develop the draft design document.

Offsets

Draft Recommendations for Offsets

The primary role of the offset program is to reduce the overall compliance costs for the cap-and-trade system, by enabling the offset market to deliver lower-cost emission reduction options than are available in the sectors/sources included in the cap-and-trade system. In addition, by lowering overall costs, an offset program can potentially offer greater environmental benefits. The offset program can also serve to encourage innovation, co-benefits, greenhouse gas emission reductions from sources not covered by the cap-and-trade system and removals by sinks.

- <u>Offset project types and protocols</u>
  The WCI recommends:
  - development of an initial set of eligible project types and approved protocols prior to cap-and-trade program launch;
  - developing a process to review and approve other project types and related protocols proposed by project developers;
  - using protocols that are standardized to the extent possible; and,
  - making use of, and adapting if needed, existing protocols as appropriate.

- <u>Offset projects approved through the WCI offsets program</u>
  The WCI should consider a method that gives priority to offset projects located within WCI jurisdictions. The method should also consider other roles of the offset system, such as ensuring that co-benefits occur within the region.

  In addition to those offset projects approved within its jurisdictions, the WCI should consider approving offset projects located throughout Canada, the United States, and Mexico, where such projects would be subject to comparably rigorous oversight, validation, verification and enforcement as those located within the WCI jurisdictions and would not undermine the ability for the WCI to link to other trading systems.

- <u>Tradable units from government-regulated GHG emission trading systems</u>
  For compliance purposes, the WCI should consider allowing individual regulated entities to use tradable units (offsets and allowances) from other government-regulated GHG emission trading systems that the WCI recognizes as meeting similarly rigorous criteria for environmental integrity.

  The WCI should ensure accounting systems are in place to prevent using tradable units more than once for compliance.

- <u>Quantity Limits</u>
  The WCI recommends limiting the use of offsets and non-WCI tradable units for compliance by individual regulated entities:
  - to ensure that meaningful emission reductions take place within the sources covered by the cap-and-trade system.
  - in recognition that foregoing emission reductions at facilities covered by the cap-and-trade program in the WCI states has the potential to forego health benefits and other benefits near those facilities.

The WCI Offsets Subcommittee will consider making a specific draft recommendation to the WCI, based on further analysis and considering the level of the cap set for the cap-and-trade system.

Summary of Major Comments Received to Date on Offsets Recommendations

In each of the opportunities for stakeholder engagement on the design of a cap-and-trade system for the Western Climate Initiative, there has been strong support for including an offset program. Stakeholders have expressed a desire to see the offset program focus on ways to reduce the overall cost of meeting GHG emission reduction targets, whether through reduced compliance costs for emitters, reduced economic impact for consumers, or increased economic opportunities to encourage emission reductions. Stakeholders have also shown a strong and consistent concern for the environmental integrity of the offset program, realizing the direct connection between the integrity of the offsets and the integrity of the regional target.

Many stakeholders feel that offsets should be allowed to enter the WCI system from sources outside the WCI, by project approval through the WCI process or as approved trading units from other cap-and-trade systems. A number of stakeholders also believe there are compelling economic, environmental and social reasons to give priority to offset projects from within the WCI or to phase in other regions over time as experience grows. Several stakeholders suggested ways to develop or design limits on the type of offsets, including basing limits on project location. The WCI Offsets Subcommittee recognizes that offset projects must reduce or remove GHG emissions and may have co-benefits regardless of where the project is located, and will continue to examine the balance of economic, environmental and social benefits in the design of the program.

Given the encouragement to focus the offset program on reducing cost for the cap-and-trade system, some stakeholders find the concept of limiting the use of offsets to be counterproductive, reasoning that limiting the use of lower cost compliance alternatives simply means higher cost compliance. Other stakeholders argue that an oversupply of inexpensive offsets could reduce the impetus for capped emitters to make progress on direct emission reductions. The subcommittee invites further suggestions on the design of limits or alternative methods to balance the use of offsets with reductions under the cap.

Stakeholders generally supported the recommendation to establish a centralized administrative body to perform routine processing and management functions.

Regional Organization

Draft Recommendations for Regional Organization

WCI recognizes that a regional organization will be helpful for coordinating Partner activities and improving efficiency by centralizing the execution of administrative tasks. While WCI is continuing to identify suitable roles for a regional organization, the following options have been identified to date:

- Although emission allowances will be issued and distributed by each Partner, a regional organization may be directed to coordinate the regional auction of allowances, track emissions and allowances, monitor and report on market activity, and conduct other activities. A centralized offset registry is also required that integrates with the emissions and allowance tracking system.

- A regional organization may provide a venue for coordinating analyses of competitiveness and leakage issues resulting from potentially divergent allocation procedures among the WCI Partners. Such issues could be resolved through this regional organization or some other forum.

- A regional organization may provide a forum through which each Partner updates the other Partners every two years on its progress toward achieving the regional goal and its individual goal

- The administrative structure of the offsets program should combine optimal aspects of jurisdiction-by-jurisdiction, public-private partnership, and centralized regional approaches, and may draw from existing programs. The role of a regional organization may include:
  - coordinating review and adoption of protocols for offsets;
  - coordinating review and issuing of offsets;
  - providing the criteria and means to accredit service providers to deliver validation and verification services for offsets.

Each jurisdiction will retain its regulatory authority and enforcement responsibilities. By centralizing administrative tasks and coordinating Partner activities, the regional organization will help reduce administrative costs and improve program transparency and consistency.

May 16, 2008 Draft Design Recommendations on Elements of the Cap-and-Trade Program

List of Commenters

Air Transport Association of America

American Gas Association

Arizona Public Service

Associated Oregon Industries

Association of Washington Business

Burkhart, Dick

Business Council for Sustainable Energy

Camco

Canadian Cement Industry

Canadian Lime Institute

Canadian Parks and Wilderness Society

Carbon Offsets Providers Coalition

Cement Association of Canada

Center for Energy Efficiency and Renewable Technology

Chevron

Climate Protection Campaign

Climate Solutions

Climate Trust

ConocoPhillips

Consultec

EcoSecurities

EcoTrust

Environmental Defense Fund, Natural Resources Defense Council, Pacific Forest Trust, and Western Resource Advocates

FPL Energy Project Management, Inc.

Grant County Public Utility District

Hydro Quebec

Independent Energy Producers Association

Industry Provincial Offsets Group

MISYS

Morgan Stanley Capital Group, Inc.

Northwest Natural

Northwest Pulp and Paper Association

Nucor Steel

Offset Quality Initiative

Oregon Municipal Electric Utilities Association

PNGC Power

Portland General Electric

Public Power Council

Public Utility District No. 1 of Chelan County

Puget Sound Energy

Renewable Energy Marketers Association

Renewable Northwest Project

Rio Tinto

Salt River Project

Sightline Institute

Soil Carbon Coalition

Solid Waste Industry for Climate Solutions

Southern California Edison

Tacoma Power

Terasen Gas

Tri-State Generation and Transmission Association, Inc.

Union of Concerned Scientists

Utah Association of Energy Users

Washington Electric Cooperatives Association

Washington Forest Protection Association

Washington Public Utility Districts Association

Washington Rural Electric

WEST Associates

Western Climate Action Network

Western Forestry Leadership Coalition

Williams

Western Climate Initiative

Welcome

May 21, 2008

Salt Lake City, Utah

Western Climate Initiative

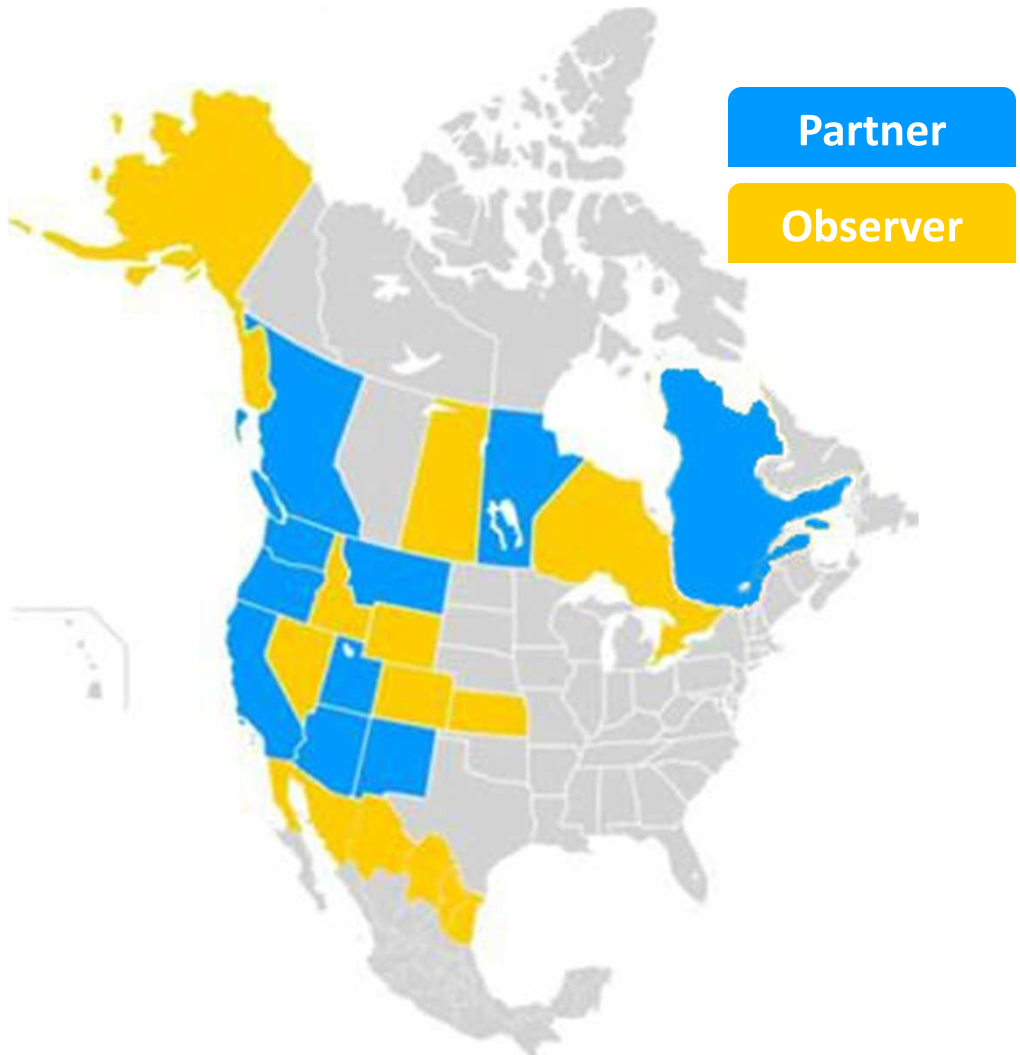
WCI Overview and Status

May 21, 2008

Salt Lake City, Utah

Western Climate Initiative

- **Develop regional strategies to address climate change**
- **Washington, Oregon, California, Arizona, and New Mexico signed in February, 2007**
- **Montana, Utah, British Columbia, Manitoba and Quebec have signed on**
- **6 US states, 6 Mexican states and 2 Provinces are official observers**



Collaboration includes

Three specific directives:

- Set a regional emissions reduction goal
- Join a multi-state registry to track, manage and credit reductions
- Design a regional multi-sector market-based mechanism

Joint work to:

- Promote clean and renewable energy in the region
- Increase energy efficiency
- Advocate for regional and national climate policies that are in the interest of western states
- Identify measures to adapt to climate change impact

Western Climate Initiative Status

Achieved two of the three directives:

- A regional goal established
  - 15% below 2005 by 2020
  - Committed to long term reductions to significantly lower the risk of dangerous threat

- All partners and observers have joined The Climate Registry as founding members

Timeline

- 5 subcommittees underway
  - Preliminary recommendations released in Feb and March, 2008
- Consolidated recommendations released on May 16, 2008
- Initial draft design mid-Summer, 2008
  - Next workshop July 29 in San Diego
- 'Final' design recommendations late-Summer, 2008
  - Will include next steps on design details and program implementation

Subcommittees

- Scope
  - Sectors; sources; gases; and point(s) of regulation
- Allocations
  - Apportioning allowances under the cap
- Electricity
  - Point(s) of regulation
- Reporting
  - Coordination: Regional, TCR, EPA; Verification
- Offsets
  - Project location and types; limits; links to other systems

Subcommittees are also starting to identify areas for coordination through a regional organization

Stakeholder Involvement

- Stakeholder input is critical to the success of the initiative
- All WCI Partners appreciate the interest and input to date
- A number of important design issues are still under discussion
- Today's workshop will help inform the dialogue among the partners on these issues
- Additional input opportunities over the summer
- Stakeholder process will continue in the next phase of program development

Western Climate Initiative

Scope Draft Recommendations

Michael Gibbs, Cal/EPA

Scope Subcommittee, Chair

May 21, 2008

Salt Lake City, Utah

Overview

- Mission
- Process
- Draft Recommendations
- Comments

Mission

- Recommend the scope of a proposed cap and trade program:
  - The sectors that fall under the cap.
  - The emissions sources that fall under the cap.
  - The greenhouses gases that fall under the cap.
  - The point(s) of regulation where the cap would be enforced.
- Electric Sector evaluated by the Electricity Subcommittee.

Mission (Continued)

- The Subcommittee is balancing multiple objectives, consistent with the WCI design principles
  - …administratively simple …
  - …minimizes administrative costs…
  - …covers as many sources as is practical…
  - …minimizes the potential for leakage…
  - …facilitates linkage…

Mission (Continued)

- Evaluate:
  - Emissions
  - Ability to measure/calculate emissions at the entity level
  - Administrative feasibility
  - Risk of emission leakage

Process

- Work Plan: October 2007
- Major Options: January 2008
- Workshop: January 2008
- Conference Call: February 2008
- Draft Recommendations: March 2008
- Conference Call: March 2008
- Written comments throughout

Draft Recommendations

- Industrial and Commercial Sources
  - Stationary combustion
  - Industrial processes
  - Waste management
  - Fossil fuel production and processing
  - All six GHGs
- Subject to:
  - Thresholds
  - Quantification methods

Draft Recommendations

- Thresholds
  - Balance emission coverage with administrative burden
  - Cover at least 90% of non-power plant stationary source fuel combustion
  - Assure consistency of coverage within industries and across jurisdictions
  - Examining:
    - 10,000 to 25,000 metric tons of CO_2e per year
    - Categories of facilities

Draft Recommendations

- Residential and Commercial Fuel Combustion
  - Include CO_2 emissions with upstream points of regulation
    - Local distribution companies
    - Refineries, wholesalers, distributors
    - Continuing work on points of regulation
  - Other fiscal measures
  - Examining: 1^{st} or 2^{nd} compliance period

Draft Recommendations

- Transportation Fuels
  - Continuing to evaluate

Draft Recommendations

- Future Program Expansion
  - Scope may expand over time
    - Monitoring technologies, procedures, protocols
    - Address leakage
    - Resolution of legal or administrative issues
    - New jurisdictions

Comments

- Diverse set of commenters
- Broad coverage
  - Technically and administratively feasible
  - Lower total cost of compliance
- Point of regulation close to emissions
- Emphasized:
  - Transportation fuels
  - Quantification methods; reliable data
  - Certainty of coverage
  - Non-covered sector emission reduction responsibilities

Questions

Western Climate Initiative

The Electricity Subcommittee Recommendations

David Van't Hof, Chair

Regional Stakeholders' Meeting
Salt Lake City
May 21, 2008

Overview

- Review Recommendation Process
- Review Draft Recommendation
- First Jurisdictional Deliverer Explained
- Questions

Recommendation Process

- Identified options for covering electricity
- Identified opportunities and challenges of each
- Sought stakeholder input
- Identified and ranked design principles
- Applied design principles to the options
- Discussed and ranked options
- Released Draft Recommendation March 3rd
- Sought stakeholder input
- Included recommendation in Initial Program Design May 16th

Draft Recommendation

- Key Starting Point:

  "The point of regulation for the electricity sector should maximize coverage and minimize emissions leakage."
- Partners recognize that this coverage could be realized through a generator-based program with broad participation in western interconnect
- The initial recommendation calls for greater participation in WCI.

Draft Recommendation

- In the absence of broad participation in WECC region, first jurisdictional deliverer approach would achieve the coverage goal.
- First jurisdictional deliverer, or “FJD”, covers nearly all emissions related to the electricity consumed in the WCI partner jurisdictions, because it focuses on all deliverers of electricity.

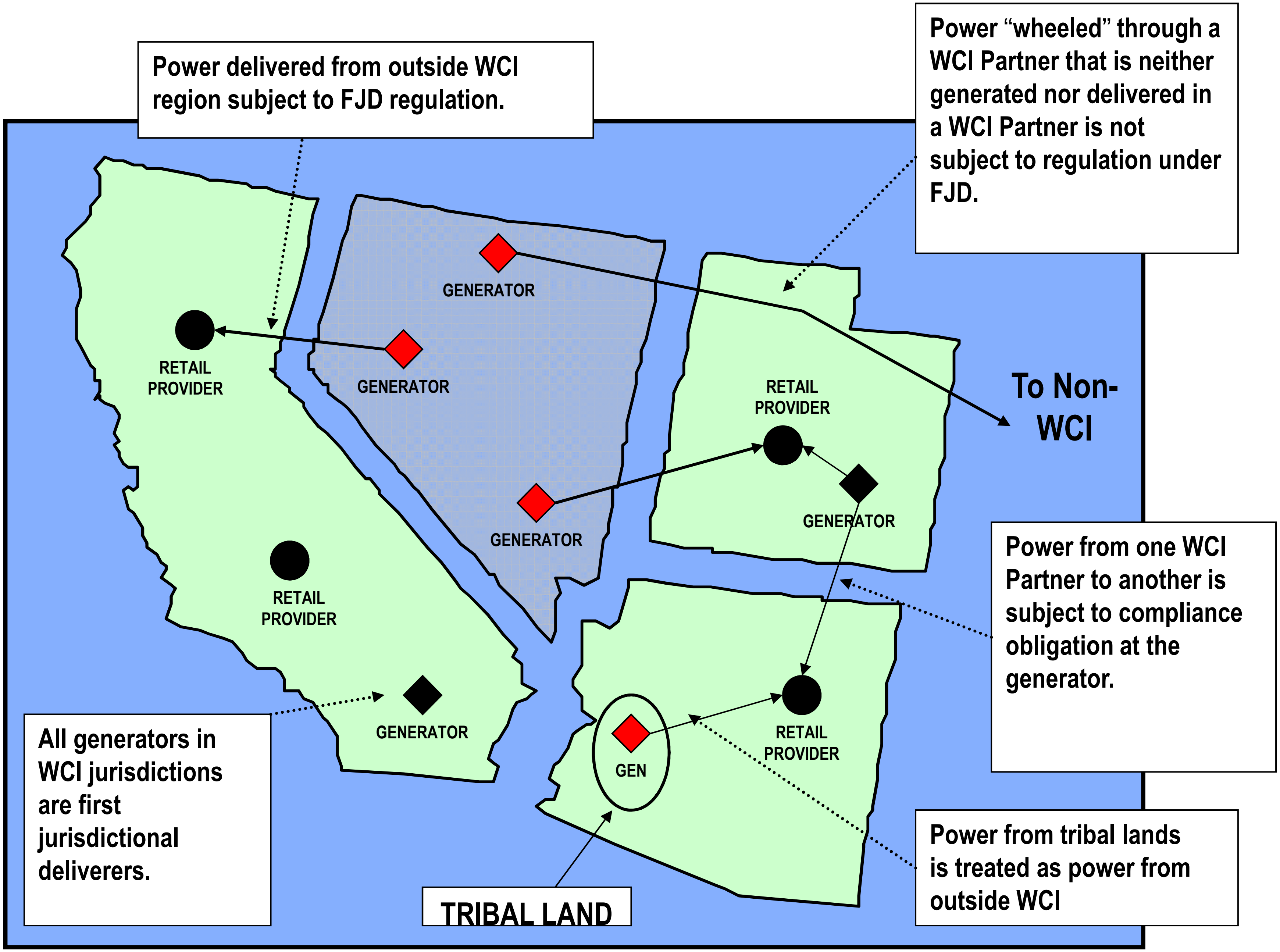
Since February

Subcommittee has focused on two priorities:

1. Better understanding how the FJD approach would be implemented in the region, including:
   – Answering questions from partners; and
   – Reviewing stakeholder input on the draft
2. Consider the allowance issues--both apportionment and allowance distribution--as they relate specifically to FJD or Generator and FJD

What is FJD?

- It is a point of regulation approach for electricity:
  - First deliverers are:
    - Generator deliverers in WCI jurisdictions
    - Deliverers of imported electricity in WCI jurisdictions
- Seeks to cover nearly all emissions related to electricity consumed in region, wherever that electricity is generated


Power delivered from outside WCI region subject to FJD regulation.
Power "wheeled" through a WCI Partner that is neither generated nor delivered in a WCI Partner is not subject to regulation under FJD.
GENERATOR
RETAIL PROVIDER
GENERATOR
RETAIL PROVIDER
To Non-WCI
GENERATOR
GENERATOR
RETAIL PROVIDER
Power from one WCI Partner to another is subject to compliance obligation at the generator.
GENERATOR
RETAIL PROVIDER
GEN
All generators in WCI jurisdictions are first jurisdictional deliverers.
Power from tribal lands is treated as power from outside WCI
TRIBAL LAND

FJD Reporting

All FJDs would have a reporting obligation:

- *Deliverer of power generated in a WCI jurisdiction is the generator. The generator would report emissions measured at the stack or through fuel factors.*
- *Deliverer of power generated outside jurisdiction would report emissions attributable to the power delivered based on:*
  - NERC e-tag and/or bilateral contract. Emissions would be calculated based on MWhrs times emissions factor for generator type.
- In all cases where FJD is unable to supply good emissions data will require substitution of default emissions rate

FJD Compliance

- *All FJDs would have a compliance obligation:*
  - *Must surrender enough allowances to "cover" all emissions reported during the compliance period.*
- The emissions baseline for the FJDs would be established using available emissions data from generator FJDs in the region, plus emissions attributable to imported power based on all available information for imports during the baseline period.
- Emissions and allowances would be tracked in the same way as existing cap-and-trade programs:
  - FJDs have emissions account where emissions reporting data are "deposited"
  - FJDs have compliance accounts where allowances are deposited.

Questions?

Break

Western Climate Initiative

Draft Allocations Design Recommendations

Patrick Cunningham
Arizona Dep't of Environmental Quality

May 21, 2008
Salt Lake City, Utah

Regional Cap & Partner Allowance Budgets

- The WCI recommends establishing a regional cap that will decline over time, and each Partner will have an allowance budget within the cap.
- The regional cap will be equal to the sum of the Partner allowance budgets.
  - Reductions achieved by the cap plus reductions from uncapped sources resulting from complementary measures should achieve the WCI regional goal of a 15 percent reduction below 2005 levels by 2020.
- The initial regional cap and Partner allowance budgets will be set through 2020.

Establishment of Partner Allowance Budgets

- The WCI recommends that each Partner's allowance budget be established in a transparent manner.

- The Partners will develop a methodology for calculating the Partner allowance budgets. The methodology should set the Partner allowance budgets at the levels needed to achieve the WCI economy-wide emissions reduction goal.

  – *The WCI seeks comments from stakeholders on the methodology for establishing Partners' allowance budgets and the factors to be included in the methodology.*

Partner Discretion to Issue Allowances

- The WCI recommends that once the allowance budget has been established for each Partner, allowances will be issued by each Partner rather than issued by a regional organization.

- The WCI recommends each Partner initially have flexibility to issue its remaining allowances as it sees fit, subject to the minimum percentage auction amount and sector-specific assessments, including:

  - auctioning more than the minimum amount of allowances;
  - issuing some or all of the remaining allowances for free;
  - holding some or all of the remaining allowances within a compliance period; and/or
  - retiring some or all of the remaining allowances.

- The WCI recommends each Partner initially have discretion to issue allowances differently to different sectors within its jurisdiction.

Allocation of Allowances by Partners

- Each Partner will be required to advise the other WCI Partners how it intends to allocate the remaining allowances, so that the WCI can make the Partners' plans public in a coordinated fashion.
- Any Partner that chooses to hold allowances must allocate or retire those allowances by the end of the applicable compliance period.
- While the Partners initially will have flexibility to issue allowances, over time, the WCI will seek to standardize distribution of allowances as much as possible.
- The Partners will continue to examine the impacts of Partners using different approaches to allocate allowances to the same sectors
  - *WCI seeks comments from stakeholders on this issue.*
- The Partners also will continue to consider the impacts of Partners making different use of auction proceeds
  - *WCI seeks comments from stakeholders on this issue.*

Sector-Specific Assessments

WCI will conduct sector-specific assessments to assess whether allocations to a particular sector should be treated uniformly by all Partners in the WCI region:

- to address competition among entities within the WCI region
  - Only a few sectors face significant risks of unfair competition from differing allocation methods among the WCI Partners, and a harmonized approach would be limited to carbon-intensive industries facing significant competition among WCI jurisdictions WCI jurisdictions.
- to address competition and leakage from entities outside the WCI region
  - Leakage of this type is likely an issue only for bulk commodity sectors with high GHG emissions per unit of output that face significant non-WCI competition.

Allowance Auctions

- <u>Minimum Auction Percentage</u>
  - The WCI recommends each Partner auction a minimum percentage, between 25 percent and 75 percent, of its allowance budget through a coordinated regional auction process.
  - The Partners will determine a specific minimum percentage auction amount.
  - *The WCI seeks comments from stakeholders on this question.*
- <u>Phased Increase of Auctioning</u>
  - Greater emphasis could be given to free allocation in the early years of the program
  - The minimum percentage of allowances to be auctioned should be increased over time

Compliance Periods

- The WCI recommends the compliance periods be three years long.
- To accommodate start-up issues, both from the covered entity standpoint and the regulatory standpoint, the WCI recommends that the initial compliance period include special rules, such as a two-year period, or other measures to assist in the transition into a cap-and-trade system, while maintaining the integrity of the cap and value of the allowances.

Early Actions, Banking & Borrowing

- Credits for Early Reductions: The WCI recommends each Partner have discretion to give credit for early actions, but any credit for early action must come from within the cap and will come out of the individual Partner's allowance budget.

- Banking: The WCI recommends purchasers and covered entities be allowed to bank allowances, without restrictions on the amount of allowances that may be banked or on how long they may be banked.

- Borrowing: The WCI recommends that borrowing of allowances from future compliance periods not be allowed.

New Partners

- The WCI recommends that allowances for new Partners be in addition to the existing allowance budgets for current Partners. The regional cap will be expanded to accommodate emissions from the new Partner.

- Once the cap-and-trade program has been instituted, new Partners will come into the cap-and-trade program at a regionally coordinated and designated time, such as the beginning of the relevant compliance period.

Stakeholder Comments

- The WCI particularly sought comments on:
  - the methodology for establishing Partners' allowance budgets and the factors to be included in the methodology
  - different approaches to allocate allowances to the same sectors
  - making different use of auction proceeds
  - minimum percentage auction amount
- Fifty-six (56) comments received by the April 16, 2008 deadline:
  - Industry/trade associations (15); Utilities (13); NGOs (11); Government agencies (3); Private citizens (2); Miscellaneous business entities (12)
  - Five (5) additional comments received after the deadline
- Geographic distribution of commenters:
  - Nineteen (19) multi-state stakeholders; Washington (10); California (9); Oregon (5); British Columbia (4); Arizona (4); Canada (3); New Mexico (2)

Examples of the Wide Diversity of Stakeholder Comments

- Regional cap and the Partner allowance budgets
  - The allowance budgets should be based on load or output.
  - The allowance budgets should be based on historical emissions.
  - The allowance budgets should be based on the state and provincial goals.
  - Partner budgets should be identical to Partner commitment to the regional goal.
  - Budgets should not be determined until accurate data are available.
  - Budgets should include some set aside (3-5 percent) of allowances for new entrants.

- Allocation of Allowances
  - Allowances should be allocated free to utilities
  - A significant percentage of all allowances should be auctioned
  - Some commenters (e.g., NGOs) called for 100 percent auctioning
  - Others (e.g., utilities) opposed auctions or argued that only a very small percentage (5 percent or less) of allowances should be auctioned, if at all.

- Partner Discretion to Allocate Allowances
  - A lack of uniformity could result in leakage
  - To minimize potential for leakage, adopt consistent rules for reporting, tracking and compliance obligations
  - Distribute allowances to a third party

Stakeholder Comments (cont.)

- Banking & Borrowing: Most commenters supported the recommendations to allow unlimited banking but prohibit borrowing of allowances.

- Compliance Periods: Commenters supported the recommended three-year compliance periods by a wide margin.

- Other Comments (mostly relating to auctions):
  - Develop an independent Market Oversight Committee to develop best practices to guard against market manipulation, hold down consumer costs and avoid burdens on state economies.
  - Consider more practical alternatives to address hoarding of allowances.
  - Have a cost containment mechanism
  - Have a safety valve.
  - Do not have a safety valve.
  - Have a price ceiling for allowances for a defined period.
  - Allow only emitters to participate in auctions.
  - Allow anyone to purchase allowances at auctions.

Questions

Lunch Break

(Reconvene at 1:00 p.m.)

Western Climate Initiative

Phase 1 Modeling

Presented to

Western Climate Initiative Stakeholders

May 21, 2008
Salt Lake City, Utah

Topics

- Phase 1 Status
- Preliminary Results
- Example Model Outputs
- Status of Assumptions Book

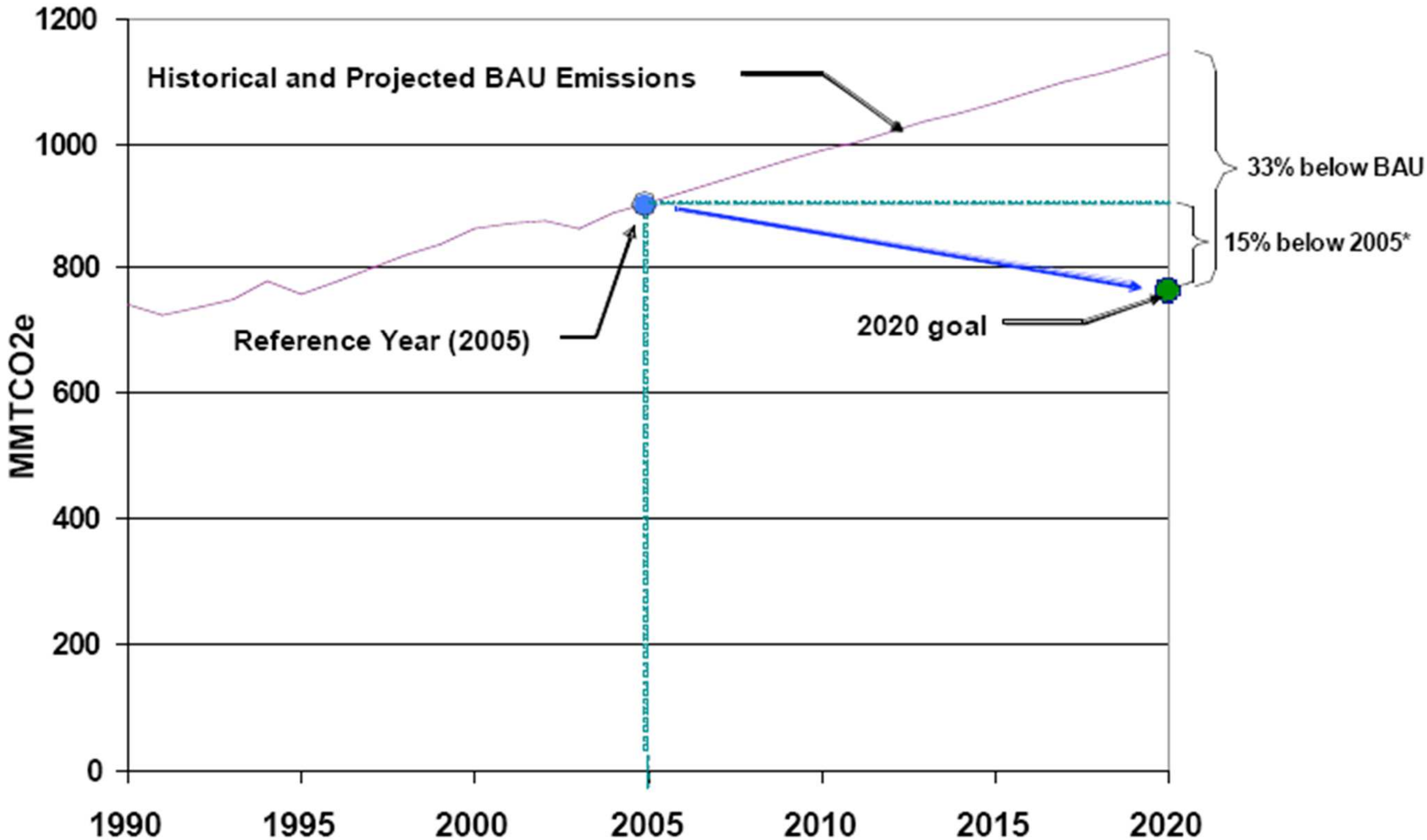
Phase 1 Status

- Reference case
  - "Reasonably close" to 8 partners' 2005 inventories
  - Incorporate 2007 national energy bill (EISA) and existing renewable portfolio standards
- Complementary policies
  - CA car standards, VMT reduction
  - Energy efficiency programs (electric & gas utilities, LPG, heating oil)
- Cap-and-trade scenarios (in progress)
  - First-jurisdictional deliverer (proxy with WECC-wide cap)
  - Proper treatment of tribal power plants
  - Manitoba and Quebec not yet incorporated

WCI Partner Data

- GHG inventories and forecasts (August 2007)
- The forecasts show aggregate growth of >25% in emissions from 2005-2020
- Reducing emissions to 15% below 2005 levels would require a 33% reduction from forecasted 2020 levels

WCI Partner GHG Emissions and Regional Goal[3]



ENERGY 2020 Phase 1 Reference Case

- The model simulates the partner inventories for 2005 reasonably well
- GHG emissions in 2020 in the Reference Case are significantly lower. Why?
  - Partner forecasts are ~1 to 5 years old
  - Energy prices are projected to be higher
  - Reference Case includes EISA and state RPS's
  - Reference Case assumes no new conventional coal plants (beyond "committed coal plants")
  - Not using partner-specific population growth rates in Phase 1 modeling

Impact of Higher Energy Prices AEO Estimates

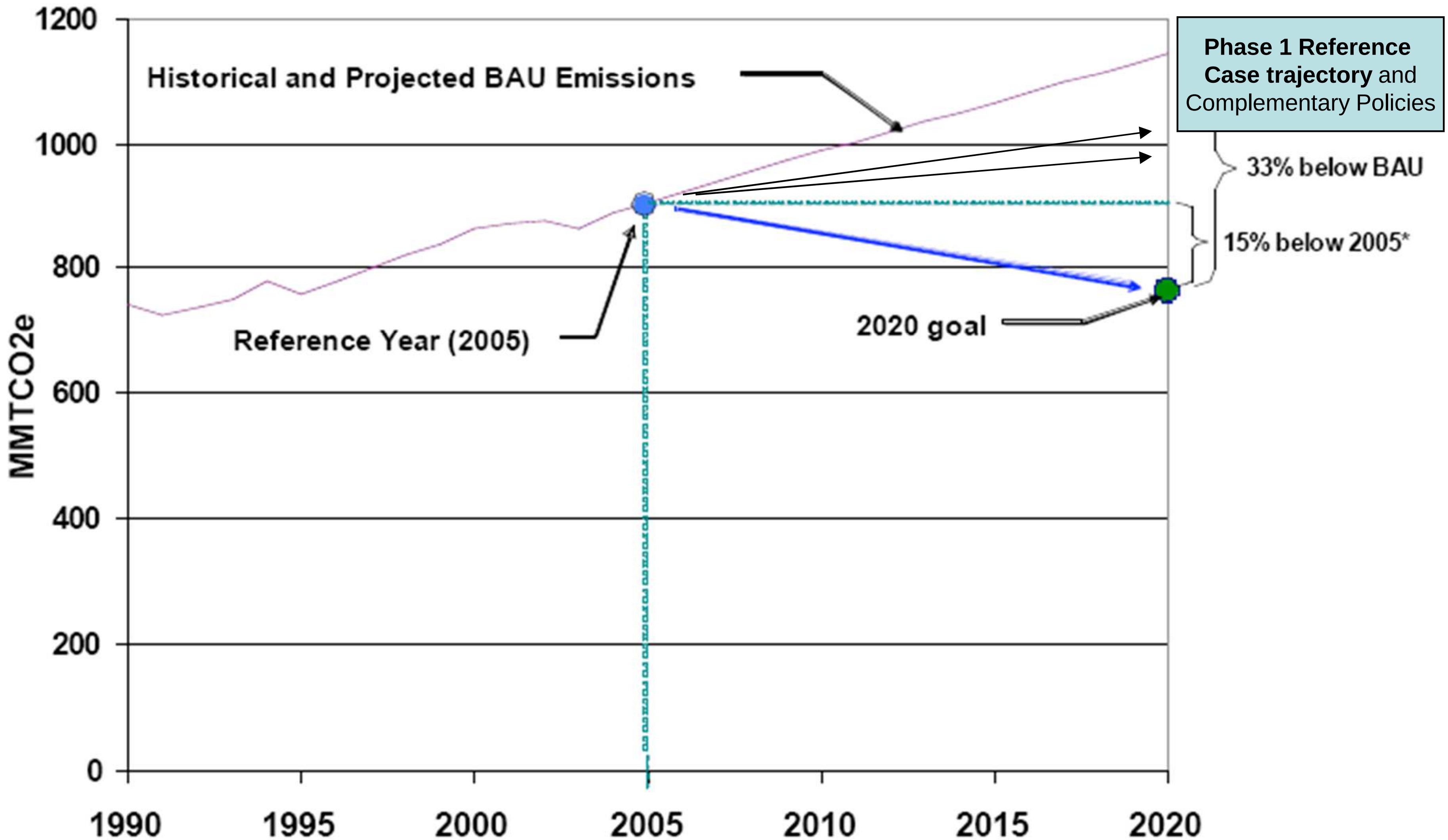
		AEO 2007		AEO 2008	
	2005	2020	% Incr	2020	% Incr
Total CO2 Emissions (MMT)	5982	6944	16%	6384	7%
Ave Annual Growth 2005-2030					
Energy Consumption			1.2%		0.7%
Economic Growth			2.9%		2.4%

- Significant decreases in projected CO2: 16% vs. 7%
- Oil prices substantially higher
- Energy consumption grows more slowly
- Economy grows more slowly
- All projections are from AEO “mid-price” cases, Table 18.

ENERGY 2020 Phase 1 Reference Case and Complementary Policies

- Graph illustrates likely trajectories of
  1) Reference Case and
  2) Complementary Policies model run
  which includes three WCI-wide policies:
  - CA car standards (including “Part 2” to these standards)
  - Total VMT reduced below levels in 2020 Reference Case
  - Aggressive energy efficiency programs that reduce demand below the Reference Case for electricity, natural gas, LPG, and heating oil

WCI Partner GHG Emissions and Regional Goal[3]



Example Model Outputs

- GHG Emissions
  - With market-clearing allowance price for GHG cap-and-trade program
  - GHG offset prices and quantities used
- Power Sector
  - Demand, generation, capacity, wholesale prices, retail electric rates
- Fuel use and market shares
  - Oil, natural gas, coal, gasoline, diesel, ethanol, biodiesel, etc.
- Levels of Energy Efficiency
- Examples of model output
  - http://www.epa.state.il.us/air/climatechange/documents/07-09-06/modeling-of-policy-proposals.ppt (Illinois)
  - http://dnr.wi.gov/environmentprotect/gtfgw/documents/reference_case_outputs_20080416.pdf (Wisconsin)

Status of Assumptions Book

- We are processing input from April 14 stakeholder call and from emails
- We will post a new version prior to June 9 stakeholder call

Questions

Western Climate Initiative

Offsets
Draft Design Recommendations

Tim Lesiuk (BC), Offsets Subcommittee Chair

May 21, 2008

Salt Lake City, Utah

Overview

- Revised Draft Recommendations
  - Offsets project types and protocols
  - Offsets project locations
  - Tradable units from government-regulated GHG emission trading systems
  - Quantity Limits
- Summary of Stakeholder Comments to date

Mission

- Recommend whether to include a greenhouse gas offset mechanism as an element of the Western Climate Initiative cap and trade system, and if so,
- Recommend design, scope and operation of such a mechanism.

Members

Affiliation	Member	Affiliation	Member
Arizona	Ed Ranger	New Mexico	Jim Norton
British Columbia	Tim Lesiuk	New Mexico	Rita Bates
British Columbia	Rachel Boston	Oregon	Cameron Smith
British Columbia	Dennis Paradine	Oregon	Bill Drumheller
British Columbia	Tom Neimann	Ontario	John Hutchison
California	Kristin Ralff-Douglas	Ontario	Sheri Beaton
California	Stephen Shelby	Quebec	Robert Noel De Tilly
California	Brieanne Douke	Quebec	Nadine Gaudette
Colorado	Ginny Brannon	Saskatchewan	Howard Loseth
Manitoba	Jane Gray	Utah	Colleen Delaney
Manitoba	Juliane Schaible	Utah	Chad Harris
Manitoba	Karen Hildahl	Washington	Spencer Reeder
Montana	Julie Anderson	Washington	Greg Nothstein
Nevada	Ryan McGinness	Wyoming	Kelly Bott

Offsets project types & protocols

The WCI recommends:

- development of an initial set of eligible project types and approved protocols prior to cap-and-trade program launch;
- developing a process to review and approve other project types and related protocols proposed by project developers;
- using protocols that are standardized to the extent possible; and,
- making use of, and adapting if needed, existing protocols as appropriate.

Offsets Project Location

The WCI should consider:

- A method that gives priority to offset projects located within WCI jurisdictions (also considering other roles of the offset system, such as ensuring that co-benefits occur within the region).
- Approving offset projects located throughout Canada, the United States, and Mexico, where such projects would be subject to comparably rigorous oversight, validation, verification and enforcement as those located within the WCI jurisdictions and would not undermine the ability for the WCI to link to other trading systems.

Tradable units from other systems

The WCI should:

- For compliance purposes, consider allowing individual regulated entities to use tradable units (offsets and allowances) from other government-regulated GHG emission trading systems that the WCI recognizes as meeting similarly rigorous criteria for environmental integrity.
- Ensure accounting systems are in place to prevent using tradable units more than once for compliance.

Quantitative Limits

The WCI recommends limiting the use of offsets and non-WCI tradable units for compliance by individual regulated entities:

- to ensure that meaningful emission reductions take place within the sources covered by the cap-and-trade system.
- in recognition that foregoing emission reductions at facilities covered by the cap-and-trade program in the WCI states has the potential to forego health benefits and other benefits near those facilities.

Stakeholder Comments

- **Strong support for including an offset program**
- **Desire for strong environmental integrity of the offset program**
- **Support for establishing a centralized administrative body**
- **A mix of views on location:**
  - allow offsets from outside the WCI, by project approval through WCI or as certified trading units from other approved systems
  - give priority to offset projects from within the WCI or to phase in other regions over time as experience grows
- **A mix of views on quantitative limits:**
  - limits increase cost of compliance
  - oversupply of inexpensive offsets could reduce the impetus for capped emitters to reduce their own emissions

Questions

Western Climate Initiative

Reporting Recommendations

Reporting Subcommittee

Jim Norton, Chair

May 21, 2008

Salt Lake City, UT

Practical Impacts for Reporting

- Key Elements
  - Consistent, transparent, robust quantification and reporting across sources and states/provinces
  - Broadest possible coverage / inclusion
- Maximum reliance on and linkage with The Climate Registry (TCR) and international reporting programs
  - Anticipate employing TCR quantification protocols and reporting systems and services

Subcommittee Deliberations

- Subcommittee Conference Calls
- Subcommittee Work Plan
- Major Options Paper
  - Major Options (1 through 7)
- Draft Recommendations Paper
- Stakeholder Input:
  - Written Comments
  - Conference Calls
  - Stakeholder Workshops

Draft Program Reporting Recommendations for Comment

1. Breadth/Scope of Coverage
2. Initiation of Reporting
3. Coordination Among Partner Jurisdictions on Reporting
4. Data Management and TCR Interaction
5. Verification
6. Administrative Costs & Fees
7. Mandatory Federal GHG Reporting

1. Breadth/Scope of Coverage

Draft Recommendation:

The WCI recommends that reporting requirements apply to the capped sectors and to certain non-capped sectors that may be phased in later (will have to determine which ones -- lower thresholds may apply).

Representative Comments:

- Include only capped sectors initially; non-capped can be offsets
- Including sectors outside initial cap:
  - Allows for more accurate accounting across all sectors
  - Provides better basis for allocations
  - Provides more comprehensive public information
- Reasonable thresholds needed
- Divided opinion on inclusion of sectors/sources not likely to be phased in later

2. Initiation of Reporting

Draft Recommendation:

The WCI recommends that reporting start before cap-and-trade commences in order to avoid reporting-related delays to the start of the cap-and-trade program.

Representative Comments:

- Most commenters support early start to reporting
- Start reporting ASAP; phase in problematic sectors
- Reporting before cap-and-trade will help provide:
  - Accurate data for allocations and offsets
  - “shake out” period for program
- Some recommend voluntary reporting with no verification or enforcement (as training) before cap-and-trade
- Don’t let reporting delay the introduction of the cap; emissions from large sources are already being reported federally

3. Coordination Among Partner Jurisdictions

Draft Recommendation:

The WCI recommends developing essential requirements for a model WCI reporting rule by the end of 2008 and will incorporate consideration for jurisdictions that already have reporting rules adopted or in process.

Representative Comments:

- Wide range of opinion on uniformity needed vs. jurisdictional variation
- A universally consistent rule would be more administratively effective and cost-efficient
- Lack of consistency would increase gaming, lead to errors in reporting and higher costs for reporters, including verification costs
- Less burden for companies with facilities in multiple jurisdictions
- Desire continuity for existing state-mandated reporting; allow for nuances in certain sectors or jurisdictions
- Hybrid: Single rule, but allow partners to supplement core with additional reporting

4. Data Management & TCR Interaction

Draft Recommendation:

The WCI recommends that sources report either (a) directly to jurisdictions (which would then upload the data to TCR's central repository), or (b) through the TCR's program framework (which would then download the data to the necessary jurisdiction(s)).

Representative Comments:

- Relying on TCR would avoid patchwork, allow "one-stop shopping"
- TCR reporting simplifies reporting for companies with facilities in multiple jurisdictions
- Legal restrictions may not allow reporting except to states/provinces
- Partners should not cede authority to TCR; use TCR only for storage
- Jurisdictional reporting would allow coupling with other pollutant discharge reporting
- Divided opinion: some opposed to one option, some to the other
- Multi-jurisdictional companies tend to favor direct TCR reporting

5. Verification

The WCI recommends establishing essential quality assurance elements for reported data. These elements will be consistent across jurisdictions. Each jurisdiction will have an oversight mechanism to ensure compliance with the reporting requirements. As part of this mechanism, each jurisdiction will establish procedures to ensure that the quality assurance elements are met. This could include third-party verification, rigorous compliance audits or other appropriate approaches.

Representative Comments:

- Divergent opinions
- Consistency and credibility is vital, especially for capped sectors
- Some view third party verification as essential for market
- Potential costs of third party verification are a concern, especially for smaller companies
- Some say third party verification should not be needed if emissions are calculated using CEMS data and/or other federally approved methods

6. Administrative Costs & Fees

Draft Recommendation:

The WCI recognizes that jurisdictions may collect fees from sources reporting directly to them and contract with TCR to administer the program. Jurisdictions may also accept data directly from TCR if they choose to do so; entities that report through TCR may have to pay an additional fee if one is required by the jurisdiction(s).

Representative Comments:

- Opinions similar to views on reporting to TCR vs. jurisdictions
- Reporter payment to TCR could reduce administrative complexity
- Requiring TCR payment may need enabling legislation
- Need accountability for how fees are used
- Many recommend payment should go to wherever sources are required to report
- Must ensure that fees are used only to support the reasonable costs of the program
- Some jurisdictions may pay costs

7. Mandatory Federal GHG Reporting

Draft Recommendation:

The WCI recommends getting involved in federal GHG reporting program development in the U.S. and Canada to ensure that federal reporting programs are harmonized with the jurisdictions' interests to the greatest extent possible.

Representative Comments:

- Goal should be consistency and single (one-time) reporting
- WCI should seek to influence federal reporting
- WCI should seek to follow federal reporting (US & Canada)

Implementation Schedule

- Sign contract for development of essential requirements of WCI reporting rules in June 2008
- Contractor will work with Reporting Subcommittee
- Finish essential requirements for reporting rules by December 31, 2008
- Will provide opportunities for stakeholder review and comment

Questions

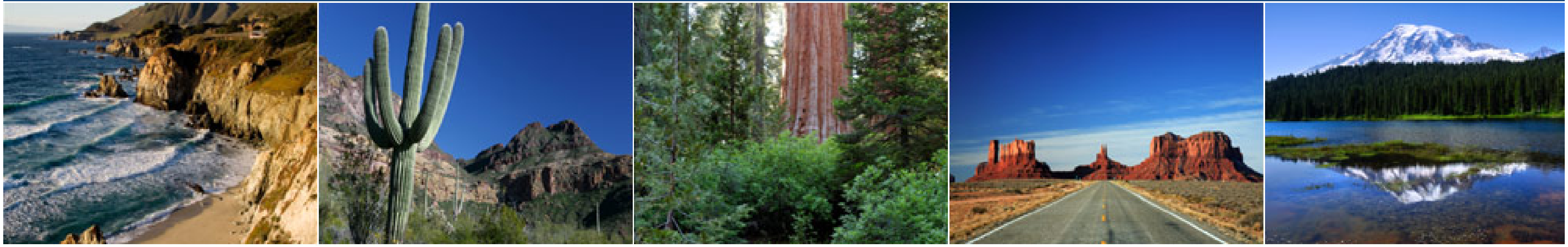
Break

Expanded Stakeholder Comment Opportunity

Wrap Up and Next Steps

Adjourn

Western Climate Initiative



Additional Information on ENERGY 2020 Model Inputs

Presented to

Western Climate Initiative Stakeholders

June 9, 2008

Topics

1. Update on modeling & assumptions book.
2. Additional information on selected model input data, and guidance on exploring them
   a) 3.1 Population and Economic Data
   b) 3.2, 3.3 Energy Prices, Consumption, Expenditures
   c) 3.5 Electricity Sector Data
   d) Appendix C: Transmission Capacity

Objective

Stakeholder feedback indicated interest in data sources used in modeling.

Data sources are being enhanced in the revised “Assumptions Book” to include specific sources

Objective of presentation is to illustrate how stakeholders can follow these links to review actual source data.

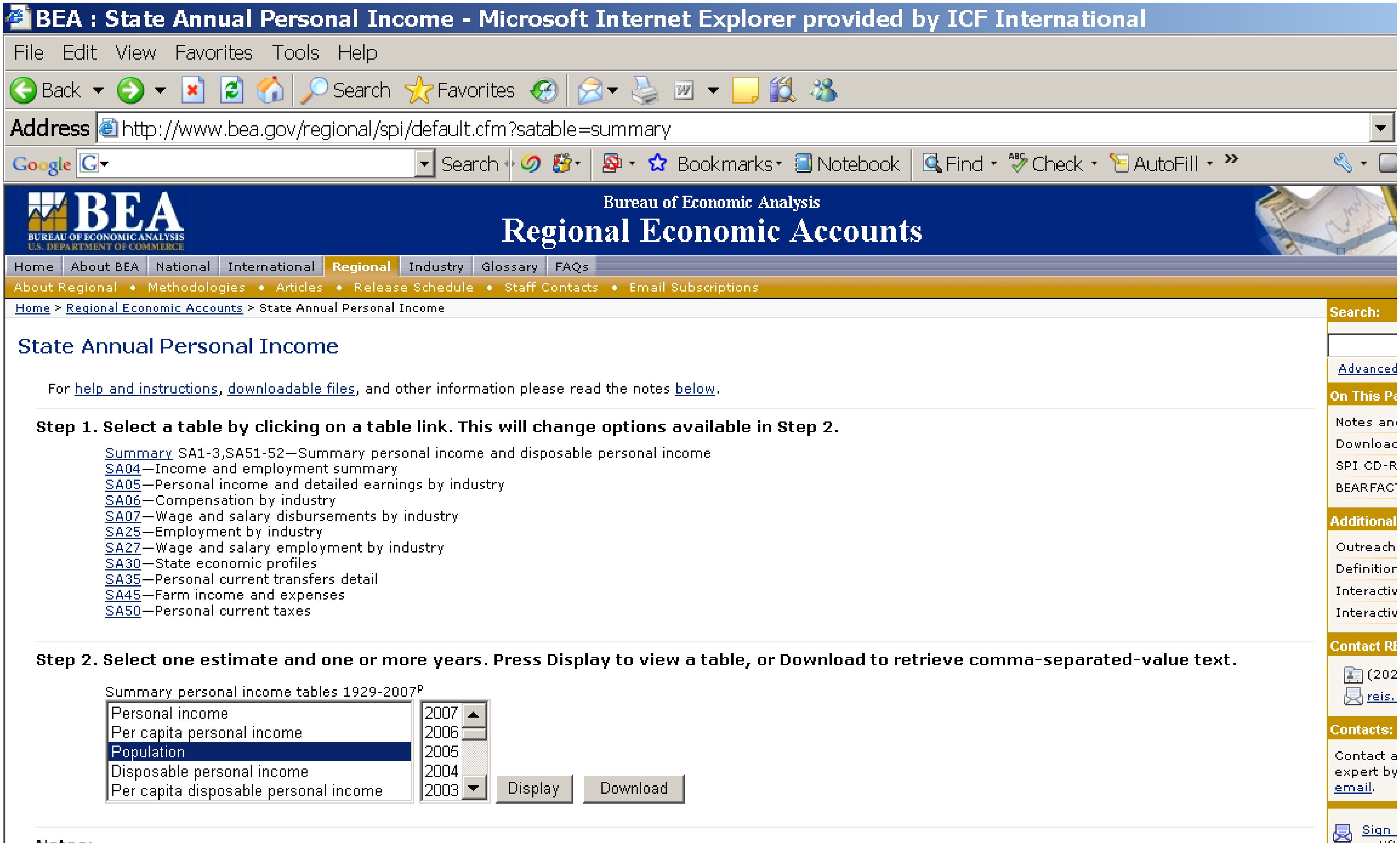
Partner-supplied data will not be discussed today, though some is already in the model, and more is being gathered and provided.

3

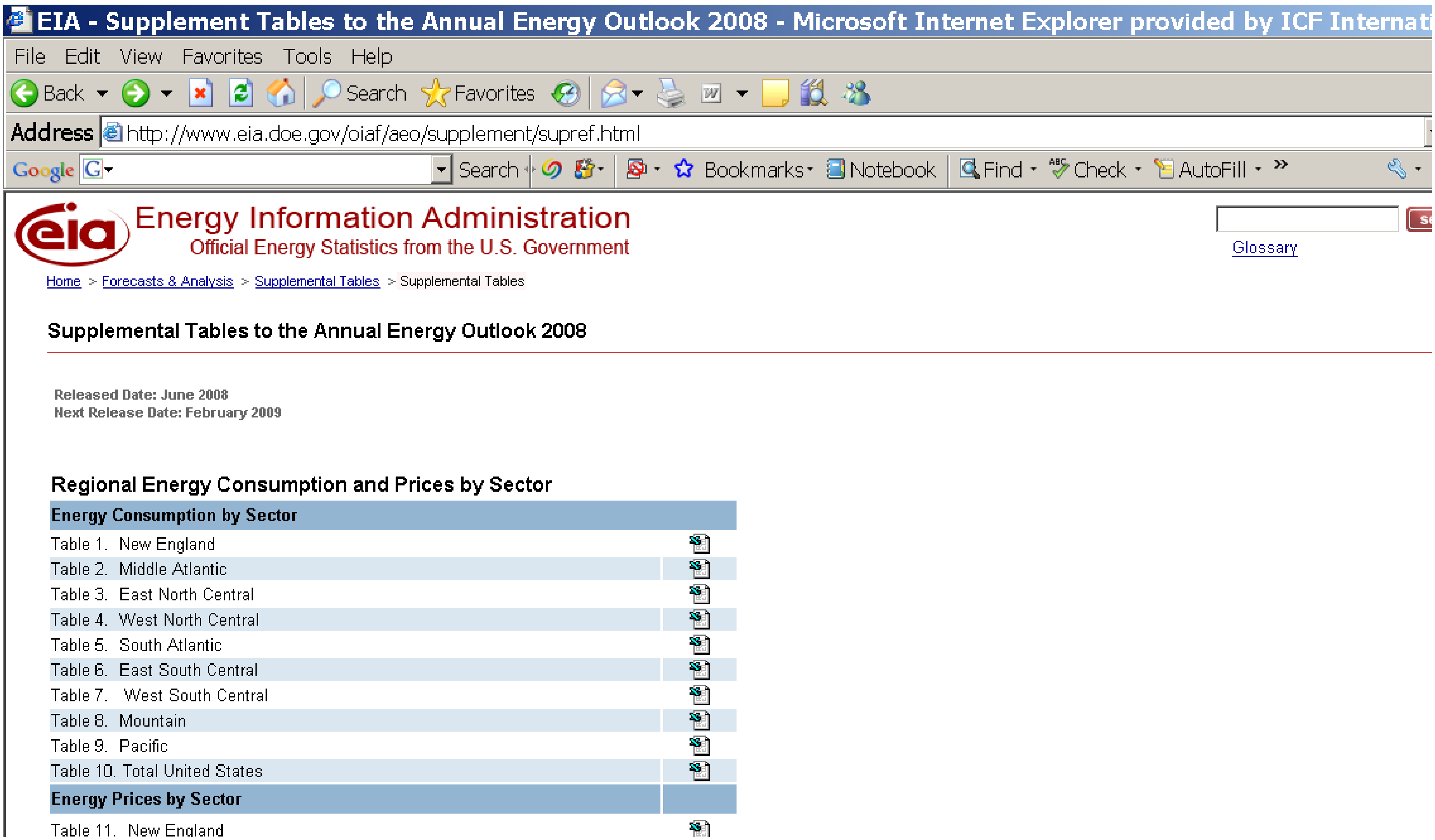
3.1 Population and Economic Data

- *Population - Historic (1985-2006)*:
  - Regional Economic Information System, Bureau of Economic Analysis, U.S. Department of Commerce. http://www.bea.gov/regional/spi/default.cfm?satable=summary
  - Statistics Canada Table 051-0001 (based on census data) http://www.statcan.ca/english/freepub/11-008-XIE/2006007/tables/soc_ind_pop_spr06.htm
- *Population – Forecast:* annual population growth rates are taken from Regional Forecasts from AEO then applied to the state historical population. Annual Energy Outlook 2007 (February 2007 release). http://www.eia.doe.gov/oiaf/aeo/supplement/suptab_1.xls through suptab_9.xls
- Households by housing type: *U.S. Census Bureau, Housing and Household Economic Statistics Division* http://www.census.gov/hhes/www/housing/census/historic/units.html

Historical U.S. Population data: Ignore Step 1; in step 2, click Population; highlight one or more years; click Display



U.S. Population forecast: Click on XLS for appropriate region; go to line 156 for regional population forecast; apply regional growth rate to state historical data.

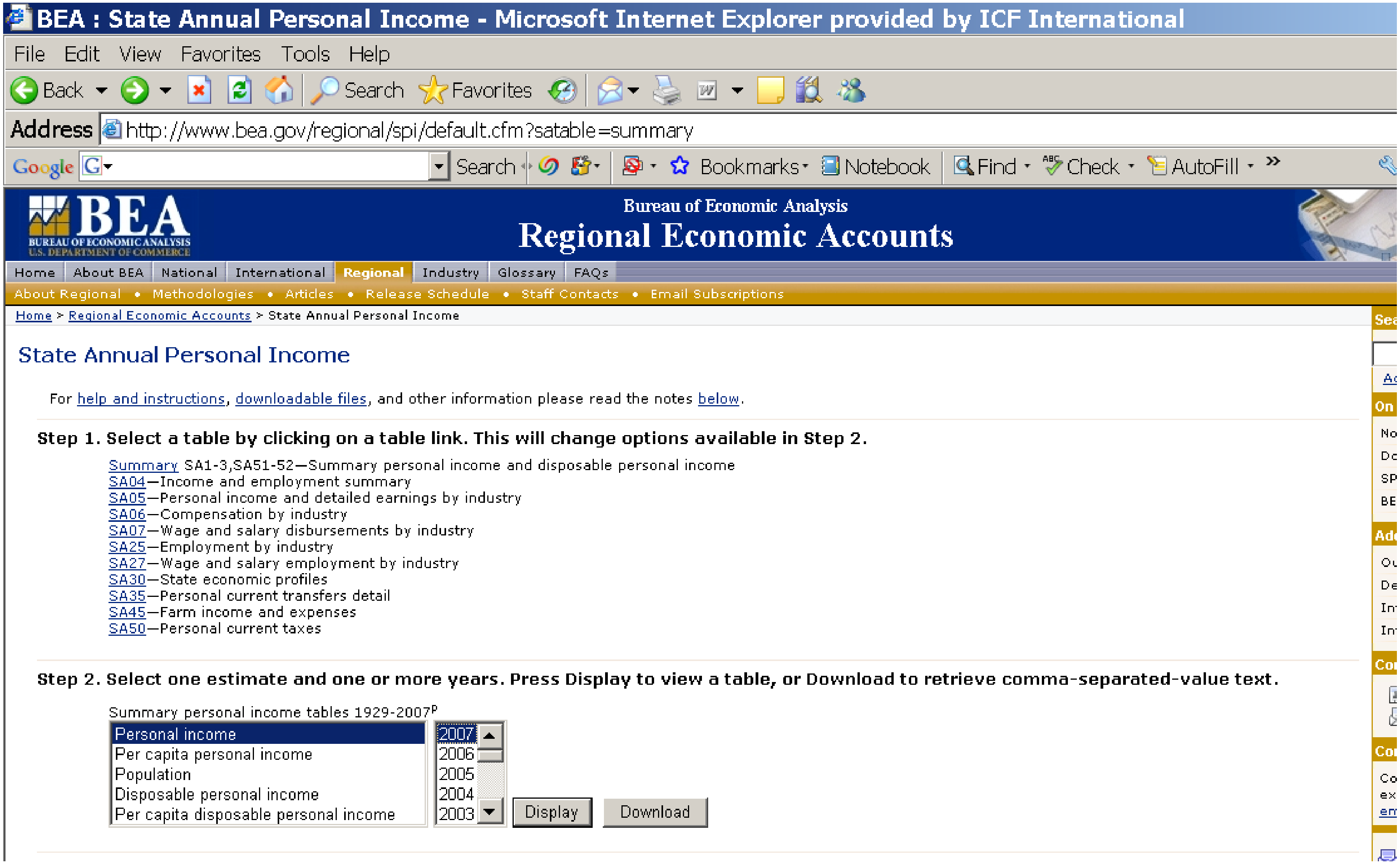


3.1 Population and Economic Data (cont.)

- *Personal Income - Historic (1985-2006)*: Bureau of Economic Analysis, 6/24/07http://www.bea.gov/regional/spi/default.cfm?satable=summary

- *Personal Income - Forecast:* Assume ratio of ratio of state-level historic Personal Income to state-level Gross Domestic Product remains constant. Apply the 2006 ratio to forecasted state-level GDP to forecast state-level Personal Income.
  - State-level GDP data: http://www.bea.gov/regional/gsp/default.cfm?series=NAICS

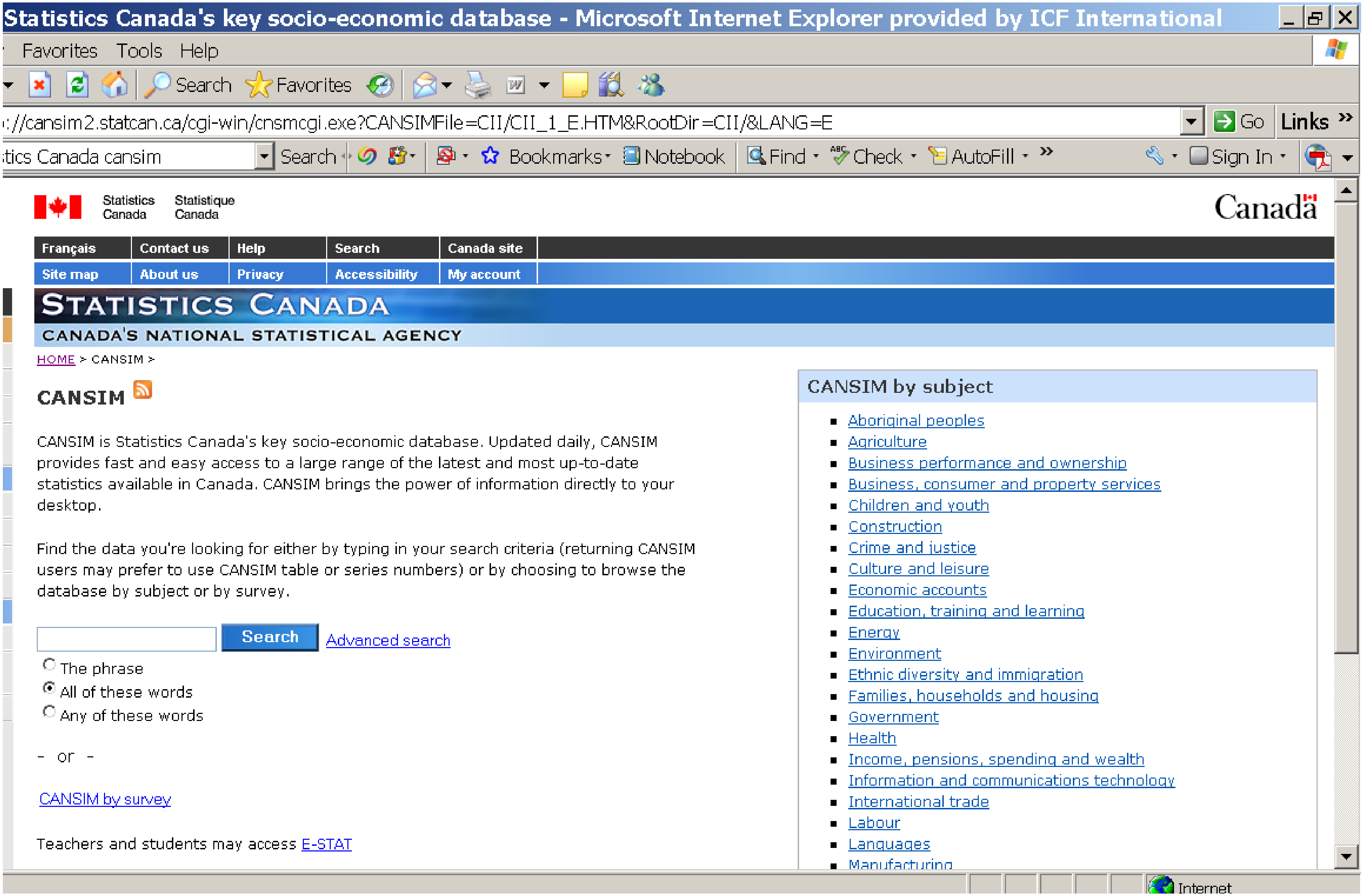
Historical U.S. Personal Income data: Ignore Step 1; in step 2, click Personal Income; highlight one or more years; click Display



3.1 Population and Economic Data (cont.)

- For Canada: CANSIM
  - Canada's National Statistics Agency
    http://cansim2.statcan.ca/
    (click English or French)
- Examples
  - Population
  - Economic accounts (GDP, Personal Income)
  - Environment (air, climate

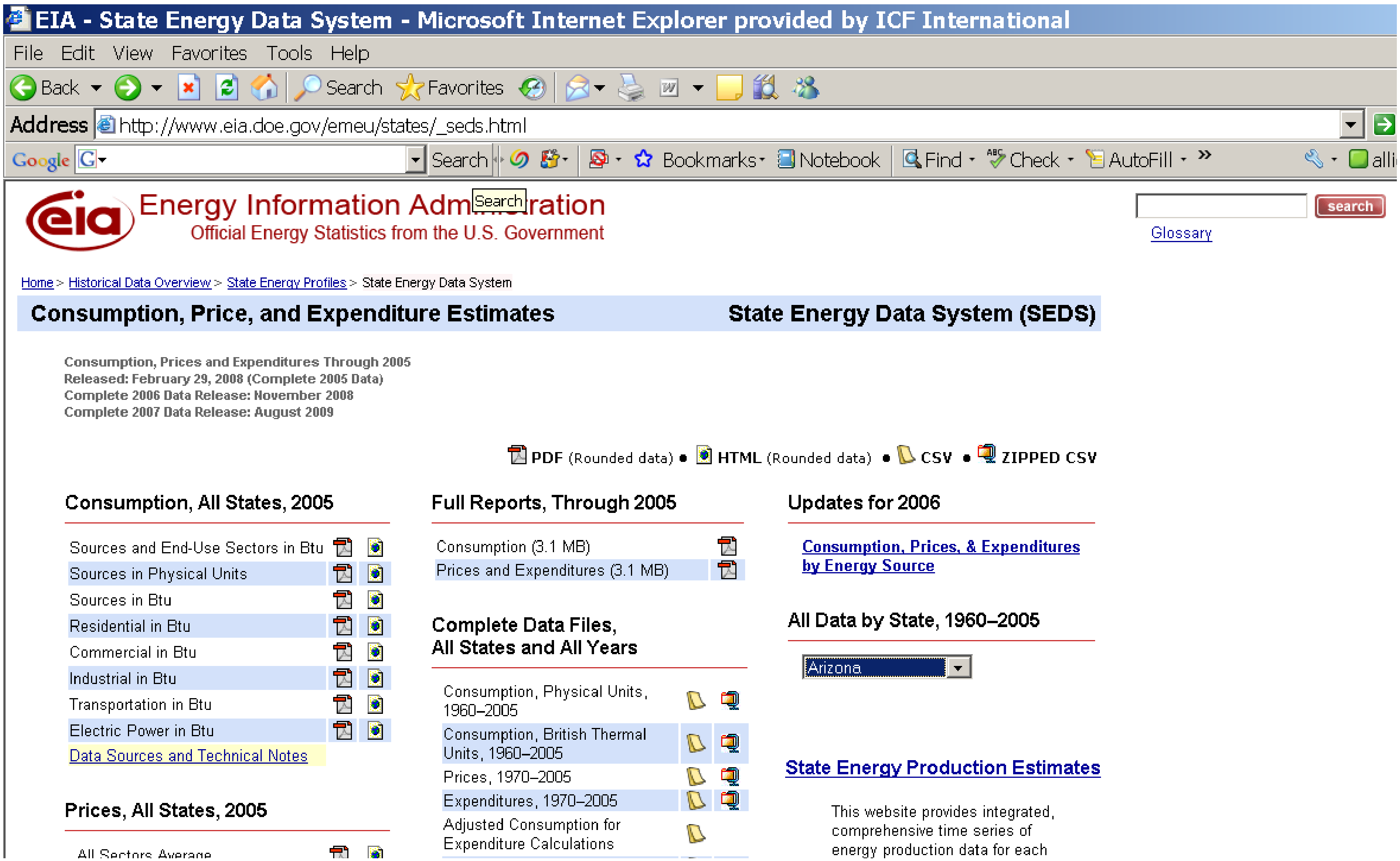
CANSIM Home Page (English)



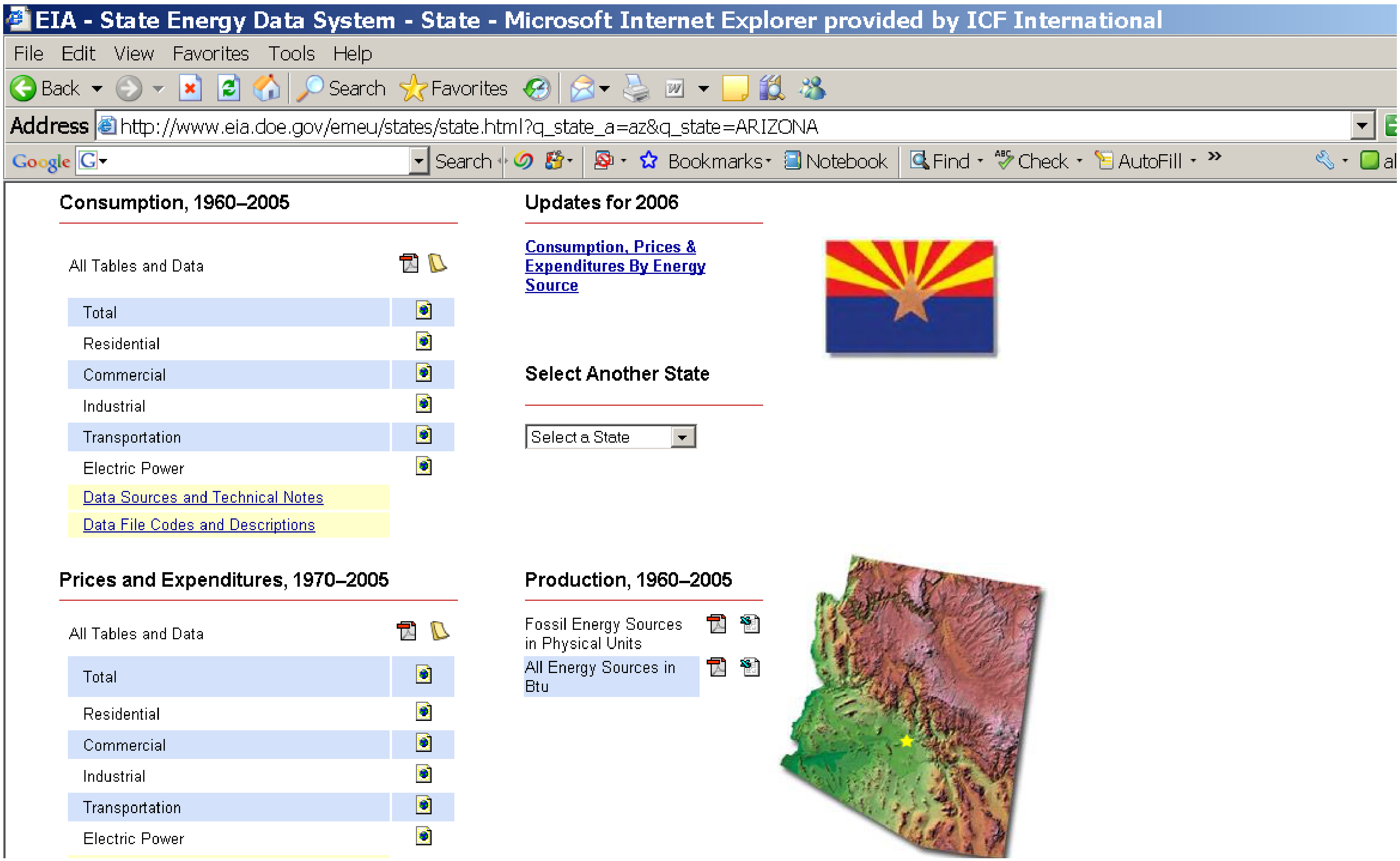
3.2 Energy Price Data by State
3.3 Energy Consumption and Expenditure Data by State

- *Historical prices/consumption/expenditures:* EIA State Energy Data System (SEDS) http://www.eia.doe.gov/emeu/states/_seds.html
- *Forecast prices (national):* EIA Annual Energy Outlook, 2007, High Price Case http://www.eia.doe.gov/oiaf/archive/aeo07/aeohighprice.html (to be replaced by 2008 High Price Case when available)
  - Estimate state-level prices using historical relationships between national and state-level delivered prices
- Energy consumption forecasts are endogenous

Historical energy price, consumption, and expenditure data by state: click on a state under “All Data by State, 1960-2005”



Arizona example



3.3 Energy Consumption Data (cont.)

- ***Residential:*** 2001 EIA Residential Energy Consumption Survey (RECS), by Census Region and Division (2005 RECS in process) http://www.eia.doe.gov/emeu/recs/contents.html
  - Household income by housing type
  - No. of people per household
  - End-use consumption data, including fuels used for space and water heating, air conditioning, etc.

3.3 Energy Consumption Data (cont.)

- ***Commercial:*** 2003 EIA Commercial Buildings Energy Consumption Survey (CBECS), by Census Region and Division (2007 CBECS is underway) http://www.eia.doe.gov/emeu/cbecs/contents.html
  - Floor area by sub-sector
  - End-use consumption data, including fuels used for space and water heating and energy intensities

3.3 Energy Consumption Data (cont.)

- ***Industrial:*** 2002 EIA Manufacturing Energy Consumption Survey (MECS), by Census Region (2006 MECS underway) http://www.eia.doe.gov/emeu/mecs/contents.html
  - Energy use by fuel for each sub-sector and end-use

- Combining national and state-level data for industry
  - Estimate state-level energy consumption by industrial sector by applying the proportions from the MECS data to state-level total industrial energy consumption.

3.5 Electricity Sector Data

Input	Sources Used/Available
Plant type	Form EIA-860: Annual Electric Generator Report, 2006 http://www.eia.doe.gov/cneaf/electricity/page/eia860.html Canadian IPM Base Case, 2004 http://www.ec.gc.ca/cleanair-airpur/caol/canus/IPM_TECHNICAL/ipm_technical_report/toc_e.cfm Natural Resources Canada, *Canada's Energy Outlook: Reference Case, 2006* http://www.nrcan-rncan.gc.ca/com/resoress/publications/peo/peo-eng.php Supplemented by National Energy Board info.
Plant capacity	Form EIA-860: Annual Electric Generator Report, 2006 Canada: as above
Plant historical generation	Form EIA-906 and EIA-920 Databases (data on generation and fuel consumption), 2001-2006 http://www.eia.doe.gov/cneaf/electricity/page/eia906_920.html Canada: as above.
Plant fuel type	Form EIA-860: Annual Electric Generator Report, 2006 Canada: as above.
Plant Heat Rate	Form EIA-906 and EIA-920 Databases, 2001-2006 Canada: as above

3.5 Electricity Sector Data (cont.)

Input	Sources Used/Available
Plant fuel consumption	Form EIA-906 and EIA-920 Databases, 2001-2006
Plant emissions by pollutant	EPA, direct communication. Environment Canada, direct communication
Plant costs (O&M, variable and fixed)	EPA, direct communication. Environment Canada, direct communication
Plant historical capacity factor	Form EIA-906 and EIA-920 Databases, 2001-2006 Statistics Canada, direct communication
Plant availability (outages)	Calculated using generation data Statistics Canada, as above
Plant owner and location	Form EIA-860: Annual Electric Generator Report, 2006 Canada: as above
Planned capacity additions and retirements	Form EIA-860: Annual Electric Generator Report, 2006 California Public Utility Commission GHG Modeling process (E3) Natural Resources Canada, *Canada's Energy Outlook: Reference Case, 2006*
Transmission Capability	NERC, *2004 Summer Assessment & 2004/2005 Winter Assessment: Reliability in the Bulk Electricity Supply in North America* http://www.nerc.com/~filez/rasreports.html Western US – Additional data provided by BPA. Canada: National Energy Board, *Canadian Electricity Trends and Issues (2001)* http://www.neb.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/lctrcty/lctrctytrndsssscnd2001-eng.pdf National Energy Board, *Canadian Electricity Exports and Imports (2003)* http://www.neb.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/lctrcty/lctrctyxprtsmprtscnd2003-eng.pdf

Data in Form EIA-860

- Generator-specific information including:
  - Generating capacity
  - Energy sources
  - Status of existing and proposed generators, and proposed changes to existing generators
  - County and State location, ownership
  - FERC qualifying facility status
  - Ability to use multi-fuels, co-firing, and fuel switching.
- The 2006 data are compressed into a self-extracting (.exe) zip file that expands into 10 .XLS files, including 2 files on the ability to use multi-fuels.
  - XLS files are described on the EIA-860 home page.

Form EIA-860: Annual Electric Generator Report, 2006

Annual Electric Generator data - EIA-860 data file - Microsoft Internet Explorer provided by ICF International

Address http://www.eia.doe.gov/cneaf/electricity/page/eia860.html

Energy Information Administration
Official Energy Statistics from the U.S. Government

search
Glossary

Home > Electricity > Electricity Database Files > Form EIA-860 Database

Form EIA-860 Database

Form EIA-860 Database
Annual Electric Generator Report

The EIA-860 is a generator level data file that includes specific information about generators at electric power plants owned and operated by electric utilities and nonutilities (including independent power producers, combined heat and power producers, and other industrials). The file contains generator-specific information such as initial date of commercial operation, prime movers, generating capacity, energy sources, status of existing and proposed generators, proposed changes to existing generators, county and State location, ownership, and FERC qualifying facility status. Starting in 2004, data are included on the ability to use multi-fuels; specifically data on co-firing and fuel switching. Data on the ability to use multi-fuels are not available for previous years.

The 2006 data are compressed into a self-extracting (.exe) zip file that expands into 10 .XLS files, including 2 files on the ability to use multi-fuels. The files are UTILY06.XLS (Utility file), PLANTY06.XLS (Plant file), GENY06.XLS (Existing generators), MFEXISTY06.XLS (Multi-fuel data for existing generators), PRGENY06.XLS (proposed generators), MFPROPY06.XLS (Multi-fuel data for proposed generators), PCGENY06.XLS (Proposed changes to existing generators), OWNERY06.XLS (Owner file), INTCON06.XLS (interconnection data), and LAYOUT.XLS (File description).

The 2001-2003 data are compressed into a self-extracting (.exe) zip file that expands into 6 DBF files: 1 company file (UTILYyy.DBF*), 1 plant file (PLANTYyy.DBF*), and 4 generator files (GENYyy.DBF*, PCGENYyy.DBF*, PRGENYyy.DBF* and OWNERYyy.DBF*) and an EXCEL layout file (Layout.xls).

*Note: Substitute the applicable year for "yy" in the file nam

Download

Year	Formats	
2006	EXE	ZIP
2005	EXE	ZIP
2004	EXE	ZIP
2003	EXE	ZIP
2002	EXE	ZIP
2001	EXE	ZIP
P=Preliminary		

Superseded Forms (with data prior to

EIA-860A (Annual Electric Generator Report - Ut

EIA-860B (Annual Electric Generator Report - N

Electric Generating Capacity

Appendix C: Inter-regional Transmission Capacity

- Source: Federal Energy Regulatory Commission, *FERC-714 Annual Power System Reports* http://www.transmission.bpa.gov/orgs/opi/FERC714/index.shtm

July 15, 2008 Economic Analysis and Modeling Support to the WCI, ENERGY 2020 Assumptions Book

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Economic Analysis and Modeling Support to the Western Climate Initiative

ENERGY 2020 Model Inputs and Assumptions

July 15, 2008
(revision date)

Prepared for:
Western Governors' Association

ICF INTERNATIONAL

Prepared By:
ICF Consulting Canada, Inc.
277 Wellington St. W.
Suite 808
Toronto, ON M5V 3E4

Contact:
Glen Wood
T: (416) 341-8952
F: (416) 341-0383

PLEASE NOTE:

This report outlines the assumptions and data inputs used in developing a Reference Case for the Western Governors' Association, in support of the Western Climate Initiative.

The development of the Reference Case is on-going and as such this should be viewed as a living document that will evolve as the model is reviewed and refined.

D R A F T

Economic Analysis and Modeling Support to the Western Climate Initiative
ENERGY 2020 Inputs and Assumptions

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Acronyms & Definitions

AEO	Annual Energy Outlook (published by EIA)
ARB	California Air Resources Board
BPA	Bonneville Power Administration
Btu	British Thermal Units
CAC	Criteria Air Contaminants (SO_x, NO_x, PM, etc.)
CFL	Compact Fluorescent Light bulb
CHP	Combined Heat and Power
CO_2e	Carbon Dioxide equivalent
GDP	Gross Domestic Product
GO	Gross Output
GWP	Global Warming Potential
DG	Distributed Generation
E3	Energy and Environmental Economics, Inc.
EIA	Energy Information Administration
EPACT	Energy Policy Act of 2005
ESCO	Energy Service Company
GHG	Greenhouse Gas
IECC	International Energy Conservation Code
IGCC	Integrated Gasification Combined Cycle
kW	Kilowatt
kWh	Kilowatt-hour
Mt	Megatonne
MW	Megawatt
MWe	Megawatt electric
Mt CO_2e	Megatonnes Carbon Dioxide Equivalent (also referred to as MTCE)
NOx	Nitrogen Oxides
OGCC	Oil/Gas Combined Cycle Turbine
OGCT	Oil/Gas Combustion Turbine
OGST	Oil/Gas Steam Turbine
PC	Pulverized Coal
REMI	Regional Economic Models, Inc.
RECS	Renewable Energy Certificates
Rest of US	Balance of systems in US
SO_x	Sulfur Oxides (including sulfur dioxide)
USEPA	United States Environmental Protection Agency
W	Watt
WCI	Western Climate Initiative
WECC	Western Electricity Coordinating Council

1. Background and Project Scope

The Western Climate Initiative (WCI) has retained ICF International and its partner Systematic Solutions Inc., to assist in modeling a cap-and-trade system for the western US and Canada. The WCI envisions a trading scheme that may ultimately link with the Midwestern Regional Greenhouse Gas Reduction Accord (MGA) and the Regional Greenhouse Gas Initiative (RGGI). The environmental, energy, and economic stakes are high in this endeavor.

The ICF Team has offered a suite of models that represent the state-of-the-art to support the WCI in this plan; starting with ENERGY 2020. This report outlines the assumptions and data inputs used in developing the Reference Case which will be used as the basis for evaluating proposed policy changes. The report describes the initial data and assumptions used, the sources of this data, and the processes used in developing the Reference Case.

2. Organization of the Report

The report is organized into four main sections. Section 1 provides background information regarding the purpose and scope of the project, this section (2) describes how the report is organized. Section 3 describes the analytic approach used by ENERGY 2020 and the characteristics of the model. The final section (4) describes the model inputs. A more detailed explanation of the ENERGY 2020 model is included as Appendix A.

3. Analytic Approach

This project uses ENERGY 2020 to model the business-as-usual outlook for the regions participating in the WCI (WCI partners)[1] as well as surrounding states and provinces and the impact of potential GHG reduction policies.

ENERGY 2020 is an integrated multi-region energy model that provides complete and detailed, all-fuel demand and supply sector simulations. These simulations can additionally include macroeconomic interactions to determine the benefits or costs to the local economy of new facilities or changing energy prices.

[1] *Arizona, California, Montana, New Mexico, Oregon, Utah, Washington, British Columbia, Manitoba, and Quebec.*

The model can be used in regulated as well as deregulated and transitioning environments. Greenhouse Gas and Criteria Air Contaminant pollution emissions and costs, including allowances and trading, are endogenously determined, thereby allowing assessment of environmental risk and co-benefit impacts.

The basic implementation of ENERGY 2020 for North America now contains a user-defined level of aggregation down to the 10 provincial and 50 state (and sub-state) level. ENERGY 2020 contains historical information on all generating units in the US and Canada. Data for Mexico can be incorporated as needed. ENERGY 2020 is parameterized with local data for each region/state/province as well as all the associated energy suppliers it simulates. Thus, it captures the unique characteristics (physical, institutional and cultural) that affect how people make choices and use energy. Collections of state and provincial models are currently validated from 1986 to the latest quarterly numbers.[2]

ENERGY 2020 can be linked to a detailed macroeconomic model to determine the economic impacts of energy/environmental policy and the energy and environmental impacts of national economic policy. For US regional and state level analyses, the REMI macroeconomic model is regularly linked to ENERGY 2020.[3] The Informetrica macroeconomic model is linked to ENERGY 2020 for Canadian national and provincial efforts.[4] The REMI and Informetrica macroeconomic models include inter-state/provincial, US and world trade flows, price and investment dynamics, and simulate the real-time impact of energy and environmental concerns on the economy and vice versa.

The structure of the model is well tested and has been used to simulate not only US and Canadian energy and environmental dynamics, but also those of several countries in South America, Western, Central, and Eastern Europe. These efforts include strategic and tactical analyses for both planning and energy industry restructuring/deregulation. In the 1990s, the US EPA made ENERGY 2020 available to interested states to analyze emissions, energy, and economic impacts of state-level climate change initiatives. Further, the model has been used successfully for deregulation analyses in all the US states and Canadian

[2] *Energy supplier data comes from FERC and US DOE for the US and Statistics Canada. US and Canadian fuel and demand data come from the US Department of Energy and Natural Resources Canada, respectively. US and Canadian pollution data come from US EPA and Environment Canada, respectively.*
[3] *Regional Economic Models, Inc. www.remi.com*
[4] *Informetrica Limited www.informetrica.ca*

provinces. Many US and Canadian energy suppliers use the model for the analysis of combined electricity and gas deregulation dynamics.[5]

The default model simulates demand by three residential categories (single family, multi-family, and agriculture/rural), over 40 NAICS commercial and industrial categories[6], and three transportation services (passenger, freight, and off-road). There are approximately six end-uses per category and six technology/mode families per end-use.[7] Currently the technology families correspond to six fuels groups (oil, gas, coal, electric, solar and biomass) and 30 detailed fuel products. The transportation sector contain 45 modes including various type of automobile, truck, off-road, bus, train, plane, marine and alternative-fuel vehicles. More end-uses, technologies, and modes can be added as data allow. For all end-uses and fuels, the model is parameterized based on historical, locale-specific data. The load duration curves are dynamically built up from the individual end-uses to capture changing conditions under consumer choice and combined gas/electric programs.

Each energy demand sector includes cogeneration, self-generation, and distributed generation simulation, including mobile-generation, micro-turbines, and fuel-cells. Fuel-switching responses are rigorously determined. The technology families (which can be split, as an option, to portray specific technology dynamics) are aggregates that, within the model, change building shell, economic-process and device efficiency and capital costs as price or other information that the decision makers see, change. ENERGY 2020 utilizes the historical and forecast data developed for each technology family to parameterize and disaggregate the model.

The supply portion of the model includes endogenous detailed electric supply simulation of capacity expansion/construction, rates/prices, load shape variation due to weather, and changes in regulation.[8] The model dispatches plants

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[5] *ENERGY 2020 is the only model known to have simulated and predicted the dynamics that occurred in the UK electric deregulation. These include gaming, market consolidation and re-regulation dynamics.*
[6] *NAICS is the North America Industrial Classification System which was developed jointly by the U.S., Canada, and Mexico to provide new comparability in statistics about business activity across North America.*
[7] *End-uses include Process Heat, Space Heating, Water Heating, Other Substitutable, Refrigeration, Lighting, Air Conditioning, Motors, and Other Non-Substitutable (Miscellaneous). Detailed modes include: small auto, large auto, light truck, medium-weight truck, heavy-weight truck, bus, freight train, commuter train, airplane, and marine. Each mode type can be characterized by gasoline, diesel, electric, ethanol, NG, propane, fuel-cell, or hybrid vehicles.*
[8] *ENERGY 2020 does include a complete, but aggregate representation of the electric transmission system. Electric transmission data is provided by FERC, the Department of Energy, and the National Electric*

according to the specified rules whether they are optimal or heuristic and simulates transmission constraints when determining dispatch.[9] A sophisticated dispatch routine selects critical hours along seasonal load duration curves as a way to provide a quick but accurate determination of system generation. Peak and base hydro usage is explicitly modeled to capture hydro-plant impacts on the electric system.

ENERGY 2020 supply sectors include electricity, oil, natural gas, refined petroleum products, ethanol, land-fill gas, and coal supply. Energy used in primary production and emissions associated with primary production and its distribution is included in the model. The supply sectors included in a particular implementation of ENERGY 2020 will depend on the characteristics of the area being simulated and the problem being addressed. If the full supply sector is not needed, then a simplified simulation determines delivered-product prices.

The ENERGY 2020 model includes pollution accounting for both combustion (by fuel, end-use, and sector) and non-combustion, and non-energy (by economic activity) for SO_2, NO_2, N_2O, CO, CO_2, CH_4, PMT, $PM_{2.5}$, PM_5, PM_{10}, VOC, CF_4, C_2F_6, SF_6, and HFC at the state and provincial level by economic sector. Other (gaseous, liquid, and solid) pollutants can be added as desired. Pollution does not need to be determined directly by coefficients but can recognize the accumulation of capital investments that result in pollution emission with usage. National and international allowance trading is also included. Plant dispatch can consider emission restrictions.

The model captures the feedback among energy consumers, energy suppliers, and the economy using Qualitative Choice Theory and co-integration.[10] For example, a change in price affects demand that then affects future supply and price. Increased economic activity increases demand; increased demand increases the investment in new supplies. The new investment affects the economy and energy prices. The energy prices also affect the economy.

Reliability Council. The dispatch technologies in the basic model include: Oil/Gas Combustion turbine, Oil/Gas Combined Cycle, Oil/Gas Combined Cycle with CCS, Oil/Gas Steam Turbine, Coal Steam Turbine, Advanced Coal, Coal with CCS, Nuclear, Baseload Hydro, Peaking Hydro, Small Hydro, Wind, Solar, Wave, Geothermal, Fuel-cells, Flow-Battery Storage, Pumped Hydro, Biomass, Landfill Gas, Trash, and Biogas.

[9] *A 110 node transmission system is used in the default model, but a full AC load-flow bus representation model has also been interfaced with ENERGY 2020.*

[10] *The model has used the work of Daniel McFadden and Clive Granger since its inception in the late 1970s.*

Finally, the system includes confidence and validity testing software that places uncertainty bounds on simulation results, quantifies confidence intervals, and ranks the contributions to uncertainty in future conditions. This feature can be used to limit data efforts to information most important to the analysis.

In order to assess the potential impacts of proposed policy options, a b*usiness-as-usual* scenario is developed as a point of reference. This *Reference Case* represents a scenario that is viewed as a reasonable expectation of how the economy, energy use and emissions might develop over time.

Part of the nature of developing a Reference Case is the need to address inherently uncertain issues that can have significant impacts on future energy use and emissions. No forecast is going to be *right* or *accurate* in that no one can tell today how some of the key underlying issues may develop. Given the level of uncertainty involved in any projection of a possible future, caution should be used in applying a high level of precision to the modeling results. Understanding the Reference Case, however, can be extremely useful in providing an underlying structure against which to model proposed policies, and in determining directionality and cause and effect.

Numerous assumptions are required to perform an analysis of this type across a range of topic areas, including economic developments, fuel and electric markets, and regulatory structures. Projected outcomes are only as good as the input assumptions upon which they are based, with more rigorous assumptions leading to a more rigorous analysis. The inputs and assumptions described in this document were developed to provide as accurate a representation as possible of the activities and structures underlying energy use and greenhouse gas emissions in the WCI region.

4. Reference Case Inputs

ENERGY 2020 derives energy demands, such as the demand for electricity based on economic activity and device efficiency. The following sections provide a brief overview of the data inputs and assumptions as well as the sources of data used in the Reference Case. Actual data inputs for specific elements such as generating units, emission factors, etc., can be provided separately in Excel spreadsheets as required.

As a multi-sector analytical tool, ENERGY 2020 requires data and assumptions covering a broad range of economic sectors and their interactions. In most cases, the necessary data – both historical and projected – is available from the federal government (EIA, EPA, etc.). In past analyses, ENERGY 2020 has relied heavily on these federal sources to populate and calibrate the model. In developing the model used for the WCI partners a considerable amount of state-specific information was available and has been used wherever possible.

The following sections provide an overview of the data and assumptions that will be required to perform the multi-sector analysis, and list the data sources that have been used to populate ENERGY 2020 to this point. It is expected that this data will change as the model is reviewed and evolves to incorporate more detailed data specific to the WCI region.

Data[11] inputs for ENERGY 2020 will be required in five areas:

1. Population and economic
2. Fuel prices
3. Energy use and consumption
4. Emissions and air regulations
5. Electricity generation capacity and operation

The sections below list the key data elements required in each of these areas, along with the sources that have been used to supply this data for other analyses. Appendix B lists a number of default data sources used by the model. The sections that follow provide a more specific description of the data used for this project including state-specific data used in place of national sources.

[11] *"Data" here refers to both historical data and assumptions and projections of future inputs.*

ENERGY2020 requires both historical data and projections to calibrate and generate forward-looking projections. Various historical data will be used for the period 1985-2005 (the last year for which certain detailed sectoral and end-use are available). Projections for the period to be modeled (e.g. through 2030) will be gathered where possible to provide points of comparison and check the reasonableness of the projection.

The implementation of ENERGY 2020 used for the WCI project will begin with inclusion of the geographic areas of Arizona, California, Montana, New Mexico, Oregon, Utah, Washington, and British Columbia. Manitoba and Quebec may be added later in the project. These provinces pose more complex modeling issues as they lay outside of the Western Electricity Coordinating Council (WECC). Interactions between these states and provinces are modeled, particularly with respect to electricity generation. To ensure consistency the assumptions used within the WCI region are applied to other states to the extent possible.

4.1 *Population and Economic Data*

Demographic and economic data is required to generate demands for services. The historic data for the US states was obtained from the US Bureau of Economic Analysis (BEA). For the Canadian provinces, historic data is from Statistics Canada's CANSIM.

4.1.1 Phase I data

The following data sources were used during Phase I modeling in which readily available data was used:

Description of Data/Input	Sources	Detailed Reference
Total population, historical and growth over time	US Census Bureau	*Historic (1985-2006):* Regional Economic Information System, Bureau of Economic Analysis, U.S. Department of Commerce. http://www.bea.gov/regional/spi/default.cfm?satable=summary *California:* California population taken from: CEC *California Energy Demand 2008-2018 Staff Revised Forecast*
	Statistics Canada	Statistics Canada Table 051-0001 (based on census data)
	Future	Future annual population growth rates are taken from Regional Forecasts from AEO then applied to the state historical population. Annual Energy Outlook 2007 (February 2007 release). http://www.eia.doe.gov/oiaf/aeo/supplement/suptab_1.xls through suptab_9.xls

Description of Data/Input	Sources	Detailed Reference
Population by housing type (single-family, multi-family, etc.)	US Census Bureau	Population Estimates Program, Population Division
	Statistics Canada	Household type, Structural Type of Dwelling and housing tenure for Private Households of Canada
Households by housing type (single-family, multi-family, etc.)	US Census Bureau	Household splits (data through 2001 then held constant): *Source: U.S. Census Bureau, Housing and Household Economic Statistics Division* Last Revised: *December 16, 2005* http://www.census.gov/hhes/www/housing/census/historic/units.html **Household size** US Census Bureau, Census 2000 - assumes household size is same for all housing types in state. **Number of households** Calculated based on population, household fraction, and household size.
	Statistics Canada	Household type, Structural Type of Dwelling and Housing Tenure for Private Households of Canada
	Future	Projected based on Informetrica forecast.
Personal income	US Bureau of Economic Analysis	*Historic (1985-2006)*: Bureau of Economic Analysis, 6/24/07 http://www.bea.gov/regional/spi/default.cfm?satable=summary *California*: Estimates provided by ARB (see Appendix C).
	Statistics Canada	Statistics Canada CANSIM table 384-0012
	Future	Apply changes in historic Personal Income to Total GRP ratio and apply to future to forecast out to 2030.

4.1.2 Phase II data

In Phase II of the WCI partners had the opportunity to provide jurisdiction-specific data for use in the model.

The following states and provinces indicated that the readily available data used in Phase I could continue to be used in the Phase II modeling:

- Montana
- Oregon

- Utah
- British Columbia
- California

The other states provided the following data:

- Arizona: personal income; population (state total); and gross output (from REMI).
- New Mexico: population
- Washington: population

Data added in Phase II are included in Appendix C.

4.2 *Energy Price Data*

Energy prices can play a significant role in end user decisions on equipment, capital and operating decisions. Fuel costs can be critical in determining the costs of electric dispatch, as well as input costs of some industrial processes and home heating. ENERGY2020 calculates future electric prices based in part on these fuel costs.

Energy prices are largely determined by international markets, although domestic demand, such as electric sector demand for natural gas can influence prices. As a result, fuel prices are treated by the model as an exogenous input.

Historic energy price data are taken from US DOE State Energy Data and Statistics Canada. The model currently uses energy price forecast data for the US from the Energy Information Administration's 2008 Annual Energy Outlook High Price Case scenario for 2008 to 2030.[12] For Canada, the National Energy Board's price forecast is used.[13]

Biomass prices in the model are based on research completed for a previous project, shown in the table below. Unlike other fuels, biomass prices are significantly

Biomass Cost *(per MBtu in 2006$)*	
Residential	$11.53
Commercial	$10.09
Industrial	$10.06

[12] Energy Information Administration, Annual Energy Outlook 2008, Report #DOE/EIA-0383(2008), June 2008, http://www.eia.doe.gov/oiaf/aeo/
[13] Canada's Energy Future: An Energy Market Assessment, November 2007. http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/nrgyftr/2007/nrgyftr2007-eng.html

influenced by local cost and supply issues.

Power prices are calculated endogenously by the model based on generation costs and dispatch. While, the model estimates retail electricity prices, actual consumer prices may differ as a result of political, regulatory or market influences. The model can be calibrated to actual prices, within reasonable parameters, for the historic period.

Given the time and resources available for the project, the model does not account for the different regulatory regimes among the partner jurisdictions with respect to electric price regulation (i.e., cost-of-service ratemaking vs. various forms of market-driven pricing). The intent of the modeling is rather to produce reasonable estimates of retail prices at the state or provincial level based on generation costs and historical mark-ups above generation costs.

4.3 *Historic Energy Consumption Data*

ENERGY 2020 models energy use at the end-use level within each economic sector based on the existing physical stock and the efficiency of that stock. The database of device efficiencies reflects both the average efficiency of energy use for current stocks and the efficiency/energy alternatives available to consumers at the margin. Technology and efficiency choices are modeled based on past experience with consumer choice rather than on a purely economic evaluation.

Historic energy use and consumption data used in the model is derived from the federal Energy Information Administration (EIA) State Energy Data (SEDS) database. Where state-specific data was available, this data was used to replace national data sources.

Default sectoral and end-use data as well as energy intensities are based on the Residential Energy Consumption Survey (RECS), Commercial Energy Consumption Survey (CECS) and Manufacturers Consumption Energy Survey (MECS).

Description of Data/Input	Sources Used/Available
Residential Data - Household income by housing type - No. of people per household - End-use consumption data, including	2001 EIA Residential Energy Consumption Survey (RECS), by Census Region and Division (2005 RECS in process) http://www.eia.doe.gov/emeu/recs/contents.html

Description of Data/Input	Sources Used/Available
fuels used for space and water heating, air conditioning, etc.	For Canada – Natural Resources Canada Office of Energy Efficiency Database http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/comprehensive_tables/index.cfm?attr=0
Commercial Data - Floor area by sub-sector - End-use consumption data, including fuels used for space and water heating and energy intensities	2003 EIA Commercial Buildings Energy Consumption Survey (CBECS), by Census Region and Division (2007 CBECS underway) http://www.eia.doe.gov/emeu/cbecs/contents.html For Canada – NRCan OEE Database
Industrial/Manufacturing Data - Energy use by fuel for each sub-sector and end-use	2002 EIA Manufacturing Energy Consumption Survey (MECS), by Census Region (2006 MECS underway) http://www.eia.doe.gov/emeu/mecs/contents.html For Canada – NRCan OEE Database
State/Provincial Energy Data: - Energy consumption and expenditures by sector and energy source	2004 EIA State Energy Data System (SEDS) http://www.eia.doe.gov/emeu/states/_seds.html Canada: NRCan OEE Database and CANSIM

4.4 *Historic Emission Data*

4.4.1 Emissions and Air Regulations

Historic GHG emissions are based on the Canadian national inventory published by Environment Canada and the US GHG emissions inventory as published by the EPA.[14] More specific state and provincial inventories will be sought from WCI partners. ENERGY 2020 is calibrated using historic information on all of the major greenhouse gas emissions including:

- Carbon dioxide (CO_2),
- Nitrous oxide (N_2O),
- Methane (CH_4),
- Sulfur hexafluoride (SF_6),
- Hydrofluorocarbons (HFCs) and
- Perfluorocarbons (PFCs).

[14] *EPA website: http://www.epa.gov/climatechange/emissions/usinventoryreport.html*

GHG emissions are presented in CO_2 equivalent (CO_2e) terms. The global warming potentials used to convert the different greenhouse gas emissions into CO_2e terms are provided in Appendix H.

Input	Sources Used/Available
Emissions by sector, end-use, fuel & GHG	US EPA http://www.epa.gov/climatechange/emissions/usinventoryreport.html Environment Canada http://www.ec.gc.ca/pdb/ghg/inventory_e.cfm

4.4.2 Emission Factors

Emission factors for most fuels are based on values used by ICF in developing national and state inventories. For the transportation sector however, the emission factors for CH_4 and N_20 pollutants were adapted from the Canadian National Inventory Report.[15] ENERGY 2020 calculates GHG emissions at the point of combustion for most fuels. Upstream emissions from extraction and processing are captured as part of those respective economic sectors.

Emissions associated with the use of biomass as a fuel are deemed to be biogenic and therefore not contribute to global warming. As a result, the model assumes no GHG emissions are created from the use of biomass.

Emissions from ethanol and other biofuels represent an exception from a modeling perspective. In order to capture the emissions associated with their production and distribution, the model applies full cycle emission factors for these fuels. While the combustion of ethanol and biodiesel are not deemed to result in any anthropogenic emissions, the model uses an emission factor to recognize upstream emissions.

The full-cycle emission factors used in the model for each biofuels type are shown in the table below:[16]

Corn Ethanol	76 gCO2e / MJ
Cellulosic Ethanol	14 gCO2e / MJ
Biodiesel	30 gCO2e / MJ

[15] *Environment Canada. National Inventory Report 1990-2005, Greenhouse Gas Sources and Sinks in Canada, April 2007. (Annex 12 Emission Factors)*
[16] *Alexander Farrell, UC Berkeley and Daniel Sperling, UC Davis, A Low-Carbon Fuel Standard for California Part 1: Technical Analysis May 29, 2007 Table 2-3 http://www.energy.ca.gov/low_carbon_fuel_standard/UC-1000-2007-002-PT1.PDF*

When these fuels are used in combination with other fuels, for example in a mix of gasoline and ethanol, the emissions associated with gasoline combustion are reported as part of total gasoline-related emissions.

4.5 *Electricity Sector Data*

4.5.1 Generation Data

The electricity sector differs from other sectors in the extent to which emissions associated with power use within the state may result from emissions outside the WCI as power is imported from or exported to other areas.

ENERGY 2020 contains information on every generating unit in the state or province, as well as in neighboring jurisdictions which may supply power to the state. The model tracks and uses the following information for each generating unit:

- Historic Peak Capacity (MW);
- Historic generation levels (GWh);
- Type of fuel used;
- Heat rate;
- Historic annual fuel use (PJ);
- Emissions by pollutant type;
- O&M costs;
- Capacity factors;
- Emission rates;
- Outage rates;
- State or Province;
- Physical location (latitude and longitude);
- Ownership information;
- Plant type (Hydraulic, Coal, Combined Cycle Turbine, etc.)

The data on existing and committed generating units in the US was obtained from the National Electric Energy Data System (NEEDS) 2006 database and reconciled with a list of plants from BPA. The database of plants in Canada was developed based on the Canadian IPM®[17] module, modified and updated based

[17] ICF's Integrated Planning Model®.

on information from Statistics Canada, Environment Canada and the National Energy Board.

4.5.2 Electricity Generation Capacity and Operation Data

ENERGY 2020 is populated with data describing the type, operation and performance of every generating unit in the western US and the two Canadian provinces. In order to improve model performance, some smaller units with common characteristics may be combined (i.e. wind units at the same site, or small hydraulic units). In addition to plant-level data, the table below includes other inputs necessary to describe the electric system, including transmission capability.

Input	Sources Used/Available
Plant type	Annual Electric Generator Report: EIA Form 860 (2006) Canadian IPM® Base Case 2004[18] Natural Resources Canada, Canada's Energy Outlook: Reference Case 2006[19] Supplemented by National Energy Board info.
Plant capacity	Annual Electric Generator Report: EIA Form 860 (2006) Canada: as above
Plant historical generation	EIA Form 906/920 (2001-2006) Total generation output by plant type for California from CEC Canada: as above
Plant fuel type	Annual Electric Generator Report: EIA Form 860 (2006) Canada: as above
Plant Heat Rate	EIA Form 906/920 (2001-2006) Canada: as above
Plant fuel consumption	EIA Form 906/920 (2001-2006)
Plant emissions by pollutant	EPA CAMD (2001-2006) Environment Canada

[18] http://www.ec.gc.ca/cleanair-airpur/caol/canus/IPM_TECHNICAL/ipm_technical_report/toc_e.cfm
[19] http://www.nrcan-rncan.gc.ca/com/resoress/publications/peo/peo-eng.php

Input	Sources Used/Available
Plant costs (operation and maintenance, variable and fixed)	CA: E3 model data Canada: as above
Plant historical capacity factor	EIA Form 906/920 (2001-2006) Statistics Canada
Plant availability (outages)	Calculated using generation data Statistics Canada
Plant owner and location	Annual Electric Generator Report: EIA Form 860 (2006) Canada: as above
Planned capacity additions and retirements	Annual Electric Generator Report: EIA Form 860 California Public Utility Commission GHG Modeling process (E3) NRCan Energy Outlook
Transmission Capability	Canada: National Energy Board, *Canadian Electricity Trends and Issues (2001)* & *Canadian Electricity Exports and Imports (2001)*; National Resources Canada, *Electric Power in Canada 1998 – 1999*; NERC, *2004 Summer Assessment* & *2004 Winter Assessment: Reliability in the Bulk Electricity Supply in North America* Western US – Additional data provided by BPA and reports from the WECC (Approved 2006 Spring OTC Limits, March 16, 2006).

This data has been compared to generation data provided as part of modeling for the California Public Utilities Commission.[20]

The resulting list of generating units was matched to emission data from the EPA in order to calculate emission rates. The resulting emission rates for the targeted GHG emissions were then reviewed for reasonableness based on plant type and capacity factors, etc.

Historic generation by plant type will be calibrated with historic generation data available from the EIA.

[20] *www.ethree.com/cpuc_ghg_model.html*

4.5.3 Transmission Structure and Dispatch

Power flows between neighboring US states are modeled within ENERGY 2020 based on existing transmission capabilities and interconnections as obtained from NERC reports.

Appendix D describes the inter-regional transmission capabilities between model regions (or nodes) as well as the maximum capacity limit of each transmission path used in the model. Interconnection capacities and transmission nodes used in the model were based on the IPM® Model 2006[21] updated to reflect changes in the region based on past work for past clients including the Bonneville Power Administration and review by the Economic Modeling Team.

Generation is dispatched at the node level for a set of sample hours in each season. Each node is economically dispatched, selecting lowest cost generation first with the resulting clearing price determining the generation price for that node as described in Appendix A. As part of the calculation the model can utilize resources from a neighboring node within the constraints of the transfer capacity between nodes. The transfer of energy between nodes is subject to a 1% loss to represent additional transmission losses.

4.5.4 Planned Capacity Changes

As part of the modeling process, ENERGY 2020 builds new capacity endogenously as needed to meet capacity and reserve requirements or to minimize the total cost of generation (e.g., in response to allowance prices). At any given time, however, plans may already be in place to build, re-furbish, upgrade or retire generation facilities. These plans must be incorporated into the model in order to reflect decisions and commitments that have already been made.

For this project, we reviewed information on a number of generation projects planned in the Region, with particular emphasis on planned coal facilities. This list was then reviewed with the WCI Economic Modeling Team to determine which projects were felt to be most likely to proceed based on the current status. While it is not possible to determine which specific projects will proceed, for

[21] *Table 3.5 of section 3 of the documentation for the EPA Base Case 2006 (v3.0) posted on the EPA website: http://epa.gov/airmarkets/progsregs/epa-ipm/index.html#docs*

modeling purposes we have assumed that the units listed in Appendix F will be built during the modeled period.

ENERGY 2020 can determine the need for new generation based on a pre-determined reserve requirement. Normally, this determination is based on the highest level of demand for power and the available capacity at the time of that peak. Some types of generation, such as wind or some types of hydro-electric generation however, may not be available at the time of the peak. For modeling purposes the model assumes that only 15% of installed wind capacity is available at the time of the peak.

4.5.5 New Generation Characteristics

The costs and characteristics of new generation are based on information developed as part of the GHG modeling process for the California Public Utility Commission[22] and are shown in Appendix G.

Carbon capture and storage (CCS) is assumed to be available after 2020. The performance and cost assumptions for new generating units equipped with CCS are shown in Appendix G. It should be noted that these costs represent capture costs only and do not include transportation or sequestration costs.

The model assumes that no new nuclear generation capacity will come online through 2020.

4.5.6 Industrial Generation and Co-generation

ENERGY 2020 models both utility generation, which supplies the power grid, and industrial generation which supplies a particular end user. Industrial generation is defined as power generation that is within the industrial end user's facility and is not used to supply power to the grid. Industrial generation, as defined in ENERGY 2020, could also be referred to as self-generation or load displacement generation. Industrial generation may be supplied by any of the fuels listed below:

- Biomass
- Coal
- LPG
- Oil

[22] *www.ethree.com/cpuc_ghg_model.html*

- Solar
- Steam

Co-generation, or combined heat and power facilities, simultaneously generate electricity and supply a heat load. ENERGY 2020 recognizes that co-generation may occur either as industrial generation or as utility generation and may use any of a number of fuels.

- Within the power sector, these plants are treated as 'must run' units, meaning that they will always operate when available. Power from these units contributes to overall electricity supply. Heat from these units may be captured as part of a separate steam supply system, however, limited data is available regarding overall US steam demand.
- Within the industrial sector, co-generation capacity will run based on heating requirements. Heat produced from co-generation is used to meet industrial heat requirements based on a co-generation heat rate. Co-generated electricity is used to meet industrial power requirements, reducing net demand from the grid.

Where the heat contribution of co-generation is significant, the preferred modeling approach is to include these units in the industrial sector.

The databases used to represent electricity generation often include all significant generators, including both utility and industrial boilers and generators. By contrast, reported electricity consumption information tends to be based on metered electricity sales, and as such are net of self generation. Total electricity consumption and generation will generally be slightly higher than reported electricity sales. It is therefore important in calibrating the model with historic electricity consumption that existing generation used as industrial or self-generation be appropriately identified.

4.6 *Transportation*

ENERGY 2020 models passenger, freight and off road transportation separately, based on different underlying drivers. Transportation is assumed to be a derived demand based on levels of economic output (for freight) or personal income (for passenger). As the economic drivers (industrial gross output and personal income) grow, transportation demand increases. The amount of transportation required per unit of economic output changes over time based on historic trends.

Transportation requirements are developed for each geographic area in the model based on historic demands for transportation, consumer preferences, business requirements, and the cost for each mode of transportation. Consumers of transportation select among available modes within the model based on preferences and relative costs. Mode choices include bus, train, and various types of personal and freight vehicles. Consumers choose among modes based on consumer preferences and cost. The model uses average vehicle lifetimes to vintage the vehicle stock.

Personal vehicle choices are made in a similar manner. Consumers consider capital cost, fuel cost and efficiency as well as non-price factors in their purchase decision and seek to maximize perceived utility. Historically, non-price factors such as vehicle size, performance and appearance have dominated the choice decision with efficiency playing a relatively minor role. Costs are presented in the model in terms of the capital cost per mile traveled for different vehicle classes. Larger vehicles therefore have a higher associated capital cost as well as lower energy efficiency for the level of delivered service (miles traveled).

The transportation categories represented in the model are shown below.

E2020 Classifications				
Economic Categories	**Modes**	**Vehicle Classes** *(for Personal Vehicles)*	**Fuel Types** *(for Personal Vehicles)*	**Technology Types**
Passenger	Personal Vehicles	Light	Gasoline	Internal Combustion Engine
Freight	Motorcycle	Medium	Diesel	Hybrids
Off Road	Train	Heavy	Propane	Fuel Cell
	Plane		CNG	Plug-In Hybrid
	Marine		Electric	
			Ethanol	
			Hydrogen	

At present, plug-in hybrid and fuel cell options are not populated in the model. As more information on the costs and characteristics of these options becomes available these choices can be made available to transportation consumers.

Vehicle and modal efficiencies used in the model are based on the *Transportation Energy Data Book* (Edition 26, 2007)[23] published by the US

[23] http://cta.ornl.gov/data/download26.shtml

Department of Energy's Oak Ridge National Laboratory. Specific data references are provided in the table below.

Input	Sources Used/Available
All tables below are from ***Transportation Energy Data Book*** *(Edition 26, 2007)*[24] *published by the US Department of Energy's Oak Ridge National Laboratory.*	
Average fuel economy	Tables 4.17 and 4.18
New Vehicle Efficiency	Tables 4.7 and 4.8
Scrap/Survival Rates	Tables 3.8, 3.9 and 3.10
Freight Truck Fuel Economy	Tables 5.1 and 5.2
Bus Efficiency	Table 2.13
Rail Efficiency – Passenger	Table 9.10 and 9.11
Rail Efficiency - Freight	Table 9.8
Marine - Freight	Table 9.5
Air Travel	Table 9.2

The model reflects the most recent changes in new passenger vehicle in CAFÉ standards, as embodied in the *Energy Independence and Security Act of 2007* (see section 4.8).

Off road transportation energy use in ENERGY 2020 is driven by activity in the Agriculture, Forestry and Construction sectors.

4.7 *Built Environment*

ENERGY2020 has been used to model energy for almost three decades. Much of the data on energy efficiency and costs was originally based on information provided by the Energy Information Administration's *Annual Report to Congress*[25] which was last published in 1980. Over the years, this data has been updated based on information gathered from clients as part of numerous projects. The resulting cost and efficiency data is used as default values in the model.

When a new model is built for a particular project, actual historic energy use is input to the model (generally from the EIA SEDS database) and allocated by

[24] http://cta.ornl.gov/data/download26.shtml
[25] EIA, *Annual Report to Congress, 1980: Volume 3*. Energy Information Administration, USDOE, Report #: DOE/EIA-0173(80)/3.

sector based on census region data from the most recent energy surveys available from the EIA (e.g. Residential Energy Consumption Survey, Commercial Building Energy Consumption Survey, etc). Average and maximum device efficiencies are adjusted within the model over time in calibrating to this actual energy use data. For the WCI project, ICF and SSI have subjected this data to an internal review and updated the values based on expert opinion and data from a variety of sources.

Appendix J presents the assumptions used in modeling the residential and commercial sectors, showing assumed levels of efficiency by period, maximum efficiency levels, initial and operating costs per mmBtu of energy use and device lifetimes for each end use for each fuel type. This data is used in the choice curves within the model.

Several of the jurisdictions involved in the WCI have had a long history of promoting energy efficiency and demand side management for electricity and natural gas energy use. As a result, average appliance and equipment efficiencies are expected to be higher than for the US and Canada as a whole. As part of Tasks 4 and 5 we will attempt to gather information on current levels of equipment efficiency and the state of the market for efficiency technologies. This information will then be used to adjust end-use data within the model to reflect current levels of efficiency and market saturations.

The Reference Case does not assume any increase in equipment or appliance efficiency other than the improvements due to the *Energy Independence and Security Act of 2007*, as noted in section 4.8.

4.8 *Programs/Policies Incorporated in Reference Case*

As this assumptions document is further refined and developed, a table listing the specific laws and regulations included in the Reference Case will be inserted here.

Of particular importance, the *Energy Independence and Security Act of 2007* was passed into law in early January 2008. The following assumptions will be used to model the Act in the Reference Case:

- Transportation: The current marginal vehicle efficiency for passenger cars and light trucks will be incrementally increased by a fixed percentage each year starting in 2011 to reach the mandated fleet efficiency in 2020.

- Renewable Fuels: The Act specifies a minimum volume of biofuels to be produced each year. For modeling purposes we have assumed that this volume of biofuels is produced and consumed in each year. The model assumes that each of the US states will use their pro-rata share of the available fuels.
- Residential Boilers and Furnace Fans: Savings estimates developed by the ACEEE for each state will be used to model this portion of the Act, using only the benefits realized by upgrades to the residential energy boilers, leaving out any energy benefits associated with reduced electricity consumption by furnace fans.
- Walk-In Coolers and Walk-In Freezers: Savings estimates developed by the ACEEE for each state will be used to model this portion of the Act.
- Electric Motor Efficiency Standards: The model will utilize the ACEEE savings projections, pro-rated to California's relative industrial electricity sales.
- External Power Supply Efficiency Standard: savings estimates developed by the ACEEE for each state will be used to model this portion of the Act.
- Energy Efficient Light Bulbs: Information will be collected on existing market shares for efficient lighting in the WCI region in order to estimate the impact of this aspect of the Act. The base assumptions are that general service lighting accounts for about 90% of residential lighting, 10% of commercial lighting and 5% of industrial lighting.
- Metal Halide Lamp Fixtures: The model assumes that 15% of commercial lighting and 60% of industrial lighting now use metal halide fixtures. For new installations the model assumes that 80% of this market would use pulse start ballasts.

The model will also include regulations affecting the power sector which have been approved but have not yet come into effect. Such regulations may be significant to the extent that they influence dispatch decisions which in turn will affect CO_2 emissions.

For the Canadian provinces, the model assumes that existing requirements for biofuels are met. Existing legislation requires that

The reference case includes Renewable Portfolio Standards for each WCI partner jurisdiction according to the rules in each jurisdiction. Please refer to Appendix I for summaries of each jurisdiction's RPS.

4.9 *Complementary Policies*

A *Complementary Policies* scenario is being modeled for the WCI that includes the following WCI-wide policies that are not part of the Reference Case:

- **Vehicle Miles Traveled** – Assumes that policies will be introduced to reduce VMT in all WCI partner jurisdictions by 2% from BAU levels in 2020.
- **Energy Efficiency Programs** – Assumes that energy efficiency programs will be undertaken in all WCI partner jurisdictions to reduce energy use (electricity, natural gas, fuel oil and propane) by 1% per year below the reference forecast between 2011 and 2020.
- **California Clean Cars** – Assumes that all WCI partners will implement the California clean car standards as currently formulated, along with Phase 2 standards currently contemplated by the California ARB.

Appendix A: The ENERGY 2020 Model

The Model – ENERGY 2020

ENERGY 2020 is an integrated multi-region, multi-sector energy analysis system that simulates the supply, price and demand for all fuels. It is a causal and descriptive model, which dynamically describes the behavior of both energy suppliers and consumers for all fuels and for all end-uses. It simulates the physical and economic flows of energy users and suppliers. It simulates how they make decisions and how those decisions causally translate to energy-use and emissions.

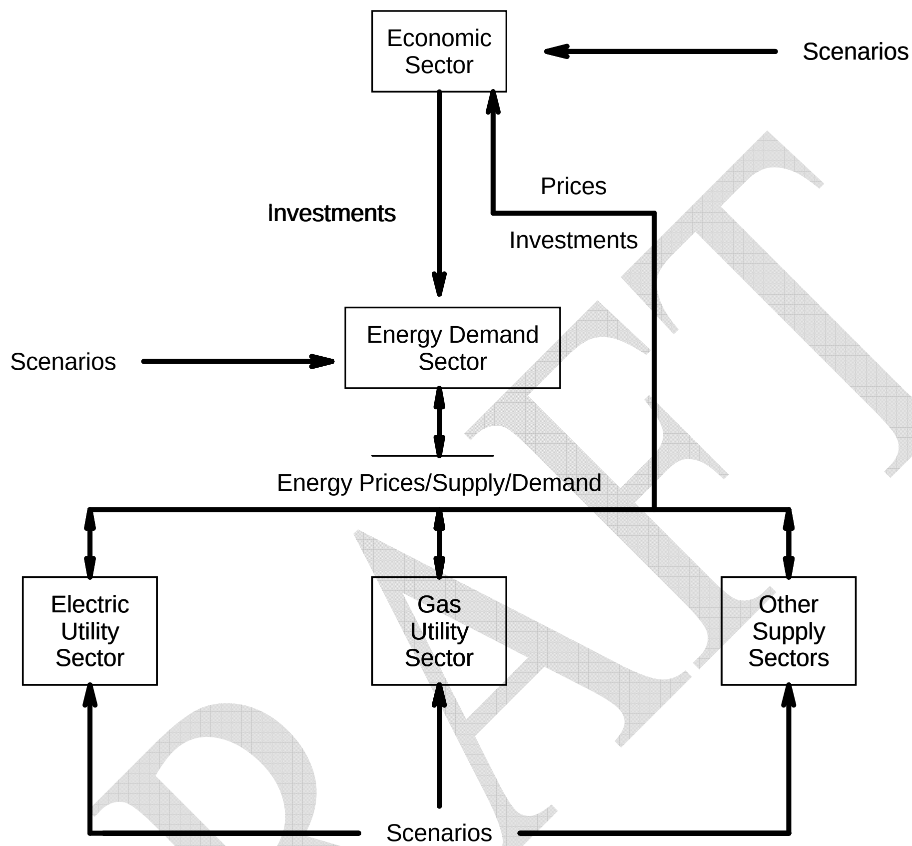
ENERGY 2020 is an outgrowth of the FOSSIL2/IDEAS model developed for the US Department of Energy (DOE) and used for all national energy policy since the Carter administration.[26] This early version of ENERGY 2020 was developed in 1978 at Dartmouth College for the DOE's Office of Policy Planning and Analysis.

Model Overview:

The basic structure of ENERGY 2020 is provided in Figure 1-1. Energy Demand sector interacts with the Energy Supply sector to determine equilibrium levels of demand and energy prices. Energy Demand is driven by the Economy sector, which in turn provides inputs to the Economy sector in terms of investments in energy using equipment and processes and energy prices. The model has a simplified Economy sector to capture the linkages between the energy system and the macro-economy. However, the model is best run with full integration with a macroeconomic model such as REMI. Given the modular nature of ENERGY 2020, additional sectors or modules from other, non-ENERGY 2020 related, models (macroeconomic, supply such as oil, gas, renewables etc.) can be incorporated directly into the ENERGY 2020 framework.

[26] *FOSSIL2 was the original version but was renamed to IDEAS a few years ago to reflect its evolutionary development since its original construction.*

Figure 1.1: ENERGY 2020 Overview



Energy Demand:

The demand sector of the model represents the geographic area by disaggregating the four economic sectors into subsectors based on energy services. As many or as few subsectors can be incorporated as required. Multiple technologies, multiple end-uses and multiple fuels are detailed. The level of detail that can be incorporated is of course subject to the data availability. The four economic sectors are:

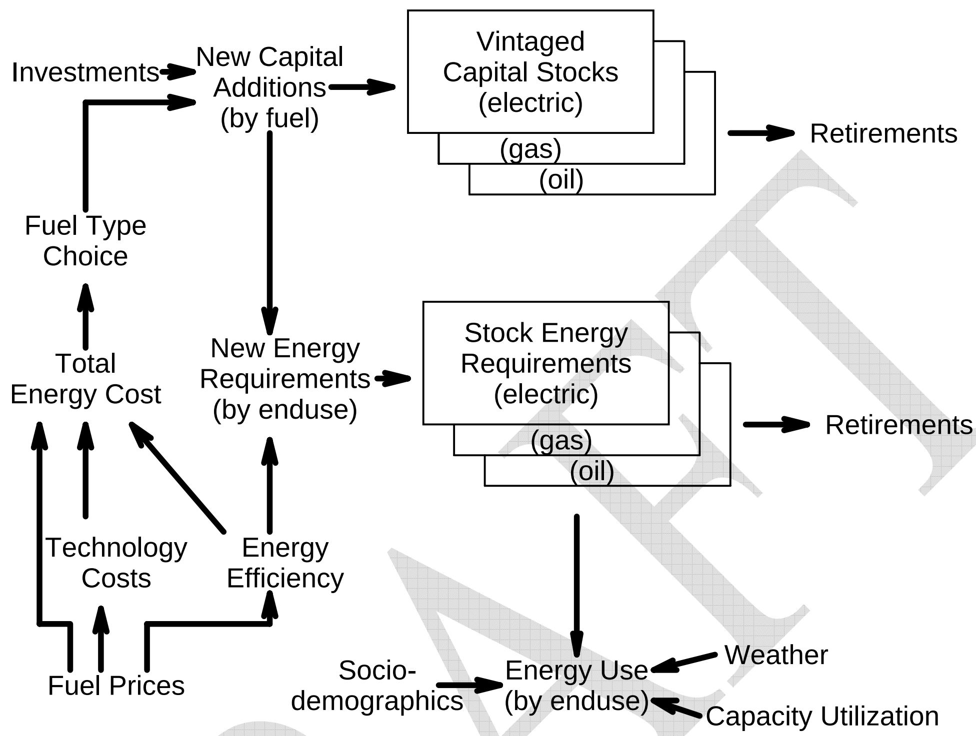
- Residential sector which includes three classes, single family, multifamily and rural/agricultural with 8 end-uses including space heating, water heating, lighting, cooling, refrigeration, other substitutable, and other non-substitutable.
- Commercial sector which is aggregated into one class and end-uses including space heating, water heating, cooling, lighting, other substitutable, other non-substitutable.

- Industrial sector which includes 10 (23 for US) 2-digit SIC categories and is further broken down into process heat, motors, lighting, miscellaneous as the end uses.
- Transportation sector which includes several modes of transportation including automobile, truck, bus, train, plane, marine and electric vehicles. Also, each of the residential, commercial and industrial sectors has separate transportation demands.

For each of the end-uses, up to six fuels are modeled, for example, the residential space heating has the choice of a gas, oil, coal, electric, solar and biomass space heating technologies. Added end-uses, technologies and modes can be added as data allow. For all end-uses and fuels, the model is parameterized based on historical locale-specific data. The load duration curves are dynamically built up from the individual end-uses to capture changing condition under consumer choice and combined gas/electric programs.

A few basic concepts are crucial to an understanding of how the model simulates the energy system. These concepts including, the capital stock driver, the modeling of energy efficiency through trade-off curves, the fuel market share calculation, utilization multipliers and the cogeneration module are discussed below in abbreviated form. Figure 3-1 (Demand Overview) illustrates the demand sector interactions.

Figure 3.2: Demand Overview



Energy Demand as a Function of Capital Stock:

The model assumes that energy demand is a consequence of using capital stock in the production of output. For example, the industrial sector produces goods in factories, which require energy for production; the commercial sector requires buildings to provide services; and the residential sector needs housing to provide sustained labor services. The occupants of these buildings require energy for heating, cooling, and electromechanical (appliance) uses.

The amount of energy used in any end-use is based on the concept of energy efficiencies. For example, the energy efficiency of a house along with the conversion efficiency of the furnace determines how much energy the house uses to provide the desired warmth. The energy efficiency of the house is called the capital stock energy or process efficiency. This efficiency is primarily technological (e.g. insulation levels) but can also be associated with control or life-style changes (e.g. less household energy use because both spouses work outside the home.) The furnace efficiency is called the device or thermal efficiency. Thermal efficiency is associated with air conditioning, electromotive devices, furnaces and appliances.

The model simulates investment in energy using capital (buildings and equipment) from installation to retirement through three age classes or vintages. This capital represents embodied energy requirements that will result in a specified energy demand as the capital is utilized, until it is retired or modified.

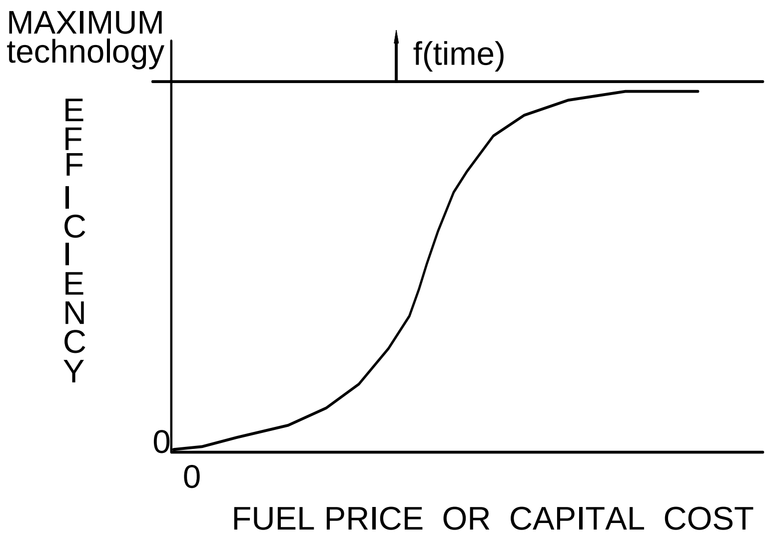
The size and efficiency of the capital stock, and hence energy demands, change over time as consumers make new investments and retire old equipment. Consumers determine which fuel and technology to use for new investments based on perceptions of cost and utility. Marginal trade-offs between changing fuel costs and efficiency determine the capital cost of the chosen technology. These trade-offs are dependent on perceived energy prices, capital costs, operating costs, risk, access to capital, regulations and other imperfect information.

The model formulates the energy demand equation causally. Rather than using price elasticities to determine how demand reacts to changes in price, the model explicitly identifies the multiple ways price changes influence the relative economics of alternative technologies and behaviors, which in turn determine consumers' demand. In this sense, price elasticities are outputs, not inputs, of the model. The model accurately recognizes that price responses vary over time, and depend upon factors such as the rate of investment, age and efficiency of the capital stock, and the relative prices of alternative technologies.

Device and Process Energy Efficiency:

The energy requirement embodied in the capital stock can be changed only by new investments, retirements, or by retrofitting. The efficiency with which the capital uses energy has a limit determined by technological or physical constraints. The trade-off between efficiency and other factors (such as capital costs) is depicted in Figure 3.3 (Efficiency/Capital Cost Trade-Off). The efficiency of the new capital purchased depends on the consumer's perception of this trade-off. For example, as fuel prices increase, the efficiency consumers choose for a new furnace is increased despite higher capital costs. The amount of the increase in efficiency depends on the perceived price increase and its relevance to the consumer's cash flow.

Figure 3.3: Efficiency/Capital Cost Trade-Off



The standard the model efficiency trade-off curves are called consumer-preference curves because they are estimated using cross-sectional (historical) data showing the decisions consumers made based on their perception of a choice's value. Many planners are now interested in measure-by-measure or least-cost curves which use engineering calculations and discount rates to show how consumers should respond to changing energy prices. Another analysis focuses on the technical/price differences in alternative technologies and the incentives needed to increase the market-share or market penetration of a specific technology. This perspective on the choice process uses market share curves. The model allows the user to select any of these three types of curves to represent the way consumers make their choices. Shared savings, rebate, subsidy programs, etc. can be tested using any of the curves.

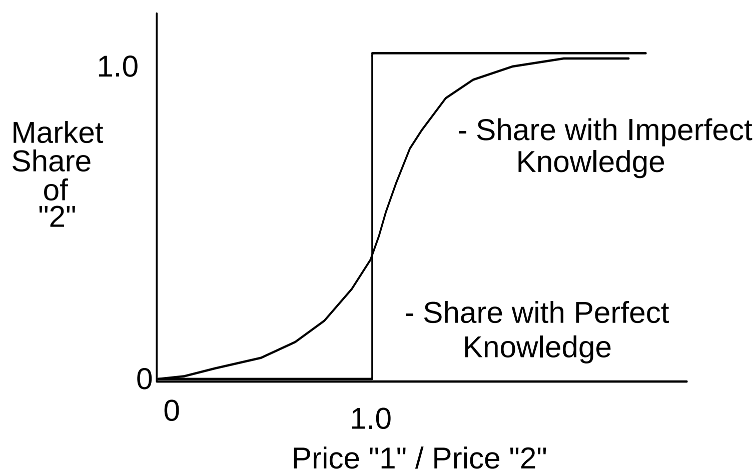
Cumulative investments determine the average embodied efficiency. The efficiency of new investments versus the average efficiency of existing equipment is one measure of the gap between realized and potential conservation savings.

The model uses saturation rates for devices to represent the amount of energy services necessary to produce a given level of output. Saturation rates may change over time to reflect changes in standard of living or technological improvements. For example, air conditioning has historically increased with rising disposable incomes. These rates can be specified exogenously or can be defined in relation to other variables within the model (such as disposable income).

The Market Share Calculation:

Not all investment funds are allocated to the least expensive energy option. Uncertainty, regional variations, and limited knowledge make the perceived price a distribution. The investments allocated to any technology are then proportional to the fraction of times one technology is perceived as less expensive (has a higher perceived value) than all others. This process is shown graphically in Figure 3.4 (Market Share Dynamics).

Figure 3.4: Market Share Dynamics



Short Term Budget Responses:

A short-term, temporary response to budget constraints is included in the model. Customers reduce usage of energy if they notice a significant increase in their energy bills. The customers' budgets are limited and energy use must be reduced to keep expenditures within those limits. These cutbacks are temporary behavioral reactions to changes in price, and will phase out as budgets adjust and efficiency improvements (true conservation) are implemented. This causes the initial response to changing prices to be more exaggerated than the long-term response, a phenomenon called "take-back" in studies of consumer behavior.

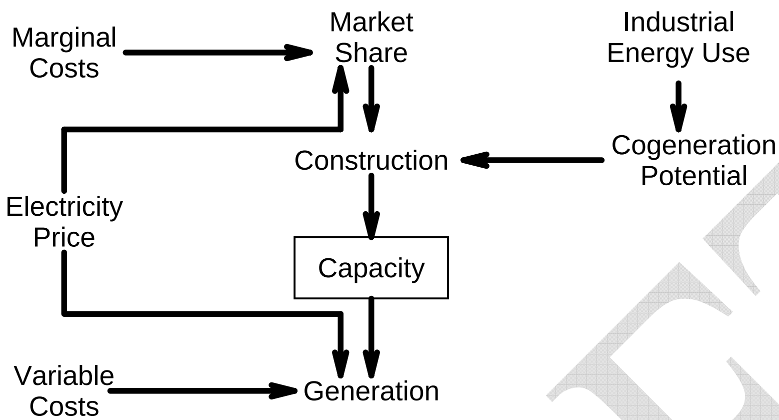
Accounting for Fungible Demand:

Some furnaces and processes can use multiple fuels. That is, they can switch almost instantaneously between, for example, gas and oil or coal and biomass as prices or the market dictates. Energy demand that is affected by this short-term fuel switching phenomena is called fungible demand. The model explicitly simulates this market share behavior.

Modeling Cogeneration:

Most energy users meet their electricity requirements through purchases from a utility. Some users (industrial and commercial) can, however, convert some of their own waste heat into usable electricity when economics warrant such action. Other users (residential and commercial) can purchase self-generation energy sources such as gas turbines, diesel-generators or fuel cells. Figure 3.4 shows a simplified overview of the cogeneration structure.

Figure 3.5: Cogeneration Concepts



In the model all energy used for heating is a candidate for cogeneration. The cost of cogeneration is the fixed capital cost of the investment plus the variable fuel costs (net of efficiency gains). This cogeneration cost is estimated for all technologies and compared to the price of electricity. The marginal market share for each cogeneration technology is based on this comparison.

Cogeneration is restricted to consumers who directly produce part of their own electricity requirement. Companies which generate power primarily for resale to the electric utility are considered independent power producers and are included in the electric supply model.

Energy Supply:

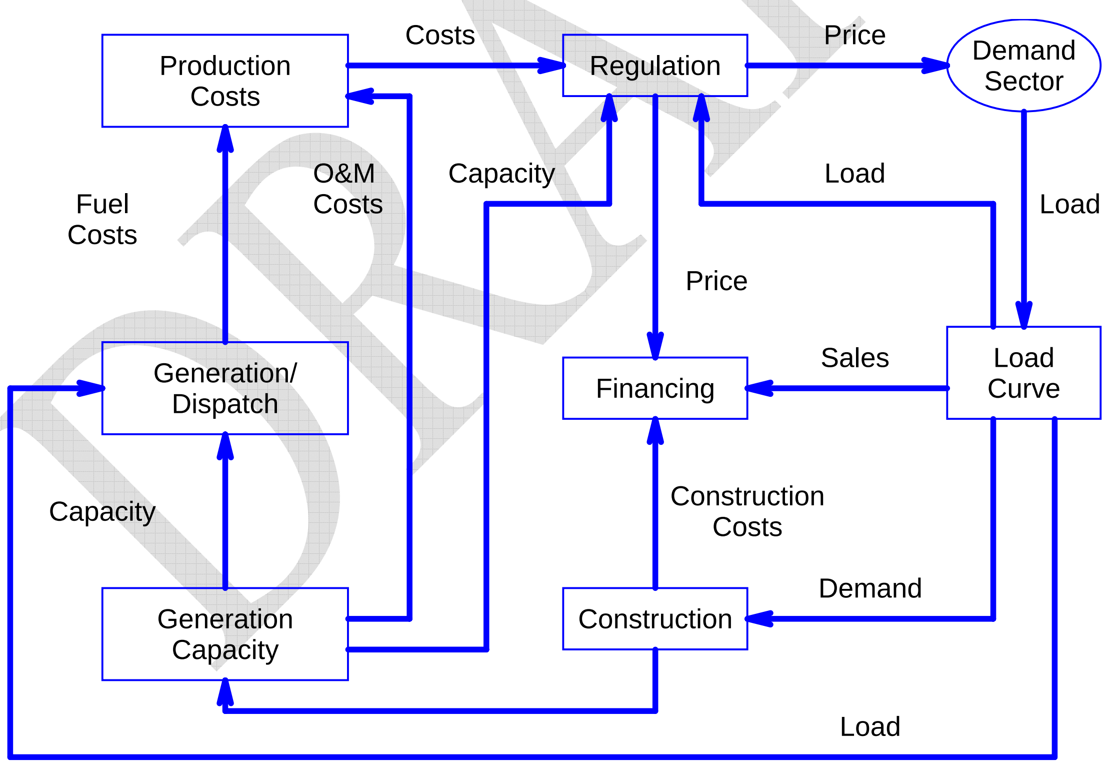
For electric and gas utilities (separate or combined), ENERGY 2020 internally and self-consistently simulates sales, load (by end-use, time-of-use, and class), production (across thirty-six dispatch types), demand-side management (by technology), forecasting, capacity expansion (new generation, independent power producers, purchases, and DSM), all important financial variables, and rates (by class, end-use, and time-of-use.)

The version currently used in this analysis only has the electricity utility sector (a full fledged natural gas utility sector for Canada is currently unavailable in the model, only a simplified natural gas supply function is used to calculate the supply price response).

With the inclusion of the electric utility sector, the generic supply model turns over the calculation of electricity prices to that sector. The model is capable of endogenously simulating the forecasting of capacity needs, as well as the planning, construction, operation and retirement of generating plants and transmission facilities. Each step is financed in the model by revenues, debt, and the sale of stock. The simulated utility, like its real world counterpart, pays taxes and generates a complete set of accounting books. In ENERGY 2020, the regulatory function is modeled as a part of the utility sector. The regulator sets the allowed rate of return, divides revenue responsibility among customer classes, approves rate base, revenues and expenses, and sets fuel adjustment charges.

The interactions in the electric utility sector are summarized in Figure 3.6

Figure 3.6: Electric Utility Structure Overview



Expansion Planning:

The utility sector endogenously forecasts future demand for electricity. From the forecast it projects the future capacity required meeting future demand by taking into account retirements and plants already under construction. Construction of additional capacity is initiated if future electricity requirements, including reserves, are forecast to exceed available capacity (using seasonal ratings).

If additional capacity is needed to meet forecasted needs, the basic capacity expansion module in ENERGY 2020 determines whether base or peaking capacity is required. The model determines the maximum number of hours that new peaking capacity can be economically operated, before it would be less expensive to construct and operate base load capacity instead. If the forecasted peaking capacity would operate more than that economic maximum, base loads units are initiated, otherwise peaking units are initiated. Any plant type including geothermal, wind, biomass and storage can be considered.

New plants, of a pre-specified minimum size, are initiated when the reserve margin would be violated if the plants were not built or if base load capacity is inadequate to serve base load energy needs at the end of the forecast period. The model does allow the minimum reserve margin to be temporarily violated at the peak if new base load capacity is scheduled to be available within the year. Peaking units are allowed to serve more than the maximum economical number of hours until base load capacity comes on-line.

Minimum plant size is exogenous. The mix of new base load plants (i.e. alternative coal technologies, hydro, or nuclear) is user-specified in the standard ENERGY 2020 configuration. The model also evaluates the financial implications of new construction, including total construction costs, cost schedules, and AFUDC/CWIP. The gross rate on AFUDC equals the weighted average cost of capital. The actual construction progress and financial impacts are simulated on a year by year basis.

ENERGY 2020 can also be configured to consider intermediate load units, firm purchases contracts, external sales, independent power producers, and demand-side options. These options can be optionally selected based on endogenous least-cost analysis or can be chosen by user-specified criteria to meet. A detailed automatic Integrated Resource Planning module that would endogenously choose (with user control) from DSM measures utility and non-utility generation and purchase alternatives using linear programming techniques is now being offered as an enhancement.

Financing:

The ENERGY 2020 utility finance sub-sector simulates the activities of a utility's finance department. It forecasts funding requirements and follows corporate policies for obtaining new funds. The model simulates borrowing and issuing of stock, and can repurchase stock or make investments if it has excess cash. Cash flows are explicitly modeled, as are any decision that affects them. Coverage ratios, intermediate- and long-term debt limits, capitalization, rates of return, new stock issues, bond financing, and short-term investments are endogenously calculated. The model keeps track of gross, net, and tax assets. It also calculates the depreciation values used for the income statement and tax obligations.

For WCI modeling, this element of the model is not used, and a simpler approach to estimating retail electricity prices is used.

Regulation:

The utility sector sets electricity prices according to regulatory requirements. The regulatory procedures use allowed rate-of-return and test year cost and demands to determine allowed revenues. Electricity prices are calculated from peak-demand fractions by allocation of costs. Any other allocation scheme can also be considered. The regulatory sub-sector of ENERGY 2020 automatically factors in a wide variety of regulatory policies and options. More importantly, the model can be readily modified to consider a wide spectrum of scenarios.

The regulatory process revolves around a test year, usually one year forward, when proposed rates will go into effect. The utility sector forecasts test year sales and peak demands by season and customer class, just as it does to determine capacity needs. These test year demand estimates are used to allocate responsibility for system peak, and therefore, generation capacity costs.

Fuel costs for the test year are estimated by dispatching the plants that will be available in the test year, using the dispatching routine explained below. Fuel costs and operating and maintenance costs are adjusted for expected inflation, and these costs are factored into the electricity rates using forecasted sales.

ENERGY 2020 calculates the utility rate-base according to a detailed conventional rate making formula. The model allows the user to adjust allowable costs, and has been used extensively to evaluate alternative rate-base scenarios for individual plants, including allowing return of, but no return on investment, and partial disallowment of construction and interest costs.

The ENERGY 2020 system also includes estimation of avoided costs, which determines when the utility may be required to purchase third party power. Environmental constraints, such as air pollution restrictions, can also be included in the model. If ENERGY 2020 is configured as a regional or state-wide system, municipal utilities, with their unique tax and rate structures, are incorporated. Similarly, regional or power pool interchange is also recognized by ENERGY 2020. As with the other sectors of ENERGY 2020, the regulatory subsector is flexible enough to accommodate any existing or hypothetical circumstance.

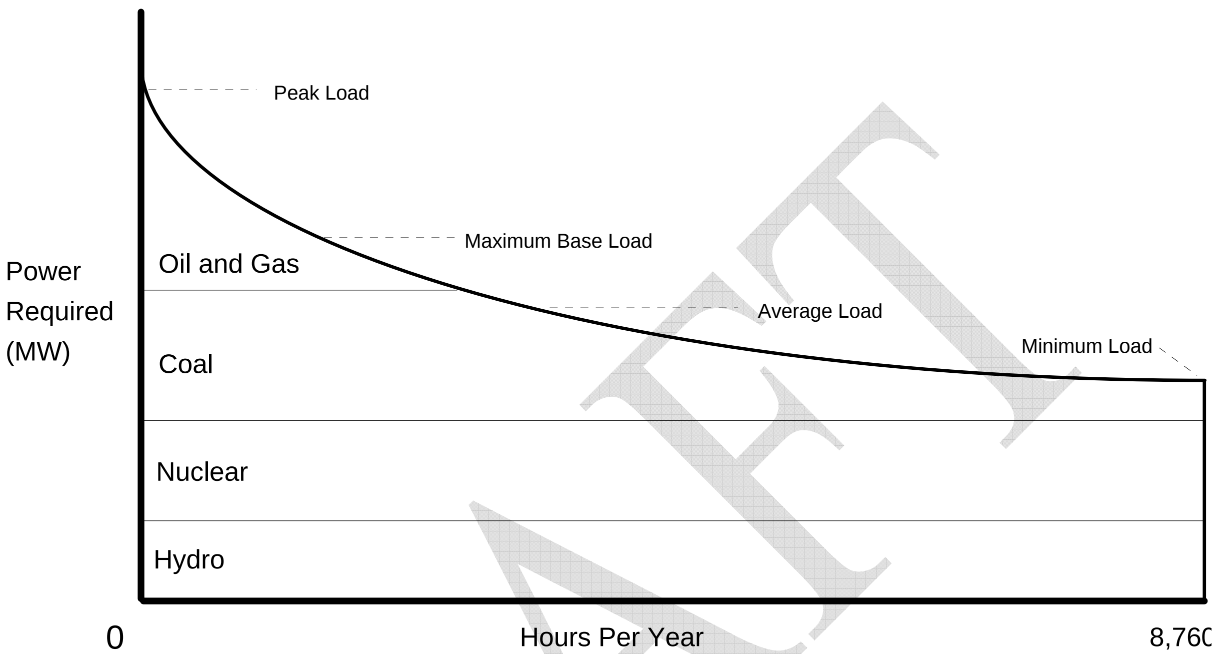
For WCI modeling, this element of the model is not used, and a simpler approach to estimating retail electricity prices is used.

Operations:

Each end-use in ENERGY 2020 has a related set of load shape factors. Typically, these factors define the relationship between peak, minimum and average load for each season. These factors when combined with the weather-adjusted energy demand by end-use and corrected for cogeneration, resale, and load management programs, form the basis of the approximated system load duration curve. Alternatively, unit hourly loads for each end-use for three days per month (average weekday, weekend and peak weekday) are used.

The standard ENERGY 2020 production subsector uses an advanced de-rating or chronological method to estimate the seasonal or hourly dispatch of plants. It purchases power externally when economic or necessary. Plant availability and generation for coal, nuclear, hydroelectric, oil and gas are currently considered, as well as pumped storage, firm purchases, interruptible load, and fuel switching and qualified facilities. Figure 3.7 also shows a typical plant dispatch schedule.

Figure 3.7: Generation from the Load Curve



The ENERGY 2020 system estimates conventional fuel costs based on the unit dispatch, heat rates, and fuel prices (from the supply sector.) Nuclear fuel costs are capitalized and depreciated throughout the re-fuelling cycle. Nuclear fuel expenses also include fuel disposal costs.

ENERGY 2020 explicitly models the costs of maintaining the transmission and distribution (T&D) system. New facility investments are scheduled and incurred endogenously. In addition, the user can specify the decision rules that dictate T&D expenditures. ENERGY 2020 also explicitly models both fixed and variable operation and maintenance costs, power pool interchanges, nuclear decommissioning costs, plant capital additions, plant cancellations, and general administration costs.

Model Applications:

The structure of the model is well tested and has been used to simulate not only US and the Canada energy and environmental dynamics but also those of several countries in Western, Central and Eastern Europe. Current efforts include strategic and tactical analyses for South America deregulation. Further, the model has been used successfully for deregulation analyses in over 50 energy suppliers and in all the US states and Canadian provinces. Several US and Canadian energy suppliers currently use the model for the analysis of combined electricity and gas deregulation dynamics.[27] The model contains confidence and validity packages that allow it to determine how to take maximal advantage of RTO rules. The ISO NE used the model to find gaps in its rules and to develop more efficient market conditions. The model was used for the CAPX/ISO to model to show, before the fact, many of the “games” played in the California market.

[27] *ENERGY 2020 is the only model known to have simulated and predicted the dynamics that occurred in the UK electric deregulation. These include gaming, market consolidation and re-regulation dynamics.*

Appendix B: Data Sources

The following describes the default data sources used in ENERGY 2020. Where this data has been replaced by jurisdiction-specific information, the jurisdiction-specific data is described in the main body of the document.

Historical Energy Prices and Demands

Historic energy prices and demands are from *State Energy Data*, Integrated Energy Statistics Divisions of the Office of Energy Markets and End Use, Energy Information Administration, USDOE. This document provides annual time series estimates of State-level energy consumption, prices, and expenditures by major economic sectors. In 2000, the *State Energy Data* replaced two former EIA reports: State Energy Data Report (SEDR) and State Energy Price and Expenditure Report (SEPER). Tables by major economic sector can be found at: http://www.eia.doe.gov/emeu/states/_states.html. New tables by energy source can be found at: http://www.eia.doe.gov/emeu/states/multi_states.html.

Future Energy Prices

To estimate future energy prices, we apply the forecasted price growth rates from the *Annual Energy Outlook (AEO) 2008* to the prices from the last historical year (obtained from *State Energy Data*). The Annual Energy Outlook 2008 presents a forecast and analysis of US energy supply, demand, and prices through 2030.
http://www.eia.doe.gov/oiaf/aeo/supplement/index.html

Note that there is a gap between the most recently reported historical year of data and the first forecast year. We resolve this by including one year's worth of price data from the AEO of the previous year.

Future Energy Demands

Future energy demands are computed by the model, but the model can calibrate to future energy demands if desired. In the modeling completed for WCI the model projections have been compared to other forecasts but have not been calibrated to any other forecast.

Device Energy Efficiency Standards

Device efficiency standards come mainly from the *Energy Policy Act of 1992*, with some efficiencies coming from other selected sources.
http://energy.navy.mil/publications/law_us/92epact/hr776toc.htm

This initial base of efficiency standards have been updated as new regulations have come into effect. Requirements in the ***Energy Independence and Security Act*** have also been included in the Reference Case.

Device Capital Cost, Efficiency, and Device Lifetimes; Cogeneration Capital Costs, Heat Rates and Parameters

These values were originally developed from the *Annual Report to Congress, 1980: Volume 3*. Energy Information Administration, USDOE, Report #: DOE/EIA-0173(80)/3. ICF and SSI have reviewed and updated this data which is used to provide the shape of choice curves within the model based on expert opinion and data from a variety of sources. The values used are presented in Appendix J.

End-Use Load Shapes

The end use load shapes were originally based on 1995 NEPOOL published reports. Load shapes for temperature sensitive loads are modified based on actual weather data for the state/region being modeled.

Industrial Energy Splits, Industrial End Use Splits and Commercial End-Use Splits

The energy that we obtain from *State Energy Data* is a total value that needs to be split among different industries and/or uses (end use demands, cogeneration demands, feedstock demands). We obtain the splits among industries and uses from the *Manufacturing Energy Consumption Survey*, Energy Information Administration, USDOE. The Manufacturing Energy Consumption Survey is conducted every five years and provides detailed data on energy consumption in the manufacturing sector. http://www.eia.doe.gov/emeu/mecs/contents.html

Residential Devices Saturations and Market Shares

Residential devices saturations and market shares are obtained from the *Residential Energy Consumption Survey*, Energy Information Administration, USDOE. http://www.eia.doe.gov/emeu/recs/contents.html

Inflation Rate

Historical inflation rates are calculated from the consumer price index reported by the Bureau of Labor. Projections for inflation from 2004 through 2030 are calculated from the consumer price index projections of the *Annual Energy Outlook 2008*, Energy Information Administration, USDOE. http://www.eia.doe.gov/oiaf/aeo/index.html.

Fuel Choice Variance Factors, Return on Investment, and Maximum Process Efficiency Multiplier

The fuel choice variance factors, return on investment and maximum process efficiency multiplier variables come from projections obtained from the DEMAND81 energy model. Backus, George A. 1981. DEMAND81: National Energy Policy Model. Four Volumes. AFC 7-10. School of Industrial Engineering. Purdue University. West Lafayette, Indiana. These factors are updated as part of the calibration process.

Process Capital Costs

The data was developed from the US I/O Tables by REMI in $1987 and have been updated based on work with past clients.

Residential Energy Usage Per Appliance

The average usage per appliance was originally based on *NEPOOL April 1994 Forecast for Massachusetts*. The miscellaneous end use category is computed by adding the residential energy for all miscellaneous end uses and dividing by the number of households. Average use per appliance has been updated since that time based on input from various clients and is calibrated to actual energy use as part of the process of calibrating to actual energy use.

Number of Households

The number of households comes from the United States Census, US Census Bureau. http://www.census.gov/main/www/cen2000.html.

Appendix C: Phase II data

Arizona

Population Forecast	
Year	**Population**
2006	6,239,482
2007	6,432,007
2008	6,622,885
2009	6,812,137
2010	6,999,810
2011	7,186,070
2012	7,370,993
2013	7,554,429
2014	7,736,022
2015	7,915,629
2016	8,093,110
2017	8,268,253
2018	8,441,095
2019	8,611,507
2020	8,779,567
2021	8,945,447
2022	9,109,289
2023	9,271,163
2024	9,430,974
2025	9,588,745
2026	9,744,463
2027	9,898,153
2028	10,049,900
2029	10,199,674
2030	10,347,543

REMI 2006 Forecast Output - Arizona
Arizona Personal Income - Billions of Nominal $

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Earnings by Place of Work	148	157	169	181	193	205	217	230	243	255	268	281	294	307	320
Contr for Gov Social Ins	16	18	19	20	22	23	25	27	28	30	31	33	35	37	38
Adj for Residence	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Dividends, Interest, and Rent	34	37	39	43	46	49	52	55	58	61	65	69	72	76	81
Personal Current Transfer Receipts	30	33	35	38	41	43	46	48	51	54	57	60	63	67	70
Personal Income	196	210	226	243	258	274	290	307	325	341	359	377	395	414	433
Personal Taxes	22	25	27	29	31	33	35	37	39	41	43	45	48	50	52
Disp Pers Inc	173	185	198	213	227	241	255	270	285	300	316	331	348	364	381
Personal Income Pct Change		**7%**	**7%**	**8%**	**6%**	**6%**	**6%**	**6%**	**6%**	**5%**	**5%**	**5%**	**5%**	**5%**	**5%**

REMI 2006 Forecast Output - Arizona
Arizona Personal Income - Billions of Nominal $

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Earnings by Place of Work	334	349	364	380	396	412	430	447	466	486	506	527	550	573	597
Contr for Gov Social Ins	40	42	44	47	49	51	54	56	59	62	65	68	71	75	78
Adj for Residence	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Dividends, Interest, and Rent	85	89	94	99	104	110	116	122	128	135	142	150	158	166	175
Personal Current Transfer Receipts	74	78	82	86	91	95	100	106	111	117	123	129	136	143	151
Personal Income	453	474	496	519	542	567	593	619	647	676	707	739	773	809	845
Personal Taxes	54	57	59	62	65	68	71	74	77	80	84	88	92	96	100
Disp Pers Inc	399	417	437	457	478	499	522	545	570	596	623	652	682	713	745
Personal Income Pct Change	**5%**	**5%**	**5%**	**5%**	**5%**	**5%**	**5%**	**5%**	**5%**	**5%**	**5%**	**5%**	**5%**	**5%**	**5%**

REMI 2006 Forecast Output - Arizona
Arizona Personal Income - Billions of Nominal $

	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Earnings by Place of Work	622	648	675	703	731	762	793	825	859	892	928	965	1,003	1,043	1,084
Contr for Gov Social Ins	82	86	90	94	99	103	108	113	119	124	130	136	142	148	155
Adj for Residence	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0
Dividends, Interest, and Rent	184	194	205	216	227	240	252	266	280	294	310	325	342	359	376
Personal Current Transfer Receipts	158	165	174	183	192	202	212	223	233	244	255	267	279	291	303
Personal Income	883	922	964	1,008	1,052	1,100	1,149	1,201	1,253	1,307	1,364	1,422	1,482	1,544	1,608
Personal Taxes	105	109	114	119	124	130	135	141	147	154	160	167	174	181	189
Disp Pers Inc	778	813	850	889	928	971	1,014	1,060	1,106	1,154	1,204	1,255	1,308	1,363	1,420
Personal Income Pct Change	**4%**	**4%**	**5%**	**5%**	**4%**	**5%**	**4%**	**4%**	**4%**	**4%**	**4%**	**4%**	**4%**	**4%**	**4%**

DRAFT

Economic Analysis and Modeling Support to the Western Climate Initiative
ENERGY 2020 Inputs and Assumptions

Arizona Output by Industry - $2000
(1 of 4)

REMI 2006 Forecast Output - Arizona Arizona Output by Industry - $2000	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Forestry, Fishing, Other	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4
Mining	2.6	2.0	2.3	2.5	2.4	2.3	2.2	2.1	2.0	2.1	2.2	2.2
Utilities	7.0	7.0	7.2	7.4	7.6	7.7	7.9	8.0	8.2	8.4	8.7	9.0
Construction	23.4	22.9	23.9	25.9	27.0	28.1	29.2	30.2	31.4	32.3	33.1	33.9
Manufacturing	63.5	63.6	70.9	78.9	85.3	92.1	99.0	106.2	114.0	120.1	126.3	132.8
Wholesale Trade	20.1	20.8	22.9	25.3	27.4	29.6	31.9	34.4	37.2	39.0	40.9	42.8
Retail Trade	27.8	29.3	31.3	34.0	35.9	38.0	40.0	42.2	44.6	46.5	48.5	50.5
Transp, Warehousing	11.7	12.0	12.6	13.3	13.9	14.5	15.1	15.7	16.3	16.9	17.5	18.2
Information	12.7	13.2	14.0	15.1	16.1	17.1	18.1	19.2	20.5	21.4	22.3	23.3
Finance, Insurance	29.5	30.3	31.7	33.3	34.6	36.0	37.4	38.9	40.5	41.9	43.3	44.8
Real Estate, Rental, Leasing	46.2	47.4	49.7	52.5	54.7	57.1	59.4	61.9	64.5	66.7	68.8	70.9
Profess, Tech Services	16.7	17.0	18.1	19.5	20.6	21.8	23.0	24.3	25.7	26.8	28.0	29.3
Mngmt of Co, Enter	4.6	4.8	5.2	5.7	6.1	6.6	7.1	7.5	8.1	8.5	8.9	9.3
Admin, Waste Services	14.7	15.2	16.0	16.9	17.8	18.7	19.5	20.5	21.5	22.3	23.1	24.0
Educational Services	2.2	2.3	2.4	2.5	2.5	2.6	2.7	2.8	2.9	3.0	3.1	3.2
Health Care, Social Asst	22.3	23.2	24.2	25.3	26.5	27.7	28.9	30.3	31.7	33.0	34.3	35.7
Arts, Enter, Rec	3.3	3.4	3.6	3.8	3.9	4.1	4.3	4.5	4.7	4.9	5.1	5.2
Accom, Food Services	11.1	11.5	11.9	12.5	12.8	13.2	13.6	14.0	14.5	14.8	15.2	15.5
Other Services (excl Gov)	7.6	7.8	8.1	8.5	8.8	9.2	9.5	9.9	10.3	10.6	11.0	11.4
Total	**$327.5**	**$333.9**	**$356.5**	**$383.3**	**$404.4**	**$426.8**	**$449.2**	**$472.9**	**$498.8**	**$519.6**	**$540.8**	**$562.3**
Annual Percent Change		**2.0%**	**6.8%**	**7.5%**	**5.5%**	**5.5%**	**5.3%**	**5.3%**	**5.5%**	**4.2%**	**4.1%**	**4.0%**

Arizona Output by Industry - $2000

(2 of 4)

REMI 2006 Forecast Output - Arizona Arizona Output by Industry - $2000												
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Forestry, Fishing, Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5
Mining	2.3	2.3	2.4	2.5	2.5	2.6	2.6	2.7	2.8	2.8	2.9	2.9
Utilities	9.2	9.5	9.7	10.0	10.2	10.5	10.7	11.0	11.2	11.5	11.7	12.0
Construction	34.5	35.2	35.7	36.3	36.9	37.4	38.0	38.6	39.2	39.8	40.5	41.2
Manufacturing	139.1	145.7	152.2	158.8	165.5	172.3	179.2	186.0	192.8	199.5	206.3	213.2
Wholesale Trade	44.7	46.7	48.6	50.5	52.5	54.5	56.5	58.5	60.6	62.6	64.6	66.7
Retail Trade	52.5	54.5	56.4	58.4	60.4	62.5	64.6	66.7	68.8	71.0	73.3	75.7
Transp, Warehousing	18.7	19.3	19.9	20.5	21.1	21.7	22.3	22.9	23.5	24.1	24.7	25.3
Information	24.2	25.1	26.1	27.0	28.0	28.9	29.9	30.9	31.8	32.8	33.8	34.8
Finance, Insurance	46.2	47.6	49.0	50.5	51.9	53.4	54.8	56.3	57.8	59.3	60.8	62.4
Real Estate, Rental, Leasing	72.9	74.9	76.8	78.7	80.7	82.6	84.6	86.6	88.5	90.5	92.6	94.7
Profess, Tech Services	30.5	31.7	32.9	34.1	35.3	36.5	37.8	39.0	40.3	41.5	42.7	44.0
Mngmt of Co, Enter	9.6	10.0	10.4	10.8	11.3	11.7	12.1	12.5	12.9	13.3	13.8	14.2
Admin, Waste Services	24.8	25.6	26.4	27.2	28.0	28.9	29.7	30.6	31.4	32.2	33.1	34.0
Educational Services	3.3	3.4	3.5	3.6	3.7	3.8	3.9	4.0	4.1	4.2	4.3	4.5
Health Care, Social Asst	37.0	38.3	39.6	40.9	42.3	43.6	45.0	46.4	47.8	49.2	50.7	52.2
Arts, Enter, Rec	5.4	5.6	5.7	5.9	6.0	6.2	6.4	6.5	6.7	6.9	7.0	7.2
Accom, Food Services	15.9	16.2	16.5	16.8	17.1	17.3	17.6	17.9	18.2	18.5	18.8	19.1
Other Services (excl Gov)	11.7	12.1	12.4	12.7	13.1	13.4	13.8	14.1	14.5	14.8	15.2	15.6
Total	**$583.0**	**$604.1**	**$624.7**	**$645.6**	**$666.8**	**$688.3**	**$710.0**	**$731.6**	**$753.3**	**$775.0**	**$797.3**	**$820.1**
Annual Percent Change	**3.7%**	**3.6%**	**3.4%**	**3.3%**	**3.3%**	**3.2%**	**3.1%**	**3.0%**	**3.0%**	**2.9%**	**2.9%**	**2.9%**

Arizona Output by Industry - $2000

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REMI 2006 Forecast Output - Arizona Arizona Output by Industry - $2000												
	2030	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**
Forestry, Fishing, Other	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6
Mining	3.0	3.1	3.1	3.2	3.3	3.4	3.4	3.5	3.6	3.7	3.8	3.8
Utilities	12.3	12.5	12.8	13.1	13.5	13.8	14.1	14.4	14.8	15.1	15.5	15.8
Construction	41.9	42.7	43.5	44.4	45.3	46.3	47.2	48.2	49.2	50.3	51.3	52.5
Manufacturing	219.9	226.7	233.6	240.6	247.6	254.7	262.2	269.8	277.6	285.5	293.6	302.2
Wholesale Trade	68.8	70.9	73.0	75.3	77.5	79.8	82.2	84.6	87.1	89.6	92.2	94.9
Retail Trade	78.1	80.6	83.3	86.0	88.9	91.9	94.9	98.0	101.2	104.5	107.8	111.4
Transp, Warehousing	26.0	26.6	27.3	28.0	28.7	29.4	30.2	31.0	31.7	32.5	33.3	34.1
Information	35.8	36.8	37.8	38.9	40.0	41.1	42.3	43.4	44.6	45.8	47.1	48.4
Finance, Insurance	63.9	65.5	67.2	69.0	70.8	72.6	74.4	76.3	78.2	80.1	82.0	84.0
Real Estate, Rental, Leasing	96.8	99.0	101.4	103.8	106.3	108.7	111.3	113.9	116.5	119.2	121.8	124.7
Profess, Tech Services	45.2	46.5	47.8	49.1	50.4	51.8	53.2	54.6	56.1	57.5	59.0	60.6
Mngmt of Co, Enter	14.6	15.1	15.5	16.0	16.5	16.9	17.4	17.9	18.4	18.9	19.5	20.0
Admin, Waste Services	34.8	35.7	36.7	37.6	38.6	39.6	40.6	41.6	42.7	43.7	44.8	45.9
Educational Services	4.6	4.7	4.8	4.9	5.1	5.2	5.3	5.5	5.6	5.7	5.9	6.0
Health Care, Social Asst	53.8	55.4	57.1	58.8	60.6	62.2	63.8	65.4	67.0	68.5	69.9	71.3
Arts, Enter, Rec	7.4	7.6	7.8	8.0	8.2	8.4	8.6	8.8	9.1	9.3	9.5	9.8
Accom, Food Services	19.5	19.8	20.1	20.5	20.9	21.3	21.6	22.0	22.4	22.8	23.2	23.6
Other Services (excl Gov)	15.9	16.3	16.7	17.2	17.6	18.1	18.5	19.0	19.5	19.9	20.4	20.9
Total	**$842.8**	**$866.2**	**$890.2**	**$914.9**	**$940.2**	**$965.6**	**$991.8**	**$1,018.5**	**$1,045.7**	**$1,073.4**	**$1,101.2**	**$1,130.7**
Annual Percent Change	**2.8%**	**2.8%**	**2.8%**	**2.8%**	**2.8%**	**2.7%**	**2.7%**	**2.7%**	**2.7%**	**2.6%**	**2.6%**	**2.7%**

D R A F T

Economic Analysis and Modeling Support to the Western Climate Initiative
ENERGY 2020 Inputs and Assumptions

Arizona Output by Industry - $2000

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REMI 2006 Forecast Output - Arizona Arizona Output by Industry - $2000									
	2042	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**
Forestry, Fishing, Other	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7
Mining	3.9	4.0	4.1	4.2	4.3	4.4	4.5	4.6	4.7
Utilities	16.2	16.6	17.0	17.3	17.7	18.1	18.5	18.9	19.4
Construction	53.6	54.8	55.9	57.1	58.2	59.4	60.6	61.7	62.9
Manufacturing	310.9	320.1	329.4	338.8	348.8	358.9	369.6	380.4	391.7
Wholesale Trade	97.7	100.6	103.5	106.4	109.5	112.6	115.9	119.2	122.6
Retail Trade	115.0	118.7	122.4	126.2	130.2	134.1	138.2	142.3	146.6
Transp, Warehousing	35.0	35.8	36.7	37.5	38.4	39.3	40.3	41.2	42.2
Information	49.7	51.0	52.4	53.8	55.2	56.6	58.2	59.7	61.2
Finance, Insurance	86.0	88.0	90.0	92.0	94.1	96.2	98.3	100.5	102.7
Real Estate, Rental, Leasing	127.5	130.4	133.2	136.0	138.9	141.8	144.7	147.6	150.6
Profess, Tech Services	62.2	63.9	65.5	67.2	69.0	70.7	72.6	74.5	76.4
Mngmt of Co, Enter	20.6	21.1	21.7	22.3	22.9	23.6	24.2	24.9	25.5
Admin, Waste Services	47.0	48.2	49.3	50.5	51.7	52.9	54.1	55.4	56.7
Educational Services	6.2	6.3	6.5	6.6	6.8	6.9	7.1	7.2	7.4
Health Care, Social Asst	72.7	74.2	75.6	76.8	78.2	79.5	80.8	82.1	83.4
Arts, Enter, Rec	10.0	10.2	10.5	10.7	11.0	11.2	11.5	11.7	12.0
Accom, Food Services	24.0	24.5	24.9	25.3	25.7	26.1	26.5	26.9	27.3
Other Services (excl Gov)	21.5	22.0	22.5	23.0	23.6	24.1	24.6	25.2	25.7
Total	**$1,160.2**	**$1,190.9**	**$1,221.7**	**$1,252.5**	**$1,284.8**	**$1,317.1**	**$1,350.8**	**$1,384.8**	**$1,419.8**
Annual Percent Change	**2.6%**	**2.6%**	**2.6%**	**2.5%**	**2.6%**	**2.5%**	**2.6%**	**2.5%**	**2.5%**

California Population and Household Projections:

	B	C	D	E	F	G	H	I	J	K
14	**California**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**
15	Population (Millions)	34.6	35.0	35.5	35.8	36.2	36.5	36.9	37.2	37.6

	B	L	M	N	O	P	Q	R	S	T	U	V
14	**California**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
15	Population (Millions)	38.0	38.4	38.9	39.3	39.7	40.1	40.6	41.0	41.4	41.9	42.3

	B	C	D	E	F	G	H	I	J	K	L
66	**California Households (Thousands)**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
67	Total	12,038	12,204	12,358	12,488	12,597	12,703	12,841	12,978	13,116	13,256
68	Single Family	7,697	7,803	7,901	7,984	8,054	8,122	8,210	8,297	8,386	8,475
69	Multi Family	3,776	3,828	3,876	3,917	3,952	3,985	4,028	4,071	4,114	4,158
70	Other Residential	565	573	580	586	591	596	603	609	616	622

	B	M	N	O	P	Q	R	S	T	U	V
66	**California Households (Thousands)**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
67	Total	13,397	13,540	13,686	13,832	13,981	14,130	14,280	14,431	14,582	14,734
68	Single Family	8,565	8,657	8,750	8,844	8,939	9,034	9,130	9,227	9,323	9,420
69	Multi Family	4,202	4,247	4,293	4,339	4,386	4,432	4,479	4,527	4,574	4,622
70	Other Residential	629	636	643	649	656	663	670	678	685	692

D R A F T

Economic Analysis and Modeling Support to the Western Climate Initiative
ENERGY 2020 Inputs and Assumptions

California Gross Output by Industry

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V
18	**California Gross Output (Billions of 2000 $/Year)**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
19	Total	9,618	9,704	9,931	10,387	10,715	11,107	11,436	11,795	12,215	12,649	13,096	13,545	14,009	14,483	14,903	15,317	15,724	16,134	16,547	16,964
20	Single Family	781	776	786	808	831	854	879	904	929	956	983	1,011	1,039	1,069	1,099	1,130	1,162	1,195	1,229	1,264
21	Multi Family	247	246	249	256	263	271	278	286	294	303	311	320	329	338	348	358	368	378	389	400
22	Other Residential	35	35	35	36	37	38	39	40	41	43	44	45	46	48	49	50	52	53	55	56
23	Transportation Services	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2
24	Pipelines	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2
25	Communication	63	64	62	69	68	74	78	83	88	93	98	103	109	114	118	122	126	131	135	140
26	Utilities	15	21	22	23	23	23	23	23	23	23	23	23	23	23	24	24	25	26	26	27
27	Wholesale	75	75	75	77	83	89	94	99	104	110	116	122	129	136	141	146	151	156	162	167
28	Retail	122	126	128	131	134	140	147	153	158	162	167	172	177	183	188	194	200	206	212	218
29	FIRE	276	287	301	322	332	342	351	360	367	375	383	392	400	409	419	430	441	452	463	475
30	Offices - Business Services	171	166	169	177	183	192	199	207	215	223	231	240	248	257	266	274	283	292	301	311
31	Education	9	10	10	11	12	12	12	13	13	13	13	13	14	14	14	15	15	15	16	16
32	Health & Social	69	75	79	82	85	87	90	93	95	97	100	102	105	108	111	114	118	121	125	130
33	Food, Lodging, Recreation	48	50	52	55	56	58	59	61	62	63	64	65	66	67	68	70	71	73	74	76
34	Government	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2
35	Food & Tobacco	15	16	15	14	15	16	16	16	16	16	16	17	17	17	17	17	18	18	18	18
36	Textiles	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
37	Apparel	5	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	5
38	Lumber	2	2	2	2	2	2	2	2	2	3	3	3	3	3	3	3	3	3	3	3
39	Furniture	3	3	3	3	3	4	4	4	4	4	4	4	4	4	4	4	4	5	5	5
40	Paper	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	3	3	3	3
41	Printing	22	20	20	21	22	23	25	26	27	29	31	32	34	36	37	39	41	42	44	45
42	Chemical	13	10	13	17	16	17	17	17	17	18	18	18	18	19	19	20	20	21	21	22
43	Petroleum Products	7	5	6	8	12	12	12	12	12	11	11	11	11	11	11	12	12	12	13	13
44	Rubber	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2
45	Leather	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2
46	Nonmetallic Minerals	4	4	4	4	4	4	4	4	5	5	5	5	5	5	5	5	5	5	5	6
47	Primary Metals	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	3	3	3	3	3
48	Fabricated Metals	11	9	9	9	10	11	11	11	11	11	11	11	11	12	12	12	13	13	14	14
49	Machines	9	7	7	8	7	7	7	7	7	7	7	7	7	7	7	7	8	8	8	9
50	Computers	42	34	30	28	30	35	39	44	49	55	62	68	75	82	87	91	96	100	105	109
51	Electric Equipment	4	3	3	3	3	3	3	3	3	3	3	3	3	3	4	4	4	4	4	4
52	Transport Equipment	12	12	11	11	9	9	10	10	10	11	11	12	12	12	13	13	14	14	14	15
53	Other Manufacturing	9	9	10	10	11	11	11	12	12	12	13	13	14	14	15	15	16	16	17	18
54	Mining Except Oil & Gas	2	2	2	3	3	4	4	4	4	4	3	3	3	3	3	4	4	4	4	4
55	Oil & Gas Extraction	4	3	4	5	7	7	6	6	6	6	6	6	6	6	6	6	6	6	7	7
56	Construction	56	56	57	63	70	71	70	69	70	71	71	72	73	73	75	76	77	79	80	82
57	Forestry	6	6	6	6	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	7
58	Agriculture	11	12	14	17	15	15	15	15	15	15	15	15	16	16	16	17	17	17	18	18

New Mexico:

Year	Population (Millions)
2001	1.82
2002	1.85
2003	1.88
2004	1.91
2005	1.95
2006	1.98
2007	2.01
2008	2.05
2009	2.08
2010	2.16
2011	2.19
2012	2.23
2013	2.26
2014	2.30
2015	2.34
2016	2.37
2017	2.41
2018	2.45
2019	2.49
2020	2.53
2021	2.56
2022	2.59
2023	2.62
2024	2.65
2025	2.68

Year	Population (Millions)
2026	2.72
2027	2.75
2028	2.78
2029	2.82
2030	2.85
2031	2.88
2032	2.91
2033	2.94
2034	2.96
2035	2.99
2036	3.02
2037	3.05
2038	3.08
2039	3.12
2040	3.15
2041	3.17
2042	3.20
2043	3.23
2044	3.25
2045	3.28
2046	3.31
2047	3.33
2048	3.36
2049	3.39
2050	3.42

Washington: population

Population Forecast	
Year	Population (Millions)
1990	4.9
1991	5.0
1992	5.1
1993	5.3
1994	5.4
1995	5.5
1996	5.6
1997	5.7
1998	5.8
1999	5.8
2000	5.9
2001	6.0
2002	6.0
2003	6.1
2004	6.2
2005	6.3
2006	6.4
2007	6.5
2008	6.6
2009	6.7
2010	6.8

Year	Population (Millions)
2011	6.9
2012	7.0
2013	7.1
2014	7.2
2015	7.3
2016	7.4
2017	7.5
2018	7.6
2019	7.7
2020	7.7
2021	7.8
2022	7.9
2023	8.0
2024	8.1
2025	8.2
2026	8.3
2027	8.3
2028	8.4
2029	8.5
2030	8.6

Appendix D: Inter-Regional Transmission Capacity in ENERGY 2020

Region From	Region To	Capacity Limit (MW)
Alberta	British Columbia	1,000
British Columbia	Alberta	1,200
Allston, OR	Olympia, WA	4,200
Olympia, WA	Allston, OR	4,200
Allston, OR	Williamet, OR	4,120
Williamet, OR	Allston, OR	4,120
Arizona	LADWP, CA	1,229
LADWP, CA	Arizona	1,229
Arizona	New Mexico	2,500
New Mexico	Arizona	2,500
Arizona	Pace, UT	600
Pace, UT	Arizona	600
Arizona	San Diego & Imperial Valley, CA	1,133
San Diego & Imperial Valley, CA	Arizona	1,133
Arizona	Southern California	2,150
Southern California	Arizona	2,150
Arizona	WAPA L.C. (AZ,NM)	9,999
WAPA L.C. (AZ,NM)	Arizona	9,999
British Columbia	North Puget, WA	2,850
North Puget, WA	British Columbia	2,000
British Columbia	Spokane, WA	200
Spokane, WA	British Columbia	200
British Columbia	West Kootenay, BC	9,999
West Kootenay, BC	British Columbia	9,999
Bonanza, UT	Bridger, WY	300
Bridger, WY	Bonanza, UT	300
Bonanza, UT	Pace, UT	785
Pace, UT	Bonanza, UT	400
Bonanza, UT	WAPA R.M., CO	650
WAPA R.M., CO	Bonanza, UT	650
Bridger, WY	Eastern Idaho	2,200
Eastern Idaho	Bridger, WY	600
Bridger, WY	WAPA R.M., CO	1,450
WAPA R.M., CO	Bridger, WY	1,450
Bridger, WY	Wyoming R.M.	400
Wyoming R.M.	Bridger, WY	400

Region From	Region To	Capacity Limit (MW)
Bridger, WY	Yellowtail, MT	625
Yellowtail, MT	Bridger, WY	400
Brownlee, ID	Lower Columbia (WA,OR)	50
Lower Columbia (WA,OR)	Brownlee, ID	50
Brownlee, ID	McNary, WA	300
McNary, WA	Brownlee, ID	300
Brownlee, ID	Oxbow, OR	1,700
Oxbow, OR	Brownlee, ID	1,700
Brownlee, ID	Southern Idaho	1,850
Southern Idaho	Brownlee, ID	1,850
Coulee, WA	Grant County, WA	2,396
Grant County, WA	Coulee, WA	2,396
Coulee, WA	Mid Columbia (WA,OR)	1,844
Mid Columbia (WA,OR)	Coulee, WA	1,844
Coulee, WA	North Puget, WA	1,451
North Puget, WA	Coulee, WA	1,451
Coulee, WA	Olympia, WA	126
Olympia, WA	Coulee, WA	126
Coulee, WA	Seattle South, WA	5,275
Seattle South, WA	Coulee, WA	5,275
Coulee, WA	Spokane, WA	1,140
Spokane, WA	Coulee, WA	1,140
Eastern Idaho	Garrison, MT	224
Garrison, MT	Eastern Idaho	337
Eastern Idaho	Idaho	400
Idaho	Eastern Idaho	270
Eastern Idaho	Pace, UT	400
Pace, UT	Eastern Idaho	630
Eastern Idaho	Southern Idaho	2,557
Southern Idaho	Eastern Idaho	2,557
Garrison, MT	WAPA U.M., MT	200
WAPA U.M., MT	Garrison, MT	200
Garrison, MT	Western, MT	1.300
Western, MT	Garrison, MT	1.300
Garrison, MT	Yellowtail, MT	2,573
Yellowtail, MT	Garrison, MT	2,573
Idaho	Ogden, UT	9,999
Ogden, UT	Idaho	9,999
Idaho	Pace, UT	9,999
Pace, UT	Idaho	9,999

Region From	Region To	Capacity Limit (MW)
Idaho	Wyoming R.M.	9,999
Wyoming R.M.	Idaho	9,999
LADWP, CA	Lower Columbia (WA,OR)	3,100
Lower Columbia (WA,OR)	LADWP, CA	3,100
LADWP, CA	Pace, UT	1,400
Pace, UT	LADWP, CA	1,200
LADWP, CA	Sierra, NV	235
Sierra, NV	LADWP, CA	235
LADWP, CA	Southern Nevada	1,841
Southern Nevada	LADWP, CA	1,841
LADWP, CA	Southern California	9,999
Southern California	LADWP, CA	9,999
LADWP, CA	WAPA L.C. (AZ,NM)	1,231
WAPA L.C. (AZ,NM)	LADWP, CA	1,231
Lower Columbia (WA,OR)	Malin, OR	1,708
Malin, OR	Lower Columbia (WA,OR)	1,708
Lower Columbia (WA,OR)	McNary, WA	1,948
McNary, WA	Lower Columbia (WA,OR)	1,948
Lower Columbia (WA,OR)	Mid Columbia (WA,OR)	5,277
Mid Columbia (WA,OR)	Lower Columbia (WA,OR)	5,277
Lower Columbia (WA,OR)	Slatt, OR	3,031
Slatt, OR	Lower Columbia (WA,OR)	3,031
Lower Columbia (WA,OR)	Williamet, OR	3,334
Williamet, OR	Lower Columbia (WA,OR)	3,334
Lower Granite Dam, WA	Mid Columbia (WA,OR)	5,560
Mid Columbia (WA,OR)	Lower Granite Dam, WA	5,560
Lower Granite Dam, WA	Spokane, WA	1,155
Spokane, WA	Lower Granite Dam, WA	1,155
Malin, OR	PG and E, CA	4,800
PG and E, CA	Malin, OR	4,800
Malin, OR	Sierra, NV	300
Sierra, NV	Malin, OR	300
Malin, OR	Southern Idaho	1,500
Southern Idaho	Malin, OR	1,500
Malin, OR	Southern Oregon	4,782
Southern Oregon	Malin, OR	4,782
McNary, WA	Mid Columbia (WA,OR)	2,000
Mid Columbia (WA,OR)	McNary, WA	2,000
McNary, WA	Slatt, OR	2,854
Slatt, OR	McNary, WA	2,854

Region From	Region To	Capacity Limit (MW)
McNary, WA	Williamet, OR	227
Williamet, OR	McNary, WA	227
Baja, Mexico	San Diego & Imperial Valley, CA	800
San Diego & Imperial Valley, CA	Baja, Mexico	800
Mid Columbia (WA,OR)	Oxbow, OR	400
Oxbow, OR	Mid Columbia (WA,OR)	400
Mid Columbia (WA,OR)	Seattle South, WA	3,700
Seattle South, WA	Mid Columbia (WA,OR)	3,700
Mid Columbia (WA,OR)	Slatt, OR	4,100
Slatt, OR	Mid Columbia (WA,OR)	4,100
Mid Columbia (WA,OR)	Spokane, WA	273
Spokane, WA	Mid Columbia (WA,OR)	273
Mid Columbia (WA,OR)	Williamet, OR	2,600
Williamet, OR	Mid Columbia (WA,OR)	2,600
N. King, WA	Seattle South, WA	526
Seattle South, WA	N. King, WA	526
New Mexico	PS Colorado	558
PS Colorado	New Mexico	558
New Mexico	WAPA L.C. (AZ,NM)	817
WAPA L.C. (AZ,NM)	New Mexico	817
New Mexico	WAPA R.M., CO	690
WAPA R.M., CO	New Mexico	690
North Puget, WA	Seattle North, WA	3,000
Seattle North, WA	North Puget, WA	3,000
North Puget, WA	Seattle South, WA	3,000
Seattle South, WA	North Puget, WA	3,000
Ogden, UT	Pace, UT	9,999
Pace, UT	Ogden, UT	9,999
Olympia, WA	Seattle South, WA	4,500
Seattle South, WA	Olympia, WA	4,500
OVERTHRS, WY	Wyoming R.M.	9,999
Wyoming R.M.	OVERTHRS, WY	9,999
Oxbow, OR	Southern Idaho	90
Southern Idaho	Oxbow, OR	50
Oxbow, OR	Spokane, WA	450
Spokane, WA	Oxbow, OR	300
Pace, UT	Scenic SW, UT	300
Scenic SW, UT	Pace, UT	300
Pace, UT	Sierra, NV	205
Sierra, NV	Pace, UT	205

Region From	Region To	Capacity Limit (MW)
Pace, UT	Station Load, WY	9,999
Station Load, WY	Pace, UT	9,999
Pace, UT	WAPA L.C. (AZ,NM)	265
WAPA L.C. (AZ,NM)	Pace, UT	265
Pace, UT	Wyoming R.M.	9,999
Wyoming R.M.	Pace, UT	9,999
PG and E, CA	Sierra, NV	160
Sierra, NV	PG and E, CA	150
PG and E, CA	Southern Oregon	30
Southern Oregon	PG and E, CA	80
PG and E, CA	Southern California	3,400
Southern California	PG and E, CA	3,000
PS Colorado	WAPA R.M., CO	9,999
WAPA R.M., CO	PS Colorado	9,999
Southern California Edison	Southern California	200
Southern California	Southern California Edison	200
Scenic SW, UT	Southern Nevada	300
Southern Nevada	Scenic SW, UT	300
Scenic SW, UT	St. George, UT	9,999
St. George, UT	Scenic SW, UT	9,999
Scenic SW, UT	Station Load, WY	26
Station Load, WY	Scenic SW, UT	26
San Diego & Imperial Valley, CA	Southern California	5,000
Southern California	San Diego & Imperial Valley, CA	5,000
Seattle North, WA	Seattle South, WA	1,690
Seattle South, WA	Seattle North, WA	1,690
Sierra, NV	Southern Idaho	262
Southern Idaho	Sierra, NV	500
Sierra, NV	Southern California	17
Southern California	Sierra, NV	17
Southern Oregon	Williamet, OR	4,495
Williamet, OR	Southern Oregon	4,495
Southern Nevada	Southern California	2,754
Southern California	Southern Nevada	2,754
Southern Nevada	WAPA L.C. (AZ,NM)	4,554
WAPA L.C. (AZ,NM)	Southern Nevada	4,554
Southern California	WAPA L.C. (AZ,NM)	1,140
WAPA L.C. (AZ,NM)	Southern California	1,140
Spokane, WA	West Kootenay, BC	200
West Kootenay, BC	Spokane, WA	200

Region From	Region To	Capacity Limit (MW)
Spokane, WA	Western, MT	1,300
Western, MT	Spokane, WA	2,200
Station Load, WY	Wyoming R.M.	9,999
Wyoming R.M.	Station Load, WY	9,999
WAPA L.C. (AZ,NM)	WAPA R.M., CO	485
WAPA R.M., CO	WAPA L.C. (AZ,NM)	485
WAPA U.M., MT	Yellowtail, MT	390
Yellowtail, MT	WAPA U.M., MT	390

Source: Federal Energy Regulatory Commission, *FERC-714 Annual Power System Reports*
http://www.transmission.bpa.gov/orgs/opi/FERC714/index.shtm

Appendix E: Data Sets Used in ENERGY 2020

This Appendix describes the initial set definitions for ENERGY 2020 used for this project. The sets are the dimensions of the variables (sometimes called indexes) which delineate the scope and detail of the model. For example, the time frame set could be defined as a base year 1990 and every 5 years.

Time Frame

The initial historical year for calibration is 1990.
Current end year of the analysis is 2020, but analysis can be extended to 2030 or beyond.
The last historic year of data will be 2005.
All data sets include annual data for each year of history and the forecast.

For some data sets, the period covered by actual data will depend on available data (e.g., emissions).

Geographical Areas

Each area in the model will represent a state or a province (no sub-state break-outs).
The model will provide separate results for the eight WCI partners currently modeled with plans to extend the modeling to include Manitoba and Quebec.
The surrounding Region (the rest of the WECC) and the rest of the US and Canada are also modeled.

The States and Provinces included in the WCI Region for modeling purposes include:

- Arizona
- New Mexico
- Washington
- California
- Oregon
- British Columbia
- Montana
- Utah
- Manitoba

Generating Units

The list of units is based on the NEEDS database for the US plus a similar database for the units in Canada. Within the Region and the rest of the US, some of the smaller plants may be aggregated by plant type in order to allow the expedite model operation. Under these assumptions regarding aggregation, this version of the model will likely end up with approximately 3,000 units/plants.

Electric Companies

Although ENERGY 2020 can model individual utilities or groups of utilities, for the WCI project the model assumes that each state has a single aggregate utility.

Sectors and Classes

The energy demand portion of the model will simulate residential, commercial, industrial, and transportation demands. There will be an electric sales class for each sector.

Emission Only Sectors

Several sectors generate emissions, but do not have full energy demand simulations in the model. These include solid waste, waste water, incineration, and land use. It may be possible to develop a full energy demand simulation for one or more of these.

Offsets

Possible offset categories, if broken out as a set, could include:

- Sequestration
- Landfill Gas Capture
- Agricultural Methane
- Energy Efficiency (for each sector)

Pollutants

The model currently has the capability to cover 15 pollutants, although the final set will depend on the WCI partner's requirements and available data. The GHG pollutants include Carbon Dioxide, Methane, Nitrous Oxide, Sulfur-Hexafluoride, Perfluorocarbon, and Hydrofluorocarbon. The criteria air pollutants include Sulfur Dioxide, Nitrogen Oxides, Total Particulate Matter, Volatile Organic Compounds, Carbon Monoxide, Particulate Matter 2.5, Particulate Matter 10, Mercury, and Ozone.

Fuels

There are currently two sets of fuels in the model. The largest category contains 33 fuels (shown below). The second category is the list of technologies which the energy demand sectors choose from. This smaller set contains only the basic types of fuels (Electricity, Natural Gas, Oil, LPG, Biomass, Solar). The aggregate category oil is later broken out into the different types of oil (LFO, HFO, petroleum coke, etc.).

Entire List of Fuels

- Asphalt
- Aviation Fuel
- Biomass
- Coal
- Coke
- Coke Oven Gas
- Diesel
- Electric
- Ethanol
- Geothermal
- Heavy Fuel Oil
- Hydro
- Hydrogen
- Kerosene
- Landfill Gases
- Light Fuel Oil
- LPG
- Lubricants
- Motor Gasoline
- Naphtha Specialties
- Natural Gas
- Nuclear
- Oil, Unspecified
- Other Non-Energy Products
- Petrochemical Feedstocks
- Petroleum Coke
- Solar
- Steam
- Still Gas
- Wave
- Wind
- Unknown 1
- Unknown 2

Electric Generation Plants Types

The electric generation plant types are used to hold the data for future generic plants which the model will construct endogenously. The list currently includes:

- Gas/Oil Peaking
- Gas/Oil Combined Cycle
- Gas/Oil Steam
- Coal
- Coal Advanced
- Coal with CCS
- Gas CC with CCS
- Nuclear
- Base Hydro
- Peak Hydro

- Other Generation
- Biomass
- Landfill Gas
- Wind
- Solar
- Fuel Cells
- Pumped Hydro
- Small Hydro
- Wave
- Geothermal
- Other Storage
- Biogas
- Trash

Residential Sectors

The residential sector is split into housing types:

- Single Family
- Multi-Family
- Other Residential

Commercial Sectors

- Transportation Services
- Pipelines
- Communication
- Electric Utilities
- Gas Utilities
- Water & Other Utilities
- Wholesale
- Retail
- FIRE
- Offices - Business Services
- Education
- Health & Social
- Food, Lodging, Recreation
- Government

Industrial Sectors

- Food & Tobacco
- Textiles
- Apparel
- Lumber
- Furniture
- Pulp & Paper Mills
- Converted Paper
- Printing
- Petrochemicals
- Industrial Gas
- Other Chemicals
- Fertilizers
- Petroleum Products
- Rubber
- Leather
- Cement
- Glass
- Lime & Gypsum
- Other Non-Metallic
- Iron & Steel
- Aluminum
- Other Nonferrous
- Fabricated Metals
- Machines
- Computers
- Electric Equipment
- Transport Equipment
- Other Manufacturing
- Iron Ore Mining
- Other Metal Mining
- Non-metal Mining
- Light Oil Mining
- Heavy Oil Mining
- Frontier Oil Mining
- Oil Sands In-Situ
- Oil Sands Mining
- Oil Sands Upgraders
- Gas Mining
- Coal Mining
- Construction
- Forestry
- Agriculture

Transportation Sectors

- Passenger
- Freight
- Off Road

Miscellaneous Sectors

- Misc. & Street Lighting
- Electric Resale
- Utility Electric Generation
- Industry Electric Generation
- Steam Generation
- Solid Waste
- Waste Water
- Incineration
- Land Use

Residential End-Uses

- Space Heating
- Water Heating
- Other Substitutable
- Refrigeration
- Lighting
- Air Conditioning
- Other Non-Substitutable

Commercial End-Uses

- Space Heating
- Water Heating
- Other Substitutable
- Refrigeration
- Lighting
- Air Conditioning
- Other Non-Substitutable

Industrial End-uses

- Process Heat
- Electric Motors
- Other Substitutable
- Miscellaneous

Transportation End-Uses

- Ground
- Air/Water

Residential, Commercial, and Industrial Technology Types

Each technology type has its own trade-off curve which determines the efficiency and the capital cost of the technology type. These curves allow the model to contain many different technologies within these broad types.

- Electric
- Gas
- Coal
- Oil
- Biomass
- Solar
- LPG
- Steam

Transportation Technology Types

Several technology types are provided for transportation, and each of these contains a trade-off curve which allows the model to simulate even more individual technologies.

- Plug-in Hybrids
- Light Gasoline
- Light Diesel
- Light Propane
- Light CNG
- Light Electric (Plug-in)
- Light Ethanol
- Light Hybrid Gasoline
- Light Hybrid Diesel
- Light Fuel Cell Gasoline
- Light Fuel Cell CNG
- Light Fuel Cell Hydrogen
- Medium Gasoline
- Medium Diesel
- Medium Propane
- Medium CNG
- Medium Ethanol
- Medium Hybrid Gasoline
- Medium Hybrid Diesel
- Medium Fuel Cell Gasoline
- Medium Fuel Cell CNG
- Medium Fuel Cell Hydrogen
- Heavy Gasoline
- Heavy Diesel
- Heavy Propane
- Heavy CNG
- Heavy Ethanol
- Heavy Hybrid Gasoline
- Heavy Hybrid Diesel
- Heavy Fuel Cell Gasoline
- Heavy Fuel Cell CNG
- Heavy Fuel Cell Hydrogen
- Motorcycle
- Bus Gasoline
- Bus Diesel
- Bus Propane
- Bus CNG
- Bus Fuel Cell Gasoline
- Bus Fuel Cell Hydrogen
- Bus Fuel Cell Ethanol
- Train
- Plane
- Marine
- Off Road

Prices

Delivered energy prices are presented for the following fuels:

- Residential Electricity
- Residential Natural Gas
- Residential Coal
- Residential Oil
- Residential Biomass
- Residential LPG
- Residential Steam
- Commercial Electricity
- Commercial Natural Gas
- Commercial Coal
- Commercial Oil
- Commercial Biomass
- Commercial LPG
- Commercial Steam
- Industrial Electricity
- Industrial Natural Gas
- Industrial Coal
- Industrial Oil
- Industrial Biomass
- Industrial LPG
- Industrial Steam
- Gasoline

- Diesel
- Aviation Fuel
- Transportation HFO
- Transportation Natural Gas
- Transportation LPG
- Electric Utility Residual Oil
- Electric Utility Distillate Oil
- Electric Utility Natural Gas
- Electric Utility Coal
- Electric Utility Nuclear
- Electric Utility Biomass
- Ethanol
- Hydrogen

Electric Load Segments

The model dispatches for 6 different hour types (high peak, low peak, high intermediate, low intermediate, high base load, low base load) for each of the four seasons.

Appendix F: Planned or Committed Coal Plants Post-2005

State	Plant_Name	Plant Type	On-Line Year	Capacity (MW)	Fuel	HeatRate	Owner	Notes
AZ	Bowie Power Station LLC	Oil/Gas Combined Cycle	2012	500	NaturalGas	7,548	Southwestern Power Group IILLC	
AZ	Bowie Power Station LLC	Oil/Gas Combined Cycle	2010	500	NaturalGas	7,548	Southwestern Power Group IILLC	
AZ	Springerville	Coal	2010	400	Coal	10,178	Salt River Project	
CO	Comanche	Coal	2009	750	Coal	8,763	Public Service Co of Colorado	
NE	Nebraska City	Coal	2009	663	Coal	9,508	Omaha Public Power District	
NV	TS Power Plant	Coal	2008	200	Coal	10,700	Newmont Nevada Energy Investment, LLC	
TX	J K Spruce	Coal	2010	750	Coal	9,273	City of San Antonio	
WY	Wygen 2	Coal	2007	70	Coal	11,044	Cheyenne Light Fuel & Power Co	
WY	Wygen 3	Coal	2010	100	Coal		Black Hills Corporation	
CO	Lamar Plant	Oil/Gas Steam	1972	25	Natural Gas	14,500	City of Lamar	
CO	Lamar	Coal (Advanced)	2008	39	Coal	9,000	Lamar Utility Board	Repowering
NE	Public Power Generation Agency, Whelan Energy Center 2	Coal	2012	220	Coal	10,047	Public Power Generation Agency	
NM	Estancia Biomass Power Plant	Biomass	2010	25	Biomass (wood)	12,000	Western Water & Power Production LLC	
ND	Great River Energy, Spiritwood	Combined Heat & Power	2010	99		9,000		
TX	Tuminent (TXU) Oak Grove Plant	Coal (Lignite)	2009/10	1600	Lignite	9,130		
TX	Luminent (TXU) Sandow 5	Coal (Advanced)	2009	600	Coal	9,130		
TX	City Public Service, Spruce Plant	Coal	2009	750	Coal	9,000		
WY	Black Hills Corporation, Wygen II Plant	Coal	2008	95		12,500	Black Hills Corporation	
WY	Basin Electric Coop, Dry Fork	Coal (Advanced)	2011	385	Coal	9,000	Basin Electric Coop	
WY	North American Power Gp, 2 Elk Power Plant Unit 1	Coal	2010	325	Coal	9,000	North American Power Group	
WY	DKRW Energy LLC	Coal	2010	200	Coal	9,000	DKRW	

<u>Note:</u> These units have been included for modeling purposes only. It is not possible to determine at this time which specific projects will be completed.

Appendix G: New Generation Performance and Cost Assumptions

Table 1A. Input Values to Busbar Energy Costs - California Resources (2008 $)

Resource Technology	2020 Overnight Capital Cost ($/kW) ($/kW)		Fixed O&M Cost ($/kW-year)		Variable O&M Cost ($/MWh)		Capacity Factor	Nominal Heat Rate (Btu/kWh)
	Low (if range)	High (if range)	Low (if range)	High (if range)	Low (if range)	High (if range)		
Biogas	$3,065		$139		1.20		80%	13,648
Biomass	$4,484		$65		1.20		80%	8,911
Geothermal	$3,339	$8,131	$157	$226	1.20		90%	n/a
Hydro - Small	$2,539	$5,170	$14	$31	0.94	1.81	25% - 65%	n/a
Solar - Thermal	$3,235		$64		1.20		37% - 40%	n/a
Wind	$1,962		$37		1.20		27% - 40%	n/a
Coal ST	$2,479		$33		1.20		85%	8,844
Coal IGCC	$2,866		$47		1.20		85%	8,309
Coal IGCC with CCS	$4,101		$55		1.20		85%	9,713
Gas CCCT	$1,054		$14		1.20		90%	6,917
Gas CT	$807		$15		1.20		5%	10,807
Hydro - Large	$1,486	$2,193	$9	$13	0.63	0.89	12% - 57%	n/a
Nuclear	$3,999		$83		1.20		85%	10,400

Table 1B. Input Values to Busbar Energy Costs - Rest of WECC Resources (2008 $)

Resource Technology	2020 Overnight Capital Cost ($/kW) ($/kW)		Fixed O&M Cost ($/kW-year)		Variable O&M Cost ($/MWh)		Capacity Factor	Nominal Heat Rate (Btu/kWh)
	Low (if range)	High (if range)	Low (if range)	High (if range)	Low (if range)	High (if range)		
Biogas	$2,350	$2,835	$107	$128	0.92	1.11	80%	13,648
Biomass	$3,438	$4,148	$50	$60	0.92	1.11	80%	8,911
Geothermal	$1,582	$19,451	$157	$226	0.96	1.11	90%	n/a
Hydro - Small	$1,758	$4,782	$11	$28	0.71	1.69	22% - 65%	n/a
Solar - Thermal	$2,588	$2,939	$51	$58	0.96	1.09	36% - 39%	n/a
Wind	$1,504	$1,815	$28	$34	0.92	1.11	27% - 40%	n/a
Coal ST	$1,901	$2,293	$26	$31	0.92	1.11	85%	8,844
Coal IGCC	$2,197	$2,651	$36	$43	0.92	1.11	85%	8,309
Coal IGCC with CCS	$3,144	$3,794	$42	$51	0.92	1.11	85%	9,713
Gas CCCT	$808	$975	$11	$13	0.92	1.11	90%	6,917
Gas CT	$619	$747	$11	$14	0.92	1.11	5%	10,807
Hydro - Large	$1,122	$2,031	$5	$11	0.41	0.78	15% - 65%	n/a
Nuclear	$3,066	$3,699	$63	$76	0.92	1.11	85%	10,400

Note: Variable O&M Costs do not include fuel costs. Range of costs is similar for several of the technologies.
Source: Energy and Environmental Economics, Inc., CPUC GHG Modeling - Generation Costs (Word document), 11/16/2007.www.ethree.com/cpuc_ghg_model.html

Appendix H: Global Warming Potential

ENERGY 2020 models emissions of each of the six greenhouse gases reported under the Kyoto protocol. These emissions are then translated into equivalent quantities of CO_2 emissions (CO_2e) based on the global warming potential of each of the gases.

The Global Warming Potential (GWP) values used in ENERGY 2020 are shown in the table below.

Greenhouse Gas	Global Warming Potential
Carbon Dioxide (CO2)	1
Methane (CH4)	21
Nitrous Oxide (N2O)	310
Sulfur Hexafluoride (SF6)	23,900
Perfluorocarbons (PFC)	7,000
Hydrofluorocarbons (HFC)	1,300

These values are consistent with the Global Warming Potential values used in the 1996 Second Assessment Report based on 100-year warming potential for the individual gases. In the case of HFCs and PFCs the GWP values used in the model are based on an estimated average GWP for these gases.

Appendix I: Renewable Portfolio Standards

State or Prov	Target	Policy
AZ	15% of generation from renewables by 2025	Renewable Energy Standards (formerly known as the Environmental Portfolio Standard) on February 27, 2006. The new rules require regulated electric utilities to generate 15% of their energy from renewable resources by 2025. By 2012, at least 30% of the sta
CA	Major utilities 20% from renewable sources by 2010 on a retail sales basis	California's Investor-Owned Utility, Electric Service Providers, Small and Multi-Jurisdictional Utilities and Community Choice Aggregators to produce at least 20% of their electricity using renewable sources by 2010 based on renewable retail sales. Eligib
MT	10% of generation load to be renewable by 2010; 15% by 2015	Each investor-owned and public utility should: Meet 20% of its load using renewable energy resources by 2020, increasing to 25% by 2025. The legislation contains a cost cap that encourages utilities to invest in renewable generation that is cost competiti
NM	10% of generation by 2011; 15% renewable by 2015; 20% by 2020	Applies to Investor-Owned Utility, Rural Electric Cooperative. IOUs: 15% power generation from renewable sources and 20% by 2020. RECs: 10% by 2020. This legislation expands on NM's current renewable portfolio standard requiring that 10% of the state's en
OR	25% of electric load must be renewable sources by 2025 (ramps up from 2015)	OR's largest utilities 25% of their electric load with new renewable energy sources by 2025. Interim targets of 5% by 2011; 15% by 2015; 20% by 2020; and 25% by 2025. Based on total retail sales volumes. Eligible technology: wind, solar, wave, geothermal,
UT	No Policy in place	Considering RPS through consultation process in 2007

State or Prov	Target	Policy
WA	All new long term baseload facilities must meet 1,100 lbs CO2/MWh starting July 2008	GHG performance standard for all new, long-term baseload electric power generation. Under the standard, all baseload generation for which utilities enter into long-term contracts must meet a greenhouse gas emissions standard of 1,100 pounds per megawatt-h
WA	15% of production to be renewable by 2020	All utilities serving >25,000 people to produce 15% of their energy using renewable sources by 2020. Eligible technology: wind, solar, and tidal power as well as landfill-methane capture.
BC	Offset all O&G grid power emissions by 2016.	All existing natural gas and oil-fired generating facilities part of the integrated grid will need to completely offset their GHG emissions by 2016. All coal will need to use CCS, sequester or otherwise offset emissions, and all new O&G will need to offs
BC	Maintain 90% "clean" sources - all new sources zero emissions.	Maintaining 90% 'clean' power supply, including hydro. Note that no nuclear will be built in the province. Government will issue guidelines to define what sources qualify as clean or renewable and provide additional policy direction as required. In 2004
MB	1,000 MW of wind power by 2016	Most of Manitoba's power production is already from renewable sources. Target: 1,000 MW of wind power by 2016. The 1,000 MW will reduce GHGs by 3.5 Mt annually, and stimulate $2 billion in new investments.

Appendix J: Efficiency and Cost Data – Built Environment

Residential:

Residential Device Standards	
Equipment	**Effective Efficiency Standard**
Gas hot water from 1990 to the final year	59%
Oil hot water from 1990 to the final year	51%
Electric hot water from 1990 to the final year (inc.tank losses)	92%
LPG hot water from 1990 to the final year	59%
Electric air conditioning for 1990	260% COP = 2.6
Electric air conditioning for 1991	261% COP = 2.61
Electric air conditioning for 1992 to 2006	265% COP = 2.65
Electric air conditioning for 2007 to the final year	344% COP = 3.44
Electric Refrigeration for 1990 to 1992	34.5%
Electric Refrigeration for 1993	40.0%
Electric Refrigeration for 1994 to 2000.	42.0%
Electric Refrigeration from 2001 to the final year	54.7%
Biomass space Heating from 1993 to the final year (wood burning equipment)	63.0%
Gas space Heating from 1993 to the final year	80.0%
Oil space Heating from 1993 to the final year	80.0%
LPG space Heating from 1993 to the final year	80.0%

Residential (cont'd.)

Maximum Device Efficiency							
(Btu/Btu)	Electric	N.Gas	Coal	Oil	Biomass	LPG	Steam
Primary Heat	278%	97%	97%	97%	78%	97%	99%
Water Heating	250%	86%	97%	97%	78%	97%	99%
Other Substitutable Loads	130%	97%	97%	97%	65%	97%	99%
Refrigerators	98%	0%	0%	0%	0%	0%	0%
Lighting	95%	0%	0%	0%	0%	0%	0%
Air Conditioning	447%	113%	0%	0%	0%	113%	0%
Other Non-Substitutable Loads	98%	0%	0%	0%	0%	0%	0%

Note – Electric heating applications include heat pumps.
Non-substitutable loads are those loads which require electricity (refrigerators, electronics, etc.).
Substitutable loads are those loads which can use multiple fuels (ie. Range, dryers, etc.).

Device Capital Cost								
1985$/mmBtu/Year	Electric	N.Gas	Coal	Oil	Biomass	Solar	LPG	Steam
Space Heating	17.7	23.1	19.0	36.0	17.2	132.0	23.1	36.0
Water Heating	8.5	18.5	19.0	23.5	17.2	82.0	18.5	23.5
Other Substitutable Loads	65.0	85.0	19.0	85.0	17.2	-	85.0	85.0
Refrigerators	96.5	-	-	-	-	-	-	-
Lighting	0.23	-	-	-	-	-	-	-
Air Conditioning	4.4	34.1	-	-	-	-	34.1	-
Other Non-Substitutable Loads	19.8	-	-	-	-	-	-	-

Device Operating Costs								
1985 $/mmBtu	Electric	N.Gas	Coal	Oil	Biomass	Solar	LPG	Steam
Space Heat	0.018	0.024	0.011	0.020	0.013	0.012	0.024	0.030
Water Heating	-	-	-	-	-	0.010	-	-
Other Substitutable Loads	-	-	-	-	-	-	-	-
Refrigeration	-	-	-	-	-	-	-	-
Lighting	-	-	-	-	-	-	-	-
Air Conditioning	0.015	0.017	-	-	-	-	0.017	-
Other Non-Substitutable Loads	-	-	-	-	-	-	-	-

Residential (cont'd.)

Physical Life of Equipment in Years (Residential)							
	Space Heat	**Water Heating**	**Substitutable Loads**	**Refrigeration**	**Light**	**Air Conditioning**	**Non-Substitutable Loads**
Electric	18	15	13	18	6	15	10
Natural Gas	18	15	13	0	0	15	0
Coal	18	15	13	0	0	0	0
Oil	18	15	13	0	0	0	0
Biomass	18	15	13	0	0	0	0
Solar	18	15	13	0	0	0	0
LPG	18	15	13	0	0	0	0
Steam	18	15	13	0	0	0	0

Commercial:

Device Efficiency Standards (Commercial)								
Btu/Btu	**Electric**	**N.Gas**	**Coal**	**Oil**	**Biomass**	**Solar**	**LPG**	**Steam**
Space Heating (primary)	450%	97%	97%	97%	65%	1000%	97%	99%
Water Heating	400%	97%	97%	97%	65%	1000%	97%	99%
Other Substitutable Loads	130%	97%	97%	97%	65%	1000%	97%	99%
Refrigerators	140%	0%	0%	0%	0%	0%	0%	0%
Lighting	95%	0%	0%	0%	0%	0%	0%	0%
Air Conditioning	400%	240%	0%	0%	0%	0%	200%	0%
Other Non-Substitutable Loads	98%	0%	0%	0%	0%	0%	0%	0%

Device Capital Cost (Commercial)								
$/mmBtu/Year	**Electric**	**N.Gas**	**Coal**	**Oil**	**Biomass**	**Solar**	**LPG**	**Steam**
Primary Heat	9.20	7.5	42.2	19.0	25.5	138.9	22.9	42.2
Water Heating	5.20	8.9	42.2	19.0	-	138.9	22.9	42.2
Other Substitutable Loads	19.80	11.3	11.3	19.0	-	-	11.3	11.3
Refrigeration	0.21	-	-	-	-	-	-	-
Lighting	0.02	-	-	-	-	-	-	-
Air Conditioning	9.20	34.1	-	-	-	-	34.1	-
Other Non Substitutable Loads	22.00	-	-	-	-	-	-	-

Device Operating Cost Fraction ($/Year/$)								
1985 $/mmBtu	**Electric**	**N.Gas**	**Coal**	**Oil**	**Biomass**	**Solar**	**LPG**	**Steam**
Space Heating (primary)	0.02	0.03	0.01	0.03	0.01	0.01	0.03	0.04
Water Heating	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00
Other Substitutable Loads	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Refrigeration	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lighting	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Air Conditioning	0.01	0.02	0.00	0.00	0.00	0.00	0.03	0.00
Other Non-Substitutable Loads	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Commercial: (cont'd.)

Physical Life of Equipment in Years							
	Space Heat	Water Heating	Substitutable Loads	Refrigeration	Light	Air Conditioning	Non-Substitutable Loads
Electric	18	8	10	15	7	18	7
Natural Gas	25	8	10	0	0	18	0
Coal	18	8	10	0	0	0	0
Oil	25	8	10	0	0	0	0
Biomass	18	8	10	0	0	0	0
Solar	18	8	10	0	0	0	0
LPG	18	8	10	0	0	18	0
Steam	18	8	10	0	0	0	0

Western Climate Initiative

Draft Design of the Regional Cap-and-Trade Program

July 23, 2008

The Western Climate Initiative (WCI) Partners recommend a design for a broad cap-and-trade program as part of a comprehensive regional effort to reduce emissions of global warming pollution to achieve the WCI 2020 regional goal. The recommended design contains costs through emission trading, allowance banking, and inclusion of an offsets component that will provide opportunities to obtain low-cost emission reductions. Further, the WCI design is intended to mitigate the economic impact on consumers, and the costs passed onto consumers, through design features such as allowance distribution and the use of offsets.

1. SCOPE[1]

1.1. Gases covered: Carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride.

1.2. Emissions covered:

1.2.1. Electricity generation, including emissions from electricity imported into WCI from non-WCI jurisdictions;

1.2.2. Combustion at industrial and commercial facilities;

1.2.3. Industrial process emission sources, including oil and gas process emissions;

1.2.4. Residential, commercial, and industrial fuel combustion at facilities below the WCI thresholds (as described below in the Point of Regulation section, these emissions will be covered upstream). Coverage of these emissions will begin at the start of the second compliance period;

1.2.5. Transportation fuel combustion from gasoline and diesel (as described below in the Point of Regulation section, these emissions will be covered upstream). Coverage of these emissions will begin at the start of the second compliance period;

1.2.6. The WCI Partners recommend covering combustion from transportation, residential and commercial, and industrial fuel sources with the expectation that the individual Partner jurisdictions will:

- Mitigate the economic impact on consumers;
- Implement other policies that will reduce GHG emissions from the transportation sector and reduce demand for transportation fuels (such as vehicle standards, smart growth, low carbon fuel standards, transit options, etc.); and

[1] The *scope* defines the GHG emissions that are included in the cap-and-trade program, including the emissions sources and greenhouse gases that fall under the cap.

- Address any issues associated with the point of regulation and its implementation.

1.3. Carbon dioxide emissions from the combustion of biomass or biofuel are not included in the cap-and-trade program.

1.4. As described below under Role of Other Policies, WCI Partners acknowledge that individual jurisdictions may instead utilize comparable fiscal measures, such as British Columbia's carbon tax, to address transportation fuels and fuel use by residential and commercial sources.

1.5. Adequate quantification methods will be established for emissions sources prior to including them in the program.

2. POINT OF REGULATION[2]

2.1. Industrial sources (both process and combustion) with emissions above the threshold: At the point of emission.

2.2. Electricity: First Jurisdictional Deliverer: the generator for sources within WCI jurisdictions and the first entity over which a Partner has regulatory authority that delivers electricity generated outside the WCI into a WCI Partner jurisdiction for consumption in that Partner jurisdiction.

2.3. Residential, commercial, and industrial fuel combustion at facilities with emissions below the threshold: Where the fuels enter commerce in the WCI Partner jurisdictions; generally at a distributor; precise point to be determined and may vary by jurisdiction.

2.4. Transportation fuel combustion: Where the fuels enter commerce in the WCI Partner jurisdictions; generally at the terminal rack, final blender, or distributor; precise point to be determined and may vary by jurisdiction.

2.5. Cogeneration facilities: How to handle emissions associated with cogeneration facilities is still under consideration by the Partners.

[2] The *point of regulation* is the entity or facility with the compliance obligation, i.e., the requirement to surrender sufficient GHG allowances to cover actual emissions during the compliance period. An allowance is the tradable permit to emit one metric ton of GHG emissions. The term *entity* is generally used when the point of regulation is upstream of the point of emissions, to describe a company that has an obligation to surrender allowances to cover the carbon content of the fuel the company is moving through commerce. When the point of regulation is at the source or point of emissions, the term *facility* is generally used. The term *source* is used to refer to emissions from either a facility or an entity.

3. THRESHOLDS[3] FOR COVERAGE UNDER THE CAP-AND-TRADE PR0GRAM

3.1. Emission threshold: 25,000 metric tons of carbon dioxide equivalents (CO_2e) annually defines the facilities or entities (e.g., first jurisdictional deliverer, fuel distributor, fuel blender) that would have a regulatory compliance obligation under the cap-and-trade program. Mandatory reporting data may be used to adjust this threshold for specific industries where necessary. Additional analyses will be done to determine if adjustments to the threshold are needed to ensure sufficient coverage or to address competitiveness issues within individual sectors prior to the beginning of the program (e.g., because different Partner jurisdictions may have the same industry but with different sized sources).

3.2. A method will be developed to prevent first jurisdictional deliverers from avoiding coverage, such as by breaking themselves into separate power deliverers such that each delivers electricity with emissions below the threshold.

4. PROGRAM EXPANSION

4.1. Future Program Expansion: The WCI Partners recommend that the scope of the cap-and-trade program be capable of expanding over time (including possibly adjusting applicability thresholds over time). Prior to each compliance period, the Partners will review whether to bring new sources (and if so which ones) into the program.

5. ROLE OF OTHER POLICIES[4]

5.1. The role of other greenhouse gas-reducing policies is to help the WCI Partners achieve their 2020 reduction goal. Those policies will work in concert with the cap-and-trade program and may apply to any source of greenhouse gas emissions.

5.2. Carbon Tax and Other Fiscal Measures:

5.2.1. The WCI Partners agree that individual jurisdictions may use fiscal measures that contribute to achieving overall comparable GHG emission reductions and internalize the price of carbon as expected through the regional cap-and-trade program for transportation and residential/commercial fuels.

5.2.2. British Columbia currently has a carbon tax. By 2012 the Partners will determine the mechanism for integrating the cap-and-trade program with the BC carbon tax.

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[3] *Thresholds* are levels at which it is determined that a particular entity or facility will have a compliance obligation under the cap-and-trade program.

[4] *Other policies* include complementary policies and alternative policies. A *complementary policy* is used in this context to mean policies other than a cap-and-trade program that aid in the goal of achieving emissions reductions for capped or uncapped sources. *An alternative policy* is a policy that is employed in lieu of a cap-and-trade program for one or more sources.

6. SETTING THE REGIONAL CAP[5]

6.1. The aggregate regional cap for the cap-and-trade program will:

6.1.1. Equal the sum of the Partner allowance budgets (see Apportionment section below).

6.1.2. Include annual caps (with 3-year compliance periods) from the beginning of the program in 2012 through 2020. The annual caps will be set in advance of the program start in 2012 so that the reductions required in each 3-year compliance period through 2020 are predictable.

6.1.3. Decline over time. The regional cap trajectory for covered sectors will be a straight line from the year of initial coverage (2012 for some sources and 2015 for other sources) to 2020.

6.2. 2012: The initial cap will be set at the best estimate of expected actual emissions for those sources covered in the initial year of the program (i.e., 2012). The estimate of expected actual emissions in 2012 will be developed using the best available data (including any available mandatory reporting data) and by accounting for expected changes in emissions by 2012. Population growth, economic growth, voluntary and mandatory emission reductions, and other factors will be considered. The 2012 cap will also recognize actions to reduce greenhouse gas emissions before the start of the program.

6.3. 2015: The regional cap for the second compliance period will be set by adding the best estimate of expected actual emissions in 2015 from transportation fuels and residential, commercial, and industrial fuels (and any other sectors or sources that may be added to the program for the first time in 2015) to the emissions trajectory for the sources first included in the program in 2012.

6.4. 2020: The regional cap for 2020 will be set so that reductions achieved by the cap plus reductions from other greenhouse gas reduction policies will achieve the WCI regional 2020 goal.

6.5. Post-2020 caps: The Partners shall set these regional caps not less than three years in advance.

6.6. Once established, the regional cap for each compliance period will not be adjusted except as necessary to account for:

- Changes in WCI membership,
- Changes in scope or thresholds, or
- Errors discovered in data used to determine the cap, which may become apparent, for example, after the start of mandatory reporting.
- Any adjustments will be made prior to the beginning of the compliance period.

[5] The *regional cap* is the overall limit on total emissions set for the emissions included in the cap-and-trade program.

7. APPORTIONMENT[6]

7.1. Each Partner will have an annual allowance budget within the regional cap from 2012 to 2020. The annual Partner allowance budgets for each year through 2020 will be set prior to the start of the program in 2012.

7.2. The Partners are working on an apportionment methodology based on Partner and regional emission reduction goals and requirements. The apportionment methodology will address factors such as production and consumption of electricity, projected population growth and economic activity, and other factors. The Partners intend to have a recommended apportionment methodology by Fall 2008.

7.3. For years post-2020, the Partners will set allowance budgets not less than three years in advance.

7.4. Once established, each Partner's allowance budget will not be adjusted except as necessary to account for:

- Changes in WCI membership;
- Changes in scope or thresholds;
- Errors discovered in data used to determine the cap or the Partner budgets, which may become apparent, for example, after the start of mandatory reporting.
- Such adjustments will take effect at a regionally coordinated and designated time, such as at the beginning of a compliance period.

7.5. Partners will recognize within their own jurisdictions allowances issued by other Partners so that all WCI allowances are of equivalent use and fungible throughout the WCI region, regardless of which Partner issues the allowances.

7.6. Determination of allowance budgets for new Partners will take into account the following parameters:

- The WCI regional goal;
- Allowance budgets for existing Partners;
- The share of the new Partner's budget that is already included through the WCI's provisions covering imported electricity; and
- The apportionment methodology that is being developed by the Partners (above).

[6] *Allowance apportionment* describes the Partners' budget or share of GHG emission allowances. Allowance budgets must be set for each Partner jurisdiction.

8. DISTRIBUTION OF ALLOWANCES[7]

8.1. Distribution of Allowances by Partners: Once the allowance budget has been established for each Partner, allowances will be issued by each Partner.

8.2. The WCI Partners agree that a minimum percentage of the value of each Partner's allowance budget (for example, through set-asides of allowances, through a distribution of revenues from the auctioning of allowances, or other means) may be dedicated to one or more of the following public purposes that provide benefits across all WCI jurisdictions:

- Energy efficiency and renewable energy incentives and achievement;
- Research, development, demonstrations and deployment (RDD&D) with particular reference to carbon capture & sequestration (CCS); renewable energy generation, transmission and storage; and energy efficiency; and
- Promoting emission reductions and sequestration in agriculture and forestry and other uncapped sources;

8.3. The remaining percentage of Partner allowance budgets will be distributed as each Partner sees fit. When distributing allowances Partners may consider objectives such as:

- Reducing consumer impacts, especially for low-income consumers;
- Providing for worker transition and green jobs;
- Providing transition assistance to industries;
- Adaptation to climate change impacts;
- Recognizing early actions to reduce emissions; and/or
- Promoting economic efficiency.

8.4. In advance of the first compliance period, and at least one year before the beginning of each relevant compliance period thereafter, each Partner will advise the other WCI Partners how it intends to distribute or retire allowances so that Partners' plans can be made public in a coordinated fashion.

8.5. To address competitiveness issues between Partner jurisdictions, the WCI Partners shall consider standardizing the distribution of allowances over time, such as:

- Treating similar emissions-intensive industries operating in more than one Partner jurisdiction, but in the same market, similarly (such as aluminum, electricity, steel, cement, lime, pulp and paper, and oil refining);
- Developing benchmarks to harmonize allocations to similar industries, and;
- Providing a level playing field for new emission sources.

8.6. Partners will allocate or retire all the allowances in their allowance budgets by the end of the applicable compliance period. A Partner will not hold allowances beyond the end of the compliance period.

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[7] *Allowance distribution* is the Partners' initial distribution of GHG emission allowances into the market.

8.7. The issue of establishing a minimum percentage of allowances subject to auction by each Partner is still under discussion by the Partners. The Partners expect to make a recommendation on this issue by Fall, 2008.

8.8. To the extent Partners decide to auction allowances, Partners will undertake auctions through a coordinated regional auction process by which each Partner will auction allowances throughout the WCI region and receive the proceeds of the auction.

8.9. Credits for Early Reductions: Each Partner has discretion to give credit for early actions, but any credit for early action will come from within the cap and will come out of the individual Partner's allowance budget. Early action credits will not be added to or be on top of the amount of allowances in each Partner's allowance budget.

8.10. Banking: Purchasers and covered entities or facilities will be allowed to bank allowances without limitation, except to the extent that restrictions on the number of allowances any one party may hold are necessary to prevent market manipulation.

8.11. Borrowing: Borrowing of allowances from future compliance periods will not be allowed.

8.12. Compliance Periods: Each compliance period will be three years long.

9. OFFSETS,[8] AND ALLOWANCES FROM OTHER SYSTEMS

9.1. The WCI Partners will include a rigorous offsets program. The primary role of the offsets program is to reduce the compliance costs for the cap-and-trade system, while ensuring the environmental integrity of the cap.

9.2. The WCI Partners will establish a limit on the use of offsets approved/certified by WCI Partners, and/or offsets or allowances from other government-approved GHG emission trading systems. This limit will be expressed as a percentage limit on each covered entity's or facility's compliance obligation that can be satisfied during each compliance period using offsets or allowances from other government-approved GHG emission trading systems. The WCI Partners are considering a limit not greater than ten (10) percent of an individual entity's or facility's compliance obligation (i.e., the number of allowances a covered entity or facility is required to surrender to cover its emissions). The specific limit will be evaluated based on further analysis and consideration of both the cost reduction objective and the desire to ensure a meaningful fraction of emissions reductions occur at WCI covered sources.

9.3. The WCI Partners have identified the following list of project types as a priority for investigation and development to participate in the WCI offset system. Making these project types a priority means the Partners are interested in understanding if they are suitable for the offset system, if they will meet the criteria for environmental integrity, and if adequate protocols /methodologies for

[8] *Offsets* are emission reduction projects undertaken to address emissions not included in a cap-and-trade program. An offset mechanism enables covered entities to offset their own emissions by purchasing emission reduction credits generated through projects that address emissions not covered by the cap.

their quantification and monitoring can be adapted or developed. Priority does not mean these project types are guaranteed to be in an offset system. Project types that reduce emissions that would eventually be covered by the cap-and-trade system would only be eligible until that coverage begins. Project types that reduce emissions covered by the cap-and-trade system would not be eligible to create offsets because the result would be a double counting of the emission reduction. The list is in alphabetical order and does not directly or indirectly represent a ranking or order of preference:

- Agriculture (soil sequestration and manure management);
- Forestry (afforestation/reforestation, forest management, forest preservation/conservation, forest products); and
- Waste management (landfill gas and wastewater management).

9.4. Starting in 2009, the WCI Partners will coordinate to review, develop, and approve, as appropriate, protocols for the project types that meet the necessary criteria for inclusion. The WCI Partners will use offset protocols that are standardized to the extent possible, and make use of (or adapt if needed), existing protocols as appropriate. The WCI Partners will also initiate the establishment of a process during 2009 to coordinate the review and approval other project types and protocols proposed by project developers.

9.5. WCI Partners may approve and certify offset projects located throughout Canada, the United States, and Mexico, where such projects would be subject to comparably rigorous oversight, validation, verification and enforcement as those located within the WCI jurisdictions.

9.6. WCI protocols must meet rigorous criteria to preserve the environmental integrity of the overall cap-and-trade system.

9.7. In the case of offset credits from the Clean Development Mechanism (CDM) and Joint Implementation (JI), the WCI Partners may establish added criteria to ensure similar rigor to WCI approved/certified offset projects or other requirements appropriate to enable use of these offset credits in the WCI program.

9.8. WCI Partners may allow individual regulated entities or facilities to use tradable units (allowances) from other government-regulated GHG emission trading systems that the WCI Partners recognize as meeting similarly rigorous criteria for environmental integrity for compliance purposes. These allowances would be subject to the overall limit described above.

9.9. The WCI Partners are considering a method that restricts the use of offsets from projects located outside WCI jurisdictions for compliance purposes in the WCI cap-and-trade regulatory program.

9.9.1. The use of offsets as a regulatory instrument in the WCI cap-and-trade program will substitute for allowances issued by WCI partner states and provinces for compliance within the cap-and-trade program. Limitations on the use of offsets from projects located outside the WCI would reflect the goal of the regulatory program to achieve reductions in greenhouse gas emissions within the region. Such restrictions would also ensure that WCI partner states and provinces are able to inspect offset projects and enforce any laws relevant to project operations and the use of offsets for compliance. Collateral benefits associated with some offsets projects, such as health, social and environmental benefits would also accrue within WCI partner states and provinces.

9.9.2. WCI Partners have no intention to regulate or restrict the existing voluntary market in offsets, to restrict the sale of offsets from projects located within the WCI states and provinces, or to place restrictions on ownership of offsets projects located within WCI partner states and provinces.

10. REPORTING

10.1. Mandatory measurement and monitoring for all six GHGs will commence in January 2010 for all entities and facilities subject to reporting. Reporting of 2010 emissions will begin in early 2011.

10.2. The entities and facilities subject to reporting are those with annual emissions equal to or greater than 10,000 metric tons of CO_2e. However, in some limited instances the threshold may be based on other parameters, such as throughput or capacity, as long as these thresholds represent the equivalent of, or are lower than, the 10,000-metric-ton threshold.

10.3. Partners may require third-party verification or may carry out government audit programs. (Partners are still discussing whether verification by third parties accredited under a common framework should be required for all reports submitted by entities or facilities covered by the cap.)

10.4. As each Partner collects additional emissions data from entities and facilities required to report, data will be made available to all Partners for review and consideration for inclusion in the cap-and-trade program.

10.5. Nothing in the WCI program design would limit any Partner’s discretion to require reporting earlier, at lower thresholds, or for entities and facilities not covered by the cap-and-trade program.

11. START DATE FOR CAP-AND-TRADE

11.1. The cap-and-trade program will launch January 1, 2012.

12. COMPLIANCE AND ENFORCEMENT

12.1. Each jurisdiction will retain and/or enhance its regulatory and enforcement authority and responsibilities to enforce compliance with the cap-and-trade program within its own Partner jurisdiction.

12.2. Each covered entity or facility will demonstrate compliance with the cap-and-trade program by surrendering sufficient allowances after the end of each compliance period.

12.3. If by the deadline for demonstrating compliance a covered entity or facility does not have sufficient allowances to cover its emissions for the previous compliance period, it shall be required to surrender three allowances for every metric ton not covered by an allowance at the deadline. This does not preclude other penalties allowed under individual state or provincial laws.

12.4. The WCI Partners recognize that during the first compliance period, both they and the entities and facilities covered by the cap-and-trade program will likely encounter issues that arise in the implementation of a new program. Consequently, the Partners are committed to providing appropriate technical and other compliance assistance to the program participants.

12.5. The WCI Partners will ensure accounting systems are in place to prevent using allowances, tradable units, and offsets more than once for compliance.

13. REGIONAL ORGANIZATION AND NEW PARTNERS

13.1. To reduce administrative costs and improve program transparency and consistency, a regional administrative organization will be created to:

- Coordinate the regional auction of allowances;
- Track emissions;
- Monitor and report on market activity, including any potential market manipulation;
- Serve as a forum for Partners to update one another on program progress;
- Coordinate review and adoption of protocols for offsets;
- Coordinate review and adoption of updated reporting protocols;
- Coordinate review and issuing of offset credits; and
- Provide criteria and means to accredit service providers to deliver validation and verification services.

13.2. New Partners will come into the cap-and-trade program at a regionally coordinated and designated time, such as the beginning of the relevant compliance period.

13.3. A new Partner must have adopted an economy-wide greenhouse gas reduction goal for 2020 that reflects a level of effort that is consistent with that of the WCI Partners.

July 23, 2008 Draft Design of the Regional Cap-and-Trade Program

List of Commenters

AES Pacific

America Forest Resource Council

American Forest Paper Association

Air Transport Association

American Trucking Association

APX, Inc.

Ash Grove Cement

Associated Oregon Industries

Association of Power Producers of Ontario

Avista Corporation

Arizona Electric Power Cooperative

Arizona Public Services Corporation

Arizona Chamber of Commerce & Industry

BC Forestry Climate Working Group

Boise Inc.

BP America

Bullfrog Power

Business Council for Sustainable Energy

CA League of Food Processors

California Forestry Association

Camco International Group

Campaign for Environmental Literacy

Canadian Association of Petroleum Producers

Canadian Lime Institute

Canadian Parks and Wilderness Association

Cascade Sierra Solutions

Cement Association of Canada

The Center for Energy Efficiency and Renewable Technologies in coordination with the Center for Resource Solutions and the Renewable Northwest Project

Chelan County Public Utility District No. 1

Chevron

City of Phoenix

City of Portland

City of Seattle

Clark Public Utility District

Climate Literacy Network

Climate Protection Campaign

Climate Solutions

Climate Action Network Canada

ClimateToday.org

Colorado Alliance for Environmental Education

Conoco Phillips

Covanta Energy Corp.

Deluge, Inc.

Devon Energy Corp.

Douglas County Global Warming Coalition

Douglas County Public Utility District

Earth Advantage

Ecotrust

El Paso Corporation

Entegra

Energy Producers & Users Coalition, Cogeneration Association of California, and Cogeneration Coalition of Washington

ExxonMobil

Goldman Sachs

Gregory, L. Jay

Hydro-Quebec

International Climate Change Partnership

International Council on Clean Transportation

Industrial Customers of Northwest Utilities

Independent Energy Producers Association

Interfaith Power & Light

International Emissions Trading Association

Lane County

Mining Association of British Columbia

Morgan Stanley Capital Group

National Alliance of Forest Owners

Northern California Power Agency

Northwest Food Processors Association

Northwest Pulp & Paper

Nucor Steel

Oregon Center on Public Policy, California Budget Project, Children's Action Alliance of Arizona, New Mexico Voices for Children, Voices for Utah Children, Washington State Budget & Policy Center

Oregon Environmental Council

Oregon Forest Carbon Working Group

Oregon Forest Industries Council

Oregon Municipal Electric Utility Association (OMEU)

Oregon Rural Electric Cooperative Association

Pacific Forest Trust

Pacificorp

Pacific Gas & Electric

Plasco Energy Group

PNGC

Public Power Council

Puget Sound Energy

Redding Electric Utility

Reliant Energy

Rio Tinto

Sacramento Municipal Utility District

Saint Gobain Containers

Salt River Project

Sempra Energy

Sierra Club

Sightline Institute

Smurfit Stone

Southern California Edison

Southern California Public Power Authority

Spectra Energy

Springfield Utility Board (SUB)

Tacoma Public Utilities

Tax Fairness (Oregon)

Terasen Gas

The Climate Trust

The Nature Conservancy

Trans Alta

Tri State Generation and Transmission Association

Union of Concerned Scientists

Utah Business Climate Change Coalition

Wasatch Clean Air Coalition

Washington Forest Protection Association

Washington Rural Electric Cooperatives Association

Washington Public Utilities Association

Waste Management (w/ attachment)

Western Climate Action Network (WeCAN) – submitted 3 documents:

West Associates

Western Forestry Leadership Coalition

Western Power Trading Forum

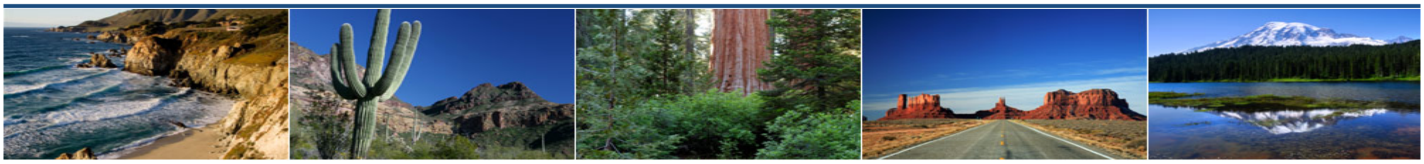
Western States Petroleum Association

Weyerhaeuser

Western Resource Advocates

Xcel Energy

Western Climate Initiative



Draft Essential Requirements of Mandatory Reporting for the Western Climate Initiative

July 23, 2008

Introduction

To complete the essential requirements of a model reporting rule, the Western Climate Initiative (WCI) must make numerous decisions about how it wishes to approach, define, and structure the essential requirements that have been identified as necessary to an effective WCI cap-and-trade program. A number of these decisions have already been made by the WCI jurisdictions, but many have not.

The purposes of this paper are to: 1) document the current status of WCI's consideration of essential requirements; 2) identify the decisions that remain to be made; and 3) seek public comment on these essential requirements. As decisions are made to finalize the essential requirements, the WCI will move toward developing a regulatory structure for the essential requirements in future steps.

The paper is divided into 10 categories of essential requirements related to mandatory reporting of GHGs: definitions, pollutants, applicability, timing, confidentiality, report content and submittal, compliance, emissions quantification and monitoring, and verification and quality assurance. For each group of essential requirements, the following information is presented:

- "Discussion and Notes" describes the essential requirements that are proposed to be addressed in the context of future model rule sections.
- "Draft Design of the Regional Cap-and-Trade Program" summarizes the specific recommendations contained in the most current draft design document (July 23, 2008) and/or a previous version (May 16, 2008), if applicable to the essential requirement.
- "Additional Decisions Needed" summarizes the decisions that need to be made about the approach, definition and structure of the essential requirement.

An understanding of existing general reporting requirements for WCI jurisdictions is valuable to the process of determining essential elements for WCI mandatory reporting. Attachment A contains three tables comparing general reporting requirements of existing and imminent programs in WCI jurisdictions and related areas (e.g., The Climate Registry, Regional Greenhouse Gas Initiative, etc.). Table A1 summarizes general requirements related to the scope of the programs (e.g., GHGs reported, sources required to report, thresholds, etc.). Table A2 summarizes the verification and/or quality assurance requirements for each program. Table A3 summarizes the overall reporting requirements (e.g., timing/schedules, reporting procedures, confidentiality, etc.). This information provides a basis for developing WCI's essential elements for reporting, and for identifying early any potential conflicts and/or harmonization between WCI's reporting requirements and jurisdiction reporting requirements.

Definitions

Discussion and Notes

1. This rule section will contain clear and appropriately detailed definitions of key terms used in the monitoring and reporting rule.

2. When source category-specific requirements are considered, there may be hundreds of terms that need definition. The most efficient approach to creating a list is to "borrow" from other jurisdiction's rules. There are a number of precedents to consider for definitions. Terminology defined by The Climate Registry (TCR) could be used, although some definitions might not be sufficiently detailed for regulatory use. If TCR's list is not comprehensive enough for a mandatory reporting rule, then CARB's reporting rule has a very detailed and lengthy list of definitions that may be used. CARB's list combines source category-specific definitions with those common to all source categories in a single list. The definitions established by the U.S. EPA, Canadian agencies, and states like New Mexico should also be considered.

3. Definitions will facilitate communications among WCI jurisdictions and stakeholders by defining common terminology very early in the process of developing the details of essential requirements for model GHG reporting rule language. For example, the term "source categories" is used throughout this paper to indicate groupings of sources and activities; definitions for these types of terms should be agreed upon and articulated by the WCI jurisdictions.

Additional Decisions Needed

1. Using the CARB definitions as a starting point, compile the list of definitions for review by the Reporting Subcommittee.

Pollutants

Discussion and Notes

1. Pollutants – This section will list the pollutants that must be quantified and reported.

2. Conversion factors – The section will specify the 100-year global warming potential factors used to convert other pollutants to CO_2e. The WCI presumably will use the same conversion factors as are used nationally and internationally, such as the IPCC Second Assessment Report, 1995.

Draft Design of the Regional Cap-and-Trade Program (July 23, 2008):

1. Greenhouse gases covered: Carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride.

Additional Decisions Needed

1. Confirm decision on conversion factors.

Applicability

Discussion and Notes

1. This rule section describes who must comply with the reporting rule. As a minimum, the reporting system must include all activities and sources that will be part of the cap.

2. This rule section will also list any source categories that are not subject to the initial cap but which will be required to report emissions.

3. Thresholds – This section will contain the thresholds for mandatory reporting, stated as metric tons of CO_2 or CO_2e per year, or other appropriate emissions or operational indicators.

4. Sources not included – This section will describe sources or activities in affected source categories that are not subject to reporting requirements.

5. Level of reporting – This rule section will address by source category at what level (i.e. corporate [entity], facility or process level) reporting will be required.

Draft Design of the Regional Cap-and-Trade Program (July 23, 2008):

1. Emissions covered:

    - Electricity generation, including emissions from electricity imported into WCI from non-WCI jurisdictions;
    - Combustion at industrial and commercial facilities;
    - Industrial process emission sources, including oil and gas process emissions;
    - Residential, commercial, and industrial fuel combustion at facilities below the WCI thresholds (as described below in the Point of Regulation section, these emissions will be covered upstream). Coverage of these emissions will begin at the start of the second compliance period;
    - Transportation fuel combustion from gasoline and diesel (as described below in the Point of Regulation section, these emissions will be covered upstream). Coverage of these emissions will begin at the start of the second compliance period.

    Adequate quantification methods will be established for emissions sources prior to including them in the program.

2. Point of Regulation:

- Industrial sources (both process and combustion) with emissions above the threshold: At the point of emission.
- Electricity: First Jurisdictional Deliverer: the generator for sources within WCI jurisdictions and the first entity over which a Partner has regulatory authority that delivers electricity generated outside the WCI into a WCI Partner jurisdiction for consumption in that Partner jurisdiction.
- Residential, commercial, and industrial fuel combustion at facilities with emissions below the threshold: Where the fuels enter commerce in the WCI Partner jurisdictions; generally at a distributor; precise point to be determined and may vary by jurisdiction.
- Transportation fuel combustion: Where the fuels enter commerce in the WCI Partner jurisdictions; generally at the terminal rack, final blender, or distributor; precise point to be determined and may vary by jurisdiction.
- Cogeneration facilities: How to handle emissions associated with cogeneration facilities is still under consideration by the Partners.

3. The entities and facilities subject to reporting are those with annual emissions equal to or greater than 10,000 metric tons of CO_2e. However, in some limited instances the threshold may be based on other parameters, such as throughput or capacity, as long as these thresholds represent the equivalent of, or are lower than, the 10,000-metric-ton threshold.

4. Nothing in the WCI program design would limit any Jurisdiction's discretion to require reporting earlier, at lower thresholds, or for entities and facilities not covered by the cap-and-trade program.

Additional Decisions Needed

1. Complete decisions on which source categories will be subject to mandatory reporting. Select the numeric value and form of applicability thresholds for those source categories.

2. Complete detailed definitions of each source category to address point of regulation issues and further clarify which sources and activities within each source category are covered by the reporting requirement (i.e., activities, sources, and operational boundaries).

3. Determine sources, activities and processes to be excluded from reporting.

4. Determine by source category whether reporting will occur at the corporate (entity), facility, or process level.

Timing

Discussion and Notes

1. Effective Date – This rule section will specify the date or dates when mandatory record keeping and reporting begins for affected source categories. It may be necessary to evaluate the potential use of measurement and monitoring data for years prior to 2010.

2. Reporting Period – This requirement specifies the calendar year or other period within which emissions must be quantified. The Draft Design (July 23, 2008) suggest starting on January 1, thus implying a calendar year reporting period. Consideration may have to be made for some form of more frequent or interim reporting to support the development and implementation of the cap-and-trade program.

3. Report Submission Date – This section will specify when reports must be submitted. To maintain alignment with future cap-and-trade allocations and reconciliation periods, it would seem preferable for reports to be submitted at the same time in all jurisdictions. A key issue is how long after the reporting year ends that reports be due.

Draft Design of the Regional Cap-and-Trade Program (July 23, 2008):

1. Mandatory measurement, monitoring, and reporting for all six GHGs will commence in January 2010 for all entities and facilities subject to reporting. Reporting of 2010 emissions will begin in early 2011.

Additional Decisions Needed

1. Determine whether all jurisdictions are to have the same effective date, reporting year and report submission date, and establish those dates.

2. Determine what the WCI's policy will be on collecting and using data from years prior to 2010.

3. Determine how any jurisdictions that have started reporting early, or plan to do so, will make the transition to the WCI schedule.

4. Determine whether more frequent interim reports are necessary to support the development and implementation of the cap-and-trade program.

5. Establish deadlines for emissions reporting, verification or QA of reported data, and public release of data.

Confidentiality

Discussion and Notes

1. In general, emissions data are not considered confidential although some operational information can be protected, depending on each jurisdiction's legal authority.

2 Stakeholders have offered a range of comments with some favoring a narrow construction of confidentiality to protect the public's right to know, and others favoring a broader construction that would better protect sensitive operational information from competitors.

Additional Decisions Needed

1. Determine policy and procedures pertaining to confidential information and data and the extent of public disclosure.

Report Content and Submittal

Discussion and Notes

1. Content – These sections and subsections will specify the information that each reporting unit will be required to submit. Examples of typical administrative information are facility names, identification numbers, physical addresses, mailing addresses, locations, responsible officials, various operational information, ownership structure, etc. More detailed information will be addressed in the source category-specific requirements.

   Technical content includes such examples as pollutants, quantification methods, and supporting operational and activity information and data. Requirements need to be specific and detailed and some will be source category-specific.

   There are a number of existing reporting rules that could provide potential starting points, however many specific decisions on content will evolve from the choices made for other essential requirements.

2. Submittal – This section will specify who is responsible for submitting the report and to whom, and certifying the accuracy of the information contained in it.

Draft Design Recommendations (May 16, 2008):

1. The WCI has recommended using TCR's central repository for data storage as well as offering flexibility as to where affected sources initially report. Reports could either be submitted directly to jurisdictions (which will then upload the data to TCR's central repository), or be submitted directly through TCR's program framework (which will then download the data to the necessary jurisdictions).

Additional Decisions Needed

1. Determine the specific contents of report to be submitted.

2. Confirm decision on submittal mechanism: direct to TCR or through jurisdictions to TCR.

Compliance

Discussion and Notes

1. Rule violations – This section will discuss the actions that will be considered violations of the rule, for example failure to submit complete reports when required to do so, knowingly submitting false information with a intent to deceive, etc.

2. Enforcement Mechanisms – The WCI will develop consistent administrative practices to respond to non-compliance issues, however specific enforcement actions, such as levying fines and penalties, will likely be carried out by jurisdictions.

3. Records Retention – This section will describe which records must be kept and for how long. More detailed requirements may be included in source-category-specific requirements.

4. Revisions – The rule will describe the process for revising reports that contain inaccurate or missing information and data. The revision process might differ depending on the timing and the circumstances in which the inaccuracies were discovered.

Additional Decisions Needed

1. Determine which actions will be considered violations of the reporting rule.

2. Develop guidelines to promote consistent administrative practices and responses to non-compliance issues among jurisdictions.

3. Determine which records must be maintained for all source categories subject to the reporting rule.

4. Establish procedure and policy for revisions.

Emissions Quantification and Monitoring

Discussion and Notes

1. The essential requirements to the model rule will provide an introduction to quantification, probably in a "General Requirements" section, but will also specify source category-specific quantification requirements.

2. In addition to the technical issues related to reporting, there are also a number of policy-oriented choices to be made. Examples are the degree of coordination with other (non GHG) emissions reporting requirements and *de minimis* requirements.

3. A key factor in determining emissions quantification and monitoring requirements is that the requirements must provide levels of accuracy necessary for an effective cap-and-trade program. It is generally accepted that quantification methods must be more rigorous under mandatory reporting for cap-and-trade, than for some methods allowed for voluntary reporting. For example, while a voluntary program might allow a range of methods, quantification and monitoring requirements for mandatory reporting might include "higher tier" methods that assure the appropriate level of accuracy needed to support a cap-and trade program.

4. Several key issues of concern to stakeholders include: 1) how to deal with combined heat and power (CHP) sources; 2) treatment of biomass combustion; 3) methods for quantifying emissions from imported electricity; and, 4) method for quantifying emissions for waste management.

5. Existing GHG emission quantification and monitoring requirements in the WCI jurisdictions and other relevant programs are currently being summarized and reviewed by the Reporting Subcommittee. This review will determine applicability of existing methods to the WCI reporting requirements for a cap-and-trade program, and provide a basis for evaluating consistency with existing WCI jurisdiction reporting rules.

Draft Design of the Regional Cap-and-Trade Program (July 23, 2008):

1. Adequate quantification methods will be established for emissions sources prior to including them in the program.

Additional Decisions Needed

1. The Reporting Subcommittee will establish a process for selecting and approving general and source category-specific emissions quantification and monitoring methods.

2. Based on the process defined, select the methods, and provide the details for each source category-specific method.

Verification and Quality Assurance

Discussion and Notes

1. This essential requirement will address how reported information will be quality assured.

2. The Reporting Subcommittee is currently writing an issue paper addressing "Third Party Verification" that will inform its recommendations and provide a mechanism for public comment on this issue.

Draft Design of the Regional Cap-and-Trade Program (July 23, 2008):

1. Jurisdictions may require third-party verification or may carry out government audit programs. (Jurisdictions are still discussing whether verification by third parties accredited under a common framework should be required for all reports submitted by entities or facilities covered by the cap.)

Additional Decisions Needed

1. Determine the type of verification and quality assurance program.

2. Based on the type of program recommended, define the specific requirements (e.g., accreditation of verifiers, schedules for completion, etc.).

Comments on this Document

Comments on this document will be solicited in person at the July 29, 2008, WCI stakeholders meeting in San Diego, and we encourage written comments to be submitted by Wednesday, August 13, through the WCI website (www.westernclimateinitiative.org). Also, there will be several other opportunities to submit comments on the essential requirements for mandatory reporting after future drafts are released in the Fall of 2008. We are seeking your opinion on whether we should rely most heavily on conference calls and written comments for stakeholder comments on future drafts of the essential requirements or portions thereof, and have only one or two in-person stakeholder meetings.

Attachment A:

Comparison Matrix of Existing and Imminent General Reporting Requirements for WCI Jurisdictions and Related Programs:

- *Table A1: Scope*
- *Table A2: Verification and Quality Assurance*
- *Table A3: Reporting*

Table A1. Comparison Matrix of Existing and Imminent General Reporting Requirements for WCI Jurisdictions and Related Programs: Scope

Reporting Program/ Jurisdiction	Voluntary, Mandatory, C&T	Coverage (GHGs)	Sources/Sectors		Threshold(s) for Reporting	CO2 from Biomass Provisions	GWPs	De Minimis Provisions
			Included	Excluded				
Canada (EC) (Section 71)	Mandatory, C&T (under development)	CO_2, CH_4, N_2O, SF_6, HFCs, PFCs	Emissions sources are sector dependent	On-site mobile combustion emissions	Section 71 – thresholds are sector dependent *Phase 1, 100kt CO2e	Required, reported separately from other emissions	IPCC Second Assessment Report (1995): • CO2: 1 • CH4: 21 • N2O: 310 • SF6: 23900 • HFCs and PFCs vary by formula	None
Québec	Mandatory	CO_2, CH_4, N_2O, SF_6, HFCs, PFCs	Enterprise, facility, or establishment emitting above threshold provided by an annual public notice related to the Section 46 of Canadian Environmental Protection Act (1999). Sources include stationary fuel combustion, industrial process, venting and flaring, other fugitive emissions, on-site transportation and waste and wastewater	None	Any enterprise, facility, or establishment emitting ≥100,000 metric tons of CO2e	Required	IPCC Second Assessment Report (1995)	None
U.S. EPA	Mandatory (to be proposed September 2008)							
CA (ARB)	Mandatory	CO_2, CH_4, N_2O, SF_6 , HFCs and PFCs as specified by sector	Stationary combustion, process and fugitive sources from facilities that are operational as of Jan 1st, 2008, including: • Cement plants • Petroleum refineries • Hydrogen plants, • Electricity generating facilities • Electricity retail providers • Electricity marketers • Cogeneration facilities • Other facilities emitting ≥25,000 metric tonnes CO2 from general	• Electricity generating facilities solely powered by nuclear, hydroelectric, wind, or solar • Portable equipment • Backup generating units or permitted emergency generators • Hospitals (NAICS 62) • Primary and secondary schools (NAICS 611110)	• ≥25,000 metric tonnes CO2 from stationary combustion sources at petroleum refineries and hydrogen plants, and GSC sources • ≥2,500 metric tonnes CO2 from stationary combustion sources at cogeneration or electricity generation facilities	Calculate and report separately all direct combustion emissions	IPCC Second Assessment Report (1995)	No more than 3% of facility's total CO2e (not to exceed CO2e of 20,000 metric tons)

Table A1 - Continued

Reporting Program/ Jurisdiction	Voluntary, Mandatory, C&T	Coverage (GHGs)	Sources/Sectors		Threshold(s) for Reporting	CO2 from Biomass Provisions	GWPs	De Minimis Provisions
			Included	Excluded				
			from general stationary combustion (GSC) Not required, but may voluntarily report separately facility CO2, CH_4, N_2O emissions from mobile combustion.					
NM	Mandatory	• First year: Direct emissions of CO_2 • Second year: Direct emissions of CO_2 and CH_4. For source types specified in Part 87, also include indirect emissions from all electricity, steam, and heat purchased/consumed at the facility. • Third and subsequent years: all GHGs. For source types specified in Part 87, include indirect (as above).	Part 87 specifies Electrical generators, Petroleum refining and Cement manufacturing. Part 73 gives the state authority to require GHG emissions reporting from all sources with criteria emissions greater than 10 tons/year. Currently requiring all Title V operating permit sources to include GHG direct emissions as specified above. All oil and gas production and processing sources must report GHG emissions for 2010.	Direct emissions from motor and non road vehicles	For Part 87, electrical generating units equal to or greater than 25 MW. For Part 73, authority to require GHG reporting upon request for sources emitting greater than 10 tons of a criteria pollutant or VOC.	Fuel use and fuel type must be reported; biomass is not excluded from reporting.	As specified in reporting procedures, which are published outside of rulemaking and must be as consistent as feasible with other GHG programs.	Reporting procedures may specify simplified or limited reporting requirements for up to 5% of facility emissions.

Table A1 - Continued

Reporting Program/ Jurisdiction	Voluntary, Mandatory, C&T	Coverage (GHGs)	Sources/Sectors		Threshold(s) for Reporting	CO2 from Biomass Provisions	GWPs	De Minimis Provisions
			Included	Excluded				
OR	Mandatory	Direct emissions of CO_2, CH_4, N_2O ,HFCs, PFCs, and SF_6	• Sources required to obtain a Title V Operating permit, including those under OAR Chapter 340, Division 218 • Sources required to obtain an air contaminate discharge permit, including those under OAR Chapter 340, Division 216, referred by activities and sources, and by SIC codes (pg 3-4) • Any source listed below that does not have an air permit and emits ≥2500 t of CO2e: – Solid waste disposal facilities – Wastewater treatment facilities – Electric generating units – Electricity and natural gas T&D systems	Emissions from categorically insignificant activities, indirect emissions, and mobile source emissions (voluntary)		Not specified. (Note: although not specified in the rules, Oregon would follow The Climate Registry General Reporting Protocol (GRP) for reporting biomass emissions.)	IPCC Second Assessment Report (1995)	
WA	Mandatory (under development)	CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6	Stationary sources and mobile source fleets	None	Any source that emits ≥ 10,000 metric tons The owner/ operator of an on-road motor vehicle fleet that emits ≥ 2,500 metric tons	Required, reported separately (not considered in totals)	IPCC Second Assessment Report (1995)	To be included in the department rules

Table A1 - Continued

Reporting Program/ Jurisdiction	Voluntary, Mandatory, C&T	Coverage (GHGs)	Sources/Sectors		Threshold(s) for Reporting	CO2 from Biomass Provisions	GWPs	De Minimis Provisions
			Included	Excluded				
TCR Voluntary Program	Voluntary	CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6	All sectors are encouraged to report. Sectors must report Scope 1 and 2 emissions; scope 3 emissions are voluntary. • Scope 1: Direct emissions from stationary combustion, mobile combustion, physical and chemical processes (12 categories), and fugitive sources • Scope 2: Indirect emissions (e.g., electricity purchases) • Scope 3: Upstream/ downstream emissions	None	None	Required, CO2 reported separately.	IPCC Second Assessment Report (1995)	No concept of de minimis. Simplified techniques may be used for up to 5% of emissions
RGGI	Mandatory, C&T	CO2	Fossil fuel fired EGUs	• EGUs that commenced operation after 2005: <5% of heat input from fossil fuels • EGUs that commenced operation before 2005: <50% of heat input from fossil fuels • Sources that sell less than 10% of electricity generated to the grid. • Sources that sell less than 10% of electricity generated to the grid	Fossil-fuel fired EGUs with nameplate capacity ≥ 25 MW; low emitters excluded	CO2 emissions from biomass unit can be deducted. Excludes biomass mixed with other fuels and old growth timber	Consistent with IPCC	

Table A1 - Continued

Reporting Program/ Jurisdiction	Voluntary, Mandatory, C&T	Coverage (GHGs)	Sources/Sectors		Threshold(s) for Reporting	CO2 from Biomass Provisions	GWPs	De Minimis Provisions
			Included	Excluded				
Climate Leaders	Voluntary	CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6	• Onsite fuel consumption and energy use • Industrial process-related emissions (as applicable) • Onsite waste disposal • Onsite air conditioning/ refrigeration use • Indirect emissions from electricity/steam purchases • Mobile sources			CO2 emissions required, reported separately, not included in tracking progress toward reduction goals	Consistent with IPCC	None, but documentation is needed where emissions cannot be estimated
EU ETS	Mandatory, C&T	CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6	• Mineral oil refineries • Coke ovens • Metal ore roasting and sintering installations • Pig iron and steel • Cement clinker production • Lime production • Glass manufacturing • Ceramic products manufacturing • Pulp and paper production	Emissions from mobile internal combustion engines for transportation purposes	Originally proposed as 25,000 metric tons of CO2 (may be revised in the future)	Required, reported as memo item (not accounted for in total emissions), and amounts of biomass combusted	IPCC Second Assessment Report (1995)	2%, not to exceed 20,000 metric tons
UK ETS	Voluntary, C&T	CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6	Direct emissions from on-site combustion and industrial processes (7 categories), and indirect emissions from electricity generated on the grid		10,000 metric tons CO2e	CO2 from biomass energy excluded	Consistent with IPCC	1% of entity emissions

Table A1 - Continued

Statutory and Regulatory Citations, and References:

Environment Canada Section 71:
- Statutory: Canadian Environmental Protection Act (CEPA), 1999, Section 46 (Large Final Emitters), Section 71 (Reporting of GHGs and other substances)
- Regulatory: Requirements to be developed under CEPA, Section 93. http://www.ec.gc.ca/cleanair-airpur/Turning_the_Corner-WSF3084CB7-1_En.htm

Québec:
- Statutory: Québec Environmental Quality Act, Section 2.2, 109.1 and 124.1
- Regulatory: Regulation respecting mandatory reporting of certain emissions of contaminants into the atmosphere, *Gazette Officielle du Québec, October 17, 2007, Vol. 129, No. 42.*

U.S. Environmental Protection Agency:
- Statutory: Clean Air Act, Sections 114 and 208
- Regulatory: 40 CFR Part 98

California:
- Statutory: AB 32, the Global Warming Solutions Act of 2006 (Nunez, Chapter 488, Statutes of 2006)
- Regulatory: Sections 95100 to 95133, title 17, California Code of Regulations (CCR), adopted by the Air Resources Board at its December 6, 2007, public hearing (Note: This regulation is undergoing review and approval and is expected to become effective in the Fall of 2008.) http: http://www.arb.ca.gov/regact/2007/ghg2007/isor.pdf

New Mexico:
- Statutory: Environmental Improvement Act, NMSA 1978, Section 74-1-8(A)(4), and Air Quality Control Act, NMSA 1978, Sections 74-2-1 et seq., including specifically Sections 74-2-5(B)(1) & 74-2-(5)(C)(5)(d) & (e). [20.2.87.3 NMAC - N, 01/01/08]
- Regulatory: NMAC, Title 20, Chapter 2, Parts 2, 73, 87: http://www.nmcpr.state.nm.us/nmac/_title20/T20C002.htm

Oregon:
- Statutory: House Bill 3543 (2007)
- Regulatory: OAR 340, Division 215: http://www.deq.state.or.us/aq/climate/rulemaking.htm, http://www.deq.state.or.us/aq/climate/docs/oar.pdf

Washington:
- Statutory: House Bill 2815 (2/12/08), http://apps.leg.wa.gov/documents/billdocs/2007-08/Pdf/Bills/House%20Passed%20Legislature/2815-S2.PL.pdf
- Regulatory: Requirements to be developed.

RGGI: http://www.rggi.org/docs/model_rule_corrected_1_5_07.pdf
The Climate Registry: http://www.theclimateregistry.org/downloads/GRP.pdf
Climate Leaders: http://www.epa.gov/climateleaders/resources/index.html
EU ETS GHG emissions monitoring and reporting guidelines and protocols: http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=CELEX:52008PC0017:EN:NOT
UK ETS: http://www.defra.gov.uk/environment/climatechange/trading/

Table A2. Comparison Matrix of Existing and Imminent General Reporting Requirements for WCI Jurisdictions and Related Programs: Verification and Quality Assurance

Reporting Program/ Jurisdiction	Verification Requirements	Approach to Verification	Requirements for Verifiers	Schedule and Deadlines	Accreditation Procedures
Canada (EC) (Section 71)	Phase 1: No specific requirements for third party verification for 2005 GHG emissions, as long as the information reported is verifiable and verification is retained.				
Québec	Third party verification is not required.	The province performs its own verifications. All the information reported by the facilities is analyzed in relation with the previous year's data. Calculation is verified with the fuels used, production levels, raw materials and emission factors provided by sources. Occasional site visits can be performed.			
U. S. EPA	Verification requirements currently unknown; mandatory reporting rule will not be proposed until September 2008				
CA (ARB)	Operators may use the same verification body for both CCAR and ARB emission data report if operators are already members of CCAR and verification body is accredited by ARB and CCAR. **Annual verification**: Annual submission of the verification opinion for: • Retail providers, marketers, and operators of petroleum refineries and hydrogen plants • Operators of general stationary combustion (GSC) facilities in oil and gas sector • Operators of electric generating and cogeneration facilities that combust fossil fuels and are rated ≥10 MW Verification: • Upon positive verification opinion under full verification requirements, operator may choose less intensive verification services, but full verification shall apply at least once very 3 years • Shall not use the same verification body for more than 6 consecutive years **Triennial verification:** Triennial verification and submission of the verification opinion for: • Cement plants	• Site visit during the first year • Development of verification plan • Development of sampling plan • Data checks • Verification opinion submitted to ARB	Strict accreditation requirements including mandatory years of experience and successful completion of ARB training All verification agreements are subject to conflict-of-interest determination Procedure: • Submit Notice of Verification Services to ARB • Begin services 10 or more days after executive officer receives the notice • Notice include information: staff of the verification team • Documentation of required verification skills of the verification team (A,B,C) Conflict of Interest (COI) Requirements: • ARB will approve verification teams before verification activities take place. Teams must demonstrate acceptable	Verification is optional in 2009 and required in 2010 for all reporting facilities. Schedule: • October 1st for reports due April 1st • December 1st for reports due June 1st Verification body shall submit the opinion to ARB within 6 months of the emissions report, in the same year	Rigorous accreditation requirements consistent with ISO standards and other programs (pre-screening and training)

Table A2 - Continued

Reporting Program/ Jurisdiction	Verification Requirements	Approach to Verification	Requirements for Verifiers	Schedule and Deadlines	Accreditation Procedures
	• Electricity generating or cogeneration facilities that combust pure biomass fuel or geothermal generating facilities • Electricity generating and cogeneration facilities with a capacity ≤10MW • GSC facilities excluding oil and gas sector Verification: • May choose to obtain less intensive verification services for the 2 years following completion of full verification services and prior to the next three-year cycle. • Cannot use the same verification body for more than two consecutive verification cycles.		level of COI and expertise for verifying the facility they contract with. • Term Limit: Verification body to be changed after 6 years of verification services (two cycles). Allowed to resume with client after 3 years off (one cycle). • COI Policy: Verification body and verifier may not provide both consulting and verification services within a 3-year period.		
NM	Third party verification is not required. Owners/operators required to report may choose to register and verify their emissions with TCR or CCAR providing the department has access to the information.				
OR	Use existing verification method: Self-certification with periodic inspections by DEQ and Lane Regional Air Pollution Authority (LRAPA) inspectors.	Verification methodology includes: • Strategic analysis • Risk analysis • Verification • Internal verification report • Verification report			
WA	Verify compliance in accordance with department rules.				
TCR Voluntary Program	Third party verification is required.	• Assess conformance with TCR requirements • Assess completeness to ensure all sources are identified and emissions are quantified • Review methodologies and systems in place to prevent data collection, data handling, and calculation errors. • Implement a sampling plan and conduct site visits • Verify that available information supports emission estimates	Firms submit application and qualification packages to the American National Institute of Standards (ANSI). ANSI conducts site visits COI Requirements: • A key factor in relation to the delivery of verification services is the ability of the Verification Body to be independent and impartial. • The verification body must demonstrate that it undertakes a robust COI assessment for each and every verification	Emission reports due June 30; verification reports due December 15.	TCR has partnered ANSI; ensures consistency with ISO 14065:2007 and ISO 14064-3:2007, as well as TCR calculation and reporting requirements. TCR oversight panel monitors the ANSI accreditation process.

Table A2 - Continued

Reporting Program/ Jurisdiction	Verification Requirements	Approach to Verification	Requirements for Verifiers	Schedule and Deadlines	Accreditation Procedures
			engagement by delivering in a timely manner to the Registry the completed COI Assessment Form (see the Registry's *General Verification Protocol*) and responding to any queries that the Registry or its partner accreditation bodies might have as a result of their review of the Assessment Form. • Where subcontracted verifiers are used, the verification body must assess their competencies against those identified by the verification body in its competency needs evaluation, obtain a signed agreement from the subcontractor in relation to the use of accredited verification processes and procedures, and obtain a signed agreement in relation to the maintenance of confidentiality and a declaration of conformance to COI and impartiality requirements.		
RGGI	Allows first party (i.e., self) verification; third party verification required for offset project sponsors only		Regulatory agencies may accredit independent verifiers. Verifiers must demonstrate knowledge in quantifying GHG emissions and developing and evaluating air pollutant emission inventories. COI Requirements: • Prior to engaging in verification services for an offset project sponsor, the accredited verifier shall disclose all relevant		Regulatory agencies may require training or testing for accreditation.

Table A2 - Continued

Reporting Program/ Jurisdiction	Verification Requirements	Approach to Verification	Requirements for Verifiers	Schedule and Deadlines	Accreditation Procedures
			information to the Regulatory Agency to allow for an evaluation of potential COI with respect to an offset project, offset project developer, or project sponsor. The verifier shall disclose information concerning its ownership, past and current clients, related entities, and any other facts or circumstances that have the potential to create a COI. • Accredited verifiers shall have an ongoing obligation to disclose to the regulatory agency any facts or circumstances that may give rise to a COI with respect to an offset project, offset project developer, or project sponsor. • The regulatory agency may reject a verification report and certification statement from an accredited verifier if the regulatory agency determines that the accredited verifier has a COI related to the offset project, offset project developer, or project sponsor. • The regulatory agency may revoke the accreditation of a verifier at any time given cause.		
Climate Leaders	Third party verification is not required.				
EU ETS	Reports are verified in accordance with the detailed requirements established by member state.	• Assess sources, data, and calculation procedures • Develop a verification plan (including a sampling plan) • Conduct site visits • Prepare verification reports	European Standard EN45011 provides criteria for accreditation of verifiers and for conducting the verification process.	Verification report due March 31 for previous calendar year.	Some member states have a national accreditation body, others have independent accreditation services that certify verifiers, and

Table A2 - Continued

Reporting Program/ Jurisdiction	Verification Requirements	Approach to Verification	Requirements for Verifiers	Schedule and Deadlines	Accreditation Procedures
		(internal and submitted to member state)	COI Requirements: Not specified		others require an exam.
UK ETS	Independent third party verification is required.	Verify the following: • Responsibilities for data collection, aggregation, and quality control • Existence of appropriate tools or procedures to support consistency in data estimation • Methods for systematic data archiving and process documentation • Processes for internal audit, data checking, and quality assurance • Processes for corrective actions • Clearly articulated methods of data interpretation • Processes for periodic review of the data management system	United Kingdom Accreditation Service (UKAS) accreditation (http://www.ukas.com/) COI Requirements: Not specified		UKAS accreditation required

Table A3. Comparison Matrix of Existing and Imminent General Reporting Requirements for WCI Jurisdictions and Related Programs: Reporting

Reporting Program/ Jurisdiction	Year Reporting Commences	Reporting Deadline	Initial Reporting Year Requirements	Reporting Procedures	Record Retention Requirements	Release of Reports	Confidentiality	Noncompliance Penalty	Other Requirements
Canada (EC) (Section 71)	2008 for 2006 emissions.	May 31	Facility and parent company identification and contact information.	Sector-specific	Three years	Minister of Environment will publish GHG totals by gas by facility, unless facility requests confidentiality. Non-confidential data will be published by Statistics Canada subject to laws.	Confidential Information will not be disclosed (written request is required) except in accordance with provisions of CEPA1999 and the access to information act.	Under section 272 of CEPA 1999, may be subject to fines, imprisonment or both (Environment Canada's enforcement and compliance policy).	Administrative information of the operator and source/facility required, as well as a signed statement of certification.
Québec	2008 for 2007 emissions	June 1	None specified.	Requirements include: • Submit separate reports for each facility. • Identify separately activities, processes, or equipment that are the sources of emissions. • Report quantities of fuels, raw materials used and volume of production. • Use forms provided. • Report all data otherwise reported to the EC Minister under public notices given related to Section 46 of the Canadian environmental Protection Act (1999). • Use best data available, and one of these methods: − Emission source sampling;	Minimum of 5 years	Not specified.	Information that is necessary to calculate the quantity of the contaminants emitted, such as data pertaining to production, fuels, raw materials, equipment and processes, is considered confidential.	Failure to submit is liable to a fine of: • $2,000 to $12,000 (natural person) • $5,000 to $25,000 (legal person) Second offenses are doubled.	Facility identification information, emission factors and a conformity report.

Table A3 - Continued

Reporting Program/ Jurisdiction	Year Reporting Commences	Reporting Deadline	Initial Reporting Year Requirements	Reporting Procedures	Record Retention Requirements	Release of Reports	Confidentiality	Noncompliance Penalty	Other Requirements
				– Sampling and CEMS; – Emission estimation model; – Calculation that may include the use of an emission factor published in the scientific literature or documentation specific to the enterprise, facility or establishment; – Mass balance; or – Predictive emission monitoring.					
U.S. EPA	Reporting requirements currently unknown; mandatory reporting rule will not be proposed until September 2008								
CA (ARB)	2009 for 2008 emissions	April 1 : • General stationary combustion (GSC) facilities excluding oil and gas • Electricity generating facilitates and cogeneration facilities not under other operational controls June 1 : • Retail provider	Use methods specified in regulation. For each GHG source specified in the regulation, provide GHG emission estimates, fuel use, and other data identified in the regulation. If during the first year data are not available to implement the full regulatory methods or data reporting requirements, use the best available data for estimating GHG emissions and provide other specified data for those sources with incomplete data.	General requirements include: • Calculate and report each GHG separately for each fuel type used • Monitor and report fuel consumption for the facility and for each process unit or group of units where fuel use is separately metered. • Quantify fuel use with accuracy within ± 5%. • Procedure provided for addressing equipment breakdowns of fuel analytical data monitoring equipment. • Report separately consumption of purchased/acquired electricity, heat, cooling, or steam – no emissions attached.	• Retain reporting records for minimum 5 years • Establish and maintain procedures for records retention • The retained documents including emissions data should be sufficient for verification • Upon request by ARB, all retained documents including data are to be provided within 20 working days • Retain a listing of specific	By statue, all submitted emissions data are public information. Emissions data will be released to the public through web-based reporting and other methods. Other facility information submitted to ARB under the reporting program (e.g., fuel use, process data, etc.) may be designated	All emissions data is public information, any may not be designated as confidential. Reporters may designate non-emission data as confidential during reporting. Third-party requests for submitted data designated as confidential will be handled in accordance with California code of regulations. When requests for confidential data are received, facility operators must provide justification to the ARB for their [illegible]	Failure to submit, knowing submission of false information, late submittal constitute a single separate violation.	Administrative information of the operator and source/facility is required, as well as a signed statement of certification. Web-based interactive tool provided for mandatory GHG facility emissions reporting, facility operator registration, initial QA/QC, reporting progress tracking, verifier relationship tracking, and other functions.

Table A3 - Continued

Reporting Program/ Jurisdiction	Year Reporting Commences	Reporting Deadline	Initial Reporting Year Requirements	Reporting Procedures	Record Retention Requirements	Release of Reports	Confidentiality	Noncompliance Penalty	Other Requirements
		s, • Marketers • GSC facilities within oil and gas sector, • Cement plants • Petroleum refineries • Hydrogen plants		• Obtain a specified fuel analytical data capture rate. • Other requirements are sector dependent.	information for at least 5 years (A-31,32)	as confidential by the facility operator.	confidential data designations to avoid release of the data.		
NM	2009 for 2008 emissions	• July 1 for Part 87 sources. • April 1 or with operating permit emissions report for Part 73 sources.	Direct emissions of CO2	Regulations establish guidelines for development of Reporting Procedures by the department. Procedures must be as consistent as feasible with quantification methods accepted by TCR/CCAR and include: • Recommended calculation methods, conversion factors, and report of supporting data used. • Alternate methods that are available and appropriate. • Means for simplified and limited documentation of CO_2e that collectively account for 5% or less of total facility emissions. • Means to document calculation methods, if different from the proposed tool. • Amounts of fuel use and specifications of	Minimum of 5 years	By statute, all emissions reports are public information. Supporting information may be designated confidential under certain circumstances.		Penalty not to exceed $15,000 per day per violation (NM Air Quality Control Act, section 74-2-12).	• Administrative information of the operator and source/ facility required, as well as a signed statement of certification. • Use reporting tool and procedures provided by the department, except for the persons registering and verifying with TCR or CCAR.

Table A3 - Continued

Reporting Program/ Jurisdiction	Year Reporting Commences	Reporting Deadline	Initial Reporting Year Requirements	Reporting Procedures	Record Retention Requirements	Release of Reports	Confidentiality	Noncompliance Penalty	Other Requirements
				each fuel type, directly related to reported emissions • Calculations for each GHG and means to sum all emissions in CO_2e metric tons, including emissions from regular operation and events such as startup, malfunction. • A listing including percentages of the owners of equity shares of the emissions reported. • Report of the county where facilities are located, for emissions from facilities within the jurisdiction. • For emissions from facilities located on tribal lands, another state or another country, report the tribe, identification of the state or the country.					
OR	2010 for 2009 emissions (2011 for 2010 for sources not under Title V and Air Permits with >2500 metric tons of emissions)	Same as Title V or Air Contaminant Discharge Permit report, or March 15	None	• Any source not required to register and report emissions may do so voluntarily. • GHG emissions pursuant to department approved protocols including estimated annual emissions, activity data, emissions factors, conversion factors, GWP factors and calculation methods.	Minimum 5 years	Not specified	Not specified in these rules, but data would be subject to Oregon Public Records Law.	Not specified in these rules, but would be subject to DEQ enforcement rules.	• Administrative information of the operator and source/facility required, as well as a signed statement of certification. • Registration and reports must be submitted on paper or electronic forms issued by the department.

Table A3 - Continued

Reporting Program/ Jurisdiction	Year Reporting Commences	Reporting Deadline	Initial Reporting Year Requirements	Reporting Procedures	Record Retention Requirements	Release of Reports	Confidentiality	Noncompliance Penalty	Other Requirements
WA	2010 for 2009 emissions. (May phase in largest sources first until Jan. 1st, 2012 when all sources at or above the 10,000 metric tons threshold must be in.)	Oct 31	None	• Requires owner/operator of air contaminant sources of any class to register and report • Reporting consistent with the federal government rules and/or other established protocols. State rules when adopted will clarify.	Not specified	Not specified		Any persons failing to report or pay the required fee may be subject to enforcement penalties.	Administrative information of the operator and source/facility required, as well as a signed statement of certification.
TCR Voluntary Program	First year specified by reporter and may include historical data from as far back as 1990	June 30 data submission required within CRIS	May opt for transitional reporting for up to 2 years (CO2 and for one state at a minimum)	• Protocols currently being developed for various industries • Reporters may opt to report worldwide and scope 3 emissions • Emissions not made public until data verified by third party	Historical data submitted and verified will be held indefinitely unless company requests removal of data from CRIS.	Data visible to public for all reporters at facility level except those that apply for CBI status and roll-up to state level	Data are transparent at the facility level for reporters. Allowances for CBI reasons that allow data to be rolled up at the state level (CO_2e) which must be applied for annually.	None	Administrative information of the operator and source/facility required.
RGGI	2009	March 1		Each CO2 budget source must submit an output monitoring plan. All emissions monitoring information; copies of all reports, compliance certifications, and other submissions and all records made or required under the CO2 Budget Trading Program; copies of all documents used to complete a CO2 budget permit application and other submission under the CO2 Budget Trading Program or to demonstrate compliance with the requirements.	10 years	No specific provisions; intention is for information to be publicly available	Varies by state	Varies by state	• Signed statement of certification required. • Quarterly electronic reports with emissions, operating parameters, and quality assurance test data.

Table A3 - Continued

Reporting Program/ Jurisdiction	Year Reporting Commences	Reporting Deadline	Initial Reporting Year Requirements	Reporting Procedures	Record Retention Requirements	Release of Reports	Confidentiality	Noncompliance Penalty	Other Requirements
Climate Leaders	Within one year for new partners	June 30	Partners complete and maintain an Inventory Management Plan (IMP): • Partner Information: company name, address, contact information • Boundary Conditions: organizational and operational boundary descriptions • Emissions Quantification: quantification methodologies, emission factors • Data Management: data sources, collection process, QA assurance • Base Year: adjustments for structural and methodology changes • Management Tools: roles and responsibilities, training, file maintenance; Auditing & Verification: auditing, management review, corrective action	Base year and annual GHG emissions (CO2 equivalents). inventory management plan documenting GHG estimation approaches, factors, and data sources that will be used.	Not specified, but policy must insure data are maintained long enough to adjust base year emissions in goal year, if needed	Partners commit to reporting annual inventory data and documentin g progress towards their reduction goal, and to publicize their participation , reduction goal, and accomplish ments achieved through the program.	Not specified; partners probably do not submit confidential data	None	
EU ETS		March 31	None	Data identifying the installation and its permit	• Document and archive	Emission reports held	Operators may indicate in their		Administrative information of

Table A3 - Continued

Reporting Program/ Jurisdiction	Year Reporting Commences	Reporting Deadline	Initial Reporting Year Requirements	Reporting Procedures	Record Retention Requirements	Release of Reports	Confidentiality	Noncompliance Penalty	Other Requirements
		A monitoring plan approved by the competent authority is required before reporting.		number. • Total emissions; chosen approach, tiers and methods. • Other items that are not accounted for emissions reported as memo items. • If emission factors and activity data for fuels are related to mass instead of energy, report supplementary proxy data for the annual average net calorific value and emission factor for each fuel. • If a mass balance approach applied, report the mass flow, carbon and energy content for each fuel, material stream in/ out of the installation and their stocks. • If continuous emissions applied, report annual CO2 emissions from fossil and biomass use, and other supplementary proxy data. • If a fall back approach applied, report supplementary proxy data for every parameter. • Where fuel use occurs, but emissions are calculated as process emissions, report supplementary proxy data for variables of the default emissions calculation for combustion	monitoring emission data. • Monitoring data shall be sufficient for verification. • Retain the list of information for minimum 10 years.	by the competent authority should be made available to the public subject to the rules.	report for information considered commercially sensitive.		the operator and source/facility required, as well as a signed statement of certification.

Table A3 - Continued

Reporting Program/ Jurisdiction	Year Reporting Commences	Reporting Deadline	Initial Reporting Year Requirements	Reporting Procedures	Record Retention Requirements	Release of Reports	Confidentiality	Noncompliance Penalty	Other Requirements
				emission. • Temporal or permanent changes of tiers, reasons, starting, ending dates for these changes. • Any other relevant changes.					
UK ETS	2002 (ended 2006)	March 31	A direct participant must submit his source list to the Secretary of State for approval	A direct participant must submit to the Secretary of State a statement of baseline emissions together with a signed verification opinion in relation to his original baseline.	Two years after the end of the final commitment year	Monitoring plan, annual verification statement, and official annual reports published	Unless otherwise agreed any adjudication will be conducted and any adjudication report issued on an open basis.	Participant's statement of emissions or verification opinion for that commitment year is invalid in whole or in part.	Signed statement of certification required Electronic Emissions Trading Registry used to record the allocation, holding, transfer, cancellation and retirement of allowances.

July 23, 2008 Draft Essential Requirements of Mandatory Reporting

List of Commenters

Alcoa

APX, Inc.

Ash Grove Cement Company

Associated Oregon Industries

BC Forestry Climate Change Working Group

BP America, Inc.

Bullfrog Power, Inc.

Canadian Association of Petroleum Producers

Carbon Disclosure Project

Public Utility District No. 1 of Chelan County

El Paso Corporation

Northern California Power Agency

Pacific Gas and Electric Company

Salt River Project

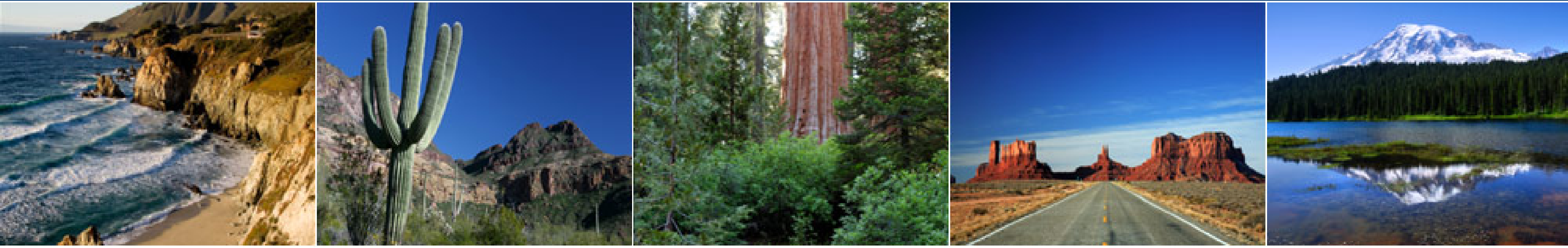
Sempra Energy

Smurfit-Stone Container Enterprises, Inc.

Spectra Energy Transmission

Western States Petroleum Association

Western Climate Initiative

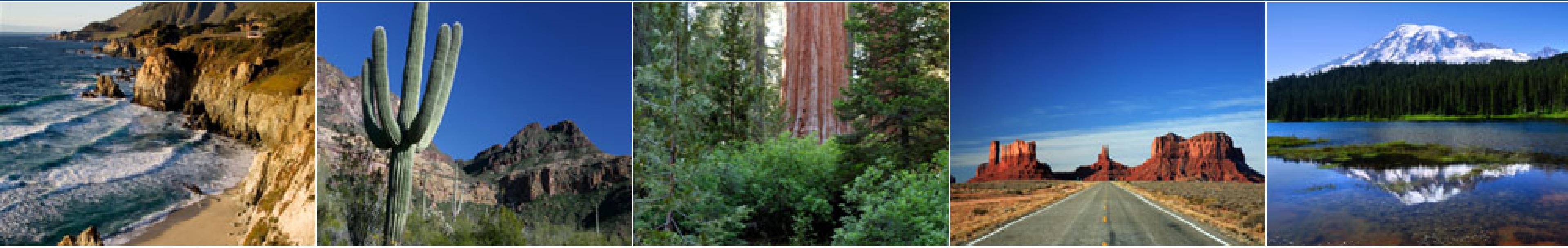


Welcome

July 29, 2008

San Diego, California

Western Climate Initiative



WCI Overview and Status

July 29, 2008

San Diego, California

Western Regional Climate Action Initiative (WCI)

Partner

Observer

Initiative Collaboration Includes

Three specific directives:

- Set a regional emissions reduction goal
- Join a multi-state registry to track, manage and credit reductions
- Design a regional multi-sector market-based mechanism

Joint work to:

- Promote clean and renewable energy in the region
- Increase energy efficiency
- Advocate for regional and national climate policies that are in the interest of western states
- Identify measures to adapt to climate change impact

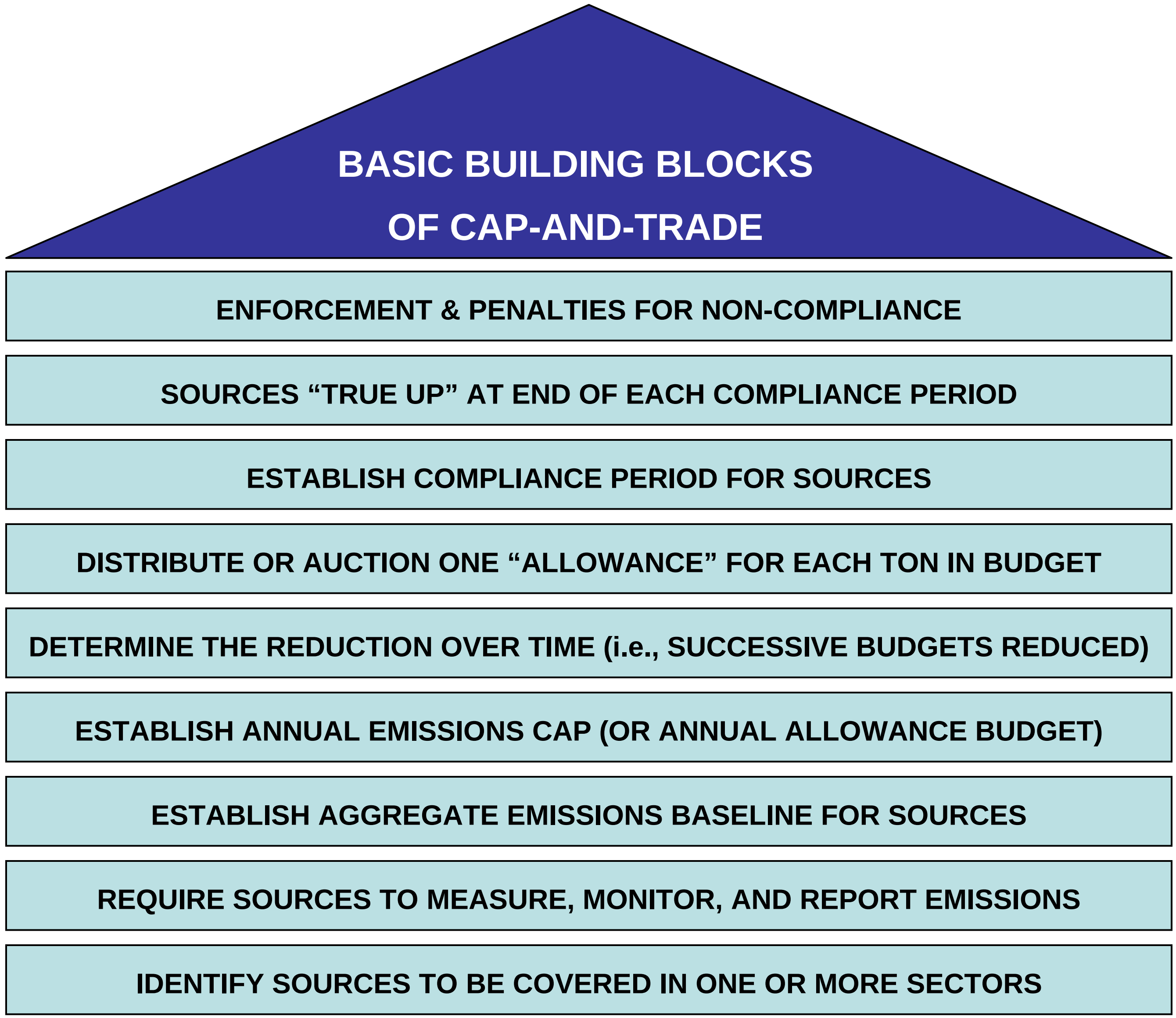
Why Regional Action

- Each WCI partner supports a comprehensive approach to reducing greenhouse gas emissions
- Each has its own reduction goals and is taking steps to implement
- The WCI jurisdictions are particularly vulnerable to climate impacts
- Western US and Canadian partners have a long history of energy efficiencies and renewable energy
- Climate change requires action now – we cannot afford to wait

By leading, we can help ensure the WCI perspective is included in future federal (US and Canadian) action

Why Cap and Trade

- Emission reductions are certain compared to tax
  - Cap sets reduction; tax sets cost
- Lets the market find lowest cost reductions
  - Cost effective for covered sources
- Clean Air Act is largely technology driven
  - Technologies for carbon capture are not widely available
- Cost effective to implement
  - Individual emission permits not required


BASIC BUILDING BLOCKS
OF CAP-AND-TRADE
ENFORCEMENT & PENALTIES FOR NON-COMPLIANCE
SOURCES “TRUE UP” AT END OF EACH COMPLIANCE PERIOD
ESTABLISH COMPLIANCE PERIOD FOR SOURCES
DISTRIBUTE OR AUCTION ONE “ALLOWANCE” FOR EACH TON IN BUDGET
DETERMINE THE REDUCTION OVER TIME (i.e., SUCCESSIVE BUDGETS REDUCED)
ESTABLISH ANNUAL EMISSIONS CAP (OR ANNUAL ALLOWANCE BUDGET)
ESTABLISH AGGREGATE EMISSIONS BASELINE FOR SOURCES
REQUIRE SOURCES TO MEASURE, MONITOR, AND REPORT EMISSIONS
IDENTIFY SOURCES TO BE COVERED IN ONE OR MORE SECTORS

WCI Design Principles

- Equitable, administratively simple, clear compliance path
- Maximize total benefits and avoid localized or disproportionate environmental or economic impacts
- Advance economic, environmental, and public health objectives;
- Real, verifiable, enforceable reductions
- Stimulate investment and reward innovations
- Encourage reductions beyond capped sectors/sources
- Recognition/incentives for early reductions
- Transparent and robust accounting system
- Minimize potential for leakage
- Facilitate links to other systems

WCI Organization

- Scope
  - Gases, Sectors and sources, points of regulation
- Electricity
  - Point of regulation
- Allocations
  - Starting point and 2020 cap
  - Establishing partner allowance budget methodology
- Reporting
  - Required elements including verification
  - Coordination with The Climate Registry and EPA
- Offsets
  - Project types and limits (% and/or geographic)
- Legal Team

Draft Design Recommendations

- Six primary greenhouse gases
- Starting dates and thresholds
  - Reporting
  - Cap and Trade
- Sectors and Points of Regulation
- Cost Containment (in addition to cap and trade)
  - Offsets
  - Banking but no borrowing
  - Three year compliance periods
- Role of other policies
- Program expansion

Draft Design Recommendations (cont.)

- Methodology to develop starting cap
- Distribution of allowances
- Regional organization
  - Shared administrative functions
  - Monitor market
  - Conduct auctions
  - Approve offsets
- Enforcement
  - Three tons for every one ton short
  - Commitment to provide technical assistance

Design issues still to come

- Partner budget - or share - of regional allowances
- Common reporting elements
  - Draft released July 23, 2008
- Specifics around first jurisdictional deliverer
- Implementation schedule, including development of model rule

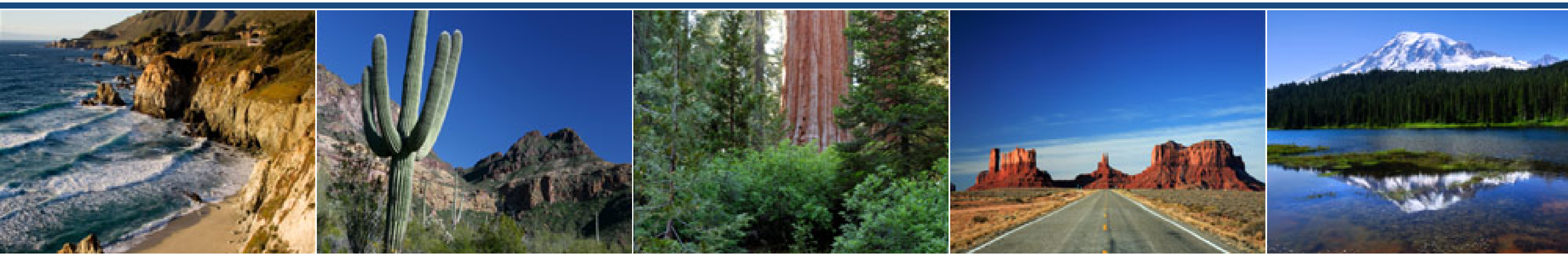
Timeline

- Draft initial design (policy framework)
  - July 23
- Submit comments on draft design by August 13 (through WCI website)
  - Follow outline of the draft when commenting: Will make it easier to quickly analyze comments
- "Final" design recommendations (policy framework)
  - Expect to release week of September 22

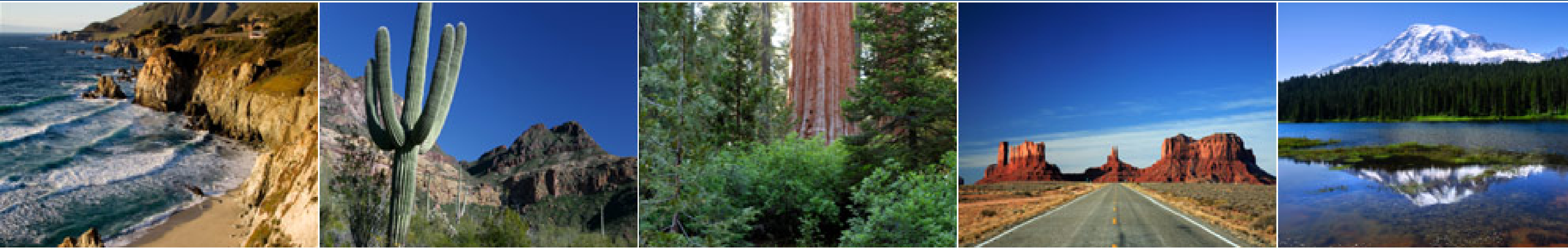
Timeline

- Continued work by WCI Partners to refine design
  - September thru December 2008
  - Further stakeholder involvement during this time period
- 2009 and beyond:
  - Obtain necessary legislative authority
  - Work on model rules and other implementation issues
  - Other complimentary policies of common interest

Comments and Questions



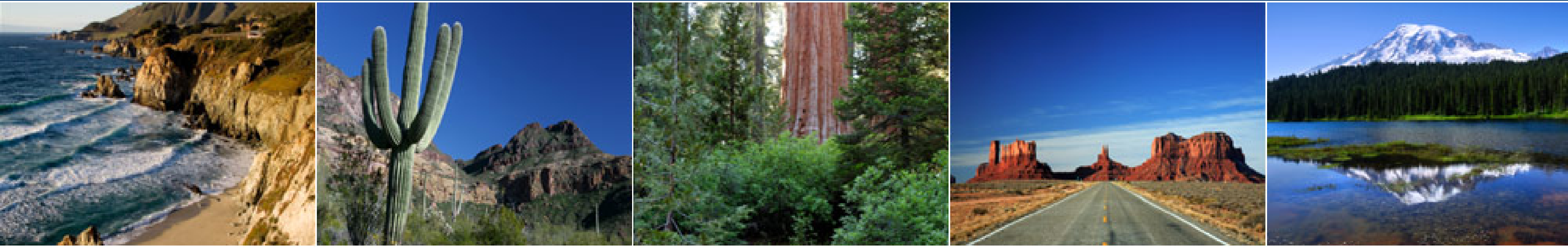
Break



Next Up

Scope Recommendations

Western Climate Initiative



Scope Recommendations

Michael Gibbs, Cal/EPA

Scope Subcommittee, Chair

July 29, 2008

San Diego, California

Overview

- Mission
- Process
- Recommendations
- Electric Sector

Mission

- Recommend the scope of a proposed cap and trade program:
  - The sectors that fall under the cap.
  - The emissions sources that fall under the cap.
  - The greenhouses gases that fall under the cap.
  - The point(s) of regulation where the cap would be enforced.

Mission (Continued)

- Balance multiple objectives, consistent with the WCI design principles
  - …administratively simple …
  - …minimizes administrative costs…
  - …covers as many sources as is practical…
  - …minimizes the potential for leakage…
  - …facilitates linkage…

Mission (Continued)

- Evaluate:
  - Emissions
  - Ability to measure/calculate emissions at the entity level
  - Administrative feasibility
  - Risk of emission leakage

Process

- Work Plan: October 2007
- Major Options: January 2008
- Workshop: January 2008
- Conference Call: February 2008
- Draft Recommendations: March 2008
- Conference Call: March 2008
- Workshop: May 2008
- Written comments throughout

Recommendations

- Greenhouse gases covered:
  - Carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride.

Recommendations

- Emissions covered:
  - Electricity generation, including emissions from electricity imported into WCI jurisdictions from non-WCI jurisdictions
  - Combustion at industrial and commercial facilities
  - Industrial process emission sources, including oil and gas process emissions
  - Residential, commercial, and industrial fuel combustion
  - Transportation fuel combustion from gasoline and diesel

Recommendations

- Quantification methods:
  - Adequate quantification methods will be established for emissions sources prior to including them in the program
- Threshold:
  - 25,000 metric tons of CO_2e annually
  - Applies to facilities or entities with a regulatory compliance obligation under the cap-and-trade program
  - Additional analyses to ensure sufficient coverage or to address competitiveness issues

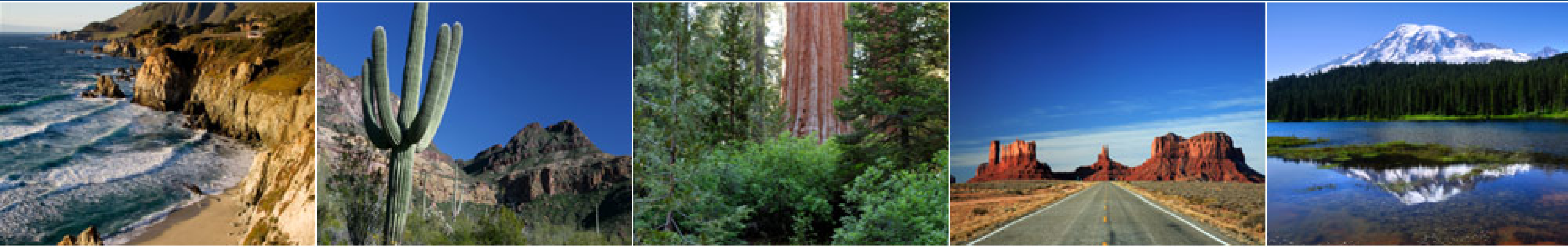
Recommendations

- Points of Regulation: Entities and Facilities
  - Industrial sources (both process and combustion) with emissions above the threshold: At the point of emission
  - Electricity: First Jurisdictional Deliverer
  - Residential, commercial, and industrial fuel combustion at facilities with emissions below the threshold: Where the fuels enter commerce in the WCI Partner jurisdictions
  - Transportation fuel combustion: Where the fuels enter commerce in the WCI Partner jurisdictions

Recommendations

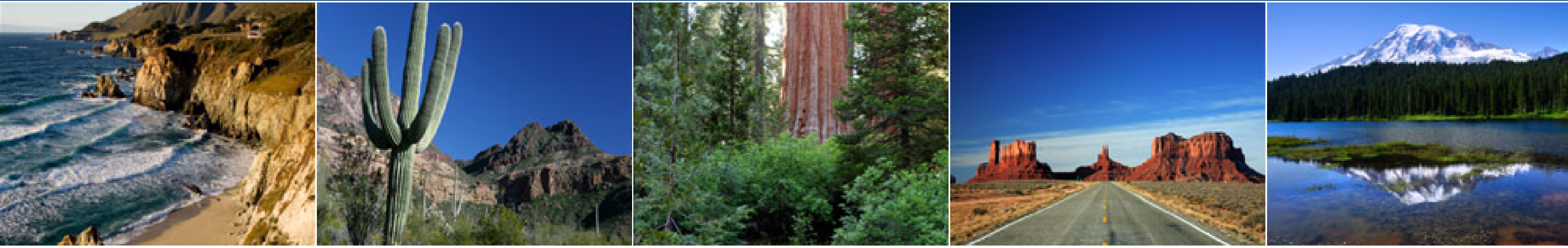
- Future Program Expansion
  - The WCI Partners recommend that the scope of the cap-and-trade program be capable of expanding over time (including possibly adjusting applicability thresholds over time).

Comments and Questions



Next Up

Allocations Recommendations



Draft Allocations Design Recommendations

Steve Owens
Arizona Dep’t of Environmental Quality

July 29, 2008
San Diego, CA

Regional Cap

- The regional cap will be equal to the sum of the Partner allowance budgets.
- The initial regional cap and Partner allowance budgets will be set through 2020.
- 2012: The initial cap will be set at the best estimate of actual emissions for sources covered in the initial year of the program.
- 2015: Expected actual emissions from transportation fuels and residential, commercial & industrial fuels will be added.
- 2020: Cap will set so that reductions achieved by the cap plus reductions from other GHG reduction policies will achieve the WCI regional goal.

Regional Cap

- The regional cap that will decline over time, and each Partner will have an allowance budget within the cap.
- Once established, the regional cap for each compliance period will not be adjusted except as necessary to account for:
  - Changes in WCI membership
  - Changes in scope or thresholds
  - Errors discovered in data used to determine the cap, which may become apparent, for example, after the start of mandatory reporting
- Any adjustments to the regional cap will be made prior to the beginning of the compliance period.
- Post-2020 caps: The Partners will set these regional caps not less than three years in advance.

Partner Allowance Budgets

- The Partners will develop a recommended methodology for calculating the Partner allowance budgets by Fall 2008.
- For post-2020, allowance budgets will be set not less than three years in advance.
- Once established, each Partner’s allowance will not be adjusted except as necessary to account for:
  - Changes in WCI membership
  - Changes in scope or thresholds
  - Errors discovered in data used to determine the cap, which may become apparent, for example, after the start of mandatory reporting

Distribution of Allowances

- Once the allowance budget has been established for each Partner, allowances will be issued by each Partner within its own jurisdiction.
- A minimum percentage of the value of each Partner's allowance budget may be dedicated to one or more of the following public purposes:
  - Energy efficiency and renewable energy incentives and achievement
  - Research, development, demonstrations & deployment with particular reference to carbon capture & sequestration; renewable energy generation, transmission and storage; and energy efficiency
  - Promoting emission reductions and sequestration in agriculture and forestry and other uncapped sources
- The remaining percentage of Partner allowance budgets will be distributed as each Partner sees fit.

Distribution of Allowances (cont.)

- Each Partner will be required to advise the other WCI Partners how it intends to allocate the remaining allowances, so that the WCI can make the Partners' plans public in a coordinated fashion.
- Any Partner that chooses to hold allowances must allocate or retire those allowances by the end of the applicable compliance period.
- The issue of establishing a minimum percentage of allowances subject to auction is still under discussion.
- To address competitiveness issues between WCI jurisdictions, the Partners will consider standardizing the distribution of allowances over time.

Banking, Borrowing & Compliance Periods

- Banking: Purchasers and covered entities will be allowed to bank allowances without limitation, except to the extent that restrictions on the number of allowances any one party may hold are necessary to prevent market manipulation.

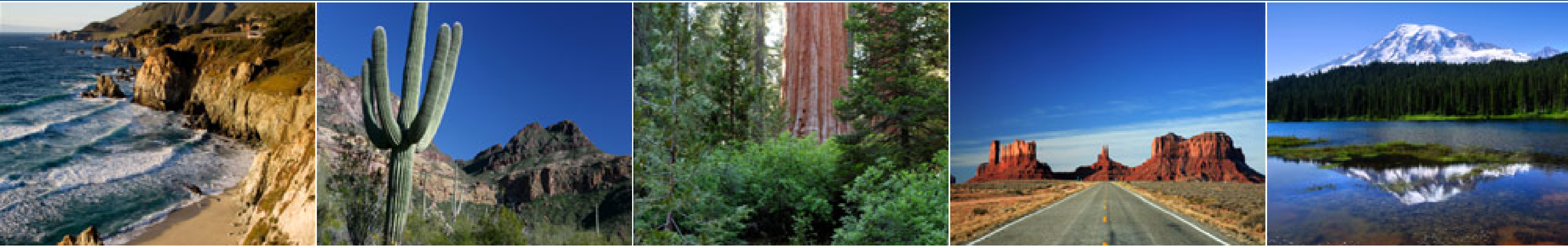
- Borrowing: Borrowing of allowances from future compliance periods will not be allowed.

- Compliance Periods: Each compliance period will be three years long.

New Partners

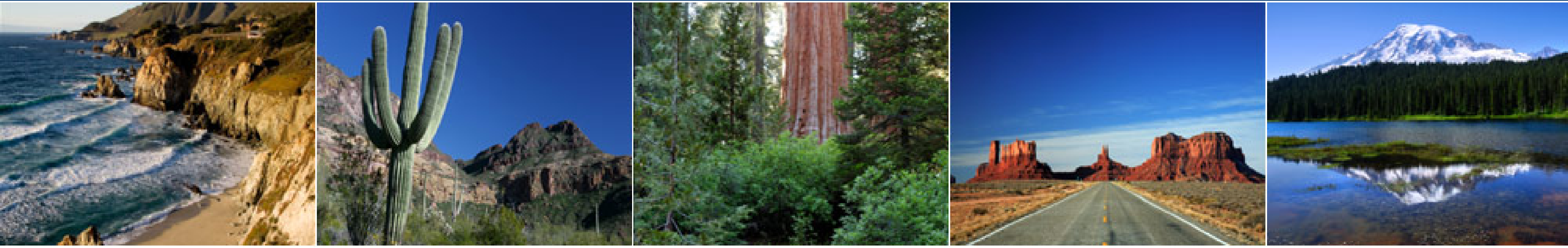
- The determination of allowance budgets for new Partners will take into account:
  - The WCI regional goal
  - Allowance budgets for existing Partners
  - The share of the new Partner's budget that is already included through the WCI's provisions covering imported electricity
  - The apportionment methodology (still being developed)
- New Partners will come into the cap-and-trade program at a regionally coordinated and designated time, such as the beginning of the relevant compliance period.
- A new Partner must have adopted an economy-wide GHG reduction goal for 2020 that reflects a level of effort that is consistent with that of the WCI Partners.

Comments and Questions



Lunch Break

(Reconvene at 1:00)



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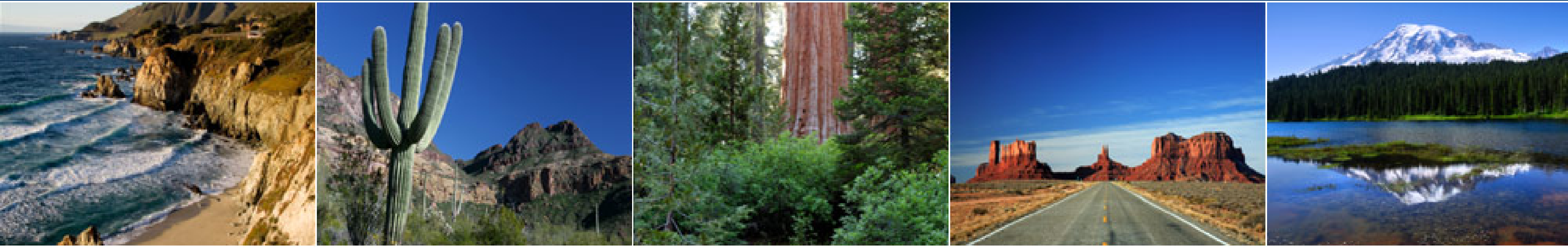
Offsets Recommendations



Offsets Recommendations

Tim Lesiuk
Province of British Columbia
Offsets Subcommittee, Chair

July 29, 2008

San Diego, California

Offsets and Allowances from other systems

- The WCI Partners will include a rigorous offsets system. The primary role of the offsets system is to reduce the compliance costs for the cap-and-trade program, while ensuring the environmental integrity of the cap.
  - *Strong stakeholder support for including an offset program.*
  - *Strong stakeholder desire for offset program to focus on reducing overall cost of targets through reduced compliance costs for emitters, reduced economic impact for consumers, and increased economic opportunities to encourage emission reductions.*
  - *Strong stakeholders concern for environmental integrity and connection between the integrity of the offsets and the integrity of the regional target.*

Offsets and Allowances from other systems

- The WCI Partners will establish a limit on the use of offsets. The WCI Partners are considering a limit not greater than ten (10) percent of an individual entity's or facility's compliance obligation.
  - *Some stakeholders think limiting is counterproductive;*
  - *Some stakeholders think oversupply of offsets could mean less direct emission reductions.*

Offsets and Allowances from other systems

- The WCI Partners have identified the following list of project types as a priority for investigation and development to participate in the offset system.
    - Agriculture (soil sequestration and manure management)
    - Forestry (afforestation/reforestation, forest management, forest preservation/conservation, forest products)
    - Waste management (landfill gas and wastewater management)
  - *Stakeholders have identified many project types the WCI could investigate*
  - *Many stakeholders feel the WCI should identify a list of project types that will be eligible*
  - *Some stakeholders feel project types should be limited*

Offsets and Allowances from other systems

- The WCI Partners will coordinate to review, develop, and approve, as appropriate, protocols for the project types that meet the necessary criteria for inclusion. The WCI Partners will use offset protocols that are standardized to the extent possible, and make use of (or adapt if needed), existing protocols as appropriate. The WCI Partners will also initiate the establishment of a process to coordinate the review and approval of other project types and protocols proposed by project developers.
  - *Stakeholders have advocated for government issued protocols and developer driven protocols.*
  - *Stakeholders strongly support protocols approved before overall program startup.*

Offsets and Allowances from other systems

- WCI Partners may approve and certify offset projects located throughout Canada, the United States, and Mexico, where such projects would be subject to comparably rigorous oversight, validation, verification and enforcement as those located within the WCI jurisdictions.
  - *Stakeholders would like the flexibility to purchase offsets from the lowest cost sources.*
  - *Stakeholders are concerned that the quality of the offsets remain high and consistent with the cap and trade program.*
  - *Stakeholders would like to see the environmental, economic and social co-benefits remain in the WCI jurisdictions.*

Offsets and Allowances from other systems

- WCI design protocols will meet rigorous criteria to preserve the environmental integrity of the overall cap-and-trade program.

Offsets and Allowances from other systems

- In the case of offset credits from the Clean Development Mechanism (CDM) and Joint Implementation (JI), the WCI Partners may establish added criteria to ensure similar rigor to WCI approved/certified offset projects or other requirements appropriate to enable use of these offset credits in the cap-and- trade program.

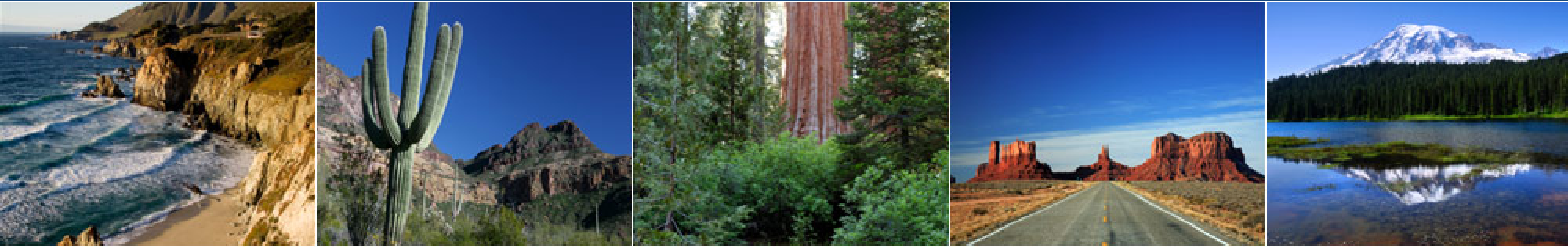
Offsets and Allowances from other systems

- WCI Partners may allow individual regulated entities or facilities to use tradable units (allowances) from other government-regulated GHG emission trading systems that the WCI Partners recognize as meeting similarly rigorous criteria for environmental integrity for compliance purposes. These allowances would be subject to the overall limit described above.

Offsets and Allowances from other systems

- The WCI Partners are considering a method that restricts the use of offsets from projects located outside WCI jurisdictions for compliance purposes in the WCI cap-and-trade regulatory program.

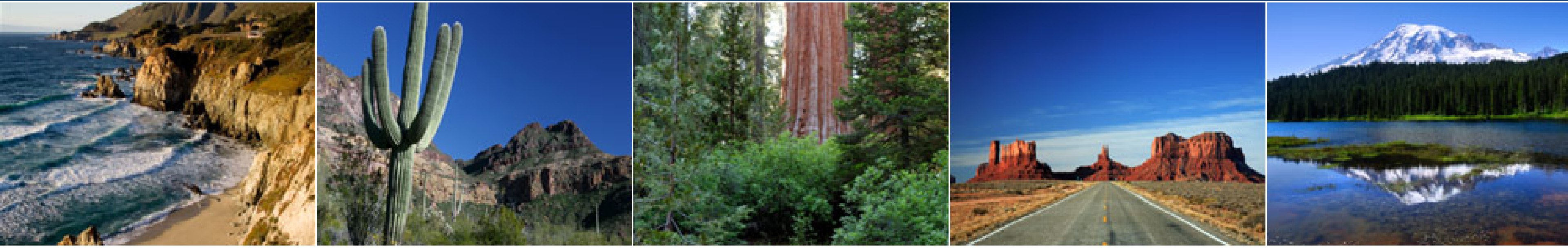
Comments and Questions



Next Up

Reporting Recommendations

Western Climate Initiative



Draft Design
Reporting Subcommittee

Jim Norton, Subcommittee Chair

NM Environmental Protection Division Director

July 29, 2008

San Diego, CA

Practical Impacts for Reporting

- Key Elements
  - Consistent, transparent, robust quantification and reporting across sources and states/provinces
  - Broadest possible coverage / inclusion
- Maximum reliance on and linkage with The Climate Registry (TCR) and international reporting programs
  - Anticipate employing TCR quantification protocols and reporting systems and services

Draft Design Recommendations for Reporting

- **10.1:** *Mandatory measurement and monitoring for all six GHGs will commence in January 2010 for all entities and facilities subject to reporting. Reporting of 2010 emissions will begin in early 2011.*

- **10.2:** *The entities and facilities subject to reporting are those with annual emissions equal to or greater than 10,000 metric tons of CO2e. However, in some limited instances the threshold may be based on other parameters, such as throughput or capacity, as long as these thresholds represent the equivalent of, or are lower than, the 10,000-metric-ton threshold.*

Draft Design Recommendations for Reporting – cont.

- **10.3:** *Partners may require third-party verification or may carry out government audit programs. (Partners are still discussing whether verification by third parties accredited under a common framework should be required for all reports submitted by entities or facilities covered by the cap.)*
- **10.4:** *As each Partner collects additional emissions data from entities and facilities required to report, data will be made available to all Partners for review and consideration for inclusion in the cap-and-trade program.*
- **10.5:** *Nothing in the WCI program design would limit any Partner's discretion to require reporting earlier, at lower thresholds, or for entities and facilities not covered by the cap-and-trade program.*

Draft Essential Requirements of Mandatory Reporting

- Purpose of ER Document
  - Document current status of essential requirements
  - Identify remaining decisions
  - Seek public comment

- Scope of ER Document
  1. Definitions
  2. Pollutants
  3. Applicability
  4. Timing
  5. Confidentiality
  6. Report content and submittal
  7. Compliance
  8. Emissions quantification and monitoring
  9. Verification and quality assurance

1. Definitions

- Background
  - Defines Key Terms
  - Facilitates Communications Via Common Terminology
  - Several Jurisdictions Have Definitions
- Additional Decisions Needed
  - Using CARB as a starting point, compile applicable definitions

2. Pollutants

- Background
  - Clearly Defines Pollutants
  - Provides 100-Year Global Warming Potential (GWP) Factors (e.g., IPCC Second Assessment, 1995)
- Draft Design of the Regional Cap-and-Trade Program (7/23/08)
  - GHGs Covered: Section 1.1
- Additional Decisions Needed
  - Determine GWP factors

3. Applicability

- Background
  - Describes Who must Report
    - Sources subject to cap and not subject to cap
    - Sources not subject to reporting
  - Defines Threshold(s)
  - Defines Level of Reporting
    - Entity, facility, process
- Draft Design of the Regional Cap-and-Trade Program (7/23/08)
  - Sources: Sections 1.2.1 through 1.2.6, 1.5
  - POR: Section 2
  - Thresholds: Section 10.2, 10.5
- Additional Decisions Needed
  - Identification of source categories (i.e., which processes)
  - Definitions of sources to address POR issues
  - Sources to exclude from reporting
  - Level of reporting (by source category)

4. Timing

- Background
  - Effective date
  - Reporting period
  - Report submission date
- Draft Design of the Regional Cap-and-Trade Program (7/23/08)
  - Section 10.1
- Additional Decisions Needed
  - Need for uniform dates across jurisdictions?
  - Need for prior years' data?
  - Plan for transitioning to WCI schedule for jurisdictions with existing programs
  - Need for more frequent interim reports to support cap-and-trade program?
  - Deadlines for verification/QA and public release of data

5. Confidentiality

- Background
  - In general, emissions data are not considered confidential
  - Stakeholder comments range from protection of public right-to-know to a broader definition to protect confidential business information
- Additional Decisions Needed
  - Policies and procedures

6. Report Content and Submittal

- Background
  - General requirements (administrative information)
  - Source category-specific requirements
  - Submittal requirements (responsible party)
- Draft Design Recommendations (5/16/08)
  - TCR's central repository
  - Optional submittal directly to TCR or to jurisdictions (who will upload to TCR)
- Additional Decisions Needed
  - Specific contents of report
  - Submittal mechanism

7. Compliance

- Background
  - Rule violations
  - Enforcement mechanisms
  - Records retention
  - Revisions
- Additional Decisions Needed
  - Which actions are violations
  - Guidelines to promote consistent administrative practices among jurisdictions
  - Which records must be retained
  - Procedure and policy for report revision

8. Emissions Quantification and Monitoring

- Background
  - De minimus emissions
  - Accuracy necessary to support a cap-and-trade program
  - Key stakeholder issues: CHP, biomass combustion, methods for electricity imports and waste management
  - First step: review existing methods
- Draft Design Recommendations (5/16/08)
  - Section 1.5
- Additional Decisions Needed
  - Process for selecting and approving methods
  - Select methods and determine details for each source category-specific method

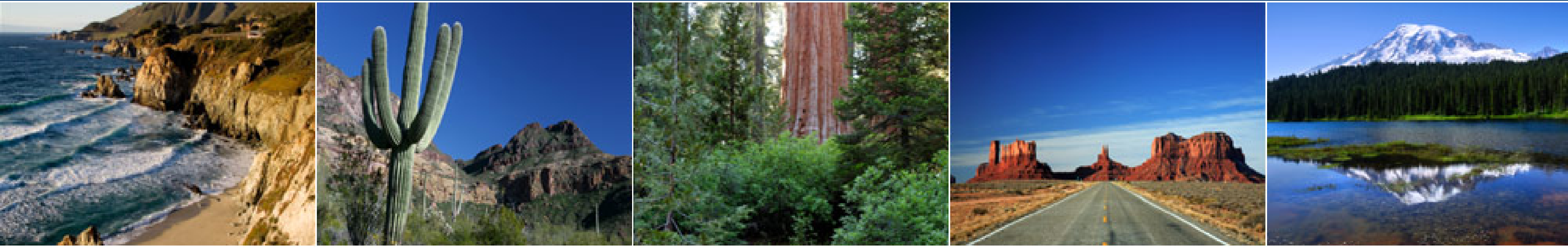
9. Verification and Quality Assurance

- Background
  - Reporting Subcommittee is writing issue paper to inform decision on third party verification or other QA procedures
- Draft Design of the Regional Cap-and-Trade Program (7/23/08)
  - Section 10.3
- Additional Decisions Needed
  - Type of verification and quality assurance program
  - Specific requirements

Next Steps

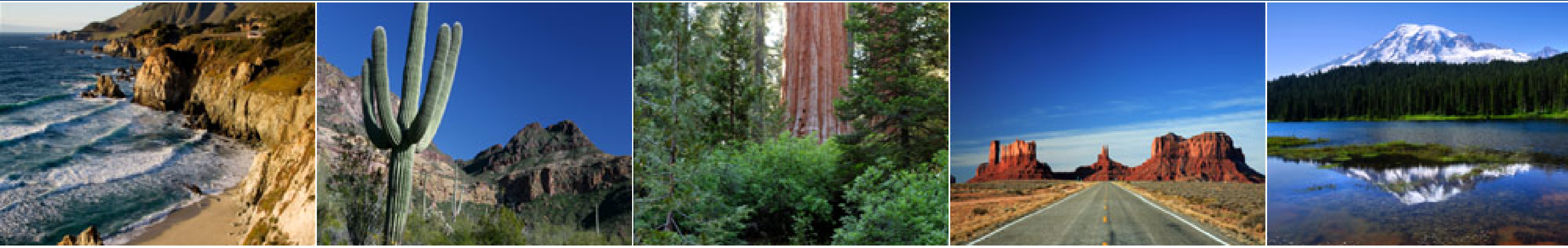
- Respond to Stakeholder Comments on Essential Requirements (comments due August 13)
- Complete Work Plan
  - Facilitates decision making process on all essential elements
  - Establishes critical path
- Study and Recommend Emissions Quantification and Monitoring Methodologies
- Finalize Essential Requirements Dec 2008
- Welcome Stakeholder Comments Throughout the Process

Comments and Questions



Next Up

Economic Analysis



Update on Economic Modeling

Economic Modeling Team

July 29, 2008

San Diego, California

Outline of Presentation

- Status
- Quick review of structure of ENERGY 2020
- Updates to Model Inputs
- Comments and questions

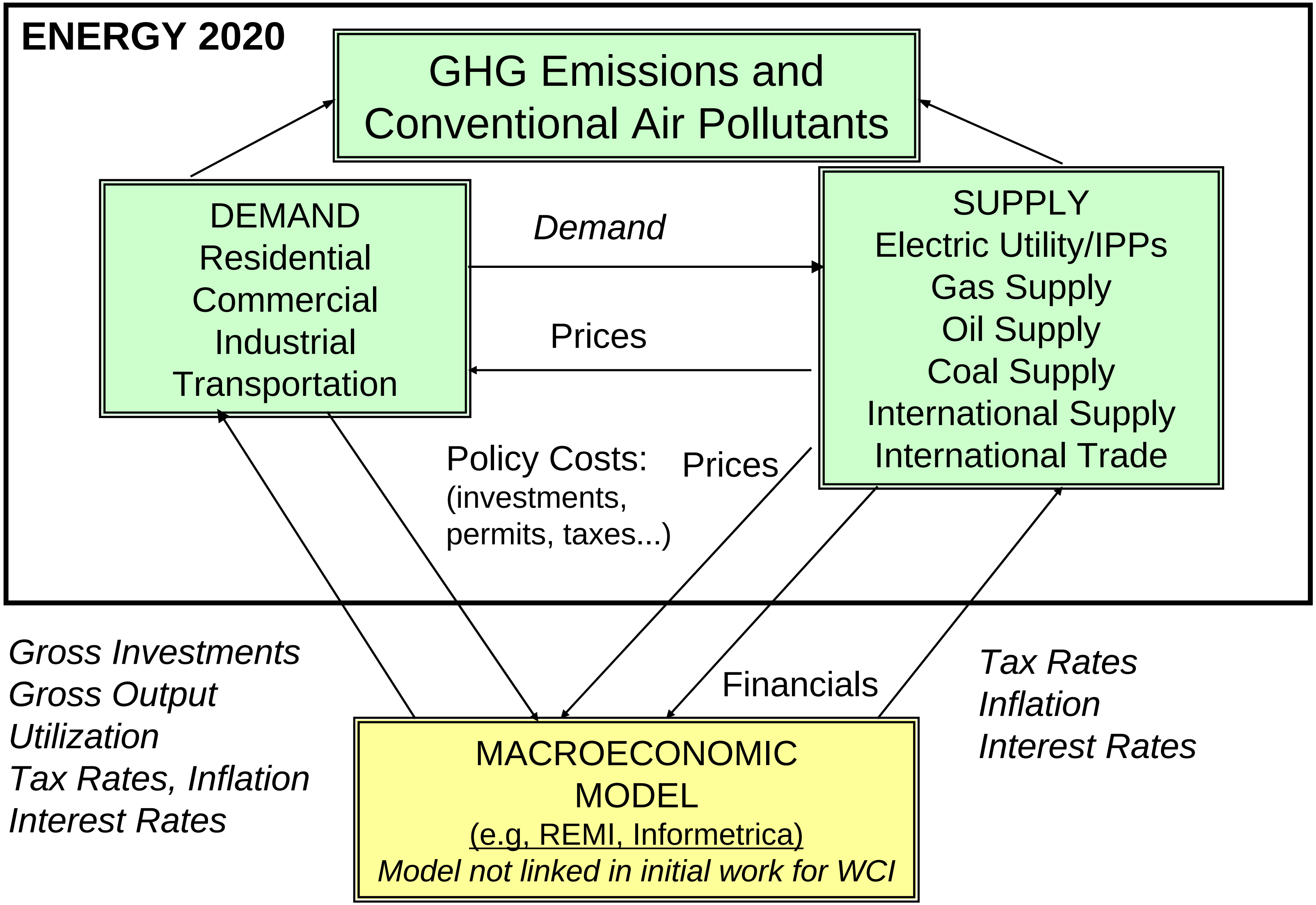
Status

- Model specified
  - Economic and population drivers – partner specific data
  - Energy price forecasts
  - “First Jurisdictional Deliverer”
  - Western Electric Coordinating Council (WECC) area
- Inputs being finalized
  - Cost data
  - Existing policies
    - Renewable Portfolio Standards
    - Energy Independence and Security Act
- Sensitivity analysis requirements being identified
  - Stakeholder conference calls

Status (continued)

- Policy cases being defined
  - Reference case
  - Complementary policies case
  - Cap-and-Trade cases
- Model outputs
  - Emissions
  - Allowance prices
  - Expenditures and costs

ENERGY 2020 Model Structure



Update to Model Inputs

- This “Assumptions Book” catalogs key inputs and assumptions.
- This second draft:
  - Reflects ongoing guidance from WCI.
  - Incorporates widely available and accepted public data sources.
  - Incorporates some partner-specific data.
  - A new section 2 provides a brief overview of the organization of the Assumptions Book. This caused the Analytic Approach section to be renumbered as section 3, and Reference Case Inputs to be renumbered as section 4. Otherwise, the layout of the Assumptions Book is basically unchanged.

4.1 Population and Economic Data

- Section 4.1 now gives specific links to public data sources used for population and economics data (e.g. table below)
- Assumptions (2006-2020): 3% real GDP growth, 2.5% inflation, 5% real discount rate.

Description of Data/Input	Sources	Detailed Reference
Total population, historical and growth over time	US Census Bureau	*Historic (1985-2006):* Regional Economic Information System, Bureau of Economic Analysis, U.S. Department of Commerce. http://www.bea.gov/regional/spi/default.cfm?satable=summary *California:* California population taken from: CEC *California Energy Demand 2008-2018 Staff Revised Forecast*
	Statistics Canada	Statistics Canada Table 051-0001 (based on census data)
	Future	Future annual population growth rates are taken from Regional Forecasts from AEO then applied to the state historical population. Annual Energy Outlook 2007 (February 2007 release). http://www.eia.doe.gov/oiaf/aeo/supplement/suptab_1.xls through suptab_9.xls

4.2 Price Data

- Future energy prices
  - For U.S. states: Have switched from EIA AEO 2007 High Price Case to AEO 2008 High Price Case (see table below)
  - For Canadian provinces: same as U.S. with adjustments for differences in delivered cost
- Also lays out how electric prices are forecast

AEO Price Projections - Imported Crude Oil ($/bbl)

	2005		2010	2020	2030
2007 High Price Case	$49.19		$62.53	$82.60	$92.83
2008 High Price Case	$59.05	*	$69.19	$88.31	$96.42

source: Table C5, AEO 2007 & 2008 (wgt'd average price to refineries)

* $59.05 figure is for 2006

4.5 Electricity Sector Data

- Now gives specific sources of public data used for electric generating capacity and operation data (e.g., table below)
- E3 generation cost projections from 11/07

Input	Sources Used/Available
Plant type	Annual Electric Generator Report: EIA Form 860 (2006) Canadian IPM® Base Case 2004[18] Natural Resources Canada, Canada's Energy Outlook: Reference Case 2006[19] Supplemented by National Energy Board info.
Plant capacity	Annual Electric Generator Report: EIA Form 860 (2006) Canada: as above
Plant historical generation	EIA Form 906/920 (2001-2006) Total generation output by plant type for California from CEC Canada: as above
Plant fuel type	Annual Electric Generator Report: EIA Form 860 (2006) Canada: as above
Plant Heat Rate	EIA Form 906/920 (2001-2006) Canada: as above

Changes in E3 New Generation Cost Estimates

Table shows 2/08 estimates minus 11/07 estimates.

I.e., increase in black and decrease in (red).

Technology	cost basis yr 2005 Total Capital Costs $/kW	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Capacity Factor	Nominal Heat Rate
	2008$	2005	2005		
Biogas	(442)	(31.50)	(1.19)	5%	(2,082)
Biomass	(648)	(14.82)	1.76	5%	6,598
Geothermal	236	(2.08)	(1.20)	0%	NA
Hydro - Small	(9)	(0.86)	2.36	a/	NA
Solar - Thermal	(395)	(14.37)	(1.20)	a/	NA
Wind	21	(8.49)	(1.20)	a/	NA
Coal ST	192	(7.09)	3.12	0%	0
Coal IGCC	221	(10.64)	1.55	0%	0
Coal IGCC w/ CCS	1,026	(12.18)	2.98	0%	0
Gas CCCT	(176)	(2.96)	1.20	0%	0
Gas CT	(13)	(3.60)	2.16	0%	0
Hydro - Large	1,044	4.14	2.67	a/	NA
Nuclear	1,000	(19.12)	(0.73)	0%	0

a/ Capacity factor is at upper end of range in 11/07 E3 estimates.

4.6 Transportation

- The description of transportation sector modeling has been expanded and more data sources provided (e.g., table below).

Input	Sources Used/Available
All tables below are from ***Transportation Energy Data Book*** *(Edition 26, 2007)*[24] *published by the US Department of Energy's Oak Ridge National Laboratory.*	
Average fuel economy	Tables 4.17 and 4.18
New Vehicle Efficiency	Tables 4.7 and 4.8
Scrap/Survival Rates	Tables 3.8, 3.9 and 3.10
Freight Truck Fuel Economy	Tables 5.1 and 5.2
Bus Efficiency	Table 2.13
Rail Efficiency – Passenger	Table 9.10 and 9.11
Rail Efficiency - Freight	Table 9.8
Marine - Freight	Table 9.5
Air Travel	Table 9.2

4.7 Built Environment

- The description of the modeling of the built environment has been expanded and supplemented by new Appendix J (e.g., table below).

Residential Device Standards	
Equipment	**Effective Efficiency Standard**
Gas hot water from 1990 to the final year	59%
Oil hot water from 1990 to the final year	51%
Electric hot water from 1990 to the final year (inc.tank losses)	92%
LPG hot water from 1990 to the final year	59%
Electric air conditioning for 1990	260% COP = 2.6
Electric air conditioning for 1991	261% COP = 2.61
Electric air conditioning for 1992 to 2006	265% COP = 2.65
Electric air conditioning for 2007 to the final year	344% COP = 3.44

Efficiency and Cost Data

- Section 4.7 describes how efficiency choices are made in in the “Built Environment” (residential, commercial and industrial buildings).
- Appendix J presents efficiency and cost data related to the built environment.
- Historic energy use and survey data are used to establish patterns of past & current energy use by sector/end-use.
- Increased requirements for energy services are driven by economic and population changes.
- Additional services can be met using different fuels and at varying levels of efficiency (i.e., Gas or electric water heating, a medium or high efficiency furnace).

Efficiency and Cost Data (cont'd.)

- New investments are assumed to achieve the level of efficiency specified in existing standards (i.e., Residential Device Standards – new gas furnaces must be at least 80% efficient).
- Model recognizes that standards change over time.
- Higher efficiency can be achieved at a cost (i.e., Device Capital Cost in $/mmBtu/Year).
- Capital costs are presented on annualized basis based on the expected life of the investment.
- Upper limit for available efficiency specified as Maximum Device Efficiency (i.e., Natural gas furnaces cannot exceed 97% efficiency).

Efficiency and Cost Data (cont'd.)

- Model evaluates efficiency choice based on energy costs, capital and operating costs within range between minimum standard and maximum efficiency available.
- All standards, maximum efficiency levels, costs and equipment life are specified for each fuel/end-use combination.
- Energy choices are modeled based on both price and non-price factors.
- Non-price factors include market imperfections as well as non-energy considerations (i.e. equipment features, etc.)
- Following slide illustrates model structure used to determine energy demands.

Efficiency and Cost Data (cont'd.)

Example: Additional water heating requirement

- Model would consider fuel choice – ie. natural gas, electricity, LPG, oil, solar, etc.
- Portion which chooses natural gas for water heating can choose any level of efficiency from 59% to 86%
  (see line 1 in table on slide 9 and line 2 in table of Maximum Device Efficiency on page 79 of Assumptions Book)
- The model would compare the cost of the new water heater ($18.50/mmBtu/Year) and the additional O&M costs ($0 in this case) vs. the cost of energy saved over the assumed life of the water heater (15 years).
- For a household using 18 mBtu/year for water heating, moving from 60% to 80% would save about 4.5mBtu/year. The $83.25 cost of this increase (4.5mBtu x $18.50/mBtu/year) would be compared to the value of the energy saved as part of the efficiency decision.

Transportation Choices:

- Transportation choices are conceptually similar to other efficiency choices.
- Economic activity and population changes drive demand for transportation for each geographic area.
- Existing transportation patterns and energy use are established by historic data.
- Consumers can choose between transportation modes (i.e., Rail, marine, trucking for freight;
  Air, train, bus, personal vehicles, etc. for passenger travel).
- Non-price factors including consumer preferences, business requirements and the costs of each transportation mode are represented in model.

Transportation Choices:

- Personal vehicle choices are made in similar manner
- Consumers consider capital and operating costs, fuel choices/costs, and efficiency.
- Costs are presented in the model in terms of capital cost per mile traveled for different vehicle classes (light, medium and heavy passenger vehicles, motorcycles, etc.).
- Larger vehicles with higher capital costs and lower efficiencies therefore have higher cost per vehicle mile traveled.
- Historically non-price factors (i.e., Vehicle size, performance and appearance) have dominated decisions.

4.8 Programs/Policies Incorporated in Reference Case

- This description of "current policies" reflected in the Reference Case is now supplemented by new Appendix I containing state RPS provisions.

State or Prov	Target	Policy
AZ	15% of generation from renewables by 2025	Renewable Energy Standards (formerly known as the Environmental Portfolio Standard) on February 27, 2006. The new rules require regulated electric utilities to generate 15% of their energy from renewable resources by 2025. By 2012, at least 30% of the sta
CA	Major utilities 20% from renewable sources by 2010 on a retail sales basis	California's Investor-Owned Utility, Electric Service Providers, Small and Multi-Jurisdictional Utilities and Community Choice Aggregators to produce at least 20% of their electricity using renewable sources by 2010 based on renewable retail sales. Eligib
MT	10% of generation load to be renewable by 2010; 15% by 2015	Each investor-owned and public utility should: Meet 20% of its load using renewable energy resources by 2020, increasing to 25% by 2025. The legislation contains a cost cap that encourages utilities to invest in renewable generation that is cost competiti
NM	10% of generation by 2011; 15% renewable by 2015; 20% by 2020	Applies to Investor-Owned Utility, Rural Electric Cooperative. IOUs: 15% power generation from renewable sources and 20% by 2020. RECs: 10% by 2020. This legislation expands on NM's current renewable portfolio standard requiring that 10% of the state's en

4.9 (New) Complementary Policies

- Contains a description of policies that make up the Complementary Policies scenario.

  - **Vehicle Miles Traveled –** Assumes that policies will be introduced to reduce VMT in all WCI partner jurisdictions by 2% from BAU levels in 2020.

  - **Energy Efficiency Programs –** Assumes that energy efficiency programs will be undertaken in all WCI partner jurisdictions to reduce energy use (electricity, natural gas, fuel oil and propane) by 1% per year below the reference forecast between 2011 and 2020.

  - **California Clean Cars –** Assumes that all WCI partners will implement the California clean car standards as currently formulated, along with Phase 2 standards currently contemplated by the California ARB.

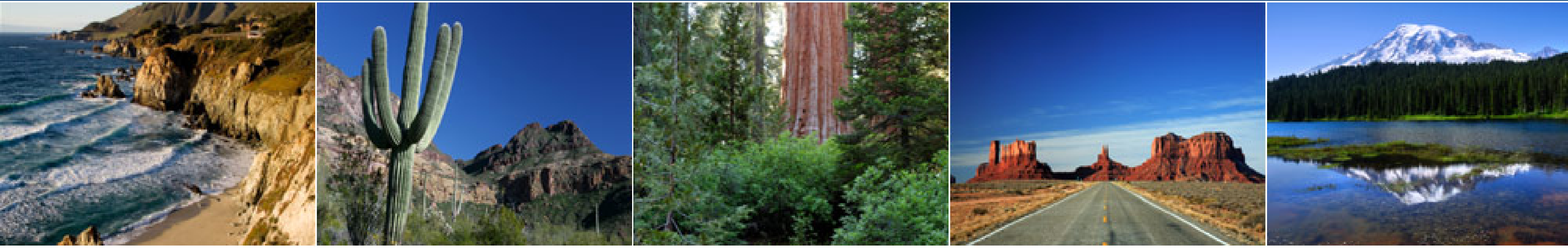
Changes to Appendices

- Appendix A has been modified to better explain the ENERGY 2020 model.
- Appendix B has been modified to clarify the description of some of the original sources of the default data and how the data have been updated over time.
- New Appendix C now contains Phase 2 data for Arizona, California, New Mexico, and Washington.
- Appendix D (formerly “C”) presents inter-regional transmission capacity based on FERC sources, now supplemented with information supplied by the EMT.
- Appendix E (formerly “D”) presents more description of various datasets used in ENERGY 2020, i.e., the dimensions of the variables that delineate the scope and detail of the model.

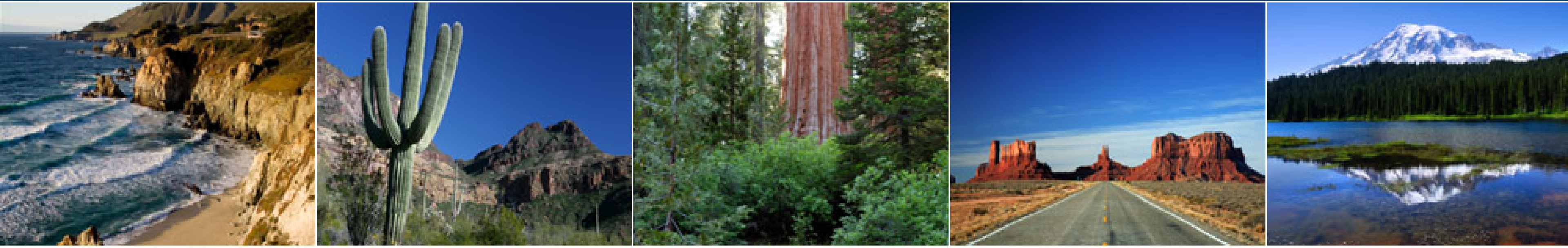
Changes to Appendices (cont.)

- New Appendix F contains planned or committed coal capacity additions in the post-2005 period, based on public data sources and a thorough review by the EMT.
- Appendix G (formerly “F”) presents new generation performance and cost assumptions (unchanged - still based on the E3 report for California).
- Appendix H (formerly “G”) presents global warming potential coefficients for the six greenhouse gases (unchanged).
- New Appendix I summarizes Renewable Portfolio Standard provisions among the WCI partners.
- New Appendix J presents efficiency and cost data related to the built environment.

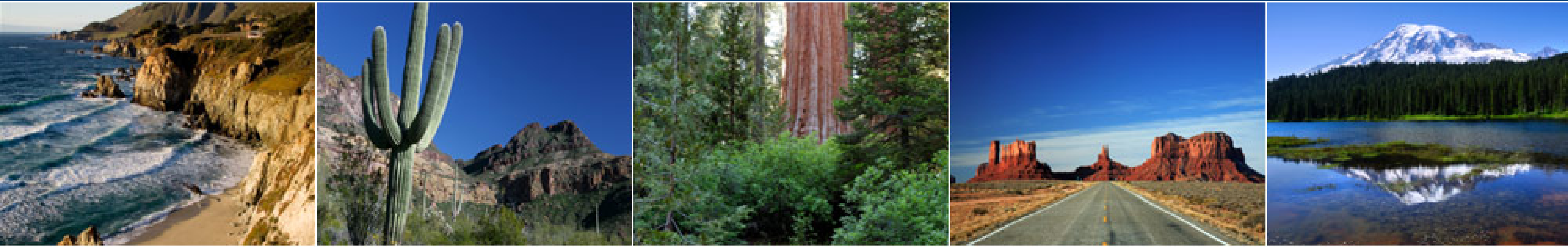
Comments and Questions



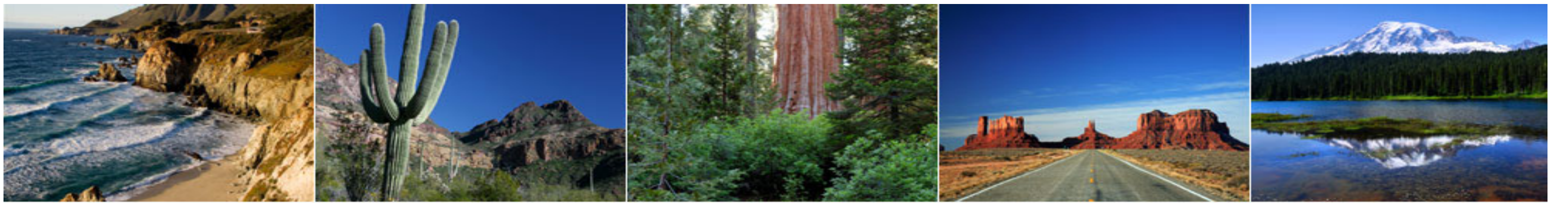
General Stakeholder Comments



Wrap Up
Next Steps



Adjourn



Western Climate Initiative

Design Recommendations for the WCI Regional Cap-and-Trade Program

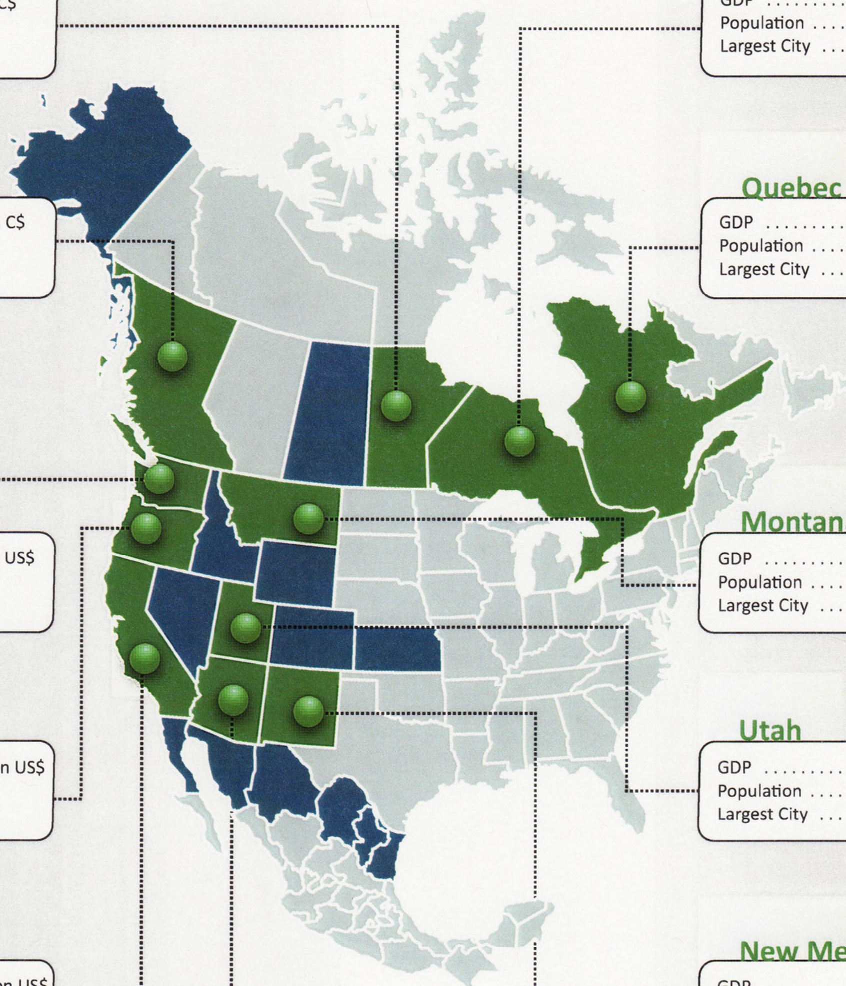
September 23, 2008
Corrected March 13, 2009

Arizona *British Columbia* *California*

Manitoba *Montana* *New Mexico* *Ontario*

Oregon *Quebec* *Utah* *Washington*

Western Climate Initiative



Manitoba

GDP	48,586 Million C$
Population	1,186,700
Largest City	Winnipeg

British Columbia

GDP	190,214 Million C$
Population	4,380,300
Largest City	Vancouver

Washington

GDP	311,270 Million US$
Population	6,468,424
Largest City	Seattle

Oregon

GDP	158,233 Million US$
Population	3,747,455
Largest City	Portland

California

GDP	1,812,968 Million US$
Population	36,553,215
Largest City	Los Angeles

Arizona

GDP	247,028 Million US$
Population	6,338,755
Largest City	Phoenix

Ontario

GDP	582,019 Million C$
Population	12,803,900
Largest City	Toronto

Quebec

GDP	298,157 Million C$
Population	7,700,800
Largest City	Montreal

Montana

GDP	34,253 Million US$
Population	957,861
Largest City	Billings

Utah

GDP	105,658 Million US$
Population	2,645,330
Largest City	Salt Lake City

New Mexico

GDP	76,178 Million US$
Population	1,969,915
Largest City	Albuquerque

Partners Observers

WCI OBSERVERS

CANADA
Saskatchewan

UNITED STATES
Alaska
Colorado
Idaho
Kansas
Nevada
Wyoming

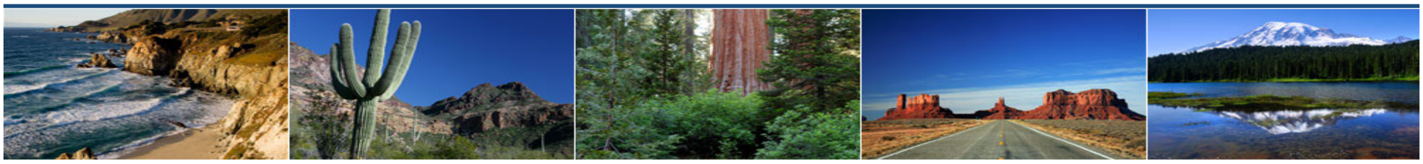
MEXICO
Baja California
Chihuahua
Coahuila
Nuevo Leon
Sonora
Tamaulipas

All figures for 2007

Source for US data: US Census Bureau and US Bureau of Economic Analysis

Source for Canadian data: Statistics Canada

Western Climate Initiative



September 23, 2008

To All Interested Parties:

In February 2007, the governors of Arizona, California, New Mexico, Oregon and Washington kicked off this ambitious effort to design a regional, market-based approach for reducing greenhouse gas emissions. Since that time, the governors of Montana and Utah and the premiers of British Columbia, Manitoba, Ontario, and Quebec have joined in this historic effort and today we are pleased to release our "Design Recommendations for the WCI Regional Cap-and-Trade Program."

Each of our states and provinces recognizes the need to take action now to address the threats posed by global climate change. The design recommendations being released today are an important milestone in our collective effort to respond to the leadership role states and provinces have established on this issue.

While we are pleased to reach this milestone, we recognize that much more remains to be done to move from program design to program implementation. Over the next couple of months, we will prepare a detailed work plan to guide the next phase of the Western Climate Initiative. The work plan will identify the priorities for the coming year and will provide information on how all interested parties can continue to engage in our process.

As we developed these recommendations over the last 18 months, we benefited greatly from the input provided by a wide variety of stakeholders representing business, industry, labor, and environmental groups. The dedication of our state and provincial staff and the assistance of our technical and policy advisors were also critical to our success.

On behalf of the governors and premiers of the Western Climate Initiative, we again thank you for your interest in our work and for your many contributions to date. We look forward to working with you as we move into the next phase of this initiative. We know that together we can meet the challenge of climate change while enhancing overall environmental health and economic vitality throughout the region.

Sincerely,

The WCI Partners

State of Arizona

Lori Faeth
Office of the Governor

Steve Owens
Dept. of Environmental Quality
Co-Chair, WCI

Jessica Youle
Dept. of Commerce/
Energy

Province of British Columbia

Tim Lesiuk
Climate Action Secretariat

Lee Thiessen
Ministry of Environment

State of California

Darren C. Bouton
Office of the Governor

Michael J. Gibbs
Cal/EPA

Charles M. Shulock
Air Resources Board

Province of Manitoba

Scott Stothers
Climate & Green Initiatives Branch

Juliane Schaible
Climate & Green Initiatives Branch

State of Montana

Paul Cartwright
Dept. of Environmental Quality

State of New Mexico

Sarah Cottrell
Office of the Governor

Jim Norton
Environment Dept.

Sandra Ely
Environment Dept.

Province of Ontario

John Lieou
Ministry of the Environment

Jim Whitestone
Ministry of the Environment

State of Oregon

David Van't Hof
Office of the Governor

Province of Québec

Robert Nöel de Tilly
Ministére du Développement durable, de l'Environnement et des Parcs

Jean-Yves Benoit
Ministére du Développement durable, de l'Environnement et des Parcs

Michel Lesueur
Ministére du Ressources naturelles et de la Faune

State of Utah

Dianne R. Nielson
Office of the Governor

Rick Sprott
Dept. of Environmental Quality

State of Washington

Matt Steuerwalt
Office of the Governor

Janice Adair
Dept. of Ecology
Chair, WCI

Tony Usibelli
Community, Trade & Economic Development

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Rob Greenwood and Bill Ross of Ross and Associates provided exceptional facilitation services during the last several negotiating sessions of the WCI, helping us get to success. Lydia Dobrovolny, also with Ross and Associates, provided critical support during the final negotiating sessions.

Karl Hausker, Glen Wood and their colleagues at ICF International and Jeff Amlin at Systematic Solutions, Inc. provided assistance to the WCI Economic Modeling Team as they evaluated a number of important questions related to the costs and benefits of the WCI cap-and-trade program.

Tim Smith with Waggener Edstrom Worldwide developed our communication tools with amazing speed. Deb Kinsley with the Western Governors' Association provided unparalleled service in making all of the arrangements for our Partner meetings and stakeholder workshops. We want to also thank Marcus Schneider and his colleagues at the Energy Foundation who provided the seed money to get this effort underway.

Our biggest thanks go to Pat Cummins with the Western Governors' Association. As our project manager, he kept us on track, on course and within budget. We simply would not have gotten through the process without Pat's assistance and support.

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Section 1: Design Recommendations for the WCI Regional Cap-and-Trade Program

The Western Climate Initiative (WCI) jurisdictions are recommending a design for a broad cap-and-trade program as part of a comprehensive regional effort to reduce emissions of global warming pollution to achieve the WCI 2020 regional goal. The recommended design will provide opportunities to obtain low-cost emission reductions through emission trading, allowance banking, and inclusion of an offsets component. The design is also intended to mitigate economic impacts, including impacts on consumers, income, and employment. The design balances all principles adopted by the WCI Partner jurisdictions to maximize total benefits throughout the region, including reducing air pollutants, diversifying energy sources, and advancing economic, environmental, and public health objectives, while also avoiding localized or disproportionate environmental or economic impacts. Finally, the WCI Partner jurisdictions have designed a program that can stand alone, provide a model for, be integrated into, or be implemented in conjunction with programs that might ultimately emerge from the federal governments of the United States and Canada.

1. Scope[1]

1.1. Greenhouse gases (GHGs) covered: Carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride.

1.2. Emissions covered:

1.2.1. Electricity generation, including emissions from electricity generated outside the WCI jurisdictions (or generated by a federal entity or on tribal lands) that is delivered into a WCI Partner jurisdiction for consumption in that WCI Partner jurisdiction;

1.2.2. Combustion at industrial and commercial facilities;

1.2.3. Industrial process emission sources[2], including oil and gas process emissions;

1.2.4. Residential, commercial, and industrial fuel combustion at facilities with emissions below the WCI thresholds3 (as described below in the Point of Regulation section, these emissions will be covered upstream). Coverage of these emissions will begin at the start of the second compliance period;

---

[1] The *scope* defines the GHG emissions that are included in the cap-and-trade program, including the emission sources and GHG emissions that fall under the cap.

[2] As used here, process emissions include emissions from chemical, biological, and other non-combustion processes. These emissions may be deliberate (e.g., vented), fugitive (e.g., leaked), or accidental.

[3] *Thresholds* are emission levels that determine when a particular entity or facility will have a compliance obligation under the cap-and-trade program.

1.2.5. Transportation fuel combustion (as described below in the Point of Regulation section, these emissions will be covered upstream.) Coverage of these emissions will begin at the start of the second compliance period.

1.2.6. The WCI Partner jurisdictions recommend covering combustion from transportation, residential, commercial, and industrial (including electricity) fuel sources with the expectation that the individual WCI Partner jurisdictions will:

- Mitigate the economic impact on consumers;
- Implement other policies that will reduce GHG emissions from the transportation sector and reduce demand for transportation fuels (such as vehicle standards, smart growth, low carbon fuel standards, transit options, etc.); and
- Address any issues associated with the point of regulation and its implementation.

1.3. For biomass determined by each WCI Partner jurisdiction to be carbon neutral, the carbon dioxide emissions from the combustion of that biomass are not included in the cap-and-trade program, except for purposes of reporting.

1.4. Carbon dioxide emissions from the combustion of pure biofuels, or the proportion of carbon dioxide emissions from the combustion of biofuel in a blended fuel (e.g., B20 or E85), are not included in the cap-and-trade program, except for purposes of reporting.

1.5. Prior to program start, the WCI Partner jurisdictions will assess whether and how to include upstream emissions from biofuel and fossil fuel production, taking into consideration the potential for emissions leakage, the potential role of other policies (such as a low carbon fuel standard), consistent treatment among fuels, and other factors (such as practicality of implementation).

1.6. As described in Section 5, Role of Other Policies, WCI Partner jurisdictions acknowledge that individual jurisdictions may utilize other fiscal measures such as British Columbia's carbon tax, to address transportation fuels and fuel use by residential and commercial sources that contribute to achieving overall comparable GHG emission reductions and internalize the price of carbon as expected through the regional cap-and-trade program.

1.7. Adequate quantification methods will be established for emissions sources prior to including them in the program.

2. Point of Regulation[4]

2.1. Industrial sources (both process and combustion) with emissions above the threshold: The point of regulation will be at the point of emission.

2.2. Electricity: The point of regulation is the First Jurisdictional Deliverer (FJD). For sources within WCI jurisdictions, the FJD is the generator. For power that is generated outside the WCI jurisdictions (or generated by a federal entity or on tribal lands) for consumption within a WCI Partner jurisdiction, the FJD is the first entity that delivers that electricity over which the consuming WCI partner jurisdiction has regulatory authority.

2.3. Residential, commercial, and industrial fuel combustion at facilities with emissions below the threshold: The point of regulation will be where the fuels enter commerce in the WCI Partner jurisdictions, generally at a distributor. The precise point is to be determined and may vary by jurisdiction.

2.4. Transportation fuel combustion: The point of regulation will be where the fuels enter commerce in the WCI Partner jurisdictions, which for liquid fuels is generally at the terminal rack, final blender, or distributor. The precise point is to be determined and may vary by jurisdiction.

3. Thresholds for Coverage Under the Cap-and-Trade Program

3.1. Emission threshold: 25,000 metric tons of carbon dioxide equivalents (CO_2e) annually defines the entities or facilities (e.g., First Jurisdictional Deliverer, fuel distributor, fuel blender) that will have a regulatory compliance obligation under the cap-and-trade program. Mandatory reporting data may be used to adjust this threshold for specific industries where necessary. Additional analyses will be performed to determine if adjustments to the threshold are needed to ensure sufficient coverage or to address competitiveness issues within individual sectors prior to the beginning of the program (e.g., because different WCI Partner jurisdictions may have the same industry but with different sized sources).

3.2. A method will be developed to prevent entities or facilities from avoiding coverage, such as by breaking themselves into separate power deliverers that each deliver electricity with emissions below the threshold.

4. Program Expansion

4.1. Future Program Expansion: The scope of the cap-and-trade program is capable of expanding over time (including possibly adjusting applicability thresholds). Prior to each compliance period, the WCI Partner jurisdictions will review whether to bring new sources into the program and, if so, which ones.

[4] The *point of regulation* is the entity or facility with the compliance obligation, i.e., the requirement to surrender sufficient GHG allowances to cover actual emissions during the compliance period. An *allowance* is the tradable permit to emit one metric ton of GHG emissions in CO_2e. The term *entity* is generally used when the point of regulation is upstream of the point of emissions, to describe a company that has an obligation to surrender allowances to cover the carbon content of the fuel the company is moving through commerce, or when the point of regulation is at the First Jurisdictional Deliverer, to describe a company that has an obligation to surrender allowances to cover the emissions attributable to the generation of power the company is importing. When the point of regulation is at the point where the emissions occur, the term *facility* is generally used. The term *source* is used to refer to emissions from either a facility or an entity.

5. Role Of Other Policies[5]

5.1. The role of other GHG-reducing policies is to help the WCI Partner jurisdictions achieve their 2020 reduction goal and provide other benefits. Those policies will work in concert with the cap-and-trade program and may apply to any source of GHG emissions.

5.2. Carbon Tax and Other Fiscal Measures:

5.2.1. The WCI Partner jurisdictions agree that individual jurisdictions may use fiscal measures that contribute to achieving overall comparable GHG emission reductions and internalize the price of carbon as expected through the regional cap-and-trade program for transportation and residential/commercial fuels.

5.2.2. British Columbia currently has a carbon tax. By 2012, the WCI Partner jurisdictions will determine the mechanism for integrating the cap-and-trade program with the BC carbon tax.

6. Setting the Regional Cap[6]

6.1. The aggregate regional cap for the cap-and-trade program will:

6.1.1. Equal the sum of the WCI Partner jurisdictions allowance budgets (as referenced in Section 7.1).

6.1.2. Include annual caps (with 3-year compliance periods7) from the beginning of the program in 2012 through 2020. The annual caps will be set in advance of the program start in 2012 so that the total number of allowances issued in each 3-year compliance period through 2020 is known.

6.1.3. Decline over time. The regional cap trajectory for covered sectors will be a straight line from the year of initial coverage (2012 for some sources and 2015 for other sources) to 2020.

6.2. 2012: The initial regional cap will be set at the best estimate of expected actual emissions for those sources covered in the initial year of the program (i.e., 2012) as calculated through the Partner allowance budgets as described in 7.2.

[5] *Other policies* include complementary policies and alternative policies. A *complementary policy* is used in this context to mean policies other than a cap-and-trade program that aid in the goal of achieving emissions reductions for capped or uncapped sources. *An alternative policy* is a policy that is employed in lieu of a cap-and-trade program to achieve emissions reductions for one or more sources.

[6] The *regional cap* is the overall limit on total emissions set for the total emissions included in the cap-and-trade program.

[7] The 3-year compliance periods are 2012-2014, 2015-2017, and 2018-2020.

6.3. 2015: The regional cap in 2015 will be set by adding the best estimate of expected actual emissions in 2015 from transportation fuels and residential, commercial, and industrial fuels (and any other sectors or sources that may be added to the program for the first time in 2015) to the emissions trajectory for the sources first included in the program in 2012.

6.4. 2020: The regional cap for 2020 will be set so that reductions achieved by the cap plus reductions from other GHG reduction policies for uncapped sources will achieve the WCI regional 2020 goal.

6.5. Post-2020 caps: The WCI Partner jurisdictions will set these regional caps not less than three years in advance.

6.6. Once established, the regional cap for each compliance period will not be adjusted except as necessary to account for:

- Changes in WCI membership;
- Changes in scope or thresholds; or
- Data found to be incorrect or inaccurate that was used to determine the cap, which may become apparent, for example, after the start of mandatory reporting.

Any adjustments will be made prior to the beginning of the compliance period.

7. Apportionment[8]

7.1. Each WCI Partner jurisdiction will have an annual allowance budget within the declining regional cap from 2012 to 2020. The annual WCI Partner jurisdiction allowance budget for each year through 2020 will be set prior to the start of the program in 2012.

Each WCI Partner jurisdiction's 2020 allowance budget will be derived from its individual WCI Partner jurisdiction goal[9] used for purposes of the program, accounting for other policies described in Section 5.[10]

There are instances in which electricity is generated in one WCI Partner jurisdiction, but consumed in another WCI Partner's jurisdiction, giving rise to the possibility of double-counting emissions. WCI Partner jurisdictions in such situations will agree to an equitable solution in the context of the WCI cap-and-trade program design.

7.2. For 2012, each WCI Partner jurisdiction's allowance budget will be based on the best estimate of expected emissions for sources covered in the cap-and-trade program in the WCI Partner jurisdiction in 2012. The estimate of expected actual emissions in 2012 will be developed using the best available data (including any available mandatory reporting data) and by accounting for expected changes in emissions in 2012. Population growth, economic growth,

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[8] *Allowance apportionment* describes the Partners' budget or share of WCI region-wide GHG emission allowances. Allowance budgets must be set for each Partner jurisdiction.

[9] Partner goals are those reduction goals or limits that have been established by each individual WCI Partner jurisdiction.

[10] By the end of 2009, Oregon will determine its cap-and-trade specific Partner goal at a level which is at least as stringent as the WCI regional goal.

voluntary and mandatory emission reductions, and other factors will be considered in making the estimate. Each WCI Partner jurisdiction's allowance budget will be adjusted to account for the production and consumption of electricity megawatt hours within each WCI Partner jurisdiction, population growth, and the share of total WCI Partner jurisdictions emissions in 2001 through 2005. Each WCI Partner jurisdiction will make a one-time contribution of 1% of their 2012 budget to be allocated to make these adjustments.

7.2.1. For 2015, each WCI Partner jurisdiction's allowance budget will be set by adding the best estimate of expected actual emissions in 2015 from transportation fuels and residential, commercial, and industrial fuels (and any other sectors or sources that may be added to the program for the first time in 2015) to the emissions trajectory for the sources first included in the program in 2012. The estimate of expected actual emissions in 2015 will be developed using the best available data (including any available mandatory reporting data) and by accounting for expected changes in emissions in 2015 for the sources added to the cap in 2015. Population growth, economic growth, voluntary and mandatory emissions reductions, and other factors will be considered in making the estimate.

7.2.2. From 2015-2020, the trajectory for each WCI Partner jurisdiction's annual allowance budget for covered sectors will be a straight line from the year of initial coverage (2012 for some sources and 2015 for other sources) to 2020.

7.3. For years post-2020, the WCI Partner jurisdictions will set allowance budgets not less than three years in advance.

7.4. Once established, each WCI Partner jurisdiction's allowance budget will not be adjusted except as necessary to account for:

- Changes in WCI membership;
- Changes in scope or thresholds; or
- Data found to be incorrect or inaccurate that were used to determine the cap or the WCI Partner jurisdiction allowance budgets, which may become apparent, for example, after the start of mandatory reporting.

Such adjustments will take effect at a regionally coordinated and designated time, such as at the beginning of a compliance period.

7.5. WCI Partner jurisdictions will recognize within their own jurisdictions allowances issued by other WCI Partner jurisdictions so that all WCI allowances are of equivalent use and fungible throughout the WCI region, regardless of which WCI Partner jurisdiction issues the allowances.

8. Distribution of Allowances[11]

8.1. Distribution of Allowances by WCI Partner jurisdictions: Once the allowance budget has been established for each WCI Partner jurisdiction, allowances will be issued by each WCI Partner within its own jurisdiction. Each allowance will be equal to one metric ton of carbon dioxide equivalent.

8.2. The WCI Partner jurisdictions agree that a portion of the value represented by each WCI Partner jurisdiction's allowance budget (for example, through set-asides of allowances, a distribution of revenues from the auctioning of allowances, or other means) will be dedicated to one or more of the following public purposes which are expected to provide benefits region wide:[12]

- Energy efficiency and renewable energy incentives and achievement;
- Research, development, demonstrations, and deployment (RDD&D) with particular reference to carbon capture & sequestration (CCS); renewable energy generation, transmission and storage; and energy efficiency;
- Promoting emission reductions and sequestration in agriculture, forestry and other uncapped sources; and
- Human and natural community adaptation to climate change impacts.

8.3. The remaining portion of the value represented by each WCI Partner jurisdiction's allowance budgets will be used as that jurisdiction sees fit. WCI Partner jurisdictions may consider objectives such as:

- Reducing consumer impacts, especially for low-income consumers;
- Providing for worker transition and green jobs;
- Achieving emission reductions in communities that experience disproportionate environmental impacts;
- Supporting community-wide efforts funded by local governments to reduce GHG emissions;
- Providing transition assistance to industries;
- Recognizing early actions to reduce emissions; and/or
- Promoting economic efficiency.

8.4. In advance of the first compliance period, and at least one year before the beginning of each relevant compliance period thereafter, each WCI Partner jurisdiction will advise the other WCI Partner jurisdictions how it intends to distribute or retire allowances so that all WCI Partner jurisdictions' plans can be made public in a coordinated fashion.

8.5. If analysis demonstrates that allocations to a particular sector should be treated uniformly by some WCI Partner jurisdictions in order to address competition among like facilities or entities within that sector, and if from that analysis some WCI Partner jurisdictions determine that it is necessary to address those competitiveness issues between the WCI Partner jurisdictions where the facilities or entities operate, those WCI Partner jurisdictions will

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[11] *Allowance distribution* is the Partners' initial distribution of GHG emission allowances into the market.

[12] This will recognize pre-existing commitments to action and legislative requirements on use of revenue (e.g., through BC's Climate Action Plan and Carbon Tax).

standardize the distribution of allowances as necessary to address competitive impacts sufficiently, in advance of the first compliance period.

- Potential sectors where analysis to consider similar treatment is appropriate include those with process (non-combustion) emissions where the greatest emission reduction potential is associated with large technology changes and high GHG emission intensity, such as aluminum, steel, cement, lime, pulp and paper, and oil refining.
- Some WCI Partner jurisdictions may also decide that based on analysis of competitive factors in the electricity sector, distribution of allowance value or auction revenues in that sector should be standardized between those WCI Partner jurisdictions where competitive issues are recognized.

8.6. A WCI Partner jurisdiction will allocate or retire all the allowances in its allowance budget by the end of the applicable compliance period. Except as provided in Section 8.10, a WCI Partner jurisdiction will not hold allowances beyond the end of the compliance period.

8.7. Recognizing the WCI Partner jurisdictions objective of standardizing treatment of some sectors, and acknowledging the differences in the appropriate use of auctions by sector:

8.7.1. Consistent with applicable state and provincial law, the WCI Partner jurisdictions will auction a minimum of 10% of the allowance budget in the first compliance period beginning in 2012. This minimum percentage will increase to 25% in 2020. The WCI Partner jurisdictions aspire to a higher auction percentage over time, possibly to 100%.

8.7.2. Each WCI Partner jurisdiction has discretion to auction a greater portion of its allowance budget as it sees fit.

8.7.3. If a WCI Partner jurisdiction cannot auction allowances, that Partner jurisdiction will notify the other WCI Partner jurisdictions at least six months before the beginning of auctions scheduled for each compliance period. The fact that a WCI Partner jurisdiction cannot auction allowances shall not preclude the other Partner jurisdictions from doing so.

8.8. To the extent WCI Partner jurisdictions auction allowances, those jurisdictions will undertake auctions through a coordinated regional auction process by which each participating WCI Partner jurisdiction will auction allowances throughout the WCI region and receive their proceeds from the auction.

8.9. By the end of 2009 the WCI Partner jurisdictions will develop a design for the coordinated regional auction process. The WCI Partner jurisdictions will design the auction process to consider and prevent market manipulation.

8.10. To manage the risk of inadvertently setting the program cap higher than intended relative to emissions covered by the program, a reserve or minimum price will be established for a portion of the auctioned allowances. Consistent with applicable state and provincial law, this portion will equal 5% of allowances issued by any WCI Partner jurisdiction. If any of these allowances when offered at auction are not purchased at or above the reserve or minimum price, a fraction of the unsold ones will be retired. The unsold allowances that are not retired may be auctioned in later compliance periods or retained by the individual WCI Partner jurisdictions for use as each sees fit in later compliance periods, as determined in advance by the WCI Partner jurisdictions. Any WCI Partner jurisdiction that does not participate fully in the auction with the reserve or minimum price will retire the same proportion of its allowance budget as those retired by the WCI Partner jurisdictions that participated in the auction. The percentage of the allowance budgets, the reserve price, the fraction of unsold allowances that will be retired, and the fraction of unsold allowances that will be retained by the individual WCI Partner jurisdictions will be determined as part of the auction design.

8.11. Early Reduction Allowances. The program will encourage entities and facilities included under the cap to reduce GHG emissions before the start of the first compliance period in 2012.

8.11.1. Each WCI Partner jurisdiction may issue Early Reduction Allowances for certain emissions reductions at covered entities and facilities within its jurisdiction that are achieved after January 1, 2008 and before January 1, 2012.

8.11.2. By the end of 2009, the WCI Partner jurisdictions will jointly establish criteria to determine which early reductions will be eligible for Early Reduction Allowances. The criteria will ensure that the reductions are voluntary, additional, real, verifiable, permanent and enforceable.

8.11.3. Each WCI Partner jurisdiction that issues Early Reduction Allowances will do so in 2012. Any Early Reduction Allowances issued will be in addition to each WCI Partner jurisdiction's 2012 allowance budget.

8.11.4. These allowances shall be treated like other allowances in the cap-and-trade program.

8.12. Other Early Actions and Set-Asides: Each WCI Partner jurisdiction has discretion to recognize early actions other than those under Section 8.11, or otherwise set-aside allowances for distribution. Recognition for early action or set-asides under this subsection will come from within the cap and will come out of the individual WCI Partner jurisdiction's allowance budget.

8.13. Banking: Purchasers and covered entities or facilities, and parties who otherwise obtain allowances, will be allowed to bank allowances without limitation, except to the extent that restrictions on the number of allowances any one party may hold are necessary to prevent market manipulation.

8.14. Borrowing: Borrowing of allowances from future compliance periods will not be allowed.

8.15. Compliance Periods: Each compliance period will be three years long.

9. Offsets,[13] and Allowances From Other Systems

9.1. The WCI Partner jurisdictions will include a rigorous offsets system. The primary role of the offsets system is to reduce the compliance costs for the cap-and-trade program, while ensuring the environmental integrity of the cap.

9.2. The WCI Partner jurisdictions will limit the use of all offsets, and allowances from other GHG emission trading systems that are recognized by the WCI Partner jurisdictions, to no more than 49% of the total emission reductions from 2012-2020 in order to ensure that a majority of emission reductions occur at WCI covered entities and facilities. Each WCI Partner jurisdiction will have the discretion to set a lower percentage limit. All offsets and non-WCI allowances must meet the rigorous criteria established by the WCI Partner jurisdictions.

The WCI Partner jurisdictions will establish criteria to ensure that all offset projects used to meet a compliance obligation result in a GHG reduction, removal or avoidance that is real, surplus/additional, verifiable and permanent or that meets a comparably rigorous standard as described in Section 9.7 below. Offset projects must also be enforceable by the individual WCI Partner jurisdiction that is issuing the credit and the credit must be verifiable by the individual WCI Partner jurisdiction that is accepting it. The criteria will ensure that the quantification of the GHG reduction, removal, or avoidance is accurate and not double counted. The standards and processes for approving offset projects will be developed and implemented in an open and transparent manner that will be well-defined in advance of the start of the cap-and-trade program.

9.3. The WCI Partner jurisdictions encourage the development of offset–projects located inside WCI jurisdictions for compliance purposes in the WCI cap-and-trade regulatory program in order to capture collateral benefits associated with some offsets projects, such as health, social, and environmental benefits.

9.4. The WCI Partner jurisdictions have identified the following list of project types as a priority for investigation and development to participate in the offset system. Making these project types a priority means the WCI Partner jurisdictions are interested in understanding if they are suitable for the offset system, if they will meet the criteria for environmental integrity, and if adequate protocols/methodologies for their quantification and monitoring can be adapted or developed. Priority does not mean these project types are guaranteed to be in an offset system. Project types that reduce emissions that would eventually be covered by the cap-and-trade system would only be eligible until that coverage begins. Project types that reduce emissions covered by the cap-and-trade system would not be eligible to create offsets because the result would be a double counting of the emission reduction. The list is in alphabetical order and does not directly or indirectly represent a ranking or order of preference:

[13] *Offsets* are emission reduction projects undertaken to address emissions not included in a cap-and-trade program. An offset mechanism enables covered entities to offset their own emissions by purchasing emission reduction credits generated through projects that address emissions not covered by the cap.

- Agriculture (soil sequestration and manure management);
- Forestry (afforestation/reforestation, forest management, forest preservation/conservation, forest products); and
- Waste management (landfill gas and wastewater management).

9.5. Starting in 2009, the WCI Partner jurisdictions will coordinate to review, develop, and approve, as appropriate, protocols for the project types that meet the necessary criteria for inclusion. The WCI Partner jurisdictions will use offset protocols that are standardized to the extent possible and make use of (or adapt if needed), existing protocols as appropriate. The WCI Partner jurisdictions will also initiate the establishment of a process during 2009 to coordinate the review and approval of other project types and protocols proposed by project developers. The WCI Partner jurisdictions will establish rigorous criteria for inclusion of offsets in the WCI program.

9.6. WCI Partner jurisdictions will recognize offsets meeting the WCI criteria within their own jurisdictions regardless of which WCI Partner jurisdiction issued them, so that all WCI offsets are of equivalent use and fungible throughout the WCI region. Offsets not meeting the WCI criteria will not be accepted for compliance purposes.

9.7. WCI Partner jurisdictions may approve and certify offset projects located throughout the United States, Canada, and Mexico where such projects are subject to comparably rigorous oversight, validation, verification, and enforcement as those located within the WCI jurisdictions. WCI Partner jurisdictions will not approve offset credits for GHG reductions in developed countries (Annex 1 countries in UN Framework Convention on Climate Change) for projects that reduce, remove, or avoid emissions from sources that within WCI Partner jurisdictions are covered by the cap-and-trade program.

9.8. The WCI Partner jurisdictions may accept offset credits from developing countries through the Clean Development Mechanism (CDM) of the Kyoto protocol, and the WCI Partner jurisdictions may establish added criteria to ensure similar rigor to WCI approved/certified offset projects or other requirements, such as international offset standards, as appropriate to enable use of these offset credits in the cap-and-trade program.

9.9. The offset protocols used by the WCI Partner jurisdictions will meet rigorous criteria to preserve the environmental integrity of the overall cap-and-trade program.

9.10. WCI Partner jurisdictions do not intend to regulate or restrict the existing voluntary market in offsets, to restrict the sale of offsets from projects located within a WCI Partner jurisdiction, or to place restrictions on ownership of offsets projects located within WCI Partner jurisdictions.

10. Reporting

10.1. Mandatory measurement and monitoring for the six included GHG emissions will commence in January 2010 for all entities and facilities subject to reporting. Reporting of 2010 emissions will begin in early 2011.

10.2. The entities and facilities subject to reporting are those with annual emissions equal to or greater than 10,000 metric tons of CO_2e. Where fuel combustion emissions are covered upstream (e.g., emissions from transportation fuel combustion and emissions from fuel combustion at residential, commercial, and industrial facilities with emissions below the threshold) the reporting threshold will apply to entities (e.g., fuel distributors and blenders) based on the expected combustion emissions from the fuels distributed. In some limited instances the threshold may be based on other parameters, such as throughput or capacity, as long as these thresholds represent the equivalent of, or are lower than, the 10,000-metric-ton threshold..

10.3. WCI Partner jurisdictions will require third party verification of reported emissions from entities and facilities that will be included under the cap.

10.4. Prior to the start of the mandatory reporting program, the WCI Partner jurisdictions will establish the essential requirements for reporting by all entities and facilities required to report in each of the WCI Partner jurisdictions.

10.5. As each WCI Partner jurisdiction collects additional emissions data from entities and facilities required to report, data will be made available to all WCI Partner jurisdictions for review and consideration for possible expansion of the cap-and-trade program.

10.6. Nothing in the WCI program design limits the discretion of any WCI Partner jurisdiction to require reporting earlier, at lower thresholds, or for entities and facilities not covered by the cap-and-trade program.

11. Start Date for Cap-and-Trade

11.1. The cap-and-trade program will launch January 1, 2012.

12. Compliance and Enforcement

12.1. Each WCI Partner jurisdiction will retain and/or enhance its regulatory and enforcement authority and responsibilities to enforce compliance with the cap-and-trade program within its own jurisdiction.

12.2. Each covered entity or facility will demonstrate compliance with the cap-and-trade program by surrendering sufficient allowances by July 1 of the year following the end of each compliance period. To ensure transparency and maintain public confidence, certain data from the emissions reports, allowances, and offsets that are used for compliance will be made public in a timely manner.

12.3. If by the deadline for demonstrating compliance a covered entity or facility does not have sufficient allowances to cover its emissions for the previous compliance period, it shall be required to obtain and surrender three allowances for every metric ton of CO_2e not covered by an allowance at the deadline. This does not preclude other penalties allowed under individual state or provincial laws.

12.4. The WCI Partner jurisdictions recognize that during the first compliance period, both they and the entities and facilities covered by the cap-and-trade program will likely encounter issues that arise in the implementation of any new program. Consequently, the WCI Partner jurisdictions are committed to providing appropriate technical and other compliance assistance to the program participants.

12.5. The WCI Partner jurisdictions will ensure accounting systems are in place to prevent using allowances, tradable units, and offsets more than once for compliance.

13. Regional Organization, New WCI Partner Jurisdictions, and Linkage

13.1. To reduce administrative costs and improve program transparency and consistency, a regional administrative organization will be created to:

- Coordinate the regional auction of allowances;
- Track emissions and provide public information on progress towards the WCI regional goal;
- Monitor and report on market activity, including any potential market manipulation;
- Serve as a forum for WCI Partner jurisdictions to update one another on program progress;
- Coordinate review and adoption of protocols for offsets;
- Coordinate review and adoption of updated reporting protocols;
- Coordinate review and issuing of offset credits; and
- Suggest criteria and means to accredit service providers to deliver validation and verification services.

13.2. New WCI Partner jurisdictions will come into the cap-and-trade program at a regionally coordinated and designated time, such as the beginning of the relevant compliance period.

13.3. Before joining, a new WCI Partner jurisdiction must have adopted an economy-wide GHG reduction goal for 2020 that is at least as stringent as the WCI regional goal.

13.4. Determination of allowance budgets for new WCI Partner jurisdictions will take into account the following parameters:

- The WCI regional goal;
- Allowance budgets for existing WCI Partner jurisdictions;
- The share of the new WCI Partner jurisdiction's budget that is already included through the WCI's regional cap-and-trade program provisions covering imported electricity; and
- The new Partner's individual GHG emissions reduction goal.

13.5. The WCI Partner jurisdictions will seek bilateral and multilateral linkages with other government-approved cap-and-trade systems so that those allowances and allowances issued by WCI Partner jurisdictions would be fully fungible. Until such bilateral or multilateral linkages are established, the use of allowances from other cap-and-trade systems will be limited as described in Section 9.2.

14. WCI Design and Possible Federal Programs

14.1. The WCI Partner jurisdictions have designed a program that can stand alone, provide a model for, be integrated into, or be implemented in conjunction with programs that might ultimately emerge from the federal governments of the United States and Canada. The WCI Partner jurisdictions intend to promote and influence federal GHG emission reduction programs that are consistent with WCI cap-and-trade design principles, and ensure those programs translate into absolute GHG reductions. In the event WCI issues allowances before a federal program in Canada or the United States, WCI Partner jurisdictions will work to ensure that those allowances are fully recognized and valued in the operation of a federal program.

14.2. The approach taken by the WCI Partner jurisdictions builds upon the experience gained by the WCI Partner jurisdictions in developing and implementing climate change action plans and other market-based programs to address air quality issues, including the regional haze and acid rain programs in the United States. Continued leadership in developing a regional cap-and-trade program allows the WCI Partner jurisdictions to take important action now and promote and protect the interests of early actors in the design and implementation of future national and international programs. Taking action now to achieve emission reductions will position WCI Partner jurisdictions to be leaders in the carbon constrained future.

Section 2: Background Report on the Design Recommendations for the WCI Regional Cap-and-Trade Program[14]

The Western Climate Initiative (WCI) is a cooperative effort of seven U.S. states and four Canadian provinces (the "Partners") that are collaborating to identify, evaluate, and implement policies to reduce greenhouse gas (GHG) emissions, including the design and implementation of a regional cap-and-trade program.[15] The Initiative began in February 2007 with the governors of Arizona, California, New Mexico, Oregon, and Washington, who have since been joined by the premiers of British Columbia, Manitoba, Ontario, and Quebec, and the governors of Montana and Utah.[16] Participation in the WCI reflects each Partner's strong commitment to identifying, evaluating, and implementing collective and cooperative actions to address climate change. This Background Report accompanies the Design Recommendations for the regional cap-and-trade program.

The WCI cap-and-trade program is the most comprehensive cap-and-trade program designed to date. Nearly 90 percent of the GHG emissions in the states and provinces will be covered by the cap when it is fully implemented in 2015. It will include more sectors and emissions than either the Regional Greenhouse Gas Initiative (RGGI) in the northeastern United States, which covers the electricity sector only, or the European Union's Emissions Trading Scheme (EU ETS), which does not cover transportation or residential and commercial fuel use. Through its broad scope, the WCI program will reduce costs while reducing emissions across the economy. It will also spur growth in new green technologies, help build a strong clean-energy economy, and reduce dependence on foreign oil.

The Partner jurisdictions are motivated by the impacts of climate change already being felt in the region. Observed trends include rising temperatures leading to warmer, earlier springs and more frost-free days; changing precipitation patterns that include both prolonged drought and increased flooding, as well as shifts in springtime precipitation from snow to rain; changes in water availability due to earlier spring snowmelt, changes in available water volume, and increased evaporation from reservoirs; rising sea levels; and a growing number of large wildfires. Additional impacts expected from unabated climate change include more heat waves, shrinking glaciers and reduced snowpack, reduced biodiversity as invasions of non-native species increase and local habitat moves northward and to higher elevations, and reduced air quality due to elevated levels of ozone and

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[14] No statement in this document should be taken to contradict the Design Recommendations released concurrently with this Background Report; any perceived conflict should defer to the Design Recommendations.

[15] The complete text of the February 26, 2007 Memorandum of Understanding can be found in Appendix A.

[16] The states of Alaska, Colorado, Idaho, Kansas, Nevada, and Wyoming participate as observers, as do the province of Saskatchewan and the Mexican border states of Baja California, Chihuahua, Coahuila, Nuevo Leon, Sonora, and Tamaulipas.

particulates. These impacts affect a wide range of economic sectors, from electricity generation to public health, from agriculture to tourism. The cost of inaction is enormous.

The analyses conducted on the WCI design suggest that the region can mitigate the costs of reducing emissions and realize a cost savings through increased efficiencies and reduced fuel consumption. These savings come in addition to the benefits the region will accrue from a cleaner environment and the promotion of investment and innovation to accelerate the transition to a green economy. The WCI cap-and-trade program is a winning proposition for Partner jurisdictions.

The initial phase of the WCI cap-and-trade program will be a time of transition during which WCI Partner jurisdictions will manage risks, protect the economy, and see real reductions in greenhouse gas emissions. Action is needed now to reduce greenhouse gas emissions and to adapt to climate change impacts. Working together, the states and provinces in the WCI are leading the way.

1. Public Comments and Discussion of WCI Recommendations

The process that led to the recommended design of the regional cap-and-trade program was careful and deliberative. At each step of design development, the WCI Partners sought extensive stakeholder input, as described in part 3.1.3, which yielded a great volume of comments on the range of issues confronted by participating WCI Partner jurisdictions. The comments submitted to the WCI Partner jurisdictions have been posted on the WCI website.[17] The WCI Partners carefully reviewed and considered stakeholder comments in order to formulate the design recommendations for the cap-and-trade program.

This section elaborates on the key program design recommendations. Each design element is defined and the design recommendation is summarized. Stakeholder input on the design element is reviewed briefly. Finally, the WCI Partners' recommendation is discussed in light of stakeholder input, the balancing required between disparate stakeholder positions, lessons learned from other cap-and-trade programs, economic analyses, and expert opinion. The design recommendations also rely on the design principles adopted by the WCI Partner jurisdictions and the overarching program goal of ensuring that greenhouse gas (GHG) emissions are reduced within the WCI Partner jurisdictions.

In conjunction with the cap-and-trade program, individual WCI Partner jurisdictions will:

- Mitigate economic impacts on consumers;
- Implement other policies that will reduce GHG emissions from the transportation sector and reduce demand for transportation fuels (such as vehicle standards, smart growth, low carbon fuel standards, and transit options); and

[17] www.westernclimateinitiative.org.

- Address jurisdiction-specific issues associated with the point of regulation and its implementation.
- If any of the design elements differ between the Design Recommendations and the following explanatory text, the Design Recommendations take precedence.

1.1. Scope

1.1.1. Definition

The *scope* defines the GHG emissions that are included in the cap-and-trade program, including the sectors, emissions sources, and greenhouse gases that fall under the cap. The cap is the absolute aggregate limit on GHG emissions.

1.1.2. Design Recommendation

The WCI Partner jurisdictions recommend a multi-sector greenhouse gas cap-and-trade program covering emissions of the six major GHGs: carbon dioxide, methane, nitrous oxide, perfluorocarbons (PFCs), hydrofluorocarbons (HFCs), and sulfur hexafluoride.[18] In the initial compliance period beginning in 2012, the program will cover emissions from electricity, including imported electricity; industrial combustion at large sources; and industrial process emissions[19] for which adequate quantification methods exist. In the second compliance period, beginning in 2015, the program will expand to cover fuels combusted at industrial, residential, and commercial buildings that are not otherwise covered as emissions sources, as well as transportation fuels. The first compliance period of the program will include about half of the economy-wide emissions in the WCI Partner jurisdictions. Starting with the second compliance period, the program will include about 90 percent of emissions. The program is capable of expanding further over time based on new information.

The carbon dioxide emissions from the combustion of biomass that are determined to be carbon neutral will not be covered by the cap-and-trade program emissions cap. Similarly, the carbon dioxide emissions from the combustion of bio-fuels or the bio-fuel component of blended fuels will not be covered by the program emissions cap. However, carbon dioxide emissions from biomass, bio-fuels, and the bio-fuel component of blended fuels will be subject to the program reporting requirements. The WCI Partner jurisdictions are continuing to assess whether and how to include upstream emissions from bio-fuel and fossil fuel production that do not take place within the WCI Partner jurisdictions.

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[18] The Scope Draft Design Recommendations describes the options considered by the scope subcommittee, the evaluation criteria applied to the options, the data and analytical inputs (including data on emissions, numbers of entities, and potential cost impacts), and the decision process for deciding on the recommendations. Available at www.westernclimateinitiative.org/ewebeditpro/items/O104F16031.PDF.

[19] As used here, process emissions include emissions from chemical, biological, and other non-combustion processes. These emissions may be deliberate (e.g., vented), fugitive (e.g., leaked), or accidental.

Individual jurisdictions may utilize comparable fiscal measures, such as British Columbia's carbon tax, to address transportation fuels and fuel use by residential and commercial sources, and industrial fuels not otherwise covered at the emissions source. Adequate quantification methods will be established for emissions sources before they are included in the program.

1.1.3. Stakeholder Input

Stakeholder comments expressed strong support for the broadest possible coverage of sources and emissions under the cap-and-trade program. Factors identified by stakeholders supporting a broad scope include:

- To provide greater certainty that economy-wide emission reductions will be achieved;
- To reduce compliance costs by covering a broad set of emissions sources with diverse emission reduction opportunities;
- To create a level playing field for all fuels;
- To ensure that carbon is priced throughout the economy; and
- To create a more robust GHG trading market.

Many stakeholders stressed the importance of having reliable measurement, monitoring, and reporting protocols in place in order to include an emissions source in the program. For example, stakeholders from the waste management industry highlighted their view that the quantification protocols for landfill methane emissions cannot currently calculate methane emissions at individual landfills with adequate precision for a cap-and-trade program.

Considerable input was received on whether to include transportation fuels in the cap-and-trade program. Many stakeholders supported including transportation fuels in the program, emphasizing that these fuels are the largest source of GHG emissions across the WCI Partner jurisdictions and for most of the individual jurisdictions. They argued that these fuels need to be included to ensure that the economy-wide emission reduction goals can be achieved. Some stakeholders pointed out that if transportation fuels were omitted from coverage, then they would enjoy a competitive advantage over electricity as a vehicle fuel, since electricity would be covered by the program. Stakeholders also provided analyses indicating that including transportation fuels will reduce the concentration of the carbon trading market by including significant additional participants. Reduced concentration may help protect against market manipulation and provide for a more robust market.

A small group of stakeholders expressed opposition or hesitation to including transportation fuels citing concerns regarding: economic impacts, particularly on low-income communities; administrative complexity; and the lack of technical options for reducing reliance on fossil-carbon-based fuels. Some stakeholders suggested that the demand for transportation fuels has been shown to be highly inelastic, so that there would be little emission reduction achieved by including the fuels in the program. Other stakeholders cited analyses suggesting that the demand for transportation may be inelastic, but the demand for traditional transportation fuels was or is becoming increasingly elastic.

The timing for including transportation fuels in the program was also the subject of considerable input. Some stakeholders said it was best to include the fuels in the first compliance period, in particular to internalize the price of carbon as soon as possible. Others said that a delay in coverage was warranted to allow the point of regulation to be adequately determined and to enable complementary policies to enhance the availability of options for reducing emissions.

Stakeholders also commented on whether and when residential and commercial fuels should be included in the cap-and-trade program. Some stakeholders expressed concerns regarding economic impacts and administrative complexity. Some commented that direct use of natural gas at a residence or business is a more efficient use of that fuel than using it to generate electricity and, for this reason, should be excluded from coverage in the program. It was also argued that energy efficiency programs would be a more effective method of reducing emissions from these fuels. Others stressed the importance of creating a level playing field across all fuels, indicating that natural gas competes with electricity in residential and commercial applications.

The inclusion of industrial process emissions was also the subject of stakeholder input. Stakeholders pointed out that some process emissions are due to chemical reactions that are fundamental to their production processes. They recommended that these “fixed process emissions” be excluded from the program. Similarly, some stakeholders suggested that the process emissions from geothermal electricity generation should be excluded because geothermal electric generation is a low-emitting process.

Issues were also raised by stakeholders related to incorporating combined heat and power (cogeneration) into the program since it has implications in both the industrial and electricity sectors.

1.2. Discussion of WCI Partners’ Recommendation

The WCI Partner jurisdictions have weighed all input carefully and have proposed a program scope that best achieves the program objectives and addresses stakeholder concerns. The WCI Partners are persuaded by the multiple benefits of having as broad a scope as possible, including transportation fuels and fuels for residential, commercial, and small industrial users along with electric sector emissions and industrial emissions. Recognizing that transportation fuels are the largest source of GHG emissions in the region, the WCI Partners have concluded that transportation fuels must be included in order to achieve the objective of reducing emissions not only by 2020, but by 2050. Additionally, the WCI Partners believe that it is important to internalize the cost of carbon throughout the economy and to ensure a level playing field across all fuels. Consequently, the WCI Partners have also concluded that there are important benefits from including transportation fuels and fuels for residential, commercial, and small industrial users.

The timing of the coverage of transportation fuels and fuels for residential, commercial, and small industrial users was considered carefully. While there are benefits of including these fuels starting with the first compliance period, multiple factors necessitated covering them starting in the second compliance period. Electric sector emissions and industrial emissions are traditional emissions sources regulated in the context of clean air regulations. In the WCI Partners' judgment, it is practical to cover these sectors from the start of the program in 2012.

Emissions from fuels for residential, commercial, and small industrial users and transportation fuels are different than those typically dealt with by regulatory agencies under either the U.S. or Canadian Clean Air Acts. The WCI Partner jurisdictions concluded that it is important to have time to develop clear requirements for the entities that will have a regulatory obligation for these emissions, including how to calculate or measure their emissions. In addition, the Partner jurisdictions believe it is important for other policies that will reduce overall consumer demand for these fuels (such as the California clean car standards and strategies to reduce vehicle miles traveled, and to increase the use of low carbon or other "cleaner" fuels) be put in place before these fuels are covered by the cap-and-trade program. The WCI Partner jurisdictions recognize the importance of increased emphasis on energy efficiency to reduce fuel combustion in residential, commercial, and small industrial uses. The WCI Partner jurisdictions also believe it is important to develop strategies to address any potential consumer impacts from covering these emission sources in advance of the second compliance period.

All process emissions with adequate quantification methods will be included in the program. The WCI Partner jurisdictions believe that it is important to incorporate the price of carbon throughout the economy, including in products with fixed process emissions. However, the WCI Partners also recognize that the competitive position of some industrial sources could be affected by this decision. Consequently, the WCI Partners are continuing to evaluate the potential competitive impacts on these sources and will address these impacts if they are found to be significant.

Economic analyses support the recommendation for broad coverage in the cap-and-trade program. The analysis conducted for the WCI Partners is consistent with the body of literature supporting a broad scope, including transportation fuels. In particular, the analysis found that compliance costs can be reduced if the program includes a broad scope.

The WCI Partner jurisdictions recognize the importance of combined heat and power (cogeneration) in the program scope and are continuing to evaluate its implications for the program design.

1.3. Point of Regulation

1.3.1. Definition

The *point of regulation* is the entity or facility with the compliance obligation. The term *entity* is used (a) when the point of regulation is upstream of the point of emissions, to describe a company that has an obligation to surrender allowances to cover the expected emissions from the combustion of the fuel the company is moving through commerce, or (b) when the point of regulation is at the First Jurisdictional Deliverer, to describe a company that has an obligation to surrender allowances to cover the emissions attributable to the generation of power the company is importing. When the point of regulation is at the point where the emissions occur, the term *facility* is generally used. A *compliance obligation* is the requirement to surrender GHG allowances sufficient to cover actual emissions during the compliance period.

1.3.2. Design Recommendation

The WCI Partner jurisdictions are recommending the following points of regulation for the cap-and-trade program:

- For industrial process and combustion sources with emissions above the threshold, the point of regulation is at the facility that has the point of emissions.
- For entities generating and/or delivering electricity with attributed emissions above the threshold, the point of regulation is at the First Jurisdictional Deliverer. This means at the facilities generating power within the WCI Partner jurisdictions and at the first entity over which a Partner has regulatory authority that delivers electricity generated outside the WCI into a WCI Partner jurisdiction for consumption in that Partner jurisdiction.
- For residential, commercial, and industrial fuel combustion at facilities with emissions below the threshold, the point of regulation is where the fuels enter commerce in the WCI Partner jurisdictions, generally at a fuel distributor. The precise point will be determined before the fuels are brought into the program in 2015 and may vary by jurisdiction.
- For transportation fuel combustion, the point of regulation is where the fuels enter commerce in the WCI Partner jurisdictions, generally at the terminal rack, final blender, or distributor. The precise point will be determined before these fuels are brought into the program in 2015 and may vary by jurisdiction.

1.3.3. Stakeholder Input

Stakeholders provided a broad range of comments regarding the preferred points of regulation for the various emissions included in the program. Some stakeholders supported a point of regulation as close to the point of emissions as is practical in order to provide a regulatory obligation on the actual emitter. Other stakeholders supported an upstream point of regulation, particularly for transportation and other fuels in order to provide as broad coverage as possible.

The WCI Partner jurisdictions received a great variety of comments on the point of regulation for the electricity sector. A majority of commenters favored some approach to cover emissions associated with electricity from outside the WCI Partner jurisdictions. However, there was a wide variety of opinions on how best to cover emissions from imported electricity. A specific challenge relative to covering all deliverers of electricity is the need to track the emissions from the point of generation to the point of delivery inside the WCI Partner jurisdictions. Some commenters observed that, considering this challenge, the WCI Partners should start with a generator-based only point of regulation for electricity, then expand to include power imported for consumption into the WCI Partner jurisdictions once the tracking issue was resolved. Some stakeholders suggested that the tracking issues are complex enough that additional technical assessment is necessary to ensure an adequate approach can be successfully deployed.

1.3.4. Discussion of WCI Partners' Recommendation

In selecting the point of regulation for the different covered sources, the WCI Partner jurisdictions considered the experience of prior cap-and-trade programs, the administrative requirements for the covered facilities and entities, the number of facilities and entities that would be included, and especially given the regional nature of the program, the potential for leakage. For industrial facilities, the point of regulation will be at the facility with the source of the emissions, putting the regulatory obligation at the point of emission. Because there are a very large number of small combustion sources in the transportation, residential and commercial sectors, and at small industrial facilities, the Partner jurisdictions decided it would be impractical to regulate at the point of emissions for these sectors. Rather, the WCI Partners found that these emissions can best be covered upstream at the point of entry of the fuel into the region's economy. By starting the inclusion of these fuels in the second compliance period, the Partners have allowed sufficient time to address issues related to defining the precise upstream point of regulation for these sources.

For electricity, the point of regulation will be at the First Jurisdictional Deliverer. The First Jurisdictional Deliverer is the generator of electricity in a WCI jurisdiction, or the first deliverer of electricity that is generated outside the region to be consumed within a WCI Partner jurisdiction. Emissions associated with power that is wheeled through the WCI Partner jurisdictions but not consumed in any of them is not covered by the program. The Partners recognize that there will be challenges to tracking emissions from the source where electricity is generated to the jurisdiction where it will be consumed. However, the WCI Partners also recognize that a significant amount of electricity consumed in the WCI Partner jurisdictions is generated by federal entities, on tribal land, or in non-WCI jurisdictions. Due to the interconnected nature of the electric grid, leakage of electricity emissions to jurisdictions or entities that are not part of the WCI is a significant concern that the First Jurisdictional Deliverer point of regulation is intended to address. Additionally, the Partners determined that this point of regulation can best address leakage while maintaining compatibility with wholesale electricity markets.

The recommendation to put the electricity point of regulation at the First Jurisdictional Deliverer represents a WCI innovation to eliminate emissions leakage. Previous programs—such as the Regional Greenhouse Gas Initiative, which follows a pure generator-based approach—have generally failed to address the leakage potential at all. As a new approach, First Jurisdictional Deliverer will pose some new challenges to implement. Given these challenges, work will continue on the First Jurisdictional Deliverer approach, including additional opportunities for stakeholder input during five stakeholder technical working sessions scheduled through the fall and winter of 2008/09. These meetings will provide the WCI Partners, technical experts, and other stakeholders additional opportunities to work together on key issues associated with the implementation of the First Jurisdictional Deliverer approach.

1.4. Thresholds Triggering a Compliance Obligation under the Cap-and-Trade Program

1.4.1. Definition

Thresholds are annual emission levels that are used to determine whether a particular entity or facility will have a compliance obligation under the cap-and-trade program.

1.4.2. Design Recommendation

The cap-and-trade program will apply an emissions threshold of 25,000 metric tons of CO_2e annually to determine the facilities or entities that will have a regulatory compliance obligation under the program.[20] Additional analyses, including data from mandatory reporting, will be performed to determine if adjustments to the threshold are needed to ensure sufficient coverage or to address competitiveness issues within individual sectors prior to the beginning of the program (i.e., because different Partner jurisdictions have the same industry but with different-sized sources). The WCI Partner jurisdictions will develop a method to prevent entities or facilities from avoiding coverage by breaking themselves into smaller units that individually have emission levels that are below the threshold.

1.4.3. Stakeholder Input

Stakeholders provided a broad range of comments regarding how best to apply emission thresholds. The comments were broadly consistent with the goal of covering the vast majority of emissions while reducing administrative burden by minimizing the number of entities and facilities with a direct compliance obligation. Stakeholders differed in their

[20] The Scope Draft Design Recommendations address the question of thresholds and include a section (Section 4.3) on considerations for setting emissions thresholds. Available at http://www.westernclimateinitiative.org/ewebeditpro/items/O104F16031.PDF.

balancing of these objectives, with some recommending lower thresholds, such as 10,000 metric tons of CO_2e annually, and at least one stakeholder recommending 100,000 metric tons annually. Sector-specific thresholds were also discussed, including thresholds defined in terms of production capacity (such as megawatt (MW) capacity for electric power generation) and other units.

Stakeholders also emphasized the importance of defining how the threshold would be applied, including the definition of "facility" or "entity" that would be used. The definition of facility was discussed particularly with reference to oil and gas production fields that may contain equipment dispersed over large areas. Some stakeholders inquired whether the threshold would be applied prospectively (i.e., prior to the start of the compliance period), annually during a compliance period, or after the end of the compliance period.

1.4.4. Discussion of WCI Partners' Recommendation

The WCI Partner considered a broad range of thresholds for the program, with the objective of covering a large portion of emissions (e.g., 90 percent of the emissions in the covered sectors) with as few facilities and entities as possible. The WCI Partner jurisdictions agree with the objective of minimizing the number of facilities and entities with a direct regulatory obligation to minimize the program's administrative burden for both the complying industries and the program administrators. The WCI Partners reviewed available data from several jurisdictions to assess how many facilities and entities would be expected to have compliance obligations and the portion of total emissions covered for a range of threshold values.[21] Based on this review, the WCI Partners concluded that current data support setting an emission threshold of 25,000 metric tons of CO_2e per year and that this threshold would cover more than 90 percent of emissions.

The WCI Partners recognize that additional data will be valuable for assessing the appropriateness of the threshold level. The comprehensive mandatory emissions reporting will provide more complete data, which will be examined to ensure that the threshold is set to achieve the level of program coverage desired. Of note is that by including residential, commercial, and small industrial fuels in the program at an upstream point of regulation, the threshold becomes less important for ensuring coverage of emissions from these fuels: the emissions at facilities below the threshold are covered upstream. Additionally, as discussed above, the WCI Partners will assess whether the threshold creates competitiveness impacts within industries.

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[21] For example, The California Air Resources Board found that in California, a threshold of 25,000 metric tons of CO2 covered about 94 percent of emissions from stationary sources. A threshold of 10,000 metric tons of CO2 increased coverage to only 96 percent of emissions, but nearly doubled the number of regulated sources. See the Staff Report: Initial Statement of Reasons for Rulemaking, available online at http://www.arb.ca.gov/regact/2007/ghg2007/isor.pdf.

1.5. Program Expansion

1.5.1. Definition

Program expansion allows the cap-and-trade program to incorporate additional sectors, greenhouse gases, or facilities or entities under the cap, or to include a new Partner in the cap-and-trade-program.

1.5.2. Design Recommendation

The WCI Partner jurisdictions have designed a cap-and-trade program that is capable of expanding over time (including possibly adjusting applicability thresholds over time). Prior to each compliance period, the WCI Partner jurisdictions will review whether to bring new sources into the program, and if so, which ones.

1.5.3. Stakeholder Input

The great majority of stakeholders commenting suggested broad coverage to the extent practicable. Some also expressed a desire to bring all of the states and provinces that are part of the western interconnected electrical grid into the program.

1.5.4. Discussion of WCI Partners' Recommendation

A provision that allows for expansion over time is responsive to public comments calling for broad coverage of the cap-and-trade program. The scope of the program will expand from its initial coverage of industrial combustion and process sources and electricity sources in the first compliance period. In the second compliance period, transportation fuels will be included, along with residential, commercial, and industrial fuels serving facilities not covered by the program in the first compliance period. In addition, the program emissions threshold has been set initially at 25,000 metric tons of CO_2e annually, but will be revisited based on the mandatory emissions data to be reported by emissions sources region-wide, and additional facilities or entities may be brought into the program. Finally, the WCI Partner jurisdictions would like any states, provinces or tribes that have committed to making GHG emission reductions comparable to the WCI regional reduction goal to become Partners in the WCI.

1.6. Role of Other Policies

1.6.1. Definition

Other policies include complementary policies and alternative policies. A *complementary policy* is used in this context to mean policies other than a cap-and-trade program that aid in the goal of achieving emission reductions inside or outside the capped sectors. *An* *alternative policy* is a policy that is employed in lieu of a cap-and-trade program for one or more sectors.

1.6.2. Design Recommendation

The role of other GHG-reducing policies is to help the WCI Partner jurisdictions achieve their 2020 reduction goal and provide other benefits. Those policies will work in concert with the cap-and-trade program and may apply to any source of GHG emissions.

In addition, the WCI Partner jurisdictions have agreed that individual jurisdictions may use fiscal measures that contribute to achieving overall comparable GHG emission reductions and internalize the price of carbon as expected through the regional cap-and-trade program for transportation and residential/commercial/small industrial fuel users. British Columbia currently has a carbon tax on these fuels. By 2012, the WCI Partner jurisdictions will determine the mechanism for integrating the cap-and-trade program with British Columbia's carbon tax.

1.6.3. Stakeholder Input

Many stakeholders emphasized the importance of complementary measures, especially for the residential, commercial, and transportation sectors. Others expressed concern that complementary measures would not provide the same level of certainty in emissions reductions from these sectors as would coverage under the cap.

1.6.4. Discussion of WCI Partners' Recommendation

The WCI Partner jurisdictions recognize that it will take numerous policies working in concert with cap-and-trade to achieve the regional reduction goal. The WCI economic analysis supports this point. It also makes sense: for example, codes that require energy efficient buildings complement the inclusion of electricity and residential, commercial, and small industrial fuel use under the cap.

In addition to aiding in the achievement of reductions at sources covered by the cap, complementary policies are needed for reductions at sources not covered by the cap-and-trade program. For example, during the first compliance period, the WCI Partners are recommending that complementary policies be instituted to reduce fuel demand in the transportation residential, and commercial sector, and by small industrial fuel users. This will help ensure consumers have real choices about the cars they drive, the fuels they use, and energy efficient appliances and buildings when these fuels are included in the cap-and-trade program in 2015.

The WCI Partner jurisdictions also agree that other policies, such as British Columbia's carbon tax, can be used as an alternative to cap-and-trade if designed to achieve comparable emission reductions and to internalize the cost of carbon for transportation fuel and fuel use by residential, commercial, and small industrial sources, as expected through the cap-and-trade program.

1.7. Setting the Regional Cap for the Cap-and-Trade Program

1.7.1. Definition

The *regional cap* is the overall GHG emissions limit set for the facilities and entities covered by the cap-and-trade program. The cap declines over time to the desired reduction limit in 2020. For the WCI Partner jurisdictions, the program is designed to achieve their 2020 emissions goal.

1.7.2. Design Recommendation

The WCI Partner jurisdictions are recommending the following with respect to the aggregate regional emissions cap:

- The aggregate regional cap for the cap-and-trade program will (a) represent the sum of the WCI Partner jurisdictions allowance budgets; (b) include annual caps with three-year compliance periods, and (c) decline over time to reach the 2020 cap level.
- The initial 2012 regional cap will be set based on the best estimate of expected actual emissions. Among the factors that will be considered in making these estimates are population growth, economic growth, voluntary and mandatory emission reductions, and other factors including reporting data that is available when the cap is set. Of particular importance is that the voluntary emission reductions recognized through the issuance of Early Reduction Allowances be reflected in the estimates for the 2012 allowance budgets for each WCI Partner, and consequently the region as a whole (see Part 1.10 for a discussion of the Early Reduction Allowances). A mechanism will be developed that reconciles the 2012 allowance budgets for each Partner with the Early Reduction Allowances issued by each Partner.
- The 2015 regional cap will be set by adding the best estimate of actual emissions in 2015 from transportation fuels and residential, commercial, and industrial fuels (and any other sectors or sources that may be added to the program in 2015) to the emissions cap trajectory for the sources first included in the program in 2012.
- The 2020 regional cap will be set so that reductions achieved by the cap plus reductions from other GHG reduction policies will achieve the WCI 2020 regional emissions goal.
- Annual regional caps for calendar years 2012 through 2020 will be established before the start of the program in 2012 so that the total number of allowances issued in each three-year compliance period through 2020 will be known.
- The annual regional caps will only be adjusted for changes in WCI membership, changes in program scope or applicability thresholds, or to correct for data discovered

to be incorrect or inaccurate. Any adjustments will be made before the beginning of a compliance period.

1.7.3. Stakeholder Input

A number of stakeholders cautioned against beginning the cap-and-trade program with a cap that over-allocates emissions allowances, with some recommending use of actual, historic emissions as opposed to estimates of future emissions that rely on best available data. Many stakeholders expressed concern that setting the regional cap at the level of emissions expected in 2012 will encourage emitters to increase their emissions prior to the setting of the regional cap in order to increase the allowances in the system. Some stakeholders expressed support for setting the initial cap far ahead of the 2012 program start, so that the program reduces emissions in the first year and does not penalize early actions or create a "perverse incentive" for higher emissions before the program starts. Stakeholders were not unanimous on whether the cap should decline in a uniform straight line from the start of the program, or begin without a reduction and decline at an accelerating rate over time. Many stakeholders stressed the importance of having good emissions data for setting the cap to avoid over-allocation and to ensure more robust reductions from the program.

1.7.4. Discussion of WCI Partners' Recommendation

Recognizing that good emissions data will not be available before it is time to set the 2012 cap, the WCI Partner jurisdictions have accounted for the need to project actual emissions in the first year of the program. This projection will take into account population growth, economic growth, voluntary and mandatory emissions reductions, and other factors. Some WCI Partner jurisdictions will have limited emissions reporting in place prior to the recommended start of the WCI reporting in 2010; this reporting data will also be considered. The 2015 cap will bring in additional sectors under the cap, and the initial cap for these sectors will be established in a similar manner, with the reporting data playing a larger role.

The recommended approach for setting the 2012 emissions cap does not provide an incentive to increase emissions through 2012. The estimate for 2012 will be completed at the latest in 2010. Consequently, there is no opportunity to increase emissions prior to 2012 to influence the estimate of the 2012 emissions cap. Also, to provide an incentive to reduce emissions before the start of the program in 2012, the WCI Partner jurisdictions are recommending Early Reduction Allowances, which will provide allowances for certain voluntary reductions made during a specific period prior to 2012.

To guard against over-allocation, the WCI Partner jurisdictions have also recommended that the first five percent of the auctioned allowances have a minimum reserve price. If allowances are not purchased at or above the minimum reserve price, a portion will be retired, auctioned in a subsequent period, or distributed in a subsequent period. This mechanism will serve to remove "extra" allowances from the market. This auction provision is detailed below in Part 1.9.

The WCI Partner jurisdictions are recommending that the annual regional caps from 2012 to 2020 follow a straight-line declining trajectory, recognizing that the total amount of allowances will increase in 2015 when transportation and other fuels are added to the program. It should be noted that the end point for 2020 will not change when those fuels are added. All caps will be established in advance of the start of the program in 2012 so that the reductions accomplished from the program will be known well in advance. Setting the caps in advance will also allow the WCI Partner jurisdictions to ensure the 2020 reduction goal will be met.

The economic modeling analysis suggests that the cap-and-trade program can achieve reductions from capped sectors consistent with the regional reduction goal with modest economic benefits. The cost per metric ton of allowances is expected to remain below $25 through 2020 with complementary policies, banking, and offsets. WCI's economic modeling found that the savings from reduced fuel expenditures under a cap-and-trade program with complementary policies could exceed the cost of additional investments in energy efficiency. The overall effect on the economy (e.g., the effect of the WCI program on state GDP, employment, and income) remains to be analyzed via additional macroeconomic modeling; however, prior modeling studies of other proposed cap-and-trade programs found that the economy can continue to grow robustly under well-designed climate policies.

1.8. Allowance Apportionment to WCI Partners

1.8.1. Definition

Allowance apportionment describes the individual Partner share of the overall "budget" of GHG emission allowances under a regional cap. An allowance budget must be set for each Partner jurisdiction.

1.8.2. Design Recommendation

The WCI Partner jurisdictions are recommending the following concerning the establishment of individual WCI Partner allowance budgets:[22]

- Each WCI Partner will have an annual allowance budget within the regional cap. All annual allowance budgets through 2020 will be established before the start of the program in 2012. The sum of the individual Partner's allowance budgets will equal the regional cap.

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[22] The Allocation Options paper describes the advantages and disadvantages of different allocation options and the relevant design principles. Available at http://www.westernclimateinitiative.org/ewebeditpro/items/O104F14628.pdf.

- Each WCI Partner's 2012 allowance budget will be based on the best estimate of expected emissions for sources covered in the cap-and-trade program in the WCI Partner's jurisdiction in 2012, developed using the best available data and by accounting for expected changes in emissions in 2012. Population growth, economic growth, voluntary and mandatory emissions reductions, and other factors will be considered. Of particular importance is that the voluntary emission reductions recognized through the issuance of Early Reduction Allowances be reflected in the estimates for the 2012 allowance budgets. A mechanism is needed, and will be developed, that reconciles the 2012 allowance budgets for each Partner with the Early Reduction Allowances issued by each Partner.
- There will be a one-time adjustment in 2012 to each WCI Partner jurisdiction's allowance budget to account for the production and consumption of electricity megawatt hours within each WCI Partner jurisdiction, population growth, and the share of total WCI Partner jurisdictions emissions in 2001 through 2005. Each WCI Partner jurisdiction will make a one-time contribution of one percent of its 2012 budget to make these adjustments.
- For 2015, each WCI Partner jurisdiction's allowance budget will be set by adding the best estimate of expected actual emissions in 2015 from transportation, residential, and commercial fuels, and small industrial fuel users (and any other sectors or sources that may be added to the program for the first time in 2015) to the emissions trajectory for the sources first included in the program in 2012. The estimate of expected actual emissions in 2015 will be developed using the best available data (including available mandatory reporting data) and by accounting for expected changes in emissions in 2015 for the sources added to the cap at that time. Population growth, economic growth, voluntary and mandatory emissions reductions, and other factors will be considered in making the estimate.
- Each WCI Partner jurisdiction's 2020 allowance budget will be derived from its individual WCI Partner jurisdiction goal used for purposes of the program.[23] Reductions from other greenhouse gas reduction policies will also be considered.
- In order to avoid the double counting of emissions associated with electricity that is generated in one WCI Partner jurisdiction but consumed in another Partner jurisdiction, the affected WCI Partner jurisdictions will negotiate an equitable solution for apportioning those allowances.
- For years post-2020, the WCI Partner jurisdictions will set allowance budgets not less than three years in advance, based on future reduction limits or goals and using at least three years of reporting data for covered sectors.
- Individual WCI Partner jurisdiction allowance budgets will be established before the start of the program in 2012 and will only be adjusted for changes in WCI membership, changes in program scope or applicability thresholds, or to correct for errors discovered in the data.

[23] Partner goals are those reduction goals or limits that have been established by each individual WCI Partner jurisdiction for the cap-and-trade program.

1.8.3. Stakeholder Input

Stakeholders provided a wide diversity of comments on potential ways to apportion allowances among Partners, with little consensus on key issues particularly for the electricity sector. Many argued for emissions to be apportioned based on load while others were equally passionate that emissions be apportioned based on historical emission levels. The comments reflected the stakeholders' view of how the apportionment method selected might affect their potential to receive free allocation.

Several stakeholders called for WCI to recognize the voluntary market for Renewable Energy Credits (RECs) via a set-aside of allowances to reward or incentivize renewable investment at the regional or state and provincial level.

1.8.4. Discussion of the WCI Partners' Recommendation

The WCI Partners' recommendation for the establishment of individual WCI Partner jurisdiction allowance budgets reflects the special or unique circumstances in each state and province, including the mix of industries; the production and consumption of electricity and the source of that electricity; and expected growth in the economy and population. The WCI Partner jurisdictions agreed to make a one-time adjustment to take these factors into account. The formula for determining how to distribute the allowances associated with this adjustment will be part of the work plan for 2009 and beyond for the WCI Partner jurisdictions.

Nothing in this design precludes any individual WCI Partner jurisdiction from setting aside some amount of allowances to reward or incentive renewable energy. See Part 1.10 for the discussion on set-asides.

1.9. Allowance Distribution by Partners

1.9.1. Definition

Allowance distribution is the Partners' initial issuance of GHG emission allowances.

1.9.2. Design Recommendation

The WCI Partner jurisdictions are proposing the following approach to allowance distribution by the WCI Partners:[24]

[24] The Allocation Options paper describes the advantages and disadvantages of different allocation options and the relevant design principles. Available at http://www.westernclimateinitiative.org/ewebeditpro/items/O104F14628.pdf.

- Generally, allowance distribution will be done independently by each WCI Partner jurisdiction.
- In some cases, the WCI Partner jurisdictions have agreed to consider standardizing allowance distribution across specific sectors if analysis demonstrates uniform treatment is necessary to address competitiveness issues. This uniform treatment, if deemed necessary, will be implemented prior to the first compliance period.
- The WCI Partner jurisdictions have agreed that a portion of the *value* represented by each Partner's allowance budget (for example, through set-asides of allowances, a distribution of revenues from the auctioning of allowances, or other means) be dedicated to specific purposes that will benefit all of the WCI Partner jurisdictions. Those purposes are: energy efficiency; research, development, demonstrations, and deployment (RDD&D); agricultural and forestry sequestration; and adaptation to climate change impacts.
- The WCI Partner jurisdictions are recommending a number of other potential uses for the remaining allowance value. They are: reducing consumer impacts, especially for low-income consumers; providing for worker transition and green jobs; achieving emission reductions in communities that experience disproportionate environmental impacts; supporting community-wide efforts funded by local governments to reduce GHG emissions; providing transition assistance to industries; recognizing early actions to reduce emissions; and/or promoting economic efficiency.
- For the first compliance period, the WCI Partner jurisdictions will auction a *minimum* of 10 percent of the allowance budget, and to increase the minimum percentage to reach 25 percent in 2020. WCI aspires to reach higher auction percentages over time, possibly to 100 percent.
- Each WCI Partner jurisdiction may auction a greater percentage of its allowance budget at its discretion.
- Some jurisdictions may not have the legal authority to auction allowances and that will not prevent the other Partner jurisdictions with authority from doing so.
- Each WCI Partner will advise the other WCI Partners of its allocation methods before the program start, and at least one year in advance of the start of each subsequent compliance period.
- The WCI Partner jurisdictions have recommended that auctioning be coordinated through a regional auction platform. The design of the auction will be completed before the cap-and-trade program begins in 2012 and will consider how to prevent market manipulation under the auctions.
- To counter any potential oversupply of allowances in the emissions trading market, the WCI Partner jurisdictions recommend that the first five percent of the allowances auctioned during the first and second compliance period have a reserve price. Should some of the allowances not sell at the reserve price, the Partners may retire a fraction of the allowances or retain them to be auctioned in later compliance periods, as agreed to by the WCI Partners in advance.

1.9.3. Stakeholder Input

There were widely differing opinions about how the Partners should distribute allowances. Some commenters called for 100 percent free allocation to covered facilities and entities, while others favored a 100 percent auction of all allowances. Still others favored a hybrid with some distribution for free, such as to retail providers of electricity with the rest auctioned. Most stakeholders who advocated for 100 percent auction pointed to the Regional Greenhouse Gas Initiative (RGGI), which ultimately decided to auction nearly 100 percent of the allowances in that system. They expressed concern over the creation of windfall profits from the distribution of free allowances to covered facilities and entities. Some stakeholders asked that the approach for distributing allowances take into account competitiveness issues that may arise between similar industries and between industrial sectors under the cap-and-trade program. No common ground was found in the widely varying stakeholder views. A number of stakeholders commented on the use of auction revenue. A variety of uses and purposes were suggested.

1.9.4. Discussion of the WCI Partners' Recommendation

In making their recommendation on allowance distribution, the WCI Partners considered the following:

- Auctions are an efficient methodology to distribute allowances and some level of auction is necessary for price discovery, which may help to minimize price volatility, especially in the beginning of the program.
- The WCI Partner jurisdictions aspire to eventually achieve a nearly 100 percent level of auction.
- Unlike RGGI, which covers just the electricity sector in the Northeast and is a deregulated market, within the WCI most of the electric sector is vertically integrated and rate regulated. Auctions are not needed to address potential windfalls under these conditions, and the allowances that are provided will be used for public purposes.
- Like RGGI, the WCI Partners believe that the decision on the maximum amount of auctioned allowances is best left to that states and provinces. The RGGI states agreed to use a percentage of the value of the allowances for consumer benefit and strategic energy purposes. The decision to auction allowances was made by each participating state after consultation with stakeholders and legislators in part as the method to assure those uses were realized. The WCI Partner jurisdictions have recommended that the allowance value be used for purposes similar to RGGI. The allowance value could be from auction revenues, direct allocation of allowances for specific uses, through set-asides, or other means as determined by the individual states and provinces.

- In addition to electricity, the first compliance period covers industrial emission sources. Many industrial facilities face domestic and international competition from facilities that are not covered by climate policies. For those facilities that are unable to pass along compliance costs in the face of this competition, there is a substantial risk of emissions leakage: the emissions would shift to outside of the WCI Partner jurisdictions without reducing emissions overall. The related issue of job leakage or outsourcing, even to other parts of the United States or Canada, is a legitimate concern that needs to be considered by each state and province. As a regional program, the primary mechanism for addressing this leakage risk is through the judicious distribution of allowances to facilities to ensure that they have an incentive to reduce emissions, but are not disadvantaged competitively.
- If the WCI Partner jurisdictions had designed a federal program for either the US or Canada, the auction percentage would have been much higher because of the guaranteed national scope of the program and the additional policy levers available at the federal level, including the ability to address international competition.
- There is uncertainty regarding the status of future international climate agreements and which countries might be signatories to them, particularly China and India. Depending on the outcome, the portion auctioned in a federal program could be higher as the leakage issues are addressed through those international agreements.
- The WCI economic modeling found that combining cap-and-trade with a portfolio of complementary policies will make the program more cost-effective. Using some portion of allowance value for the uses recommended in the WCI design will help realize that cost-effectiveness.[25]

1.10. Early Reduction Allowances and Other Early Actions or Set-Asides

1.10.1. Definition

Early Reduction Allowances refers to rewarding certain greenhouse gas reductions that occur at facilities or entities covered by the cap-and-trade program prior to the start of the program and after a set starting date. *Early actions* refer more generally to activity that reduces emissions that may not qualify for Early Reduction Allowances. *Set-asides* are allowances that are allocated for specific purposes by individual WCI Partner jurisdictions.

1.10.2. Design Recommendation

The program will encourage entities and facilities included under the cap to reduce greenhouse gas emissions after January 1, 2008 and before the start of the first compliance period in 2012 through the issuance of Early Reduction Allowances. These allowances will be in addition to the WCI Partner jurisdictions' 2012 allowance budgets. By the end of

[25] This will recognize pre-existing commitments to action and legislative requirements on use of revenue (e.g., through BC's Climate Action Plan and Carbon Tax).

2009, the WCI Partner jurisdictions will jointly establish criteria to determine which early reductions will be eligible for these allowances. The criteria will ensure that the reductions are voluntary, additional/surplus, real, verifiable, permanent, and enforceable. Each WCI Partner jurisdiction that issues Early Reduction Allowances will do so in 2012. These Early Reduction Allowances will be treated like other allowances in the cap-and-trade program.

For all other early actions and all types of set-asides, each WCI Partner jurisdiction will have the discretion to determine which early actions it will recognize or whether and for what purposes allowances will be set-aside. Recognition for early action and other set-asides will come from within the cap and out of the individual WCI Partner jurisdiction's allowance budget.

1.10.3. Stakeholder Input

There was a general level of support for granting recognition for early actions through the award of allowances. Some commenters favored awarding those allowances through set-asides coming out of individual WCI Partner allowance budgets. However, most commenters preferred that allowances be issued in addition to each WCI Partner's allowance budget as the only meaningful way to recognize GHG emission reductions that are taken prior to program launch.

1.10.4. Discussion of WCI Partners' Recommendation

The recommendation allows for the award of Early Reduction Allowances to facilities and entities that will be covered by the program that reduce their emissions on or after January 1, 2008 and before January 1, 2012. The WCI Partner jurisdictions will develop the additional criteria for determining which reduction activities will be eligible for Early Reduction Allowances. All Early Reduction Allowances will be allocated to the facilities and entities that have made reductions that are eligible for these allowances in 2012 only. Entities that will be covered by the program in 2015 may be eligible for these allowances and will also receive them in 2012.

The WCI Partner jurisdictions believe that the granting of Early Reduction Allowances provides an additional incentive for facilities and entities that will be covered by the cap-and-trade program to reduce emissions prior to the program start. Awarding these allowances will not result in an over-allocation of allowances because the Early Reduction Allowances will apply to reductions of emissions that would have otherwise been included in each Partner's 2012 allowance budget. This design recommendation is consistent with the Northeast NO_x Budget Cap-and-Trade Program, as well as the subsequent U.S. Environmental Protection Agency (EPA) NO_x SIP-Call Program.

The WCI Partner jurisdictions also recognize that there are specific purposes for which allowance set-asides may be warranted. For example, a WCI Partner jurisdiction with hydro power may want to set-aside allowances for use during low water years. Alternatively, a WCI Partner jurisdiction may want to recognize early reduction activities that do not qualify for Early Reduction Allowances. Each Partner will have the discretion to create set-asides for specific purposes; any allowances used for these purposes will come from the Partner's allowance budget.

1.11. Banking, Borrowing and Compliance Periods

1.11.1. Definitions

Banking of emissions allowances and offset credits means that holders of the allowance or offset credit may use the allowance or credit that is received or purchased in one compliance period for sale or use in a subsequent compliance period. *Borrowing* means using allowances from a future compliance period to cover a compliance obligation in a current compliance period.

1.11.2. Design Recommendation

Emission allowances will not expire. Parties who own emission allowances will be allowed to hold, or "bank," the allowances without limitation, except to the extent that restrictions on the number of allowances any one party may hold are necessary to prevent market manipulation.

Borrowing of allowances will not be permitted.

Each compliance period will cover three specific years: 2012–2014 is the first compliance period; 2015–2017 is the second compliance period, and 2018–2020 is the third compliance period. The compliance periods will not be rolling periods. Each will start on January 1 of the first year of the compliance period.

1.11.3. Stakeholder Input

Stakeholders who commented on these issues generally favored allowing unlimited banking of allowances. Some commenters expressed concern that extensive banking could lead to manipulation of the market. Borrowing attracted some favorable comments, but also a number of negative comments. Nearly all commenters favored a multi-year compliance period.

1.11.4. Discussion of WCI Partners' Recommendation

Banking of allowances can encourage early compliance. Banking of allowances can reduce volatility over time by providing liquidity in the market. It can also give facilities and entities a stake in the continued operation of the program in that banked allowances are a financial asset. In the economic analysis conducted for the WCI program design, banking moderated allowance prices more than any other program design element, including offsets, thereby reducing the costs of the program. Banking has been used in the U.S. Acid Rain cap-and-trade program, as well as the NO_x budget trading program in the Eastern United States.

The WCI Partner jurisdictions have recommended that banking of allowances be allowed without limit, except to the extent that limits on banking prove necessary to prevent market manipulation. This is an issue that the WCI Partner jurisdictions will analyze prior to the start of the program.

Borrowing of allowances will not be allowed in the WCI cap-and-trade program. Borrowing creates a risk of undermining the program because the practice creates a debt, and could result in facilities and entities with a large debt asking for relief. Such relief may result in an over-allocation of allowances, a breaking of the emissions cap or exemptions from the program's coverage. No U.S. cap-and-trade system to date has allowed borrowing.

The three-year compliance period will allow covered facilities and entities to manage planned or emergency changes in operations over the short term, as well as low water years that might affect the generation of hydro electricity.

1.12. Offsets and Allowances from Other Cap-and-Trade Systems

1.12.1. Definition

Offsets are GHG emission reductions, GHG emissions avoided, or GHG removals from the atmosphere, measured in metric tons of CO_2e. Offsets are achieved by *offset projects*. *Offset credits* (also measured in metric tons of CO_2e) are issued for offsets that are achieved by offset projects that meet certain criteria. Offset credits can be traded, and can be used for compliance purposes, or as part of voluntary actions. When used within a cap-and-trade program, offset credits used for compliance purposes come from emission sources or sinks not covered by the cap.

Emission allowances from other cap-and-trade systems are regulatory instruments used to limit GHG emissions. These emission allowances are issued by appropriate government regulatory authorities and are used for compliance purposes.

1.12.2. Design Recommendation

The WCI Partners are recommending a rigorous offset program. The purpose of the offset program is to reduce compliance costs while encouraging emission reductions, innovation, and technology development for sources and sinks not covered by the cap-and-trade program. In order to achieve these goals, the WCI Partners recommend the following offset program design features:[26]

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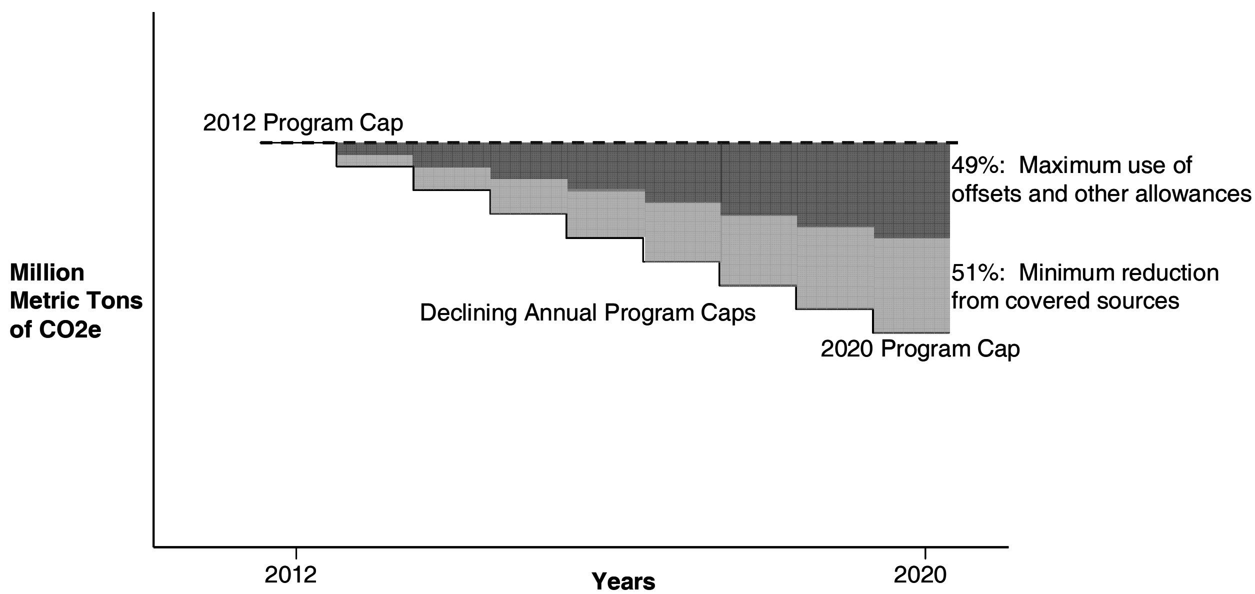
[26] The Offsets Options Paper describes how, in developing its recommendation, the Offsets subcommittee defined a range of options, including whether to have offsets, and whether to limit their quantity, location, and type. Available at http://www.westernclimateinitiative.org/ewebeditpro/items/O104F14585.PDF . WCI

- The WCI Partner jurisdictions will establish standards and processes for issuing offset credits, accepting offset credits from the Clean Development Mechanism (CDM), and recognizing emission allowances from other GHG trading systems. The offset credits issued or recognized by the WCI Partner jurisdictions and emission allowances from other GHG trading systems recognized by the WCI Partner jurisdictions can be used for compliance purposes in the WCI Partner jurisdictions cap-and-trade program. The standards and processes will be developed and implemented in an open and transparent manner that will be well-defined in advance of the start of the cap-and-trade program.
- The WCI Partner jurisdiction will limit the use of all offsets and allowances from other GHG emission trading systems that are recognized by the WCI Partner jurisdictions to no more than 49 percent of the total emission reductions from 2012-2020. This limit will ensure that a majority of emission reductions occur at WCI covered entities and facilities. The 49 percent limit is conceptually illustrated in Figure A.

Figure A: Illustration of the 49 Percent Offsets Limit



This illustration shows how the limit on the use of all offsets and allowances from other systems is limited to 49 percent of total emission reductions starting from the 2012 program emissions cap. For simplicity, this illustration does not show the expansion of the program scope in 2015.

held an Offsets Public Workshop to help inform its recommendation. Workshop materials are available at http://www.westernclimateinitiative.org/WCI_Meetings_Events.cfm . The Offsets subcommittee defined criteria and objectives for the offsets program. See the Offsets Draft Design Recommendations for details. Available at http://www.westernclimateinitiative.org/ewebeditpro/items/O104F16589.PDF

- Each WCI Partner jurisdiction will have the discretion to set a lower limit on the use of offsets and allowances from other trading systems.
- The WCI Partner jurisdictions will jointly establish criteria to ensure that all offset projects used to meet a compliance obligation result in a GHG reduction, removal or avoidance that is real, surplus/additional, verifiable and permanent. The criteria will be used to ensure that the quantification of the GHG reduction, removal, or avoidance is accurate and not double counted.
- In addition, offset projects must be enforceable by the individual WCI Partner jurisdiction that is issuing the credit and the credit must be verifiable by the individual WCI Partner jurisdiction that is accepting it.
- The standards and processes for approving offset projects will be developed and implemented in an open and transparent manner that will be well-defined in advance of the start of the cap-and-trade program.
- Offset credits will not be approved for projects that reduce, remove or avoid emissions from sources covered by the WCI cap-and-trade program.
- The WCI Partner jurisdictions have identified the following list of project types as a priority for investigation and potential participation in the offset program:
    - Agriculture (soil sequestration and manure management);
    - Forestry (afforestation/reforestation, forest management, forest preservation/conservation, forest products); and
    - Waste management (landfill gas and wastewater management).
- Starting in 2009, the WCI Partner jurisdictions will jointly coordinate to review, develop and approve protocols for the project types that meet the necessary criteria for inclusion. At the same time, WCI Partner jurisdictions will initiate the establishment of a process to coordinate the review and approval of other project types and protocols proposed by project developers.
- WCI Partner jurisdictions will recognize offsets meeting the WCI criteria within their own jurisdictions regardless of which WCI Partner jurisdiction issued them. Offsets not meeting the WCI criteria will not be accepted for compliance purposes.
- The WCI Partner jurisdictions are recommending the following geographical parameters for offsets:
    - WCI Partner jurisdictions may approve, certify, and issue offset credits for projects located throughout the United States, Canada, and Mexico where such projects are subject to comparably rigorous oversight, validation, verification and enforcement as those located within the WCI jurisdictions.
    - WCI Partner jurisdictions will not accept offset credits for GHG reductions in developed countries (Annex 1 countries in the UN Framework Convention on Climate Change) for projects that reduce, remove, or avoid emissions from sources that within WCI Partner jurisdictions are covered by the cap-and-trade program.

- The WCI Partner jurisdictions may accept offset credits from developing countries through, for example, the Clean Development Mechanism (CDM) mechanism of the Kyoto Protocol, and the WCI Partner jurisdictions may establish added criteria to ensure similar rigor to WCI approved/certified offset projects or other requirements appropriate to enable use of these offset credits in the cap-and-trade program.
- The WCI Partner jurisdictions encourage the development of offset projects located inside WCI Partner jurisdictions for compliance purposes in the WCI cap-and-trade regulatory program in order to capture collateral benefits associated with some offsets projects, such as health, social, and environmental benefits.

1.12.3. Stakeholder Input

Stakeholders generally supported a rigorous offset program. Underlying the support for an offset program is the recognition that all offsets used for compliance purposes must be of the highest quality. Stakeholders referenced issues that have arisen in previous offset programs, including the CDM, to highlight the importance of developing and applying project protocols that ensure that reductions are real, surplus/additional, verifiable, permanent, and enforceable.

Stakeholders were divided on whether the use of offsets for compliance purposes should be limited either in quantity or location. Some stakeholders suggested that there is no need to limit the use of high quality offsets because they reflect real emission reductions. Some stakeholders objected to the use of any offsets, pointing out the existing disproportionate environmental impacts experienced in some communities. Many stakeholders expressed a strong preference for a limitation on the use of offsets to ensure that a majority of reductions are made at covered facilities or entities. Many others favored no limitation provided the offsets meet rigorous criteria.

Many stakeholders expressed support for specific types of offsets. Many stakeholders also commented that the offset limitation should be applied to the reductions that are required, not to the compliance obligation of a facility or entity. Finally, some stakeholders recommended that the location of offset projects be limited to within WCI partner jurisdictions in order to assure enforcement and verification or so that the environmental co-benefits of the projects would be realized within the WCI jurisdictions. Others argued that any reduction in greenhouse gases in the world is important to combat climate change and thus the location of the project should not matter.

1.12.4. Discussion of WCI Partners' Recommendation

The WCI Partners believe that the program as designed will result in a rigorous offset program. The Partners recognize that issues have been raised regarding the quality of offsets from previous programs and the Partners propose to learn from past efforts, to build on their strengths and avoid their weaknesses. Toward this end, the Partners will develop and implement the offset program in an open and transparent manner that incorporates stakeholder input and involvement.

In making the recommendations in the program design, the WCI Partner jurisdictions considered the following:

- Offsets are an important tool to manage the risks of unexpectedly high compliance costs. Multiple analyses, including the economic analysis conducted for the WCI Partner jurisdictions, highlight the role that offsets can play in reducing the risks of high compliance costs.
- The quality of the offset project matters. It must be real, additional/surplus, permanent, verifiable, and enforceable.
- The criteria and protocols for offsets are critically important and will be developed by the WCI partner jurisdictions jointly.
- The manner in which greenhouse gases, especially carbon dioxide, mix in the atmosphere means that a reduction in any location is important to address global climate change.
- The wording of the Initiative signed by the Governors and Premiers calls for a design of a market program that will reduce greenhouse gases in the WCI Partner jurisdictions collectively "and to achieve related co-benefits."
- Co-benefits include the innovation that comes from moving toward a low carbon economy, which the cap incentivizes.
- The majority of emission reductions - at least 51 percent - will come from facilities and entities covered by the WCI program. This will help initiate the transformation to a low- carbon future within the WCI jurisdictions.
- Any WCI Partner jurisdiction that sets a limit lower than 49 percent will reduce the use of offsets and allowances from other systems from its portion of the total.
- Offset projects in developed countries (including Canada and the United States) that reduce emissions from sources that would be covered by the cap-and-trade program were they in the WCI Partner jurisdictions are not eligible to create offset credits. The WCI Partners have excluded offset credits from these projects in developed countries to avoid providing an incentive to delay the adoption of policies to reduce GHG emissions.
- Offset projects located outside the WCI jurisdictions that are subject to comparably rigorous oversight, validation, verification, and enforcement as those located within the WCI jurisdictions should help reduce compliance costs.
- The WCI Partner jurisdictions recognize that flexibility to use the limited amount of offsets and allowances from other systems any time throughout the period of 2012-2020 may help contain compliance costs. Therefore, the offset program may

incorporate flexibility to use offsets and non-WCI allowances across the three compliance periods, which each WCI Partner jurisdiction could use at its discretion.

- The WCI economic modeling analysis found that offsets contribute to managing the risk of high compliance costs in combination with banking and complementary policies. However, the analysis indicated that limiting the use of offsets and allowances from other programs to 49 percent of the reductions achieved by the program should provide adequate cost moderation.

The WCI Partner jurisdictions will establish eligible WCI offset project types, as well as requirements, methodologies and measurement and verification protocols, in advance of the program start. This approach will help ensure that project developers clearly understand the requirements for achieving acceptable reductions before the project begins. The WCI Partner jurisdictions will also develop a process by which offset project developers can propose additional offset project types for approval.

The WCI Partners did not include a recommendation to limit offset projects to WCI Partner jurisdictions in order to provide opportunities for additional low-cost reductions within the system, to support emission reductions on a global scale, and because of concerns that such a limitation may not withstand legal challenges.

1.13. Cost Containment

1.13.1. Definition

Cost containment is keeping the costs of program as low as possible, consistent with program objectives. There are a variety of cost containment mechanisms that can help manage the cost of compliance for covered entities in a cap-and-trade program. The cap-and-trade program is itself a form of cost containment, since emission trading minimizes costs. Offsets, described above, are a cost containment mechanism. Temporal flexibility, including banking, borrowing, and the length of the compliance period, is another.

1.13.2. Design Recommendation

The WCI Partner jurisdictions are recommending a broad scope and the inclusion of offsets as described above. They also recommend that purchasers and covered entities be allowed to bank allowances, without restrictions on the amount of allowances that may be banked or on how long they may be banked. WCI Partner jurisdictions recommend that borrowing of allowances from future compliance periods not be allowed. The WCI Partners recommend the compliance periods be three years long.

1.13.3. Stakeholder Input

Stakeholder input generally favored the inclusion of the cost-containment features of a broad cap-and-trade program, some offsets component, and unlimited banking. Stakeholder comment generally did not favor borrowing. In addition, some stakeholders called for an emergency clause, allowance price cap, or exit ramp in the event of a significant economic crisis attributable to the cap-and-trade program.

1.13.4. Discussion of WCI Partners' Recommendation

The WCI Partner jurisdictions have made a number of design decisions that will contain costs.

- The broad scope affords numerous opportunities to contain costs through emission trading.
- Temporal flexibility allows firms greater flexibility in compliance. Such flexibility can reduce allowance price volatility.
- Unlimited banking will help address price volatility.
- Complementary programs will also contain costs, and the program encourages their use.
- Offsets will also help contain costs.

The WCI Partner jurisdictions did not include borrowing for the reasons noted in Part 1.11. An allowance price cap was also not included because of the potential to exceed the cap and not meet the emission goal in 2020. The WCI Partners hope to link this program to other similarly rigorous programs, possibly including the EU ETS. It is the understanding of the WCI Partner jurisdictions that the EU will not link to a system with a price cap. Finally, the WCI Partner jurisdictions did not include an escape clause because each WCI Partner jurisdiction has its own laws on emergency action that must be considered in the development of any such recommendation.

1.14. Reporting

1.14.1. Definition

Reporting describes the required monitoring and measurement of GHG emissions by facilities and entities, and how these emissions will be reported.

1.14.2. Design Recommendation

The WCI Partner jurisdictions recommend that mandatory measurement and monitoring for the six included GHGs commence January 2010 with reporting of the 2010 calendar year emissions beginning in early 2011. The entities and facilities subject to reporting are those with annual emissions equal to or greater than 10,000 metric tons of CO_2e. Where fuel combustion emissions are covered upstream (e.g., emissions from transportation fuel combustion and emissions from fuel combustion at residential, commercial, and industrial facilities with emissions below the threshold) the reporting threshold will apply to entities (e.g., fuel distributors and blenders) based on the expected combustion emissions from the fuels distributed. However, in some limited instances the threshold may be based on other parameters, such as throughput or capacity, as long as these thresholds represent the equivalent of, or are lower than, the 10,000-metric-ton threshold.

WCI Partner jurisdictions will require third-party verification of reported emissions from entities and facilities that will be included under the cap.

Prior to the start of the mandatory reporting program, the WCI Partner jurisdictions will establish the essential requirements for reporting by all entities and facilities required to report in each of the WCI Partner jurisdictions. Essential requirements will include specifics regarding:

- Applicability and Boundaries
- Definitions
- Timing
- Report Content and Submittal
- Pollutants and Equivalence Factors
- Compliance
- Verification/Audit/Quality Assurance
- Emissions Quantification and Monitoring

As each WCI Partner jurisdiction collects additional emissions data from entities and facilities required to report, certain data will be made available to all WCI Partner jurisdictions for review and consideration for possible expansion of the cap-and-trade program.

Each WCI Partner jurisdiction will maintain discretion to require reporting at lower thresholds or from entities and facilities outside of the cap-and-trade program.

1.14.3. Stakeholder Input

Stakeholders said they want a reporting system that is fair, easy to manage, and not costly for reporters or WCI Partner jurisdictions. Stakeholders generally supported a transparent and robust accounting system for consistent and accurate reporting of emissions across sectors and jurisdictions. There was substantial support for the WCI Partner jurisdictions' efforts to harmonize WCI reporting and future federal greenhouse gas reporting, and there was concern regarding the burdens of having to report differently to multiple programs. Stakeholders overwhelmingly supported beginning reporting before cap-and-trade commences, in order to have accurately measured emissions as a basis for allocating allowances. Stakeholders were generally split on the topic of third-party verification.

Additional opportunities for stakeholder input will be available during the fall of 2008 as the essential requirements for reporting continue to be developed and the final draft is released in December of 2008.

1.14.4. Discussion of WCI Partners' Recommendations

Comprehensive mandatory and accurate reporting is especially important to a cap-and-trade program because of its focus on actual emissions performance and emission allowance trading. The WCI Partner jurisdictions' recommendations are consistent with the overwhelming stakeholder support for beginning reporting before cap-and-trade commences, and with the general support for the development of uniform WCI-wide reporting rules to maximize administrative simplicity and cost effectiveness.

The WCI Partners recognize the burdens that would be created by multiple widely divergent reporting programs, and will seek to harmonize reporting across WCI Partner jurisdictions. The WCI Partner jurisdictions will encourage federal reporting program development to consider the need for flexibility and accommodation of the needs of regional cap-and-trade programs already far along in their development.

The WCI Partner jurisdictions recommend a reporting threshold lower than the threshold for inclusion in the cap-and-trade program for several reasons. First, reporting must be at a lower level to ensure that accurate, verified emissions data support the exclusion of a sub-threshold entity or facility from the obligation to hold allowances. Second, reporting down to a threshold of 10,000 metric tons of CO_2e is needed to determine whether the threshold for inclusion in the cap-and-trade program is set at the appropriate level to include a high proportion of emissions. Third the lower reporting threshold is required to monitor potential leakage to facilities or entities below the threshold of the cap-and-trade program. Finally, a threshold of 10,000 metric tons of CO_2e is being considered in potential legislation for a U.S. federal cap-and-trade program.

The WCI Partner jurisdictions have considered the advantages and disadvantages of third-party verification and jurisdictional audit and quality assurance. The WCI Partner jurisdictions note that in a cap-and-trade program, every metric ton of emissions translates into a financial obligation or benefit, whereas in existing air pollutant reporting and compliance, errors in emissions data can be inconsequential if they do not affect whether a compliance limit has been exceeded. For those facilities and entities with compliance obligations, there are no inconsequential emissions totals. A high degree of accuracy and reliability for this emissions data is needed for market transparency and credibility, as well as for potential linkage to other emissions trading programs.

1.15. Enforcement

1.15.1. Definition

Enforcement is the means of assuring covered entities' compliance with the cap-and-trade program.

1.15.2. Design Recommendation

The WCI Partner jurisdictions recommend that if a covered entity or facility does not have sufficient allowances at the end of a compliance period, the entity or facility shall be required to surrender three allowances for every excess metric ton of CO2e to the jurisdiction to which they have the compliance obligation within three months of the end of each compliance period. This does not preclude other penalties allowed under individual state or provincial laws. Each WCI Partner jurisdiction will retain its existing regulatory and enforcement authority and responsibilities.

1.15.3. Stakeholder Input

Stakeholders generally recognized the importance of having an enforcement mechanism. A number of stakeholders noted a preference for financial penalties or a combined policy that calls for a violator to surrender required allowances and pay a fine. Additionally, some stakeholders requested greater flexibility during the first compliance period while regulated sources become familiar with the program. Stakeholders also highlighted the importance of transparency in the enforcement process, specifically recommending that information be made public regarding the use and origin of offset credits for compliance.

1.15.4. Discussion of WCI Partners' Recommendation

In any cap-and-trade program, participants must be accountable for their emissions and must comply with requirements for monitoring, reporting, and holding adequate emissions allowances. The enforcing jurisdiction must provide certainty through well-recognized and automatic penalties for non-compliance. Previous well-designed cap-and-trade programs have had compliance rates over 99 percent. [27]

The enforcement mechanism recommended by the WCI Partner jurisdictions is the same as the NO_x Budget Program in the northeastern United States. The Partners did not recommend a financial penalty because the price of allowances will be set by the market. It will be impossible to assure a set penalty amount will be higher than the cost of allowances.

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[27] Recommendations for Designing a Greenhouse Gas Cap-and-Trade System for California, available online at http://climatechange.ca.gov/publications/market_advisory_committee/2007-06-29_MAC_FINAL_REPORT.PDF.

However, each WCI Partner jurisdiction may establish additional penalties, including civil and criminal penalties for intentional violations of program requirements. Such penalties provide an additional level of deterrence to ensure that the financial incentives associated with the cap-and-trade program are not abused and to increase confidence in the integrity of the market and the value of an allowance.

The WCI Partner jurisdictions also recommend that certain data from the emissions reports, allowances, and offsets that are used for compliance be made public in a timely manner to ensure transparency and maintain public confidence.

1.16. Regional Organization

1.16.1. Definition

A *regional organization* centralizes the execution of administrative tasks for the WCI Partner jurisdictions. It has no authority beyond that of the individual WCI Partner jurisdictions.

1.16.2. Design Recommendation

The WCI Partner jurisdictions will create a regional administrative organization to:

- Coordinate the regional auction of allowances;
- Track emissions and provide public information on progress towards the WCI regional goal;
- Monitor and report on market activity, including any potential market manipulation;
- Serve as a forum for WCI Partners to update one another on program progress;
- Coordinate review and adoption of protocols for offsets;
- Coordinate review and adoption of updated reporting requirements and emissions measurement methods;
- Coordinate review and issuance of offset credits; and
- Suggest criteria and means to accredit service providers to deliver validation and verification services.

1.16.3. Stakeholder Input

Stakeholders generally emphasized the need for coordination across the region to ensure consistency in the program.

1.16.4. Discussion of WCI Partners' Recommendation

The regional organization recommendation is designed to help the WCI Partner jurisdictions achieve the necessary coordination. Each jurisdiction will retain its regulatory authority and enforcement responsibilities. By centralizing administrative tasks and coordinating WCI Partner activities, the regional organization will help reduce administrative costs and improve program transparency and consistency. RGGI has such an organization and it has thus far been successful in facilitating consistent implementation of RGGI's cap-and-trade program across the RGGI states.

1.17. Other Issues Raised by Stakeholders

A few stakeholders have also raised issues around market manipulation. The WCI Partners will continue to examine this issue and are committed to taking steps as the program is further designed to minimize the potential for manipulation. Evidence from existing and past allowance systems has not revealed compelling evidence that market manipulation through collusion or other market gaming situations has occurred. Price distortions did occur where there was not full price disclosure or when trading was thin, causing price volatility.

2. Overview of Cap-and-Trade

A cap-and-trade program sets a clear, mandatory, enforceable limit on GHG emissions and then allows the market to identify the least-cost ways to achieve the limit. The state or provincial government sets an absolute aggregate limit (or "cap") on GHG emissions from a sector or multiple sectors. Tradable emissions "allowances," or limited authorizations to emit,[28] are then distributed in an amount that equals the total emissions permitted by the cap, which may decline over time. These allowances can be distributed by auction, free allocation, or a combination of the two. The government specifies which entities or facilities must surrender allowances to cover their emissions at the end of a pre-determined period of time, which is called the "compliance period."

After allowances are issued by governments, they can be bought and sold ("traded"). The limit on the total number of allowances, combined with the requirement to surrender allowances to cover emissions, makes allowances valuable and scarce. Allowance trading occurs because participants face different costs for reducing emissions. Trading allowances reveals a market price for them. The price is an incentive to facilities and entities with emissions to either invest in reductions that will let them sell allowances or avoid the cost of buying them. For some participants, implementing new, low-emitting technologies may be relatively inexpensive. Those participants will buy fewer allowances or sell surplus allowances to participants that face higher emission control costs. A participant will choose to buy more allowances when the cost of an allowance is lower than the cost of reducing its emissions. By giving participants a financial incentive to control emissions and the flexibility to determine how and when emissions will be reduced, the capped level of emissions is achieved in a manner that minimizes the cost of emissions reductions.

[28] Emission allowances are not considered property rights but are a limited authorization to emit.

Emissions trading programs have been successfully implemented in the United States and other countries to control other types of emissions, such as acid rain pollutants like sulfur dioxide (SO_2), in an environmentally sound, cost-effective manner.[29]

When designed properly, cap-and-trade programs provide certainty on the level of emissions reductions achieved and help ensure these reductions are attained at the lowest cost. The cap creates a firm limit on GHG emissions. By letting individual sources choose when and how to reduce emissions, cap-and-trade minimizes the cost of emission reduction. It also stimulates the development of new technological solutions that can enable lower-cost reductions now and in the future.

Cap-and-trade programs may also cost governments less to implement than command-and-control programs in which governments specify various performance, operational, or emission requirements based upon technology.[30] The state or province needs only (1) to ensure that covered sources accurately report their emissions and, at the end of each compliance period, surrender a number of allowances equal to their emissions; and (2) to provide some market oversight to ensure fair competition.

When designed properly, cap-and-trade programs can be particularly useful in the effort to address climate change and can aid more traditional policies in achieving emissions reductions. Greenhouse gas emissions come from many different kinds of sources with widely varying options for achieving emission reductions, affording numerous opportunities for mutually advantageous trading. Also, the location of a given emissions reduction does not matter with respect to climate change. A GHG cap-and-trade program is environmentally effective because a ton of carbon dioxide (CO_2) or other greenhouse gas emitted from one source has the same global warming effect as a ton emitted from any other.[31]

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[29] Estimated savings for Phases I and II of the Acid Rain Program were more than $1 billion in 1995 dollars. The cost savings estimated in comparison to command-and-control approaches were estimated to be about 44-55 percent of the total compliance costs. *See for example* Carlson, C. P., D. Burtraw, M. Cropper, and K. L. Palmer. 2000. Sulfur dioxide control by electric utilities. *Journal of Political Economy* 108 (6):1292-1326. Ellerman, A. D., P. L. Joskow, R. Schmalensee, J. Montero, E. M. Bailey. 2000. *Markets for Clean Air: The US Acid Rain Program*. Cambridge: Cambridge University Press.

[30] For example, the U.S. acid rain program requires a staff of approximately 50 people to track all emissions data, allowance transfers, and compliance for over 4000 sources, including auditing of all hourly emissions data, tracking several thousand allowance transfers per year, annual compliance determination, and annual program assessment. See *Recommendations for Designing a Greenhouse Gas Cap-and-Trade System for California*. Recommendations of the Market Advisory Committee to the California Air Resources Board, June 2007, p. 73 and 99. Available online at www.pewclimate.org/docUploads/2007-06-29_MAC_FINAL_REPORT.pdf

[31] From a climate change perspective, because GHGs are chemically stable and persist in the atmosphere for a decade or longer and become well mixed throughout the atmosphere, the location of the reduction does not matter. Still, there may be other important policy reasons to consider the location of GHG reductions.

2.1. The Reasons for a Regional Cap-and-Trade Program

The reasons for coordinating regionally to design and implement a cap-and-trade program are compelling. A vast body of literature makes the case for a GHG cap-and-trade system that maximizes coverage of emissions and minimizes the costs of achieving a given GHG emissions level. Cap-and-trade has been applied successfully in the United States and Canada and in other regions to reduce other pollutants, and a number of countries have implemented such a system for GHGs under the Kyoto Protocol of the UN Framework Convention on Climate Change. In the absence of U.S. and Canadian federal engagement in these efforts, many U.S. states and Canadian provinces are moving ahead on their own and/or in cooperation with neighboring states and provinces to reduce GHG emissions.[32]

Because of their broader coverage, regional cap-and-trade programs perform better than individual state or provincial programs can in terms of realizing cost savings from trade, maintaining competitiveness and avoiding emissions leakage. Emissions leakage occurs when economic activity and associated emissions shift out of the jurisdiction covered by the policy in order to avoid the costs of compliance. The regional program levels the competitive playing field across the participating jurisdictions, thereby reducing the risk of emissions leakage.

Regional cap-and-trade programs can be more efficient and effective than state-by-state and province-by-province efforts because they cover more emissions sources and provide greater opportunities for mutually beneficial transactions. Administrative and technical support functions can also be shared among the participating jurisdictions, lowering the overall costs of implementation. Regional cap-and-trade programs can also help move the United States and Canada toward federal-level policies by acting as laboratories for program design and implementation. RGGI, for example, has advanced the debate in the United States around a number of cap-and-trade design issues, including allowance auctioning and offsets. WCI jurisdictions hope that their own analyses, deliberations, decisions, and implementation experiences will help to accelerate the development of U.S., Canadian, and global GHG markets.

2.2. Lessons from the European Union

The European Union (EU) developed a cap-and-trade program to meet its GHG reduction obligation under the Kyoto Protocol. The EU Emissions Trading Scheme (ETS) covers carbon dioxide emissions from certain sectors, including power generation, certain industrial process sources, and all large industrial combustion facilities. Proposed in 2001, the EU ETS began its three-year "learning phase" in 2005. The goal of the learning phase was to

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[32] In addition to the states and provinces participating in the WCI, ten Northeast states (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont) have joined to form Regional Greenhouse Gas Initiative (www.rggi.org), which is a cap-and-trade program for CO_2 from electrical utilities, and six Mid-Western States (Iowa, Illinois, Kansas, Michigan, Minnesota, and Wisconsin) and one Canadian Province (Manitoba) have signed on to the Mid-Western Greenhouse Gas Reduction Accord (www.midwesternaccord.org) to design a cap-and-trade program for their region.

develop the infrastructure and experience to successfully implement a cap-and-trade program during the second trading period, which started in 2008, and not to achieve significant reductions in GHG emissions, per se.[33]

A number of lessons can be drawn from the EU ETS. In particular, the EU ETS learning phase demonstrated:

- The importance of accurate emissions data to create an effective trading system that results in sufficient emissions reductions and to ensure that the appropriate number of allowances is distributed;
- That cost containment measures such as banking and multi-year compliance periods tend to reduce market volatility;
- Suppliers quickly factor the price of emissions allowances into their business decisions under a cap-and-trade program;
- The relationship between allowance allocation, allowance markets, and electricity regulation must be understood and addressed to avoid unintended consequences; and
- The linkage of 28 separate trading programs in the EU ETS provides a valuable prototype for a globally linked carbon market.

2.3. Lessons from Other Emission Trading Programs[34]

The United States has implemented six emissions trading programs since the late 1970s: the early U.S. EPA emissions trading programs,[35] the federal Lead-in-Gasoline, Acid Rain, and Mobile Source trading programs; the northeast regional NOx Budget Trading Program, and the Los Angeles Air Basin RECLAIM program. From an examination of the literature and experiences with these programs, there are important lessons and recommendations that emerge:

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[33] For a full examination of the EU ETS, see Ellerman, D. A. and P. Jaskow. 2008. *The European Union's Emissions Trading System in Perspective.* Pew Center on Global Climate Change. Available online at: www.pewclimate.org/docUploads/EU-ETS-In-Perspective-Report.pdf

[34] *See for example* www.epa.gov/airmarkets.usca; Aulisi, A., A. E. Farrell, J. Pershing, and S. Vandeveer. 2005. *Greenhouse Gas Emissions Trading in U.S. States. WRI White Paper.* Available online at http://pdf.wri.org/nox_ghg.pdf. Ellerman, A. D., P. L. Joskow, and D. Harrison, Jr. 2003. *Emissions Trading in the U.S*. Pew Center on Global Climate Change. Available online at www.pewclimate.org/global-warming-in-depth/all_reports/emissions_trading. *Climate Change 101: Cap and Trade*. Pew Center on Global Climate Change and Pew Center on States. Available online at www.pewclimate.org/docUploads/Cap&Trade.pdf.

[35] The early EPA programs included four programs—collectively referred to as EPA Emissions Trading or EPA ET—are related by the common objective of providing sources with flexibility to comply with traditional source-specific command-and-control standards while maintaining environmental objectives focused primarily on local air quality. They included netting, offsets, bubbles, and banking. *See* Ellerman, A. D., P. L. Joskow, and D. Harrison, Jr. 2003. *Emissions Trading in the U.S*. Pew Center on Global Climate Change.

- Emission trading has successfully reduced emissions and the costs of achieving those reductions without compromising environmental goals.[36]
- The inclusion of a broad and diverse set of emission sources under the cap will lower costs, achieve the environmental objective, and accelerate innovation, making cap-and-trade particularly applicable for reducing greenhouse gas emissions.
- A common set of rules and guidelines are required for monitoring and reporting emissions to ensure market transparency and compliance.
- Rigorous monitoring of emissions is critical to making the probability of detecting non-compliance high. Penalties for non-compliance must be strict and sure.
- There are some elements of a multi-jurisdictional cap-and-trade program that must be the same between implementing jurisdictions; these include certain elements of measurement and reporting of emissions, the schedule for distributing allowances to covered entities or facilities, compliance and reconciliation periods, the use of banking and/or borrowing, the acceptance of offsets and allowances from other trading programs, and compliance and enforcement.
- Other elements of a multi-jurisdictional cap-and-trade program do not need to be the same across implementing jurisdictions: it is not critical that the states and provinces allocate allowances within their jurisdictions in the same manner and jurisdictions may include varying levels of auction in their allowance distribution.

2.4. WCI Design Principles

To attain the Western Climate Initiative's regional GHG reduction goal, the WCI Partner jurisdictions committed to designing a cap-and-trade system that:

- Is equitable, administratively simple for government and private participants, minimizes administrative costs, and has a clear compliance path;
- Maximizes total benefits in jurisdictions throughout the region, including reducing air pollutants, diversifying energy sources, and advancing economic, environmental, and public health objectives, while also avoiding localized or disproportionate environmental or economic impacts;
- Requires all reductions to be real, verifiable, enforceable, and permanent, and surplus/additional;
- Stimulates investment, especially in low carbon technologies, and rewards innovations that will lead to long-term, permanent greenhouse gas reductions;
- Covers as many sources as is practical, while encouraging pollution reductions beyond the capped sources and sectors;

[36] When compared to a policy that would have forced scrubbing to achieve the same level of emissions (required for acid rain mitigation), cost savings of the Acid Rain Program were estimated to be $1.6 billion per year in 1995 dollars. *See* Carlson, C. P., D. Burtraw, M. Cropper, and K. L. Palmer. 2000. Sulfur dioxide control by electric utilities. *Journal of Political Economy* 108 (6):1292-1326.

- Provides appropriate recognition and incentives for early emissions reductions;
- Assures a transparent and robust accounting system that will measure and report emissions rigorously and consistently across all sectors and throughout the region;
- Minimizes the potential for leakage; and
- Facilitates linkage to similarly rigorous regional and international greenhouse gases reduction markets and encourages other states, provinces, and countries to join the market.

2.5. Statement on the Overall Policy Design

The WCI Partners are proposing the most expansive cap-and-trade program in U.S. history, covering more sectors than the EU ETS in a broad, multi-sector greenhouse gas cap-and-trade program. As designed, the program will cover approximately 90 percent of the region's GHG emissions. Recognizing that federal mandatory GHG reduction programs might emerge in the United States and/or Canada, the WCI Partner jurisdictions have designed a program that can stand alone, provide a model for, be integrated into, or be implemented in conjunction with future federal programs. The WCI Partner jurisdictions intend to promote and influence federal GHG emission reduction programs that are consistent with the WCI cap-and-trade design principles and to ensure those programs translate into absolute GHG reductions. In the event WCI issues allowances before a federal program in Canada or the United States, the WCI Partner jurisdictions will work to ensure, but cannot guarantee, that those allowances are fully recognized and valued in the operation of a federal program.

3. Process to Date and Continued Work

3.1. Setting the Regional Goal

The WCI Partner jurisdictions issued their regional GHG reduction goal on August 22, 2007 to achieve an aggregate reduction of 15 percent below 2005 levels by 2020.[37] The WCI regional goal is consistent with the state and provincial goals of the WCI Partner jurisdictions and does not replace the existing goals of the individual WCI Partner jurisdictions. Several metrics were used to establish this goal, including:

- The aggregation of GHG emissions and emissions goals of the WCI Partner jurisdictions;
- Currently available state and provincial emissions inventories, including gross emissions estimates, across all sectors, for the six GHGs reported to the United Nations Framework Convention on Climate Change by the U.S. Environmental Protection Agency in the US Greenhouse Gas Inventory and by Environment Canada in the Canada National Inventory Report: carbon dioxide (CO_2), methane (CH_4), nitrous

[37] *See* Western Climate Initiative Statement of Regional Goal. Available online at www.westernclimateinitiative.org/ewebeditpro/items/O104F13006.pdf.

oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6); and[38]

- Where available, consumption-based (or "load-based") emissions estimates for the electricity sector, reflecting the emissions associated with generating the electricity delivered to consumers in each state or province regardless of whether the electricity was generated in state/province or out of state/province.

The WCI Partner jurisdictions also committed to doing their share to reduce regional GHG emissions sufficiently over the long term to significantly lower the risk of dangerous threats to the climate. Current science suggests that this will require worldwide reductions in carbon dioxide emissions of 50 to 85 percent below 2000 levels by 2050.[39]

3.2. The Work of the Subcommittees

Five WCI subcommittees were formed to work toward a cap-and-trade program design that all WCI Partner jurisdictions can embrace and recommend for implementation in their jurisdiction. The five subcommittees and their purposes were:

- Reporting. Recommend the GHG emissions reporting system needed to support the WCI cap-and-trade program.
- Electricity. Recommend the point of regulation for the electricity sector.
- Scope. Recommend what other sectors and sources to include in the cap-and-trade program in addition to the electricity sector and the appropriate point of regulation for each sector.
- Allocations. Recommend how to apportion emissions allowances among the WCI Partner jurisdictions and how WCI Partner jurisdictions should distribute allowances to achieve jurisdictional and regional goals.
- Offsets. Recommend whether and how emissions offsets should be included.

Each subcommittee was chaired by a representative of one of the WCI Partner jurisdictions, composed of staff from WCI Partner and observer jurisdictions, and had support from various consultants and advisors working under contract to the Western Governors' Association. During the development of the draft program design, the subcommittees met regularly by conference call and at times held face-to-face meetings. All subcommittees incorporated stakeholder involvement and feedback to help design the program.

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[38] *See* EPA. 2008. *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2006*. Available online at: www.epa.gov/climatechange/emissions/usinventoryreport.html. Environment Canada. 2008. *National Inventory Report 1990-2006: Greenhouse Gas Sources and Sinks in Canada – The Canadian Government's Submission to the UN Framework Convention on Climate Change*. Available at: www.ec.gc.ca/pdb/ghg/inventory_e.cfm.

[39] IPCC. 2007. *Climate Change 2007: Synthesis Report; Summary for Policymakers.* Available online at: www.ipcc.ch/pdf/assessment-report/ar4/syr/ar4_syr_spm.pdf

In addition to these five subcommittees, an Economic Modeling Team (EMT) was established to prepare the work plan for, select, and oversee the work of a contractor to evaluate the potential economic impact of the cap-and-trade program. This effort is on-going and includes outreach to stakeholders to receive advice and data to bolster the assumptions and inputs that underlie the modeling exercise.

3.3. Stakeholder Process for the Design Recommendations

Throughout the WCI cap-and-trade design process, there have been many opportunities and methods for stakeholder input on a regional level. These opportunities supplemented and did not replace extensive stakeholder consultations at the state and provincial level. In addition, states and provinces have and are continuing to conduct extensive stakeholder consultations. The decisions reached throughout the design process have benefited greatly from stakeholder input.

The regional stakeholder process for the Design Recommendations included a number of important avenues for the sharing of information and input. Among them:

- Stakeholder Workshops. Five regional stakeholder workshops were held to allow face-to-face interaction between stakeholders and WCI Partner jurisdictions and staff. Three of these workshops were comprehensive and included subcommittee-specific sessions to explore the subject areas within each subcommittee's purview. The other two addressed offsets and electricity point-of-regulation specifically. The workshops are noted in the table below.
- Stakeholder Conference Calls. Over the course of the design effort, the WCI Partner jurisdictions held regional stakeholder conference calls to update stakeholders on progress toward a cap-and-trade design and to answer stakeholder questions.
- Review and Comment in Writing. At regular intervals throughout the process, the WCI Partner jurisdictions and the subcommittees released written work for review and comment by stakeholders.
- The Website.[40] The WCI website served as a repository for information on the design effort. The website included information on upcoming stakeholder calls and workshops, and also provided a way to submit comments to the WCI Partner jurisdictions.

The table below details the various stakeholder events along with the work products released by WCI leading up to the release of the Design Recommendations accompanying this document. As noted above, the activities outlined in the table are in addition to the individual outreach to stakeholders conducted by each individual WCI Partner jurisdiction.

[40] The Western Climate Initiative website can be accessed at www.westernclimateinitiative.org.

Part 1, Cap-and-Trade Program Design, summarizes stakeholder input on the cap-and-trade program design elements.

Table 1: The WCI Stakeholder Input Process Through September 2008

Activity	Date
Periodic Stakeholder Conference Calls	Summer-Fall 2007
Subcommittee Options Papers released for public review and comment[41]	Early January 2008
Stakeholder Workshop, Portland, OR[42]	January 10, 2008
Initial Draft Scope Recommendations and Electricity Point of Regulation Recommendations released for public review and comment	February 3, 2008
Stakeholder Conference Calls with Scope and Electricity Subcommittees	February 11, 2008
Scope of Work for Economic Analysis[43] released for public review and comment	March 3, 2008
Initial Draft Design Recommendations released[44] for public review and comment • Scope and Electricity • Offsets, Allocations, and Reporting	 March 5, 2008 April 3, 2008
Stakeholder Conference Calls with Subcommittees	Week of March 11, 2008
Offsets Workshop in Vancouver, BC[45]	March 26, 2008
Stakeholder Conference Call with Economic Modeling Team[46]	March 28, 2008
Stakeholder Conference Call with Economic Modeling Team	April 14, 2008
Stakeholder Conference Call with Economic Modeling Team	May 12, 2008
Consolidated WCI Draft Recommendations released[47] for public review and comment	May 16, 2008
Stakeholder Workshop in Salt Lake City, UT to discuss draft subcommittee recommendations[48]	May 21, 2008

[41] Allocation, Electricity, Offsets, Reporting, and Scope Options Papers are available online at www.westernclimateinitiative.org/WCI_Documents.cfm.

[42] Public workshop presentations are available online at www.westernclimateinitiative.org/WCI_Meetings_Events.cfm.

[43] Stakeholder involvement opportunities for the economic modeling effort are available online at www.westernclimateinitiative.org/Economic_Analysis.cfm.

[44] Draft Design Recommendations are available online at www.westernclimateinitiative.org/WCI_Documents.cfm.

[45] Offsets workshop materials are available online at www.westernclimateinitiative.org/WCI_Meetings_Events.cfm.

[46] Materials from the Economic Modeling Team's conference calls are available online at www.westernclimateinitiative.org/Economic_Analysis.cfm

[47] The Consolidated Draft Recommendations are available online at www.westernclimateinitiative.org/ewebeditpro/items/O104F17390.PDF.

Activity	Date
Stakeholder Conference Call with Economic Modeling Team	June 9, 2008
Electricity Subcommittee Meeting on Technical Issues Related to First Jurisdictional Deliverer in Portland, OR	July 17, 2008
Stakeholder Conference Call with Economic Modeling Team	July 21, 2008
Draft Program Design Recommendations[49] released for public review and comment	July 23, 2008
Stakeholder Workshop in San Diego, CA to Discuss Draft Design Recommendations	July 29, 2008
Final Design Recommendations to be Delivered to Governors and Premiers	September 23, 2008

3.4. Continued Work

The Design Recommendations released along with this document represent the final high-level design elements for the cap-and-trade program. Many of the design aspects will require further development. The WCI Partner jurisdictions' next task will be to develop a work plan that identifies and prioritizes those items and develop a schedule for their completion. The work plan will be shared with stakeholders once it is complete. The work plan will include opportunities for stakeholders to advise, comment, and participate in the further development of the cap-and-trade program.

4. Economic Analysis

4.1. Insights from Prior Analyses of Climate Policies

The potential economic impacts of climate protection policies have been the subject of considerable analysis and debate for more than a decade. Recognizing that significant reductions in GHG emissions are required globally to prevent the most serious climate change impacts, studies have examined how to design climate policies to minimize economic impacts. One of the important recommendations from the recent work has been that market-based policies, such as cap-and-trade programs, can reduce emissions at a lower cost than can be achieved through traditional regulation. This conclusion is grounded in economic theory as well as empirical evidence from past cap-and-trade program experience. Specifically, comprehensive carbon pricing through a cap-and-trade program takes advantage of the diverse opportunities to reduce emissions throughout the economy and provides incentives for continued innovation.

Recent efforts, therefore, move past the basic question of whether to use market-based policies, such as a cap-and-trade program, and onto the question of how to best design a

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[48] Meeting agenda and presentations are available online at www.westernclimateinitiative.org/WCI_Meetings_Events.cfm.

[49] The Draft Design Recommendations are available online at www.westernclimateinitiative.org/ewebeditpro/items/O104F18808.PDF.

cap-and-trade program. To inform the design of this program, the WCI Partner jurisdictions examined program guidance,[50] U.S. analyses of the Lieberman-Warner Climate Security Act and California AB32, and Canadian analyses by Environment Canada and British Columbia. These analyses consistently demonstrated that several program design features can have an important impact on compliance costs:

- Flexibility in the timing of GHG reductions reduces the overall costs of cumulative GHG abatement. Multiple-year compliance periods and allowance banking have been identified as effective approaches for providing flexibility.
- Allowing offset credits to be used for program compliance can lower the compliance cost of meeting emission reduction targets.
- A broad scope that covers more sectors in a cap-and-trade program can lower compliance costs by providing maximum opportunities to pursue low-cost emission reductions.

Studies have also shown that innovation in advanced, low-carbon technologies (such as carbon capture and storage for electric power generation) can have a substantial impact on compliance costs, particularly after 2020. Consequently, providing incentives for technology development and demonstration is important for minimizing costs.

Complementary policies have also been examined as a means for addressing market barriers that would otherwise hinder the exploitation of low-cost GHG emission reduction opportunities (e.g., via improved energy efficiency). Thus, complementary policies can lower the overall cost of reducing GHG emissions. Analysts differ in their treatment of complementary policies, however. Some analysts allow for cost savings to be realized from complementary policies such as building codes, appliance standards, vehicle standards, and energy efficiency programs. A recent McKinsey analysis of GHG abatement costs in the United States provides one view of the potential for gains from complementary policies.[51] McKinsey found significant opportunities to reduce GHG emissions while also saving money through investments in energy efficiency. The existence of opportunities to reduce GHG emissions at "negative cost" even in the absence of a cap-and-trade program suggests that complementary policies, such as energy efficiency standards and programs, can lead households and businesses to exploit such opportunities.

Other analysts start with the presumption that markets function efficiently, so that there is little or no opportunity for these complementary policies to lead to overall savings.[52] Under these assumptions, any climate policies must impose economic costs. This divergence of views on the potential to realize savings from complementary policies is one of the primary

[50] See, for example, U.S. Environmental Protection Agency, *A Guide to Designing a Cap and Trade Program for Pollution Control*, Office of Air and Radiation, Washington, D.C., EPA430-B-03-002, June 2003, available online at: www.epa.gov/airmarkt/resource/cap-trade-resource.html.

[51] Creyts, J., et al. (McKinsey). 2007.

[52] See generally Stavins, Robert et al. 2007. "Too Good to Be True? An Examination of Three Economic Assessments of California Climate Change Policy." AEI-Brookings Joint Center Working Paper No. 07-01.

factors that causes some studies to show a small net savings to the economy from climate policies, while others show a small net cost. What is important to recognize is that in virtually all analyses, well defined cap-and-trade programs with the cost-saving features listed above have been found to be consistent with continued robust economic growth in the U.S. and Canada. By coupling a cap-and-trade program with complementary policies, the WCI Partners expect to use the market to capture cost-effective reduction opportunities and drive innovation, while targeted complementary policies address barriers that might otherwise limit the adoption of least-cost emission reductions.

4.2. WCI Economic Analysis

In order to examine the economic impacts of WCI program design options, WCI Partner jurisdictions contracted with ICF International and Systematic Solutions, Inc. (SSI) to perform economic analyses using ENERGY 2020,[53] a multi-region, multi-sector energy model. The workings of the model and the inputs to the model were the subject of multiple stakeholder conference calls and were discussed at two WCI stakeholder workshops. Appendix B presents the results of the analysis.

To help inform the program design process, the analysis examined the implications of key design decisions, including: program scope, allowance banking, and the use of offsets. Due to time and resource constraints, the modeling was limited to the eight WCI Partner jurisdictions in the Western Electric Coordinating Council (WECC) area, thereby excluding from the analysis three Canadian provinces, Manitoba, Quebec, and Ontario. Future analyses are planned that will integrate these provinces so that a full assessment of the WCI Partner jurisdictions can be performed.

The results of the analysis provided the following insights into the program design:[54]

- Complementary Policies: The analysis demonstrated that energy efficiency programs, vehicle emissions standards, and programs to reduce vehicle miles traveled (VMT) are important for achieving emission reductions. The manner in which these policies are represented in ENERGY 2020 results in overall savings being realized from these policies. Resources from the cap-and-trade program (e.g., from the auctioning of emission allowances) can fund these complementary programs.
- Banking: The analysis demonstrated that the ability to bank allowances is critical for reducing compliance costs. Throughout all the cases examined, emission allowances

[53] More about the ENERGY 2020 model can be found online at www.energy2020.com/energy.htm.

[54] Like all analyses of climate policies, this analysis relies on a model to explore alternative policy choices and provide insights about how the economy might respond to different types and forms of regulation. The insights derived from the studies do not depend on perfectly accurate projections of the future or precise estimates of economic variables. Rather, modeling studies assess the relative impacts of policy alternatives, to estimate the likely economic effects of policies and to identify preferred policy choices. For a review of how economic models can be used in policymaking, see: Peace, Janet and John Weyant. 2008. "Insights Not Numbers: The Appropriate Use of Economic Models." White Paper prepared for the Pew Center on Global Climate Change, available at http://www.pewclimate.org/white-paper/economic-models-are-insights-not-numbers

were estimated to be banked in early years when allowance prices were below $10/metric ton, and used when allowance prices rose in later years.

- Offsets: The analysis demonstrated that under certain circumstances, offsets provide an effective mechanism for limiting compliance costs. In the analysis performed to date, offsets were assumed to be available at $20/metric ton. As allowance prices were estimated to rise to this level, offsets were estimated to be used in combination with allowance banking to reduce compliance costs.

Overall, the analysis found that the WCI Partner jurisdictions can meet the regional goal of reducing emissions to 15 percent below 2005 levels by 2020 with a small overall savings due to reduced energy expenditures exceeding the direct costs of GHG emission reductions.[55] The savings are focused primarily in the residential and commercial sectors, where energy efficiency programs and vehicle standards are expected to have the most significant impacts. Energy-intensive industrial sectors are estimated to have small net costs overall (less than 0.5 percent of output). When offsets are included in the analysis, allowance prices are estimated to increase from $6/metric ton in 2015 to about $24/metric ton in 2020. If offsets are not included, or if they cost substantially more than $20/metric ton, then the allowance price is estimated to be higher. To date the analysis has included a simplified representation of the potential supply of offsets. Additional work is being considered to develop a better estimate of the supply of offsets under various offset program policies.

The analysis examined the sensitivity of the results to various assumptions. The analysis suggests a net savings whether future energy prices are higher or lower than in the Reference Case. It also suggests a net savings with higher electricity power generation costs. If the program scope were narrowed to exclude transportation fuels and residential and commercial fuels, the overall impacts would be similar, but allowance prices may be expected to be higher because the program is focused on a smaller group of sources. If the program causes a substantial increase in natural gas prices, then the overall impact is estimated to be a small net cost to the economy. However, the program is not expected to lead to increases in natural gas prices. As discussed with stakeholders during the WCI economic analysis conference calls, it is worthwhile to explore many additional sensitivities to better understand the implications of various analytical assumptions and inputs. However, time and resources did not allow additional sensitivities to be examined for this report.

These WCI modeling results are generally consistent with the findings of prior modeling studies of both U.S. and Canadian programs. Offsets and allowance banking provide compliance flexibility that reduces allowance prices. The analysis suggests that offsets are particularly important during the years approaching 2020, but may play a minor role in the early years of the program when allowance prices are expected to be less than $10/metric ton. The overall net savings that are found are consistent with studies that assume that complementary policies, such as energy efficiency programs and vehicle standards, can

[55] Reduced energy expenditures are caused by improved energy efficiency.

result in economic savings. While the overall costs and savings from emission reductions and reduced fuel expenditures are small, potential impacts on specific energy-intensive industrial sectors warrant additional examination. In particular, the results reinforce the need to consider strategies for mitigating economic impacts on industries facing competition from facilities that are not included in climate policies.

In considering the results of the WCI analysis, it is worth highlighting several important assumptions:

- It is assumed that no new nuclear power or hydropower generation capacity will be built prior to 2020. Therefore, the analysis does not include any increase in this power as a result of the cap-and-trade program.
- It is assumed that no carbon capture and storage for electric power generation will be built prior to 2020. Consequently, the analysis does not include the benefits of this carbon-sequestering technology.
- It is assumed that no new coal-fired power plants are built in the WECC states and provinces through 2020 beyond those that are already planned.
- It is assumed that plug-in hybrid electric vehicles will not be produced in any significant quantity prior to 2020. Thus, the model does not include an increase in this low carbon transportation alternative as a result of the cap-and-trade program.
- For the U.S. states, the requirements of the Energy Independence and Security Act (EISA) are assumed to be part of the Reference Case against which the cap-and-trade program is evaluated. For the Canadian provinces, lighting, equipment, and appliance standards as set out by the Canadian Standards Association as well as the federal "ecoENERGY" Renewable Fuels Strategy are included in the Reference Case.

Finally, the analysis does not examine the potential macroeconomic impacts of the costs and savings estimated with ENERGY 2020. The WCI Partner jurisdictions are planning to continue the analysis so that macroeconomic impacts, such as income, employment, and output, can be assessed. Once completed, the macroeconomic impacts can be compared to previous studies of cap-and-trade programs considered in the United State and Canada.

4.3. Benefits of Cap-and-Trade Not Fully Represented in Economic Models

Economic models are by necessity simplified representations of the real-world economy, including the characteristics of and relationships among the households and firms that constitute the economy. The simplified nature of these models means that they may not fully capture all of the advantages of market-based climate policies, such as cap-and-trade programs, compared to prescriptive standards (i.e. command-and-control or direction regulation). The aspects of the real-world economy that are imperfectly represented in models are described below along with the implications for how well modeling studies capture the true advantages of market-based climate policies.

Heterogeneity: In direct regulation, all facilities in an industry are required to achieve a given level of performance or emission reduction. Modeling tools typically represent the industry as a single "model facility" or as a sector with demand and supply elasticities. In reality, industry is actually heterogeneous with different facilities facing different costs for reducing emissions. An important benefit of cap-and-trade is that it allows the low cost facilities to do more than the high cost facilities—i.e. the market directs the least-cost emissions reductions. The existing modeling tools may not fully capture this benefit of cap-and-trade, thus underestimating the relative cost-effectiveness of cap-and-trade compared to other policies.

Diffuse Behavioral Change: The price signal from a market program such as cap-and-trade will create consumer behavior change throughout the economy that is diffuse and not necessarily captured by existing modeling tools. These behavior changes are responses to persistent price signals that are not reflected in elasticities and are not part of "model facility" engineering cost studies. For example, bottom-up energy models may show that efficient lighting will be installed at a given allowance price, but it may not show that the consumer will also use the lights more efficiently. Existing modeling tools may not fully reflect these effects.

Induced Innovation: The price signal from a market program such as cap-and-trade will induce technological innovation in a way that is not adequately included in models.

Errors in Direct Regulation Cost Estimates: When direct regulations are promulgated, the costs of complying with the regulations will likely be estimated incorrectly, either too high or too low. When a portfolio of direct regulations is being developed, the mix and stringency of the regulations will be incorrectly estimated as a result. If the cost estimates are too high for a regulation, that regulation will not be strict enough. If the cost estimate is too low, that regulation may be too strict. Market programs such as cap-and-trade do not suffer from this problem, as the market sorts out who should do what to achieve the total emission reduction needed. Existing modeling tools presume that the costs of control are known in advance and are correct. Consequently, the benefit of avoiding these cost estimating errors is not captured by the models, thereby under-estimating the benefits of using market programs.

Appendix A: Western Regional Climate Action Initiative Agreement

Note: This agreement was subsequently signed by: Premier Gordon Campbell, British Columbia, Premier Gary Doer, Manitoba, Governor Jon Huntsman, Utah, Governor, Brian Schweitzer, Montana, Premier Jean Charest, Quebec, and Premier Dalton McGuinty, Ontario

Christine O. Gregoire **Theodore R. Kulongoski** **Arnold Schwarzenegger**

Janet Napolitano **Bill Richardson**

WESTERN REGIONAL CLIMATE ACTION INITIATIVE

WHEREAS, western states are experiencing the effects of a hotter, drier climate, including prolonged droughts, excessive heat waves, reduced snow packs, increased snowmelts, decreased spring runoffs, altered precipitation patterns, more severe forest and rangeland fires, widespread forest diseases, and other serious impacts; and

WHEREAS, scientific consensus has developed that increasing emissions of human-caused greenhouse cases (GHGs), including carbon dioxide, methane and other GHGs, that are released into the atmosphere are affecting the Earth's climate; and

WHEREAS, the Western Governors Association (WGA) has declared that climate change could have severe economic and environmental impacts on the Western States in coming decades; and

WHEREAS, the WGA also has declared that action is needed to reduce GHG emissions and that many of these actions can have significant economic and environmental benefits for the Western States, including increased energy efficiency, increased renewable energy generation, improved air quality, cost savings, job growth, increased state revenues, and reduced water pollution; and

WHEREAS, we support the development of national, regional, tribal, state and local programs to reduce GHG emissions; and

WHEREAS, we support national, regional, tribal, state and local level policies on global climate change that are consistent with efforts to develop cost-effective alternative energy sources and more efficient use of energy; and

WHEREAS, we recognize the need for collaboration among states to develop climate change policies that provide consistent approaches to recognize and give credit for actions to reduce GHG emissions; and

WHEREAS, we have already adopted or committed to adopt clean tailpipe standards for passenger vehicles that will result in major reductions in GHG emissions and other pollutants; and

WHEREAS, we support market-based policies to reduce GHG emissions in the most cost-effective manner; and

WHEREAS, we have set goals to significantly reduce GHG emissions from our respective states; and

WHEREAS, we welcome expanding the partners to this initiative to other states, tribes, Canadian provinces and Mexican states and offer monitoring status to any state, tribe or province interested in observing the initiative;

NOW, THEREFORE, we, the undersigned Governors, jointly establish the Western Regional Climate Action Initiative and agree to collaborate in identifying, evaluating and implementing ways to reduce GHG emissions in our states collectively and to achieve related co-benefits. This collaboration shall include, but is not limited to:

- Setting an overall regional goal, within six months of the effective date of this initiative, to reduce emissions from our states collectively, consistent with state-by-state goals;

- Developing, within eighteen months of the effective date of this agreement, a design for a regional market-based multi-sector mechanism, such as a load-based cap and trade program, to achieve the regional GHG reduction goal; and

- Participating in a multi-state GHG registry to enable tracking, management, and crediting for entities that reduce GHG emissions, consistent with state GHG reporting mechanisms and requirements.

In addition, we commit to continue our independent and collaborative efforts to reduce GHG emissions through:

- Promoting the development and use of clean and renewable energy within the region;

- Increasing the efficiency of energy use within our jurisdictions;

- Advocating regional and national climate policies that reflect the needs and interests of western states, tribes and provinces; and

- Identifying measures in our states, tribes and provinces to adapt to the impacts of climate change.

We will direct our staffs and the appropriate state agencies to meet as soon as is practicable to develop a work plan to move forward with this initiative.

DONE, in five (5) duplicate originals, this 26th day of February, 2007, in Washington, D.C.

Governor Christine O. Gregoire
State of Washington

Governor Theodore R. Kulongoski
State of Oregon

Governor Janet Napolitano
State of Arizona

Governor Bill Richardson
State of New Mexico

Governor Arnold Schwarzenegger
State of California

Appendix B: Economic Modeling Results

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Appendix B: Economic Modeling Results

Introduction

This appendix presents data from the economic modeling performed for WCI, including the model inputs and outputs for the cases examined. The focus here is on the data and assumptions used as model inputs and the model outputs. The main body of the Background Document discusses the policy implications of the model results.

This appendix is organized as follows:

- Cases Analyzed: describes the cases presented in this appendix.
- ENERGY 2020: provides a brief technical discussion of the model used.
- Assumptions: lists the primary assumptions used in the model.
- Outputs: defines the model outputs that are presented for the cases.
- Summary Results: provides a brief table of key model outputs.
- Reference Case: presents the results of the Reference Case.
- Cap-and-Trade Policy Cases: presents the results of the cap-and-trade policy cases.
- Sensitivity Cases: presents the results of three sensitivity cases.

As discussed below, additional detail on the ENERGY 2020 model and the model inputs and assumptions used in this analysis are presented in the *Assumptions Book for ENERGY 2020* posted on the WCI website.[1]

Cases Analyzed

This appendix presents three groups of cases. The first group is the Reference Case which reflects expectations in the absence of the WCI policies to reduce greenhouse gas emissions.

The second group is the Cap-and-Trade Policy Cases. These cases examine the primary alternatives for the cap-and-trade program, including whether to allow the use of offsets and whether to have a narrow or broad scope. The narrow scope includes stationary sources (including process emissions) and the electric sector. The broad scope also includes transportation fuels and residential/commercial fuels. The cases presented are:

- broad scope without offsets;
- broad scope with offsets; and
- narrow scope with offsets.

For all three Cap-and-Trade Policy cases, complementary policies are included along with the cap-and-trade program, including clean car standards, programs to reduce vehicle miles traveled, and energy efficiency programs. These complementary policies are defined below.

The third group of cases is the Sensitivity Cases. The purpose of the sensitivity cases is to assess the impacts of various assumptions and inputs on the model results. These assumptions can affect both the Reference Case and the Policy Cases. While a large number of

[1] The WCI website is: www.westernclimateinitiative.org.

assumptions and sensitivities are of interest, this analysis focuses on three sensitivities that were identified as most important by WCI partner jurisdictions and stakeholders.

- High Energy Prices and High Generation Costs: This sensitivity includes both higher energy prices and higher power generation costs as a set of conditions that could occur together in the future. This sensitivity was performed for both the Reference Case and the Policy Case with the broad scope and offsets.
- Low Energy Prices: This sensitivity uses energy prices that are lower than those used in the Reference Case. This sensitivity was performed for both the Reference Case and the Policy Case with the broad scope and offsets.
- High Natural Gas Prices: This sensitivity was designed to examine the impact of higher natural gas prices that may be induced by policies that are undertaken to reduce greenhouse gas emissions. Consequently, this sensitivity was applied to the Policy Case with broad scope and offsets. The results of this Policy Case are compared to the Reference Case with the standard natural gas price assumptions because the presumption is that policies are inducing the natural gas prices to increase.

Additional sensitivity analyses are warranted, and many important and worthwhile issues were identified by stakeholders during the conference calls and workshops that covered this work. However, due to time and resource constraints, additional sensitivities are not included at this time. Future work is anticipated that will enable additional sensitivity analyses to be performed.

ENERGY 2020

ENERGY 2020 was used to perform this analysis. A description of ENERGY 2020 is in the *Assumptions Book for Energy 2020* posted on the WCI website.[2] Additional documentation is available on the California Air Resources Board (ARB) website.[3] The following is a brief summary.

ENERGY 2020 is an integrated multi-region energy model that provides all-fuel demand and supply sector simulations. ENERGY 2020 can be linked to a detailed macroeconomic model to determine the economic impacts of energy/environmental policy and the energy and environmental impacts of national economic policy. However, the macroeconomic analysis was not performed for this study.

The model simulates demand by three residential categories (single family, multi-family, and agriculture/rural), over 40 NAICS commercial and industrial categories,[4] and three transportation services (passenger, freight, and off-road). There are approximately six end-uses per category and six technology/mode families per end-use.[5] The technology families

[2] The WCI website is: www.westernclimateinitiative.org.

[3] The posting on the ARB website is at: http://www.arb.ca.gov/cc/scopingplan/economics-sp/models/models.htm.

[4] NAICS is the North America Industrial Classification System which was developed jointly by the U.S., Canada, and Mexico to provide new comparability in statistics about business activity across North America.

[5] End-uses include Process Heat, Space Heating, Water Heating, Other Substitutable, Refrigeration, Lighting, Air Conditioning, Motors, and Other Non-Substitutable (Miscellaneous). Detailed modes include: small auto, large

correspond to six fuels groups (oil, gas, coal, electric, solar and biomass) and 30 detailed fuel products. The transportation sector contains 45 modes including various type of automobile, truck, off-road, bus, train, plane, marine and alternative-fuel vehicles. More end-uses, technologies, and modes can be added as data allow. For all end-uses and fuels, the model is parameterized based on historical, locale-specific data. The load duration curves for electricity demand are dynamically built up from the individual end-uses to capture changing conditions under consumer choice and combined gas/electric programs.

Each energy demand sector includes cogeneration, self-generation, and distributed generation simulation, including mobile-generation, micro-turbines, and fuel-cells. Fuel-switching responses are rigorously determined. The technology families (which can be split, as an option, to portray specific technology dynamics) are aggregates that, within the model, change building shell, economic-process and device efficiency and capital costs as price or other information that the decision makers see, change. ENERGY 2020 utilizes the historical and forecast data developed for each technology family to parameterize and disaggregate the model.

The supply portion of the model includes endogenous detailed electric supply simulation of capacity expansion/construction, rates/prices, load shape variation due to weather, and changes in regulation.[6] The model dispatches plants according to the specified rules whether they are optimal or heuristic and simulates transmission constraints when determining dispatch. A dispatch routine selects critical hours along seasonal load duration curves as a way to determine system generation. Peak and base hydro usage is explicitly modeled to capture hydro-plant impacts on the electric system.

ENERGY 2020 supply sectors include electricity, oil, natural gas, refined petroleum products, ethanol, land-fill gas, and coal supply. Energy used in primary production and emissions associated with primary production and its distribution is included in the model. The supply sectors included in a particular implementation of ENERGY 2020 will depend on the characteristics of the area being simulated and the problem being addressed. If the full supply sector is not needed, then a simplified simulation determines delivered-product prices.

ENERGY 2020 includes pollution accounting for both combustion (by fuel, end-use, and sector) and non-combustion, and non-energy (by economic activity) for SO_2, NO_2, N_2O, CO, CO_2, CH_4, PMT, $PM_{2.5}$, PM_5, PM_{10}, VOC, CF_4, C_2F_6, SF_6, and HFC at the state and provincial level by economic sector.

Assumptions

This section presents an overview of the major assumptions used in the modeling analysis. The *Assumptions Book for ENERGY 2020* presents a detailed list of the model inputs, including links to the data sources used to assemble the input data.

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auto, light truck, medium-weight truck, heavy-weight truck, bus, freight train, commuter train, airplane, and marine. Each mode type can be characterized by gasoline, diesel, electric, ethanol, NG, propane, fuel-cell, or hybrid vehicles.

[6] ENERGY 2020 includes a complete, but aggregate representation of the electric transmission system.

- Geographic Coverage: This phase of the analysis covers the area of the Western Electricity Coordinating Council (WECC), which includes eight WCI partners: British Columbia, Washington, Oregon, California, Arizona, New Mexico, Utah, and Montana. By covering the entire WECC, the impacts of the WCI programs and policies on electricity generation in the non-WCI WECC states and provinces can be examined. Future analyses are planned that will incorporate the WCI partners that are not in the WECC, including Manitoba, Ontario, and Quebec.
- Sectors and Sources: This phase of the analysis includes energy use in all sectors, as well as most industrial process emissions. Landfill methane emissions and non-energy agriculture emissions are included in the total emissions estimates, but emission reductions are not estimated for these sources.[7] The analysis is based on gross emissions, so that forestry emissions and sinks are excluded.
- WCI Population and GDP Forecast: The model is driven by forecasts provided as input that include population growth and economic growth by detailed sector. Table B-1 shows the population growth forecast and Table B-2 shows the economic growth forecast.

Table B-1: Population Forecast for Eight WCI Partners, Selected Years (Millions)

Jurisdiction	2006	2010	2015	2020	Annual Growth
Arizona	6.2	7.0	7.9	8.8	2.5%
British Columbia	4.3	4.5	4.7	4.9	0.9%
California	37.4	39.1	41.5	44.1	1.2%
Montana	0.9	1.0	1.1	1.2	1.6%
New Mexico	2.0	2.2	2.3	2.5	1.8%
Oregon	3.7	3.9	4.1	4.3	1.1%
Utah	2.6	2.7	3.0	3.2	1.6%
Washington	6.4	6.8	7.3	7.7	1.4%
WCI	**63.5**	**67.2**	**71.9**	**76.7**	**1.4%**
Source: Assumptions Book for ENERGY 2020					

[7] Examples of non-energy agriculture emissions are methane emissions from livestock, carbon and N_2O emissions from agricultural soils, and methane emissions from livestock manure management.

Table B-2: Regional Gross Product Forecast for Eight WCI Partners, Selected Years (Billions of 2007 US dollars)

Jurisdiction	2006	2010	2015	2020	Annual Growth
Arizona	237	271	322	363	3.1%
British Columbia	266	294	326	358	2.1%
California	1,800	2,066	2,458	2,782	3.2%
Montana	33	37	42	47	2.5%
New Mexico	77	87	103	117	3.0%
Oregon	159	186	227	259	3.6%
Utah	98	111	129	146	2.9%
Washington	302	345	410	462	3.1%
WCI	**2,972**	**3,396**	**4,018**	**4,534**	**3.1%**
Source: Assumptions Book for ENERGY 2020					

- Emission Reduction Options: The model simulates decisions by energy users for each end use, including: fuel choice; investment in end use efficiency (e.g., by purchasing devices that are more efficient than the minimum required by standards); and end use utilization (how much the device is used). End-use specific choices are simulated as needed, such as mode choice for freight movement and passenger transportation. Choices are simulated based on costs (increased capital costs versus the value of fuel saved) as well as non-price attributes (convenience, acceptance of the technology). Past purchasing behavior is used to calibrate the non-price choice parameters for each end use.
- Energy Independence and Security Act of 2007 (EISA): The Reference Case, Policy Cases, and Sensitivity Cases include the requirements in the EISA, including the CAFÉ standards, appliance and lighting energy efficiency standards, and the renewable fuels standard (RFS). These requirements are assumed to be implemented fully in the WCI partner jurisdictions in the United States. For British Columbia and other Canadian provinces, lighting, equipment and appliance standards as set out by the Canadian Standards Association[8] as well as federal "ecoENERGY" Renewable Fuels Strategy[9] are incorporated.
- Renewable Portfolio Standards: All cases incorporate the individual Partner's already-adopted Renewable Portfolio Standards (RPS). See Appendix I of the *Assumptions Book for ENERGY 2020* for details.

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[8] http://www.oee.nrcan.gc.ca/regulations/home_page.cfm

[9] This strategy requires 5% average renewable content based on the gasoline pool that is produced or imported, starting in 2010, and 2% average renewable content in diesel fuel and heating oil (distillate) by 2012. The Canada Gazette indicates that the 2% renewable content in diesel fuel and heating oil is equivalent to 5% renewable content in on-road diesel use. (See http://canadagazette.gc.ca/partI/2006/20061230/html/notice-e.html#i3)

- WCI Fuel Prices: The model is also driven by forecasts of fuel prices (oil, coal, natural gas). The model calculates electricity prices internally. Table B-3 shows the fuel price forecast used in the Reference Case. This forecast is taken from the Energy Information Agency's Annual Energy Outlook 2008 high price series. State- and province-specific prices are derived in the model from the prices shown in this table.

Table B-3: Fuel Price Forecast

	2006	2010	2015	2020
World Oil Price (2007 US$/barrel)	64.32	76.22	86.92	97.90
Natural Gas Wellhead Price (2007 US$/mmBtu)	6.93	7.50	7.13	7.29
Coal Prices (2007 US$/ton)	25.33	26.91	24.78	24.29
Source: EIA Annual Energy Outlook 2008 high price series.				

- First Jurisdictional Deliverer: All cases incorporate a proxy to represent First Jurisdictional Deliverer. Consequently, emissions from electricity imported into the WCI partner jurisdictions from outside the WCI partner jurisdictions are included in the analysis.
- Allowance Banking: The model enables allowances to be banked when allowance prices are low, and for allowances to be used from the bank when allowance prices are high. Attachment 1 discusses the parameters used to model allowance banking.
- Coal Plants: The cases allow no new coal plants to be built by 2020 in the WECC beyond those already planned and committed. See Appendix F of the *Assumptions Book for ENERGY 2020* for the list of coal plants that are assumed to be planned and committed.
- Nuclear Plants: The cases assume no new nuclear plants to be built by 2020 in the WECC.
- Carbon capture and storage: Carbon capture and storage is assumed not feasible for electric power generation through 2020.
- Hydropower: The cases assume no new hydropower capacity built in the WECC by 2020.
- Plug-in hybrids: The cases assume that plug-in hybrid and electric vehicles are not available in significant numbers through 2020.
- Electrical Generation Costs: The modeling effort relies on estimates of power generation capital costs, operating costs, and heat rates developed for a recent study for the California Public utilities Commission (see Table B-4).
- Macroeconomic estimates: This phase of the analysis does not include macroeconomic analysis.

Table B-4: Summary of Power Generation Cost Inputs

Technology	Total Capital Costs $/kW	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Capacity Factor	Nominal Heat Rate
Biogas	$2,623	107.5	0.01	85%	11,566
Biomass	$3,836	50.18	2.96	85%	15,509
Geothermal	$3,575	154.92	-	90%	-
Hydro - Small	$2,530	13.14	3.3	50%	-
Solar - Thermal	$2,840	49.63	-	40%	-
Wind	$1,983	28.51	-	37%	-
Coal ST	$2,671	25.91	4.32	85%	8,844
Coal IGCC	$3,087	36.36	2.75	85%	8,309
Coal IGCC with CCS	$5,127	42.82	4.18	85%	9,713
Gas CCCT	$878	11.04	2.4	90%	6,917
Gas CT	$794	11.4	3.36	5%	10,807
Hydro - Large	$2,530	13.14	3.3	50%	-
Nuclear	$4,999	63.88	0.47	85%	10,400
<5MW CHP	$1,952	11.04	2.4	40.5%	9,700
>5MW CHP	$1,259	11.04	2.4	85%	9,220

Cost Basis Year = 2005. All estimates are 2008 U.S. dollars.
Source: E3 GHG Calculator v2b, tab "Gen Cost". Available at: http://www.ethree.com/GHG/GHG%20Calculator%20v2b.zip

Outputs

The model results include estimates of energy use, GHG emissions, electricity generation, fuel prices, and costs. The following are brief explanations of the model results that are shown for the cases analyzed.

- Greenhouse Gas (GHG) Emissions: GHG emissions are presented in millions of metric tons of carbon dioxide equivalent ($MMTCO_2e$). Emissions for the eight WCI partner jurisdictions included in the analysis are presented by major sector.
- Compliance Summary: The Compliance Summary shows how GHG emissions are reduced to achieve the WCI partners' regional emissions goal of a 15% reduction from 2005 levels by 2020. The Compliance Summary shows a Compliance Total, which is the calculated emissions minus offsets used and adjusted for any allowances that are banked or that are used from the bank. The running total of emission allowances banked is also reported. The Compliance Total also considers changes in emissions in the non-WCI WECC power sector. The WCI cap-and-trade policies and complementary policies will affect GHG emissions from power generated in the non-WCI WECC states and provinces.

The change in these emissions are also included in the Compliance Total. To make this calculation, emissions associated with power imported into the WCI jurisdictions are estimated at 70 million tons per year. This estimate is preliminary, and is based on an assessment of recent power flows and emissions factors. Given the uncertainty in the estimate of these emissions, as well as the imperfect manner in which the First Jurisdictional Deliverer (FJD) policy is represented in the model, the reduction in emissions from the non-WCI WECC power sector counted toward the Compliance Total is limited to no more than 45 million tons in any year. Using this limit, the potential emission reduction from the non-WCI WECC power sector may be underestimated, thereby making the model evaluate a more stringent program than may be required in some cases. The Compliance Total is compared to 2006 emissions calculated in the model to estimate the emission reduction. In all the cases presented below, the compliance total shows approximately a 15% reduction in total economy wide emissions in 2020 relative to 2006. As discussed above, the estimates include only the eight WCI partner jurisdictions in the WECC.

- Total Energy Use: Total energy use is reported by fuel type and by major sector in units of TBtu/year.
- Electric Sector: Outputs for the electric sector include:
  - Generation Capacity in units of megaWatts (MW) by generation type. Note that estimated generation capacity grows due to capacity additions, but capacity retirement is not calculated. Consequently, generation capacity does not decline in the model outputs.
  - Generation Output in units of gigaWatt-hours per year (GWh/year) by generation type. The generation output is for the eight WCI partner jurisdictions in the WECC.
  - Electricity Sales in units of GWh/year, including electricity imports into the eight WCI partner jurisdictions in the WECC.
- Transportation Sector: Outputs for the transportation sector include vehicle miles traveled for passenger and freight vehicles, as well as miles traveled per passenger. The fleet average efficiency is reported for four vehicle types in miles per gallon.
- Fuel Prices: Fuel prices are reported for electricity, natural gas, coal, fuel oil, LPG, gasoline, and diesel in 2007 dollars per million Btu (2007 $/mmBtu). The prices include the forecasted energy prices (presented in Table B-3 above for the reference case and other tables below for the sensitivity cases) as well as the costs of delivering the fuels to market. The prices reported for the cap-and-trade policy cases also include the calculated allowance price, reflecting the appropriate carbon content of the fuel.
- Costs and Savings: Costs and savings are reported in millions of 2007 dollars per year ($M/Yr). Fuel Expenditures are reported by major sector, showing changes in expenditures from the Reference Case. These estimates of fuels expenditures do not include the value of the calculated allowance price, so a separate table of total allowance value is presented (equal to emissions times the allowance price). The allowance values reported by sector do not consider that the full allowance value may not be passed

through to consumers. Consequently, the allowance value by sector is reported as "potential" allowance value, recognizing that a portion of the allowance value may be borne by producers and not passed through to consumers. Total Costs are also reported by major sector, which are the sum of changes in fuel expenditures and changes in investment costs. Investment costs increase as more efficient devices, buildings, and processes are purchased in response to the limit on GHG emissions. The investment costs are annualized using a 5% real discount rate over the life of the equipment. The annualize costs are counted each year over the life of the equipment. The estimates of Total Costs include both the change in fuel expenditures and the change in investment costs. As shown in the tables below, the fuel expenditure savings typically offset most or all of the increased investment costs.

Results are shown only for the total of the eight WCI partners included in the analysis. State and province specific results are not included.

Reference Case

This section presents the results of the Reference Case. This case represents the future through 2020 in the absence of the WCI cap-and-trade program and related complementary GHG emission reduction policies. Table B-5 through Table B-10 show model outputs for:

- GHG emissions;
- energy use;
- electric sector results;
- transport sector results;
- fuel prices; and
- fuel expenditures.

Each table shows total results for the eight WCI Partners in the WECC. The three Canadian provinces not included in this analysis (Manitoba, Quebec, and Ontario) will be included in future modeling efforts.

Each table shows results for 2006 (the first year simulated by ENERGY 2020), 2010, 2015, and 2020. The growth rate reported for 2006-2020 is the average annual rate of exponential growth between the 2006 level and the 2020 level.

Table B-5: Reference Case Greenhouse Gas Emissions: Eight WCI Partners

GHG Emissions *(MMTCO2E)*	2006	2010	2015	2020	Growth Rate 2006-2020
Residential	49.7	53.7	58.4	63.1	1.7%
Commercial	29.3	30.5	30.7	31.8	0.6%
Energy Intensive Industry	176.8	174.5	181.5	191.0	0.6%
Other Industry	29.8	30.3	30.5	31.0	0.3%
Passenger Transport	290.8	299.4	303.9	294.0	0.1%
Freight Transport	93.0	89.6	89.9	91.7	-0.1%
Power Sector	176.6	166.8	160.0	176.9	0.0%
Waste & Wastewater	25.6	29.1	34.2	38.4	2.9%
Agriculture (non-energy)	59.9	62.1	67.5	74.9	1.6%
Total	**931.6**	**936.1**	**956.6**	**992.8**	**0.5%**

Table B-6: Reference Case Energy Use: Eight WCI Partners

Total Energy Use *(TBtu/year)*	2006	2010	2015	2020	Growth Rate 2006-2020
Aviation Fuel	609	637	683	725	1.3%
Biomass	443	429	453	493	0.8%
Coal	1,185	1,215	1,204	1,259	0.4%
Diesel	1,091	1,051	1,032	1,025	-0.4%
Ethanol	85	173	335	480	13.2%
Landfill Gas	29	29	29	29	0.2%
LPG	231	240	256	282	1.4%
Gasoline	3,303	3,313	3,256	3,053	-0.6%
Natural Gas	3,947	3,779	3,733	4,018	0.1%
Nuclear	658	658	658	658	0.0%
Oil, Unspecified	695	688	692	714	0.2%
Other	2,902	2,949	3,092	3,349	1.0%
Total	**15,178**	**15,161**	**15,422**	**16,086**	**0.4%**

Total Energy Use *(TBtu/year)*	**2006**	**2010**	**2015**	**2020**	**Growth Rate 2006-2020**
Residential	1,638	1,772	1,938	2,119	1.9%
Commercial	1,357	1,388	1,425	1,521	0.8%
Energy Intensive Industry	2,508	2,383	2,324	2,332	-0.5%
Other Industry	1,015	1,033	1,064	1,107	0.6%
Agriculture	140	127	114	104	-2.1%
Passenger Transportation	3,998	4,131	4,252	4,201	0.4%
Freight Transportation	1,219	1,183	1,208	1,251	0.2%
Waste & Wastewater	-	-	-	-	#N/A
Power Sector	3,302	3,143	3,097	3,450	0.3%
Total	**15,178**	**15,161**	**15,422**	**16,086**	**0.4%**

Table B-7: Reference Case Electric Sector Results: Eight WCI Partners

Generation Capacity *(MW)*	**2006**	**2010**	**2015**	**2020**	**Growth Rate 2006-2020**
Gas/Oil	62,973	72,139	78,999	88,519	2.5%
Coal	14,972	15,372	15,372	15,372	0.2%
Nuclear	9,330	9,330	9,330	9,330	0.0%
Hydro	61,721	63,374	63,428	63,508	0.2%
Landfill Gas/EFW	338	347	347	347	0.2%
Wind	4,083	6,827	18,575	24,513	13.7%
Other	4,358	4,537	5,572	6,582	3.0%
Total	**157,776**	**171,925**	**191,623**	**208,172**	**2.0%**
Generation Output *(GWh/year)*	**2006**	**2010**	**2015**	**2020**	**Growth Rate 2006-2020**
Gas/Oil	143,907	130,579	128,042	164,782	1.0%
Coal	99,280	100,482	98,019	101,454	0.2%
Nuclear	65,072	65,072	65,072	65,072	0.0%
Hydro	256,243	267,713	268,095	268,661	0.3%
Landfill Gas/EFW	2,036	2,088	2,088	2,088	0.2%
Wind	8,733	16,245	48,811	65,273	15.5%
Other	23,554	24,607	30,770	36,219	3.1%
Total	**598,824**	**606,784**	**640,897**	**703,548**	**1.2%**

Sales (GWh/year)	**2006**	**2010**	**2015**	**2020**	**Growth Rate 2006-2020**
Residential	202,826	218,623	240,918	267,908	2.0%
Commercial	231,140	234,126	245,573	270,164	1.1%
Industrial	163,747	161,434	167,796	187,146	1.0%
Transportation	4,864	6,728	7,908	8,461	4.0%
Street Lights/Misc.	16,447	16,447	16,447	16,447	0.0%
Resale	-	-	-	-	#N/A
Total Sales	**619,023**	**637,357**	**678,642**	**750,126**	**1.4%**

Table B-8: Reference Case Transportation Sector Results: Eight WCI Partners

Distance Travelled (millions of vehicle miles travelled)					
	2006	**2010**	**2015**	**2020**	**Growth Rate 2006-2020**
Passenger	556,055	589,783	635,948	678,750	1.4%
Freight	72,562	73,248	77,423	82,189	0.9%
Passenger: Miles/person	8,755	8,781	8,847	8,844	0.1%
Vehicle Efficiency (miles/gallon)					
	2006	**2010**	**2015**	**2020**	**Growth Rate 2006-2020**
Light Gas Vehicles	23.2	24.1	25.5	28.5	1.5%
Medium Gas Vehicles	23.2	24.1	25.5	28.4	1.5%
Heavy Gas Vehicles	16.9	17.3	18.5	20.4	1.4%
Heavy Diesel Vehicles	16.9	17.3	18.4	20.3	1.3%
Vehicle efficiency represents a fleet-wide average, not the average for new vehicles.					

Table B-9: Reference Case Fuel Prices: Eight WCI Partners

Prices (2007 $/mmBtu)	**2006**	**2010**	**2015**	**2020**	**Growth Rate 2006-2020**
Residential					
Res Electricity Prices	29.4	30.9	29.8	30.1	0.2%
Res Natural Gas Prices	11.5	13.5	13.9	14.5	1.7%
Res Oil Prices	21.0	23.3	24.0	25.5	1.4%
Res LPG Prices	22.7	24.2	21.7	21.6	-0.3%
Commercial					
Com Electricity Prices	26.4	27.8	26.7	27.3	0.2%
Com Natural Gas Prices	8.8	10.0	9.8	10.1	1.0%
Com Oil Prices	23.1	25.0	24.0	24.6	0.4%
Com LPG Prices	22.5	24.3	21.7	21.4	-0.4%
Industrial					
Ind Electricity Prices	16.3	17.1	15.5	15.4	-0.4%
Ind Natural Gas Prices	6.7	7.3	6.4	6.3	-0.5%
Ind Coal Prices	2.2	2.2	2.1	2.1	-0.1%
Ind Oil Prices	16.4	18.4	19.2	20.7	1.7%
Ind LPG Prices	23.9	25.5	23.1	23.1	-0.2%
Transportation					
Gasoline Prices	21.9	24.1	26.0	28.0	1.8%
Diesel Prices	21.8	24.0	25.8	27.7	1.7%

Table B-10: Reference Case Fuel Expenditures: Eight WCI Partners

Annual Fuel Expenditures (Million$/Yr)					
Sector	**2006**	**2010**	**2015**	**2020**	**Growth Rate 2006-2020**
Residential	31,763	37,523	40,670	45,609	2.6%
Commercial	28,452	31,306	31,632	35,373	1.6%
Energy Intensive Industry	28,969	31,248	30,889	32,725	0.9%
Other Industry	14,567	16,511	16,988	18,496	1.7%
Passenger Transportation	82,031	93,848	103,830	110,035	2.1%
Freight Transportation	28,315	30,055	32,280	35,567	1.6%
Agriculture	3,140	3,142	2,819	2,848	-0.7%
Total	**217,237**	**243,632**	**259,107**	**280,654**	**1.8%**

Cap-and-Trade Policy Cases

This section presents the results of three Cap-and-Trade Policy Cases:

- Broad Scope, with complementary policies and without offsets
- Broad Scope, with complementary policies and with offsets
- Narrow Scope, with complementary policies and with offsets

The narrow scope includes of the following:

- Electricity generation, including emissions from electricity imported into WCI jurisdictions from non-WCI jurisdictions
- Combustion at industrial and commercial facilities
- Industrial process emission sources, including oil and gas process emissions

The broad scope includes the emissions in the narrow scope plus the following:[10]

- Residential, commercial, and industrial fuel combustion at facilities with emissions below the WCI thresholds
- Transportation fuel combustion from gasoline and diesel

The banking of allowances is included in all three Policy Cases to simulate how allowances issued or auctioned in one year may be used in a later period. When allowance prices are low, allowances would likely be saved for use in a later year – which is referred to as being banked. When prices are high, allowances would be used from previous year, which is referred to as withdrawn from the bank. Attachment 1 explains how the model simulates banking and withdrawing of allowances.

Offsets are limited to 5% of the compliance obligation. The supply of offsets is modeled using an S-shaped curve that defines the portion of the offset limit that would be used as a function of allowance price. The analyses presented here limit the use of offsets to 5% of the annual compliance obligation, with an expected price of $20 per MTCO2e. Figure B-1 shows how the model simulates the use of offsets. At an allowance price of $20 per MTCO2e, approximately 58% of the offset limit is estimated to be used.

The Offsets Subcommittee is defining a process to develop offset supply curve data reflecting the availability and price of offsets under various offset policy assumptions. When available, those data would enable a more precise assessment to be conducted of the implications of policies that include offsets as a design feature.

The complementary policies have a substantial impact on the estimated emissions and costs. This analysis incorporates three broad sets of policies across all eight WCI partner jurisdictions in the analysis:

- Clean Car Standards, equivalent to California's Pavley I and II. These standards reduce emissions by about 30 MMTCO2E in 2020 compared to the Reference Case.

[10] For purposes of modeling the broad scope of the cap-and-trade program, the eight WCI partner jurisdictions included in the analysis are modeled with the broad scope starting in 2012. Note that British Columbia plans to use its carbon tax as an alternative policy for covering transportation fuels and residential/commercial fuels. This modeling effort, however, treats British Columbia the same as the other seven WCI partner jurisdictions included in the analysis.

- Programs that reduce total Vehicle Miles Traveled (VMT) by 2% from the forecast reference case by 2020. These programs reduce emissions by about 4 MMTCO2E when considered in addition to the Clean Car Standards.
- Aggressive energy efficiency programs that achieve a 1% reduction in the annual rate of electricity and natural gas demand growth. These programs reduce emissions by about 74 MMTCO2E in 2020 across all sectors.

We recognize that the WCI partner jurisdictions have climate action plans that reflect the specific opportunities and needs of the individual jurisdictions. In particular, they typically include policies that extend beyond the three included in this analysis. Based on the available time and resources for this study, as well as the focus on overall results for the WCI partner jurisdictions as a whole, the analysis is limited to reflecting these broad policies at this time.

By themselves the three complementary policies included in the analysis accomplish about 108 MMTCO2E of GHG reductions in 2020, which is about half of the reductions required from the Reference Case estimates in this analysis. Table B-11 shows the estimates for the transportation policies.

The complementary policies are modeled in conjunction with the cap-and-trade policies under the expectation that the cap-and-trade program can provide resources needed for supporting the VMT programs and the energy efficiency programs. In particular, the value of emission allowances (whether auctioned or provided for free) can be directed to support these programs.

Figure B-1: Assumed Offset Supply Curve

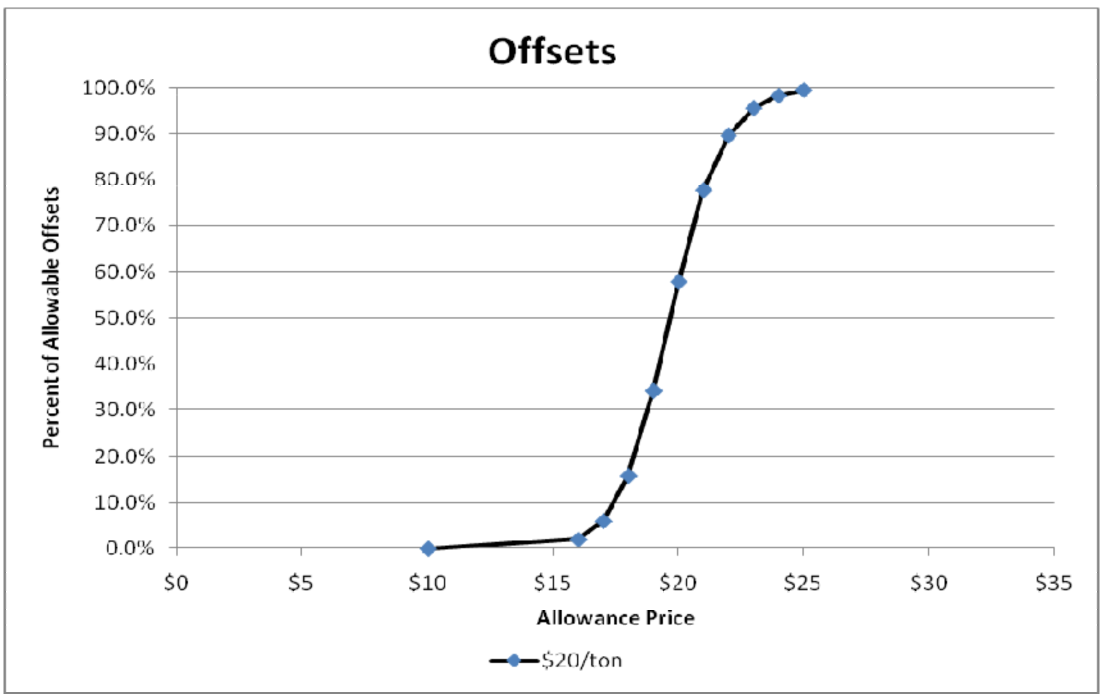


Table B-11: Impact of Transportation Complementary Policies in 2020 Compared to the Reference Case: Eight WCI Partners

	Clean Car Standards	Clean Car Standards and VMT Reduction
Change in GHG Emissions (million tons)	-30.1	-34.2
Change in Annual Vehicle Miles Traveled/Person	112	-65
Change in Annual Fuel Expenditures (million 2007$)	($11,943)	($13,549)
Change in Vehicle Capital Expenditures (million 2007$)	$10,325	($5,549)
Net Cost (Savings) (million 2007$)	($1,618)	($19,098)
Net cost does not include the cost of VMT Reduction programs.		

Table B-12 through Table B-19 show model outputs for these quantities:

- GHG emissions and compliance summary;
- energy use;
- electric sector results;
- transport sector results;
- fuel prices;
- fuel expenditures;
- potential allowance value; and
- costs.

Each table shows results for 2020 for eight WCI Partners, i.e., the seven states and British Columbia. As discussed above, the other three Canadian provinces will be included in future modeling efforts. For each policy case, the three columns indicate the Cap-and-Trade value for the quantity described in the left-most column, the difference between the Cap-and-Trade value and the Reference Case value, and the percentage difference between the two values.

Table B-16 shows fuel prices as a percent difference from Reference Case prices. Table B-19 shows the cost estimates, which only meaningful as incremental differences between the Cap-and-Trade value and the Reference Case value.

Table B-12: Cap-and-Trade Cases Greenhouse Gas Emissions and Compliance Summary: Eight WCI Partners

GHG Emissions in 2020 *(MMTCO2E)*	**Reference Case**	**Broad, Comp Policies No Offsets**			**Broad, Comp Policies With Offsets**			**Narrow, Comp Policies With Offsets**		
		Value	Diff from Reference	Percent Diff	Value	Diff from Reference	Percent Diff	Value	Diff from Reference	Percent Diff
Residential	63.1	55.0	-8.1	-12.8%	55.2	-7.9	-12.5%	55.9	-7.2	-11.4%
Commercial	31.8	26.2	-5.6	-17.5%	26.4	-5.4	-17.1%	27.0	-4.8	-15.0%
Energy Intensive Industry	191.0	174.5	-16.6	-8.7%	175.0	-16.0	-8.4%	172.6	-18.5	-9.7%
Other Industry	31.0	26.9	-4.2	-13.5%	27.0	-4.0	-12.9%	26.3	-4.8	-15.3%
Passenger Transport	294.0	258.7	-35.2	-12.0%	259.0	-34.9	-11.9%	259.9	-34.1	-11.6%
Freight Transport	91.7	89.9	-1.7	-1.9%	90.4	-1.3	-1.4%	91.7	0.0	0.0%
Power Sector	176.9	114.6	-62.2	-35.2%	131.5	-45.3	-25.6%	104.8	-72.1	-40.7%
Waste & Wastewater	38.4	38.4	0.0	0.0%	38.4	0.0	0.0%	38.4	0.0	0.0%
Agriculture (non-energy)	74.9	74.9	0.0	0.0%	74.9	0.0	0.0%	71.1	-3.7	-5.0%
WCI Sub-Total	**992.8**	**859.2**	**-133.6**	**-13.5%**	**877.9**	**-114.9**	**-11.6%**	**847.8**	**-145.0**	**-14.6%**
Non-WCI Power Sector	70.0	70.0			70.0			70.0		
Non-WCI Power Sector Reductions		-45.0			-37.0			-45.0		
Offsets		0.0			-31.8			-18.2		
Bank Flow		-31.1			-31.8			-0.2		
Compliance Total		**853.1**			**847.2**			**854.3**		
Percent of 2006 Emissions		85.2%			84.6%			85.3%		
Bank Inventory		72.6			74.4			0.5		
Allowance Price (2007 $/MT)		**$63**			**$24**			**$71**		

All emissions in millions of metric tons.

Table B-13: Cap-and-Trade Cases Energy Use: Eight WCI Partners

	Reference Case	Broad, Comp Policies No Offsets			Broad, Comp Policies With Offsets			Narrow, Comp Policies With Offsets		
		Value	Diff from Reference	Percent Diff	Value	Diff from Reference	Percent Diff	Value	Diff from Reference	Percent Diff
Total Energy Use in 2020 *(TBtu/year)*										
Aviation Fuel	725	717.9	(7.4)	-1.0%	720	(5)	-0.7%	725	-	0.0%
Biomass	493	449	(44)	-8.9%	448	(45)	-9.1%	452	(41)	-8.3%
Coal	1,259	758	(502)	-39.8%	1,043	(217)	-17.2%	618	(642)	-50.9%
Diesel	1,025	995	(30)	-2.9%	1,001	(25)	-2.4%	1,014	(11)	-1.1%
Ethanol	480	421	(59)	-12.2%	420	(59)	-12.4%	419	(61)	-12.7%
Landfill Gas	29	29	(0)	0.0%	29	0	0.0%	29	(0)	0.0%
LPG	282	248	(33)	-11.8%	249	(32)	-11.5%	250	(32)	-11.3%
Gasoline	3,053	2,625	(429)	-14.0%	2,628	(426)	-13.9%	2,635	(418)	-13.7%
Natural Gas	4,018	3,245	(774)	-19.3%	3,075	(944)	-23.5%	3,296	(722)	-18.0%
Nuclear	658	658	-	0.0%	658	-	0.0%	658	-	0.0%
Oil, Unspecified	714	686	(27)	-3.8%	688	(26)	-3.6%	687	(27)	-3.8%
Other	3,349	2,956	(393)	-11.7%	2,952	(397)	-11.9%	2,934	(415)	-12.4%
Total	**16,086**	**13,788**	**(2,298)**	**-14.3%**	**13,911**	**(2,176)**	**-13.5%**	**13,718**	**(2,369)**	**-14.7%**
Total Energy Use in 2020 (Tbtu/year)										
Residential	2,119	1,853	(266)	-12.6%	1,856	(264)	-12.5%	1,863	(257)	-12.1%
Commercial	1,521	1,259	(262)	-17.2%	1,260	(261)	-17.2%	1,265	(256)	-16.8%
Energy Intensive Industry	2,332	2,029	(303)	-13.0%	2,035	(297)	-12.7%	2,005	(328)	-14.0%
Other Industry	1,107	1,001	(106)	-9.6%	1,003	(104)	-9.4%	991	(116)	-10.5%
Agriculture	104	93	(11)	-10.2%	94	(10)	-10.1%	92	(12)	-11.4%
Passenger Transportation	4,201	3,698	(503)	-12.0%	3,702	(499)	-11.9%	3,712	(489)	-11.6%
Freight Transportation	1,251	1,229	(22)	-1.8%	1,235	(16)	-1.3%	1,251	-	0.0%
Waste & Wastewater	-	-			-			-		
Power Sector	3,450	2,626	(824)	-23.9%	2,727	(724)	-21.0%	2,539	(912)	-26.4%
Total	**16,086**	**13,788**	**(2,298)**	**-14.3%**	**13,911**	**(2,176)**	**-13.5%**	**13,718**	**(2,369)**	**-14.7%**

Table B-14: Cap-and-Trade Cases Electric Sector Results: Eight WCI Partners

	Reference Case	Broad, Comp Policies No Offsets			Broad, Comp Policies With Offsets			Narrow, Comp Policies With Offsets		
		Value	Diff from Reference	Percent Diff	Value	Diff from Reference	Percent Diff	Value	Diff from Reference	Percent Diff
Generation Capacity in 2020 *(MW)*										
Gas/Oil	88,519	109,759	21,240	24.0%	109,919	21,400	24.2%	109,879	21,360	24.1%
Coal	15,372	15,372	-	0.0%	15,372	-	0.0%	15,372	-	0.0%
Nuclear	9,330	9,330	-	0.0%	9,330	-	0.0%	9,330	-	0.0%
Hydro	63,508	63,471	(37)	-0.1%	63,471	(37)	-0.1%	63,462	(46)	-0.1%
Landfill Gas/EFW	347	347	-	0.0%	347	-	0.0%	347	-	0.0%
Wind	24,513	22,943	(1,570)	-6.4%	22,945	(1,569)	-6.4%	22,721	(1,792)	-7.3%
Other	6,582	6,354	(228)	-3.5%	6,354	(228)	-3.5%	6,344	(238)	-3.6%
Total	**208,172**	**227,576**	**19,405**	**9.3%**	**227,738**	**19,566**	**9.4%**	**227,456**	**19,284**	**9.3%**
Generation Output 2020 *(GWh/year)*										
Gas/Oil	164,782	127,711	(37,072)	-22.5%	101,382	(63,400)	-38.5%	134,044	(30,738)	-18.7%
Coal	101,454	58,979	(42,474)	-41.9%	85,318	(16,136)	-15.9%	46,848	(54,606)	-53.8%
Nuclear	65,072	65,072	-	0.0%	65,072	-	0.0%	65,072	-	0.0%
Hydro	268,661	268,398	(263)	-0.1%	268,398	(263)	-0.1%	268,337	(324)	-0.1%
Landfill Gas/EFW	2,088	2,088	(0)	0.0%	2,088	0	0.0%	2,088	(0)	0.0%
Wind	65,273	60,920	(4,353)	-6.7%	60,925	(4,348)	-6.7%	60,305	(4,968)	-7.6%
Other	36,219	34,579	(1,640)	-4.5%	34,579	(1,640)	-4.5%	34,558	(1,661)	-4.6%
Total	**703,548**	**617,746**	**(85,803)**	**-12.2%**	**617,761**	**(85,788)**	**-12.2%**	**611,251**	**(92,297)**	**-13.1%**
Sales in 2020*(GWh/year)*										
Residential	267,908	232,745	(35,163)	-13.1%	232,447	(35,462)	-13.2%	230,725	(37,183)	-13.9%
Commercial	270,164	223,406	(46,758)	-17.3%	222,998	(47,166)	-17.5%	221,170	(48,994)	-18.1%
Industrial	187,146	162,812	(24,333)	-13.0%	162,071	(25,075)	-13.4%	162,118	(25,027)	-13.4%
Transportation	8,461	8,268	(193)	-2.3%	8,229	(232)	-2.7%	7,923	(538)	-6.4%
Street Lights/Misc.	16,447	16,447	-	0.0%	16,447	-	0.0%	16,447	-	0.0%
Total Sales	**750,126**	**643,678**	**(106,447)**	**-14.2%**	**642,191**	**(107,935)**	**-14.4%**	**638,383**	**(111,743)**	**-14.9%**

Table B-15: Cap-and-Trade Cases Transportation Sector Results: Eight WCI Partners

	Reference Case	Broad, Comp Policies No Offsets			Broad, Comp Policies With Offsets			Narrow, Comp Policies With Offsets		
		Value	Diff from Reference	Percent Diff	Value	Diff from Reference	Percent Diff	Value	Diff from Reference	Percent Diff
Distance Travelled in 2020 *(millions of vehicle miles travelled)*										
Passenger	678,750	672,238	(6,512)	-1.0%	672,665	(6,085)	-0.9%	673,720	(5,031)	-0.7%
Freight	82,189	81,516	(673)	-0.8%	81,715	(474)	-0.6%	82,189	-	0.0%
Passenger: Miles/person	8,844	8,759	(85)	-1.0%	8,765	(79)	-0.9%	8,778	(66)	-0.7%
Vehicle Efficiency in 2020 *(miles/gallon)*										
Light Gas Vehicles	28.5	33	4	15.3%	33	4	15.4%	33	4	15.3%
Medium Gas Vehicles	28.4	33	4	15.3%	33	4	15.3%	33	4	15.3%
Heavy Gas Vehicles	20.4	24	4	17.4%	24	4	17.5%	24	4	17.5%
Heavy Diesel Vehicles	20.3	24	4	17.5%	24	4	17.5%	24	4	17.5%
Vehicle efficiency represents a fleet-wide average, not the average for new vehicles.										

Table B-16: Cap-and-Trade Cases Fuel Price Results: Eight WCI Partners

Prices in 2020 (2007 $/mmBtu)	**Reference Case**	**Broad, Comp Policies No Offsets**	**Broad, Comp Policies With Offsets**	**Narrow, Comp Policies With Offsets**
	Price	Percent Diff	Percent Diff	Percent Diff
Residential				
Res Electricity Prices	30.1	-0.3%	1.0%	12.7%
Res Natural Gas Prices	14.5	31.4%	12.2%	1.0%
Res Oil Prices	25.5	20.4%	7.7%	-0.1%
Res LPG Prices	21.6	14.6%	5.6%	0.0%
Commercial				
Com Electricity Prices	27.3	-2.4%	-0.2%	14.3%
Com Natural Gas Prices	10.1	23.7%	7.9%	-1.0%
Com Oil Prices	24.6	4.9%	2.1%	0.4%
Com LPG Prices	21.4	9.2%	4.4%	1.3%
Industrial				
Ind Electricity Prices	15.4	4.7%	6.6%	35.6%
Ind Natural Gas Prices	6.3	19.2%	7.1%	20.2%
Ind Coal Prices	2.1	167.4%	64.3%	182.4%
Ind Oil Prices	20.7	17.2%	6.5%	19.4%
Ind LPG Prices	23.1	6.2%	2.9%	7.0%
Transportation				
Gasoline Prices	28.0	17.4%	6.6%	0.0%
Diesel Prices	27.7	16.8%	6.4%	0.0%

Table B-17: Cap-and-Trade Cases Fuel Expenditure Results: Eight WCI Partners

Annual Fuel Expenditures in 2020 (M$/Yr)	Reference Case	Broad, Comp Policies No Offsets			Broad, Comp Policies With Offsets			Narrow, Comp Policies With Offsets		
		Value	Diff from Reference	Percent Diff	Value	Diff from Reference	Percent Diff	Value	Diff from Reference	Percent Diff
Sector										
Residential	45,609	39,918	(5,691)	-12.5%	40,244	(5,365)	-11.8%	43,138	(2,471)	-5.4%
Commercial	35,373	28,861	(6,512)	-18.4%	29,356	(6,017)	-17.0%	32,098	(3,275)	-9.3%
Energy Intensive Industry	32,725	29,018	(3,707)	-11.3%	29,119	(3,606)	-11.0%	29,831	(2,894)	-8.8%
Other Industry	18,496	17,001	(1,495)	-8.1%	17,062	(1,434)	-7.8%	17,977	(519)	-2.8%
Passenger Transportation	110,035	96,146	(13,889)	-12.6%	96,251	(13,784)	-12.5%	96,577	(13,458)	-12.2%
Freight Transportation	35,567	34,932	(636)	-1.8%	35,111	(457)	-1.3%	35,568	0	0.0%
Agriculture	2,848	2,482	(366)	-12.8%	2,499	(349)	-12.2%	2,669	(178)	-6.3%
Total	**280,654**	**248,358**	**(32,296)**	**-11.5%**	**249,641**	**(31,012)**	**-11.0%**	**257,859**	**(22,794)**	**-8.1%**

Table B-18: Cap-and-Trade Program Potential Allowance Value: Eight WCI Partners

Allowance Value in 2020 (M$)	Broad, Comp Policies No Offsets	Broad, Comp Policies With Offsets	Narrow, Comp Policies With Offsets
	Diff from Reference	Diff from Reference	Diff from Reference
Sector			
Residential	$3,445	$1,321	$0
Commercial	$1,641	$631	$1,925
Energy Intensive Industry	$10,922	$4,188	$12,293
Other Industry	$1,681	$647	$1,873
Passenger Transportation	$16,197	$6,199	$0
Freight Transportation	$5,630	$2,164	$0
Agriculture	$0	$0	$0
Total	**39,516**	**15,150**	**16,092**
Potential allowance value is calculated as the allowance price times the emissions in the sector. The full allowance value may not be incurred in each sector depending on the manner in which allowances are distributed and the ability to pass allowance costs to customers.			

Table B-19: Cap-and-Trade Cases Cost Results: Eight WCI Partners

Annualized Costs in 2020 (M$/Yr)	Broad, Comp Policies No Offsets	Broad, Comp Policies With Offsets	Narrow, Comp Policies With Offsets
	Diff from Reference	Diff from Reference	Diff from Reference
Sector			
Residential	(6,443)	(6,158)	(3,327)
Commercial	(7,845)	(7,369)	(4,760)
Energy Intensive Industry	10,935	10,908	12,674
Other Industry	1,979	1,996	3,250
Passenger Transportation	(20,988)	(20,511)	(19,005)
Freight Transportation	(722)	(522)	0
Agriculture	(442)	(425)	(254)
Total	**(23,525)**	**(22,080)**	**(11,422)**
These costs do not include costs of VMT Reduction programs, Energy Efficiency programs, nor Potential Allowance Value.			

Sensitivity Cases

This section presents the results of three sensitivity cases. These cases consider alternatives to the energy prices and generation costs assumed in the Reference Case. The cases discussed here are:

- High Energy Prices and High Generation Costs
- Low Energy Price Case
- High Natural Gas Price Case

Other cases are also of interest, but time did not allow for development of input data for them to be modeled in a meaningful way.

For the first two of these sensitivity cases, it was necessary to produce a new Reference Case as well as a policy case. In these cases the policy is compared to its appropriate sensitivity Reference Case.

For all the sensitivity cases, the WCI policy case is for the broad scope with offsets. The sensitivities are variations of the assumptions embedded in the Reference Case, not variations of cap-and-trade policy design.

High Energy Prices and High Generation Costs

The purpose of this sensitivity is to examine the implications of energy prices being higher than assumed in the Reference Case. There has been considerable stakeholder comment that the energy prices in the Reference Case may be too low. Additionally, some stakeholders have commented that the power generation cost assumptions maybe too low, indicating that the recent increases in commodity prices have had an impact on these costs.

This sensitivity includes both increased energy prices and increased power generation costs as a set of conditions that could occur together in the future. The high energy cost case assumes that energy prices start at current 2008 prices and increase in real terms by 50% by 2020, as shown in Table B-20. The high power generation cost case assumes that capital and operation and maintenance (O&M) costs are 30% higher than in the Reference Case.

Table B-20: Fuel Price Forecast:
High Energy Prices and High Generation Costs Sensitivity Case

	2006	2010	2015	2020
World Oil Price (2007 US$/barrel)	64.21	120.37	143.52	166.67
Natural Gas Wellhead Price (2007 US$/mmBtu)	5.97	11.12	13.26	15.40
Coal Prices (2007 US$/ton)	28.98	41.47	48.52	55.90

Low Energy Price Case

The purpose of this sensitivity is to examine the implications of energy prices being lower than assumed in the Reference Case. While there has not been stakeholder comment suggesting that energy prices may be lower, it is prudent to examine the implications of lower prices. The low energy price case uses the mid-price case from the Annual Energy Outlook 2008 (Table B-21).

Table B-21: Fuel Price Forecast: Low Energy Price Sensitivity Case

	2006	2010	2015	2020
World Oil Price (2007 US$/barrel)	$64.21	$71.60	$57.88	$57.74
Natural Gas Wellhead Price (2007 US$/mmBtu)	$5.97	$7.11	$6.09	$6.25
Coal Prices (2007 US$/ton)	$25.37	$26.66	$23.53	$22.33
Source: EIA Annual Energy Outlook 2008 mid-price series.				

High Natural Gas Price Case

The purpose of this sensitivity is to examine the implications of natural gas prices being higher than assumed in the Reference Case. There has been considerable stakeholder comment that efforts to reduce GHG emissions may increase the demand for natural gas. Consequently, the price of natural gas may increase as a result of the policies that are implemented to reduce emissions.

In the cases examined above, the demand for natural gas declines overall as a result of the complementary policies and the cap-and-trade program. Consequently, the policies examined in this analysis would not be expected to lead to an increase in natural gas prices. Nevertheless, this sensitivity was performed to examined the implications of higher natural gas prices.

To perform this sensitivity, the high natural gas price shown in Table B-20 was used with the cap-and-trade policy. The results were compared to the original Reference Case with the Reference Case natural gas prices. So, the natural gas prices are higher in the cap-and-trade case than in the Reference Case.

Results

Table B-22 through Table B-29 show model outputs for 2020: Each table shows results for eight WCI Partners, i.e., the seven states and British Columbia. The other three provinces will be included in future modeling efforts.

For each policy case, the three columns indicate the relevant Reference Case value (because each policy case has a different Reference Case), Cap-and-Trade value for the quantity described in the left-most column, and the difference between the Cap-and-Trade value and its Reference value.

Table B-26 shows fuel prices as a percent difference from Reference prices. Table B-29 shows the costs, which are only meaningful as incremental differences between the Cap-and-Trade value and the appropriate Reference Case.

Table B-22: Sensitivity Cases Greenhouse Gas Emissions and Compliance Summary: Eight WCI Partners

GHG Emissions in 2020 *(MMTCO2E)*	**Original Reference Case**	**High Energy Prices & Generation Costs**			**Low Energy Prices**			**High Natural Gas Prices**		
		Ref Case	Cap-Trade Case	Diff	Ref Case	Cap-Trade Case	Diff	Ref Case	Cap-Trade Case	Diff
Residential	63.1	58.5	52.2	-6.3	63.9	55.1	-8.7	63.1	51.9	-11.2
Commercial	31.8	28.0	23.9	-4.1	32.1	26.2	-5.9	31.8	23.7	-8.1
Energy Intensive Industry	191.0	182.4	170.0	-12.4	193.4	174.6	-18.8	191.0	174.5	-16.6
Other Industry	31.0	28.0	25.0	-3.0	31.9	27.0	-4.9	31.0	25.7	-5.4
Passenger Transport	294.0	276.0	244.1	-31.9	299.6	262.4	-37.2	294.0	259.1	-34.9
Freight Transport	91.7	79.0	78.5	-0.5	100.2	95.9	-4.3	91.7	90.7	-1.0
Power Sector	176.9	166.5	126.2	-40.3	177.1	102.4	-74.7	176.9	126.6	-50.2
Waste & Wastewater	38.4	38.4	38.4	0.0	38.4	38.4	0.0	38.4	38.4	0.0
Agriculture (non-energy)	74.9	74.9	74.9	0.0	74.9	74.9	0.0	74.9	74.9	0.0
WCI Sub-Total	**992.8**	**931.8**	**833.3**	**-98.6**	**1011.4**	**857.0**	**-154.5**	**992.8**	**865.4**	**-127.4**
Non-WCI Power Sector	70.0	70.0	70.0	-	70.0	70.0	-	70.0	70.0	-
Non-WCI Power Sector Reductions			(42.4)			(45.0)			(45.0)	
Offsets			(12.7)			(34.1)			(26.6)	
Bank Flow			-0.2			-0.1			-11.7	
Compliance Total			**847.9**			**847.8**			**852.1**	
Percent of 2006 Emissions			*84.7%*			*84.6%*			*85.1%*	
Bank Inventory			30.8			0.1			168.4	
Allowance Price (2007 $/MT)			**$18**			**$56**			**$20**	

All emissions in millions of metric tons.

Table B-23: Sensitivity Cases Energy Use Results: Eight WCI Partners

	Original Reference Case	High Energy Prices & Generation Costs			Low Energy Prices			High Natural Gas Prices		
		Ref Case	Cap-Trade Case	Diff	Ref Case	Cap-Trade Case	Diff	Ref Case	Cap-Trade Case	Diff
Total Energy Use in 2020 (TBtu/year)										
Aviation Fuel	725	680	678	(2)	753	738	(15)	725	721	(4)
Biomass	493	528	469	(59)	495	448	(47)	493	456	(37)
Coal	1,259	1,223	1,055	(168)	1,252	609	(642)	1,259	1,100	(160)
Diesel	1,025	876	861	(15)	1,126	1,067	(59)	1,025	1,004	(21)
Ethanol	480	509	445	(64)	466	412	(55)	480	420	(60)
Landfill Gas	29	29	29	0	29	29	(0)	29	29	(0)
LPG	282	332	285	(47)	271	243	(28)	282	273	(9)
Gasoline	3,053	2,824	2,439	(385)	3,120	2,666	(454)	3,053	2,631	(423)
Natural Gas	4,018	3,478	2,687	(791)	4,065	3,252	(813)	4,018	2,641	(1,378)
Nuclear	658	658	658	-	658	658	-	658	658	-
Oil, Unspecified	714	681	662	(19)	757	714	(43)	714	706	(7)
Other	3,349	3,347	2,987	(360)	3,347	2,943	(404)	3,349	3,017	(332)
Total	**16,086**	**15,164**	**13,255**	**(1,909)**	**16,340**	**13,780**	**(2,560)**	**16,086**	**13,656**	**(2,431)**
Total Energy Use in 2020 (TBtu/year)										
Residential	2,119	2,028	1,802	(226)	2,135	1,854	(281)	2,119	1,803	(316)
Commercial	1,521	1,453	1,231	(222)	1,530	1,261	(269)	1,521	1,233	(288)
Energy Intensive Industry	2,332	2,205	1,963	(242)	2,361	2,029	(332)	2,332	2,004	(328)
Other Industry	1,107	1,050	968	(82)	1,118	1,000	(118)	1,107	976	(131)
Agriculture	104	95	88	(8)	108	95	(13)	104	91	(13)
Passenger Transportation	4,201	3,960	3,500	(460)	4,274	3,745	(530)	4,201	3,699	(502)
Freight Transportation	1,251	1,092	1,085	(6)	1,360	1,305	(55)	1,251	1,238	(13)
Waste & Wastewater	-	-	-	-	-	-	-	-	-	-
Power Sector	3,450	3,281	2,618	(664)	3,454	2,492	(962)	3,450	2,610	(840)
Total	**16,086**	**15,164**	**13,255**	**(1,909)**	**16,340**	**13,780**	**(2,560)**	**16,086**	**13,656**	**(2,431)**

Table B-24: Sensitivity Cases Electric Sector Results: Eight WCI Partners

	Original Reference Case	High Energy Prices & Generation Costs			Low Energy Prices			High Natural Gas Prices		
		Ref Case	Cap-Trade Case	Diff	Ref Case	Cap-Trade Case	Diff	Ref Case	Cap-Trade Case	Diff
Generation Capacity in 2020 *(MW)*										
Gas/Oil	88,519	89,519	106,599	17,080	86,239	108,759	22,520	88,519	136,359	47,840
Coal	15,372	15,372	15,372	-	15,372	15,372	-	15,372	15,372	-
Nuclear	9,330	9,330	9,330	-	9,330	9,330	-	9,330	9,330	-
Hydro	63,508	63,914	63,426	(488)	63,507	63,464	(43)	63,508	63,397	(111)
Landfill Gas/EFW	347	347	347	-	347	347	-	347	347	-
Wind	24,513	22,766	21,533	(1,233)	24,290	22,829	(1,461)	24,513	23,967	(546)
Other	6,582	6,695	6,330	(365)	6,646	6,384	(262)	6,582	6,343	(239)
Total	**208,172**	**207,943**	**222,938**	**14,995**	**205,731**	**226,485**	**20,754**	**208,172**	**255,115**	**46,943**
Generation Output 2020 *(GWh/year)*										
Gas/Oil	164,782	145,539	81,131	(64,407)	162,219	128,052	(34,167)	164,782	84,935	(79,847)
Coal	101,454	101,513	88,202	(13,312)	101,389	46,101	(55,288)	101,454	88,847	(12,606)
Nuclear	65,072	65,072	65,072	-	65,072	65,072	-	65,072	65,072	-
Hydro	268,661	271,519	268,082	(3,437)	268,649	268,349	(300)	268,661	267,877	(784)
Landfill Gas/EFW	2,088	2,088	2,088	0	2,088	2,088	(0)	2,088	2,088	(0)
Wind	65,273	60,428	57,011	(3,417)	64,654	60,603	(4,051)	65,273	63,758	(1,515)
Other	36,219	36,501	34,019	(2,482)	36,886	34,499	(2,387)	36,219	32,919	(3,299)
Total	**703,548**	**682,659**	**595,605**	**(87,055)**	**700,956**	**604,763**	**(96,193)**	**703,548**	**605,496**	**(98,052)**
Sales in 2020 *(GWh/year)*										
Residential	267,908	267,531	233,815	(33,717)	267,625	232,186	(35,439)	267,908	235,623	(32,286)
Commercial	270,164	272,103	227,845	(44,257)	268,841	222,860	(45,980)	270,164	228,621	(41,542)
Industrial	187,146	186,028	163,446	(22,582)	185,238	160,256	(24,983)	187,146	164,351	(22,795)
Transportation	8,461	7,533	7,413	(120)	8,537	8,071	(465)	8,461	7,458	(1,003)
Street Lights/Misc.	16,447	16,447	16,447	-	16,447	16,447	-	16,447	16,447	-
Total Sales	**750,126**	**749,642**	**648,966**	**(100,676)**	**746,687**	**639,820**	**(106,867)**	**750,126**	**652,500**	**(97,625)**

Table B-25: Sensitivity Cases Transportation Sector Results: Eight WCI Partners

	Original Reference Case	High Energy Prices & Generation Costs			Low Energy Prices			High Natural Gas Prices		
		Ref Case	Cap-Trade Case	Diff	Ref Case	Cap-Trade Case	Diff	Ref Case	Cap-Trade Case	Diff
Distance Travelled in 2020 *(millions of vehicle miles travelled)*										
Passenger	678,750	663,044	659,404	(3,640)	686,691	677,633	(9,058)	678,750	672,895	(5,855)
Freight	82,189	77,505	77,301	(205)	85,286	83,768	(1,518)	82,189	81,805	(384)
Passenger: Miles/person	8,844	8,639	8,592	(47)	8,948	8,829	(118)	8,844	8,768	(76)
Vehicle Efficiency in 2020 *(miles/gallon)*										
Light Gas Vehicles	28.5	30.2	34.9	4.7	28.4	32.8	4.3	28.5	32.8	4.4
Medium Gas Vehicles	28.4	30.2	34.9	4.7	28.4	32.7	4.3	28.4	32.8	4.4
Heavy Gas Vehicles	20.4	20.6	24.2	3.6	20.5	24.0	3.6	20.4	24.0	3.6
Heavy Diesel Vehicles	20.3	20.4	24.0	3.6	20.3	23.9	3.6	20.3	23.9	3.5
Vehicle efficiency represents a fleet-wide average, not the average for new vehicles.										

Table B-26: Sensitivity Cases Fuel Price Results: Eight WCI Partners

Prices in 2020 (2007 $/mmBtu)	High Energy Prices & Generation Costs		Low Energy Prices		High Natural Gas Prices	
	Ref Price	Percent Diff	Ref Price	Percent Diff	Ref Price	Percent Diff
Residential						
Res Electricity Prices	37.5	-4%	29.0	10%	30.1	12%
Res Natural Gas Prices	22.8	6%	13.4	31%	14.5	68%
Res Oil Prices	40.0	4%	19.9	23%	25.5	6%
Res LPG Prices	21.7	4%	21.6	13%	21.6	5%
Commercial						
Com Electricity Prices	34.8	-4%	26.2	11%	27.3	11%
Com Natural Gas Prices	19.0	4%	9.4	23%	10.1	96%
Com Oil Prices	43.3	1%	22.5	7%	24.6	2%
Com LPG Prices	22.2	3%	21.6	8%	21.4	7%
Industrial						
Ind Electricity Prices	22.9	-2%	14.6	28%	15.4	28%
Ind Natural Gas Prices	16.4	2%	5.9	17%	6.3	169%
Ind Coal Prices	5.1	20%	2.1	148%	2.1	52%
Ind Oil Prices	35.0	3%	15.0	21%	20.7	4%
Ind LPG Prices	23.5	2%	23.2	6%	23.1	4%
Transportation						
Gasoline Prices	40.7	3%	20.7	21%	28.0	6%
Diesel Prices	40.6	3%	20.6	20%	27.7	5%

Table B-27: Sensitivity Cases Fuel Expenditure Results: Eight WCI Partners

Annual Fuel Expenditures in 2020 (M$/Yr)	**Original Reference Case**	**High Energy Prices & Generation Costs**			**Low Energy Prices**			**High Natural Gas Prices**		
		Ref Case	Cap-Trade Case	Diff	Ref Case	Cap-Trade Case	Diff	Ref Case	Cap-Trade Case	Diff
Sector										
Residential	45,609	59,685	51,704	(7,981)	43,546	40,351	(3,195)	45,609	49,857	4,247
Commercial	35,373	46,310	37,665	(8,646)	33,624	29,954	(3,670)	35,373	35,121	(252)
Energy Intensive Industry	32,725	45,447	40,833	(4,614)	28,528	25,567	(2,961)	32,725	34,487	1,762
Other Industry	18,496	26,917	24,680	(2,237)	15,624	14,919	(705)	18,496	19,811	1,315
Passenger Transportation	110,035	153,023	134,505	(18,518)	82,147	71,469	(10,677)	110,035	96,875	(13,160)
Freight Transportation	35,567	45,436	45,174	(262)	29,929	28,755	(1,174)	35,567	35,199	(369)
Agriculture	2,848	3,807	3,328	(478)	2,564	2,349	(216)	2,848	2,779	(69)
Total	**280,654**	380,625	337,889	(42,736)	235,962	213,364	(22,598)	280,654	274,129	(6,525)

Table B-28: Sensitivity Cases Potential Allowance Value: Eight WCI Partners

Allowance Value in 2020 (M$)	**High Energy Prices & Generation Costs**	**Low Energy Prices**	**High Natural Gas Prices**
	Diff from Reference	Diff from Reference	Diff from Reference
Sector			
Residential	$925	$3,064	$1,031
Commercial	$424	$1,456	$471
Energy Intensive Industry	$3,013	$9,705	$3,468
Other Industry	$443	$1,502	$510
Passenger Transportation	$4,325	$14,584	$5,150
Freight Transportation	$1,391	$5,332	$1,802
Agriculture	$0	$0	$0
Total	**10,521**	**35,642**	**12,434**
Potential allowance value is calculated as the allowance price times the emissions in the sector. The full allowance value may not be incurred in each sector depending on the manner in which allowances are distributed and the ability to pass allowance costs to customers.			

Table B-29: Sensitivity Cases Cost Results: Eight WCI Partners

Annualized Costs in 2020 (M$/Yr)	**High Energy Prices & Generation Costs**	**Low Energy Prices**	**High Natural Gas Prices**
	Diff from Reference	Diff from Reference	Diff from Reference
Sector			
Residential	($9,724)	($3,749)	$4,833
Commercial	($12,158)	($4,120)	($1,394)
Energy Intensive Industry	$12,294	$11,335	$18,778
Other Industry	$1,917	$2,782	$5,806
Passenger Transportation	($21,999)	($20,845)	($19,589)
Freight Transportation	($298)	($1,362)	($423)
Agriculture	($546)	($287)	($131)
Total	**($30,514)**	**($16,245)**	**$7,880**
These costs do not include costs of VMT Reduction programs, Energy Efficiency programs, nor Potential Allowance Value.			

Summary Results

Table B-30 presents summary results for the cases presented above. The GHG emissions are reported for the eight WCI partner jurisdictions included in the analysis. Fuel Expenditures and Total Costs (Savings) are relative to the appropriate Reference Case. The potential value of allowances is shown assuming that the full allowance value is passed through to consumers. Total Costs (Savings) include Fuel Expenditures and annualized investment costs. All emissions are in MMTCO2E and all costs are in 2007 dollars.

Table B-30: Summary Results for 2020: Eight WCI Partners

Case	**GHG Emission** (MMTCO2E)	**Offsets Used** (MMTCO2E)	**Allowance Price** (2007 $)	**Change in Fuel Expenditures** ($M/Yr)	**Potential Allowance Value** ($M/Yr)	**Total Costs (Savings)** ($M/Yr)
Reference Case	992.8	--	--	--	--	--
Cap-and-Trade Policy Cases						
Broad Scope, No Offsets	859.2	--	$63	(32,296)	39,516	(23,525)
Broad Scope, With Offsets	877.9	31.8	$24	(31,012)	15,150	(22,080)
Narrow Scope, With Offsets	847.8	18.2	$71	(22,794)	16,092	(11,422)
Sensitivity Cases						
High Price	833.3	12.7	$18	(42,736)	10,521	($30,514)
Low Price	857.0	34.1	$56	(22,598)	35,642	($16,245)
High Natural Gas Price	865.4	26.6	$20	(6,525)	12,434	$7,880
Fuel Expenditures and Total Costs (Savings) are changes from Reference Case values. Potential Allowance Value calculated as emissions times allowance price. Total Costs (Savings) do not include costs of VMT Reduction programs, Energy Efficiency programs, nor Potential Allowance Value.						

Attachment 1: Banking

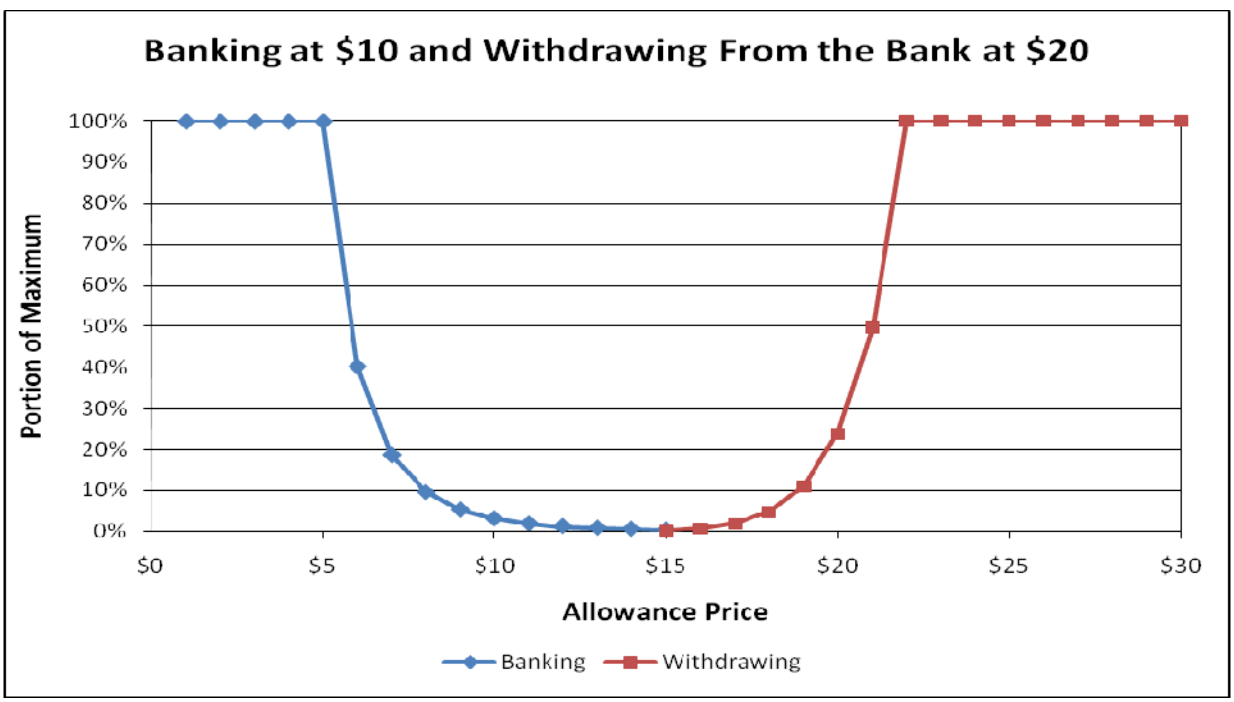
The purpose of banking is to enable allowances issued or auctioned in one year to be used in a later period. When allowance prices are low, allowances would likely be banked. When prices are high, allowances would be withdrawn from the bank. The model does not have the ability to optimize the banking behaviour in the market. Rather, banking is simulated using the following model input parameters:

- The price below which allowances are put into the bank.
- The maximum portion of emission allowances in a given year that can be banked.
- The price above which allowances are withdrawn from the bank.
- The maximum portion of the allowances in the bank in a given year that can be withdrawn.

Figure A-2 shows the banking and withdrawing curves used the cases presented here. The curves shown in the figure set the price below which allowances are banked at $10/ton. The price above which allowances are withdrawn from the bank is set at $20/ton.

The curves in the figure indicate the portion of the allowable banking and redeeming amounts that are simulated to be used. The recommended program design sets no limits on the amounts that can be banked. However, bounds are set in the model to better simulate behavior, particularly in the early years of the program when allowances prices are simulated to be low. The maximum amount put into the bank in a single year is limited to 10% of total allowances available in that year. The maximum amount withdrawn from the bank in a single year is limited to 30% of the allowances in the bank.

Figure B-2: Banking Curves



Attachment 2: Detailed Cap-and-Trade Policy Results

This attachment shows the detailed results for two of the cap-and-trade program model runs:

- Broad Scope, with complementary policies and with offsets; and
- Narrow Scope, with complementary policies and with offsets.

Cap-and-Trade Program: Broad Scope with Complementary Policies and Offsets

Table B-31: Cap-and-Trade Program Greenhouse Gas Emissions and Compliance Summary: Eight WCI Partners Broad Scope with Complementary Policies and Offsets

	2006	2010	2015	2020	Growth Rate 2006-2020
GHG Emissions *(MMTCO2E)*					
Residential	49.7	53.6	54.7	55.2	0.8%
Commercial	29.3	30.4	28.0	26.4	-0.8%
Energy Intensive Industry	176.8	174.0	172.2	175.0	-0.1%
Other Industry	29.8	30.2	28.5	27.0	-0.7%
Passenger Transport	290.8	291.7	276.5	259.0	-0.8%
Freight Transport	93.0	89.6	89.6	90.4	-0.2%
Power Sector	176.6	166.4	133.0	131.5	-2.1%
Waste & Wastewater	25.6	29.1	34.2	38.4	2.9%
Agriculture (non-energy)	59.9	62.1	67.5	74.9	1.6%
WCI Sub-Total	**931.6**	**927.1**	**884.1**	**877.9**	**-0.4%**
Compliance Summary					
Non-WCI Power Sector	70.0	70.0	70.0	70.0	
Non-WCI Power Sector Reductions	-	(0.1)	(20.3)	(37.0)	
Offsets	-	-	-	(31.8)	
Bank Flow	0.0	0.0	21.2	-31.8	
Compliance Total	**1,001.6**	**997.0**	**955.0**	**847.2**	
Percent of 2006 Emissions	*100.0%*	*99.5%*	*95.3%*	*84.6%*	
Bank Inventory	0.0	0.0	107.4	74.4	
Allowance Price (2007 $/MT)	**$0**	**$0**	**$6**	**$24**	
Percentage of Offsets Allowed	5%	5%	5%	5%	
Percent Allowable Offsets Used			**0%**	**100%**	
All emissions in million metric tons.					

Table B-32: Cap-and-Trade Program Energy Use: Eight WCI Partners
Broad Scope with Complementary Policies and Offsets

Total Energy Use *(TBtu/year)*	**2006**	**2010**	**2015**	**2020**	**Growth Rate 2006-2020**
Aviation Fuel	609	637	682	720	1.2%
Biomass	443	427	440	448	0.1%
Coal	1,185	1,212	1,063	1,043	-0.9%
Diesel	1,091	1,048	1,021	1,001	-0.6%
Ethanol	85	165	298	420	12.1%
Landfill Gas	29	29	29	29	0.2%
LPG	231	239	242	249	0.5%
Gasoline	3,303	3,219	2,920	2,628	-1.6%
Natural Gas	3,947	3,764	3,217	3,075	-1.8%
Nuclear	658	658	658	658	0.0%
Oil, Unspecified	695	687	679	688	-0.1%
Other	2,902	2,944	2,892	2,952	0.1%
Total	**15,178**	**15,031**	**14,139**	**13,911**	**-0.6%**
Total Energy Use *(TBtu/year)*	**2006**	**2010**	**2015**	**2020**	**Growth Rate 2006-2020**
Residential	1,638	1,769	1,813	1,856	0.9%
Commercial	1,357	1,385	1,291	1,260	-0.5%
Energy Intensive Industry	2,508	2,374	2,151	2,035	-1.5%
Other Industry	1,015	1,031	1,011	1,003	-0.1%
Agriculture	140	127	107	94	-2.8%
Passenger Transportation	3,998	4,025	3,870	3,702	-0.5%
Freight Transportation	1,219	1,183	1,204	1,235	0.1%
Waste & Wastewater	-	-	-	-	#N/A
Power Sector	3,302	3,137	2,693	2,727	-1.4%
Total	**15,178**	**15,031**	**14,139**	**13,911**	**-0.6%**

Table B-33: Cap-and-Trade Program Electric Sector Results: Eight WCI Partners Broad Scope with Complementary Policies and Offsets

Generation Capacity *(MW)*	**2006**	**2010**	**2015**	**2020**	**Growth Rate 2006-2020**
Gas/Oil	62,973	72,139	96,879	109,919	4.1%
Coal	14,972	15,372	15,372	15,372	0.2%
Nuclear	9,330	9,330	9,330	9,330	0.0%
Hydro	61,721	63,374	63,444	63,471	0.2%
Landfill Gas/EFW	338	347	347	347	0.2%
Wind	4,083	6,827	17,979	22,945	13.1%
Other	4,358	4,537	5,618	6,354	2.7%
Total	**157,776**	**171,925**	**208,969**	**227,738**	**2.7%**
Generation Output *(GWh/year)*	**2006**	**2010**	**2015**	**2020**	**Growth Rate 2006-2020**
Gas/Oil	143,907	130,007	97,216	101,382	-2.5%
Coal	99,280	100,365	86,458	85,318	-1.1%
Nuclear	65,072	65,072	65,072	65,072	0.0%
Hydro	256,243	267,713	268,207	268,398	0.3%
Landfill Gas/EFW	2,036	2,088	2,088	2,088	0.2%
Wind	8,733	16,245	47,160	60,925	14.9%
Other	23,554	24,606	30,894	34,579	2.8%
Total	**598,824**	**606,095**	**597,095**	**617,761**	**0.2%**
Sales (GWh/year)	**2006**	**2010**	**2015**	**2020**	**Growth Rate 2006-2020**
Residential	202,826	218,393	223,899	232,447	1.0%
Commercial	231,140	233,974	220,827	222,998	-0.3%
Industrial	163,747	161,191	155,272	162,071	-0.1%
Transportation	4,864	6,663	7,729	8,229	3.8%
Street Lights/Misc.	16,447	16,447	16,447	16,447	0.0%
Resale	-	-	-	-	#N/A
Total Sales	**619,023**	**636,669**	**624,174**	**642,191**	**0.3%**

Table B-34: Cap-and-Trade Program Transportation Sector Results: Eight WCI Partners Broad Scope with Complementary Policies and Offsets

Distance Travelled (millions of vehicle miles travelled)					
	2006	**2010**	**2015**	**2020**	**Growth Rate 2006-2020**
Passenger	556,055	585,955	631,048	672,665	1.4%
Freight	72,562	73,248	77,307	81,715	0.9%
Passenger: Miles/person	8,755	8,724	8,779	8,765	0.0%
Vehicle Efficiency (miles/gallon)					
	2006	**2010**	**2015**	**2020**	**Growth Rate 2006-2020**
Light Gas Vehicles	23.2	24.6	28.3	32.8	2.5%
Medium Gas Vehicles	23.2	24.6	28.2	32.8	2.5%
Heavy Gas Vehicles	16.9	17.8	20.8	24.0	2.5%
Heavy Diesel Vehicles	16.9	17.8	20.8	23.9	2.5%
Vehicle efficiency represents a fleet-wide average, not the average for new vehicles.					

Table B-35: Cap-and-Trade Program Fuel Prices: Eight WCI Partners Broad Scope with Complementary Policies and Offsets

Prices (2007 $/mmBtu)	**2006**	**2010**	**2015**	**2020**
Residential				
Res Electricity Prices	29.4	30.9	29.7	30.4
Res Natural Gas Prices	11.5	13.5	14.4	16.3
Res Oil Prices	21.0	23.3	24.5	27.5
Res LPG Prices	22.7	24.2	22.0	22.8
Commercial				
Com Electricity Prices	26.4	27.8	26.5	27.2
Com Natural Gas Prices	8.8	10.0	10.0	10.9
Com Oil Prices	23.1	25.0	24.2	25.1
Com LPG Prices	22.5	24.3	22.0	22.3
Industrial				
Ind Electricity Prices	16.3	17.1	15.6	16.4
Ind Natural Gas Prices	6.7	7.4	6.6	6.7
Ind Coal Prices	2.2	2.2	2.5	3.5
Ind Oil Prices	16.4	18.4	19.6	22.0
Ind LPG Prices	23.9	25.5	23.3	23.8
Transportation				
Gasoline Prices	21.9	24.1	26.5	29.8
Diesel Prices	21.8	24.0	26.3	29.5

**Table B-36: Cap-and-Trade Program Fuel Expenditures: Eight WCI Partners
Broad Scope with Complementary Policies and Offsets**

Annual Fuel Expenditures (M$/Yr)					
Sector	**2006**	**2010**	**2015**	**2020**	**Growth Rate 2006-2020**
Residential	31,763	37,464	38,001	40,244	1.7%
Commercial	28,452	31,263	28,475	29,356	0.2%
Energy Intensive Industry	28,969	31,127	28,693	29,119	0.0%
Other Industry	14,567	16,483	16,156	17,062	1.1%
Passenger Transportation	82,031	91,324	93,969	96,251	1.1%
Freight Transportation	28,315	30,055	32,173	35,111	1.5%
Agriculture	3,140	3,140	2,625	2,499	-1.6%
Total	**217,237**	**240,856**	**240,093**	**249,641**	**1.0%**

**Table B-37: Cap-and-Trade Program Potential Allowance Value: Eight WCI Partners
Broad Scope with Complementary Policies and Offsets**

Allowance Value (M$)				
Sector	**2006**	**2010**	**2015**	**2020**
Residential	$0	$0	$355	$1,321
Commercial	$0	$0	$182	$631
Energy Intensive Industry	$0	$0	$1,118	$4,188
Other Industry	$0	$0	$185	$647
Passenger Transportation	$0	$0	$1,794	$6,199
Freight Transportation	$0	$0	$581	$2,164
Agriculture	$0	$0	$0	$0
Total	**$0**	**$0**	**$4,215**	**$15,150**
Potential allowance value is calculated as the allowance price times the emissions in the sector. The full allowance value may not be incurred in each sector depending on the manner in which allowances are distributed and the ability to pass allowance costs to customers.				

Table B-38: Cap-and-Trade Program Annualized Costs (Savings): Eight WCI Partners Broad Scope with Complementary Policies and Offsets

Annualized Cost (M$/Yr) (Change from Reference Case)				
Sector	**2006**	**2010**	**2015**	**2020**
Residential	$0	$331	($2,279)	($6,158)
Commercial	$0	($37)	($3,632)	($7,369)
Energy Intensive Industry	$0	$1,109	$4,981	$10,908
Other Industry	$0	$258	$858	$1,996
Passenger Transportation	$0	($5,326)	($15,388)	($20,511)
Freight Transportation	$0	($0)	($119)	($522)
Agriculture	$0	($3)	($231)	($425)
Total	**$0**	**($3,668)**	**($15,810)**	**($22,080)**
These costs do not include costs of VMT Reduction programs, Energy Efficiency programs, nor Potential Allowance Value.				

Cap-and-Trade Program: Narrow Scope with Complementary Policies and Offsets

Table B-39: Cap-and-Trade Program Greenhouse Gas Emissions and Compliance Summary: Eight WCI Partners Narrow Scope with Complementary Policies and Offsets

GHG Emissions *(MMTCO2E)*	**2006**	**2010**	**2015**	**2020**	**Growth Rate 2006-2020**
Residential	49.7	53.6	54.8	55.9	0.9%
Commercial	29.3	30.4	28.1	27.0	-0.6%
Energy Intensive Industry	176.8	174.0	171.4	172.6	-0.2%
Other Industry	29.8	30.2	28.3	26.3	-0.9%
Passenger Transport	290.8	291.7	276.8	259.9	-0.8%
Freight Transport	93.0	89.6	89.9	91.7	-0.1%
Power Sector	176.6	166.4	132.4	104.8	-3.7%
Waste & Wastewater	25.6	29.1	34.2	38.4	2.9%
Agriculture (non-energy)	59.9	62.1	64.5	71.1	1.2%
WCI Sub-Total	**931.6**	**927.1**	**880.4**	**847.8**	**-0.7%**
Compliance Summary					
Non-WCI Power Sector Reductions	-	-	(21.3)	(45.0)	
Offsets	-	-	(11.7)	(18.2)	
Bank Flow	0.0	0.0	0.0	-0.2	
Compliance Total	**1,001.6**	**997.1**	**917.4**	**854.3**	
Percent of 2006 Emissions	*100.0%*	*99.5%*	*91.6%*	*85.3%*	
Bank Inventory	0.0	0.0	2.7	0.5	
Allowance Price (2007 $/MT)	**$0**	**$0**	**$19**	**$71**	
Percentage of Offsets Allowed	5%	5%	5%	5%	
Percent of Allowable Offsets Used			**57%**	**100%**	

Table B-40: Cap-and-Trade Program Energy Use: Eight WCI Partners Narrow Scope with Complementary Policies and Offsets

Total Energy Use *(TBtu/year)*	**2006**	**2010**	**2015**	**2020**	**Growth Rate 2006-2020**
Aviation Fuel	609	637	683	725	1.3%
Biomass	443	427	441	452	0.1%
Coal	1,185	1,212	1,054	618	-4.5%
Diesel	1,091	1,048	1,024	1,014	-0.5%
Ethanol	85	165	298	419	12.1%
Landfill Gas	29	29	29	29	0.2%
LPG	231	239	242	250	0.5%
Gasoline	3,303	3,219	2,923	2,635	-1.6%
Natural Gas	3,947	3,764	3,210	3,296	-1.3%
Nuclear	658	658	658	658	0.0%
Oil, Unspecified	695	687	678	687	-0.1%
Other	2,902	2,944	2,889	2,934	0.1%
Total	**15,178**	**15,031**	**14,129**	**13,718**	**-0.7%**
Total Energy Use *(TBtu/year)*	**2006**	**2010**	**2015**	**2020**	**Growth Rate 2006-2020**
Residential	1,638	1,769	1,815	1,863	0.9%
Commercial	1,357	1,385	1,292	1,265	-0.5%
Energy Intensive Industry	2,508	2,374	2,141	2,005	-1.6%
Other Industry	1,015	1,031	1,008	991	-0.2%
Agriculture	140	127	107	92	-2.9%
Passenger Transportation	3,998	4,025	3,873	3,712	-0.5%
Freight Transportation	1,219	1,183	1,208	1,251	0.2%
Waste & Wastewater	-	-	-	-	#N/A
Power Sector	3,302	3,137	2,685	2,539	-1.9%
Total	**15,178**	**15,031**	**14,129**	**13,718**	**-0.7%**

Table B-41: Cap-and-Trade Program Electric Sector Results: Eight WCI Partners Narrow Scope with Complementary Policies and Offsets

Generation Capacity *(MW)*	**2006**	**2010**	**2015**	**2020**	**Growth Rate 2006-2020**
Gas/Oil	62,973	72,139	96,879	109,879	4.1%
Coal	14,972	15,372	15,372	15,372	0.2%
Nuclear	9,330	9,330	9,330	9,330	0.0%
Hydro	61,721	63,374	63,444	63,462	0.2%
Landfill Gas/EFW	338	347	347	347	0.2%
Wind	4,083	6,827	17,979	22,721	13.0%
Other	4,358	4,537	5,618	6,344	2.7%
Total	**157,776**	**171,925**	**208,969**	**227,456**	**2.6%**
Generation Output *(GWh/year)*	**2006**	**2010**	**2015**	**2020**	**Growth Rate 2006-2020**
Gas/Oil	143,907	130,007	97,031	134,044	-0.5%
Coal	99,280	100,365	86,172	46,848	-5.2%
Nuclear	65,072	65,072	65,072	65,072	0.0%
Hydro	256,243	267,713	268,207	268,337	0.3%
Landfill Gas/EFW	2,036	2,088	2,088	2,088	0.2%
Wind	8,733	16,245	47,160	60,305	14.8%
Other	23,554	24,606	30,926	34,558	2.8%
Total	**598,824**	**606,095**	**596,656**	**611,251**	**0.1%**
Sales (GWh/year)	**2006**	**2010**	**2015**	**2020**	**Growth Rate 2006-2020**
Residential	202,826	218,393	223,631	230,725	0.9%
Commercial	231,140	233,974	220,504	221,170	-0.3%
Industrial	163,747	161,191	155,498	162,118	-0.1%
Transportation	4,864	6,663	7,691	7,923	3.5%
Street Lights/Misc.	16,447	16,447	16,447	16,447	0.0%
Resale	-	-	-	-	#N/A
Total Sales	**619,023**	**636,669**	**623,771**	**638,383**	**0.2%**

Table B-42: Cap-and-Trade Program Transportation Sector Results: Eight WCI Partners Narrow Scope with Complementary Policies and Offsets

Distance Travelled *(millions of vehicle miles travelled)*					
	2006	**2010**	**2015**	**2020**	**Growth Rate 2006-2020**
Passenger	556,055	585,955	631,324	673,720	1.4%
Freight	72,562	73,248	77,423	82,189	0.9%
Passenger: Miles/person	8,755	8,724	8,782	8,778	0.0%
Vehicle Efficiency *(miles/gallon)*					
	2006	**2010**	**2015**	**2020**	**Growth Rate 2006-2020**
Light Gas Vehicles	23.2	24.6	28.2	32.8	2.5%
Medium Gas Vehicles	23.2	24.6	28.2	32.8	2.5%
Heavy Gas Vehicles	16.9	17.8	20.8	24.0	2.5%
Heavy Diesel Vehicles	16.9	17.8	20.8	23.9	2.5%
Vehicle efficiency represents a fleet-wide average, not the average for new vehicles.					

Table B-43: Cap-and-Trade Program Fuel Prices: Eight WCI Partners Narrow Scope with Complementary Policies and Offsets

Prices (2007 $/mmBtu)	**2006**	**2010**	**2015**	**2020**
Residential				
Res Electricity Prices	29.4	30.9	30.4	33.9
Res Natural Gas Prices	11.5	13.5	14.0	14.6
Res Oil Prices	21.0	23.3	24.0	25.5
Res LPG Prices	22.7	24.2	21.7	21.6
Commercial				
Com Electricity Prices	26.4	27.8	27.2	31.2
Com Natural Gas Prices	8.8	10.0	9.8	10.0
Com Oil Prices	23.1	25.0	24.0	24.7
Com LPG Prices	22.5	24.3	21.8	21.7
Industrial				
Ind Electricity Prices	16.3	17.1	16.3	20.8
Ind Natural Gas Prices	6.7	7.4	6.8	7.5
Ind Coal Prices	2.2	2.2	3.3	6.0
Ind Oil Prices	16.4	18.4	20.3	24.7
Ind LPG Prices	23.9	25.5	23.6	24.7
Transportation				
Gasoline Prices	21.9	24.1	26.0	28.0
Diesel Prices	21.8	24.0	25.8	27.7

Table B-44: Cap-and-Trade Program Fuel Expenditures: Eight WCI Partners Narrow Scope with Complementary Policies and Offsets

Annual Fuel Expenditures (M$/Yr)					
Sector	**2006**	**2010**	**2015**	**2020**	**Growth Rate 2006-2020**
Residential	31,763	37,464	38,520	43,138	2.2%
Commercial	28,452	31,263	28,989	32,098	0.9%
Energy Intensive Industry	28,969	31,127	28,806	29,831	0.2%
Other Industry	14,567	16,483	16,327	17,977	1.5%
Passenger Transportation	82,031	91,324	94,072	96,577	1.2%
Freight Transportation	28,315	30,055	32,280	35,568	1.6%
Agriculture	3,140	3,140	2,661	2,669	-1.2%
Total	217,237	240,856	241,656	257,859	1.2%

Table B-45: Cap-and-Trade Program Potential Allowance Value: Eight WCI Partners Narrow Scope with Complementary Policies and Offsets

Allowance Value (M$)				
Sector	**2006**	**2010**	**2015**	**2020**
Residential	$0	$0	$0	$0
Commercial	$0	$0	$521	$1,925
Energy Intensive Industry	$0	$0	$3,176	$12,293
Other Industry	$0	$0	$524	$1,873
Passenger Transportation	$0	$0	$0	$0
Freight Transportation	$0	$0	$0	$0
Agriculture	$0	$0	$0	$0
Total	**$0**	**$0**	**$4,221**	**16,092**
Potential allowance value is calculated as the allowance price times the emissions in the sector. The full allowance value may not be incurred in each sector depending on the manner in which allowances are distributed and the ability to pass allowance costs to customers.				

Table B-46: Cap-and-Trade Program Annualized Costs (Savings): Eight WCI Partners Narrow Scope with Complementary Policies and Offsets

Annualized Cost (M$/Yr) (Change from Reference Case)				
Sector	**2006**	**2010**	**2015**	**2020**
Residential	$0	$331	($1,771)	($3,327)
Commercial	$0	($37)	($3,144)	($4,760)
Energy Intensive Industry	$0	$1,109	$5,237	$12,674
Other Industry	$0	$258	$1,085	$3,250
Passenger Transportation	$0	($5,326)	($15,073)	($19,005)
Freight Transportation	$0	($0)	$0	$0
Agriculture	$0	($3)	($194)	($254)
Total	**$0**	**($3,668)**	**($13,859)**	**($11,422)**
These costs do not include costs of VMT Reduction programs, Energy Efficiency programs, nor Potential Allowance Value.				

Appendix C: General Q & A

Western Climate Initiative

Q: What is the Western Climate Initiative announcing today?

The Western Climate Initiative (WCI) Partners today announced their proposed design of a regional market-based cap-and-trade program. This program is an important component of a comprehensive regional effort to reduce the pollution that causes global warming to 15 percent below 2005 levels by 2020.

Q: What are the market design elements being released by the WCI?

The WCI partners are recommending a multi-sector cap-and-trade program to reduce the pollution that causes global warming to 15% below 2005 levels by 2020. This program includes the following design parameters:

- A limit on the emissions from all major sources of global warming pollutants;
- Include under the cap all electricity-related emissions, including those associated with electricity imported from outside the WCI partner jurisdictions;
- Ensure that all regulated entities use a consistent reporting methodology; and
- Mitigate economic impacts on consumers and regulated entities by allowing flexibility in how and when the reductions are made (e.g., banking of allowances and the limited use of offsets).

Q: How was the WCI market design developed?

The release of the WCI design recommendations is the culmination of 18 months of extensive analysis, stakeholder consultation and deliberation by the WCI Partners. We will continue to consult with and seek input from the broad range of stakeholders who contributed to this process.

Q: What are the next steps?

The release of this market design program marks the culmination of 18 months of extensive analysis, stakeholder consultation and deliberation by the WCI Partners. This proposal will now be further developed by each WCI Partner with the objective of taking the steps necessary to implement the program.

The timeline agreed to by the WCI Partners is that each will begin reporting emissions in 2011 for emissions that occur in 2010. The first phase of the cap-and-trade program will begin on January 1, 2012, with a three-year compliance period. The second phase will begin in 2015, when the program is expanded to include transportation fuels and residential, commercial and industrial fuels.

Q: What emissions sources are subject to the cap under the WCI agreement?

The WCI cap-and-trade program covers the largest emitters from each state and province, including energy (electricity generation, natural gas and heating fuels), industrial emissions and transportation emissions.

Q: How will emissions allowances be distributed under the WCI agreement?

Each WCI Partner jurisdiction will have an emission allowance budget under the cap-and-trade program that is consistent with its jurisdiction-specific emissions goal for 2020. Each Partner has the flexibility to decide how best to allocate its allowance budget within its jurisdiction.

For instance, a Partner could "give" allowances to the emitters operating within its jurisdiction, "auction" the allowances to willing buyers, or provide for some combination of the two. The WCI design calls for a minimum auction level of 10% at the start of the program, increasing to at least 25% by 2020. Each jurisdiction may auction a higher percentage if it so chooses. In addition, the WCI Partners have agreed to use a portion of the allowance value for purposes with region-wide benefits, such as energy efficiency and low-carbon technology development.

Q: How will compliance be determined under the WCI agreement?

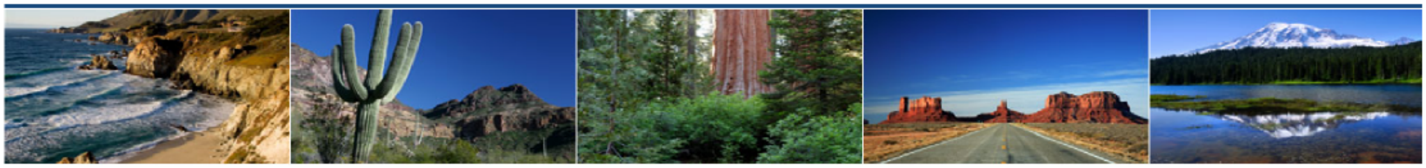
The bedrock of a cap-and-trade system is a rigorous emissions reporting requirement. The regulated sources are required to ensure the data are accurate and complete. Each WCI partner will require third party validation of reported emissions from entities and facilities that will be included under the cap.

The WCI agreement is consistent with previous well-designed cap-and-trade programs that have had compliance rates of over 99 percent. At the end of each compliance period, facilities and entities with emissions are required to submit the same number of emission allowances to the government as the emissions they had during that compliance period. If the facility or entity does not have sufficient emission allowances to cover its emissions, a "penalty" of three allowances will be assessed for each one they are short.

Q: What are offsets? How are they handled under the WCI agreement?

Offsets are reductions in greenhouse gas emissions from outside of the capped sectors, such as forestry and agriculture. Offset credits may be used, provided they meet rigorous criteria to ensure that emission reductions are real, verifiable, surplus/additional, permanent and enforceable. Offset credits may be traded. The WCI program limits the use of offsets for compliance purposes to ensure that a majority of the required emission reductions is achieved in the sources covered by the cap-and-trade program.

Western Climate Initiative



September 30, 2008

To All Interested Parties:

Today, the WCI Reporting Subcommittee is releasing their “Essential Requirements of Mandatory Reporting for the Western Climate Initiative, Second Draft.” This document builds on the draft recommendations released in July, incorporates reporting elements from the Design Recommendations for the WCI Regional Cap-and-Trade Program (released September 23, 2008), and identifies additional decisions to be made.

As noted in the draft recommendations released in May, completion of the essential requirements for mandatory emissions reporting is scheduled for December 2008. As noted in this current draft, we have many additional decisions that will need to be made in order to complete the essential requirements, and we intend to provide additional opportunities for stakeholder input and comment as the work proceeds.

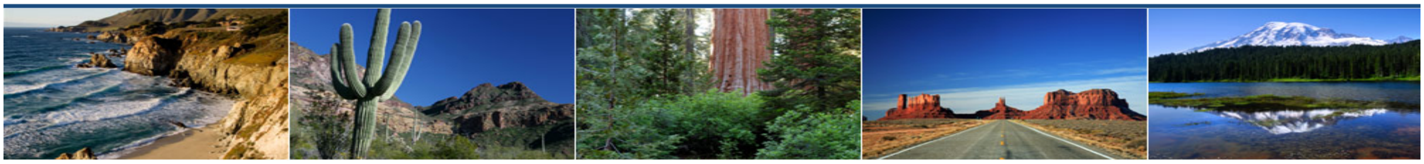
Stakeholder comments on the reporting-related elements of the July Draft Design document and the initial draft of the Essential Requirements are summarized in Attachment D of this Second Draft. Stakeholder comments have been very helpful in shaping the decisions made to date, and we look forward to receiving your comments on this current document and its Attachments. Additional opportunities for public comment will be provided as future drafts of the Essential Requirements for Reporting are completed. These future drafts will include increasing level of detail and the final document will address all the Essential Requirements.

You are invited to participate in a stakeholder conference call to discuss the present draft on October 7 at 11 AM Mountain Time. The call-in number is 800-868-1837 (direct dial 404-920-6440), access code 659-537#. We ask that written comments be submitted through the WCI Website (www.westernclimateinitiative.org) by Tuesday, October 14.

Sincerely,

Jim Norton, Chair
WCI Reporting Subcommittee
State of New Mexico

Western Climate Initiative



Essential Requirements of Mandatory Reporting
for the Western Climate Initiative,
Second Draft

September 30, 2008

Introduction

The "Design Recommendations for the WCI Regional Cap-and-Trade Program" (September 23, 2008) state that "prior to the start of the mandatory reporting program, the WCI Partner jurisdictions will establish the essential requirements for reporting by all entities and facilities required to report in each of the WCI Partner jurisdictions." To complete the essential requirements for reporting rules, the Western Climate Initiative (WCI) must make numerous decisions about how it wishes to approach, define, and structure the elements that have been identified as necessary to an effective WCI cap-and-trade program. A number of these decisions have already been made by the WCI, but many have not. This paper documents the current status of the essential requirements of mandatory reporting, and is an update to the document previously issued on July 23, 2008, addressing continuing work being conducted by the WCI Partners and the Reporting Subcommittee (RSC). Also, this paper strives to incorporate responses to comments made by Stakeholders on the July 23 version (see Attachment D).

The purposes of this paper are to: 1) document the current status of WCI's consideration of essential requirements; 2) identify the decisions that remain to be made; and 3) seek public comment on these essential requirements. As decisions are made to finalize the essential requirements, the WCI will move toward developing a regulatory structure for the essential requirements in future steps.

The paper is divided into nine categories of essential requirements related to mandatory reporting of GHGs: definitions, pollutants, applicability, timing, confidentiality, report content and submittal, compliance, emissions quantification and monitoring, and verification and quality assurance. For each group of essential requirements, the following information is presented:

- "Discussion and Notes" describes the essential requirements that are proposed to be addressed in the context of future model rule sections.
- "Design Recommendations for the WCI Regional Cap-and-Trade Program" summarizes the specific recommendations contained in the most current design document (September 23, 2008) and/or previous draft versions (July 23, 2008 or May 16, 2008), if applicable to the essential requirement.
- "Recommendations for Reporting" summarizes the specific recommendation being made by the RSC pertaining to reporting, if applicable to the essential requirement.
- "Additional Decisions Needed" summarizes the decisions that need to be made concerning the approach, definition and structure of the essential requirement, and any options, if applicable to the essential requirement.

Comments on this document should be submitted in writing by Tuesday, October 14, through the WCI Website (www.westernclimateinitiative.org). Please note that relative to the previous version (released July 23, 2008), most of the new material is contained in the Attachments. Also, there will be other opportunities to submit comments on the essential requirements for mandatory reporting after future drafts are released in the Fall of 2008.

Definitions

Discussion and Notes

1. This rule section will contain clear and appropriately detailed definitions of key terms used in the monitoring and reporting rule.

2. When source category-specific requirements are considered, there may be hundreds of terms that need definition. The most efficient approach to creating a list is to "borrow" from other jurisdiction's rules. There are a number of precedents to consider for definitions. Terminology defined by The Climate Registry (TCR) could be used, although some definitions might not be sufficiently detailed for regulatory use. If TCR's list is not comprehensive enough for a mandatory reporting rule, then CARB's reporting rule has a very detailed and lengthy list of definitions that may be used. CARB's list combines source category-specific definitions with those common to all source categories in a single list. The definitions established by the U.S. EPA, Canadian agencies, and states like New Mexico should also be considered.

3. Definitions will facilitate communications among WCI jurisdictions and stakeholders by defining common terminology very early in the process of developing the details of essential requirements for model GHG reporting rule language. For example, the term "source categories" is used throughout this paper to indicate groupings of sources and activities; definitions for these types of terms should be agreed upon and articulated by the WCI jurisdictions.

Recommendations for Reporting

1. The Reporting Subcommittee recommends the partial list of definitions shown in Attachment A. We will add to the list as required during on-going development of the Essential Requirements for Mandatory Reporting. In general, we will include definitions that are necessary to understanding specific essential reporting requirements and avoid definitions that are not absolutely essential. For example, we will not define terms that are used in their common English context (e.g., fence line, unit) or that explain acronyms or chemical formulae.

Additional Decisions Needed

1. Using the CARB, Environment Canada, and TCR definitions as a starting point, compile the list of definitions for review by the Reporting Subcommittee.

2. Continue to develop definitions.

Pollutants

Discussion and Notes

1. Pollutants – This section will list the pollutants that must be quantified and reported.

2. Global warming potential (GWP) factors – The section will specify the 100-year GWP factors used to convert other pollutants to CO_2e. The WCI presumably will use the same GWP factors as are used regionally and internationally, such as the IPCC Second Assessment Report, 1995, updating that list only for new GHGs as identified in the IPCC Third Assessment Report, 2001.

Design Recommendations for the WCI Regional Cap-and-Trade Program (September 23, 2008):

1. Greenhouse gases (GHGs) covered: Carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride.

Recommendations for Reporting:

1. According to the Intergovernmental Panel on Climate Change (IPCC), the global warming potential (GWP) of a GHG is defined as the ratio of the time-integrated radiative forcing from the instantaneous release of 1 kilogram (kg) of a trace substance relative to that of 1 kg of a reference gas. The reference gas used is CO_2. It is recommended that the values listed in the table below be used to be consistent with other statewide and national GHG inventories. (This table is the same as contained in the TCR General Reporting Protocol, Version 1.1, May 2008.) Operators would use these values when converting emissions of GHGs to carbon dioxide equivalent values (CO_2e) for purposes of estimating de minimis or other emissions as specified in these essential requirements.

Additional Decisions Needed

1. In order to remain consistent with international practice, and in the event that more recent GWP values are adopted as standard practice by the international community (e.g., when reporting under the United Nations Framework Convention on Climate Change [UNFCCC]), then a mechanism for updating the GWPs would need to be developed.

Global Warming Potential Factors for Required Greenhouse Gases

Common Name	Formula	Chemical Name	GWP
Carbon dioxide	CO_2		1
Methane	CH_4		21
Nitrous oxide	N_2O		310
Sulfur hexafluoride	SF_6		23,900
Hydrofluorocarbons (HFCs)			
HFC-23	CHF_3	trifluoromethane	11,700
HFC-32	CH_2F_2	difluoromethane	650
HFC-41	CH_3F	fluoromethane	150
HFC-43-10mee	$C_5H_2F_{10}$	1,1,1,2,3,4,4,5,5,5- decafluoropentane	1,300
HFC-125	C_2HF_5	pentafluoroethane	2,800

Common Name	Formula	Chemical Name	GWP
HFC-134	$C_2H_2F_4$	1,1,2,2-tetrafluoroethane	1,000
HFC-134a	$C_2H_2F_4$	1,1,1,2-tetrafluoroethane	1,300
HFC-143	$C_2H_3F_3$	1,1,2-trifluoroethane	300
HFC-143a	$C_2H_3F_3$	1,1,1-trifluoroethane	3,800
HFC-152	$C_2H_4F_2$	1,2-difluoroethane	43*
HFC-152a	$C_2H_4F_2$	1,1-difluoroethane	140
HFC-161	C_2H_5F	fluoroethane	12*
HFC-227ea	C_3HF_7	1,1,1,2,3,3,3- heptafluoropropane	2,900
HFC-236cb	$C_3H_2F_6$	1,1,1,2,2,3-hexafluoropropane	1,300*
HFC-236ea	$C_3H_2F_6$	1,1,1,2,3,3-hexafluoropropane	1,200*
HFC-236fa	$C_3H_2F_6$	1,1,1,3,3,3-hexafluoropropane	6,300
HFC-245ca	$C_3H_3F_5$	1,1,2,2,3-pentafluoropropane	560
HFC-245fa	$C_3H_3F_5$	1,1,1,3,3-pentafluoropropane	950*
HFC-365mfc	$C_4H_5F_5$	1,1,1,3,3-pentafluorobutane	890*
Perfluorocarbons (PFCs)			
Perfluoromethane	CF_4	tetrafluoromethane	6,500
Perfluoroethane	C_2F_6	hexafluoroethane	9,200
Perfluoropropane	C_3F_8	octafluoropropane	7,000
Perfluorobutane	C_4F_{10}	decafluorobutane	7,000
Perfluorocyclobutane	c-C_4F_8	octafluorocyclobutane	8,700
Perfluoropentane	C_5F_{12}	dodecafluoropentane	7,500
Perfluorohexane	C_6F_{14}	tetradecafluorohexane	7,400
Source: Intergovernmental Panel on Climate Change (IPCC) Second Assessment Report published in 1995, unless no value was assigned in that document. In that case, the GWP values are from the IPCC Third Assessment Report published in 2001 (those marked with *). GWP values are from the Second Assessment Report (unless otherwise noted) to be consistent with international practices. Values are 100-year GWP values.			

Applicability

Discussion and Notes

1. This rule section describes who must comply with the reporting rule. As a minimum, the reporting system must include all activities and sources that will be part of the cap.

2. This rule section will also list any source categories that are not subject to the initial cap but which will be required to report emissions.

3. Thresholds – This section will contain the thresholds for mandatory reporting, stated as metric tons of CO_2 or CO_2e per year, or other appropriate emissions or operational indicators.

4. Sources not included – This section will describe sources or activities in affected source categories that are not subject to reporting requirements.

5. Level of reporting – This rule section will address by source category at what level (i.e. corporate [entity], facility or process level) reporting will be required.

Design Recommendations for the WCI Regional Cap-and-Trade Program (September 23, 2008):

1. Emissions covered:

    - Electricity generation, including emissions from electricity generated outside the WCI jurisdictions (or generated by a federal entity or on tribal lands) that is delivered into a WCI Partner jurisdiction for consumption in that WCI Partner jurisdiction;
    - Combustion at industrial and commercial facilities;
    - Industrial process emission sources*, including oil and gas process emissions;
      *As used here, process emissions include emissions from chemical, biological, and other non-combustion processes. These emissions may be deliberate (e.g., vented), fugitive (e.g., leaked), or accidental.
    - Residential, commercial, and industrial fuel combustion at facilities with emissions below the WCI thresholds* (as described below in the Point of Regulation section, these emissions will be covered upstream). Coverage of these emissions will begin at the start of the second compliance period;
      * Thresholds are emission levels that determine when a particular entity or facility will have a compliance obligation under the cap-and-trade program.
    - Transportation fuel combustion from gasoline and diesel (as described below in the Point of Regulation section, these emissions will be covered upstream). Coverage of these emissions will begin at the start of the second compliance period.

2. For biomass determined by each WCI Partner jurisdiction to be carbon neutral, the carbon dioxide emissions from the combustion of that biomass are not included in the cap-and-trade program, except for purposes of reporting.

3. Carbon dioxide emissions from the combustion of pure biofuels, or the proportion of carbon dioxide emissions from the combustion of biofuel in a blended fuel (e.g., B20 or E85), are not included in the cap-and-trade program, except for purposes of reporting.

4. Prior to program start, the WCI Partner jurisdictions will assess whether and how to include upstream emissions from biofuel and fossil fuel production, taking into consideration the potential for emissions leakage, the potential role of other policies (such as a low carbon fuel standard), consistent treatment among fuels, and other factors (such as practicality of implementation).

5. Adequate quantification methods will be established for emissions sources prior to including them in the [cap-and-trade] program.

6. Point of Regulation*
   * The point of regulation is the entity or facility with the compliance obligation, i.e., the requirement to surrender sufficient GHG allowances to cover actual emissions during the compliance period. An allowance is the tradable permit to emit one metric ton of GHG emissions in CO_2e. The term entity is generally used when the point of regulation is upstream of the point of emissions, to describe a company that has an obligation to surrender allowances to cover the carbon content of the fuel the company is moving through commerce, or when the

point of regulation is at the First Jurisdictional Deliverer, to describe a company that has an obligation to surrender allowances to cover the emissions attributable to the generation of power the company is importing. When the point of regulation is at the point where the emissions occur, the term facility is generally used. The term source is used to refer to emissions from either a facility or an entity.

- Industrial sources (both process and combustion) with emissions above the threshold: The point of regulation will be at the point of emission.
- Electricity: The point of regulation is the First Jurisdictional Deliverer (FJD). For sources within WCI jurisdictions the FJD is the generator. For power that is generated outside the WCI jurisdictions (or generated by a federal entity or on tribal lands) for consumption within a WCI Partner jurisdiction, the FJD is the first entity that delivers that electricity over which the consuming WCI partner jurisdiction has regulatory authority.
- Residential, commercial, and industrial fuel combustion at facilities with emissions below the threshold: The point of regulation will be where the fuels enter commerce in the WCI Partner jurisdictions, generally at a distributor. The precise point is to be determined and may vary by jurisdiction.
- Transportation fuel combustion: The point of regulation will be where the fuels enter commerce in the WCI Partner jurisdictions, generally at the terminal rack, final blender, or distributor. The precise point is to be determined and may vary by jurisdiction.

7. The entities and facilities subject to reporting are those with annual emissions equal to or greater than 10,000 metric tons of CO_2e. Where fuel combustion emissions are covered upstream (e.g., emissions from transportation fuel combustion and emissions from fuel combustion at residential, commercial, and industrial facilities with emissions below the threshold) the reporting threshold will apply to entities (e.g., fuel distributors and blenders) based on the expected combustion emissions from the fuels distributed. In some limited instances the threshold may be based on other parameters, such as throughput or capacity, as long as these thresholds represent the equivalent of, or are lower than, the 10,000-metric-ton threshold.

8. Nothing in the WCI program design limits the discretion of any WCI Partner jurisdiction to require reporting earlier, at lower thresholds, or for entities and facilities not covered by the cap-and-trade program.

Recommendations for Reporting:

1. GHG emissions from combustion of biofuels and biomass will be included in the reporting requirements, and reported separately from other fuel combustion types.

Additional Decisions Needed

1. Complete decisions on which source categories will be subject to mandatory reporting. Select the numeric value and form of applicability thresholds for those source categories.

2. Complete detailed definitions of each source category to address point of regulation issues and further clarify which sources and activities within each source category are covered by the reporting requirement (i.e., activities, sources, and operational boundaries).

3. Determine sources, activities and processes to be excluded from reporting.

4. Determine by source category whether reporting will occur at the corporate (entity), facility, or process level.

Timing

Discussion and Notes

1. Effective Date – This rule section will specify the period when mandatory record keeping and reporting begins for affected source categories. An issue is whether or not to use measurement and monitoring data for years prior to 2010.

2. Reporting Period – This requirement specifies the calendar year or other period within which emissions must be quantified. The Design Recommendations (September 23, 2008) suggests starting on January 1, thus implying a calendar year reporting period. Consideration may have to be made for some form of more frequent or interim reporting to support the development and implementation of the cap-and-trade program.

3. Report Submission Date – This section will specify when reports must be submitted. To maintain alignment with future cap-and-trade allocations and reconciliation periods, it is preferable for reports to be submitted at the same time in all jurisdictions. A key issue is how long after the reporting year ends that reports be due.

Design Recommendations for the WCI Regional Cap-and-Trade Program (September 23, 2008):

1. Mandatory measurement and monitoring for the six included GHG emissions will commence in January 2010 for all entities and facilities subject to reporting. Reporting of 2010 emissions will begin in early 2011.

2. For 2012, each WCI Partner jurisdiction's allowance budget will be based on the best estimate of expected emissions for sources covered in the cap-and-trade program in the WCI Partner jurisdiction in 2012. The estimate of expected actual emissions in 2012 will be developed using the best available data (including any available mandatory reporting data) and by accounting for expected changes in emissions in 2012.

3. Each covered entity or facility will demonstrate compliance with the cap-and-trade program by surrendering sufficient allowances by July 1 of the year following the end of each compliance period.

Recommendations for Reporting

1. Mandatory measurement, and monitoring will begin in all Partner jurisdictions on January 1, 2010.

2. The reporting period is the calendar year, beginning with 2010 emissions to be reported in 2011.

3. To spread out the reporting and verification workload in the early years of reporting, reporting deadlines will be staggered for emissions occurring in the calendar years 2010 and 2011. Some source categories will submit their reports April 1, three months after the end of the reporting period, and the remainder will report on May 1, four months after the end of the reporting period. Electrical generating units; facilities which only contain stationary combustion sources of GHGs; and transportation and residential, commercial, and industrial fuels will report on April 1. All other source categories, including facilities and other reporting entities with a combination of stationary combustion and non-combustion sources, will report on May 1.

4. For the reporting periods 2010 and 2011, facilities and other reporting entities that are subject to verification requirements will complete the verification process no later than five months following their reporting deadline (i.e., September 1 or October 1).

5. Requirements for reporting of pre-2010 emissions will not be specified in the Essential Requirements. Jurisdictions cannot adopt retrospective requirements for measurement and monitoring, but some jurisdictions may have pre-existing reporting requirements that can be used in obtaining the "best available data" for pre-2010 emissions.

Additional Decisions Needed

1. Establish report submission and verification deadlines for the 2012 and subsequent reporting periods.

2. Determine whether more frequent interim reports are necessary to support the development and implementation of the cap-and-trade program.

3. Establish a timetable for the public release of reported data.

Confidentiality

Discussion and Notes

1. In general, emissions data are not considered confidential although some operational information can be protected, depending on each jurisdiction's legal authority.

2 Stakeholders have offered a range of comments with some favoring a narrow construction of confidentiality to protect the public's right to know, and others favoring a broader construction that would better protect sensitive operational information from competitors.

Design Recommendations for the WCI Regional Cap-and-Trade Program (September 23, 2008):

1. As each WCI Partner jurisdiction collects additional emissions data from entities and facilities required to report, data will be made available to all WCI Partner jurisdictions for review and consideration for possible expansion of the cap-and-trade program.

2. Each covered entity or facility will demonstrate compliance with the cap-and-trade program by surrendering sufficient allowances by July 1 of the year following the end of each compliance period. To ensure transparency and maintain public confidence, certain data from the emissions reports, allowances, and offsets that are used for compliance will be made public in a timely manner.

Additional Decisions Needed

1. WCI is considering whether WCI-wide policy and procedures pertaining to emissions data and public disclosure are needed in addition to existing policy and procedures of individual WCI jurisdictions.

Report Content and Submittal

Discussion and Notes

1. Content – These sections and subsections will specify the information that each reporting unit will be required to submit. Examples of typical administrative information are facility names, identification numbers, physical addresses, mailing addresses, locations, responsible officials, various operational information, ownership structure, etc. More detailed information will be addressed in the source category-specific requirements.

   Technical content includes such examples as pollutants, quantification methods, and supporting operational and activity information and data. Requirements need to be specific and detailed and some will be source category-specific.

   There are a number of existing reporting rules that could provide potential starting points; however, many specific decisions on content will evolve from the choices made for other essential requirements.

2. Submittal – This section will specify who is responsible for submitting the report and to whom, and certifying the accuracy of the information contained in it.

Draft Design Recommendations (May 16, 2008):

1. The WCI has recommended using TCR's central repository for data storage as well as offering flexibility as to where affected sources initially report. Reports could either be submitted directly to jurisdictions (which will then upload the data to TCR's central repository), or be submitted directly through TCR's program framework (which will then download the data to the necessary jurisdictions).

Recommendations for Reporting: Upon further consideration and discussion, the May 16, 2008 design recommendation is revised as follows:

1. The WCI recommends using a version of TCR's Climate Registry Information System (CRIS), modified to support mandatory reporting, to collect and manage WCI's regional database of emissions information. In addition, jurisdictions may use the CRIS Common Reporting Framework to meet their individual jurisdictional database needs for emission collection, verification, and compliance.

2. Emission reports must be submitted to the appropriate jurisdiction or their agent, where verification and compliance will be conducted.

3. All jurisdictional databases will transfer or ensure the transfer of verified emissions and related information into the regional database.

Additional Decisions Needed

1. Determine the specific contents of report to be submitted.

Compliance

Discussion and Notes

1. Rule violations – This section will discuss the actions that will be considered violations of the rule (e.g., failure to submit complete reports when required to do so, knowingly submitting false information with a intent to deceive, etc.).

2. Enforcement Mechanisms – The WCI will develop consistent administrative practices to respond to non-compliance issues; however specific enforcement actions, such as levying fines and penalties, will likely be carried out by jurisdictions.

3. Records Retention – This section will describe which records must be kept and for how long. More detailed requirements may be included in source category-specific requirements.

4. Revisions – The rule will describe the process for revising reports that contain inaccurate or missing information and data. The revision process might differ depending on the timing and the circumstances in which the inaccuracies were discovered.

Design Recommendations for the WCI Regional Cap-and-Trade Program (September 23, 2008):

1. Each WCI Partner jurisdiction will retain and/or enhance its regulatory and enforcement authority and responsibilities to enforce compliance with the cap-and-trade program within its own jurisdiction.

Additional Decisions Needed

1. Determine which actions will be considered violations of the reporting rule.

2. Develop guidelines to promote consistent administrative practices and responses to non-compliance issues among jurisdictions.

3. Determine which records must be maintained for all source categories subject to the reporting rule.

4. Establish procedure and policy for revisions.

Emissions Quantification and Monitoring

Discussion and Notes

1. The essential requirements to the model rule will provide an introduction to quantification, probably in a "General Requirements" section, but will also specify source category-specific quantification requirements.

2. In addition to the technical issues related to reporting, there are also a number of policy-oriented choices to be made. Examples are:

   a. The degree of coordination with other (non-GHG) emissions reporting requirements;
   b. De minimis requirements; and
   c. Procedures for missing data.

3. A key factor in determining emissions quantification and monitoring requirements is that the requirements must provide levels of accuracy necessary for an effective cap-and-trade program. It is generally accepted that quantification methods must be more rigorous under mandatory reporting for cap-and-trade, than for some methods allowed for voluntary reporting. For example, while a voluntary program might allow a range of methods, quantification and monitoring requirements for mandatory reporting might include "higher tier" methods that assure the appropriate level of accuracy needed to support a cap-and-trade program. Attachment B explains the relative accuracy of several general types of GHG emissions quantification and monitoring methods, and Attachment C contains a preliminary assessment of the adequacy of GHG emissions quantification methods for various source categories.

4. Several key issues of concern to stakeholders include the following:

   a. How to deal with combined heat and power (CHP) sources;
   b. Treatment of biomass combustion;
   c. Methods for quantifying emissions from imported electricity; and
   d. Methods for quantifying emissions for waste management.

5. Existing GHG emission quantification and monitoring requirements in the WCI jurisdictions and other relevant programs are currently being summarized and reviewed by the Reporting Subcommittee. This review will determine applicability of existing methods to the WCI reporting requirements for a cap-and-trade program, and provide a basis for evaluating consistency with existing WCI jurisdiction reporting rules.

Draft Design of the Regional Cap-and-Trade Program (July 23, 2008):

1. Adequate quantification methods will be established for emissions sources prior to including them in the program.

Additional Decisions Needed

1. Select the methods, and provide the details for each source category-specific method.

2. Determine if a de minimis reporting level will be allowed, and if so, then determine its level and the method(s) for estimating de minimis emissions.

3. Specify procedures for missing data. These may be source-category specific.

4. We are considering requiring reporting of emissions as estimated by best practice estimates for some specified emissions source categories in cases where accurate methods are not currently available and are not prescribed in the Essential Requirements.

Verification and Quality Assurance

Discussion and Notes

1. This essential requirement will address how reported information will be quality assured.

2. ISO 14064-3 and ISO 14065 are international standards for GHG verification and accreditation, respectively. In an effort to promote international consistency of GHG reporting and verification, many GHG reporting and market programs, including EU ETS, UK ETS, and TCR have based their verification programs on these standards. In addition, California's mandatory reporting regulation is based on ISO standards. WCI also intends to design its verification and accreditation programs to be consistent with ISO 14064-3 and ISO 14065 (as much as possible).

Design Recommendations for the WCI Regional Cap-and-Trade Program (September 23, 2008):

1. WCI Partner jurisdictions will require third party verification of reported emissions from entities and facilities that will be included under the cap.

Recommendations for Reporting

1. The Reporting Subcommittee will evaluate and modify the existing California regulation to lay out a standardized approach to verification that will assure integrity in the reported GHG data and a consistent quality of verifications across all WCI partners. Key areas of focus will be accreditation of verifiers, core verification services, and conflict of interest requirements. The WCI verification requirements will also ensure an enforceable verification program with direct oversight.

Additional Decisions Needed

1. Define the specific requirements for third-party verification by reporting entities and facilities.

2. Determine the level of quality assurance required for entities and facilities that are required to report, but will not be included in the cap.

Approach

The Reporting Subcommittee will add to the definitions list as required during on-going development of the Essential Requirements for Mandatory Reporting. In general, we will include definitions that are necessary to understanding specific essential reporting requirements and avoid definitions that are not absolutely essential. For example, we will not define terms that are used in their common English context (e.g., fence line, combustion, unit) or that explain acronyms or chemical formulae.

Partial List of Definitions

"Stationary combustion unit" means any boiler, heater, furnace, kiln, turbine, internal combustion engine, incinerator or other non-mobile source device that combusts any solid, liquid, or gaseous fuel for purposes of producing useful heat or energy for industrial, commercial, or institutional use; or for purposes of reducing the volume of waste by removing combustible material. [1]

"Facility" means any property, plant, building, structure, stationary source, stationary equipment or grouping of stationary equipment or stationary sources located on one or more contiguous or adjacent properties, in actual physical contact or separated solely by a public roadway or other public right-of way, and under common operational control.[2]

"Carbon dioxide equivalent" or "CO_2 equivalent" or "CO_2e" means a measure for comparing carbon dioxide with other GHGs, based on the quantity of those gases multiplied by the appropriate global warming potential (GWP) factor and commonly expressed as metric tons of carbon dioxide equivalent.

"Continuous emissions monitoring system" or "CEMS" means the total equipment required to obtain a continuous measurement of a gas concentration or emission rate from combustion or industrial processes.

"Greenhouse gas", "greenhouse gases" or "GHG" means carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), and perfluorocarbons (PFCs).

"Global warming potential" or "GWP factor" means the radiative forcing impact of one mass-based unit of a given greenhouse gas relative to an equivalent unit of carbon dioxide over a given period of time.

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[1] The intent is to require any collection of stationary combustion units, located at any facility, that collectively emit 10,000 tons of CO_2e on an annual basis, to report emissions. In other words, the requirement applies to any individual stationary combustion unit, or any collection of units, whether or not they are located at a source-specific category facility addressed by this rule. Biomass-fueled units are included but would be reported separately.

[2] Some special "facilities," such as oil or gas production fields, will have separate definitions.

“Hydrofluorocarbons” or “HFCs” means a class of GHGs primarily used as refrigerants, consisting of hydrogen, fluorine, and carbon.

“Perfluorocarbons” or “PFCs” means a class of greenhouse gases consisting on the molecular level of carbon and fluorine.

The uncertainty in the greenhouse gas (GHG) emissions reported to WCI will be evaluated by the product of the uncertainties of the various components or methods used to estimate the emissions (e.g., direct measurements of flue gas; parametric measurements of fuel flow, feed water flow and steam flow; equipment manufacturer data; etc.). Accuracy is the inverse of uncertainty; that is, a high level of accuracy is the same as a low level of uncertainty. The quantification methods required for GHG emissions reporting under the WCI cap-and-trade program should have a high level of accuracy to ensure that all emissions reported across all source categories are equal, and that each ton reported is, in fact, a ton.

This document explains the relative accuracy of several general types of GHG emissions quantification and monitoring methods: continuous emissions monitoring systems (CEMS), parametric monitoring (i.e., measuring something other than fuel or gas, such as a catalytic feed rate), and material balance. This comparison provides a basis for comparing the accuracy of various source-specific methods, and determining their adequacy for use in reporting emissions under the WCI cap-and-trade program. Also, this document provides some initial conclusions regarding the relative accuracy of methods available to estimate and monitor emissions for non-combustion emissions from several source categories. This information will be updated in the future based on a continuing analysis of accuracy of existing quantification and monitoring methods.

Types of GHG Emissions Quantification and Monitoring Methods

Direct measurement of CO_2 emissions, such as collected with a CEMS maintained to specifications, can provide a high level of measurement accuracy. On the other hand, parametric monitoring would generally provide less accuracy as compared to CEMS, although often sufficient to support cap-and-trade programs. For example, pipeline quality natural gas has a relative consistent carbon composition, so measuring the flow of natural gas to a combustor is a good predictor of the CO_2 emissions from the combustor. However, the carbon content of coal, refinery gas, or field gas can be highly variable (i.e., greater than 10%) making fuel flow an inaccurate CO_2 emissions predictor for these fuels without taking special care.

A material balance approach to estimating coal combustion emissions can provide greater accuracy than parametric monitoring for these sources. In a material balance method, the carbon content of the incoming coal and of the discarded ash are measured on a frequent basis and used in conjunction with mass flow measurements to determine the carbon emitted as CO_2. Also, the accuracy of emission quantification and monitoring methods can vary depending upon the GHG being measured or estimated. For example, continuous fuel flow measurements can be fairly accurate for determining CO_2 content, but not at all accurate for determining CH_4 or N_2O content.

Relative Accuracy of Source-Specific Methods

The relative accuracy of existing GHG quantification and monitoring methods is being evaluated on a source category-specific basis, especially for the source categories (combustion and noncombustion) that are candidates for inclusion in the WCI cap-and-trade program. Accuracy of annual emissions will be affected by the required frequency of measurement and the variability of the parameter(s) to be measured. Several metrics are being used to determine if source-specific methods support accurate reporting of GHG emissions, including:

1. Relative accuracy compared to CEMS measurements
2. Whether or not other cap-and-trade programs (e.g., European Union) require, recommend, or allow use of the method for a particular source category.

Based on the preliminary information on existing methods collected and examined to date, several source categories have been judged to have inadequate quantification methods for some of their non-combustion emissions to support including those emissions in the WCI cap-and-trade program at this time. It should be noted that facilities in these source categories could be subject to the program if they had sufficient combustion emissions to exceed cap-and-trade thresholds.

For now, this assessment is qualitative, and based on engineering judgment, in order to expedite the identification of source categories for which no accurate methods currently exist. A more detailed assessment of methods for other source categories will be necessary in order to select specific methods, when more than one method exists for estimating emissions. In addition to this qualitative assessment, the fact that some source categories are not included in other cap-and-trade programs, such as the European Union, factor into the recommendation to not require allowance obligations for these source categories in the WCI cap-and-trade program. For example, the following emission sources do not appear to have quantification and monitoring methods accurate enough to support inclusion in a cap-and-trade program:

- Landfills – The generation of CH_4 in landfills is based on several site-specific factors, including waste composition, moisture content, temperature, availability of nutrients, waste density, and waste particle size. Historical estimation methods, such as the method published by the U.S. EPA in AP-42, rely on a "first order decay" equation that includes several parameters with high uncertainty, such as the methane generation potential, which can vary by as much as ±50% from the default values provided in the methods. We consider this method to be highly uncertain, especially as compared to a CEMS method. It should be noted that the Solid Waste Industry for Climate Solutions (SWICS) has proposed to replace default values with new values for landfill gas collection system efficiencies and methane oxidation in cover soils, and use new carbon storage factors for carbon sequestration.
- Municipal and Industrial Wastewater Treatment Plants- The generation of CH_4 and N_2O in large open lagoons is very difficult to measure, so the emissions are normally estimated using imprecise models and emission factors. The models attempt to predict the methane and nitrous oxide byproducts from microbial processes that are highly influenced by unknown factors in the lagoons, including temperature, waste digestibility, trace nutrient levels, oxygen and nitrogen levels, and microbial species.

As stated above, this information will be updated in the future based on a continuing analysis of accuracy of existing quantification and monitoring methods.

Source Category	*Accurate method*	*Method available, may need improved accuracy*	*Method under review*	*Identification/ development of accurate method underway*
Electricity Generation, Cogeneration (CHP)	●			
Electricity Importers (retail providers, marketers)				WCI Electricity Subcommittee
Stationary Fossil Fuel Combustion Sources: Fossil fuel combustion in equipment at industrial sources (e.g., cement plants, refineries, etc.)	●			
Biomass Combustion Sources: Biomass combustion in equipment at industrial sources.	●			
Liquid Transportation Fuels: Combustion of fuel in on- and off-road vehicles, regulated at point where fuel enters into commerce that may vary by jurisdiction (e.g., distribution terminal/rack, licensed fuel wholesalers)	●			
Residential, Commercial, Industrial (RCI) Fuels: Combustion of fuel (NG, fuel oil, other) in the RCI sector, regulated at point when fuel enters into commerce (e.g., local distribution company [LDC] for NG, distribution terminal/rack)	●			
Petroleum refineries	●			
Hydrogen production	●			
Noncombustion Emissions (Combustion Emissions for these Sources are Included in "Stationary Combustion Sources" Above)				
Oil and gas production & gas processing				WRAP/TCR
Natural gas distribution systems				CCAR
Cement production	●			
Lime manufacturing	●			
Glass production and other uses of carbonates			●	
Soda ash manufacturing			●	
Aluminum production	●			
Ferroalloy production		●		
Zinc production		●		
Lead production		●		
Pulp and paper manufacturing	●			
Iron and steel production	●			
Electronics manufacturing	●			
Petrochemical production			●	
HCFC-22 production		●		

Source Category	***Accurate method***	***Method available, may need improved accuracy***	***Method under review***	***Identification/ development of accurate method underway***
Adipic acid manufacturing		●		
Ammonia manufacturing		●		
Magnesium production			●	
Nitric acid manufacturing		●		
Phosphoric acid production			●	
SF_6 from electrical equipment	●			
Coal storage	●			
Coal mine fugitive emissions (active and abandoned)			●	
Waste Management				
Landfills		●		
Municipal wastewater		●		
Industrial wastewater		●		

Responses to July 2008 Draft Design document and Draft Essential Requirements for Reporting

Thirty-eight commenters responded regarding reporting[3]. Most were from potential reporters, with a few from other categories (environmental groups, NGOs and consulting companies, and municipalities). Many comments addressed only a few topics, but several provided comments on all reporting topics presented in the July documents. A few provided very detailed recommendations in the form of regulatory language.

1) Highlights

Stakeholders were asked to recommend effective mechanisms for stakeholder involvement in the ongoing development of the Essential Requirements this year. The few comments received were supportive of frequent conference calls, perhaps supplemented by in-person meetings at the jurisdiction level or focused on specific topics or source sectors.

One significant emerging issue is that many potential reporters are calling for uniformity with the forthcoming US EPA mandatory GHG reporting regulation. This is likely driven by concern over the burden of having to measure, monitor, and report differently to two separate programs.

A few commenters have noted the need for development of a transaction tracking system in addition to the emissions reporting system.

Many industry commenters said that the 10,000 metric ton CO2e reporting threshold was too low or had not been adequately justified.

Although there were few comments on the issue of oil and gas production emissions, it is notable that both industry and environmental group commenters recommended aggregation of field facilities into larger reporting entities.

Most of those commenting on the issue of annual versus more frequent reporting recommended annual reporting. Most advocated uniform reporting timelines across WCI, but some were concerned about possible conflicts with existing reporting rules.

Most who commented on Global Warming Potential values to be used in calculating CO2 equivalents recommended using IPCC values, and some specified use of the 1995 IPCC Second Assessment Report values. None recommended use of other values.

Several commenters expressed concern that ancillary data other than emissions should be confidential. For some industries where emissions are from fuel combustion, the close relationship of emissions to fuel use may lead to claims of confidentiality for emissions data.

Commenters remain divided on whether reporting should be direct to TCR or through jurisdictions.

[3] Excluding multiple submissions of identical coalition or group comments by group members.

Many commenters recommended that quantification methods be consistent with existing industry protocols or federal, state or provincial reporting programs. Some called for simplified methods for small emitters, or de minimis provisions and specific exclusions for insignificant emission points. There were also recommendations for flexibility in quantification methods allowed to be used.

The requirement for third party verification remains a significant issue. Most commenters on this topic were from industry, and most opposed it. They argued that use of defined protocols, self-certification, and opportunity for agency audit should be sufficient. Some recommended exempting certain categories, such as certified CEMs, Title V sources, or sources not selling credits.

2) Detailed summary

Comments are summarized below by topic. Number in parentheses indicates number of commenters on each topic, or making a specific recommendation.

Mechanisms for Stakeholder Input to Further Development of Reporting Requirements (6)

- Frequent conference calls focused on specific topics (2)
- Supplement by in-person meetings at the jurisdiction level (1) or focused on specific topics or industries (2)
- Engage industry associations (1)

General (17)

- Consistency across WCI and between jurisdictional and federal levels (5)
- WCI reporting should be identical or equivalent to EPA mandatory GHG reporting system, or use data from EPA system with no separate WCI reporting (4)
- Need transactional tracking system in addition to emissions reporting (2)
- Support draft design on reporting (1)
- Reporting system as close as possible to TCR (2)
- Support current WCI draft design for reporting (1)
- Recommend industry protocol for solid waste management sector reporting (1)

Definitions (9)

- Harmonize across US regulatory frameworks (1)
- Support use of CARB as starting point (3)
- Start with TCR GRP instead of CARB definitions, which are too specific to CARB program (1)
- Also use forthcoming EPA reporting rule definitions, harmonize with federal programs (2)
- For effective stakeholder comment, give full text of referenced definitions, (1)
- Detailed recommendations for changes to CARB definitions (1)
- Source category definitions must include details on POR and activities included (1)

<u>Applicability (29)</u>

- Threshold of 10,000 metric tons CO2e is too low and/or lacks justification, will burden small companies (7)
- Reporting threshold should be same as cap and trade threshold (4)
- Reporting threshold should be 50,000 metric tons (1)
- Support threshold of 10,000 metric tons CO2e (2)
- Reporting thresholds should be industry-specific (1)
- Exclude specific sources:
  - methane vented and fugitive emissions from oil and gas sources because quantification inaccurate (1)
  - landfills because quantification inaccurate (1)
  - emergency engines and emergency generators (1)
  - indirect emissions (1)
  - sources, activities and processes associated with aviation fuel because in federal jurisdiction only (1)
- Include specific sources:
  - oil and gas field emissions (3)
  - transportation fuels and natural gas distribution (1)
  - biomass emissions (1)
- For oil and gas E&P, develop unique definition of reporting entity that will aggregate small facilities, such as by production field (4)
- Minimize exclusions (1)
- Reduce burden on small companies by phase-in or by providing assistance (1)
- Unclear on status of landfills and wastewater treatment plants (1)
- Be flexible in determining reporting level, vary this as appropriate for source/sector (1)
- Watch out for complexity of boundary issues, see EU ETS for examples (1)
- Point of regulation for RCI fuel use and transportation fuels should be uniform across WCI (2)
- Support policies to incentivize CHP (1)
- Distinguish between biogenic and anthropogenic CO2 emissions (1)
- Support reporting at corporate or facility level, not process level (1)

<u>Timing (14)</u>

- Report annually (6)
- Report monthly or quarterly, for efficient market functioning (1)
- Set uniform deadlines across WCI (4)
- Recommend specific reporting deadlines, 6-8 mos. after end of emissions year (5)
- Concern about conflict with existing jurisdictional deadlines (2)
- Set deadlines consistent with TCR (1) or Climate Leaders and other programs (1)
- Historical data to set cap should be collected in consistent manner (1)
- Move first reporting ahead one year and allow submission of "best available information", as in CARB rule (1)
- Support 2010 as first emissions year to be reported (1)
- Pre-2010 emissions reporting should be voluntary (1)

<u>Pollutants and GWPs (6)</u>

- Use 100-yr GWP values consistent with US and international reporting (5), such as IPCC (4), specifically from IPCC Second Assessment Report, 1995 (3)
- Formally adopt policy for calculating CO2 equivalents (1)

<u>Confidentiality (8)</u>

- Some ancillary data (energy consumption, wholesale power sales and purchases, production rate, specific fuel use) should be confidential (5)
- Facility-level reports should be confidential (1)
- Emissions data or total emissions should be public (3)
- Confirm public "right to know" for GHG emissions reports (1)
- Protect confidential information in accordance with federal and jurisdictional law ((1)

<u>Report Content and Submittal (11)</u>

- Report through jurisdictions for upload to TCR (4)
- Report directly to TCR (2)
- Support reporter option on reporting to TCR vs jurisdictions (1)
- Minimize reporting of ancillary information not needed for cap and trade (2)
- Consider streamlined reporting for small entities (1)
- Be consistent with EPA mandatory GHG reporting (2)
- Reporting fees to be borne by jurisdiction (1)

<u>Compliance (3)</u>

- Use federal Acid Rain and Title V programs as examples (1)
- Assume compliance would be according to existing state law (1)
- Identifies several additional issues to be decided (1)

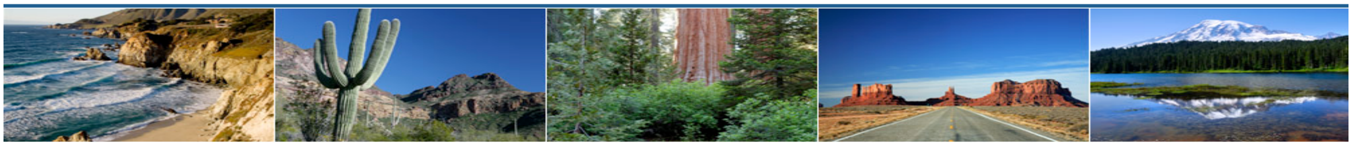
<u>Quantification (13)</u>

- Rely on existing sector-specific methods (API Compendium, WRI/WBCSD, EU ETS, Canadian and US federal programs, forest products industry protocol) (5)
- Be consistent with EPA mandatory federal reporting (2)
- Methods for landfills (1) and for methane fugitive and process emissions from oil and gas (1) are unreliable, inadequate for cap and trade
- Treat CHP like any other emissions source (1)
- For small combustion sources at oil and gas sources, use standardized emission factors (1)
- For biomass and high GHG fuels (LNG and tar sands), do not use arbitrary emission factors unsupported by analysis (1)
- De minimis emissions should be set at 3%, also use list of de minimis activities as in Title V program (1)
- Level of accuracy should be based on significance and materiality of emissions (1)
- Allow for flexibility and avoid dictating specific methods (1)
- Share with stakeholders the process for selecting and approving methods (1)

<u>Verification (21)</u>

- No third party verification for all sources (8)
- No third party verification, use defined protocols and self-certification with agency audit authority, for:
  - power plant CEMs (1)
  - sources not selling credits (1)
  - Title V reporters (2)
  - sources subject to permitting (3)
  - small emitters (1)
- Support third party verification (2)
- Support CARB approach of multiyear verification cycle with one full verification and several less intensive verifications per cycle (1)
- Common approach and consistent standards for verification (2)
- If allow jurisdictional audit, set minimum standards for compliance assurance such as budget and staff levels, audit rates (1)
- Need accreditation process for verifiers to ensure program integrity (1)

Western Climate Initiative



ELECTRICITY SUBCOMMITTEE
TECHNICAL WORKING SESSION

SALT LAKE CITY, UT
October 16, 2008

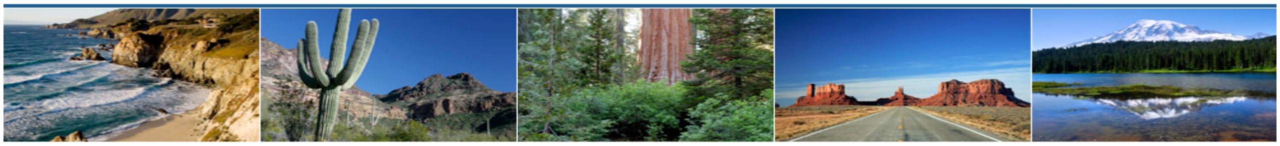
10:00 a.m. to 4:15 p.m.

Location:
Utah Department of Environmental Quality
Building #2 (North Building)
168 North 1950 West
Salt Lake City

AGENDA

1.	**10:00**	**Introductions**
2.	**10:20**	**Review of Plan for Technical Working Sessions and Agenda for the Day** **David Van't Hof, Chair, WCI Electricity Subcommittee**
3.	**10:40**	**Presentation and Discussion of Leakage Issue Based on Imports and Exports Information** **Snuller Price, E3**
4.	**11:00**	**Comments from Technical Panelists, and Reactions from Technical Advisory Group**
5.	**1:00**	**Lunch (On Your Own)**
6.	**2:00**	**Presentation and Discussion of Possible Regulatory Definition(s) of "First Jurisdictional Deliverer"**
7.	**2:30**	**Reactions from the Technical Advisory Group**
8.	**3:30**	**Next Steps**
9.	**3:45**	**Public Comment Session**
10.	**4:15**	**Adjourn**

Western Climate Initiative



ELECTRICITY TECHNICAL WORKING SESSION

Operational Reliability and Liquidity Issues – Background Paper for WCI December 2 Workshop[1]

Introduction

Stakeholders for the electricity sector have asked the Western Climate Initiative (WCI) to address how a cap-and-trade market should be structured to handle electricity operational reliability and market liquidity. They have asked these issues in two roles, as one of the largest sectors participating in the cap-and-trade market and as entities with specific technical challenges in providing service to customers. The WCI Electricity subcommittee plans to provide recommendations to the WCI Partners on these technical issues and is seeking stakeholder input. This paper is designed to serve as a springboard for the December 2 Technical advisory workshop and subsequent written comments. The paper includes issues identified so far, open questions, and a range of sample solutions which WCI could employ to address operational and liquidity issues in the market design.

These issues may not be uniform across the WCI. With respect to operational reliability, while all system operators must conform with the North American Electric Reliability Corporation (NERC) and regional reliability standards, the exact procedures and products used to maintain operational reliability may be different among and between vertically integrated utilities and more de-regulated systems. Operational reliability and liquidity issues may also be different for (Western Electricity Coordinating Council (WECC) and the Eastern Canadian Provinces that are WCI members, since they have different grids with different rules and regulatory structures. We will need to identify what issues are in common and which need to be tailored to each grid's structure. Finally, we should identify which issues are appropriate for WCI-wide guidelines and which are relevant only to some jurisdictions.

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[1] *The lead author of this paper is Karen Griffin of the California Energy Commission. Generous assistance and comment on an early draft was provided by Udi Helman (California Independent system Operator), Bud Beebe (Sacramento Municipal Utility District, Mark Meldgin (Pacific Gas and Electric)) and Jessica Verhagen British Columbia). It also draws on stakeholder comments in California's proceedings on implementing AB 32 and so benefits from views of public and private utilities, power marketers, independent generators, and consumer and environmental representatives.*

Operational Reliability Description

Operational reliability is a system attribute provided mostly by generation at the behest of the balancing authority. It is the balancing authority's[2] ability to balance real-time supply and demand for energy while respecting physical and security constraints on generation and transmission operations and maintaining sufficient operating reserves to meet applicable control performance standards. While the immediate focus of this paper is on short-term reliability, there is also some discussion of longer-term reliability issues, as reflected in multi-year grid planning and resource adequacy assessments.

A fundamental complication of operational reliability in power systems is that electricity cannot, for the most part, be stored. Some generating units must be able to run when called upon to balance energy supply and demand and support grid reliability. In the current WECC grid, most units operated specifically for grid reliability purposes are fossil-fired and they emit greenhouse gases (GHG). (The WECC exception is hydropower, which plays a significant reliability role in the northwest and California). Under a cap-and-trade system, the owners of fossil-fired units will need to acquire and surrender allowances to cover their GHG emissions. Retrofitting these units with carbon reducing technologies is not yet a commercial feasible approach. Their only options to meet a tightening allowance cap are to buy allowances or not generate. For plants not owned by a utility, these units must be able to obtain allowances and recover the costs either through bilateral contracts or spot market revenues.

Some reliability issues may present problems over time for obtaining allowances, but may be fairly well defined and can be planned for. Other reliability issues, such as emergency purchases or dispatch instructions, may be difficult to plan for. Separating operational reliability into such constituent pieces may help us to craft targeted solutions without having unintended consequences on power system operations and markets.

Operational Reliability Issues Which Have Been Raised by Stakeholders

1. To what extent do non-utility generators have an opportunity to recover the full costs of acquiring allowances needed to operate in real time, including those generators with "must-run" contracts to ensure grid reliability? How many contracts executed before entities could reasonably anticipate a carbon price will still be in place in 2012? Existing contracts with no re-openers do not allow generators to recover costs of allowances. Is this a generic issue for implementing cap-and-trade or do concerns about operational reliability require specific remedies?

2. Plans to increase renewables across the WCI necessarily include new dispatchable gas plants as well as possible repowering of existing dispatchable thermal resources to counter balance for the variability of wind and solar generation. Will allowances be available for these new plants and

[2] A balancing authority may be a utility or it may be an independent system operator.

existing/repowered capacity needed for such support? On the one hand, if we are reducing greater use of baseload MWh, there would still be room for plants producing fewer hours of energy. On the other hand, fossil plants kept available on line for renewable integration may be operating at less efficient levels with higher emissions. Is this just an example of how to handle new entry and exit and hence belonging to a wider policy discussion at the Partner level before being addressed on a technical level?

3. In terms of longer-term reliability, how can the electricity sector align its resource acquisition timelines to take into account the trajectory of reductions needed to meet the carbon reduction goals? Does the carbon reduction trajectory affect the speed with which jurisdictions increase their auction percentages? Grid reliability may be threatened if either allowance prices or other policies compel high-emitting plants which are also necessary for grid reliability to shut down before resources which provide comparable attributes are brought on line.

   The lead times present for electricity sector infrastructure are substantial. To the extent that renewables require new transmission lines to be delivered to load centers, multi-year delays may be possible for getting these renewables online. Such delays threaten the ability of large amounts of renewables to be counted on for accomplishing reductions in the early years of a cap and trade. With a linearly declining cap, this would cause reliability problems for the grid towards the end of the first, and possibly second compliance periods, as generators face substantial penalties for operating without available allowances. While the sector will be under a multi-sector cap and trade, adequate availability of "excess" allowances from other capped sectors has not been evaluated.

4. Will there be pressures to over-procure allowances? To assure grid reliability, load serving entities (LSEs) will typically "over-procure" energy and capacity for the peak demand periods of the summer months. To the extent that allowances will be held in similar conservative fashion by LSEs as a hedge to assure availability of capacity, these "allowance banks" may well challenge market liquidity. Generation capacity must meet instantaneous expected and real demand at all times and there is requirement for "capacity reserve" that is very infrequently needed.

5. How will we prevent wholesale market suppliers in the WCI from withholding power if they contend that allowances are not available at a reasonable price and, conversely, how do we prevent allowance price spikes from translating into windfall profits for all market participants? [See the appended SMUD example.] Or, is this issue any different from the ones the market already faces: a coal/hydro/nuclear/renewable generator faces the same situation if the price of natural gas jumps. The market doesn't consider profits sustained in an open market to be "windfall" profits when non-natural gas generators see increased profit because the price of natural gas increases.

6. May generators be held hostage to speculators when they need allowances to cover reliability dispatch? Without careful allowance market monitoring, it may be difficult in such circumstances to distinguish between strategic physical withholding to affect wholesale energy prices and market-driven speculative price increases. Are multiyear compliance periods and banking adequate to deal with short term acute demand? Is the demand anticipated to be relatively small compared to the overall supply of allowances? Is this a generic issue which should be addressed by the monitoring and market oversight committees, or is there something unique to the electricity sector?

7. With respect to longer-term adequacy, does the electricity sector need special allocation rules to deal with very large swings in system reliance on fossil-fired generation due to variability in hydro generation output, such as those which occur in California in low and high water years, as illustrated in the following paragraphs? Are there other predictable swings in GHG emissions caused by resource trade-offs in other WCI jurisdictions?

   Hydro variability in the West is substantial. In California, hydro generation variability averaged 25 percent per year between 1990 and 2004. That is, on average, from one year to the next, the amount of hydro generation was either 25 percent above or below the previous year. For the Northwest, that variability averaged 16 percent, and when the two regions are combined, the annual variability averaged 13 percent. By splitting this timeframe into 5 three year time windows, and comparing those time windows to the typical annual combined generation over this time period, the three year windows were on average 8 percent higher or lower than the historical average. This all goes to show that even with 3 year compliance periods, hydro variability will still tend to be either above or below the historical average by an amount that is significant enough to cause a shortage or surplus of allowances.

   Currently, as a mechanism to deal with the variability of hydroelectricity, utilities will hedge for dry hydro conditions by procuring more fossil generation than may actually be necessary to meet load. If procuring fossil generation also means procuring allowances in order to operate, this may challenge liquidity of the market. As an example, in the 1970's, gasoline lines occurred as a result of the need for everyone to have a full tank of gasoline in case they were to run out. Risk adverse utilities will likely prefer to have allowances on hand, rather than risk shutting customers off.

8. Will operational reliability concerns play a bigger role in the early years of GHG allowances, until the challenges of incorporating intermittent resources into the system are overcome? For example, if we initially have a system with high wind penetration, causing substantial variability in output that represents challenges for operational reliability, but that is augmented later with solar, price-responsive demand response and storage capability that mitigate the variability but without increasing GHG emissions.

9. What parallels should we look at for how others have handled similar problems (RGGI? NOx credits in SCAQMD, EU ETS power sector??)

10. Is operational reliability more or less an issue for the vertically integrated utilities compared to those portions of WCI, such as ISOs, which operate using market rules and tariffs?

11. Who (as exactly as we can identify) is responsible for assuring grid reliability? This is reasonably well understood for the current system, but responsibility for grid reliability as it is affected by allowance availability should be clarified prior to its challenge. (This may have a relationship to the time constants for action stated above, e.g., ISO or other Balancing Authority for day ahead and instantaneous, and LSE's or "Government" for assuring sufficient capacity availability over long time-frames.) It may be good to explore various key entities in this regard (six month actions, one year actions, three year or one Compliance Period actions, Power plant development time frames, transmission development time frames). Vertically Integrated LSE's, market dependent LSE's, Power Marketers, Merchant Generators, Electricity Consumers. In this regard, is forced DSM (i.e., directed curtailment) an acceptable "Reliability Enhancer?"

    Examples of issues which might arise include:

    - If a Generator, near the end of a compliance period, had no allowances, and their availability was uncertain (illiquid market) would they bid? Would they bid and/or run if told to by, what, LSE?, ISO?, BA? What entity is responsible for this decision, and which entities are responsible for dealing with the outcome?
    - If a generator has a contract (like a futures contract) for allowances to cover their position, but the contractually obligated company cannot get allowances because (pick one or more) they go bankrupt, the allowances are all gone or held by price independent entities (like say an LSE that "must hold" some reserve amount above their apparent need), Who pays fine? Who comes up with "pay-back" allowances from next allowance vintage?
    - What is the price elasticity of all of the individual capped sectors? Are there specific inelastic incompatibilities within sectors? (At 30 $/ton a manufacturer can switch from natural gas to electricity to heat my plastic, but electricity sector can't absorb that load for 30$/ton.) Electricity rate structures are not responsive enough to prevent this type of dislocation.
    - Effect of commodity inventory buffers and their effect on allowance purchase (and timing) decisions. For instance, natural gas in the pipeline

offers a physical storage buffer (with known response time and limitations) therefore the gas market has some time to respond to changing demand. What, for instance, are aluminum supplier inventory response time issues and effect on decision time for (HFC) GHG allowance and electricity demand adjustments in response to carbon price signals? What, for instance, are Portland Cement inventory options to contribute to GHG allowance liquidity in short-term? Would market "know" when coal combustion had used more allowances than would be compatible with reliable grid capacity to the end of a compliance period?

Liquidity Description

Liquidity measures the capability for an asset, such as an emission credit, to be bought or sold quickly without causing a significant movement in price and with minimum loss of value. Some literature suggests that liquidity is largely a question of how we design the allowance contract. If there are more players, if the emissions certificate is more uniform, if there is price transparency, if it is fungible with other carbon markets so that it can be easily traded, then the market will be more liquid. These do not seem to be electricity-specialized issues.

Almost everyone favors the liquidity which comes from greater participation of entities in the cap market in order to provide lower cost allowances, but stakeholders are split on the potential for liquidity to morph into speculation and market manipulation. In this debate, "good" liquidity is when there are many buyers and sellers, and when both small and large participants can buy or sell allowances in the amounts they want at the time they want. "Bad" liquidity happens when the allowance market is dominated by "speculators" who want to profit from their buying and selling expertise regardless of the impact it has on the ability of the actual system to provide reliable power. Obviously, these are over-simple generalizations to show the bookends of the debate.

One complication that permeates these conversations is the multi-sector nature of the envisioned cap-and-trade program. Additional capped sectors should increase allowance liquidity, however without quantification of the temporal, operational, and size characterization of interacting sectors, it is guesswork to judge the potential allowance market liquidity issues posed with a linearly decreasing cap with real reductions of significant size over the decade.

Liquidity Issues Which Have Been Raised by Stakeholders

1. Is it correct that the GHG allowance/offset market will probably be liquid if people have confidence that, when they sell at some price, they can reverse, and buy back some time later, at roughly the same price? On a graph of price vs. quantity, in other words, a supply function for GHG allowances/offsets that is flatter, rather than steeper, may lead to a more liquid market. If, in contrast, a small shift in demand for GHG

allowances/offsets would cause a large change in the price, people might tend to hold their allowances, out of fear of selling allowances just before some change, like dry hydro that would cause a jump in allowance prices.

2. Hydro swings may be important for liquidity as well as operational reliability. The WCI electricity sector is larger than California; it includes more hydro, and is subject to bigger hydro swings. For example, consider 1992, which was a dry year throughout the WCI (though not as dry as 2001 or 1977). Hydroelectric generation in the WCI in 1992 was about 30 million MWh below the median of the last several years. Using gas CCs to make up the shortfall would create a need for about 12 million more allowances or offsets. Would that cause liquidity issues?

3. Are there criteria for identifying when there is a minimum critical amount of liquidity, rules to prevent market manipulation, staged processes, safety valves, monitoring standards which can be set? What specific recommendations could we make for consideration in a WCI approach? Is there evidence that rules tried so far have been successful or unsuccessful? If intermediaries are found to introduce more problems than they solve, what metrics do other markets use to determine the tipping point at which intermediaries harm rather than help the market?

4. What are the key principals that an allowance market needs to have to draw in good liquidity?

Brainstorming List of Possible Solutions: Operational Reliability

For any issue which is deemed to be significant, the WCI Electricity Committee may recommend a possible solution for Partners to consider. The following list is a starter list of ideas to be explored if there is a need to do so. These could be considered either for a WCI-wide guideline or be recommended for consideration by individual partners if the issue is relevant to them.

1. Allowance set aside for reliability. This introduction of a ‘conditional bank’ of allowances to compensate for either overly wet or overly dry compliance periods may be necessary to ensure that adequate allowances exist in order to ensure reliability. Such conditional banks may also need to be considered for temperature variability. Would it have to be accounted for within each partner’s budget?

2. Set a “de minimus” reliability exemption, e.g., for emergency transactions, under the argument that those are likely to have little impact on GHG emissions but could prove extremely difficult to appropriately assign allowance obligations, especially across WCI boundaries.

3. Make the cost of allowance automatic pass-through to customers; don’t include the price of allowances in bids.

4. Let the market set the price of reliability (i.e., incorporating the cost of high allowance prices) – if prices spike in shortage or emergency conditions, that is sending a valid signal about the worth of reliability and the need for non-GHG emitting resources to provide reliability services.

   An example of market pricing is the ISO's MRTU design which will have some mechanisms to do this. One is called "scarcity pricing" and would raise spot prices for energy, regulation and reserves when the system is short of any of those. Similarly, in periods when there is oversupply of wind (likely at night in California), the ISO is exploring mechanisms to send the right price signal for resources to curtail.

5. The balancing authority/utility acquires allowances for generation it directs be turned on for reliability.

6. In order to cut down on the potential for hoarding of allowances, introduce a vintaging element and limit maximum lifetimes for allowances. . While there is general agreement that banking of allowances is desirable, some confusion may develop between legitimate banking activities and 'hoarding' with the intent of harming market liquidity.

7. Do nothing extra; because we determine that the existing flexible compliance rules handle the issue adequately

Brainstorming – Possible Solutions: Liquidity

1. Are the flexible compliance measures already adopted sufficient or is there some additional proposal needed for either operational reliability or liquidity?

2. How could we structure the allowance auction to encourage "good" liquidity, restricting the amount of allowances purchased by an entity, restricting allowance auction to covered entities and allowing intermediaries to function in the secondary market?

3. Any market established for trading carbon allowances should have transparency as a first principle. Possibilities to ensure transparency include public disclosure of allowance ownership after auctions and at regular reporting intervals (quarterly?). Such disclosures will be necessary to ensure that entities cannot 'corner the market'. Of potentially equal importance would be a regular reporting requirement for entities to show that they hold allowances sufficient to cover generation that already occurred. Again here quarterly or bi-annual reporting may be sufficient to ensure that significant deficits are not introducing the potential for unnecessary volatility, and would help prevent the possibility of running out of allowances due to imperfect information.

4.

Operational Reliability Issue #4 - example: Fuel price differential

It is well known that coal and gas fuels have a significant difference in price. Given coal's relative abundance in the United States, in particular as compared to gas, it is likely that this cost difference will continue and, if anything, will increase over time. Because of this significant fuel price differential, coal generators have a much easier time acquiring allowances than gas generators, but they need two to three times as many allowances per MWh produced. Because of the very large difference in marginal operating costs, until carbon prices reach fairly high levels, such as $50 to $60 per ton or more, gas will not displace coal generation. Additionally, coal plants are less economic to maneuver than gas fired turbines; they don't like to be shut-down for the night, so coal based bids will likely be more resistant to being forced out of bidding than just the fuel price spread would indicate. As a result, to the extent that prices remain below the $50 to $60 per ton for any significant amount of time in a compliance period, it is possible for coal generators to consume more allowances than that which is compatible with maintaining an amount of gas generation compatible with current reliability needs.

Consider the simple scenario (no offsets, no allowances from other sectors); coal generation, natural gas generation, and other generation are available and are needed to meet capacity at some time. The allowance cap is insufficient to allow all coal and natural gas generation to run at design annual capacity. Why can't coal, running baseloaded, buy more allowances (and retire them) than is compatible with any fossil fueled generation having allowances to cover operation in, say, the last month of the compliance period?

Western Climate Initiative: Electricity Leakage Analysis

October 16, 2008
Electricity Subcommittee Technical Working Session
Salt Lake City, Utah

Snuller Price, E3

Agenda

- E3 and PLEXOS Background
- Research Objective and Approach
- Summary of 2020 Simulated Dispatch
- Analysis Results
  - Coverage
  - Contract Shuffling
  - Leakage
- Next Steps and Possible Refinements
- Question and Answer

E3 Background

Energy and Environmental Economics, Inc.

- **E3 Overview**
  - E3 is an electricity consulting firm founded in 1993 in San Francisco.
  - Clients span local, state and federal government, small and large public and investor-owned electric utilities, and energy technology companies
  - Approximately 20 staff in energy economics, policy, and resource planning
- **Related Projects**
  - California GHG Modeling of electricity sector for AB32
  - IRPs and Energy Plans in the Northwest; Idaho State Energy Plan, IRP for PNGC Power, Lower Valley Energy, Umatilla Electric Cooperative
  - Long-line transmission, British Columbia – California Renewable Energy Partnership, Load Resource Balance in the Western Interconnection: Towards 2020 for Western Electric Industry Leaders (WEIL)

PLEXOS Solutions

- Software, consulting, and information services company located in Sacramento, CA
- Company utilizes PLEXOS software for regional analyses
  - Advanced linear and mixed integer programming algorithm for “operations quality” unit commitment and dispatch
  - Simultaneous (versus sequential) optimization of generation, transmission, system, emission, and storage constraints
- Four principles, each w/ 20+ years resource planning experience
- Worked with E3 on the CPUC GHG modeling
- Currently engaged to provide renewable integration study for CAISO
- Performed similar study recently for 3 CA IOUs

Plexos Solutions

Investigation of 3 related questions

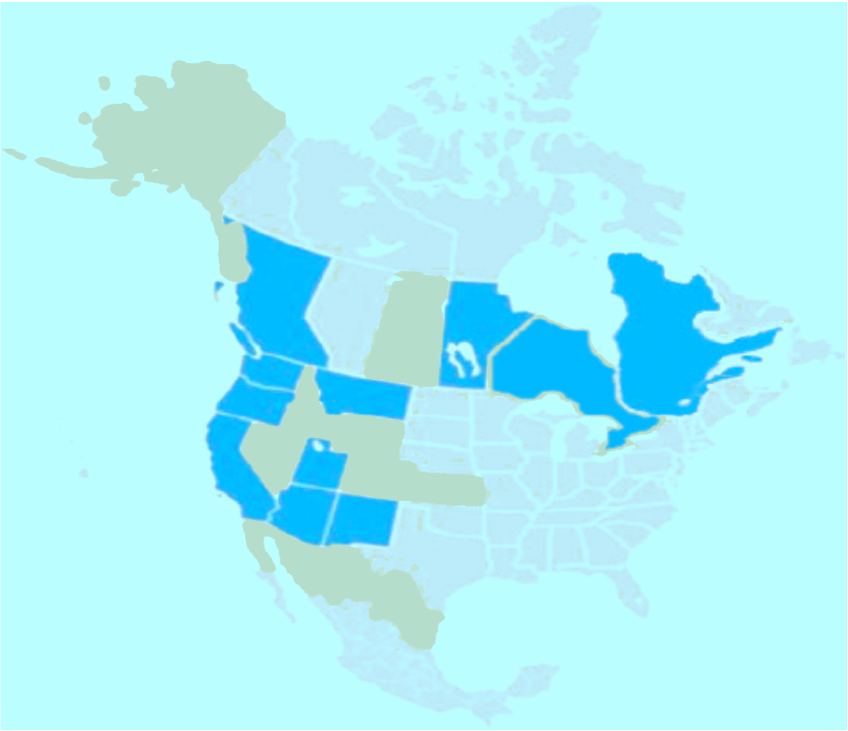
- Coverage
  - How well does the system cover the actual CO2 emitted by the electricity sector in WCI states?
- Contract Shuffling
  - What is the potential to reduce CO2 in the WCI by 'shuffling' ownership or contracts to outside the WCI?
- Leakage
  - What is the potential to change *generator operations* to reduce CO2 in the WCI but increase it outside?
  - What is the potential to change *new generation investment* choices to reduce CO2 in the WCI but increase it outside?

Analysis Limitations

- One month project that leverages prior analysis
- Analysis based on a single snapshot of 2020 WECC case
  - Estimate of 2020 generation and loads
  - Production Simulation yields 2020 GHG emissions
- Given time constraints, we also make recommendations on possible improvements to the analysis

Jurisdictions Included in Analysis

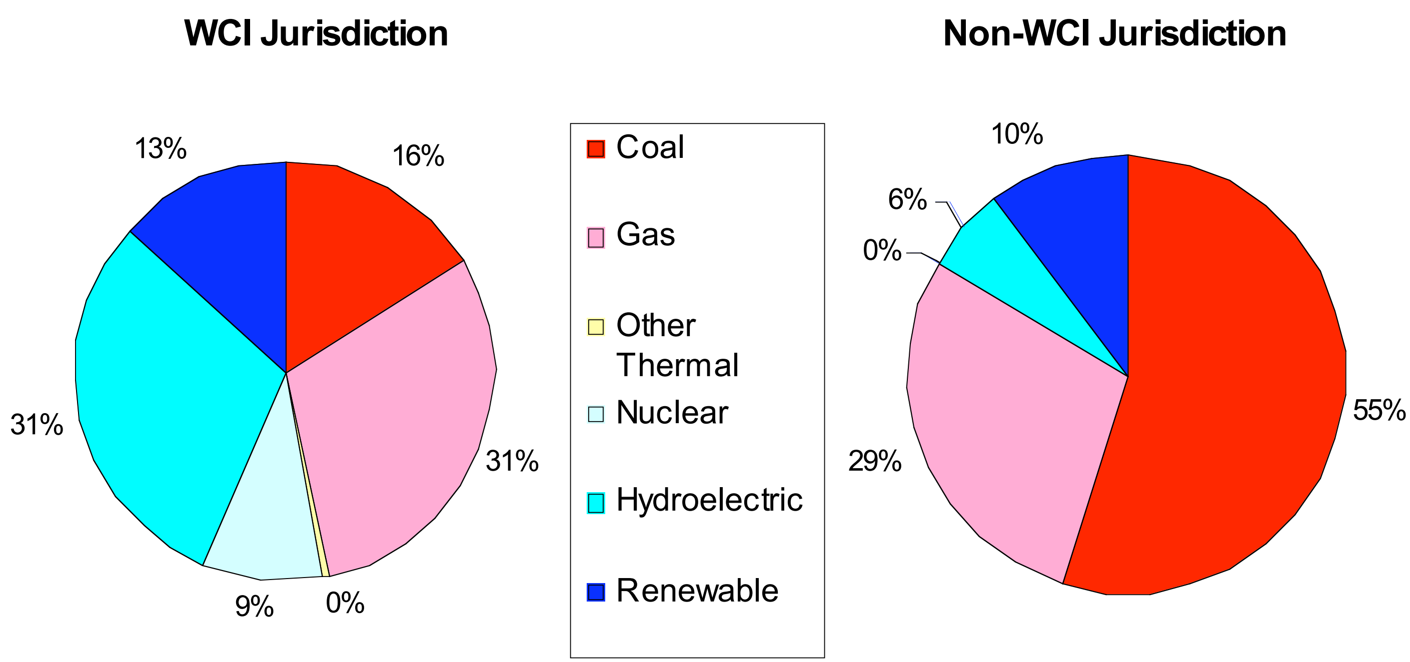
- Analysis focuses on the 8 western states and provinces
  - BC, WA, OR, CA, AZ, NM, UT, MT
- PLEXOS 2020 simulation does not include the 3 eastern province members



WCI Point-of-Regulation Recommendations for Electricity Sector

- Implement First Jurisdictional Deliverer
  - Generation within WCI is monitored at the smokestack
  - Specified imports buy CO_2 at actual rate
    - Specified: owned generation, or long-term contract
  - Unspecified imports buy CO_2 at the ‘deemed rate’
    - ‘Deemed rate’ is a pre-defined emissions intensity applied to system power imported to WCI (lbs CO_2/MWh)
    - Unspecified: Market purchases of power or short-term contract from trading point

2020 Generation by Jurisdiction

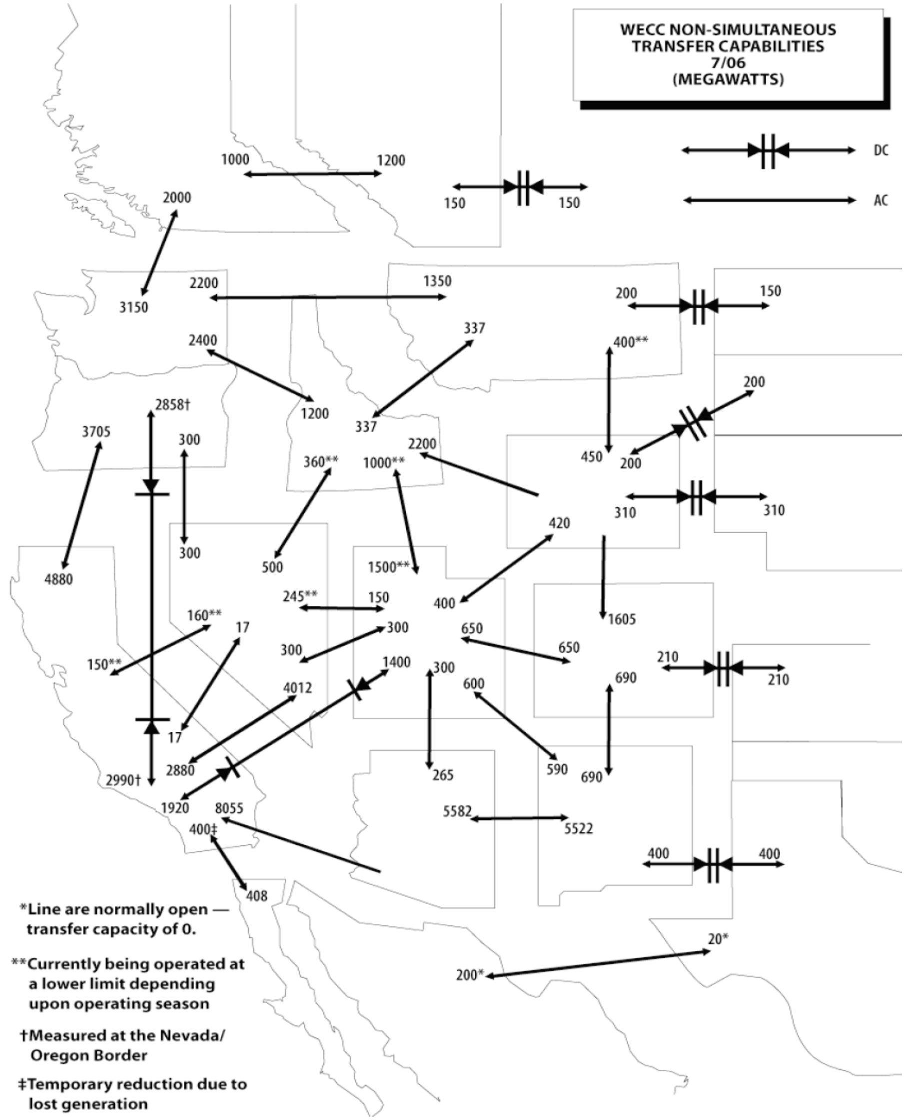


Generation (GWh)

	WCI	Non-WCI	Tribal Lands	TOTAL
Coal	126,675	146,510	42,556	*315,741*
Gas	233,015	77,355	0	*310,371*
Other Thermal	3,257	0	0	*3,257*
Nuclear	72,512	0	0	*72,512*
Hydroelectric	232,532	16,661	0	*249,193*
Renewable	103,298	27,653	0	*130,951*
TOTAL	*771,289*	*268,180*	*42,556*	*1,082,024*

Resulting Transmission Flows

- PLEXOS database contains a full model of high voltage transmission system in the WECC
- Results are based on a zonal simulation of the WECC with transmission flows between regions
- Results provide hourly flows on each major line in the WECC



Coverage Results

"Coverage" is measured as the share of emissions attributable to WCI consumption that is captured by the market design

1. Coverage Analysis

- Two bookends
  - ‘Source-based’ emissions: emissions from smokestacks within WCI
  - ‘Consumption-based’ emissions: best estimate of actual emissions based on generation assignment to states and provinces
- Ratio of source-based to consumption-based emissions provides estimate of coverage for source-based method
- FJD regulation of imports improves coverage

Consumption-Based Methodology

- Use 2020 PLEXOS Simulation
- Assign coal, hydro, and nuclear units by state based on LSE ownership / contracts
  - For LSEs that serve multiple states we apportion their fuel mix based on share of sales in each state
  - For BPA resources we assign based on share of customer requirements in each state
  - For WAPA resources we assign known specific projects to states or to the state in which the resource resides without better information
  - Assigns renewables to geographic jurisdiction (WCI & non-WCI)
- Remaining generation is natural gas, which is assigned to states based on the remaining load served using the average natural gas emissions rate

Emissions Coverage

- Source-based regulation would cover approximately 74% of WCI emissions

Regulation based on Consumption
MMT CO2

	WCI States	Non-WCI States	TOTAL
Coal	179	129	*309*
Gas	110	10	*119*
Other	4	0	*4*
TOTAL	*293*	*139*	*432*

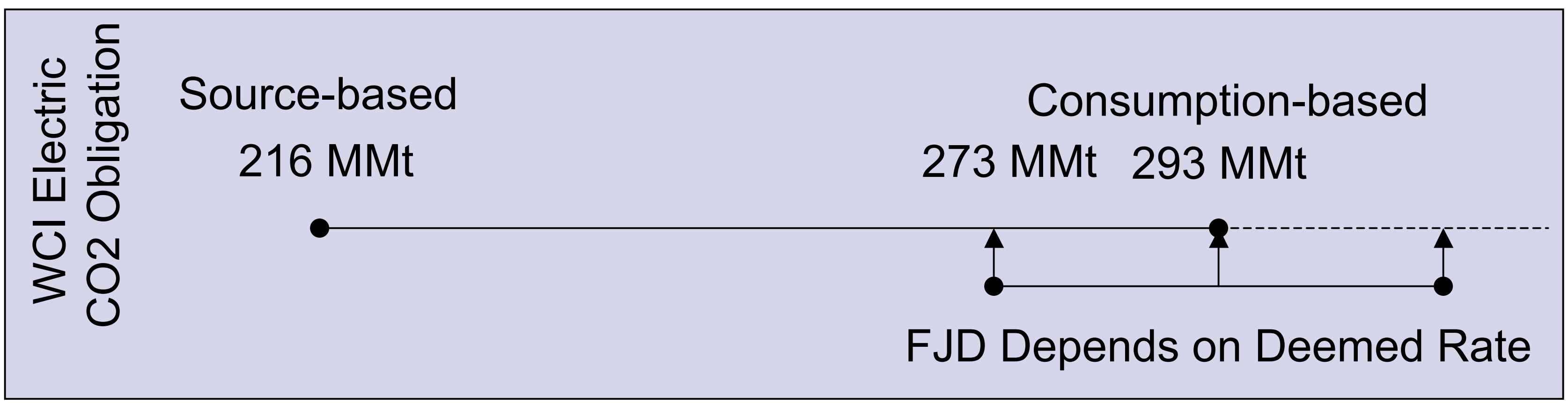
Regulation at the Source
MMT CO2

	WCI	Non-WCI	Tribal Lands	TOTAL
Coal	122	145	41	*309*
Gas	90	30	0	*119*
Other	4	0	0	*4*
TOTAL	*216*	*175*	*41*	*432*

216 MMT ÷ 293 MMT = 74%

First Jurisdictional Deliverer

- Regulation of imported electricity improves coverage
- Apply actual emissions intensity of specified generation (known contracts and ownership of generation in non-WCI states)
- Remaining imports: apply deemed emissions rate
  - High deemed rate can lead to more than 100% coverage
  - Low deemed rate can lead to less than 100% and more opportunities for leakage and incentive for shuffling



Coverage Analysis Conclusions

- Regulation of imports is necessary because a source-based point of regulation (i.e. ignoring imports) would only include approximately 74% of WCI electricity sector CO2
- Coverage analysis also provides an upper bound on contract shuffling

Contract Shuffling Results

Contract shuffling is an action that reduces WCI CO_2 obligations without any change in operations

2. Contract Shuffling Analysis

- Evaluate unconstrained shuffling
- Evaluate shuffling to specified imports
  - Potential is limited by non-WCI hydro
- Evaluate shuffling to unspecified imports
  - Potential is limited by deemed emissions intensity for system power
  - Evaluate regional exceptions

Unconstrained Contract Shuffling

- Contract shuffling is measured as the difference between pre-WCI consumption-based emissions and WCI regulated emissions
- The difference between the consumption-based CO2 emissions and source-based CO2 and is the upper bound for shuffling
- If all fossil-based imports were shuffled to zero carbon resources, 26% of the WCI carbon emissions could be shuffled (77 MMt CO2)

Unconstrained Contract Shuffling Potential
MMT CO2

	WCI States	Non-WCI States	Change in CO2
Coal	57	-57	*0*
Gas	20	-20	*0*
Other	0	0	*0*
TOTAL	*77*	*-77*	*0*

Contract Shuffling to Specified Imports

- Non-WCI hydro and renewables are the only source for shuffling to zero-carbon specified imports
  - Assumes renewables are not available for shuffling due to RPS targets
- Idaho contains most non-WCI, non-Federal hydro
- Maximum potential shuffling from hydro of 20 MMTCO2 if all non-WCI hydro was shuffled to coal (2,200lbs/MWh)

Hydroelectric Generation (GWh)

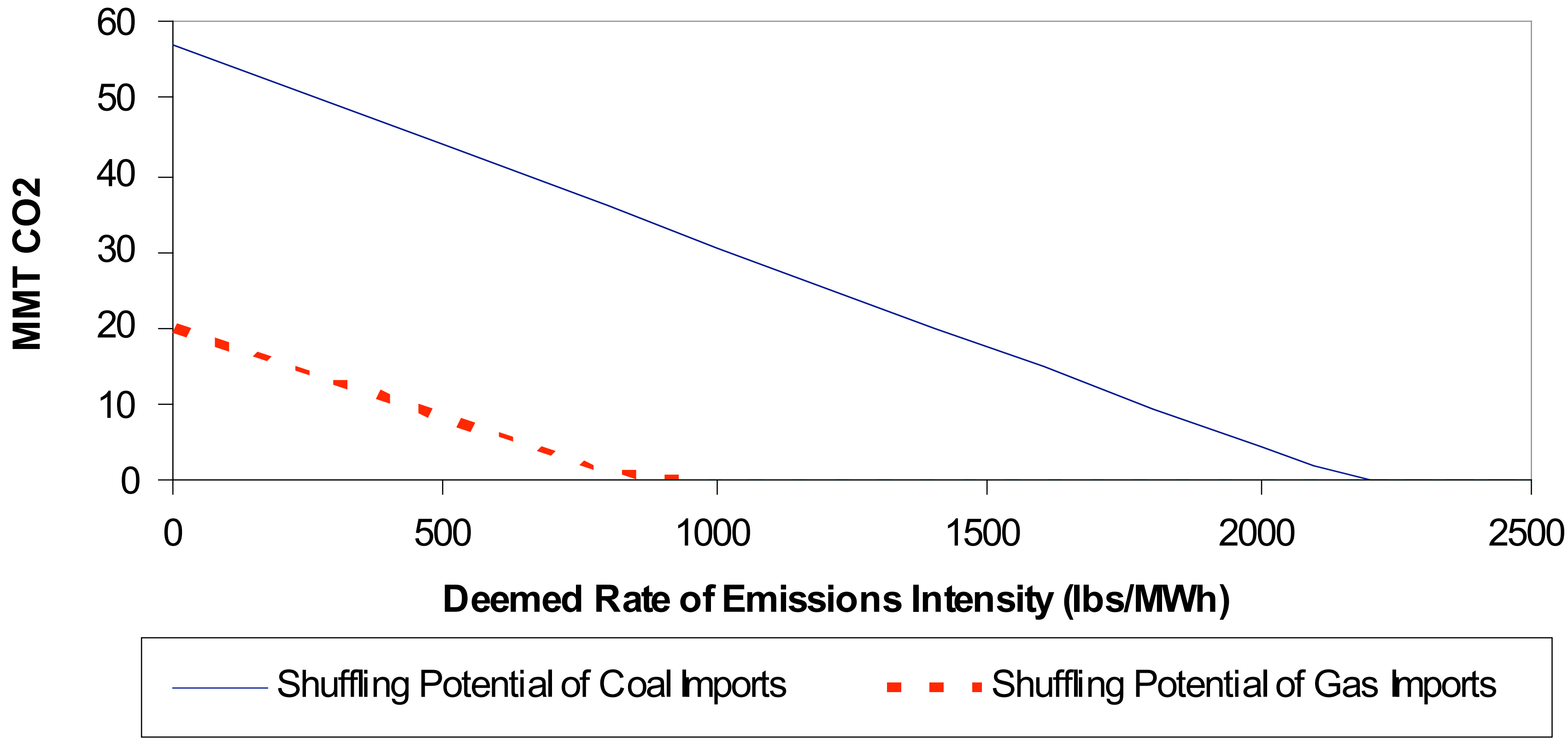
	AB	CO	ID	WY	TOTAL
Federal Hydro	0	1984	3672	1280	6936
Non-Federal Hydro	2051	1380	8835	561	12827
Total	*2051*	*3364*	*12507*	*1841*	19764

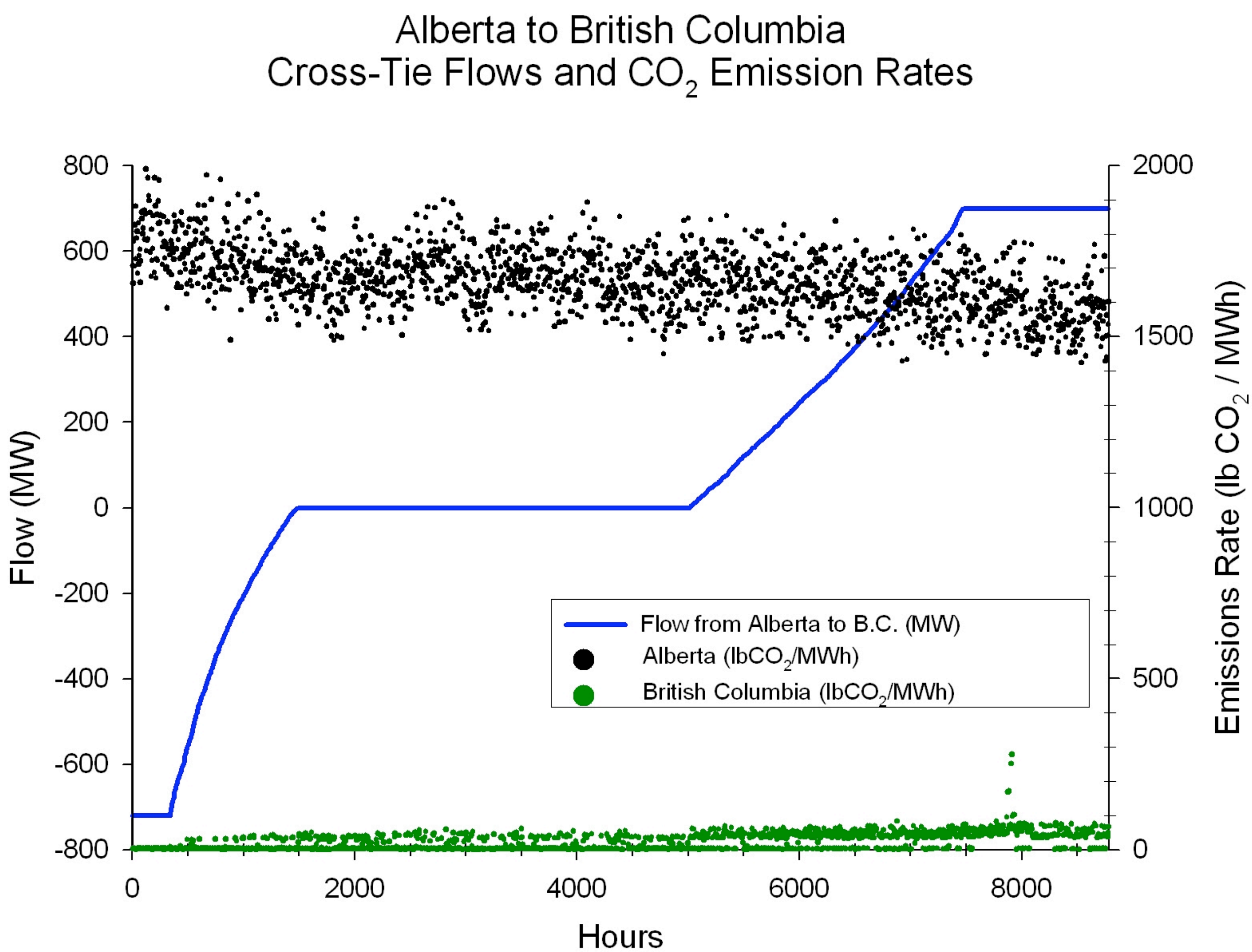
MMT CO2 - Maximum Shuffling

	AB	CO	ID	WY	TOTAL
Federal Hydro	0	2	4	1	7
Non-Federal Hydro	2	1	9	1	13
Total	2	3	12	2	20

Contract Shuffling to System Power

- Deemed emissions rate limits contract shuffling




Alberta to British Columbia
Cross-Tie Flows and CO_2 Emission Rates
Flow (MW)
800
600
400
200
0
-200
-400
-600
-800
Emissions Rate (lb CO_2 / MWh)
2000
1500
1000
500
0
0
2000
4000
6000
8000
Hours
Flow from Alberta to B.C. (MW)
Alberta (lbCO_2/MWh)
British Columbia (lbCO_2/MWh)

Shuffling Analysis Conclusions

- Ability to shuffle to specified imports is relatively small, limited by non-WCI hydro generation and federal control
- Rules for specified imports could capture most remaining coal imports
- Deemed emissions rate can limit economic incentive to shuffle remaining imports in most cases
  - Alberta to BC intertie may require separate deemed emissions intensity

Leakage Results

Leakage is a change in operations or investment which reduces WCI CO_2 emissions while increasing non-WCI CO_2 emissions

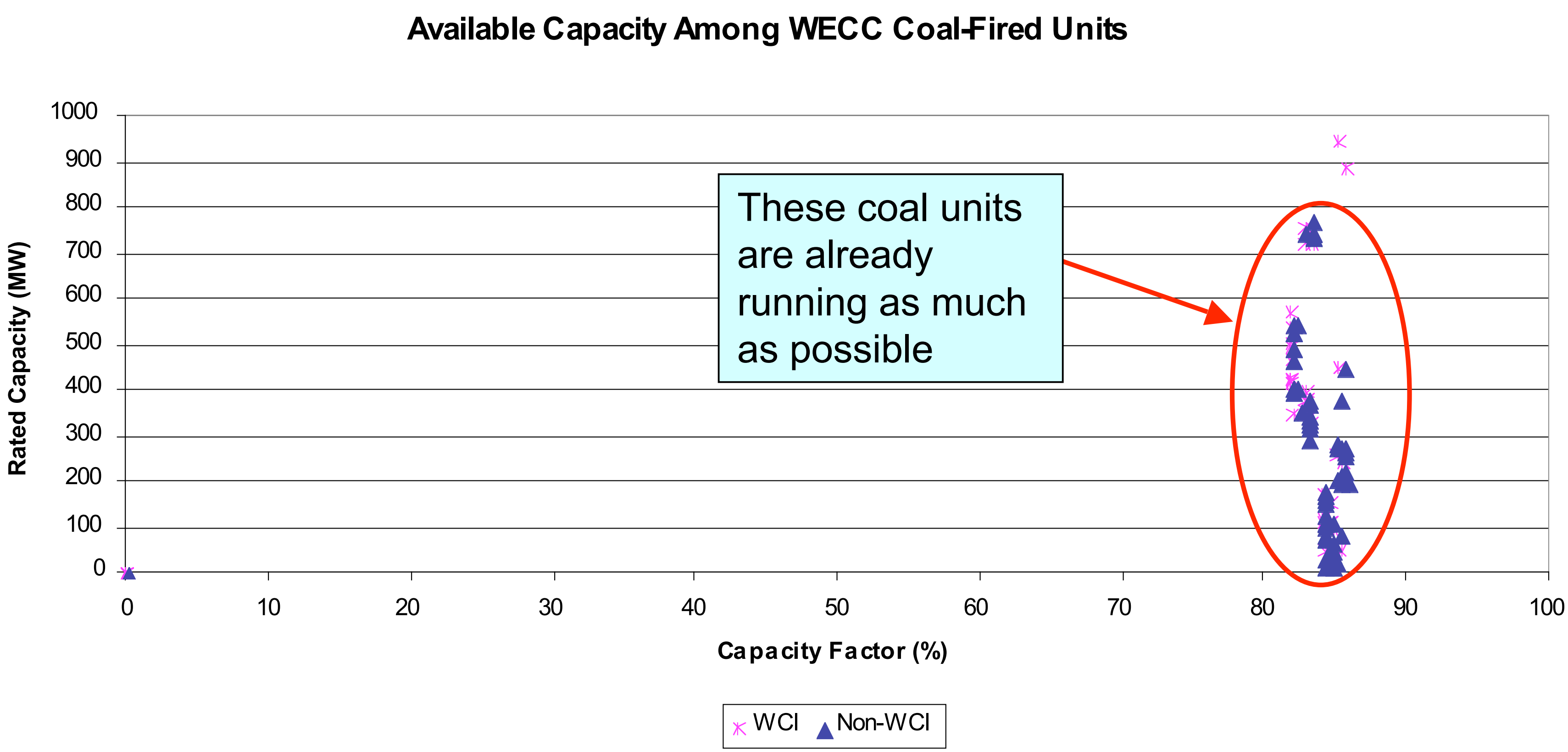
3. Leakage Analysis

- Two types of leakage:
  - Change in power plant operations
    - For example, increase generation of non-WCI coal and decrease WCI generation
  - Change in new power plant investment in non-WCI regions to avoid CO2 obligations
    - For example, build new coal plant in a non-WCI state and import generation into WCI

Inherent Barriers to Leakage

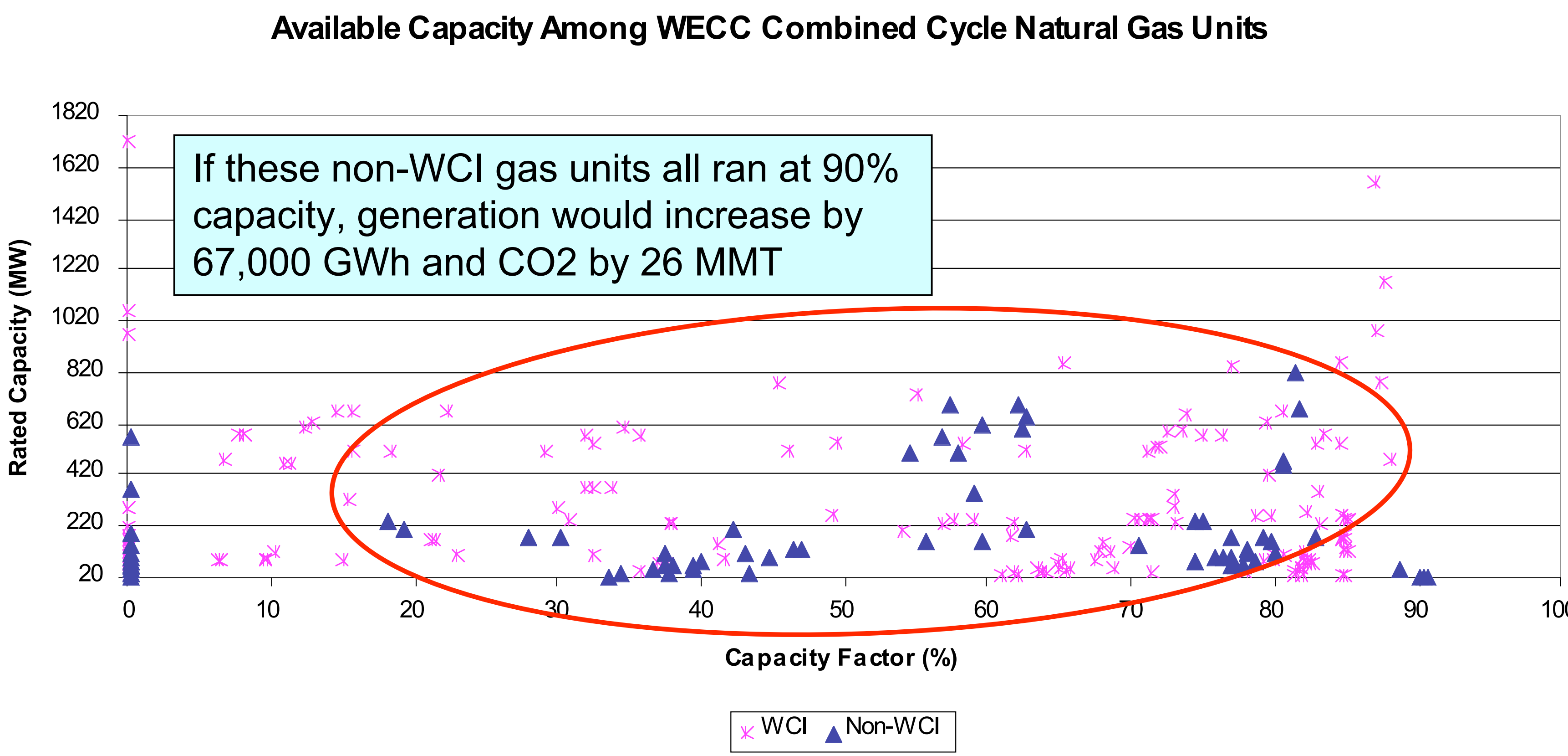
- For existing non-WCI power plants to increase operation:
  - Requires available non-WCI generation capacity
  - Requires transmission capacity to import electricity
- For new power plant construction to create leakage:
  - Requires transmission capacity to import electricity
  - Requires shuffling; either sale of electricity into WCI as system power to get the deemed emissions rate (e.g. unspecified merchant generation), or shuffling to lower carbon resource such as hydro

Leakage Potential from Change in Coal Operations is Extremely Limited



Since coal operates near the maximum technical capacity factor, there is limited potential for leakage through increased coal usage.

Some Potential for Non-WCI Gas to Increase Output

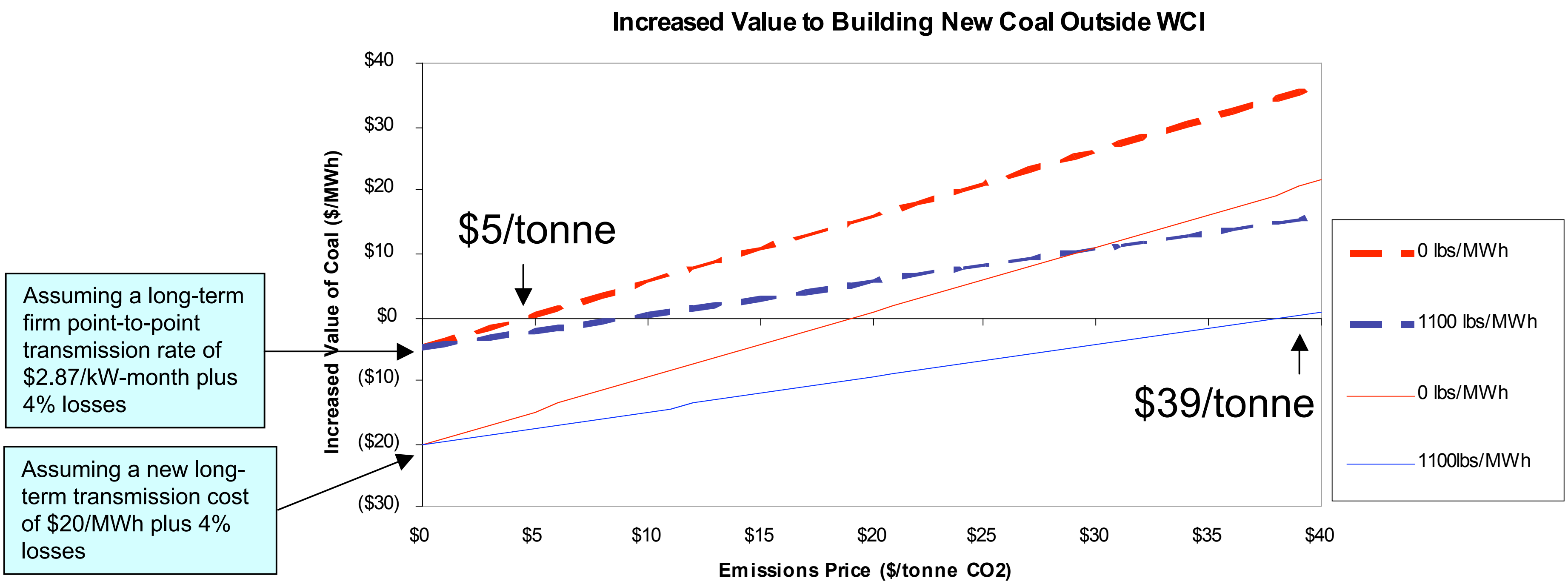


However, FJD with a deemed emissions rate at least as high as combined cycle gas reduces the potential for leakage to natural gas

Leakage through New Construction

- Will WCI carbon regulation tip the economics towards more new coal generation in non-WCI jurisdictions?
- Analysis compares economics of a new coal plant within WCI to a non-WCI jurisdiction including CO2 price differential, transmission cost and losses
- Three situations for new non-WCI coal generation:
  - Signs long-term contract (i.e. specified generation) – no leakage if owner must purchase CO2 allowances under reporting rules for specified generation
  - New plant is able to sell into WCI as system power at the FJD deemed emissions rate
  - New plant is able to sell into WCI as zero-carbon

Economic Pressure for New Coal



- CO2 price changes incentive for new non-WIC coal – but the cost of new transmission and the deemed emissions factor for imports are also important
- **Economics may not be the primary constraint for new projects**

Leakage Analysis Conclusions

- Limited leakage potential for changes in operation of coal generation
- Some leakage potential for changes in operation of combined cycle generation
  - Limited by deemed emissions rate under FJD
- Some leakage potential to new non-WCI coal investment at CO2 prices above \$5 - \$39/tonne
  - Limited by rules for specified generation under FJD
  - Limited by non-economic factors for new construction

Summary

Findings

- Regulation of CO_2 from electricity imports is necessary to increase coverage above ~74% of WCI electricity sector CO_2
- Contract shuffling potential is limited under FJD
  - ~13 MMT CO_2, assuming no shuffling potential from non-WCI federal hydro or renewables
  - Regionally specific deemed emissions rates may reduce contract shuffling potential, i.e. Alberta to BC
- Leakage potential is limited under FJD
  - Potential to increase non-WCI coal operations is approximately zero
  - Potential to increase non-WCI gas operations is small and limited by deemed rate
  - Potential for leakage through new coal investment outside of WCI is limited by FJD rules on specified generation and other factors

Any questions?

Energy and Environmental Economics, Inc.

Contact Information

Snuller Price, Partner
101 Montgomery Street, 16th Floor
San Francisco, CA 94104

snuller@ethree.com
(415) 391-5100 phone

WORLD RESOURCES INSTITUTE

To: Western Climate Initiative Electricity Subcommittee

From: Franz Litz and Nicholas Bianco, World Resources Institute

Date: October 14, 2008

Re: Initial Considerations for the Development of a "First Jurisdictional Deliverer" Definition

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This brief memorandum examines some of the issues presented in developing a regulatory definition of "first jurisdictional deliverer" (FJD) for purposes of considering those issues together with expert stakeholders. After providing some background, we consider the purpose of a regulatory definition, and provide an example from the source-based cap-and-trade context. Next, the specific issues presented by the FJD approach are identified. Finally, some possible definitions are outlined for consideration and comment.

We would like to emphasize that this memorandum represents some initial thinking on defining the term "first jurisdictional deliverer" by the authors using past experience as a guide. This memorandum is not a product of the WCI Electricity Subcommittee, nor has it been approved or otherwise adopted by the Subcommittee. It is designed to stimulate thinking and engender discussion on the part of subcommittee members and the expert stakeholders who are part of the Technical Advisory Group (TAG).

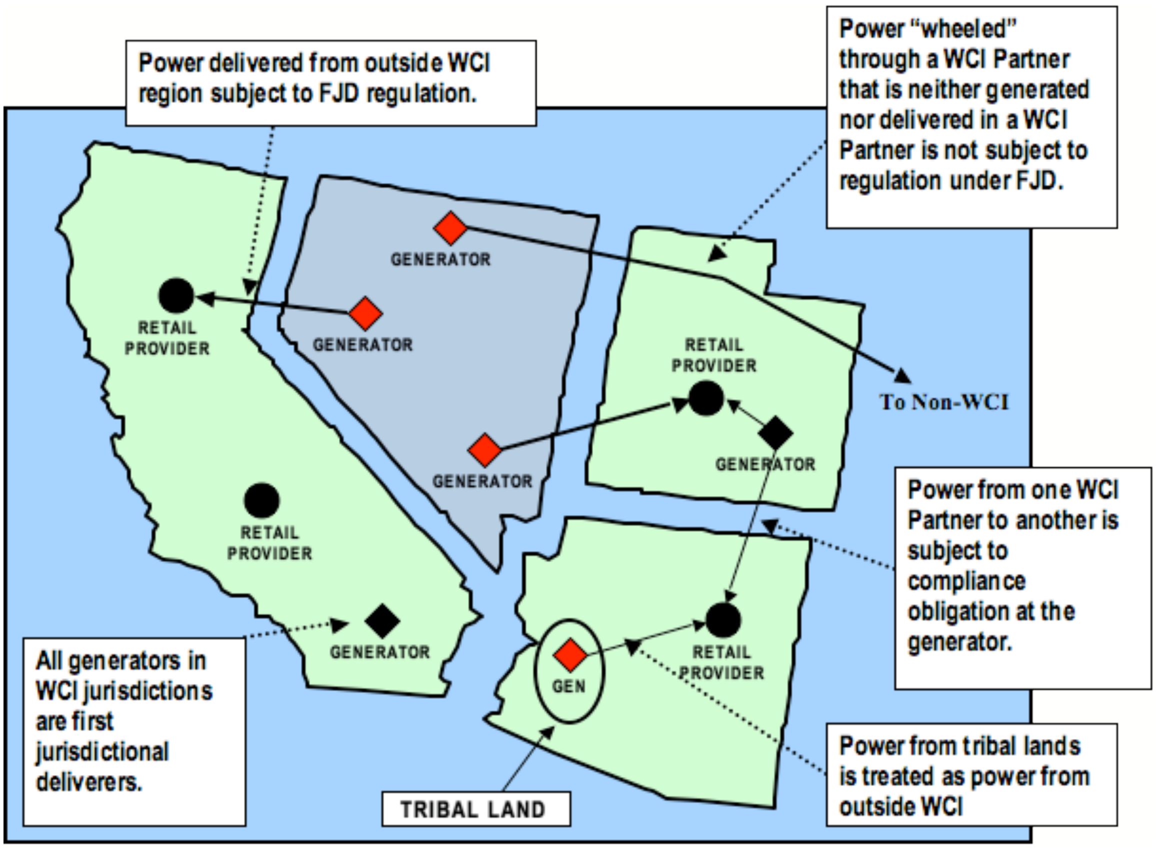
Background

The Western Climate Initiative Partner jurisdictions issued their "Design Recommendations for the WCI Cap-and-Trade Program" on September 23, 2008. The Design Recommendations included the following statement concerning the point of regulation for the electricity sector:

> *2.2 Electricity: First Jurisdictional Deliverer: For sources within WCI jurisdictions the point of regulation will be at the generator.*

For power imported into WCI jurisdictions, the point of regulation will be at the first entity that delivers electricity that is generated outside the WCI jurisdictions (or generated by a federal entity or on tribal lands) for consumption within a WCI Partner jurisdiction and over which the WCI partner jurisdiction has regulatory authority.

The WCI Electricity Subcommittee has undertaken a series of technical working sessions for electricity sector experts and stakeholders to begin developing a plan for implementing the FJD approach to covering the electricity sector. Among the tasks that the Subcommittee faces is settling on a definition for the "First Jurisdictional Deliverer". This memorandum aims to be helpful in this regard.



The figure above depicts a portion of the WCI region and very generally those circumstances in which the first jurisdictional deliverer approach is to be applied to cover electricity emissions. First jurisdictional deliverers include GHG-emitting electricity generators in WCI partner jurisdictions, as well as the first entity to deliver electricity generated outside the WCI partner jurisdictions. Power "wheeled" through a WCI partner jurisdiction but originating in a non-WCI partner jurisdiction and destined for final delivery in another non-WCI jurisdiction is not subject to regulation under the approach.

Purpose of a Regulatory Definition

A regulatory definition for First Jurisdictional Deliverer will help identify what entity or entities are subject to the requirements of the WCI cap-and-trade program requirements for the electricity sector. Because the factual circumstances that lead to the delivery of electricity (with associated CO_2 emissions) will vary, the definition must be broad enough to capture all potential factual circumstances. Failure to capture all possible circumstances results in a potential loophole in coverage and difficulty in enforcement. At the same time, a regulatory definition should result ideally in one party being held responsible for the delivery of electricity exceeding the applicable threshold.

Example of Regulatory Definitions

Before developing a regulatory definition for FJD, it is helpful to consider how the the terms “owner” and “operator” were defined in the generator-based program launched recently by the participating states of the Regional Greenhouse Gas Initiative (RGGI). Under RGGI, all of the owners and operators of an electric generating unit with a nameplate capacity of 25 megawatts are subject to the requirements of the program.[1]

RGGI defines “owner” to mean

> *(1) any holder of any portion of the legal or equitable title in a CO_2 budget unit;or*
>
> *(2) any holder of a leasehold interest in a CO_2 budget unit, other than a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based, either directly or indirectly, upon the revenues or income from the CO_2 budget unit;or*
>
> *(3) any purchaser of power from a CO_2 budget unit under a life-of-the-unit contractual arrangement in which the purchaser controls the dispatch of the unit;or…*

[1] http://rggi.org/docs/model_rule_corrected_1_5_07.pdf

RGGI defines "operator" to mean:

> *Any person who operates, controls, or supervises a CO_2 budget unit or a CO_2 budget source and shall include, but not be limited to, any holding company, utility system, or plant manager of such a unit or source.*

It should be noted that the RGGI definitions are taken from the federal model cap-and-trade rule used for the NO_x SIP Call program, and now used for the federal Clean Air Interstate Rule.[2]

A few important observations can be made about these definitions developed by EPA with the Northeast states:

(1) The program initially casts a net wide enough to implicate all possible entities associated with the covered generating unit. Indeed, in many cases it is clear that a unit may have multiple owners and another operator—meaning more than one entity is on the regulatory "hook".

(2) Yet in practice there is little doubt who is responsible for compliance. The RGGI model rule, like the federal rules that came before, calls for a single entity to step up and assume responsibility for a specific unit's emissions by becoming the "authorized account representative".

(3) In essence, these existing regulatory definitions allow the private sector entities to determine which entity will carry out the responsibilities under the cap-and-trade program for a given generating unit. As long as there is an authorized account representative, the regulatory agency has no need to enforce against the other owners and/or operators.

It may also be helpful to consider the definitions under consideration by the California Air Resources Board (CARB) for its emissions reporting regulation. While emissions reporting is in this case a broader exercise than identifying the responsible party for compliance purposes, the attached excerpt from the California reporting rule may be helpful in considering appropriate terms.

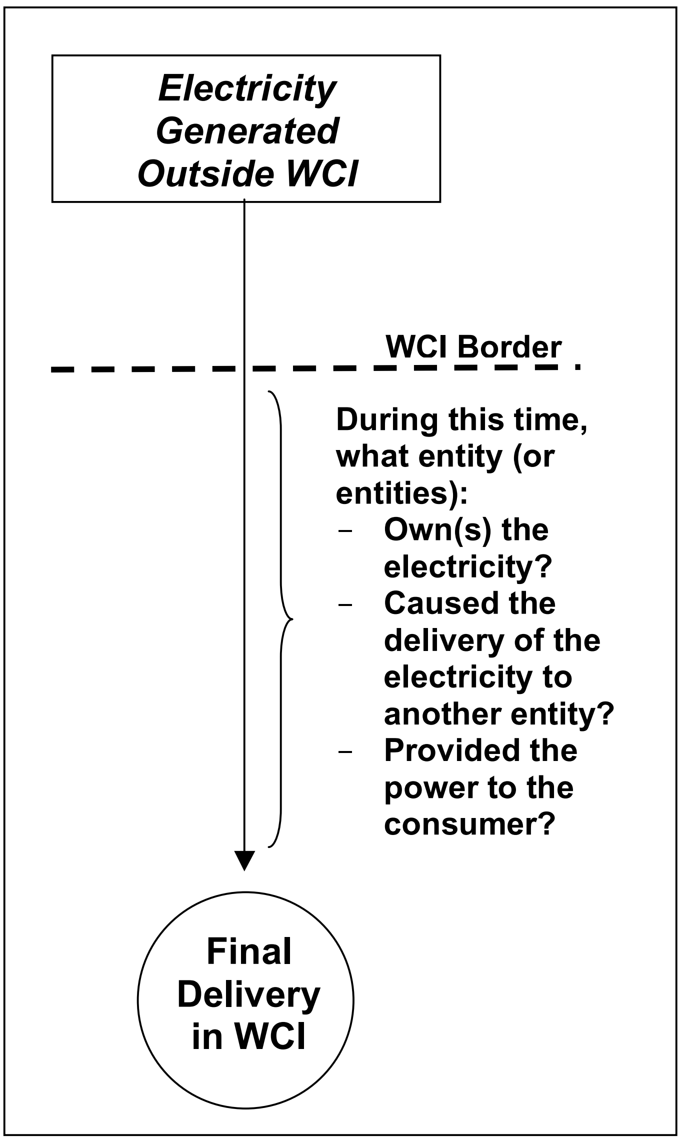
Considerations for an FJD Definition

The first jurisdictional deliverer approach will be able to borrow from the generator-based experience to define that part of the FJD universe that closely resembles the generator-based approach—the FJDs that are generators within the WCI. The

[2] See 40 CFR Part 96.

new challenge presented by the FJD approach is to develop a definition that also encompasses that part of the FJD universe that delivers electricity generated outside the WCI region. Yet, even in defining FJDs that are not generators, casting a wide definitional net while simultaneously ensuring that one entity steps up to meet the requirements of the program may prove a useful analog.

The FJD definition must take into account the entities that are responsible for delivering power generated outside the region for consumption in the region. It is helpful to consider what entities own the electricity commodity and what entities cause the resource to move to its delivery point in a WCI jurisdiction. The adjacent figure asks a number of these questions. The questions can perhaps be pared down to a version of the owner/operator definitions, i.e. the owners of the electricity delivered and the "operators" or "conveyors" in the electricity chain of custody. These conveyors may include power brokers that arrange for sales of the electricity from one owner to another, or the retail provider that ultimately delivers the electricity to the consumer.

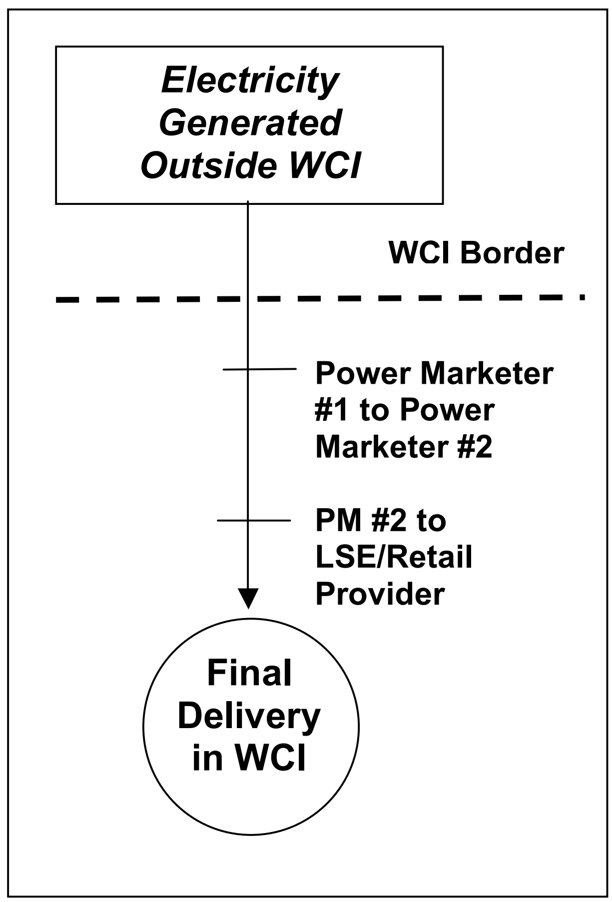


It may also be helpful to consider how these deliverers of electricity from outside WCI are different from the owner and operators of generating units inside WCI. In the case of generating units, the program regulates the emissions of actual physical assets. In contrast, regulating entities that deliver is a less tangible exercise. The potential for "gaming" to prevent these less tangible entities from being subject to a compliance obligation raises issues for defining FJD.

For example, while a generating unit cannot be divided physically in two to reduce its emissions below the applicability threshold, one must consider the potential for power transactions to be split in such a way to spread deliveries across multiple FJDs so as to remain below the applicability threshold of 25,000 metric tons per annum. The potential for dividing deliveries suggests that the definition of FJD might be broad enough to capture entities further down the chain of deliveries where those deliveries will ultimately have to be aggregated, such as the retail provider. Thus, if a retail provider accepts deliveries of electricity from numerous small FJDs that fall below the threshold, the retail provider would trigger applicability because the sum of its uncovered emissions exceeds the 25,000-metric-ton applicability threshold.

Similarly, where the entity that first delivers power into a WCI jurisdiction claims it is non-jurisdictional, such as in the case of a federal power authority, then the definition of FJD must be broad enough to capture the next entity in the chain of custody that is jurisdictional. This may mean that the regulatory definition of FJD must be broad enough to capture every entity in the delivery chain, since in some cases the first jurisdictional entity will be the retail provider.

The fact that the definition is broad enough to capture more than one entity for the same power delivery should not raise concerns, however. Just as in the case of a traditional generator-based program, where there are often numerous entities that trigger coverage under the “owner” and “operator” definitions, the broad definition is necessary to draw out one responsible party for each relevant delivery. That one entity will vary depending on the circumstances, but the private actors will ensure that one party is on the regulatory “hook” for a specific set of power deliveries.



Consider the example in the adjacent figure, depicting a chain of delivery that exceeds the 25,000 ton threshold for applicability. Here, power marketer (PM) #1 has brought the electricity into the WCI partner jurisdiction and has delivered that electricity to PM #2. If both PM #1 and PM #2 fall within the definition of FJDs, then they are both potentially liable for the emissions under the WCI cap-and-trade program. Which of them will step up to satisfy the compliance obligation?

The answer to the question may depend on a private arrangement between PM #1 and PM #2. So long as the emissions reported along this chain of delivery are "covered" with allowances by one of the two FJDs, then the regulator will not have reason to enforce. This is directly analogous to the arrangements among parties that are owners and/or operators of stationary power plants in a generator-based cap-and-trade program.

Another possible answer is that they are both liable to meet the compliance obligation. If this were the approach of the regulator, then the practical effect would be to ensure that no transactions of this type occur, because liability would proliferate as the electricity is passed along the chain of custody. PM #1 would not deliver the power to PM #2 without assuming the regulatory obligation, because that obligation attaches to PM #1 whatever PM #1 does. PM #2 might accept the power delivery, but will understand that it too has an obligation to cover the emissions attributable to the power it received from PM #1 unless PM #1 follows through with its obligation. Provided the regulator pursues an enforcement strategy that seeks to compel compliance by PM #1, the FJD will always be the first entity in the delivery chain over which the WCI partner has jurisdiction.

Now consider that PM #1 may turn out to be non-jurisdictional. In such a case, PM #1 and PM #2 may simply agree that PM # 2 will assume the obligation to comply with the cap-and-trade program. Alternatively, PM #2 may accept delivery of the electricity knowing that PM #1 has not assumed the compliance obligation attached to the delivery. Because PM #2 is also liable for those obligations, it moves to comply with the cap-and-trade program. The net effect is that PM#2 turns out to be the first entity in the delivery chain over which the WCI partner has jurisdiction, assuming PM #1 claims that it is non-jurisdictional turn out to be true.

What if I am an entity further along the chain of delivery after PM #1 and PM #2? I may be another power marketer or a broker or the retail provider and LSE. My behavior will depend on whether I will be subject to liability if I accept delivery of electricity for which the deliverer is unable to demonstrate upstream compliance. To capture large numbers of smaller transactions below the emissions threshold, the LSE or retail provider might be required to aggregate all "uncovered" power deliveries for the relevant compliance period.

<u>Possible Definitions</u>.

The following are first-cut possible definitions designed to provide for thoughtful discussion that the Subcommittee can draw from in the eventual drafting of definitions.

Owner. Any of the following persons:

(1) with respect to a [CO2 budget unit]

(a) any holder of any portion of the legal or equitable title in a CO_2 budget unit; or

(b) any holder of a leasehold interest in a CO_2 budget unit, other than a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based, either directly or indirectly, upon the revenues or income from the CO_2 budget unit; or

(c) any purchaser of power from a CO_2 budget unit under a life-of-the-unit contractual arrangement in which the purchaser controls the dispatch of the unit; or

(2) with respect to electricity generated outside of [the WCI region] and delivered for consumption within WCI any holder of any portion of the legal or equitable title in the electricity; or….

Operator. Any person who operates, controls, or supervises a [CO_2 budget unit or a CO_2 budget source] and shall include, but not be limited to, any holding company, utility system, or plant manager of such a unit or source.

Marketer. Any person who controls, brokers, or arranges for the delivery of electricity that originated outside of [the WCI region] for delivery and consumption in a [WCI partner jurisdiction].

To give effect to these definitions, the electricity component of the cap-and-trade program would have to require that:

(1) with respect to each covered electric generating unit, one authorized representative of the owners and operators of the unit will be designated, and that representative will be responsible for meeting all requirements of the program; and

(2) with respect to each electricity delivery [meeting certain conditions related to its compliance status when it enters the WCI jurisdiction], one authorized representative of the owners and marketers of the power delivered will be designated, and will be responsible for meeting all requirements of the program.

Closing Thoughts

This memorandum seeks to identify preliminary issues related to defining what entities will be first jurisdictional deliverers (FJDs) under a WCI electricity cap-and-trade program. Recognizing that no "first pass" gathers all issues or adequately addressed them, we have attempted to reduce thoughts to paper to help the WCI partner jurisdictions, and its expert stakeholders, move toward identification of additional issues and ultimately to available solutions.

REGULATION FOR THE MANDATORY REPORTING OF GREENHOUSE GAS EMISSIONS

California Air Resources Board

Key Definitions and Reporting Requirements Related to Electricity Imports and Exports

From section 95102 - Definitions

(1) “Asset controlling supplier” means any entity that operates electricity generating facilities or serves as an exclusive marketer for certain generating facilities even though it does not own them.

(2) “Asset owning supplier” means any entity owning electricity generating facilities that delivers electricity to a transmission or distribution line.

(3) “Busbar” means the power conduit of an electricity generating facility that serves as the starting point for the electricity transmission system.

(4) “California eligible renewable resource” means an electricity generating facility that the California Energy Commission has certified as an eligible renewable energy resource that may be used by a retail seller of electricity to satisfy its California Renewables Portfolio Standard Program procurement requirements, consistent with Public Utilities Code sections 399.11 through 399.16 and Public Resources Code sections 25740 through 25751.

(5) “Cogeneration facility” means an industrial structure, installation, plant, building, or self-generation facility, which may include one or more cogeneration systems configured as either a topping cycle or bottoming cycle plant.

(6) “Cogeneration system” means individual cogeneration components including the prime mover (heat engine), generator, heat recovery, and electrical interconnection, configured into an integrated system that provides sequential generation of multiple forms of useful energy (usually mechanical and thermal), at least one form of which the facility consumes on-site or makes available to other users for an end-use other than electricity generation.

(7) “Distributed emissions” means CO_2 emissions from fuel combustion at cogeneration facilities distributed between energy stream outputs including thermal energy, electricity generation and potentially other product outputs

(8) "Electricity generating facility" means generating facility.

(9) "Electricity transaction" means the purchase, sale, import, export or exchange of electric power.

(10) "Entity" means a person, firm, association, organization, partnership, business trust, corporation, limited liability company, company, or government agency.

(11) "Exchange agreement" means a commitment between electricity market participants to swap energy for energy. Exchange transactions do not involve transfers of payment or receipts of money for the full market value of the energy being exchanged, but may include payment for net differences due to market price differences between the two parts of the transaction or to settle minor imbalances.

(12) "Facility" means any property, plant, building, structure, stationary source, stationary equipment or grouping of stationary equipment or stationary sources located on one or more contiguous or adjacent properties, in actual physical contact or separated solely by a public roadway or other public right-of way, and under common operational control, that emits or may emit any greenhouse gas. Operators of military installations may classify such installations as more than a single facility based on distinct and independent functional groupings within contiguous military properties.

(13) "Final point of delivery" means the last point of delivery for a given electricity transaction.

(14) "Generating facility" means a facility that generates electricity and includes one or more generating units at the same location.

(15) "Generating unit" means any combination of physically connected generator(s), reactor(s), boiler(s), combustion turbine(s), or other prime mover(s) operated together to produce electric power.

(16) "Gross generation" means the total electrical output of the generating unit, expressed in megawatt hours (MWh) per year.

(17) "Kilowatt hour" or "kWh" means the electrical energy unit of measure equal to one thousand watts of power supplied to, or taken from, an electric circuit steadily for one hour. (A watt is a unit of electrical power equal to one ampere under pressure of one volt, or 1/746 horsepower).

(18) “Long-term power contract” means a power contract with a term of five years or more.

(19) “Marketer” means a purchasing/selling entity that is not a retail provider, and that is the purchaser/seller at the first point of delivery in California for electric power imported into California, or the last point of receipt in California for power exported from California.

(20) “Multi-jurisdictional retail provider” means a retail provider that provides electricity to end users in California and in one or more other states.

(21) “Nameplate generating capacity” means the maximum rated output of a generator under specific conditions designated by the manufacturer, expressed in megawatts (MW) or kilowatts (kW).

(22) “Net power generated” means the gross generation minus station service or unit service power requirements, expressed in megawatt hours (MWh) per year. In the case of cogeneration, this value is intended to include internal consumption of electricity for the purposes of a production process, as well as power put on the grid.

(23) “NERC E-tag” means North American Electric Reliability Corporation (NERC) energy tag representing transactions on the North American bulk electricity market scheduled to flow between or across control areas.

(24) “Null power” means any electricity produced by a renewable energy electricity generating facility from which a Western Renewable Energy Generation Information System (WREGIS) or a Nevada Tracks Renewable Energy Credits (NVTREC) certificate has been unbundled and sold separately.

(25) “NVTREC” means Nevada Tracks Renewable Energy Credits.

(26) “Operational control” for a facility subject to this article means the authority to introduce and implement operating, environmental, health and safety policies. In any circumstance where this authority is shared among multiple entities, the entity holding the permit to operate from the local air pollution control district or air quality management district is considered to have operational control for purposes of this article.

(27) "Operator" means the entity having operational control of a facility, or other entity, from which an emissions data report is required under this article. For purposes of reporting electricity transactions as required in

section 95111, “operator” means a retail provider, marketer, or facility operator.

(28) “Pacific Northwest” or “PNW” means Washington, Oregon, Idaho, Montana, and British Columbia.

(29) “Point of delivery” means a point on an electric system where a power supplier delivers electricity to the receiver of that energy. This point can be an interconnection with another system or a substation where the transmission provider’s transmission and distribution systems are connected to another system.

(30) “Point of receipt” means a point on an electric system where an entity receives electricity from a supplier. This point can be an interconnection with another system or a generator busbar.

(31) “Point source” means any separately identifiable stationary point from which greenhouse gases are emitted.

(32) “Power” means electricity, except where the context makes clear that another meaning is intended.

(33) “Power contract” means an arrangement for the purchase of electricity. Power contracts may be, but are not limited to, power purchase agreements and tariff provisions.

(34) “Prime mover” means the type of equipment such as an engine or water wheel that drives an electric generator. “Prime movers” include, but are not limited to, reciprocating engines, combustion or gas turbines, steam turbines, microturbines, and fuel cells.

(35) “Purchasing/selling entity” means an entity that is eligible to purchase or sell energy or capacity and reserve transmission services.

(36) “Qualifying facility” means a cogeneration or small power production facility that meets ownership, operating, and efficiency criteria established by the Federal Energy Regulatory Commission (FERC) pursuant to the Public Utility Regulatory Policies Act.

(37) “Renewable energy” means energy from sources that constantly renew themselves or that are regarded as practically inexhaustible. Renewable energy includes, but is not limited to, energy derived from solar, wind, geothermal, hydroelectric, wood, biomass, tidal power, sea currents, and ocean thermal gradients

(38) "Retail provider" means an entity that provides electricity to retail end users in California and is an electric corporation as defined in Public Utilities Code section 218, electric service provider as defined in Public Utilities Code section 218.3, public owned electric utility as defined in Public Resources Code section 9604, community choice aggregator as defined in Public Utilities Code section 331.1, or the Western Area Power Administration.

(39) "Self-generation facility" means a facility dedicated to serving a particular end user, usually located on the user's premises. The facility may either be owned directly by the end user or owned by an entity with a contractual arrangement to provide electricity to meet some or all of the user's load.

(40) "Source" means greenhouse gas source, as defined in this section.

(41) "Southwest" or "SW" means Arizona, Nevada, Utah, Colorado, and western New Mexico.

(42) "Specified source of power" or "specified source" means a particular generating unit or facility for which electrical generation can be confidently tracked due to full or partial ownership or due to its identification in a power contract including any California eligible renewable resource.

(43) "Supplemental firing" means an energy input to the cogeneration facility used only in the thermal process of a topping cycle plant, or in the electricity generating or manufacturing process of a bottoming cycle plant.

(44) "Thermal host" means the user of the steam or heat output of a cogeneration facility.

(45) "Topping cycle plant" means a cogeneration facility in which the energy input to the facility is first used to produce useful power output, and at least some of the reject heat from the power production process is then used to provide useful thermal output.

(46) "Unspecified source of power" or "unspecified source" means electricity generation that cannot be matched to a particular generating facility. Unspecified sources of power may include power purchased from entities that own fleets of generating facilities such as independent power producers, retail providers, and federal power agencies and power purchased from electricity marketers, brokers, and market

(47) “Useful power output” means the electric or mechanical energy made available for use, exclusive of any such energy used in the power production process.

(48) “Useful thermal output” means the thermal energy made available in a cogeneration system for use in any industrial or commercial process, heating or cooling application, or delivered to other end users, i.e., total thermal energy made available for processes and applications other than electrical generation.

(49) “Waste-derived fuel” means a fuel typically derived from waste(s) and generally used as a substitute for conventional fossil fuels. Waste-derived fuels can include fossil fuels such as waste oil, plastics, or solvents; biomass such as dried sewage or impregnated saw dust; or fractions of both fossil fuels and biomass such as municipal solid waste or tires.

(50) “WREGIS” means Western Renewable Energy Generation Information System.

From section 95111
Data Requirements and Calculation Methods for Electricity Generating Facilities, Retail Providers and Marketers.

(a) ***Electricity Generating Facilities.*** The operator of an electricity generating facility specified in section 95101(b) shall include the following information in the greenhouse gas emissions data report for each report year and shall meet the requirements specified in sections 95111(c)-(i) as applicable to the facility when calculating emissions for inclusion in the report.

(1) For each facility, operators shall include:

(A) ARB designated facility identification number (ID), nameplate generating capacity in megawatts (MW), and net power generated in the report year in megawatt hours (MWh);

(B) Fuel consumption by fuel type, reporting in units of million standard cubic feet for gases, gallons for liquids, short tons for non-biomass solids, and bone dry short tons for biomass-derived solid fuels;

(C) Average high heat value by fuel type, reporting in units of MMBtu per unit of fuel as specified in section 95111(a)(1)(B), if measured, based on values measured by the operator or the fuel supplier as specified in section 95125(c)(1)(A)-(C). If high heat value is not measured by the operator or available from the fuel supplier, then the operator shall report steam produced in MMBtu. The operator may elect to convert pounds of steam into MMBtu using the method provided in section 95125(h)(1)(B). The operator shall include boiler efficiency, if known;

(D) Average carbon content, as a percent, by fuel type, if measured, based on values measured by the operator or the fuel supplier as specified in section 95125(d);

(E) CO_2, N_2O, and CH_4 emissions from stationary combustion in metric tonnes as specified in section 95111(c)-(d) by fuel type;

(F) Process CO_2 emissions from acid gas scrubbers or acid gas reagent used in the combustion source, if applicable, in metric tonnes;

(G) Fugitive CH_4 emissions from coal storage from coal-fired facilities, if applicable, in metric tonnes;

(H) Fugitive emissions of HFC related to the operation of cooling units that support power generation, if applicable, in kilogram

(I) Fugitive CO_2 emissions from geothermal facilities, if applicable, in metric tonnes;

(J) Fugitive SF_6, in kilograms, emitted from equipment that is located at the facility and that the operator is responsible for maintaining in proper working order. Operators of multiple facilities or operators subject to the requirements in section 95111(b)(2)(A) may aggregate SF_6 emissions for all sources or any subset of sources;

(K) For facilities located inside California, wholesale sales (MWh) exported directly out-of-state, if known, that are additional to electricity transactions reported as specified in section 95111(b)(2)(E). Sales shall be aggregated by counterparty and measured at the busbar. The operator shall report the region of destination as Pacific Northwest (PNW) or Southwest (SW).

(2) For each generating unit operators shall include:

(A) Generating unit ID designated by ARB, nameplate generating capacity (MW), and net power generated (MWh);

(B) Fuel consumption by fuel type reporting in units of million standard cubic feet for gases, gallons for liquids, short tons for non-biomass solids, and bone dry short tons for biomass-derived solid fuels;

(C) CO_2, N_2O, and CH_4 emissions from fuel combustion in metric tonnes as specified in section 95111(c)-(d) by fuel type;

(D) For units of facilities located inside California, wholesale sales (MWh) exported directly out-of-state by generating unit if applicable and as specified in section 95111(a)(1)(K).

(3) ***Aggregation of Multiple Units.*** If a facility lacks the necessary metering or monitoring equipment to measure data individually for each generating unit, the operator may report data on an aggregated basis for multiple units that combust the same fuel type.

(4) ***Cogeneration Facilities.*** Operators of generating facilities with cogeneration systems subject to the requirements of this article shall also meet the requirements of section 95112.

(5) ***Out-of-State Facilities.*** Operators of out-of-state generating facilities that are not subject to any of the mandatory reporting requirements of this article may voluntarily submit a greenhouse gas emissions data

report that meets applicable requirements in this article for generating facilities.

(6) ***Asset Owning/Asset Controlling Suppliers*.** An asset owning or asset controlling supplier may voluntarily request that ARB assign a supplier-specific ID to the supplier's fleet of generating facilities if the supplier's sales of renewable energy account for 50 percent or more of their total sales of electric energy for the report year or if power purchased by the supplier from unspecified sources does not exceed 20 percent of the supplier's total sales of electric energy for the report year. An asset owning or asset controlling supplier that chooses this option shall:

(A) Meet the requirements in this article as applicable for each generating facility in the supplier's fleet;

(B) Include in its greenhouse gas emissions data report the list of the generating facilities in its fleet along with the ARB designated facility ID;

(C) If wholesale power purchased by the supplier accounts for more than 10 percent of total electric energy sold by the supplier for the report year, the supplier shall include in its greenhouse gas emissions data report wholesale power purchased (MWh) from specified and unspecified sources and wholesale power sold from specified sources according to the specifications in section 95111(b)(1)(A)-(B);

(D) Retain for verification purposes documentation that the power sold by the supplier originated from the supplier's fleet of facilities and either that the fleet is under the supplier's operation control or that the supplier serves as the fleet's exclusive marketer;

(E) Provide the supplier-specific ID to retail providers who purchase unspecified power from the supplier's fleet.

(b) ***Retail Providers and Marketers*.**

(1) ***General Requirements for Retail Providers and Marketers*.** Retail providers and marketers shall meet the following general requirements in preparing their greenhouse gas emissions data report for each report year. Retail providers and marketers shall include electricity transactions associated with both renewable and nonrenewable energy sources of power.

(A) When reporting electricity transactions, retail providers and marketers shall:

1. Specify the amount of electricity in MWh;
2. For electricity from specified sources, specify the amount of electricity as measured at the busbar;
3. For electricity from unspecified sources, specify the amount of electricity as measured at the first point of receipt for which the reporting entity has information;
4. For electricity from specified sources, specify the facility name, the ARB designated facility ID, and the generating unit ID for the unit generating the power, if applicable;
5. Specify region of origin and region of destination;
6. Retail providers shall aggregate and specify electricity transactions by counterparty;
7. Marketers shall aggregate and specify electricity transactions by power supplier;
8. Specify the amount of electricity (MWh) that is null power when applicable;
9. Specify electricity received under exchange agreements as purchases and electricity delivered under exchange agreements as wholesale sales.

(B) If the region of origin for an electricity transaction cannot be documented, the retail provider or marketer shall designate the region as unknown.

(C) ***Power Wheeled Through California.*** When reporting power transactions involving imports into California or exports out of California, the retail provider or marketer shall exclude the amount of power imported into California that terminates in a location outside of California, as measured at the first California point of delivery.

(D) ***California Department of Water Resources (DWR).*** The California Department of Water Resources shall include all applicable information identified in this article for retail providers, including the amount of power used by DWR itself.

(E) ***Multi-jurisdictional Retail Providers.*** Multi-jurisdictional retail providers shall include information required for retail providers in this article for the service territory that includes California end-use customers.

(F) ***Western Area Power Administration (WAPA).*** The Western Area Power Administration shall include information required of retail providers in this article relating to serving end use California customers and reporting fugitive SF_6 emissions. In particular, WAPA shall include electricity transactions related to sources of electricity located in California that are used to serve WAPA's end-use California customers, power imported to California to serve WAPA's end-use customers including transactions from facilities owned by the Bureau of Reclamation on the Lower Colorado River, and power exported from California.

(2) ***Greenhouse Gas Emissions Data Report: Retail Providers and Marketers.*** Retail providers and marketers shall include the following information in the greenhouse gas emissions data report for each report year. Multi-jurisdictional retail providers shall include the information in sections 95111(b)(2)(A) and 95111(b)(2)(G)-(H) but are exempt from sections 95111(b)(2)(B)-(F).

(A) Fugitive emissions of SF_6 (kg) related to transmission and distribution systems, substations, and circuit breakers located inside California that the retail provider or marketer is responsible to maintain in proper working order. SF_6 emissions shall be calculated using the methodology specified in section 95111(f).

(B) Wholesale power imported (MWh) from specified sources with final point of delivery in California and for which the retail provider or marketer was the deliverer to the first point of delivery in California, designating the region of origin as PNW or SW.

(C) Wholesale power imported (MWh) from unspecified sources with final point of delivery in California and for which the retail provider or marketer was the deliverer to the first point of delivery in California. The retail provider or marketer shall designate the region of origin as PNW, SW, or unknown and shall retain for verification purposes NERC E-tags, settlements data, or other information as confirmation of the region of origin.

(D) Retail providers shall include wholesale power imported from specified and unspecified sources with final point of delivery in California for which the retail provider is not the deliverer to the first point of delivery in California, designating the region of origin. Transactions reported under this section 95111(b)(2)(D) shall not be duplicated under section 95111(b)(3)(F).

(E) Wholesale power exported (MWh) from specified sources located inside California, and designating the region of destination (PNW, SW, or unknown).

(F) Wholesale power exported (MWh) from unspecified sources located inside California, and designating the region of destination (PNW, SW, or unknown).

(G) ***Electricity Transactions Wheeled Through California***. Wholesale power imported (MWh) into California that terminates in a location outside of California, as measured at the first California point of delivery. The retail provider or marketer shall specify these transactions separately by the counterparty supplying power and specify the region of origin (PNW or SW). The retail provider or marketer shall retain for purposes of verification NERC E-tags, settlements data, or other information to confirm the transactions.

(H) Retail providers shall include in their greenhouse gas emissions data report for each report year the additional information listed in section 95111(b)(3).

Developing a Definition for FJD

Franz Litz
Senior Fellow
Franz@wri.org

WORLD RESOURCES INSTITUTE

Nicholas Bianco
Associate
nbianco@wri.org

PROVISO

The thinking contained in this presentation and the accompanying 8-page memo represents that of its authors, and not the WCI Partners or the WCI Electricity Subcommittee. The exercise is designed to provoke thought and discussion among the Subcommittee and the expert Technical Advisory Group (TAG).

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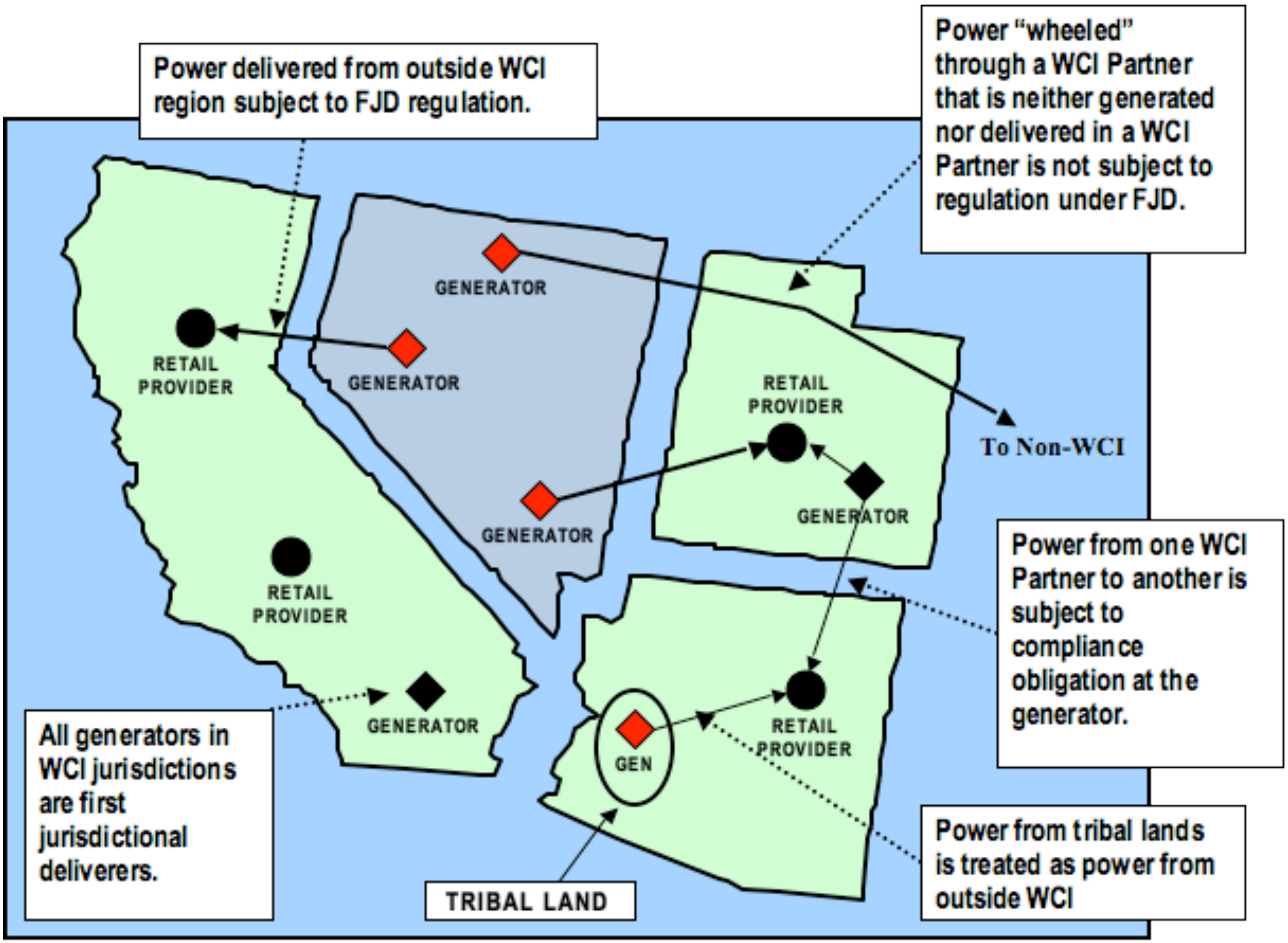
WCI Design Recommendations

2.2 Electricity: First Jurisdictional Deliverer: For sources within WCI jurisdictions the point of regulation will be at the generator. For power imported into WCI jurisdictions, the point of regulation will be at the first entity that delivers electricity that is generated outside the WCI jurisdictions (or generated by a federal entity or on tribal lands) for consumption within a WCI Partner jurisdiction and over which the WCI partner jurisdiction has regulatory authority.


Power delivered from outside WCI region subject to FJD regulation.
Power "wheeled" through a WCI Partner that is neither generated nor delivered in a WCI Partner is not subject to regulation under FJD.
GENERATOR
RETAIL PROVIDER
GENERATOR
RETAIL PROVIDER
To Non-WCI
GENERATOR
GENERATOR
RETAIL PROVIDER
Power from one WCI Partner to another is subject to compliance obligation at the generator.
GENERATOR
All generators in WCI jurisdictions are first jurisdictional deliverers.
GEN
RETAIL PROVIDER
TRIBAL LAND
Power from tribal lands is treated as power from outside WCI

Purpose of Regulatory Definition

- What entities will subject to a compliance obligation?
- Must “work” across differing factual circumstances
- If the definition (together with other applicability provisions) unintentionally misses a deliverer, then a “loophole” is present
- Ideally the provisions result in one entity as responsible for emissions even where more than one entity may be a “deliverer”

Example: RGGI

- "Owners" and "operators" of each covered electric generating unit must comply
- These terms are defined very broadly to capture all owners and all operators
- It is clear that as to many units, there are many owners and operators
- Yet only one of these entities has to step up to assume responsibility for compliance reports and other obligations
- In practice, many entities becomes one entity for compliance purposes

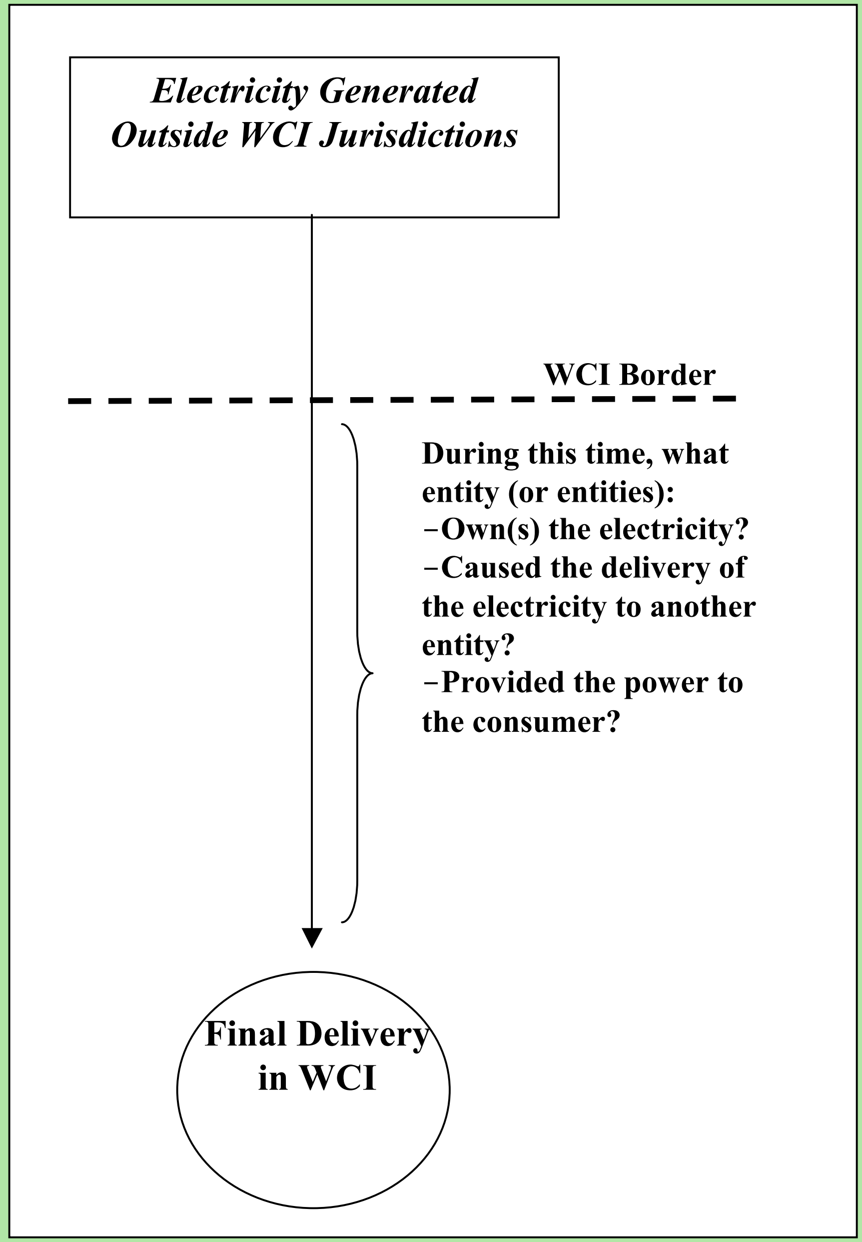
FJD Universe

First Jurisdictional Deliverers

Deliverers from Generating Units Inside WCI Partner Jurisdictions

Deliverers of Power (in the region) Originating Outside the Region

Focusing on those Deliverers that are Not Generators inside WCI



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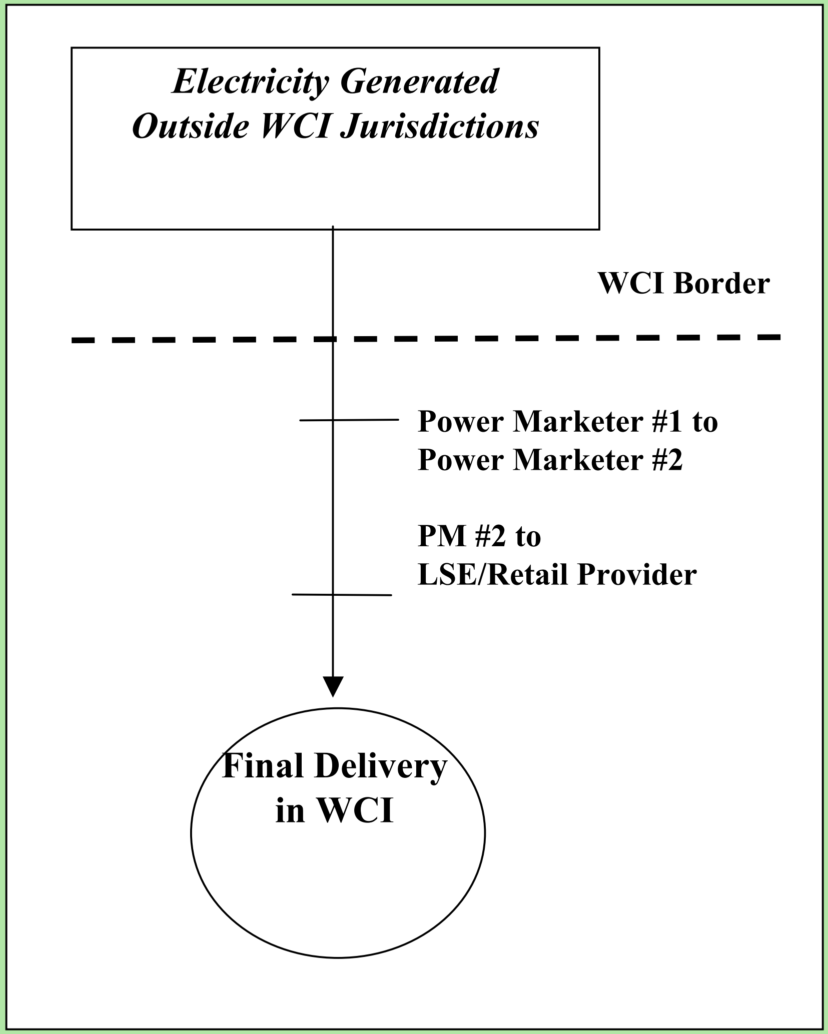
Quick Observations

- FJD seeks to capture emissions attributable to deliveries within the WCI partner jurisdiction
- Need to consider the intangible nature of the power deliveries, as contrasted with the tangible generating units making up the other part of the FJD Universe
  - For example, while an EGU cannot be physically divided to put each part below the applicability threshold (25,000 metric tons), transactions across FJDs could perhaps more easily be divided
- Need to consider that the FJD may in some cases the 2nd entity to deliver the power in the WCI partner jurisdiction, because no jurisdiction over the first entity

Example


Electricity Generated Outside WCI Jurisdictions
WCI Border
Power Marketer #1 to Power Marketer #2
PM #2 to LSE/Retail Provider
Final Delivery in WCI

Possible Definitions?

- *Owner*.

  (2) with respect to electricity generated outside of [the WCI region] and delivered for consumption within WCI <u>any holder of any portion of the legal or equitable title in the electricity</u>; or..

- *Marketer*. Any person who controls, brokers, or arranges for the delivery of electricity that originated outside of [the WCI region] for delivery and consumption in a [WCI partner jurisdiction].

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Comments?

Franz Litz
Senior Fellow
Franz@wri.org

WORLD RESOURCES INSTITUTE

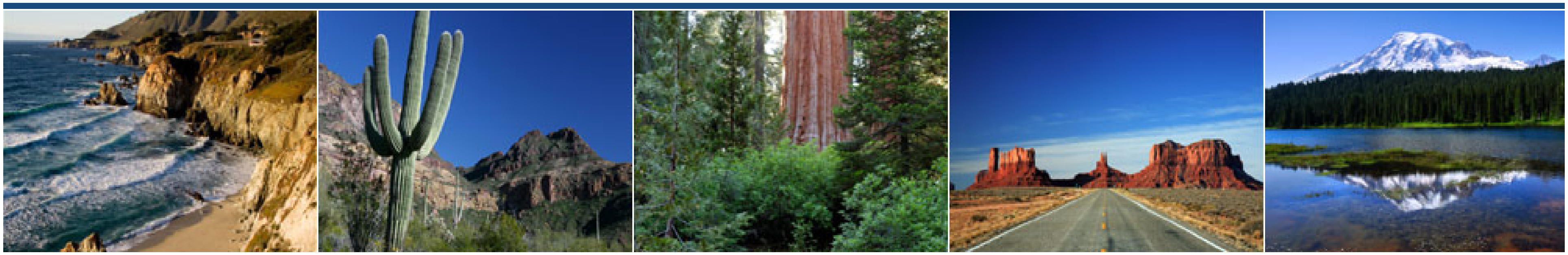
Nicholas Bianco
Associate
nbianco@wri.org

WCI Electricity Technical Advisory Group

for the TAG Meeting October 16, 2008

1. Brad Albert, Arizona Public Service (Arizona)
2. Rob Campbell, PowerEx (British Columbia)
3. Eric Little, Southern California Edison (California)
4. Bill Hamlin, Manitoba Hydro (Manitoba)
5. Brent Rice, PNM (New Mexico)
6. Lisa DeMarco, Association of Power Producers of Ontario (Ontario)
7. Bill Casey, Portland General Electric (Oregon)
8. Hugo Levert, Hydro-Québec Production (Quebec)
9. Kyle Davis, Pacificorp (Utah)
10. Kevin Nordt, Grant County Public Utility District (Washington)
11. Ken Dragoon, Renewable Northwest Project
12. Danielle Osborn Mills, Center for Energy Efficiency and Renewable Technologies (CEERT)
13. Jim Sinclair, President, BC Federation of Labour
14. Clare Breidenich, Western Power Trading Forum
15. Udi Helman, Cal ISO
16. Barry Greene, Independent Electricity System Operator
17. Steven Kelly, Independent Electricity Producers
18. Jason Eisdorfer, Bonneville Power Authority
19. Ron Moulton, WAPA

Western Climate Initiative



Update on Economic Modeling

Economic Modeling Team

November 7, 2008
Webinar

Outline of Presentation

- Introduction of new co-chairs
- Overview of next steps in modeling and stakeholder input
- Overview of results released in September
- Input on topics for December 3 workshop
- Additional comments and questions

Co-chairs of Economic Modeling Team

- Jessica Youle, Arizona
  - jessicay@azcommerce.com
- Jessica Verhagen, British Columbia
  - Jessica.Verhagen@gov.bc.ca

Next Steps / Stakeholder Input

- WCI is expanding the model to include Manitoba, Ontario, and Quebec.
  - Repeat analyses released in September to include all partners
  - Conduct additional sensitivity analyses

- WCI will hold a workshop on the ENERGY 2020 model and initial results
  - Location: San Francisco. Date/Time: December 3, 10am-4pm **http://www.westernclimateinitiative.org/WCI_Meetings_Events.cfm**
  - Workshop responds to stakeholder requests for in-depth briefing and Q&A
  - We encourage organizations to include technical or modeling staff as attendees
  - **Please register at this link (whether in-person or via webinar):** www.regonline.com/wci-emt12-3-08.

Overview of September Modeling Results

- Reference Case:
  - Economic growth is 3%
  - Growth in GHG emissions is 0.5%/yr
  - Energy consumption is 0.4%/yr
- Treatment of power sector and First Jurisdictional Deliverer (FJD)
- Role of complementary policies
- Cap-and-trade scenarios and impacts:
  - Narrow vs. broad scope
  - Offsets
  - Banking
  - Sensitivity analysis

Note: error in Table B-10 will be corrected.

Treatment of Power Sector and FJD

- Cap-and-trade scenarios place cap on power sector throughout the WECC.
- Attributed 70 Mt to power imports into WCI partner territory in the Reference Case.
- Put a maximum of 45 Mt on GHG reductions that could be attributed to power imports under a cap-and-trade scenario.
- Two scenarios hit this maximum. One scenario reached ~80% of maximum.
- Electricity Subcommittee continues work with stakeholders on FJD definition and methodology, and other topics .

Complementary Policies

- Energy efficiency programs aimed at reducing annual rate of demand growth by 1%
  - Projected GHG reductions: 74 Mt in 2020
- Clean Car Standards (equivalent to California's Pavley I and II)
  - Projected GHG reductions: 30Mt in 2020
- Programs aimed at reducing passenger Vehicle Miles Traveled by 2% from 2020 Reference Case level
  - Projected GHG reductions: additional 4 Mt in 2020
- Together, they are projected to achieve a 108 Mt reduction in 2020
  - About one-half of the projected reductions needed to reach the 15% reduction goal

Cap-and-Trade Scenarios – MMTCO2E

GHG Emissions in 2020 *(MMTCO2E)*	**Reference Case**	**Cap-and-Trade**		
		Broad w/out Offsets	**Broad with Offsets**	**Narrow with Offsets**
WCI Partners	**992.8**	**859.2**	**877.9**	**847.8**
Non-WCI Power Sector	70.0	70.0	70.0	70.0
Non-WCI Power Sector Reductions		-45.0	-37.0	-45.0
Offsets		0.0	-31.8	-18.2
Bank Flow		-31.1	-31.8	-0.2
Compliance Total		**853.1**	**847.2**	**854.3**
Percent of 2006 Emissions		85.2%	84.6%	85.3%
Bank Inventory		72.6	74.4	0.5

Projections from Table B-12 of September report. All cap-and-trade scenarios assume complementary policies. 85% target is calculated off of a base of (WCI Partners + Non-WCI Power Sector) = 992.8+70.0 = 1062.8 MMTCO2E.

Cap-and-Trade and Sensitivity Scenarios

Case	GHG Emission (MMTCO2E)	Offsets Used (MMTCO2E)	Allowance Price (2007 $)	Change in Fuel Expenditures ($M/Yr)	Potential Allowance Value ($M/Yr)	Total Costs (Savings) ($M/Yr)
Reference Case	992.8	--	--	--	--	--
Cap-and-Trade Policy Cases						
Broad Scope, No Offsets	859.2	--	$63	(32,296)	39,516	(23,525)
Broad Scope, With Offsets	877.9	31.8	$24	(31,012)	15,150	(22,080)
Narrow Scope, With Offsets	847.8	18.2	$71	(22,794)	16,092	(11,422)
Sensitivity Cases						
High Price	833.3	12.7	$18	(42,736)	10,521	(30,514)
Low Price	857.0	34.1	$56	(22,598)	35,642	(16,245)
High Natural Gas Price	865.4	26.6	$20	(6,525)	12,434	7,880

Fuel Expenditures and Total Costs (Savings) are changes from Reference Case values.

Potential Allowance Value calculated as emissions times allowance price.

Total Costs (Savings) do not include costs of VMT Reduction programs, Energy Efficiency programs, nor Potential Allowance Value.

December 3 Workshop - Context

- Workshop will go 10am-4pm, and participants can attend in-person or via webinar.
- Format: sessions focused on topics of interest to stakeholders.
- Previous webinars and public comments have indicated ongoing interest in structure of model, input assumptions, outputs, and sensitivity analysis.
- Public comments to date are available at:
  - http://www.westernclimateinitiative.org/Draft_Proposals_Comments.cfm

Input on Topics for December 3 Workshop

- *Stakeholder input requested -*
  - *Hit *1 on your phone to make a comment.*

Comments and Questions

Straw Proposal on Reporting GHG Emissions Associated with Electricity Imports

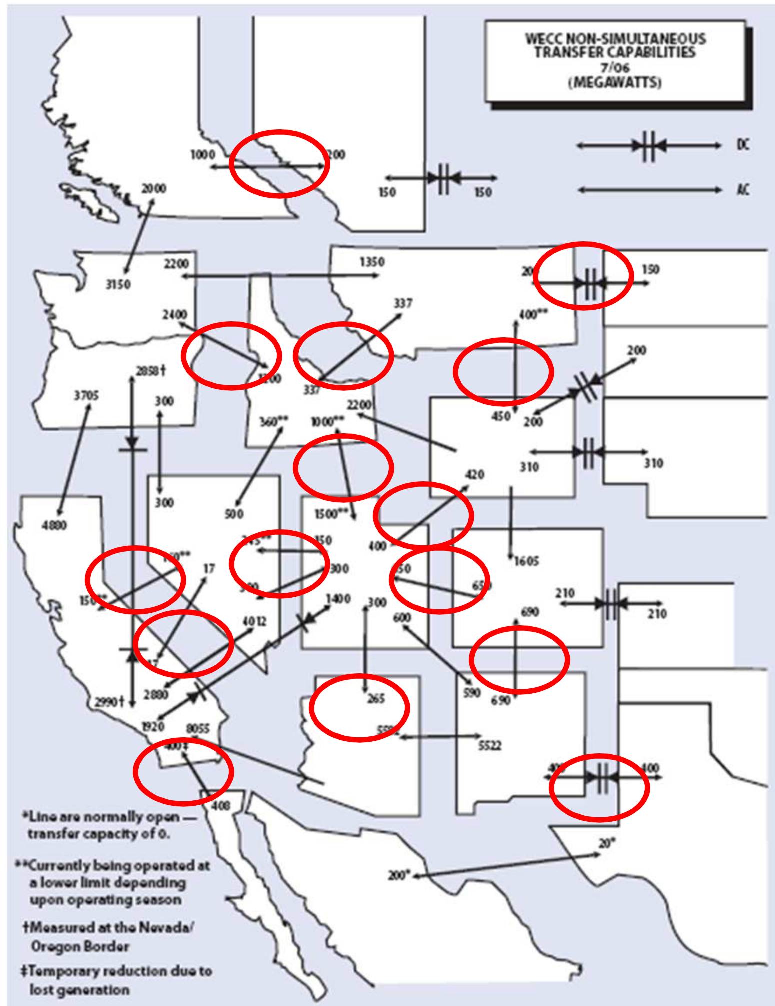
Scott Murtishaw, California PUC

Presented November 13, 2008
WCI Electricity Subcommittee Working Session
Santa Fe, New Mexico

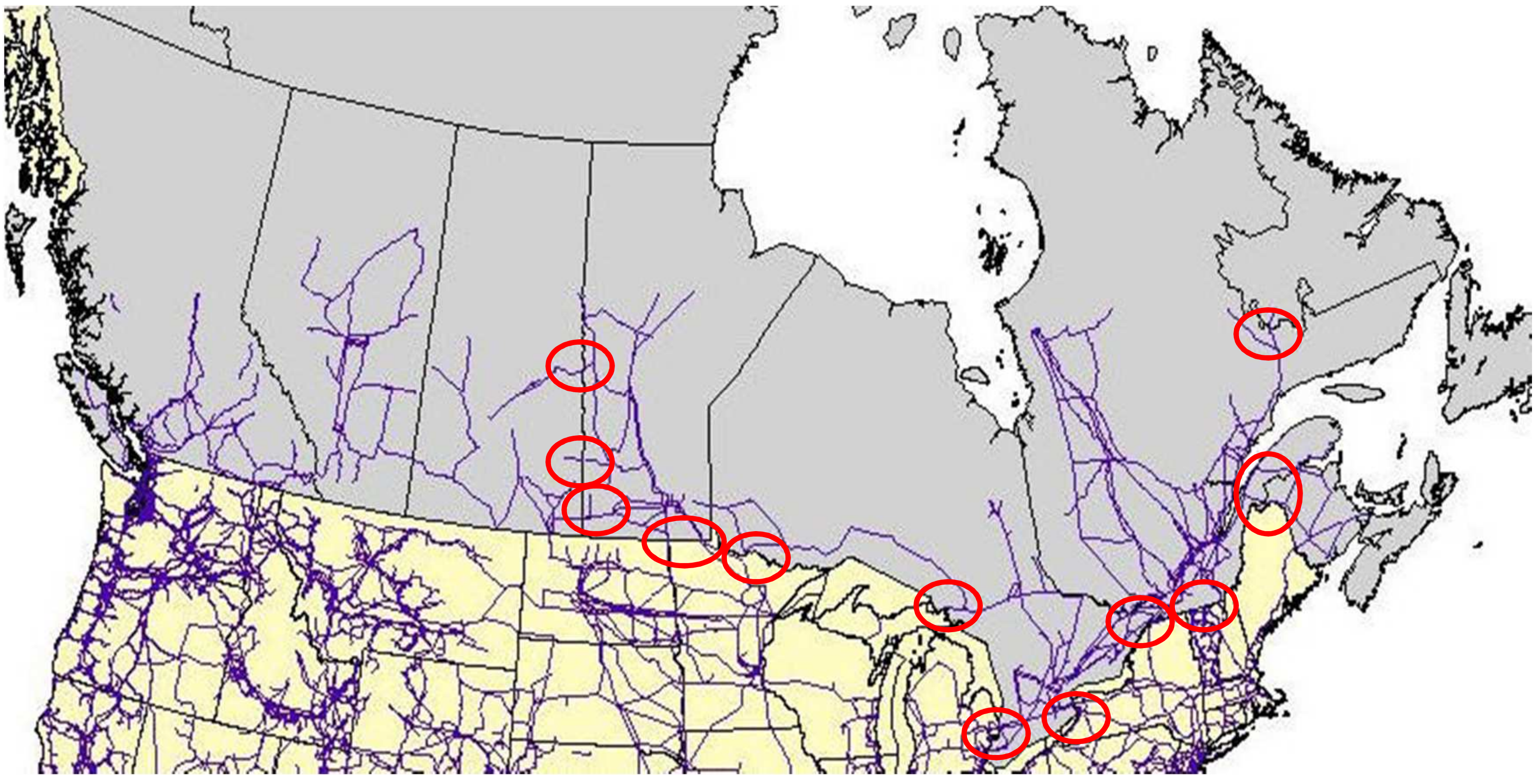
Overview of Presentation

- Identifying the Import Paths
- Reporting the Quantity of Electricity Imported
- Attributing Emissions to Specified Imports
- Unspecified Imports and Default Factors

Identifying the Regulated Western Transmission Paths



Identifying the Regulated Eastern Transmission Paths



Reporting the Quantity of Imported Electricity

- Reporting entity reports the quantities of all electricity imported on the regulated paths
- For paths crossing balancing authority areas (BAAs), e-tags are starting point for establishing reported quantity
- Transactions demonstrated to be wheel-throughs do not trigger a compliance obligation
- For inter-BAA transactions, wheel-throughs identified by last Point of Delivery in the transaction

Electricity Reporting Discussion Questions

- What data and documentation would be used for intra-BAA paths?
- When scheduled transactions are curtailed, what documentation would correct e-tag data?
- How would wheel-throughs be documented when initial import is intra-BAA?
- Should all or some paths that connect to RGGI states be exempt?

Attributing Emissions to Specified Imports

- Reporting entities identify the portion of imports on each path generated by specified facilities
- Emission rate for attribution calculated using verified emission data
- WCI retail providers with ownership shares/PPAs in non-WCI coal plants document the difference between entitlement share and reported imports
- RECs not used for GHG reporting

Conditions on Specified Imports of Low Cost Zero GHG Power

- Conditions placed on zero GHG attribution to imports from specified nuclear or large hydro facilities
  - Ownership Shares
  - PPAs executed prior to January 1, 2008 and still in effect
  - Limited "spill or sell" sales during high hydro season

Specified Import Discussion Questions

- Should a minimum contract duration be required to receive attribution for specified facilities?
- Should RECs have some role in substantiating reported imports of renewable electricity?
- In order to prevent double counting, how should specified claims on non-WCI facilities by non-WCI retail providers be tracked?

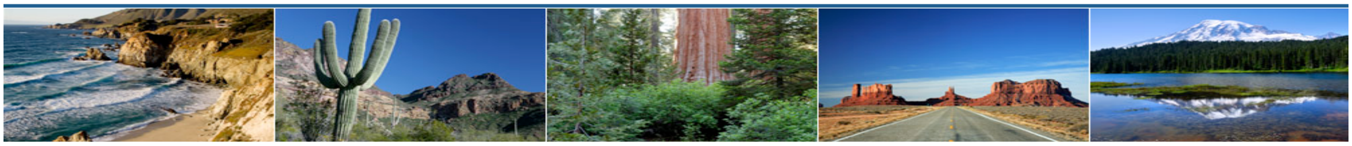
Unspecified Imports and Default Emission Factors

- Default (or "deemed") emission factors used to attribute emissions to remaining imports
- Default factors derived using marginal emission factor method
- Starting proposition
  - Five geographic zones: Alberta, western U.S., Baja, central U.S./Canada, Northeastern U.S.
  - For each zone, only one factor per reporting period (i.e., no TOU or seasonal factors)

Default Factor Discussion Questions

- Are more zones needed? (e.g., Navajo Nation, TX, NB, subsets of the five proposed regions)
- Are seasonal/TOU factors needed to accurately reflect marginal resources from certain zones?
- How far in advance should the WCI Partners publish the default factors?

Western Climate Initiative



ELECTRICITY SUBCOMMITTEE
TECHNICAL WORKING SESSION

SANTE FE, NEW MEXICO
NOVEMBER 13, 2008
9:00 a.m. to 5:00 p.m. Mountain

<u>Location</u>:
Hilton Santa Fe Historic Plaza
(http://www.hiltonofsantafe.com)
100 Sandoval Street
Santa Fe, NM 87501

<u>AGENDA</u>

1.	**9:00 am**	**Welcome and Introductions** **David Van't Hof, Chair, WCI Electricity Subcommittee**
2.	**9:15**	**Review of the Process and Agenda**
3.	**9:30**	**Presentation on Possible Circumstances** **Triggering Reporting Obligations** **Scott Murtishaw, CA PUC**
4.	**10:00**	**Comments and Discussion**
5.	**11:00**	**Presentation on Reporting Emissions** **for Specified Power Deliveries** **Scott Murtishaw, CA PUC**
6.	**11:30**	**Comments and Discussion**
7.	**12:30**	**Lunch (On Your Own)**
8.	**1:30**	**Presentation for Reporting** **Emissions for Unspecified Power and Default Rates** **Scott Murtishaw, CA PUC**
9.	**2:00**	**Comments and Discussion**
10.	**4:30**	**Public Comment Session**
11.	**5:00**	**Adjourn**

<u>An Approach to Implementing FJD in WCI</u>

- Implementing FJD via explicit tracking of all transactions is viewed as unworkable. An approach is proposed that focuses only tracking transactions within the WCI footprint at the generator and imports across a predefined set of transmission paths is proposed.

- The approach is designed to provide a high degree of certainty in reducing leakage and at the same time providing each market participant with certainty at the moment of transaction. The proposal would eliminate the potential for after the point of transaction carbon liability. Moreover there would be no cascading liability under the proposed structure.

- The basic idea is that for any party generating electricity within the WCI footprint the point of regulation is the generator smokestack. The generating party would bear the responsibility to comply with the WCI carbon mitigation requirements. Mitigation would be based upon plant specific emission rates.

- For power imported into the WCI footprint the carbon mitigation compliance obligation would lie with the party holding title to the energy as it is wheeled over a set of well defined and pre-specified transfer paths (as new paths are built they could be added but there would be no reach back if a path had inadvertently been left out of the tablation). Therefore, the energy is "clean" when it reaches the first POD in the WCI footprint. For discussion purposes, we will refer to the in-WCI trading points as "clean hubs" and the key import paths as "hot paths".

    - Specifically, all possible transfer paths from points outside the WCI into the WCI would be identified. These would be tabulated and published. Import liability for carbon mitigation would be triggered by the party electing to wheel energy across one of these paths. Monitoring of these transactions could be made via e-tags which could be supplied by Balancing Areas within the WCI.

    - If energy is wheeled across a hot path and it is delivered from a specified source, the title holder would be required to mitigate the carbon at the plant specific emission rate (e.g. hydro would have no liability). For unspecified sources, a deemed emission rate would be applied. There could be path specific or zone specific deemed emission rates so as to account for the differing generation mix across the WECC.

    - If it is desired to account for losses, a deemed loss factor for each hot path could be specified and published. This approach would be consistent with transmission contracting practices that have long been existence throughout the WECC. The importing party would then be required to comply with carbon content at the WCI POD plus the associated losses (via loss factor) back to the non-WCI POR on the hot path.

- Because the party holding title bears the WCI compliance risk as it wheels across the hot path, subsequent transactions downstream of the importer have no further carbon liability transfer. The compliance relationship shall be defined to be between the importing party and the appropriate WCI regulatory entity (e.g. partner state or province). This requirement will need to be clearly established ahead of WCI implementation. The preferred path for this would be via legislation that would require any party selling electric energy in the jurisdiction to be subject to the provisions of WCI (note – this legal authority may already exist). The terms and conditions would then be easily incorporated into contract terms if desired by market participants.

- The net effect of the above is that the default market product at WCI hubs becomes "seller pays" with respect to carbon dioxide mitigation and effectively all energy sold is "clean". For all market participants, there is certainty when purchasing energy at WCI hubs. Given that the regulatory relationship is between the in-WCI generator and the importing party, the WCI partner entities bear some risk in the event of a default by a party with a compliance obligation (this risk is not expected to be significant). There would be no cascading liability in the event of a default. The WCI partners can manage their credit risk in ways that do not result in the significant disruption that can be expected with cascaded liability.

- While this approach is not perfect, it is judged that it could be quite effective in reducing leakage and it has the benefit of being straightforward and easily implemented.

Straw Proposal on Reporting GHG Emissions Associated with Electricity Imported from non-WCI Jurisdictions

Scott Murtishaw, California Public Utilities Commission

November 10, 2008

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1. Background on Reporting Greenhouse Gas Emissions in WCI

On September 23, 2008 the WCI Partners released their design recommendations for a regional cap and trade program. These recommendations stated that the scope of the program would cover emissions from power imported into WCI jurisdictions for consumption in WCI jurisdictions in addition to generator emissions occurring in WCI jurisdictions. The design recommendations further stipulated that the point of regulation for the electricity sector should be the first jurisdictional deliverer (FJD), which for in-jurisdiction sources would be the generator, similar to the point sources covered in the industrial sector. For electricity imports from non-WCI states or provinces, the design recommendations identify the FJD as "the first entity that delivers that electricity over which the consuming WCI partner jurisdiction has regulatory authority." This will generally be a retail provider of electricity or a wholesale marketer (collectively "importer") that owns electricity as it is delivered across the border from a non-WCI jurisdiction into a WCI jurisdiction. If it is determined that the importer for a certain transaction is not subject to the regulatory authority of the WCI states and provinces (for example, a federal power administration may be immune from WCI regulation), the FJD would be the next downstream participant in the transaction.

The Electricity Subcommittee will provide recommended reporting rules for imported electricity to the WCI Reporting Subcommittee, which has been developing reporting requirements for the other sources covered by the scope of the WCI cap. This straw proposal is intended to help focus discussions at the technical working group meeting in Santa Fe on November 13. Participant feedback at the meeting and written comments will help shape the Electricity Subcommittee's recommendations to the Reporting Subcommittee.

2. Overview of Reporting Process

Accounting for emissions from sources located in WCI is a relatively straightforward process of measuring actual emissions or fuel consumption at the source. In contrast, attributing emissions to imports of electricity necessitates identifying electricity imports and matching those quantities of electricity to any of potentially hundreds of underlying generation sources.

For purposes of reporting GHG emissions, the sources of power used for imports can be classified into two types: specified sources that can be clearly tracked back to a specific generating facility or unit and unspecified sources that cannot. Clear links to specific facilities may exist when an importer owns generation facilities, has an equity share in a facility, or has a power purchase agreement with a specific facility. Some U.S. utilities also receive allocations of power from specified federally-managed dams. When these links to specified sources exist, emissions associated with the energy received can be attributed with reasonable certainty. Since the resources used for unspecified power cannot be precisely identified, emissions would have to be attributed using default (or "deemed") emission factors.

Broadly, the process of reporting regulated import transactions would occur in three steps.

1. The FJD reports the amount of electricity delivered into WCI jurisdictions during a reporting period.

2. The FJD reports emissions from deliveries from specified sources using emission data from those sources.

3. Emissions are attributed to deliveries from unspecified sources using default emission factors.

The sections below present more detail and suggested regulatory language for one possible approach to implementing GHG reporting rules for electricity imported into the WCI region.

3. Contract Shuffling

Contract shuffling is the practice of reporting imported electricity as generated by a lower emission facility or group of facilities than is actually the case. The result is to attribute GHG intensive power to states and provinces that do not have a cap while skimming the less GHG intensive power for attribution to imports. Contract shuffling reduces the environmental integrity of WCI implementation because the reported reductions in emissions are not matched by actual changes in total emissions.[1]

There are two different ways that contract shuffling can occur. Specified high GHG sources or system purchases can be shuffled by "cherry picking" specified low GHG sources from the available resources in the uncapped jurisdictions. Imports from specified sources with emission rates higher than the default rate can also be shuffled by delivering the power on an unspecified basis. The E3 presentation at the Salt Lake City workshop showed that roughly 20 million metric tons of CO_2 ($MMTCO_2$) could potentially be shuffled from coal plants using available hydro generation and that another 30 $MMTCO_2$ could be shuffled using a default rate of 1,000 lbs CO_2/MWh. Combined, this represents nearly two-thirds of the total emissions associated with imports in E3's 2020 scenario.[2]

It is important to note that importers or downstream recipients may not necessarily be aware that contract shuffling has taken place. The following example illustrates how this could occur. In Hour 1, a non-WCI utility generates 1,000 MW to serve its own load. In Hour 2, a WCI retail provider has contracted to buy 100 MW of hydro power from the non-WCI utility. The non-WCI utility must now generate 1,100 MW to serve its own load and meet its contractual obligation. The hydro resource is already running at its maximum capacity of 500 MW. The non-WCI utility generates an additional 100 MW from a natural gas plant and sells 100 MW of "hydro" to the WCI utility. The WCI utility believes it is purchasing hydro power, but its purchase actually induces natural gas generation.

4. Reporting Imported Electricity

All entities that own electricity delivered to the first point of delivery inside a WCI state or province from a non-WCI state or province shall report the quantities of electricity imported, whether consumed in a WCI state or province or wheeled through to another non-WCI jurisdiction. For purposes of GHG regulation, an import shall be deemed to have been consumed in a WCI jurisdiction if the final point of delivery for the transaction is located in a

[1] See Bushnell, Peterman and Wolfram 2007 for more information.
[2] See Price 2008.

WCI jurisdiction. Only imports consumed in a WCI state or province will trigger a GHG compliance obligation, but wheel-throughs will be reported in the interest of obtaining complete information.

Based on the current WCI membership the relevant transmission paths include

- British Columbia to Alberta
- Washington to Idaho
- Oregon to Nevada
- California to Nevada and Mexico
- Montana to Alberta, Idaho, Wyoming, and North Dakota
- Utah to Nevada, Idaho, Wyoming and Colorado
- Arizona to Navajo Nation
- New Mexico to Colorado, Texas and Navajo Nation
- Manitoba to Saskatchewan, North Dakota and Minnesota
- Ontario to Michigan and New York
- Quebec to New York, Vermont, New Hampshire, Newfoundland and New Brunswick

For each transmission link connecting these jurisdictions, importers to WCI states and provinces shall report the quantities of imported power separately for each import path. Purchasing/selling entities that are the first to purchase or otherwise receive power from an importer that is non-jurisdictional are the FJDs for purposes of WCI GHG regulation and shall report the information described below.

Because many of the transmission links listed above cross between balancing authority areas, NERC e-tags are required for the power scheduled on these paths. For inter-balancing authority transactions FJDs shall report the quantities of power listed on the e-tags for any power for which they were the purchasing/selling entity on the path that crosses the WCI boundary. The FJD shall document the reason for any discrepancy between the quantities reported on the e-tags and the quantities reported to the state or provincial agency for GHG regulatory purposes. The e-tags will be used to establish the quantity of electricity that must be reported and accounted for. Although specific generating facilities are sometimes listed on e-tags, this information will not be used as the primary source of information for attributing emissions to specified imports.

For the paths that do not cross balancing authority boundaries, regulatory authorities will need work with the transmission operators of those lines to identify the parties that reserve transmission services and ascertain the quantities of electricity imported by each importing entity.

For purchases from specified sources, the FJD shall report the quantities of power purchased as measured at the power plant's busbar. In other words, the reported quantities should include the transmission losses that occurred between the power plant and the first WCI Point of Delivery. For purchases from unspecified sources, the FJD shall report the quantity as measured at the first WCI Point of Delivery or other metered point on the transmission path designated by the WCI Partners. FJDs shall make available all e-tags, meter data, contracts, and settlement data necessary to document the reported transactions.

5. Attribution of Emissions to Imported Electricity

5.1 Specified Imports

For imports of electricity from specified sources, the WCI Partners will attribute emissions to the total quantity of electricity imported in each reporting period using the average emission rate (total CO_2e emissions in metric tons divided by total net generation in MWh) of the power plant during the calendar year when the import occurred based on the most recent greenhouse gas emissions data report that received a positive verification opinion or on CO_2 emissions reported to U.S. EPA under 40 CFR Part 75 or to Environment Canada under Section 71 of the Canadian Environmental Protection Act.[3] The FJD must provide supporting documentation to show that the electricity was generated by the specified generating facility or generating unit, as applicable.

In order to curb the potential for contract shuffling, the attribution of zero GHGs to imports of generation from existing non-WCI large hydro and nuclear facilities will be limited to imports from facilities owned or partially-owned by the FJD or WCI retail provider or to imports made pursuant to a contract negotiated prior to January 1, 2008 that remains in effect or has been renegotiated for the same facility for the same share or quantity of net generation within one year of contract expiration. For coal plants not located in a WCI jurisdiction that are owned or partially owned by WCI retail providers, the retail providers will document the disposition of the power from these plants and account for differences between the share of power the retail provider is entitled to and the quantity reported by the retail provider or other FJDs as consumed in a WCI Partner jurisdiction.

While the WCI Partners may decide to establish an allowance set-aside for the voluntary renewables market, Renewable Energy Certificates used for compliance with Renewable Portfolio Standards, whether in a WCI Partner jurisdiction or not, shall have no bearing on any entity's compliance obligation. Electricity from renewable sources, like electricity from fossil-fired sources, can be imported on a specified basis as long as there is sufficient supporting documentation. The WCI Partners will share reported information on specified imports to ensure that electricity from low-GHG sources is not double-counted.

5.2 Unspecified Imports and Default Emission Factors

For purchases of electricity from unspecified sources, the WCI Partners will attribute emissions using approved default emission factors, published in advance of the reporting period by the WCI Partners. There are several methods the WCI Partners could pursue in developing default emission factors. An average system factor approach (i.e., total emissions divided by total generation) assumes that the non-WCI seller is providing power from a mix of resources that reflects a representative share of baseload and load-following resources in

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[3] In order to provide the market certainty of an approved ex-ante emission factor it may be desirable to attribute emissions using plant emission rate data from a prior year. A lagged emission rate may even be necessary in order to allow adequate time for collection and verification of a non-WCI plant's emission data.

the region of origin. However, it is unlikely that an average emission factor would be accurate unless the pattern of exports closely matches the load profile of the exporting region, and deep baseload resources had been constructed in part, to provide power for export.

More sophisticated methods seek to identify the underlying plants with more precision. Marginal emission factor methods are based on the dispatch characteristics of the exporting region. These methods employ system modeling tools such as production cost models or simplified load duration curve models to determine which plants provide the incremental additional generation for export. Marginal dispatch analysis may also be used to generate multiple factors that reflect the marginal resources used at different times of they day or year. Whichever approach is adopted, the default factor should exclude all generating facilities, or parts thereof, that are identified as serving loads on a specified basis, whether serving WCI loads or non-WCI loads.[4]

Rather than attempting to discern which resources do in fact generate surplus power for export, some parties have suggested using a high emission rate, in the range of an existing pulverized coal unit, to discourage contract shuffling. The purpose of this approach is to prevent coal plants from shuffling their emissions by using a lower default rate. However, a high default rate would not prevent coal-fired power from being imported into a WCI jurisdiction and reported as having originated from a specified gas-fired power plant. A high default rate would not, on its own, thwart contract shuffling; it would simply affect the tactics used. For this reason, WCI Partners should strive to develop default factors that accurately reflect the mix of resources used to provide power for system sales.

Proposed decision criteria that could guide the Electricity Subcommittee's recommendations on default factors include accuracy, simplicity, and susceptibility to gaming. There are trade-offs among these criteria. Simplicity would argue for maintaining the smallest number of default factors necessary to achieve an acceptable level of accuracy. Attempts to optimize accuracy by developing numerous default factors would complicate the reporting system and could introduce more opportunities for gaming. For example, a low default factor for Idaho could motivate purchasing/selling entities to wheel power from Wyoming to Idaho and then import that power into a WCI state as if it were generated in Idaho. On the other hand, one factor used for an entire reporting period may not reflect significant seasonal or time-of-day differences in the resources used to produce power at the margin in non-WCI states and provinces.

More analysis is needed to determine if the resources used to provide system power differ sufficiently by time and place to warrant the complexity of multiple default factors. For discussion purposes, a starting proposition would be to use factors that are not temporally differentiated but that are disaggregated by the following major geographic zones: Alberta, Western U.S. (NV, ID, WY, and CO), Mexico, central U.S./Canada (MN, ND, SK), and northeastern U.S. If further analysis indicates that gas-fired power is the swing resource that provides most power for export in one or more of these regions and the emission rates do not

[4] See Marnay et al 2002; Sathaye et al 2004; Alvarado 2006; Alvarado and Griffin 2007; Murtishaw and Griffin 2007, and Broekhoff et al 2007 for more information.

differ substantially, the number of regional factors could be reduced. Assuming that natural gas is the swing resource in most of these regions, default factors would probably lie in the 400 kg CO_2e/MWh to 600 kg CO_2e/MWh range. The default factor adopted for California is currently 1,100 lbs CO_2e/MWh (approximately 500 kg CO_2e).

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Attachment A. Straw Proposal Regulatory Language

Key Definitions and Reporting Requirements
Related to Electricity Imported into the WCI Region

Definitions

(1) "Balancing authority" means the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.

(2) "Balancing authority area" means the collection of generation, transmission, and loads within the metered boundaries of the balancing authority. The balancing authority maintains load-resource balance within this area.

(3) "Busbar" means the power conduit of an electricity generating facility that serves as the starting point for the electricity transmission system.

(4) "Deliverer" means an operator of a generating facility or an importer.

(5) "Electricity transaction" means the purchase, sale, import, export or exchange of electric power.

(6) "Entity" means a person, firm, association, organization, partnership, business trust, corporation, limited liability company, company, or government agency.

(7) "Exchange agreement" means a commitment between electricity market participants to swap energy for energy. Exchange transactions do not involve transfers of payment or receipts of money for the full market value of the energy being exchanged, but may include payment for net differences due to market price differences between the two parts of the transaction or to settle minor imbalances.

(8) "Facility" means any property, plant, building, structure, stationary source, stationary equipment or grouping of stationary equipment or stationary sources located on one or more contiguous or adjacent properties, in actual physical contact or separated solely by a public roadway or other public right-of way, and under common operational control, that emits or may emit any greenhouse gas. Operators of military installations may classify such installations as more than a single facility based on distinct and independent functional groupings within contiguous military properties.

(9) "Final point of delivery" means the last point of delivery for a given electricity transaction.

(10) "First Jurisdictional Deliverer" means an importer that is jurisdictional or the immediate downstream purchaser or recipient of power from a non-jurisdictional importer.

(11) "Generating facility" means a facility that generates electricity and includes one or more generating units at the same location.

(12) "Generating unit" means any combination of physically connected generator(s), reactor(s), boiler(s), combustion turbine(s), or other prime mover(s) operated together to produce electric power.

(13) "Gross generation" means the total electrical output of the generating unit, expressed in megawatt hours (MWh) per year.

(14) "Importer" means a retail provider, or any purchasing/selling entity that is the owner of power as it is delivered to the first point of delivery in the WCI Region for electric power imported into the WCI Region

(15) "Megawatt hour" or "MWh" means the electrical energy unit of measure equal to one million watts of power supplied to, or taken from, an electric circuit steadily for one hour. (A watt is a unit of electrical power equal to one ampere under pressure of one volt, or 1/746 horsepower).

(16) "Nameplate generating capacity" means the maximum rated output of a generator under specific conditions designated by the manufacturer, expressed in megawatts (MW) or kilowatts (kW).

(17) "Net power generated" means the gross generation minus station service or unit service power requirements, expressed in megawatt hours (MWh) per year. In the case of cogeneration, this value is intended to include internal consumption of electricity for the purposes of a production process, as well as power put on the grid.

(18) "NERC E-tag" means North American Electric Reliability Corporation (NERC) energy tag representing transactions on the North American bulk electricity market scheduled to flow between or across balancing authority areas.

(19) "Null power" means any electricity produced by a renewable energy electricity generating facility from which a Western Renewable Energy Generation Information System (WREGIS) or a Nevada Tracks Renewable Energy Credits (NVTREC) certificate or other renewable energy certificate has been unbundled and sold separately.

(20) "NVTREC" means Nevada Tracks Renewable Energy Credits.

(21) "Operational control" for a facility subject to this article means the authority to introduce and implement operating, environmental, health and safety policies. In any circumstance where this authority is shared among multiple entities, the entity holding the permit to operate from the local air pollution control district or air quality management district is considered to have operational control for purposes of this article.

(22) "Operator" means the entity having operational control of a facility, or other entity, from which an emissions data report is required under this article.

(23) "Point of delivery" means a point on an electric system where a power supplier delivers electricity to the receiver of that energy. This point can be an interconnection with another system or a substation where the transmission provider's transmission and distribution systems are connected to another system.

(24) "Point of receipt" means a point on an electric system where an entity receives electricity from a supplier. This point can be an interconnection with another system or a generator busbar.

(25) "Point source" means any separately identifiable stationary point from which greenhouse gases are emitted.

(26) "Power" means electricity, except where the context makes clear that another meaning is intended.

(27) "Power contract" means an arrangement for the purchase of electricity. Power contracts may be, but are not limited to, power purchase agreements and tariff provisions.

(28) "Prime mover" means the type of equipment such as an engine or water wheel that drives an electric generator. "Prime movers" include, but are not limited to, reciprocating engines, combustion or gas turbines, steam turbines, microturbines, and fuel cells.

(29) "Purchasing/selling entity" means an entity that is eligible to purchase or sell energy or capacity and reserve transmission services.

(30) "Qualifying facility" means a cogeneration or small power production facility that meets ownership, operating, and efficiency criteria established by the Federal Energy Regulatory Commission (FERC) pursuant to the Public Utility Regulatory Policies Act.

(31) "Renewable energy" means energy from sources that constantly renew themselves or that are regarded as practically inexhaustible. Renewable energy includes, but is not limited to, energy derived from solar, wind, geothermal, hydroelectric, wood, biomass, tidal power, sea currents, and ocean thermal gradients.

(32) "Retail provider" means an entity that provides electricity to retail end users in the WCI Region

(33) "Source" means greenhouse gas source, as defined in this section.

(34) "Specified source of power" or "specified source" means a particular generating unit or facility for which electrical generation can be confidently tracked due to full or partial ownership or due to its identification in a power contract.

(35) "Unspecified source of power" or "unspecified source" means electricity generation that cannot be matched to a particular generating facility. Unspecified sources of power may include power purchased from entities that own fleets of generating facilities such as independent power producers, retail providers, and federal power agencies and power purchased from electricity marketers, brokers, and markets.

(36) "Western Climate Initiative" or "WCI" means a collaboration of several U.S. states and Canadian provinces working together to reduce greenhouse gases in the region encompassed by their respective jurisdictions.

(37) "WCI Region" means the Canadian provinces of British Columbia, Manitoba, Ontario, and Quebec plus the U.S. states of Arizona, California, Montana, New Mexico, Oregon, Utah, and Washington, excluding any tribal/First Nations' lands that are not subject to state or provincial jurisdiction.

(38) "WREGIS" means Western Renewable Energy Generation Information System.

Greenhouse Gas Emissions Data Report: Electricity Imports.

(1) **General Requirements.** First jurisdictional deliverers shall meet the following general requirements in preparing their greenhouse gas emissions data report for each report year. When reporting electricity transactions, first jurisdictional deliverers shall:

(A) Specify the amount of electricity in MWh;

(B) Aggregate imports by Point of Delivery;

(C) Include electricity transactions associated with both renewable and nonrenewable energy sources of power.

(D) For electricity from specified sources, specify the amount of electricity as measured at the generator busbar;

(E) For electricity from unspecified sources, report the amount of electricity as measured at the first point of delivery in the WCI Region, or nearest metered point designated by the WCI Partners;

(F) For electricity from unspecified sources, disaggregate imports for each Point of Delivery by counterparty from which the power was purchased, if applicable;

(G) For electricity from specified sources, specify the facility name, the WCI designated facility ID, and the generating unit ID for the unit generating the power, if applicable;

(H) Specify the amount of electricity (MWh) that is null power when applicable;

(I) Specify electricity imported under exchange agreements as you would any other import transaction;

(J) When reporting power transactions as imports into the WCI Region, exclude the amount of power imported into the WCI Region that terminates in a location outside of the WCI Region, and report the quantity wheeled as measured at the first point of delivery inside the WCI Region;

(K) Retain for purposes of verification NERC E-tags, settlements data, and all other information needed to confirm the transactions.

(2) **Report Content.** First Jurisdictional Deliverers shall include the following information in the greenhouse gas emissions data report for each report year.

(A) ***Specified Imported Power Transactions.***
Wholesale power imported from specified sources by the First Jurisdictional

Deliverer or that the First Jurisdictional Deliverer purchased or received immediately downstream from a non-jurisdictional importer.

1. Power imported into the WCI Region (MWh) from a specified hydroelectric generating facility with nameplate capacity of > 30 MW[5] or from a specified nuclear facility shall be listed as one of the following:

   a. Power purchased with a contract in effect prior to January 1, 2008 that remains in effect or has been renegotiated for the same facility for the same share or quantity of net generation within one year of contract expiration;

   b. Power purchased not meeting stipulation 1 and that is not associated with an increase in the facility's generating capacity;

   c. Power purchased not meeting stipulation 1 that is associated with an increase in the facility's generating capacity due to increased efficiencies or other capacity increasing actions;

   d. Power purchased from hydroelectric generating facilities during a "spill or sell" situation where power not purchased is lost;

   e. Power purchased that does not meet stipulation 1 due to federal power redistribution polices for federally owned resources and not related to price bidding.

2. If the first jurisdictional deliverer holds a contract that entitles the first jurisdictional deliverer to a specified percentage of the generation in the report year from a facility not located in the WCI Region, the first jurisdictional deliverer shall include power purchased or sold from that facility as being from a partially owned facility.

3. For facilities not located in the WCI Region that are fully or partially owned by the first jurisdictional deliverer, include facility name, WCI designated facility ID, generating unit ID as applicable, percent ownership share at the facility level, ownership share at the generating unit level as applicable, and net power generated in the report year (MWh).

4. For facilities not located in the WCI Region that are fully or partially owned by the first jurisdictional deliverer that have CO_2 emissions greater than 500 kg of CO_2 per MWh based on the most recent greenhouse gas emissions data report that received a positive verification opinion or on CO_2 emissions reported to U.S.EPA under 40 CFR Part 75 or reported to Environment Canada under Section 71 of the Canadian

[5] The 30 MW threshold is based on California's definition of eligible renewable hydro so this may need to be rephrased to make it more broadly applicable.

Environmental Protection Act, the first jurisdictional deliverer may elect to include:

a. Wholesale sales made by the First Jurisdictional Deliverer or on behalf of the First Jurisdictional Deliverer from the facility or unit to counterparties located outside the WCI Region where:

    i. The power could not be delivered to into the WCI Region during the hours in which it was sold due to congestion in the transmission and distribution system or similar issues or;

    ii. The First Jurisdictional Deliverer did not need the power during the hours in which it was sold for reasons not related to reducing the first jurisdictional deliverer's greenhouse gas emissions responsibility.

b. Amount of power generation that was reduced from the facility or unit in MWh per year as a result of the reduced demand for power by the First Jurisdictional Deliverer. The First Jurisdictional Deliverer shall retain documentation that associates reduced generation with reduced demand.

(B) ***Unspecified Imported Power Transactions.***
Power imported from unspecified sources by the First Jurisdictional Deliverer or that the First Jurisdictional Deliverer purchased or received immediately downstream from a non-jurisdictional importer with final point of delivery in the WCI Region.

(C) ***Electricity Transactions Wheeled Through the WCI Region***.
Power imported into the WCI Region that terminates in a location outside of the WCI Region, as measured at the first point of delivery in the WCI Region.

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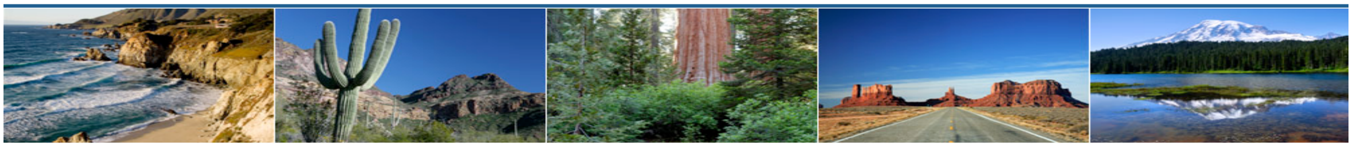

ELECTRICITY SUBCOMMITTEE
TECHNICAL WORKING SESSION

San Francisco, California
December 2, 2008
8:30 a.m. to 3:30 p.m. Pacific

Location:
Westin Hotel
50 Third Street
San Francisco

AGENDA

1.	**8:30 am**	**Welcome and Introductions** **David Van't Hof, Chair, WCI Electricity Subcommittee**
2.	**8:45**	**Review of the Process and Agenda**
3.	**9:00**	**Presentation on Reliability and Liquidity** **Karen Griffin, CA Energy Commission**
4.	**9:30**	**Comments and Suggestions in Response** • **Udi Helman, California ISO** • **Saeed Farrokhpay, FERC** • **Bud Beebe, Sacramento MUD**
5.	**10:00**	**Break**
6.	**10:20**	**Comments and Suggestions from TAG**
7.	**12:00**	**Lunch (On Your Own)**
8.	**1:00**	**Presentation on Potential Impacts on** **Liquidity in Eastern Electricity Markets** **Barry Green, Ontario IESO**
10.	**1:30**	**Comments and Discussion by TAG**
11.	**3:00**	**Public Comment Session**
12.	**3:30**	**Adjourn**

WCI Impacts on Market Liquidity and Reliability Eastern Electricity Markets

Presentation by
Barry Green
WCI San Francisco Meeting
Dec. 2, 2008

Overview

- Eastern context for this discussion
  - Nature of the Ontario market
- Key Issues
- Summary

Ontario Interconnections

Eastern Context

- Representing the Ontario Independent Electricity System Operator (IESO)
  - Power System Operator and Market Operator for the Province of Ontario
  - Also, in NERC terms the IESO is the Balancing Authority and Reliability Coordinator for Ontario

Eastern Context cont'd

- Characteristics of the Ontario market (very round numbers)
  - Total Provincial load ~150 TWh
  - Generation Mix (energy):
    - Nuclear ~51%
    - Hydroelectric ~21%
    - Fossil ~26% (18% coal;8% oil and natural gas)
  - Over the last 5 years, fossil generation has ranged from 35 TWh to 48 TWh representing a range of 23% to 33% of total Ontario generation
- Ontario Market Participants trade actively with all of the neighboring systems, specifically:
  - Hydro Québec—WCI Member/predominately hydro
  - Manitoba Hydro—WCI Member/predominately hydro
  - New York—RGGI Member/predominately fossil and mostly gas
  - Midwest ISO—predominately fossil and mostly coal
- In any given year Ontario might be a net importer or net exporter
  - Over the last 5 years exports have ranged from 6-12 TWh and imports from 6-11 TWh
  - The annual net interchange transactions has ranged from imports of 4 TWh to exports of 5 TWh

RELIABILITY and LIQUIDITY ISSUES

- Currently no identified unsolvable reliability or liquidity issues
- No identified substantial reliability and liquidity differences between East and West
- No identified substantial differences between East and West
- Need to recognize that a cap and trade approach, i.e. a market solution, to emission reductions will raise some potential problems that need to be mitigated
- Also need to recognize that 2012 and 2015 will represent step changes
- Key is to facilitate the emission allowance market
  - Maximize the number of players in the market
  - Transparency
    - In particular allow prices to be seen by all market participants including customers so that they can react to the price signals
  - Recognize transitional issues and not over-react

Identified Reliability Issues

(working from Karen Griffin's paper)

- Transitional issues
  - Existing contracts
- Resource planning issues
  - New supply
    - Back up for intermittent generation
    - New generation
- Allowance management issues
  - LSE conservatism
  - Generators with insufficient allowances
  - Speculators hoarding allowances
  - Annual swings in hydroelectric production
- Overall System Reliability
  - ISO vs. Integrated utility
  - Who orders generation post 2012? Long term vs. short term?
- Currently no other issues identified

Dealing with Reliability Issues

Transitional Issues

- Case specific
- Each partner may need to develop their own approach
- Best solution could depend on:
  - The number of contracts
  - The proportion of the market this represents
  - The solution might be through allocation of allowances

Dealing with Reliability Issues cont'd
Resource Planning Issues

- The issue is dealing with new entrants
  - Need the right mix of generation:
    - Shorter term to back up intermittent generation that is increasing quickly
    - Longer term to account for the allowance reduction trajectory
  - Allowance pricing and allocation mechanisms may help
    - Price transparency should enhance the decision-making process in a market environment or in a central planning environment
    - The allowance market will provide price signals to monetize emissions

Dealing with Reliability Issues cont'd
Allowance Management Issues

- A number of identified issues hypothesize scenarios where allowance pricing distorts the market
  - LSE conservatism
    - LSE holding allowances is not analogous to capacity reserve margins due to:
      - » Obligations are primarily on the generators
      - » Three year compliance period
    - The market for allowances will allow LSEs to "cost" them and make appropriate decisions
  - Price Spikes reducing available generation possibly due to speculation
    - Generators need to be able to pass through the costs of allowances, then should be willing to pay the market price for allowances
    - There will always be a need for market monitors to insure appropriate behavior
  - Annual allowance requirements varying substantially due to water or weather conditions
    - Geographic (east/west) and sectoral (electricity vs. other sectors) diversity will help mitigate this
- Allowances represent one more element of risk in pricing electricity
  - It is not inherently different than fuel price risk
  - Will impact fuels differently and therefore its impacts on various jurisdictions will not be uniform

Dealing with Reliability Issues cont'd
Overall system reliability

- The issue is not substantially different for ISOs vs. Integrated Utilities
  - All operate to the same NERC rules
- The entity responsible for grid reliability, short term or longer term, is not changed by allowance availability
  - We are merely adding another element of risk for market participants to manage
  - We are also adding a tool by which to manage that risk

Summary of Reliability Issues

- The issues identified are real
- Allowance pricing introduces another element of risk
  - Not unlike other risk elements such as fuel although it will impact fuels differently and therefore its impacts on various jurisdictions will not be uniform
  - Now there will be a mechanism for monetizing and dealing with it
  - We must maximize the size of the market in order to attempt to minimize the impact:
    - The use of 3-year compliance periods is a good feature
    - Allowances need to be fungible across as big a market as possible
      - The diversity between the east and west is good
      - As many sectors of the economy as possible should be included with the maximum capability to trade between sectors
  - Price transparency is key
    - All market participants, including customers, need to see prices and adapt behaviors

Identified Liquidity Issues

- Designing a market for good liquidity
- Dealing with the swings in hydroelectric production

Dealing with Liquidity Issues

- Market design for liquidity:
  - Need to anticipate some initial volatility as players learn the market and how it reacts
    - Three year compliance period helps to mitigate volatility
  - Liquidity will be enhanced by a large number of active participants
    - As many sectors of the economy as possible
    - Geographic diversity is helpful
    - A good trading platform would enhance price transparency and liquidity

Dealing with Liquidity Issues cont'd

- The issue here is really swings in fossil requirements and therefore allowance requirements
  - Could be caused by:
    - Hydro-electric availability
    - Nuclear availability
    - Unusually hot or cold weather
- Swings in hydroelectric availability can be mitigated by:
  - Maximizing the diversity amongst the entities included in the program
    - Geographic diversity
    - Sectoral diversity

Comments on the Brainstorming Lists

- Reliability set-aside
  - The need for this should be mitigated by diversifying the players and the 3-year compliance period
  - Both of these would allow for expanding the pool from which allowances can be bought without increasing the total number of allowances
- Reliability exemption for emergency purposes
  - Given the 3-year compliance window this should only be required for an emergency very near the end of the window
  - Criteria could be developed to allow borrowing from a future period under such circumstances
- Pass through of allowance costs
  - Customers do need to see the cost of allowances so they are part of the solution
  - A direct pass through would remove allowance costs from decision-making elsewhere in the resource allocation process
  - Resource planning decisions need to reflect the cost of emissions

Comments on the Brainstorming Lists cont'd

- Balancing Authorities should not be purchasing allowances for reliability contingencies
  - Has the effect of making the Balancing Authorities a market participant
  - The allowances required need to be available to market participants and are part of the price of the energy
- Before adopting any extraordinary measures to improve liquidity, such as restricting purchasers, we should examine the results of other jurisdictions such as the European market

Summary

- With respect to liquidity and reliability issues we have a good starting point
- We have not yet identified any show-stoppers although modelling of the Eastern markets is still to be done
- Key issues are:
  - Transparency
    - All participants right down to the retail customer need to see the cost of their actions
  - Maximize fungibility of the allowances and diversity of the participants
    - Utilize the geographic diversity of the WCI region
    - Utilize the sectoral diversity by maximizing the number of industrial sectors included within the program

Questions?
Comments?

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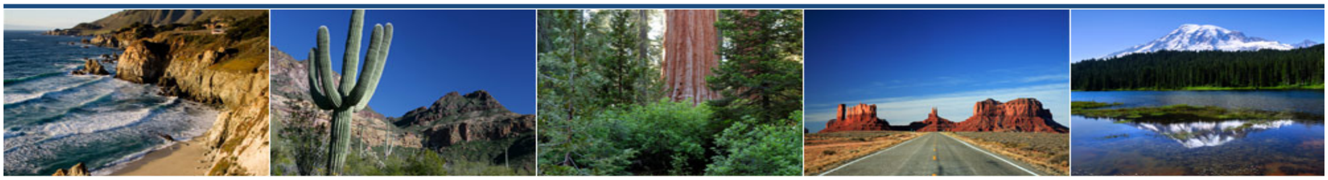

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Agenda

WCI Economic Modeling Team Workshop

December 3, 2008 10:00 am - 4:00 pm PST
Westin Hotel, 50 Third Street
San Francisco, California

Toll free call in: 1-800-868-1837
Direct dial: 1-404-920-6440
Participant Code: 659537 (followed by #)

Objectives

1. Explain how the economic analysis was performed.
2. Get feedback on how to improve the analysis.
3. Discuss how to structure the next round of analysis.

Workshop Sessions

Introduction: (5 minutes)

Session 1: Understanding Model Outputs (25 minutes)

Session 2: Review of Reference Case (60 minutes)

Session 3: Review of Policy Cases (60 minutes)

Break and Working Lunch w/ box lunch (60 minutes)

Session 4: Review of Electric Sector Results (60 minutes)

Session 5: Review of Sensitivity Analyses (30 minutes)

Session 6: General Discussion and Next Steps (60 minutes)

December 3, 2008 Stakeholder Meeting: Economic Modeling Team Workshop, San Francisco, California

List of Commenters

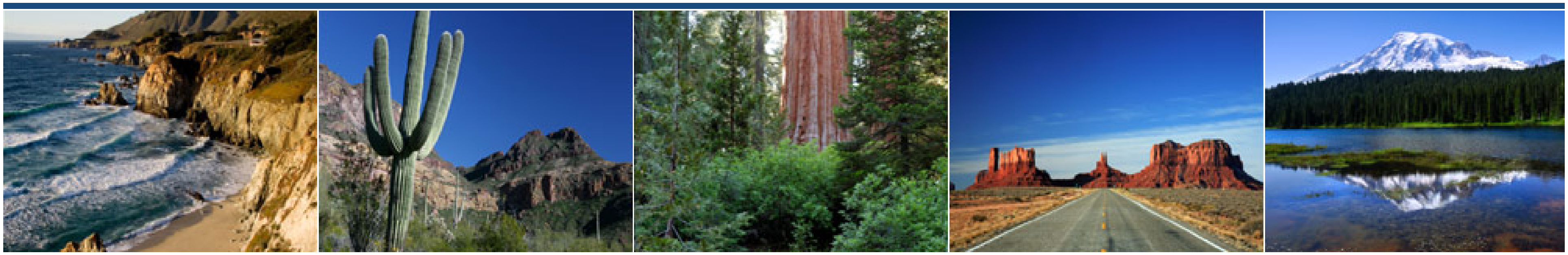
Sempra Energy

Sightline Institute

Van Horn Consulting

WEST Associates

Western Climate Initiative



Economic Modeling Team Workshop

December 3, 2008

San Francisco, California

Workshop Objectives

- Review and discuss WCI economic modeling to date
- Identify issues and concerns
- Plan for the next round of work

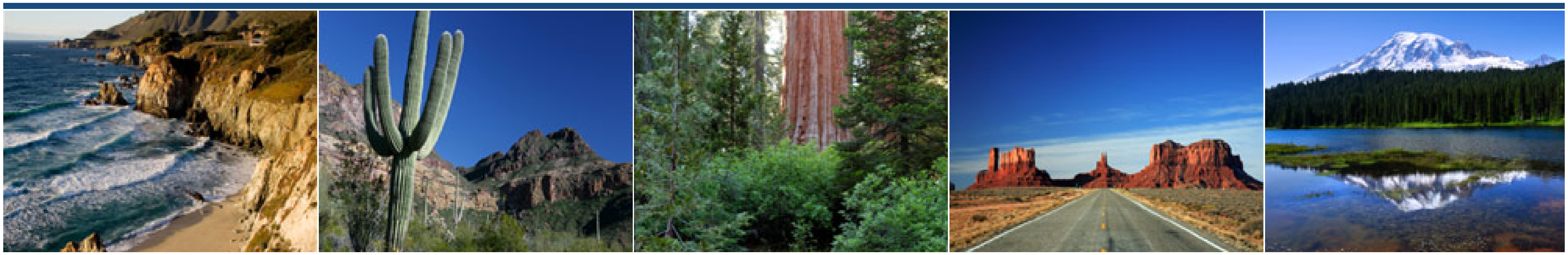
Documents Previously Made Available

- Workshop participants should be familiar with:
  - WCI Design Recommendations (esp. Appendix B)
  - Assumptions Book for ENERGY 2020
  - Documents posted for six conference calls (March to November 2008)
- All are available on the WCI Economic Analysis webpage:
  - http://www.westernclimateinitiative.org/Economic_Analysis.cfm
- In addition, detailed documentation of the ENERGY 2020 model is available at:
  - http://www.arb.ca.gov/cc/scopingplan/economics-sp/models/models.htm

Agenda

- Session 1: Understanding Outputs
- Session 2: Review of Reference Case
- Session 3: Review of Policy Cases
- Break
- Working Lunch (box lunches provided)
- Session 4: Electric Sector Results
- Session 5: Review of Sensitivity Analyses
- Session 6: General Discussion and Next Steps

Western Climate Initiative



Session 1: Understanding Outputs

Economic Modeling Team Workshop

December 3, 2008
San Francisco, California

Outline of Presentation

- Session objective: Review how to read and understand the model outputs.
- Topics:
  - Emissions, Compliance summary, Offsets and Banking
  - Total Energy Use, Electric Sector, Transportation Sector
  - Fuel Prices, Fuel Expenditures, Potential Allowance Value
  - Annualized Costs

Table B-5: Reference Case GHG Emissions

Table B-5: Reference Case Greenhouse Gas Emissions: Eight WCI Partners

GHG Emissions *(MMTCO2E)*	2006	2010	2015	2020	Growth Rate 2006-2020
Residential	49.7	53.7	58.4	63.1	1.7%
Commercial	29.3	30.5	30.7	31.8	0.6%
Energy Intensive Industry	176.8	174.5	181.5	191.0	0.6%
Other Industry	29.8	30.3	30.5	31.0	0.3%
Passenger Transport	290.8	299.4	303.9	294.0	0.1%
Freight Transport	93.0	89.6	89.9	91.7	-0.1%
Power Sector	176.6	166.8	160.0	176.9	0.0%
Waste & Wastewater	25.6	29.1	34.2	38.4	2.9%
Agriculture (non-energy)	59.9	62.1	67.5	74.9	1.6%
Total	**931.6**	**936.1**	**956.6**	**992.8**	**0.5%**

Total in 2006 is key determinant of cap as described on next slide.

Table B-12 GHG Emissions and Compliance Summary, 2020

- Setting the target:

  2020 Target =
  2006 value for WCI Sub-Total (931.6 Mt) +
  non-WCI Power Sector (70 Mt) =
  1001.6 Mt.

- Hitting the target. Case: "Broad, Comp Policies With Offsets." From Compliance Summary:

  Compliance Total =
  WCI Sub-Total (877.9) +
  Non-WCI Power Sector imports (70.0) +
  Non-WCI Power Sector Reductions (-37.0) +
  Offsets (-31.8) +
  Bank Flow (-31.8) =
  847.2 Mt (or 84.6% of 1001.6 Mt)

Table B-12: Cap-and-Trade Cases Greenhouse Gas Emissions and Compliance Summary: Eight WCI Partners

GHG Emissions in 2020 *(MMTCO2E)*	Reference Case	Broad, Comp Policies No Offsets			Broad, Comp Policies With Offsets			Narrow, Comp Policies With Offsets		
		Value	Diff from Reference	Percent Diff	Value	Diff from Reference	Percent Diff	Value	Diff from Reference	Percent Diff
Residential	63.1	55.0	-8.1	-12.8%	55.2	-7.9	-12.5%	55.9	-7.2	-11.4%
Commercial	31.8	26.2	-5.6	-17.5%	26.4	-5.4	-17.1%	27.0	-4.8	-15.0%
Energy Intensive Industry	191.0	174.5	-16.6	-8.7%	175.0	-16.0	-8.4%	172.6	-18.5	-9.7%
Other Industry	31.0	26.9	-4.2	-13.5%	27.0	-4.0	-12.9%	26.3	-4.8	-15.3%
Passenger Transport	294.0	258.7	-35.2	-12.0%	259.0	-34.9	-11.9%	259.9	-34.1	-11.6%
Freight Transport	91.7	89.9	-1.7	-1.9%	90.4	-1.3	-1.4%	91.7	0.0	0.0%
Power Sector	176.9	114.6	-62.2	-35.2%	131.5	-45.3	-25.6%	104.8	-72.1	-40.7%
Waste & Wastewater	38.4	38.4	0.0	0.0%	38.4	0.0	0.0%	38.4	0.0	0.0%
Agriculture (non-energy)	74.9	74.9	0.0	0.0%	74.9	0.0	0.0%	71.1	-3.7	-5.0%
WCI Sub-Total	**992.8**	**859.2**	**-133.6**	**-13.5%**	**877.9**	**-114.9**	**-11.6%**	**847.8**	**-145.0**	**-14.6%**
Non-WCI Power Sector	70.0	70.0			70.0			70.0		
Non-WCI Power Sector Reductions		-45.0			-37.0			-45.0		
Offsets		0.0			-31.8			-18.2		
Bank Flow		-31.1			-31.8			-0.2		
Compliance Total		**853.1**			**847.2**			**854.3**		
Percent of 2006 Emissions		85.2%			84.6%			85.3%		
Bank Inventory		72.6			74.4			0.5		
Allowance Price (2007 $/MT)		**$63**			**$24**			**$71**		

All emissions in millions of metric tons.

Attachment 2: Detailed Cap-and-Trade Policy Results

E.g., Table B-31

Cap-and-Trade Program: Broad Scope with Complementary Policies and Offsets

Table B-31: Cap-and-Trade Program Greenhouse Gas Emissions and Compliance Summary: Eight WCI Partners Broad Scope with Complementary Policies and Offsets

	2006	2010	2015	2020	Growth Rate 2006-2020
GHG Emissions *(MMTCO2E)*					
Residential	49.7	53.6	54.7	55.2	0.8%
Commercial	29.3	30.4	28.0	26.4	-0.8%
Energy Intensive Industry	176.8	174.0	172.2	175.0	-0.1%
Other Industry	29.8	30.2	28.5	27.0	-0.7%
Passenger Transport	290.8	291.7	276.5	259.0	-0.8%
Freight Transport	93.0	89.6	89.6	90.4	-0.2%
Power Sector	176.6	166.4	133.0	131.5	-2.1%
Waste & Wastewater	25.6	29.1	34.2	38.4	2.9%
Agriculture (non-energy)	59.9	62.1	67.5	74.9	1.6%
WCI Sub-Total	**931.6**	**927.1**	**884.1**	**877.9**	**-0.4%**
Compliance Summary					
Non-WCI Power Sector	70.0	70.0	70.0	70.0	
Non-WCI Power Sector Reductions	-	(0.1)	(20.3)	(37.0)	
Offsets	-	-	-	(31.8)	
Bank Flow	0.0	0.0	21.2	-31.8	
Compliance Total	**1,001.6**	**997.0**	**955.0**	**847.2**	
Percent of 2006 Emissions	*100.0%*	*99.5%*	*95.3%*	*84.6%*	
Bank Inventory	0.0	0.0	107.4	74.4	
Allowance Price (2007 $/MT)	**$0**	**$0**	**$6**	**$24**	
Percentage of Offsets Allowed	5%	5%	5%	5%	
Percent Allowable Offsets Used			**0%**	**100%**	
All emissions in million metric tons.					

Offsets and Banking

- Broad scope with offsets, year-by-year projections.
- Offset purchases ramp up as allowance price nears $20/ton.
- Banking *(see Appendix B, Attachment 1, p. 37)*
  - Banking is heavy at outset and declines as allowance price increases.
  - Bank flow turns negative when allowance price goes above $15/ton

Compliance Summary	2012	2013	2014	2015	2016	2017	2018	2019	2020
Offsets	-	-	-	-	-	(0.0)	(26.4)	(29.2)	(31.8)
Bank Flow	-	39.8	46.4	21.2	13.2	1.0	(5.4)	(9.8)	(31.8)
Bank Inventory	0.0	39.8	86.2	107.4	120.5	121.5	116.1	106.2	74.4
Allowance Price (2007 $/Ton)	**$5**	**$5**	**$6**	**$6**	**$7**	**$13**	**$19**	**$20**	**$24**

Total Energy Use (Table B-13)

- Presented by fuel and by sector
- In sectoral table, “Energy Intensive Industry” consists of:
  - Petroleum, Chemicals, Paper, Primary Metals, Non-Metallic Minerals, Mining, and Oil and Gas Extraction
- In sectoral table, “Agriculture” refers to fossil fuel energy use
  - Non-energy emissions are not capped.

Electric Sector, Transportation Sector

- Electric output tables include (Table B-14)
  - MW of capacity by fuel type (no retirements)
  - GWh of generation by fuel type <u>inside</u> WCI
  - Total sales in GWh by customer class (includes imports from outside WCI)
- Session 4 will discuss in more detail
- Proxy of First Jurisdictional Deliverer (FJD)
  - Incorporates all generation in the WECC

- Transportation sector outputs (Table B-15)

Fuel Prices (Table B-16)

- Reference case
  - Start with national price forecast, and add a mark-up for the cost of distribution and delivery of fuel to the partner-specific market.
  - Mark-up is based on historic patterns as estimated inside model.
  - Project a WCI average price by calculating a weighted average of the prices in the 8 partner jurisdictions.
- Cap-and-trade policy cases
  - Add an appropriate component to partner-specific prices reflecting the allowance price and the carbon content of the fuel.
  - Repeat weighted-average calculation for WCI.
- Fuel prices <u>include</u> a component reflecting allowance prices
  - Reasonable assumption regardless of degree to which allowances are auctioned vs. allocated without charge.

Fuel Expenditures, Potential Allowance Value

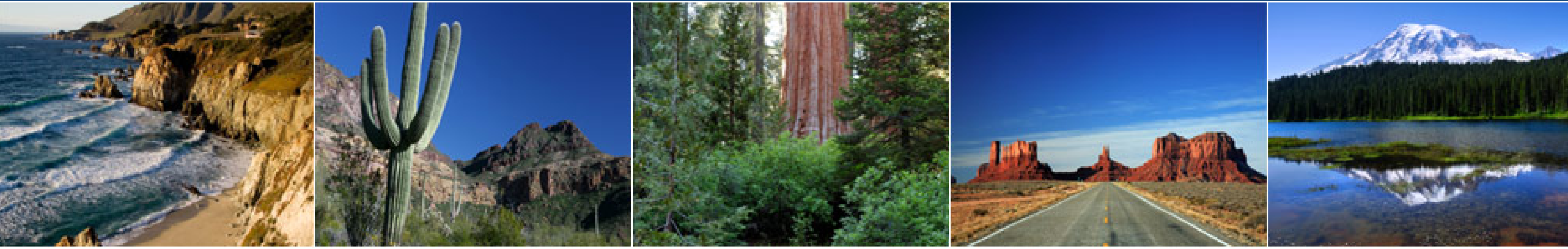
- Fuel expenditures generally do <u>not</u> reflect the price of allowances. (Table B-17)
  - Based on Reference Case fuel prices – no allowance price component
  - Exception: electricity expenditures
- “Potential Allowance Value” reflects the price of allowances and the costs they may impose on a sector. (Table B-18)
  - Projected as allowance price times sector emissions
  - Some or all of the potential value will be incurred by a sector, depending on how allowances are distributed, and the ability to pass on costs
  - When incurred it is an “accounting cost” (i.e., money is transferred), not an “economic cost” in the sense of consuming societal resources.

Annualized Costs (Table B-19)

- These are “compliance cost” estimates for reducing emissions under the cap-and-trade along with complementary policies.
- Annualized costs:
  - Consist of change in fuel expenditures plus annualized change in capital investment (5% real discount rate over life of equipment)
  - Electric sector costs are embedded in electricity prices
  - Do not include programmatic costs of complementary policies
  - Potential Allowance Value reported separately

Discussion

Western Climate Initiative



Review of Reference Case

Economic Modeling Team

December 3, 2008

San Francisco, California

Outline of Presentation:

1. Introduction
2. Key Inputs and Assumptions Used in Reference Case
3. Modeling Efficiency Investment Options
4. Modeling of Policies Included in the Reference Case
5. Review of Reference Case results
6. Discussion

1) Model Process Overview

PURPOSE OF REFERENCE CASE:

- Reference Case presents one possible future based on stated assumptions.
- Policy Cases are compared to the Reference Case to evaluate policy impacts
- Given uncertainties, sensitivity analysis is required:
  - Alternative Reference Cases
  - Implications for policy impacts

2) Key Inputs and Assumptions

Key Inputs and Assumptions Used in Reference Case

- Projected Economic Activity (from a macro-economic forecast)
  - GDP, Gross output by sector, personal Income
  - Several jurisdictions provided jurisdiction-specific demographic and economic forecasts *(See Appendix C of Assumptions Book for demographic & economic data for Arizona, California, New Mexico, and Washington).*
- Historical Data
  - Energy demand, supply, prices, and emissions by state/province
  - Electric generator data
- Projected Fuel Prices
  - For U.S. states: Assumes EIA AEO 2008 High Price Case (see table below)
  - Same forecast for Canadian provinces adjusted for differences in delivered cost.
  - Model calculates adder for delivered price for each jurisdiction based on historic relationship between wholesale and delivered prices.
- Projected Technology Cost and Performance
  - Power generation, vehicles, etc.
  - End-use and energy efficiency, including potential for improvements

2) Key Inputs and Assumptions (cont'd.)

Electric Sector

- Cost & Performance
  - Characteristics of new generation based on values from CPUC GHG modeling updated November 2007 *(Presented in Appendix G of Assumptions Book).*
- New Coal Capacity:
  - Assumed the completion of planned/committed coal capacity in the post-2005 period, based on public data sources and a review by the EMT *(units listed in Appendix F of Assumptions Book)*
  - Assumed no further coal construction within WECC beyond that listed in Appendix F.
- Inter-regional transmission capacity
  - based on FERC sources, supplemented with information supplied by the EMT *(see Appendix D in Assumptions Book)*
- Specific sources of public data used for electric generating capacity and operation data shown in section 4.5 of Assumptions Book *(tables on following slides).*
- ***Electricity sector modeling will be described in greater detail in later session.***

3) Modeling Efficiency Investment Options (cont'd.)

- New investments are assumed to achieve the level of efficiency specified in existing standards (e.g., Residential Device Standards – new gas furnaces must be at least 80% efficient).
- Standards changed over modeled period.
- Higher efficiency can be achieved at a cost.
  (i.e., Device Capital Cost in $/mmBtu/Year).
- Capital costs are presented on annualized basis based on the expected life of the investment.
- Upper limit for available efficiency specified as Maximum Device Efficiency.
  (i.e., Natural gas furnaces cannot exceed 97% efficiency – maximums may increase over time as technologies change).

3) Modeling Efficiency Investment Options (cont'd.)

- Model evaluates efficiency choice based on energy costs, capital and operating costs within range between minimum standard and maximum efficiency available.
- All standards, maximum efficiency levels, costs and equipment life are specified for each sector/fuel/end-use combination.
- Energy choices are modeled based on both price and non-price factors (doesn't assume optimal economic solution)
- Non-price factors include market imperfections as well as non-energy considerations (i.e. equipment features, etc.)

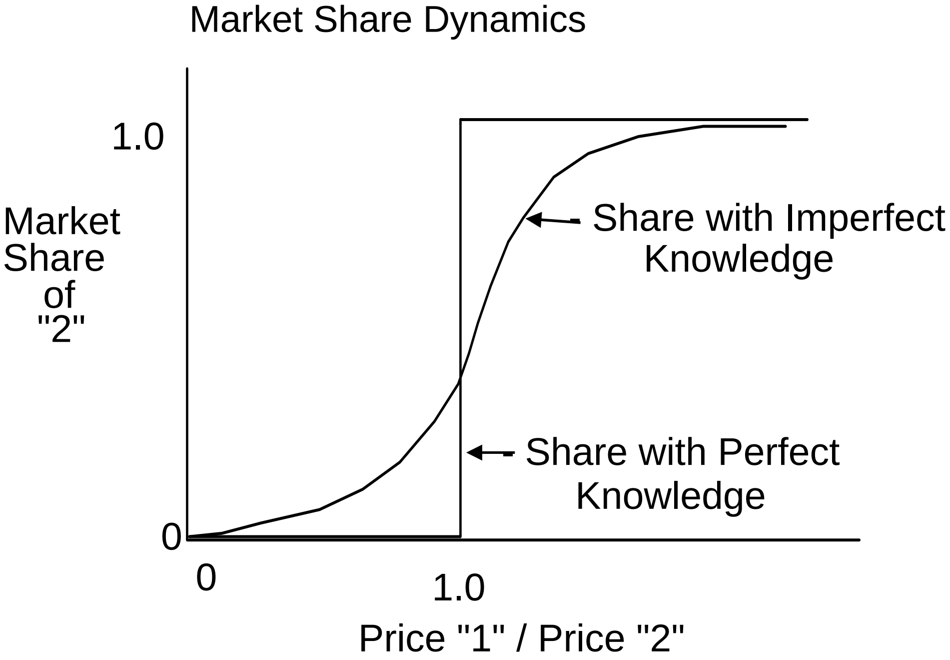
3) Modeling Efficiency Investment Options (cont'd.)

• Investment funds not necessarily allocated to the most economic energy option.

• Uncertainty, regional variations, and limited knowledge make the perceived price a distribution.

• Extent to which 'non-price' considerations affect choice revealed by historic choices: i.e. extent to which past choices varied from optimal economic choice.

• As shown in figure - If all decisions were based on optimal economic solution then choices would shift abruptly when one choice became more economic (perfect knowledge). ENERGY 2020 models imperfect knowledge.



3) Modeling Efficiency Investment Options (cont'd.)

Example 1: Additional water heating requirement

Steps:

- Fuel choice is modeled (fuel use choice actually involves evaluation of subsequent steps):
  - i.e. natural gas, electricity, LPG, oil, solar, etc.
- Portion of market which chooses natural gas for water heating can choose any level of efficiency from 59% (standard) to 86% (maximum).
- Amount of hot water service required (process requirements) may change based on policy and energy costs (e.g., efficient showerheads, front-loading washers, or choice to take shorter showers, etc.)

3) Modeling Efficiency Investment Options (cont'd.)

- Maximum efficiency allowable in model for Natural Gas Water Heater is 86%.

Maximum Device Efficiency							
(Btu/Btu)	Electric	N.Gas	Coal	Oil	Biomass	LPG	Steam
Primary Heat	278%	97%	97%	97%	78%	97%	99%
Water Heating	250%	86%	97%	97%	78%	97%	99%

- Minimum level of efficiency allowable for Natural Gas water heater is 59% (Standard for new NG water heaters).

Device	
Gas hot water from 1990 to the final year	59%
Oil hot water from 1990 to the final year	51%
Electric hot water from 1990 to the final year	92%
LPG hot water from 1990 to the final year	59%

- *from line tables in Appendix J of Assumptions Book.*

3) Modeling Efficiency Investment Options (cont'd.)

Example 1: Additional water heating requirement

Steps:

- The model compares the cost of the water heater efficiency ($36/mmBtu/Year in 2007$) and the additional O&M costs ($0 in this case) vs. the cost of energy saved over the assumed life of the water heater (15 years). Capital cost is equivalent to about $650 for a water heater for an average home.
- For a household using 18 mmBtu/year for water heating, increasing efficiency from 60% to 80% would save about 4.5 mmBtu per year.
- The $162 cost for this efficiency increase *(4.5mmBtu x $36/mmBtu/year)* would be compared to the value of the energy saved as part of the efficiency decision (including applicable carbon permit costs).
- Assuming a cost of $11.50/mmBtu for natural gas, savings over the life of the water heater would equal $776. (4.5mm Btu x 11.50x15 years).

4) Reference Case Programs/Policies

The Reference Case assumes that the provisions of the following policies are implemented in the period modeled:

- Energy Independence & Security Act - 2007
  - New CAFE standards
  - Biofuels mandate (state share assumed constant)
  - Residential boiler and furnace fan standards
  - Walk-in cooler and freezer standards
  - Electric motor efficiency standards
  - External power supply efficiency standards
  - Energy efficient light bulbs
  - Metal halide lamp fixtures
- State Renewable Portfolio Standards currently in place
- Canadian bio-fuels requirements per ecoENERGY for Biofuels/Renewable Fuels Strategy

4) Reference Case Programs/Policies

EISA – Modeling Assumptions

- **Vehicle Efficiency** - Marginal passenger car/light truck efficiency increased by a percentage each year starting in 2011 to reach the mandated fleet efficiency in 2020.
- **Renewable Fuels**:
  - The Act specifies a minimum volume of biofuels to be produced each year.
  - For modeling purposes we have assumed that this volume of biofuels is produced and consumed in each year.
  - Model assumes that each US state will use their pro-rata share of the available fuels.
- **Residential Boilers**: Savings calculated based on ACEEE estimates. Estimates of energy savings associated with furnace fans not included.
- **Walk-In Coolers and Freezers**: Savings calculated based on ACEEE estimates.

4) Reference Case Programs/Policies

EISA – Modeling Assumptions

- Electric Motor Efficiency Standards:
  - Savings calculated based on ACEEE estimates.
- External Power Supply Efficiency Standard:
  - Savings calculated based on ACEEE estimates.
- Energy Efficient Light Bulbs:
  - Implementation of efficiency light bulbs based on assumption that general service lighting accounts for about 90% of residential lighting, 10% of commercial lighting and 5% of industrial lighting.
  - Assumes that CFL’s are used in percentage of existing fixtures.
- Metal Halide Lamp Fixtures:
  - Assumes that 15% of commercial lighting and 60% of industrial lighting now use metal halide fixtures. For new installations the model assumes that 80% of this market would use pulse start ballasts.

4) Reference Case Programs/Policies

Other Policies – Modeling Assumptions

Canadian Biofuels

- 5% renewable content in gasoline required starting in 2010
- 2% average renewable content in diesel fuel and heating oil (distillate) by 2012.

Renewable Portfolio Standards

- All existing RPS for all WECC states and provinces incorporated in model for Reference Case.
- Assumes RPS requirements in any jurisdiction can be met from sources anywhere within WECC
- Provisions of RPS included in model are listed in Appendix I of Assumptions Book.
- Utah RPS not incorporated – will be added in next phase.

5) Reference Case Results

Table B-5: Reference Case Greenhouse Gas Emissions: Eight WCI Partners

GHG Emissions *(MMTCO2e)*	**2006**	**2010**	**2015**	**2020**	**Growth Rate 2006-2020**
Residential	49.7	53.7	58.4	63.1	1.7%
Commercial	29.3	30.5	30.7	31.8	0.6%
Energy Intensive Industry	176.8	174.5	181.5	191.0	0.6%
Other Industry	29.8	30.3	30.5	31.0	0.3%
Passenger Transport	290.8	299.4	303.9	294.0	0.1%
Freight Transport	93.0	89.6	89.9	91.7	-0.1%
Power Sector	176.6	166.8	160.0	176.9	0.0%
Waste & Wastewater	25.6	29.1	34.2	38.4	2.9%
Agriculture (non-energy)	59.9	62.1	67.5	74.9	1.6%
Total	**931.6**	**936.1**	**956.6**	**992.8**	**0.5%**

5) Reference Case Results

Table B-6: Reference Case Energy Use: Eight WCI Partners

Total Energy Use *(TBtu/year)*	**2006**	**2010**	**2015**	**2020**	**Growth Rate 2006-2020**
Aviation Fuel	609	637	683	725	1.3%
Biomass	443	429	453	493	0.8%
Coal	1,185	1,215	1,204	1,259	0.4%
Diesel	1,091	1,051	1,032	1,025	-0.4%
Ethanol	85	173	335	480	13.2%
Landfill Gas	29	29	29	29	0.2%
LPG	231	240	256	282	1.4%
Gasoline	3,303	3,313	3,256	3,053	-0.6%
Natural Gas	3,947	3,779	3,733	4,018	0.1%
Nuclear	658	658	658	658	0.0%
Oil, Unspecified	695	688	692	714	0.2%
Other	2,902	2,949	3,092	3,349	1.0%
Total	**15,178**	**15,161**	**15,422**	**16,086**	**0.4%**

Total Energy Use *(TBtu/year)*	**2006**	**2010**	**2015**	**2020**	**Growth Rate 2006-2020**
Residential	1,638	1,772	1,938	2,119	1.9%
Commercial	1,357	1,388	1,425	1,521	0.8%
Energy Intensive Industry	2,508	2,383	2,324	2,332	-0.5%
Other Industry	1,015	1,033	1,064	1,107	0.6%
Agriculture	140	127	114	104	-2.1%
Passenger Transportation	3,998	4,131	4,252	4,201	0.4%
Freight Transportation	1,219	1,183	1,208	1,251	0.2%
Waste & Wastewater	-	-	-	-	#N/A
Power Sector	3,302	3,143	3,097	3,450	0.3%
Total	**15,178**	**15,161**	**15,422**	**16,086**	**0.4%**

5) Reference Case Results

Table B-7: Reference Case Electric Sector Results: Eight WCI Partners

Generation Capacity *(MW)*	**2006**	**2010**	**2015**	**2020**	**Growth Rate 2006-2020**
Gas/Oil	62,973	72,139	78,999	88,519	2.5%
Coal	14,972	15,372	15,372	15,372	0.2%
Nuclear	9,330	9,330	9,330	9,330	0.0%
Hydro	61,721	63,374	63,428	63,508	0.2%
Landfill Gas/EFW	338	347	347	347	0.2%
Wind	4,083	6,827	18,575	24,513	13.7%
Other	4,358	4,537	5,572	6,582	3.0%
Total	**157,776**	**171,925**	**191,623**	**208,172**	**2.0%**
Generation Output *(GWh/year)*	**2006**	**2010**	**2015**	**2020**	**Growth Rate 2006-2020**
Gas/Oil	143,907	130,579	128,042	164,782	1.0%
Coal	99,280	100,482	98,019	101,454	0.2%
Nuclear	65,072	65,072	65,072	65,072	0.0%
Hydro	256,243	267,713	268,095	268,661	0.3%
Landfill Gas/EFW	2,036	2,088	2,088	2,088	0.2%
Wind	8,733	16,245	48,811	65,273	15.5%
Other	23,554	24,607	30,770	36,219	3.1%
Total	**598,824**	**606,784**	**640,897**	**703,548**	**1.2%**

5) Reference Case Results

Table B-7: Reference Case Electric Sector Results: Eight WCI Partners (cont'd.)

Sales *(GWh/year)*	**2006**	**2010**	**2015**	**2020**	**Growth Rate 2006-2020**
Residential	202,826	218,623	240,918	267,908	2.0%
Commercial	231,140	234,126	245,573	270,164	1.1%
Industrial	163,747	161,434	167,796	187,146	1.0%
Transportation	4,864	6,728	7,908	8,461	4.0%
Street Lights/Misc.	16,447	16,447	16,447	16,447	0.0%
Resale	-	-	-	-	n.a.
Total Sales	**619,023**	**637,357**	**678,642**	**750,126**	**1.4%**

5) Reference Case Results

Table B-8: Reference Case Transportation Sector Results: Eight WCI Partners

Distance Travelled *(millions of vehicle miles travelled)*					
	2006	**2010**	**2015**	**2020**	**Growth Rate 2006-2020**
Passenger	556,055	589,783	635,948	678,750	1.4%
Freight	72,562	73,248	77,423	82,189	0.9%
Passenger Miles/person	8,755	8,781	8,847	8,844	0.1%

Vehicle Efficiency *(miles/gallon)*					
	2006	**2010**	**2015**	**2020**	**Growth Rate 2006-2020**
Light Gas Vehicles	23.2	24.1	25.5	28.5	1.5%
Medium Gas Vehicles	23.2	24.1	25.5	28.4	1.5%
Heavy Gas Vehicles	16.9	17.3	18.5	20.4	1.4%
Heavy Diesel Vehicles	16.9	17.3	18.4	20.3	1.3%

Vehicle efficiency represents fleet-wide average, not the average for new vehicles.

5) Reference Case Results

Table B-9: Reference Case Fuel Prices: Eight WCI Partners

Prices (2007 $/mmBtu)	2006	2010	2015	2020	Growth Rate 2006-2020
Residential					
Res Electricity Prices	29.4	30.9	29.8	30.1	0.2%
Res Natural Gas Prices	11.5	13.5	13.9	14.5	1.7%
Res Oil Prices	21.0	23.3	24.0	25.5	1.4%
Res LPG Prices	22.7	24.2	21.7	21.6	-0.3%
Commercial					
Com Electricity Prices	26.4	27.8	26.7	27.3	0.2%
Com Natural Gas Prices	8.8	10.0	9.8	10.1	1.0%
Com Oil Prices	23.1	25.0	24.0	24.6	0.4%
Com LPG Prices	22.5	24.3	21.7	21.4	-0.4%
Industrial					
Ind Electricity Prices	16.3	17.1	15.5	15.4	-0.4%
Ind Natural Gas Prices	6.7	7.3	6.4	6.3	-0.5%
Ind Coal Prices	2.2	2.2	2.1	2.1	-0.1%
Ind Oil Prices	16.4	18.4	19.2	20.7	1.7%
Ind LPG Prices	23.9	25.5	23.1	23.1	-0.2%
Transportation					
Gasoline Prices	21.9	24.1	26.0	28.0	1.8%
Diesel Prices	21.8	24.0	25.8	27.7	1.7%

1.

5) Reference Case Results

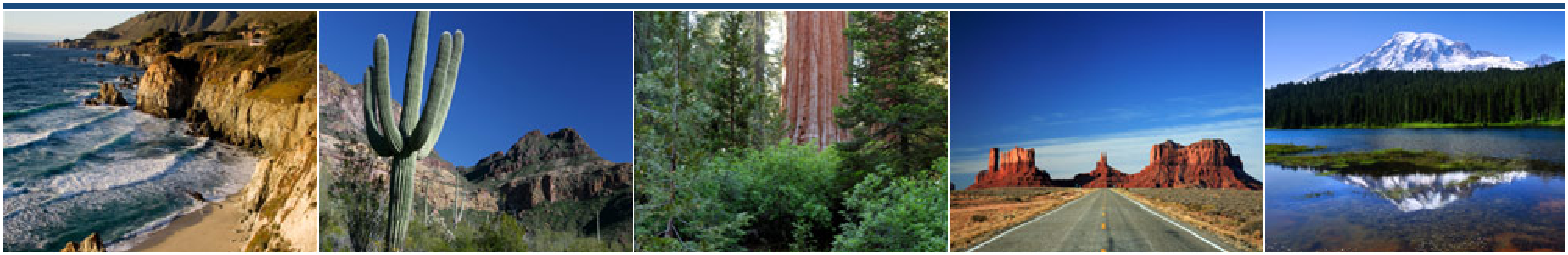
Table B-10: Reference Case Fuel Expenditures: Eight WCI Partners

Summary of Fuel Expenditures (M$/Yr)					
Sector	**2006**	**2010**	**2015**	**2020**	**Growth Rate 2006-2020**
Residential	31,763	37,523	40,670	45,609	2.6%
Commercial	28,452	31,306	31,632	35,373	1.6%
Energy Intensive Industry	28,969	31,248	30,889	32,725	0.9%
Paper	3,709	3,688	3,424	3,514	-0.4%
Chemicals	3,752	4,157	4,215	4,738	1.7%
Petroleum	13,143	14,240	14,295	15,525	1.2%
Nonmetallic Minerals	2,374	2,613	2,614	2,843	1.3%
Primary Metals	2,150	2,262	2,180	2,467	1.0%
Mining Except Oil and Gas	540	524	445	472	-1.0%
Oil and Gas Extraction	3,302	3,764	3,716	3,166	-0.3%
Other Industry	14,567	16,511	16,988	18,496	1.7%
Passenger Transportation	82,031	93,848	103,830	110,035	2.1%
Freight Transportation	28,315	30,055	32,280	35,567	1.6%
Agriculture	3,140	3,142	2,819	2,848	-0.7%
Power Sector	-	-	-	-	n.a.
Waste & Wastewater	-	-	-	-	n.a.
Total	**217,237**	**243,632**	**259,107**	**280,654**	**1.8%**

Note – Table originally presented in September 23 report was subsequently updated on WCI web site on November 10. The incorrect estimates were only used in Table B-10 and did not affect the comparisons of the Reference Case to the policy cases or the sensitivity cases.

Discussion

Western Climate Initiative



Session 3: Review of Policy Cases

Economic Modeling Team Workshop

December 3, 2008

San Francisco, California

Outline of Presentation

- Objective of session: Review Policy Cases
- Topics:
  - Policy Questions
  - Modeling of Cap and Trade
  - Modeling of Complementary Policies
  - Model Results

Policy Questions

- Program Scope: Narrow vs. Broad
- Offsets: Limits
- Banking
- Role of Complementary Policies

Policy Questions

	Two Complementary Policy Cases		Three Cap and Trade Cases		
Scope			Broad	Broad	Narrow
Offsets			No	5%	5%
Banking			Yes	Yes	Yes
Clean Car Standards	Yes	Yes	Yes	Yes	Yes
VMT Reductions	No	Yes	Yes	Yes	Yes
Energy Efficiency	No	No	Yes	Yes	Yes

What We Learned

- Banking
- Offsets
- Complementary Policies:
  - Clean Car Standards
  - VMT
  - Energy Efficiency
- Allowance Prices and Potential Allowance Value
- Compliance Costs

Modeling of Complementary Policies

- Broad-based energy efficiency programs
  - Improved end-use energy efficiencies for electricity and natural gas in iterative fashion until 1% reduction from Reference Case was achieved.
  - Examples provided:
    - **Water heating**
    - **Commercial lighting**
- Clean Car Standards and VMT Reduction
  - Simulated adoption of Clean Car Standards in all partner jurisdictions
  - Improved “process efficiency” in passenger transportation until 2% reduction in 2020 was achieved (WCI-wide)
  - Example provided of both

Example 1 – Natural Gas Water Heat for SF Dwellings

Under the Complementary Policies, by 2020, Natural Gas domestic water heating (DHW):

- Market share for NG decreases 5% - due to increase in solar DHW increases and slight increase in electric DHW
- Process efficiency
  - increases 9% at the margin; 4% on average.
- Process energy requirement for NG decreases by 8%
- Device efficiency
  - Marginal efficiency rises to 70%
  - Average efficiency increases by 8% to 65% on average.
- Energy use for NG water heating decreases by 15% (reduced market share, increased process and device efficiency)
- Device capital cost decreases 6% - reflecting decrease in process requirement offset by increases in device costs.

Example 2: Commercial Lighting

- Lighting requirement may be modified by change in process efficiency (e.g., controls, improved daylighting).
- Device efficiency can increase due to standards or the selection of more efficient lighting at the margin (e.g., CFL lamps, T8’s/electronic ballasts, etc.).

Example 2: Lighting – FIRE* sector

Reference Case

- Average efficiency rises 6% (2005 -2020)

Complementary Policies – by 2020

- Process Efficiency increases 9% on margin, 7% on average
- Device Efficiency increases 19% on margin, 14% on average.
- Energy requirements (mmBtu/year) decrease 18%
- Capital Costs increase by 30% per mmBtu/year
- Device investments increase by 19%.

* FIRE = Finance, Insurance & Real Estate

Example 3: Passenger Transportation

- Transportation requirements (VMT) driven by households and personal income
- May be met by choice of transportation modes or vehicle types.
- CAFE standard in EISA included in Reference Case
- Clean Cars standards included in Complementary Policies.
- Non-price factors tend to dominate vehicle choice

Example 3: Passenger Transportation

Complementary Policies – Change from Reference Case

- No Change to Fuel Prices
- Vehicle efficiency increases 18% at the margin, 15% on average reflecting CA Cars policy.
- VMT decreases by 1.1% reflecting policies aimed at travel demand management.
- Total energy requirements for passenger transportation decreases by 17%.
- Changes in Vehicle Device Investments

Modeling Cap-and-Trade

- Review setting the target:

  2020 Target =
  2006 value for WCI Sub-Total (931.6 Mt) +
  non-WCI Power Sector (70 Mt) =
  1001.6 Mt.

- Hitting the target. Case: "Broad, Comp Policies With Offsets." From Compliance Summary:

  Compliance Total =
  WCI Sub-Total (877.9) +
  Non-WCI Power Sector imports (70.0) +
  Non-WCI Power Sector Reductions (-37.0) +
  Offsets (-31.8) +
  Bank Flow (-31.8) =
  847.2 Mt (or 84.6% of 1001.6 Mt)

Modeling Cap-and-Trade (cont.)

- Model varies the allowance price and iterates to reach a price that results in hitting the target
- Firms and households are simulated as
  - Reducing energy demand
  - Switching to lower-carbon fuel sources
  - And/or taking other mitigation actions

Review of GHG Emissions and Compliance

- See Table B-12 next slide
- Impacts on various sectors of the three cap-and-trade cases are in line with intuition.
- Limit on reduction credit from non-WCI power sector is reached in two of three cases.
- Use of offsets is lower under Narrow vs. Broad Scope.
    - Seems counterintuitive.
    - But both cases use full 5% offsets allowed in 2020, but Narrow Scope is working off a smaller base.
- Banking balance is depleted under Narrow Scope, but healthy in other two cases

Table B-12: GHG Emissions and Compliance Summary

Table B-12: Cap-and-Trade Cases Greenhouse Gas Emissions and Compliance Summary: Eight WCI Partners

GHG Emissions in 2020 *(MMTCO2E)*	**Reference Case**	**Broad, Comp Policies No Offsets**			**Broad, Comp Policies With Offsets**			**Narrow, Comp Policies With Offsets**		
		Value	Diff from Reference	Percent Diff	Value	Diff from Reference	Percent Diff	Value	Diff from Reference	Percent Diff
Residential	63.1	55.0	-8.1	-12.8%	55.2	-7.9	-12.5%	55.9	-7.2	-11.4%
Commercial	31.8	26.2	-5.6	-17.5%	26.4	-5.4	-17.1%	27.0	-4.8	-15.0%
Energy Intensive Industry	191.0	174.5	-16.6	-8.7%	175.0	-16.0	-8.4%	172.6	-18.5	-9.7%
Other Industry	31.0	26.9	-4.2	-13.5%	27.0	-4.0	-12.9%	26.3	-4.8	-15.3%
Passenger Transport	294.0	258.7	-35.2	-12.0%	259.0	-34.9	-11.9%	259.9	-34.1	-11.6%
Freight Transport	91.7	89.9	-1.7	-1.9%	90.4	-1.3	-1.4%	91.7	0.0	0.0%
Power Sector	176.9	114.6	-62.2	-35.2%	131.5	-45.3	-25.6%	104.8	-72.1	-40.7%
Waste & Wastewater	38.4	38.4	0.0	0.0%	38.4	0.0	0.0%	38.4	0.0	0.0%
Agriculture (non-energy)	74.9	74.9	0.0	0.0%	74.9	0.0	0.0%	71.1	-3.7	-5.0%
WCI Sub-Total	**992.8**	**859.2**	**-133.6**	**-13.5%**	**877.9**	**-114.9**	**-11.6%**	**847.8**	**-145.0**	**-14.6%**
Non-WCI Power Sector	70.0	70.0			70.0			70.0		
Non-WCI Power Sector Reductions		-45.0			-37.0			-45.0		
Offsets		0.0			-31.8			-18.2		
Bank Flow		-31.1			-31.8			-0.2		
Compliance Total		**853.1**			**847.2**			**854.3**		
Percent of 2006 Emissions		85.2%			84.6%			85.3%		
Bank Inventory		72.6			74.4			0.5		
Allowance Price (2007 $/MT)		**$63**			**$24**			**$71**		
All emissions in millions of metric tons.										

Review of Total Energy Use

- See Table B-13 next slide
- Impacts on various fuels are in line with intuition
  - Coal and natural gas
  - Transportation fuels
- Impacts on sectoral energy use are in line with intuition
  - Power sector
  - Industrial sectors
  - Transportation
  - Residential and commercial

Table B-13: Cap-and-Trade Cases Energy Use: Eight WCI Partners

	Reference Case	Broad, Comp Policies No Offsets			Broad, Comp Policies With Offsets			Narrow, Comp Policies With Offsets		
		Value	Diff from Reference	Percent Diff	Value	Diff from Reference	Percent Diff	Value	Diff from Reference	Percent Diff
Total Energy Use in 2020 *(TBtu/year)*										
Aviation Fuel	725	717.9	(7.4)	-1.0%	720	(5)	-0.7%	725	-	0.0%
Biomass	493	449	(44)	-8.9%	448	(45)	-9.1%	452	(41)	-8.3%
Coal	1,259	758	(502)	-39.8%	1,043	(217)	-17.2%	618	(642)	-50.9%
Diesel	1,025	995	(30)	-2.9%	1,001	(25)	-2.4%	1,014	(11)	-1.1%
Ethanol	480	421	(59)	-12.2%	420	(59)	-12.4%	419	(61)	-12.7%
Landfill Gas	29	29	(0)	0.0%	29	0	0.0%	29	(0)	0.0%
LPG	282	248	(33)	-11.8%	249	(32)	-11.5%	250	(32)	-11.3%
Gasoline	3,053	2,625	(429)	-14.0%	2,628	(426)	-13.9%	2,635	(418)	-13.7%
Natural Gas	4,018	3,245	(774)	-19.3%	3,075	(944)	-23.5%	3,296	(722)	-18.0%
Nuclear	658	658	-	0.0%	658	-	0.0%	658	-	0.0%
Oil, Unspecified	714	686	(27)	-3.8%	688	(26)	-3.6%	687	(27)	-3.8%
Other	3,349	2,956	(393)	-11.7%	2,952	(397)	-11.9%	2,934	(415)	-12.4%
Total	**16,086**	**13,788**	**(2,298)**	**-14.3%**	**13,911**	**(2,176)**	**-13.5%**	**13,718**	**(2,369)**	**-14.7%**
Total Energy Use in 2020 (Tbtu/year)										
Residential	2,119	1,853	(266)	-12.6%	1,856	(264)	-12.5%	1,863	(257)	-12.1%
Commercial	1,521	1,259	(262)	-17.2%	1,260	(261)	-17.2%	1,265	(256)	-16.8%
Energy Intensive Industry	2,332	2,029	(303)	-13.0%	2,035	(297)	-12.7%	2,005	(328)	-14.0%
Other Industry	1,107	1,001	(106)	-9.6%	1,003	(104)	-9.4%	991	(116)	-10.5%
Agriculture	104	93	(11)	-10.2%	94	(10)	-10.1%	92	(12)	-11.4%
Passenger Transportation	4,201	3,698	(503)	-12.0%	3,702	(499)	-11.9%	3,712	(489)	-11.6%
Freight Transportation	1,251	1,229	(22)	-1.8%	1,235	(16)	-1.3%	1,251	-	0.0%
Waste & Wastewater	-	-			-			-		
Power Sector	3,450	2,626	(824)	-23.9%	2,727	(724)	-21.0%	2,539	(912)	-26.4%
Total	**16,086**	**13,788**	**(2,298)**	**-14.3%**	**13,911**	**(2,176)**	**-13.5%**	**13,718**	**(2,369)**	**-14.7%**

Electric Sector (Table B-14)

- This the focus of Session 4.

Transportation Sector (Table B-15)

- Narrow scope:
  - Excluded from narrow scope cap
  - Clean Car Standards take vehicle efficiency to higher levels
  - VMT reduction policies reduce passenger transportation demand (but not freight)
  - Net reduction in VMT is less than 2% target because higher MPG vehicles encourage people to drive more
- Broad scope
  - Allowance prices increase fuel prices and lead to additional small decreases in VMT, and some decrease in freight demand
  - No measurable effect on vehicle efficiency at projected allowance prices.

Table B-15: Transportation Sector

Table B-15: Cap-and-Trade Cases Transportation Sector Results: Eight WCI Partners

	Reference Case	Broad, Comp Policies No Offsets			Broad, Comp Policies With Offsets			Narrow, Comp Policies With Offsets		
		Value	Diff from Reference	Percent Diff	Value	Diff from Reference	Percent Diff	Value	Diff from Reference	Percent Diff
Distance Travelled in 2020 *(millions of vehicle miles travelled)*										
Passenger	678,750	672,238	(6,512)	-1.0%	672,665	(6,085)	-0.9%	673,720	(5,031)	-0.7%
Freight	82,189	81,516	(673)	-0.8%	81,715	(474)	-0.6%	82,189	-	0.0%
Passenger: Miles/person	8,844	8,759	(85)	-1.0%	8,765	(79)	-0.9%	8,778	(66)	-0.7%
Vehicle Efficiency in 2020 *(miles/gallon)*										
Light Gas Vehicles	28.5	33	4	15.3%	33	4	15.4%	33	4	15.3%
Medium Gas Vehicles	28.4	33	4	15.3%	33	4	15.3%	33	4	15.3%
Heavy Gas Vehicles	20.4	24	4	17.4%	24	4	17.5%	24	4	17.5%
Heavy Diesel Vehicles	20.3	24	4	17.5%	24	4	17.5%	24	4	17.5%
Vehicle efficiency represents a fleet-wide average, not the average for new vehicles.										

Fuel Prices (Table B-16)

- Generally, percentage changes in non-electric prices are in line with intuition.
- Changes in electricity prices are more complicated and discussed in Session 4.

Table B-16: Cap-and-Trade Cases Fuel Price Results: Eight WCI Partners

Prices in 2020 (2007 $/mmBtu)	Reference Case	Broad, Comp Policies No Offsets	Broad, Comp Policies With Offsets	Narrow, Comp Policies With Offsets
	Price	Percent Diff	Percent Diff	Percent Diff
Residential				
Res Electricity Prices	30.1	-0.3%	1.0%	12.7%
Res Natural Gas Prices	14.5	31.4%	12.2%	1.0%
Res Oil Prices	25.5	20.4%	7.7%	-0.1%
Res LPG Prices	21.6	14.6%	5.6%	0.0%
Commercial				
Com Electricity Prices	27.3	-2.4%	-0.2%	14.3%
Com Natural Gas Prices	10.1	23.7%	7.9%	-1.0%
Com Oil Prices	24.6	4.9%	2.1%	0.4%
Com LPG Prices	21.4	9.2%	4.4%	1.3%
Industrial				
Ind Electricity Prices	15.4	4.7%	6.6%	35.6%
Ind Natural Gas Prices	6.3	19.2%	7.1%	20.2%
Ind Coal Prices	2.1	167.4%	64.3%	182.4%
Ind Oil Prices	20.7	17.2%	6.5%	19.4%
Ind LPG Prices	23.1	6.2%	2.9%	7.0%
Transportation				
Gasoline Prices	28.0	17.4%	6.6%	0.0%
Diesel Prices	27.7	16.8%	6.4%	0.0%

Fuel Expenditures (Table B-17)

- **Allowance costs are incorporated into electricity expenditures, but not into other fuels.**
- **This causes some some mixed effects, and some are counterintuitive.**
- **Most significant result is very large fuel savings in passenger transportation.**

Table B-17: Fuel Expenditures

Table B-17: Cap-and-Trade Cases Fuel Expenditure Results: Eight WCI Partners

Annual Fuel Expenditures in 2020 (M$/Yr)	Reference Case	Broad, Comp Policies No Offsets			Broad, Comp Policies With Offsets			Narrow, Comp Policies With Offsets		
		Value	Diff from Reference	Percent Diff	Value	Diff from Reference	Percent Diff	Value	Diff from Reference	Percent Diff
Sector										
Residential	45,609	39,918	(5,691)	-12.5%	40,244	(5,365)	-11.8%	43,138	(2,471)	-5.4%
Commercial	35,373	28,861	(6,512)	-18.4%	29,356	(6,017)	-17.0%	32,098	(3,275)	-9.3%
Energy Intensive Industry	32,725	29,018	(3,707)	-11.3%	29,119	(3,606)	-11.0%	29,831	(2,894)	-8.8%
Other Industry	18,496	17,001	(1,495)	-8.1%	17,062	(1,434)	-7.8%	17,977	(519)	-2.8%
Passenger Transportation	110,035	96,146	(13,889)	-12.6%	96,251	(13,784)	-12.5%	96,577	(13,458)	-12.2%
Freight Transportation	35,567	34,932	(636)	-1.8%	35,111	(457)	-1.3%	35,568	0	0.0%
Agriculture	2,848	2,482	(366)	-12.8%	2,499	(349)	-12.2%	2,669	(178)	-6.3%
Total	**280,654**	**248,358**	**(32,296)**	**-11.5%**	**249,641**	**(31,012)**	**-11.0%**	**257,859**	**(22,794)**	**-8.1%**

Potential Allowance Value

- To review: “Potential Allowance Value” reflects the price of allowances and the costs they may impose on a sector. (Table B-18)
  - Projected as allowance price times emissions, by sector
  - Some or all of this potential value will become a cost incurred by a sector, depending on how allowances are distributed, and the ability of businesses to pass on costs to customers
  - When incurred it is an “accounting cost” (i.e., money is transferred), not an “economic cost” in the sense of consuming societal resources.

Table B-18: Potential Allowance Value

Table B-18: Cap-and-Trade Program Potential Allowance Value: Eight WCI Partners

Allowance Value in 2020 (M$)	Broad, Comp Policies No Offsets	Broad, Comp Policies With Offsets	Narrow, Comp Policies With Offsets
	Diff from Reference	Diff from Reference	Diff from Reference
Sector			
Residential	$3,445	$1,321	$0
Commercial	$1,641	$631	$1,925
Energy Intensive Industry	$10,922	$4,188	$12,293
Other Industry	$1,681	$647	$1,873
Passenger Transportation	$16,197	$6,199	$0
Freight Transportation	$5,630	$2,164	$0
Agriculture	$0	$0	$0
Total	**39,516**	**15,150**	**16,092**
Potential allowance value is calculated as the allowance price times the emissions in the sector. The full allowance value may not be incurred in each sector depending on the manner in which allowances are distributed and the ability to pass allowance costs to customers.			

Annualized Costs (Table B-19)

- These are "compliance cost" estimates for reducing emissions under the cap-and-trade along with complementary policies.
- Review -- Annualized costs:
  - Consist of change in fuel expenditures plus annualized change in capital investment (5% real discount rate over life of equipment)
  - Electric sector costs are embedded in electricity prices
  - Do not include programmatic costs of complementary policies
  - Potential Allowance Value reported separately
- Projected costs:
  - for two industrial sectors are positive
  - for other sectors are negative, and for economy as a whole

Table B-19: Annualized Costs

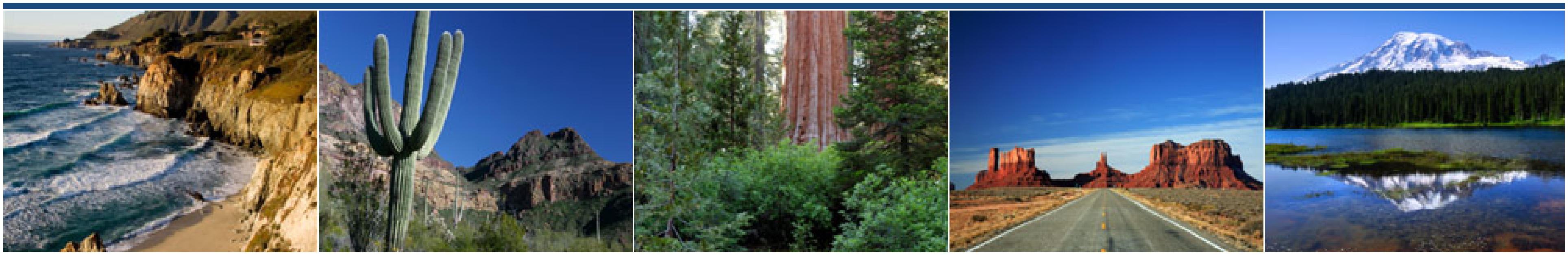
Table B-19: Cap-and-Trade Cases Cost Results: Eight WCI Partners

Annualized Costs in 2020 (M$/Yr)	Broad, Comp Policies No Offsets	Broad, Comp Policies With Offsets	Narrow, Comp Policies With Offsets
	Diff from Reference	Diff from Reference	Diff from Reference
Sector			
Residential	(6,443)	(6,158)	(3,327)
Commercial	(7,845)	(7,369)	(4,760)
Energy Intensive Industry	10,935	10,908	12,674
Other Industry	1,979	1,996	3,250
Passenger Transportation	(20,988)	(20,511)	(19,005)
Freight Transportation	(722)	(522)	0
Agriculture	(442)	(425)	(254)
Total	**(23,525)**	**(22,080)**	**(11,422)**

These costs do not include costs of VMT Reduction programs, Energy Efficiency programs, nor Potential Allowance Value.

Discussion

Western Climate Initiative



Session 4: Electric Sector Results

Economic Modeling Team Workshop

December 3, 2008

San Francisco, California

Outline of Presentation

- Overview of Electric Sector
- Inputs and Outputs
- Capacity Expansion
- Generation, Fuel Use, Emissions
- Transmission
- Financial and Prices
- Summary of Results

Electric Sector Overview

- Capacity Expansion
- Generation
- Fuel Use
- Emissions
- Transmission
- Electric Prices

Electric Sector Inputs

- Peak Load and Energy from Demand Sector
- Fuel Prices from Supply Sector
- New Plant Data – Capital, O&M and Fuel Costs and Heat Rate
- Outage Rates and Must Run
- Financial Parameters
- Regulatory Environment
- Transmission Network – Capacity, Losses, Prices
- Expansion Plan for “Large” Plants

Electric Sector Outputs

- Generating Capacity
- Generation
- Fuel Use and Emissions
- Electric Prices
- Transmission Flows
- Imports and Exports

Electric Plant Types

- Gas/Oil Peaking
- Gas/Oil Combined Cycle
- Gas/Oil Steam
- Coal
- Advance Coal
- Nuclear
- Base Hydro
- Peak Hydro
- Biomass
- Landfill Gas/Waste
- Wind
- Solar
- Fuel Cells
- Pumped Hydro
- Small Hydro
- Wave
- Geothermal
- Other Storage
- Coal with CCS
- Biogas
- Trash
- Other Generation

Individual Units

- Data for most individual plants and units
- Allows greater variety of technologies – just need to have the technological parameters for each type of plant.

Capacity Expansion

- Specify any Known or Expected Construction
- Economic Decision - Build when Wholesale Prices are higher than Cost of New Plant
- Reserve Margin Decision – Build to meet a Desired Reserve Margin
- Mixed Decision - Build when Price is high and Capacity is needed
- Imperfect Market Information – overbuilding
- Renewable Portfolio Standards

Generation Bids and Costs

- Bid Available Capacity
  - Outage Rates
- Bid Prices
  - Marginal Cost
  - Full Cost
  - Other (must run bid zero)
  - Emission Costs
- Bilateral Contract Costs
  - Capital Costs
  - Fuel and O&M Costs
  - Emission Costs

Electric Generation

- Dispatches peak hydro to maximize value of water
- Dispatches plants to minimize costs of bids subject to:
  - Capacity Limits
  - Transmission Constraints
  - Loads
  - Transmission Losses

Fuels Use and Emissions

- Fuel Use is based on Generation and Heat Rates for each unit
- Emissions are based on Fuel Usage and Emission Factors for each unit.
- Emission Reduction Equipment may be added to each unit.

Electric Prices

- LSE Power Costs
  - Bilateral Contracts (dominates)
  - Purchases from Wholesale Market
- LSE Other Costs
  - Distribution
  - Transmission
  - Other Costs (Regulatory)
- RPS Costs
  - Wholesale Price versus RPS Costs

Generator and LSE

- Electric Prices based on LSE costs.
- LSE purchase only the power they need.
- Generators bear brunt of over-building.
- Generators costs have not yet been reported.

Electric Prices and Permit Costs

- Permits costs are passed from the generator to the LSE through:
  - Wholesale Prices
  - Bilateral Contract – variable costs
- The LSE passes the Permit costs to the ratepayer.
- The costs passed on to the ratepayer will depend on the allocation scheme
- Current assumption is 100% auction.

Proxy of First Jurisdictional Deliverer (FJD)

- All WCI generation is subject to the cap.
- Emissions from non-WCI generation are capped at Reference Case levels to prevent leakage.
- Reduced electricity demand in WCI leads to reduced power imports and thus reduced emissions from non-WCI generation.
  - “Credit” for such reduced emissions is limited to 45 Mt in calculating compliance with WCI target

Electric Sector Results

- See Tables B-7 and B-14 (next slides)

- Note: Complementary Policies case inadvertently caused overbuilding of Gas CC plants.
  - This will be corrected in next round of analysis

Table B-7: Reference Case Electric Sector Results: Eight WCI Partners

Generation Capacity *(MW)*	2006	2010	2015	2020	Growth Rate 2006-2020
Gas/Oil	62,973	72,139	78,999	88,519	2.5%
Coal	14,972	15,372	15,372	15,372	0.2%
Nuclear	9,330	9,330	9,330	9,330	0.0%
Hydro	61,721	63,374	63,428	63,508	0.2%
Landfill Gas/EFW	338	347	347	347	0.2%
Wind	4,083	6,827	18,575	24,513	13.7%
Other	4,358	4,537	5,572	6,582	3.0%
Total	**157,776**	**171,925**	**191,623**	**208,172**	**2.0%**
Generation Output *(GWh/year)*	**2006**	**2010**	**2015**	**2020**	**Growth Rate 2006-2020**
Gas/Oil	143,907	130,579	128,042	164,782	1.0%
Coal	99,280	100,482	98,019	101,454	0.2%
Nuclear	65,072	65,072	65,072	65,072	0.0%
Hydro	256,243	267,713	268,095	268,661	0.3%
Landfill Gas/EFW	2,036	2,088	2,088	2,088	0.2%
Wind	8,733	16,245	48,811	65,273	15.5%
Other	23,554	24,607	30,770	36,219	3.1%
Total	**598,824**	**606,784**	**640,897**	**703,548**	**1.2%**

Continued: Table B-7: Reference Case Electric Sector Results: Eight WCI Partners

Sales (GWh/year)	**2006**	**2010**	**2015**	**2020**	**Growth Rate 2006-2020**
Residential	202,826	218,623	240,918	267,908	2.0%
Commercial	231,140	234,126	245,573	270,164	1.1%
Industrial	163,747	161,434	167,796	187,146	1.0%
Transportation	4,864	6,728	7,908	8,461	4.0%
Street Lights/Misc.	16,447	16,447	16,447	16,447	0.0%
Resale	-	-	-	-	#N/A
Total Sales	**619,023**	**637,357**	**678,642**	**750,126**	**1.4%**

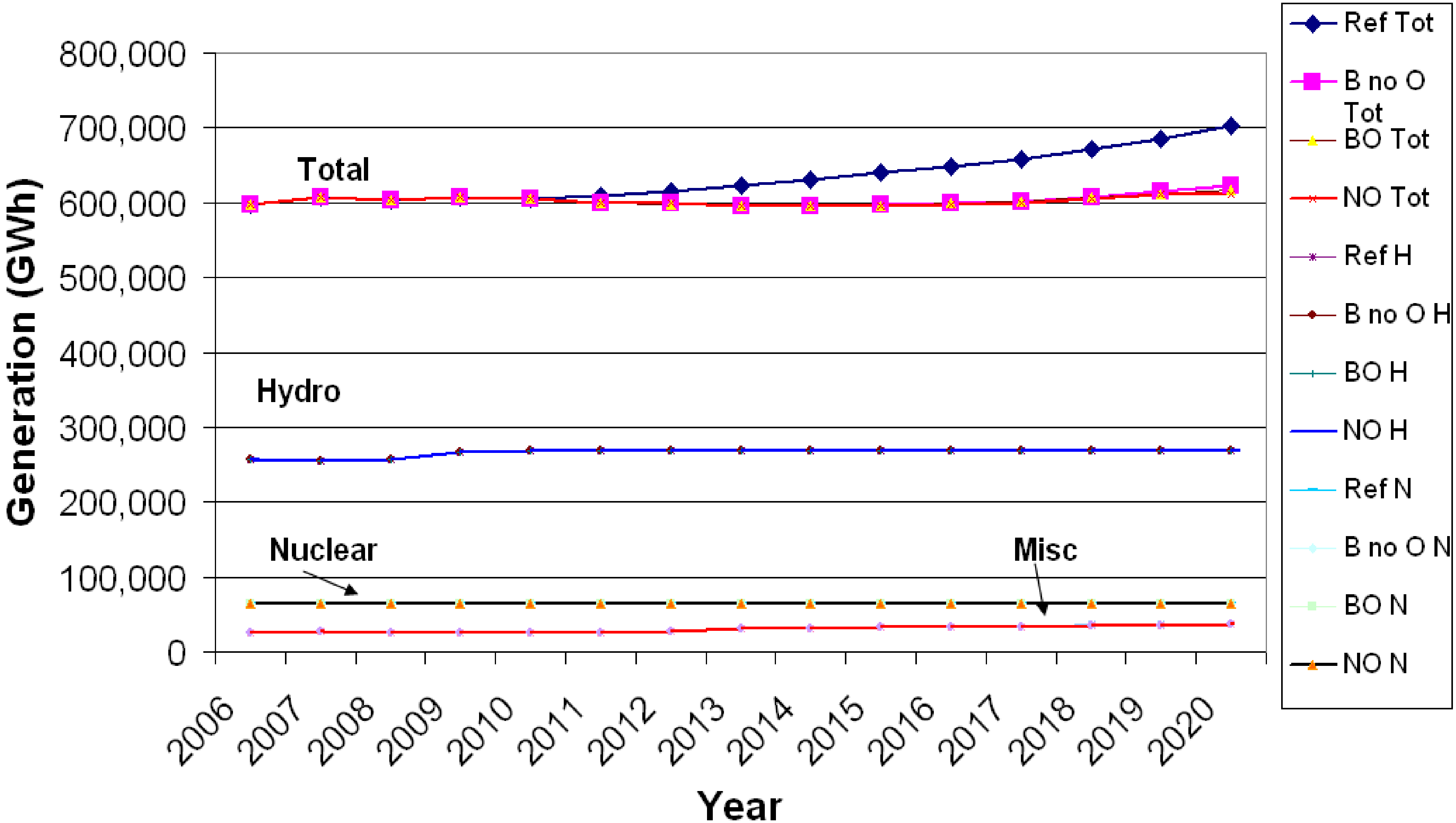
Table B-14: Cap-and-Trade Cases Electric Sector Results: Eight WCI Partners

	Reference Case	Broad, Comp Policies No Offsets			Broad, Comp Policies With Offsets			Narrow, Comp Policies With Offsets		
		Value	Diff from Reference	Percent Diff	Value	Diff from Reference	Percent Diff	Value	Diff from Reference	Percent Diff
Generation Capacity in 2020 *(MW)*										
Gas/Oil	88,519	109,759	21,240	24.0%	109,919	21,400	24.2%	109,879	21,360	24.1%
Coal	15,372	15,372	-	0.0%	15,372	-	0.0%	15,372	-	0.0%
Nuclear	9,330	9,330	-	0.0%	9,330	-	0.0%	9,330	-	0.0%
Hydro	63,508	63,471	(37)	-0.1%	63,471	(37)	-0.1%	63,462	(46)	-0.1%
Landfill Gas/EFW	347	347	-	0.0%	347	-	0.0%	347	-	0.0%
Wind	24,513	22,943	(1,570)	-6.4%	22,945	(1,569)	-6.4%	22,721	(1,792)	-7.3%
Other	6,582	6,354	(228)	-3.5%	6,354	(228)	-3.5%	6,344	(238)	-3.6%
Total	**208,172**	**227,576**	**19,405**	**9.3%**	**227,738**	**19,566**	**9.4%**	**227,456**	**19,284**	**9.3%**
Generation Output 2020 *(GWh/year)*										
Gas/Oil	164,782	127,711	(37,072)	-22.5%	101,382	(63,400)	-38.5%	134,044	(30,738)	-18.7%
Coal	101,454	58,979	(42,474)	-41.9%	85,318	(16,136)	-15.9%	46,848	(54,606)	-53.8%
Nuclear	65,072	65,072	-	0.0%	65,072	-	0.0%	65,072	-	0.0%
Hydro	268,661	268,398	(263)	-0.1%	268,398	(263)	-0.1%	268,337	(324)	-0.1%
Landfill Gas/EFW	2,088	2,088	(0)	0.0%	2,088	0	0.0%	2,088	(0)	0.0%
Wind	65,273	60,920	(4,353)	-6.7%	60,925	(4,348)	-6.7%	60,305	(4,968)	-7.6%
Other	36,219	34,579	(1,640)	-4.5%	34,579	(1,640)	-4.5%	34,558	(1,661)	-4.6%
Total	**703,548**	**617,746**	**(85,803)**	**-12.2%**	**617,761**	**(85,788)**	**-12.2%**	**611,251**	**(92,297)**	**-13.1%**
Sales in 2020*(GWh/year)*										
Residential	267,908	232,745	(35,163)	-13.1%	232,447	(35,462)	-13.2%	230,725	(37,183)	-13.9%
Commercial	270,164	223,406	(46,758)	-17.3%	222,998	(47,166)	-17.5%	221,170	(48,994)	-18.1%
Industrial	187,146	162,812	(24,333)	-13.0%	162,071	(25,075)	-13.4%	162,118	(25,027)	-13.4%
Transportation	8,461	8,268	(193)	-2.3%	8,229	(232)	-2.7%	7,923	(538)	-6.4%
Street Lights/Misc.	16,447	16,447	-	0.0%	16,447	-	0.0%	16,447	-	0.0%
Total Sales	**750,126**	**643,678**	**(106,447)**	**-14.2%**	**642,191**	**(107,935)**	**-14.4%**	**638,383**	**(111,743)**	**-14.9%**

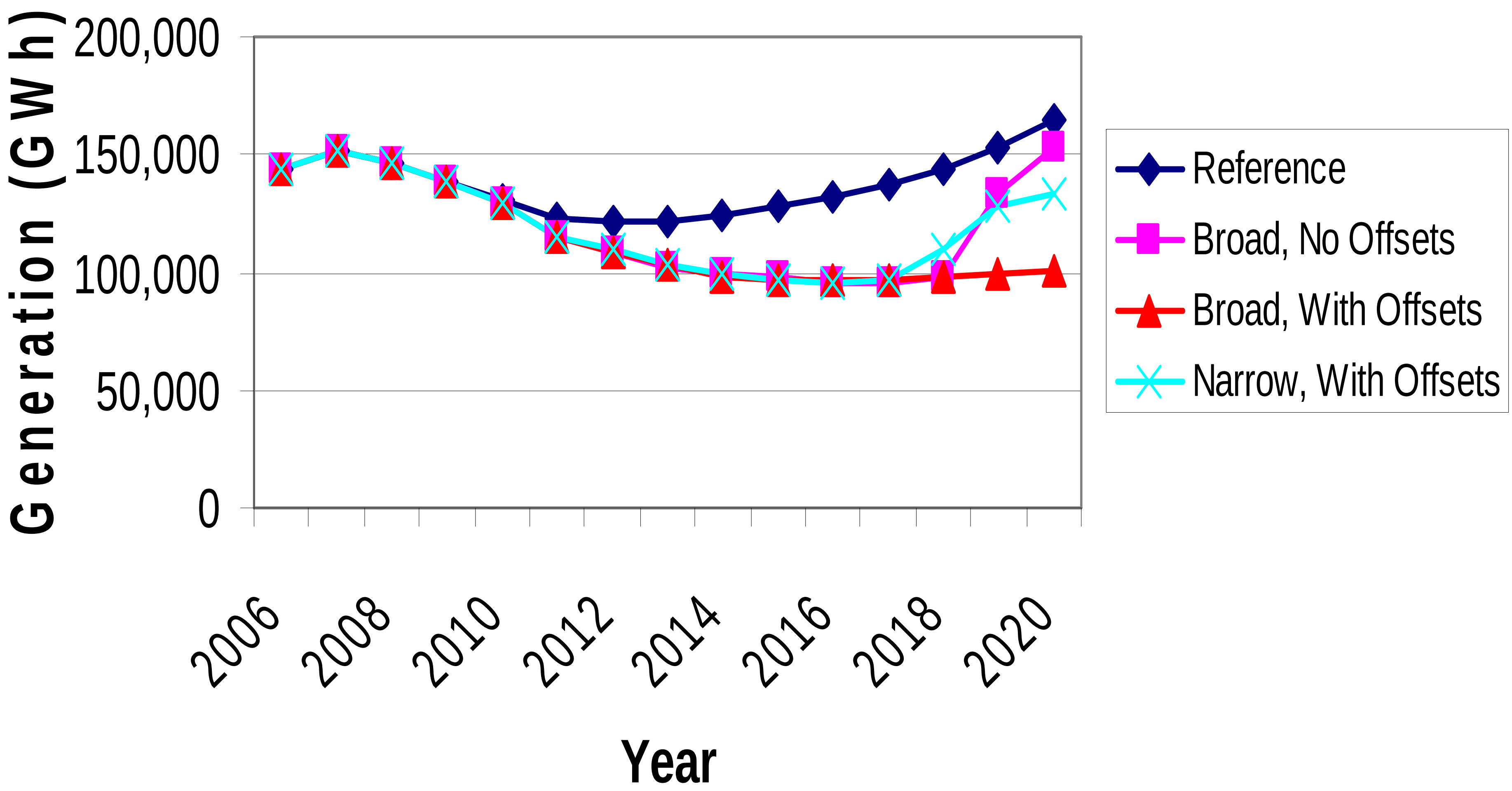
Electric Sector Results (cont.)

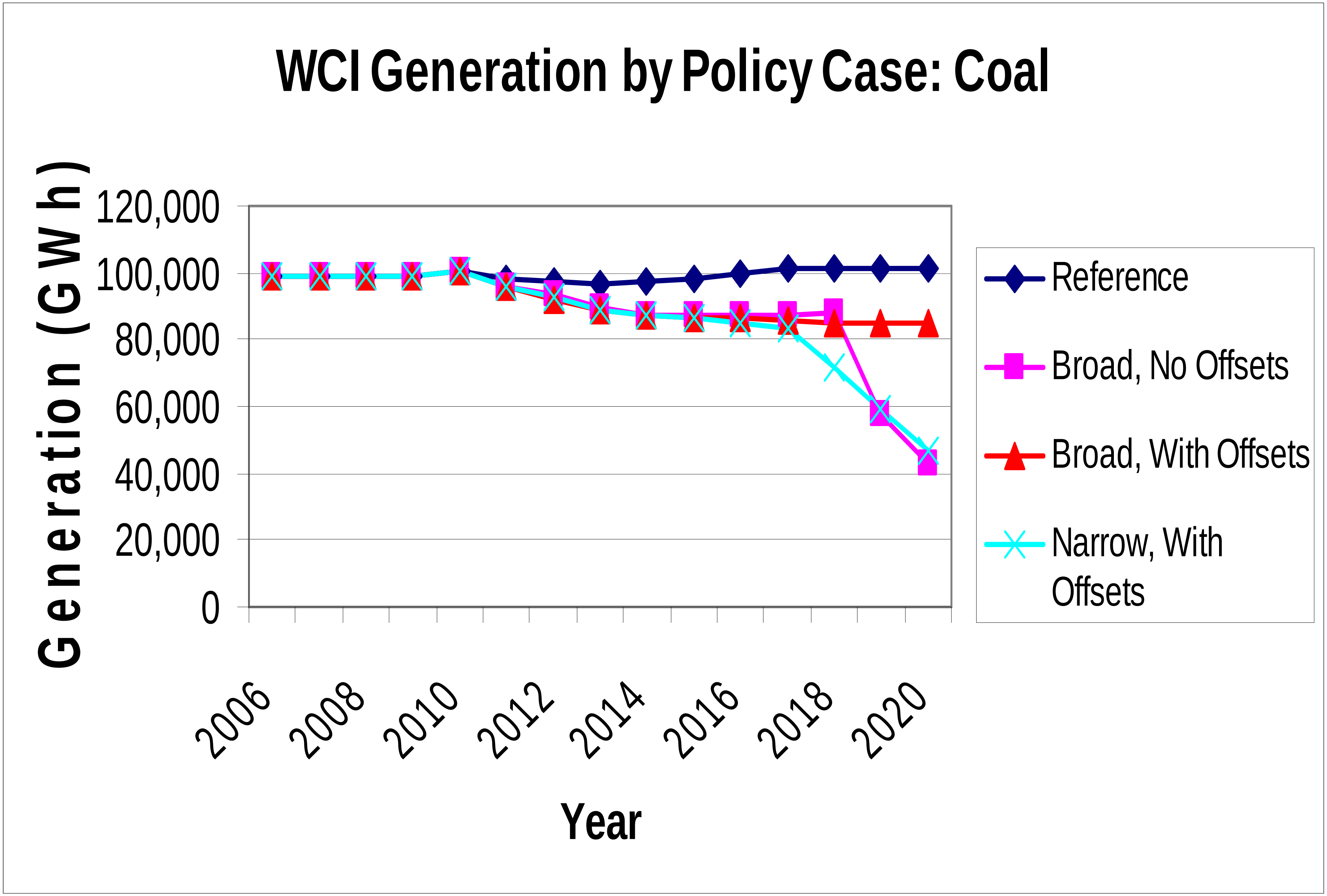
- Next slides show some key results graphically for four cases: Reference Case and 3 Policy Cases
  - Total Generation decreases slightly (and by about the same amount) in the 3 Policy Cases in response to demand reductions
  - Three types of generation are virtually unaffected by the 3 Policy Cases: Hydro, Nuclear, and "Misc" (Landfill Gas/EFW/Other)
  - The lines representing the four cases for these three generation types appear to be a single line in the graph due to lack of variation. In contrast, natural gas, coal, and wind show far more variation.
- Natural Gas and Coal
  - Cap & Trade displaces coal with gas combined cylce as one would expect when a price is put on GHG emissions.
- Wind
  - Demand reduction from complementary policy reduces total electricity sales.
  - Decline in GWh sales reduces the RPS requirement, hence less wind capacity and wind generation.

WCI Generation bu Fuel Type: Total, Hydro, Nuclear, and Misc, for Reference and Three Policy Cases

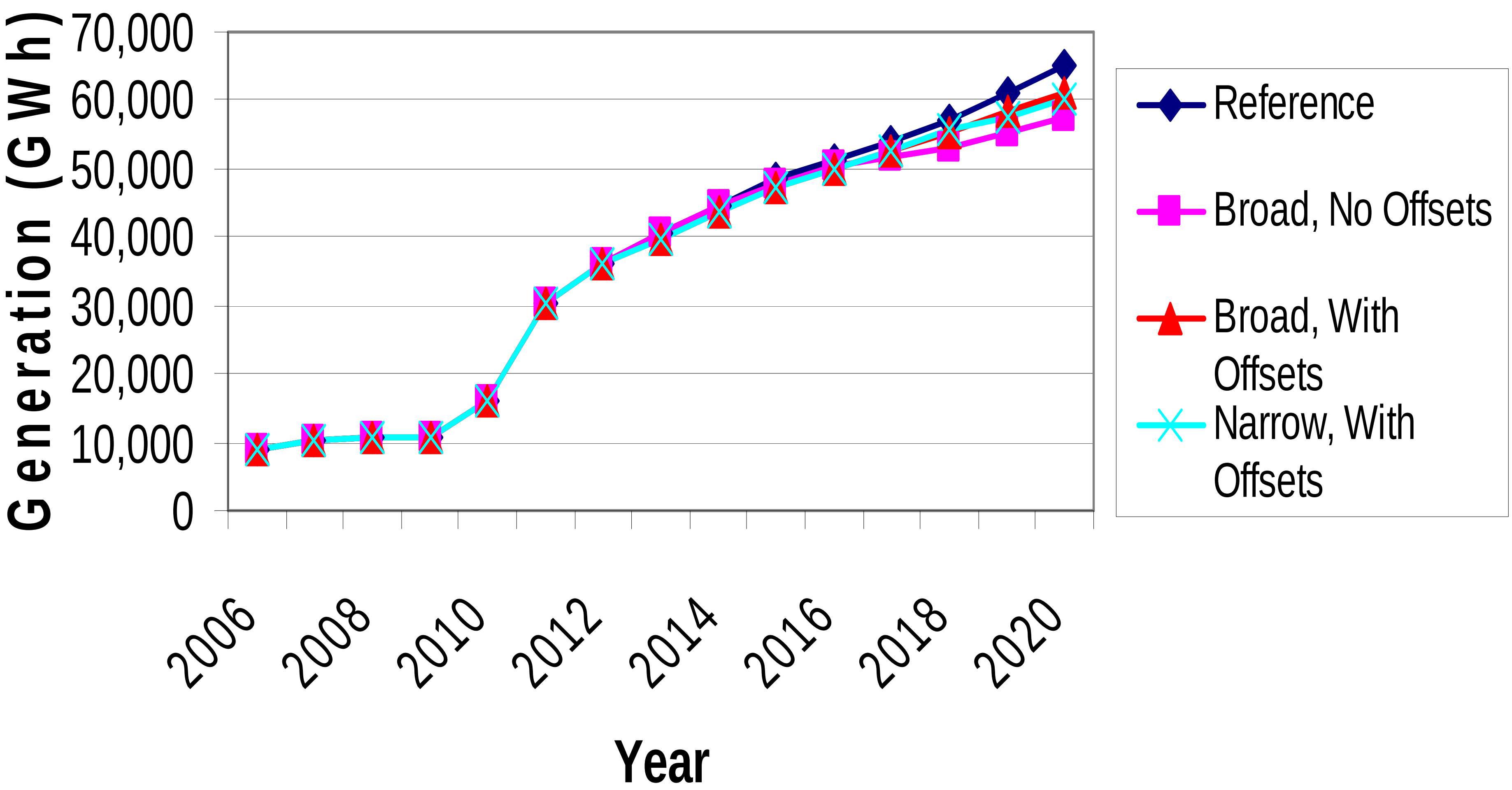


WCI Generation by Policy Case: Natural Gas




WCI Generation by Policy Case: Coal
Generation (GWh)
120,000
100,000
80,000
60,000
40,000
20,000
0
2006
2008
2010
2012
2014
2016
2018
2020
Year
Reference
Broad, No Offsets
Broad, With Offsets
Narrow, With Offsets

WCI Generation by Policy Case: Wind



Electric Prices

- Complementary Policies (implemented alone) would reduce electric prices
  - Reduction in sales enables a higher percent of generation to come from lower cost resources (hydro, nuclear). This would reduce prices.
- However, Cap & Trade Policies generally would increase electric prices.
  - Net effect would vary significantly by customer class due to different load profiles
  - Largest increases appear in "Narrow, Comp Policies, With Offsets"

- Projections below excerpted from Table B-16.

Pct Change in 2020 Electricity Prices by Customer Class	Broad, Comp Polices, No Offsets	Broad, Comp Polices, With Offsets	Narrow, Comp Polices, With Offsets
Residential	-0.3%	1.0%	12.7%
Commercial	-2.4%	-0.2%	14.3%
Industrial	4.7%	6.6%	35.6%

Emissions and Fuel Usage

- How can fuel usage grow faster than emissions?
  - Biomass fuel usage increases
  - There is a shift to newer more efficient natural gas plants with a reduction in oil/gas steam plants and oil/gas combustion turbines.

Discussion

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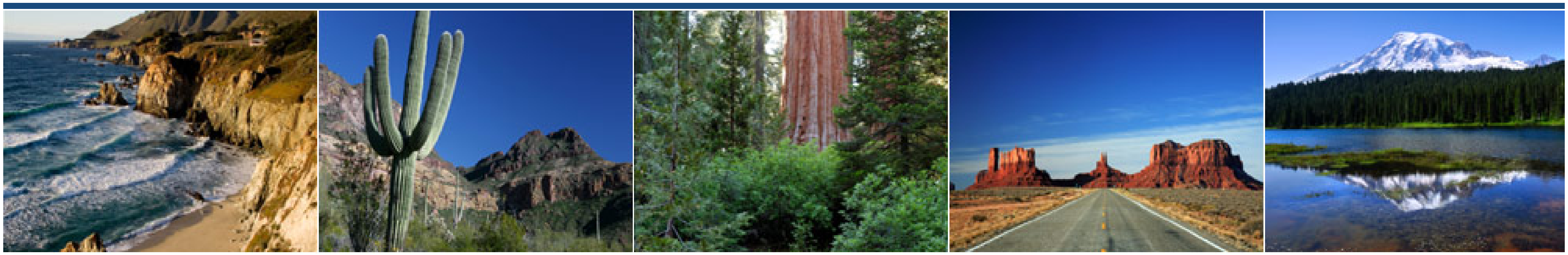

Session 5: Sensitivity Analysis

Economic Modeling Team Workshop

December 3, 2008

San Francisco, California

Outline of Presentation

- Review assumptions in Sensitivity Analyses
- Review results

Three Sensitivity Cases

- High Energy Prices and High Generation Costs Case
  - Energy prices increase by 50% (real) between now and 2020
  - Capital and O&M costs for generation are 30% higher than Reference Case
- Low Energy Price Case
  - Energy prices are as projected in the mid-price case in EIA Annual Energy Outlook 2008. (Reference Case uses high price case.)
- High Natural Gas Price Gas
  - Assumes that cap-and-trade leads to higher natural gas prices (endogenous)
  - Assumes that natural gas prices increase by 50% real between now and 2020
  - Note: projections for three Policy cases resulted in lower natural gas demand
- All three sensitivity cases were applied to cap-and-trade design of broad scope, complementary policies, with offsets

Fuel Prices: High and Low Cases

Table B-20: Fuel Price Forecast:
High Energy Prices and High Generation Costs Sensitivity Case

	2006	2010	2015	2020
World Oil Price (2007 US$/barrel)	64.21	120.37	143.52	166.67
Natural Gas Wellhead Price (2007 US$/mmBtu)	5.97	11.12	13.26	15.40
Coal Prices (2007 US$/ton)	28.98	41.47	48.52	55.90

Table B-21: Fuel Price Forecast: Low Energy Price Sensitivity Case

	2006	2010	2015	2020
World Oil Price (2007 US$/barrel)	$64.21	$71.60	$57.88	$57.74
Natural Gas Wellhead Price (2007 US$/mmBtu)	$5.97	$7.11	$6.09	$6.25
Coal Prices (2007 US$/ton)	$25.37	$26.66	$23.53	$22.33
Source: EIA Annual Energy Outlook 2008 mid-price series.				

Sensitivity Analyses

Excerpt from Table B-22 on three sensitivity analyses

- First and second cases have exogenous price changes that change the Reference Case emissions projection
- Third case has endogenous natural gas price increase, so Reference Case emissions stay the same

- Compare with allowance price of $24/ton with Reference Case fuel prices

GHG Emissions in 2020 *(MMTCO2E)*	Original Reference Case	High Energy Prices & Generation Costs			Low Energy Prices			High Natural Gas Prices		
		Ref Case	Cap-Trade Case	Diff	Ref Case	Cap-Trade Case	Diff	Ref Case	Cap-Trade Case	Diff
WCI Sub-Total	**992.8**	**931.8**	**833.3**	**-98.6**	**1011.4**	**857.0**	**-154.5**	**992.8**	**865.4**	**-127.4**
Non-WCI Power Sector	70.0	70.0	70.0	-	70.0	70.0	-	70.0	70.0	-
Non-WCI Power Sector Reductions			(42.4)			(45.0)			(45.0)	
Offsets			(12.7)			(34.1)			(26.6)	
Bank Flow			-0.2			-0.1			-11.7	
Compliance Total			**847.9**			**847.8**			**852.1**	
Percent of 2006 Emissions			*84.7%*			*84.6%*			*85.1%*	
Bank Inventory			30.8			0.1			168.4	
Allowance Price (2007 $/MT)			**$18**			**$56**			**$20**	

Results

- See next slide, table B-30
- As expected, higher energy and generation costs lead to lower allowance price, greater fuel savings, and greater total savings.
  - Vice versa for lower energy prices
- Illustrates importance of looking at full range of outputs, not just allowance price

Table B-30: Summary Results for 2020: Eight WCI Partners

Case	GHG Emission (MMTCO2E)	Offsets Used (MMTCO2E)	Allowance Price (2007 $)	Change in Fuel Expenditures ($M/Yr)	Potential Allowance Value ($M/Yr)	Total Costs (Savings) ($M/Yr)
Reference Case	992.8	--	--	--	--	--
Cap-and-Trade Policy Cases						
Broad Scope, No Offsets	859.2	--	$63	(32,296)	39,516	(23,525)
Broad Scope, With Offsets	877.9	31.8	$24	(31,012)	15,150	(22,080)
Narrow Scope, With Offsets	847.8	18.2	$71	(22,794)	16,092	(11,422)
Sensitivity Cases						
High Price	833.3	12.7	$18	(42,736)	10,521	($30,514)
Low Price	857.0	34.1	$56	(22,598)	35,642	($16,245)
High Natural Gas Price	865.4	26.6	$20	(6,525)	12,434	$7,880

Fuel Expenditures and Total Costs (Savings) are changes from Reference Case values.
Potential Allowance Value calculated as emissions times allowance price.
Total Costs (Savings) do not include costs of VMT Reduction programs, Energy Efficiency programs, nor Potential Allowance Value.

Discussion

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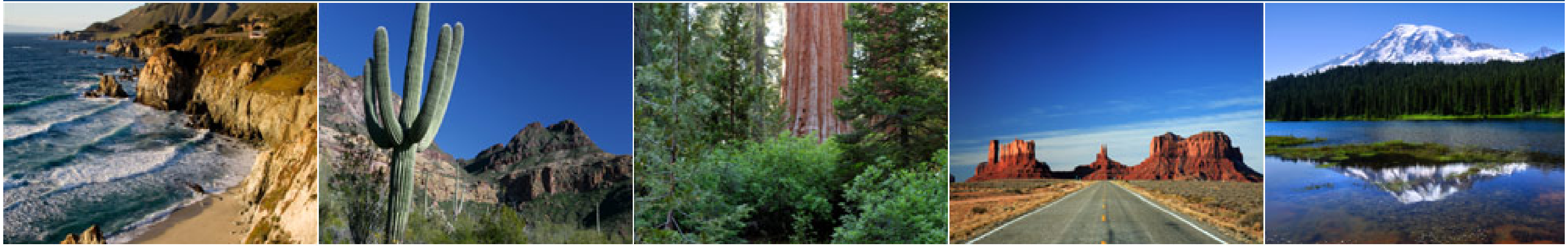

Session 6: General Discussion / Next Steps

Economic Modeling Team Workshop

December 3, 2008

San Francisco, California

Future modeling

- Workplan for Economic Modeling Team is under development
  - Input is welcome
- Draft workplan includes:
  - Expand model to include Manitoba, Ontario, and Quebec.
  - Repeat analyses released in September to include all partners.
  - Conduct additional analyses:
    - Policy Cases
    - Sensitivity Cases

Discussion

Questions for the December 10 Stakeholder Discussion on Default Emission Factors for Unspecified Imports[1]

The purpose of this stakeholder call is to help the Electricity Subcommittee develop recommendations to the WCI Partners on the development of default emission factors. There are several issues we hope to cover during call, related to the number of factors needed, calculation methodologies, and other implementation questions. The following questions will be used to help structure the discussion.

1. Geographic disaggregation
   - The straw proposal suggested that default factors be developed for five different import zones: Alberta, western U.S., Baja California, central U.S./Canada, and northeastern U.S. Are more (or fewer) zones needed?
2. Temporal disaggregation
   - Is more than one factor needed for each geographic zone to represent time-of-day or seasonal variation in resources used for export from non-WCI states and provinces or is one factor sufficiently accurate?
3. Methodology for calculating default factors
   - How sophisticated does the methodology need to be? Would a simplified load duration curve approach be acceptable or are more complex production cost models necessary?
   - Alternatively, should a high default emission factor be used?
4. Implementation questions
   - What data are available related to unspecified WCI imports and the resources used to generate the imported power?
   - How far in advance should the default factors be announced?
   - How frequently should the default factors be updated? Every year or every compliance period?

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[1] For background, please refer to the November 10 paper, "Straw Proposal on Reporting GHG Emissions Associated with Electricity Imported from non-WCI Jurisdictions."
http://www.westernclimateinitiative.org/ewebeditpro/items/O104F20477.pdf

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ELECTRICITY SUBCOMMITTEE DISCUSSION PAPER ON RENEWABLE PORTFOLIO STANDARDS, RENEWABLE ENERGY CERTIFICATES, AND GHG ACCOUNTING

December 8, 2008

Scott Murtishaw, California PUC

Introduction

Twenty-six states and the District of Columbia have adopted Renewable Portfolio Standards (RPS) that require retail providers of electricity to meet a minimum share of their loads with renewable energy sources. In order to simplify RPS compliance accounting and minimize locational constraints on renewable development, many RPS programs use Renewable Energy Certificates (RECs) to track compliance. Now that several states and provinces have implemented, or are in the process of implementing, greenhouse gas (GHG) cap and trade systems that cover electricity generation, questions have arisen concerning the appropriate role that RECs should play with respect to GHG accounting in a cap-and-trade system.

Much of the current confusion stems from the fact that some states have defined a REC as including “avoided emissions” of GHGs among the environmental attributes contained in a REC. With the impending need to develop reporting rules for the WCI Partners, it is becoming increasingly important to clarify what value the “avoided emissions” attribute conveys and how RECs may affect a purchasing entity’s GHG compliance obligation.

This discussion paper addresses the relationship between GHG accounting and RECs used for RPS compliance, as well as the “null” power that remains when RECs have been unbundled and sold separately. It does not address two related topics. First, some parties have suggested that RECs be accepted as a form of offset to reduce regulated entities’ GHG compliance obligations. While some REC definitions may allude to “avoided emissions,” recent publications have expressed serious misgivings about the direct use of RECs as offsets (Gillenwater 2007; Point Carbon 2008). Objections are raised on two accounts: 1) estimates of avoided emissions are rarely subject to a rigorous calculation taking into account both short-term (“operating margin”) and longer-term (“build margin") effects and 2) the issuance of RECs is not subject to additionality analysis. A final consideration is that since offsets must come from outside the scope of the capped sectors, the possibility of using RECs as an offset equivalent would be limited to RECs produced by facilities located in uncapped jurisdictions.

The second topic not addressed here is the possible creation of allowance set-asides to support the voluntary renewables market. Such set-asides have been adopted in nine of the ten Regional Greenhouse Gas Initiative (RGGI) states. Set-asides support the voluntary market by allowing sellers of voluntary renewable energy products to continue to make claims that the purchase of their products contributes to GHG reductions. The RGGI states operate their set-asides by reserving a certain quantity of allowances and retiring them at a fixed rate for every megawatt-hour of renewable energy produced within the cap and sold into the voluntary market. In effect, the purchase of voluntary renewable energy reduces GHG emissions by removing allowances from circulation and thereby ratcheting down the cap.[1]

Implications of Cap and Trade on Avoided Emissions

Prior to the implementation of a cap, a wide variety of mandatory programs and voluntary actions contribute to GHG reductions. One of the principal programs for achieving GHG reductions in the electricity sector is the adoption of RPS laws. Because the addition of new renewable resources presumably avoids the need for additional generation from conventional sources, the addition of renewable sources leads to some level of avoided GHG emissions.

After implementation of a GHG cap, individual measures and programs no longer reduce GHG emissions because the allowable level of emissions has been determined by the cap and the corresponding number of allowances issued. To illustrate, imagine that before a cap, a wind farm's generation results in the ramping down of fossil-based generation that would have otherwise been needed to meet load. Every megawatt-hour that wind farm produces avoids the emissions that would have been produced by the marginal generator. Once the cap is in effect, reduced generation by a fossil-based power plant also reduces the compliance obligation of that plant. The need for fewer allowances by these generators frees up allowances that may be used by other generators or any other regulated entity in the economy. However, RPS, energy efficiency programs, tailpipe emission standards and other mandatory programs continue to serve as critical strategies for meeting the cap and ensuring that GHG allowance prices remain at acceptable levels.

Because renewable electricity produced in a capped jurisdiction does not, in a sense, reduce GHG emissions, no avoided emissions occur and consequently, the avoided emission value of a REC generated in a capped region equals zero. In other words, the REC would not have a "negative" value that could be used to

[1] For a general introduction to set-asides, see Petlin 2008.

reduce the GHG compliance obligation of the buyer. To do so would be to treat the REC as an offset despite the fact that the generation that produced the REC was subject to the GHG cap. If RECs from capped jurisdictions were to have an avoided emissions value that could reduce one entity's compliance obligation, then, in order to balance the GHG accounting books, WCI regulators would have to attribute emissions to the null power. Renewable facilities would lose any additional marketable value that RECs might acquire from their offset capacity to the need to also purchase allowances to comply with the GHG cap-and-trade regime.

Continuing to assign an avoided emission value to RPS RECs after a cap would create additional complications because RPS programs and GHG cap-and-trade programs cover two different (but sometimes overlapping) points of regulation. RPS programs, by definition, apply to retail providers of electricity. Since the cap and trade system is applied at the generator level for the electricity sector, retail providers are not, per se, regulated entities in the cap and trade system. Retail providers would only have a compliance obligation for emitting generation plants that they own. Many retail providers have very little, if any, owned fossil-fired generation. This is true of electric service providers, restructured retail providers that are primarily distribution utilities, and utilities served mostly by hydro plants. Any offset value contained in the RECs would be useless to these retail providers. For utilities that do own a substantial amount of fossil-fired generation, the offset value would simply shift the compliance obligation from the utility-owned sources to renewable energy generators, who would have to factor a GHG compliance cost into their prices. While utility-owned sources would potentially benefit from the GHG compliance reduction benefits of the RPS RECs, independent generators would not.

In light of the discussion above, it is recommended that RECs produced in the WCI, or other capped jurisdictions, have no GHG compliance reduction value. These RECs would serve as an RPS compliance accounting tool, but there would be no interaction between these RECs and the reporting of GHG emissions for compliance purposes. If RECs generated within a capped jurisdiction and used for RPS compliance have no avoided emissions value, GHG accounting remains simple and straightforward. This is the approach that has been adopted in the RGGI states.

The treatment of RECs and null power imported from uncapped areas is potentially more complex. Since renewable facilities located in uncapped jurisdictions are not subject to the WCI cap (except to the extent that First Jurisdictional Deliverers (FJDs) import power from these facilities), it could be argued that purchases of RECs from uncapped jurisdictions do avoid emissions. If the RECs from an uncapped region were able to reduce a GHG compliance obligation (e.g., an electricity importer could retire a non-WCI REC for each MWh imported in lieu of surrendering allowances at the default rate) and the null power could be imported as zero-GHG power, the zero-GHG attribute of any given megawatt-hour could be double counted. In order avoid the possibility of double counting the zero-GHG attribute, the WCI Partners should not accept non-WCI

RECs as a compliance reducing mechanism and attribute zero GHG emissions to specified imports of null power.

Preventing double counting of non-WCI renewable power can be accomplished in one of three ways. To receive zero-GHG attribution:

1. renewable power would have to be sold on a bundled basis with both the power imported on a specified basis and the corresponding RECs retired by a WCI entity, or
2. RECs from uncapped jurisdictions could be paired with imported unspecified power in order to “respecify” the power as having originated from the facility designated on the REC and null power from uncapped jurisdictions would be attributed default emissions, or
3. the power from a renewable facility imported on a specified basis would be attributed zero emissions and RECs from uncapped jurisdictions would have no effect on GHG accounting.

A description of each option and the implications of each option for the electricity market, the REC market, and GHG accounting are provided below.

Option 1: Zero GHG Attribution Requires Import of Bundled Renewable Energy and RECs

This option would require imported renewable power to be bundled with RECs in order to receive the attribution of zero GHGs. Consider an example in which a retail provider in WCI enters into a contract for both the power and the RECs from a wind farm in Wyoming. The WCI retail provider retires the RECs from the wind farm in the same year they are generated. The WCI retail provider also arranges the transmission from the wind farm’s balancing authority into its own balancing authority and is therefore the entity shown on the NERC e-tag at the first point of delivery in WCI. In this case, the attribution of zero GHG is clear. The WCI retail provider is the FJD, buys both the power and the RECs, and retires the RECs. However, there are several restrictive assumptions in this scenario that, if violated, would complicate implementation of this option.

First, the retail provider may not necessarily retire RECs in the same year they are purchased. RPS programs generally allow retail providers to bank RECs so that RPS targets do not have to be perfectly matched to generation every year. If the WCI retail provider does not retire the RECs associated with its bundled imports, it could potentially sell the REC back into the market in a subsequent year, and the REC could ultimately be retired by a non-WCI utility. If that were to happen, the WCI retail provider would have received zero GHG attribution for what was essentially null power. A requirement that the RECs from bundled imports be retired during the reporting year to receive zero GHG attribution would prevent this. This would simply incentivize WCI retail providers to retire the RECs associated with bundled imports during the year of the transaction and use only WCI RECs for banking.

An additional complication arises if any entity other than the WCI retail provider retiring the RECs is the FJD selling the bundled product into the WCI. A wholesale power marketer could sell a bundled renewable energy product from a non-WCI jurisdiction to a WCI retail provider, but if the marketer is the FJD, it would depend on the purchasing retail provider to retire the RECs during the reporting year the transaction takes place. Otherwise, the FJD marketer would be hit with a compliance obligation that it did not expect.

Contracts could be structured to deal with these issues in one of two ways. Either the contracts could specify that the WCI utility buying the bundled product would always be the FJD, or the contracts could hold the WCI utility liable for the failure to retire the RECs associated with the bundled product.

Aside from the restrictive rules of this approach, one possible legal concern is that it could trigger objections related to the dormant Commerce Clause. Developers of renewable facilities in non-WCI jurisdictions might argue that the bundling and retirement obligations for imported renewable electricity are more burdensome than the zero GHG attribution given to renewable facilities in WCI, which would face no such requirement.

Option 2: Zero GHG Attribution Stays with RECs

Another option for ensuring that the zero GHG attribute is not double counted is to allow non-WCI RECs to have to the ability to respecify unspecified imported energy such that imported system power bundled with imported RECs would be treated, for GHG accounting purposes, as having originated from the facility identified on the REC.[2] In turn, any renewable energy imported on a specified basis would have emissions attributed to it at the default rate. This would probably result in very little importing of specified renewable power since there would be no compliance benefit.

Similar to Option 1, this option is relatively simple as long as the FJD of the imported power is also the same entity buying and retiring non-WCI RECs. However, FJDs of unspecified power who would have the GHG compliance obligation frequently differ from the retail providers that must purchase and retire RECs for RPS compliance. It would be unfair if marketers were not also enabled to bundle non-WCI RECs with imported system power. Like Option 1, the FJD marketers would depend on the retail providers to which they sell re-bundled power to retire the RECs. Contractual arrangements could also be made similar to Option 1, but this might raise transaction costs between marketers and retail providers. It would also complicate any transactions for FJD marketers wanting to sell the bundled product into a pooled market or at a major hub. The obligation to

[2] Theoretically, non-WCI RECs could also be used to respecify other specified power, but this may induce the use of non-WCI RECs to respecify coal-fired power. The Electricity Subcommittee hesitates to give non-WCI RECs that degree of compliance reduction potential.

retire the RECs during the reporting year would have to flow through to every subsequent buyer until it terminated with a WCI retail provider.

Any unbundled non-WCI RECs purchased by a WCI retail provider would also have foregone value if the WCI retail provider finds itself with more non-WCI RECs than imported system power for which they are the FJDs. This would offer the possibility of deals to be struck between WCI utilities and FJDs facing a compliance obligation for unspecified power. Since a retail provider's non-WCI RECs would have the ability to reduce an FJD's compliance obligation, FJDs could find retail providers who, in exchange for some cost sharing of the non-WCI RECs, would claim that the system power was imported for their loads. The non-WCI RECs would essentially be matched to unspecified imports after the fact.

Because non-WCI RECs would serve the dual function of demonstrating compliance with RPS programs and reducing GHG compliance obligations, non-WCI RECs may fetch a higher price than WCI RECs. However, this would not bias development in favor of non-WCI locations as long as emissions are attributed to the null power. The following tables demonstrate the possible market dynamics that could occur with non-WCI RECs having the ability to respecify imported power as zero-GHG power. Table 1 lists the assumed values used to derive the wholesale power prices, REC values, and compliance costs used for the WCI and non-WCI revenue comparisons in Table 2.

Table 1. Input Values for Comparison of WCI and non-WCI Renewable Energy Generation Revenues

Input Description	Value
GHG Allowance	\$40/metric ton CO_2e
Marginal Operating Emission Rate of in-WCI Generation and Imports	500 kg CO_2/MWh
Default Emission Rate	500 kg CO_2/MWh
Prevailing Wholesale Electricity Price, no GHG Cost	\$60/MWh
Prevailing WCI Wholesale Electricity Price, w/ GHG Cost	\$80/MWh
Levelized Renewable Generation Cost	\$90/MWh
WCI REC Price*	\$10/MWh

* This assumes that REC prices in a mature market will tend to cover the difference between prevailing wholesale prices and the generation cost of renewable resources.

Given these assumptions, it seems possible that non-WCI RECs would sell for a higher price than WCI RECs because the non-WCI RECs would have regulatory value for satisfying RPS requirements as well as reducing GHG compliance obligations. For example non-WCI RECs could sell for around \$30 because they would provide the RPS compliance value that \$10 WCI RECs do and a GHG compliance value of \$20.

Table 2. Comparison of per MWh Revenues for Renewable Energy Facilities in and out of WCI

Revenues and Costs	RE facility in WCI, sells power and RECs to WCI	Non-WCI RE facility sells power and RECs to WCI	Non-WCI RE facility sells RECs to WCI and power to non-WCI
Electricity REC GHG Cost	\$80 \$10 \$0	\$80 \$30 (\$20)	\$60 \$30 \$0
Total	\$90	\$90	\$90

Table 2 shows that whether the renewable facility is located in WCI or outside WCI it will in most cases earn the same per MWh revenues. If a non-WCI facility sells into the WCI markets that reflect an internalized GHG compliance cost, it will earn higher revenues but it will also face a compliance cost. Any additional revenue it could earn would be largely forfeited as an additional compliance cost.

There are some interesting implications of implementing Option 2. One is that by requiring the use of RECs to receive attribution of zero-GHG power, non-WCI renewable energy could not be used both to satisfy the RPS compliance of a non-WCI retail provider and to help the WCI meet its cap. If the REC from a non-WCI renewable facility is used by a non-WCI utility for its RPS, emissions would be attributed to the null power. However, this would not be true for renewable facilities in WCI. Their RECs could potentially be used by a non-WCI utility to meet its RPS requirements, but the null power would have no emissions attributed to it. One would expect that to the extent there are unspecified imports, non-WCI RECs would be used to respecify them as zero-GHG power. Non-WCI retail providers who need RECs would be indifferent to the source. The market would likely match non-WCI RECs closely to the level of unspecified imports, and non-WCI retail providers would purchase WCI RECs to cover any shortfall in non-WCI RECs. Simply put, this approach may induce some REC swapping between capped and uncapped jurisdictions that would not necessarily occur otherwise.

This option would seem to create incentives for unnecessary transactions among WCI retail providers and FJDs of unspecified power and a division of the REC market into two different products with different regulatory values.

Option 3: Renewable Power Imported on a Specified Basis Receives Zero-GHG Attribution and RECs from Uncapped Jurisdictions have no Effect on GHG Accounting

Under Option 3, renewable energy could be imported on a specified basis like electricity from other sources, subject to verification of contractual terms, settlements, and transmission data. Null power and RECs from non-WCI sources would be treated the same as null power and RECs from WCI sources. While this would avoid the complications that stem from explicitly linking RPS programs and RECs to GHG accounting, some parties may object on the grounds that renewable energy generated outside WCI could be used to meet a non-WCI state's RPS targets, while the null power would also receive a zero GHG attribution and thereby contribute to meeting the WCI Partners' cap. However, in this regard, the non-WCI renewable facility would be no different than in-WCI renewable generators because RECs generated in a WCI state could also be used by a non-WCI retail provider to meet its RPS requirements, and the null power would help the WCI Partners meet their cap.

Option 3 would require the WCI Partners to share information on specified imports to ensure that reported imports from any given source do not exceed output during the reporting period. Note that Option 3 does not preclude the use of shaping and firming to efficiently transmit non-WCI renewable energy from its region of origin.

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January 6, 2008 Essential Requirements of Mandatory Reporting for the Western Climate Initiative, Third Draft

List of Commenters

AB 32 Implementation Group

Air Products and Chemicals

Alcoa

Aluminium Association of Canada

American Forest & Paper Association

American Petroleum Institute

BC Forestry Climate Change Work Group

BC Hydro

Business Council of British Columbia

Canadian Association of Petroleum Producers

Canadian Chemical Producers Association

Canadian Gas Association

Canadian Lime Association

Canadian Manufacturers and Exporters

Canadian Petroleum Products Institute

Canadian Steel Producers Association

Carestream Health

Cement Association of Canada/Portland Cement Association

Coal Association of Canada

Deloitte & Touche, LLP

Devon Energy Corporation

El Paso Corporation

Forest Products Association of Canada

Independent Energy Producers Association

INVISTA (Canada) Company, Kingston Site

INVISTA (Canada) Company, Maitland Site

INVISTA (Canada) Company, Millhaven Site

Manitoba Hydro

Mining Association of British Columbia

National Lime Association

Nucor Bar Mill Group

Ontario Energy

Ontario Forest Industries Association

Ontario Power Generation

Pacific Gas and Electric Company

PNGC Power Cooperative

Puget Sound Energy

Quebec Forest Industry Council

Rio Tinto

Sacramento Municipal Utility District

Salt River Project

Shell Oil and Shell Canada

Southern California Edison

Spectra Energy

Stoel Rives

Terasen Gas Inc.

Utah Business Climate Change Coalition

Waste Management

West Associates

Western Climate Action Network

Western States Petroleum Association

Weyerhaeuser

Wyoming Mining Association

ATTACHMENT 11: ALUMINUM PRODUCTION

Applicability

These methodologies apply to all facilities that convert raw alumina mineral (Al_2O_3) to raw aluminum metal by an electrolytic process. Emissions must be reported for the following processes:

- CO_2 from anode consumption,
- CO_2 from anode and cathode baking,
- PFC from anode effects,
- CO_2 from green coke calcination, and
- SF_6 from cover gas consumption,

Primary aluminum smelting facilities can emit GHG from other activities that are not directly part of the aluminum smelting process. GHG emissions from the following activities are covered under other sections of the reporting Essential Requirements:

- Stationary combustion emissions from boilers, heaters, furnaces (§ WCI.20),
- Nonroad equipment (§ WCI.XX),
- Lime calcination (§ WCI.170), and
- SF_6 use in electrical equipment (§WCI.XX).

HFC use for refrigeration and cooling and not associated with the aluminum processes is not included in this category, nor is bauxite calcination to alumina and raw coke production which are assumed to be performed at other locations.

Emission Calculations

The following emission calculation methods were taken from the *Aluminum Production-Guidance Manual for Estimating Greenhouse Gas Emissions*, Environment Canada, March 2004. Other organizations are recommending very similar methodologies, including the International Aluminum Institute, WRI, IPCC and The Climate Registry.

Emissions will be calculated monthly using the following methods:

Pre-baked Anode Consumption:

To calculate emissions from pre-baked anode consumption, use the following equation:

$$Emissions_{CO_2} = NCC \times MP \times \frac{(100 - \%S_a - \%Ash_a - \%Imp_a)}{100} \times 3.664$$

Where:

Emissions $_{CO2}$ = carbon dioxide emissions (metric tons per year)

NCC = net annode consumption per metric ton of aluminum;(metric ton/ metric ton Al)
MP = annual aluminum production (metric ton);
S_a = sulphur content in baked anodes (wt %);
Ash_a = ash content in baked anodes (wt %);
Imp_a = content of fluorine and other impurities in baked anodes (wt %);
3.664 = conversion factor from carbon to CO_2.

Søderberg Anode Consumption:

To calculate emissions from Søderberg anode consumption, use the following equation:

$$Emissions_{CO_2} = \left[\begin{array}{l} (PC \times MP) - \left(BSM \times \frac{MP}{1000} \right) - \left(\frac{\%BC}{100} \times PC \times MP \times \left(\frac{\%S_p + \%Ash_p + \%H_p}{100} \right) \right) \\ - \left(\frac{100 - \%BC}{100} \times PC \times MP \times \frac{\%S_c + \%Ash_c}{100} \right) \end{array} \right] \times 3.664$$

Where:

$Emissions_{CO2}$ = carbon dioxide emissions (metric tons per year)
PC = paste consumption (metric tons paste/metric ton aluminum);
MP = annual aluminum production (metric tons);
BSM = emissions of benzene-soluble matter (kilograms benzene-soluble matter/metric ton aluminum);
BC = average binder (pitch) content in paste (wt %);
S_p = sulphur content in pitch (wt %);
Ash_p = ash content in pitch (wt %);
H_p = hydrogen content in pitch (wt %);
S_c = sulphur content in calcinated coke (wt %);
Ash_c = ash content in calcinated coke (wt %);
3.664 = conversion factor from carbon to CO_2.

Anode/Cathode Baking:

CO_2 emissions result from the baking of (pre-bake) anodes and cathodes. In cases where baking of anodes and cathodes occurs on-site, emissions should be calculated for both packing coke and pitch coking. The calculations require information on the net rate of raw material used for baked anode/cathode production, plus material composition information. To calculate emissions from packing coke for anodes, use the following equation:

$$Emissions_{CO_2} = \left(PCC \times BAP \times \frac{100 - \%Ash_{pc} - \%S_{pc} - \%Imp}{100} \right) \times 3.664$$

Where:

$Emissions_{CO2}$ = carbon dioxide emissions (metric tons per year)

PCC = packing coke consumption per metric ton of baked anode (metric tons coke/metric ton anodes);
BAP = annual baked anode production (metric tons);
Ash_{pc} = ash content in packing coke (wt %);
S_{pc} = sulphur content in packing coke (wt %);
Imp = content of other impurities (wt %);
3.664 = conversion factor from carbon to CO_2.

To calculate emissions that occur from oxidation of pitch volatile matter in ***pitch coking***, use the following equation:

$$Emissions_{CO_2} = \left(GAW - BAP - \left(\frac{\%H_p}{100} \times \frac{\%PC}{100} \times GAW \right) - RT \right) \times 3.664$$

Where:

$Emissions_{CO2}$ = carbon dioxide emissions (metric tons per year)
GAW = annual green anode tonnage (metric tons);
BAP = annual baked anode production (metric tons).
H_p = hydrogen content in pitch (wt %);
PC = average pitch content (wt %) in green anode;
RT = annual recovered tar (metric tons);
3.664 = conversion factor from carbon to CO_2.

To calculate similar emissions from the baking of cathodes, the methodology follows the above methodology for anodes, where values for baked cathode production, green cathode tonnage and cathode composition data are substituted into the equations for packing coke and pitch coking.

Emissions from Anode Effects:

The two PFCs known to be emitted from the occurrence of anode effects (also termed anode events) during primary aluminum smelting are CF_4 and C_2F_6. The most accurate estimates of these PFC emissions from anode effects are based on either continuous monitoring of emissions or development of smelter-specific relationships for emissions based on measured values and operating conditions. This requires both a comprehensive measurement program to establish the smelter-specific relationship as well as on-going collection of operating parameter data (e.g. frequency and duration of anode effects, anode effect over-voltage) and production data.

If continuous monitoring of PFC emissions is not selected, there are two approaches that may be used to relate monitored emissions, typically obtained from field measurements, to process data in order to develop smelter-specific relationships that can be used to estimate emissions. The two approaches are the Slope method or the Pechiney method, which are described below.

Slope Method - The **Slope** method uses a linear least squares relationship between anode effect frequency and duration and emissions, such that emissions can be calculated using the following equation:

$$Emissions_{CF_4,C_2F_6} = slope_{CF_4,C_2F_6} \times AEF \times AED \times MP$$

Where:

$Emissions_{CF4, C2F6}$	=	Emissions of CF_4 or C_2F_6 (metric tons/yr)
$slope_{CF4, C2F6}$	=	slope of the emissions relationship- measured ([Metric tons of CF_4 or C_2F_6 /metric ton Al]/[anode effect minutes/pot-days]);
AEF	=	anode effect frequency (number of anode effects per pot per day);
AED	=	anode effect duration (minutes per anode effect);
MP	=	total aluminum production (metric tons).

Note that the product of the anode effect frequency and duration can be expressed as "anode effect minutes per pot-day."

Pechiney Method - The **Pechiney** method (or over-voltage method) uses the anode effect over-voltage as the process parameter in combination with the quantity of aluminum produced to calculate PFC emissions. The anode effect over-voltage (AEO) represents the sum of the differences between the total cell voltage and the equilibrium voltage for each second during an anode event divided by the total number of seconds in the chosen period (e.g. one day). This calculation is carried out once the cell voltage exceeds 8 volts and continues until the voltage returns to the equilibrium point. The over-voltage coefficient is determined from the measurement of PFC emissions. The full calculation is:

$$Emission_{CF_4,C_2F_6} = Over-voltage \quad coefficient_{CF_4,C_2F_6} \times \frac{AEO}{CE} \times MP$$

Where:

$Emissions_{CF4, C2F6}$	=	Emissions of CF_4 or C_2F_6 (metric tons/yr)
Over-voltage coefficient $_{CF4, C2F6}$	=	experimentally measured ([Metric tons of CF_4 or C_2F_6/metric ton Al]/ mV)
AEO	=	anode effect over-voltage (millivolts per pot per day);
CE	=	current efficiency of aluminum production process, expressed as a fraction;
MP	=	annual aluminum production (metric tons).

Under either approach, the calculation is to be completed for each of the PFC gases emitted (CF_4 and C_2F_6) and for each operating pot line at the facility.

Note: It has been recommended that facilities be allowed to use a technology based emission factor in place of measuring either the slope coefficient or the over-voltage coefficient required by the above two methods. This approach is equivalent to the IPCC Tier 2 method which has a reported uncertainty of +/-6% to +/-44%, depending on the process. The IPCC Tier 3 method requires the use of site measured values for greater accuracy. The WCI seeks stakeholder *comments regarding the practicalities of requiring the IPCC Tier 3 method as opposed to allowing a Tier 2 method as well.*

CO_2 Emissions from Green Coke Calcination

The process of coke calcination, where coke is heated to high temperatures in order to drive off volatile matter, results in emissions of CO_2. The facility may purchase coke materials in the calcined state, or it may operate a calcining furnace. If coke calcination is conducted on-site at the facility, the following equation can be used to calculate the CO_2 emissions from this process:

$$Emissions_{CO_2} = \left[\left[GC \times \frac{(100 - \%H_2O_{gc} - \%V_{gc} - \%S_{gc})}{100} - (CC + UCC + DE) \times \frac{(100 - \%S_{cc})}{100}\right] \times 3.664\right] + \left[GC \times 0.035 \times \frac{44}{16}\right]$$

Where:

$Emissions_{CO2}$	=	carbon dioxide emissions (metric tons prr year)
GC	=	annual green coke feed (metric tons);
H_2O_{gc}	=	humidity in green coke feed (wt %);
V_{gc}	=	volatiles in green coke feed (wt %);
S_{gc}	=	sulphur content in green coke feed (wt %);
S_{cc}	=	sulphur content in calcinated coke (wt %);
CC	=	annual calcinated coke produced (metric tons);
UCC	=	annual under-calcinated coke produced (metric tons);
DE	=	annual coke dust emissions (metric tons);
3.664	=	conversion factor from carbon to CO_2;
0.035	=	Assumed CH4 and tar content in coke volatiles, contributing to CO_2 emissions
44/16	=	conversion factor from methane to CO_2.

For the composition parameters in the above equation, facility-specific values should be used for the coke input and output streams of the calcining operation to ensure accuracy of the emission estimates.

SF_6 Emissions from Use as a Cover Gas

For some specialized applications, SF_6 may be used as a cover gas at aluminum facilities. SF_6 is essentially non-reactive during this process. If this SF_6 use occurs, emissions are calculated based on the quantity of SF_6 consumed:

$$Emissions_{SF_6} = Consumption_{SF_6}$$

The consumption of SF_6 may be determined by:

- measured weight difference of gas cylinders used at the facility for this purpose;
- accounting of delivered purchases and inventory changes of SF6 used for this purpose; and
- metering of flow rates at the point used.

The first two methods based on weight are generally more accurate. When using measured weights, it is important to account for any gas in the heels of the cylinders returned to the supplier. If accounting or delivery records are used over an annual time period, beginning and end of year inventories must be taken into account.

Reporting Requirements

Annual emissions will be reported by emission source (i.e. emissions from prebaked anode consumption or from anode effect) and by GHG.

Sampling, Analysis, and Measurement Methods

Issue: Sampling, analysis, and measurement methods have not been specified in the available methodologies for the aluminum industry.

Note: The sampling, analysis, and measurement procedures will be standardized for each calculation input to reduce variation between facilities within the aluminum industry. Material sampling frequency and technique is distinct from material analysis conducted in a laboratory. The WCI is seeking stakeholder feedback on this topic and is specifically interested in proposals from stakeholders with expertise in this industry related to sampling, analysis and measurement procedures already in use at these facilities for the material quantities and/or concentrations listed below. Those proposing procedures should include sampling frequency and technique, indicate the uncertainty associated with the procedures, and describe the application of the procedure at a facility.

There are several possible approaches to specifying monitoring methods:

- Specify the accuracy required for each datum and allow the source to select their own methodologies that meet the accuracy requirements, and require the verifiers to certify the accuracy requirements were achieved, [*This approach is especially useful for monitoring that is currently being made with a wide variety of instruments and are likely being made with high accuracy, such as monitoring of raw material flows and product flows; however, much burden is placed on verifiers to ensure the accuracy of the methods used. This approach is used for monitoring fuel flow for combustion sources.*]
- Specify the accuracy required for each datum and require the source to submit a monitoring plan that meets the accuracy requirements, and require the verifiers to certify the source followed the approved plan. [*This approach places significant burden on WCI to approve individual monitoring plans.*]
- Specify the methodologies that should be followed, selecting them from available ASTM, ISO, U.S. EPA, and EC methodologies; however, there are not established methods for all

parameters. Listed below are examples of the available methodologies for monitoring the aluminum industry.

ISO 9055:1988. Carbonaceous materials for the production of aluminum -- Pitch for electrodes -- Determination of sulfur content by the bomb method.

ISO 10238:1999. Carbonaceous materials used in the production of aluminum -- Pitch for electrodes -- Determination of sulfur content by an instrumental method.

ISO 8006:1985. Carbonaceous materials used in the production of aluminum -- Pitch for electrodes -- Determination of ash.

ISO 8005-2005. Carbonaceous materials used in the production of aluminum -- Green and calcined coke -- Determination of ash content

ISO 10237-1997. Carbonaceous materials for use in the production of aluminum -- Calcined coke -- Determination of residual-hydrogen content.

ISO 5931:2000. Carbonaceous materials used in the production of aluminum -- Calcined coke and calcined carbon products -- Determination of total sulfur by the Eschka method.

Slope and Over-voltage Coefficient: *Protocol for Measurement of Tetrafluoromethane and Hexafluoroethane Emissions from Primary Aluminum Production.* U.S. Environmental Protection Agency and International Aluminum Institute. April 2008.

ASTM D3173 Test Method for Moisture in the Analysis Sample of Coal and Coke

The following parameters are not covered by a specific ASTM or ISO methodology. They are candidates for being addressed using one of the first two approaches listed above:

- Mass flow rates or consumption of aluminum, paste, carbon, anodes, coke, recovered tar, and coke dust,
- Emissions of benzene soluble matter,
- Binder content in paste,
- Pitch content in anodes,
- Current efficiency,
- Anode effect frequency,
- Anode effect duration,
- Anode effect over-voltage,
- Current efficiency,
- Volatile content in coke

ATTACHMENT 6: COAL STORAGE

§ WCI.100 COAL STORAGE

§ WCI.101 Source Category Definition

Coal storage piles are located at any facilities that combust coal. Coal storage piles release fugitive CH_4 emissions. Within natural coal deposits, CH_4 is either trapped under pressure within porous void spaces or adsorbed to the coal. Coal mining, post-mining activities, and coal-handling activities release pressurized CH_4 to the atmosphere; adsorbed CH_4 is also released until the CH_4 coal reaches equilibrium with the surrounding atmospheric conditions.

§ WCI.102 Greenhouse Gas Reporting Requirements

The emissions data report shall include the following information at the facility level:

(a) Annual greenhouse gas emissions in metric tons, reported as follows:

(1) Total CH_4 emissions.

(b) Annual coal purchases in tons.

(c) Source of coal purchases:

(1) Coal basin.
(2) State/province.
(3) Coal mine type (surface or underground).

§ WCI.103 Calculation of CH_4 Emissions

Note that this methodology for calculation of methane emissions uses emission factors for post-mining operations including all processes occurring after mining at the coal deposit and prior to combustion (e.g., preparation, handling, processing, transportation, storage, etc.) even though coal storage piles are only a subset of the overall post-mining operations. This follows the approach in the California Climate Action Registry, attributing all post-mining fugitive methane emissions to the facility combusting the coal, which is ultimately responsible for the coal having been processed and delivered to the facility. The Reporting Subcommittee is considering whether to require reporting of these emissions as indicated below, and whether to include these emissions in the total emissions of the coal-combusting facility. Stakeholder comment is requested.

Canadian-specific default fugitive methane emissions (i.e., a Canadian version of Table 100-1) will be developed.

Calculate fugitive CH_4 emissions from coal storage piles using the following equation:

$$CH_4 = \sum_i (PC \times EF) \times 0.04228 \ / \ 2{,}204.6 \qquad \textbf{Equation 100-1}$$

Where:

CH_4	=	Fugitive emissions from coal storage piles for each coal category *i*, metric tons CH_4 per year.
PC	=	Purchased coal, tons per year.
EF	=	Default CH_4 emission factor specified by location and mine type that coal originated from provided in Table 100-1, scf CH_4 per ton of coal.
0.04228	=	Methane conversion factor to convert scf to lbs.
2,204.6	=	Factor to convert lbs to metric tons.

Table 100-1 provides default CH_4 emission factors for U.S. post-mining operations.

These post-mining operation emission factors were used to estimate emissions from coal storage piles in the CARB rule.

The uncertainty associated with the U.S.-specific emission factors in Table 100-1 emission factors is unknown. Emission factors from U.S. underground mining activities were developed from mine-level emissions measurements; however, the surface mining and post-mining activity emission factors were estimated based upon an average in situ CH_4 content of 32.5%.

Canada-specific coal storage pile or post-mining operation emission factors could not be identified. The Canada National Inventory contains Canada-specific emission factors for coal production from underground and surface mines. Post-mining operations are included within these emission factors, but are not specifically disaggregated.

§ WCI.105 Sampling, Analysis, and Measurement Requirements

(a) Fuel Consumption Monitoring Requirements.

(1) Facilities may determine consumption on the basis of recorded fuel purchase or sales invoices measuring any stock change (short tons) using the following equation:

Fuel Consumption in the Report Year = Total Fuel Purchases – Total Fuel Sales + Amount Stored at Beginning of Year – Amount Stored at Year End

Table 100-1. U.S. Default Fugitive Methane Emission Factors from Post-Mining Coal Storage and Handling (CH_4 ft^3 per Short Ton)			
Coal Origin		**Coal Mine Type**	
Coal Basin	**States**	**Surface Post-Mining Factors**	**Underground Post-Mining Factors**
Northern Appalachia	Maryland, Ohio, Pennsylvania, West Virginia North	19.3	45.0
Central Appalachia (WV)	Tennessee, West Virginia South	8.1	44.5
Central Appalachia (VA)	Virginia	8.1	129.7
Central Appalachia (E KY)	East Kentucky	8.1	20.0
Warrior	Alabama, Mississippi	10.0	86.7
Illinois	Illinois, Indiana, Kentucky West	11.1	20.9
Rockies (Piceance Basin)	Arizona, California, Colorado, New Mexico, Utah	10.8	63.8
Rockies (Uinta Basin)		5.2	32.3
Rockies (San Juan Basin)		2.4	34.1
Rockies (Green River Basin)		10.8	80.3
Rockies (Raton Basin)		10.8	41.6
N. Great Plains	Montana, North Dakota, Wyoming	1.8	5.1
West Interior (Forest City, Cherokee Basins)	Arkansas, Iowa, Kansas, Louisiana, Missouri, Oklahoma, Texas	11.1	20.9
West Interior (Arkoma Basin)		24.2	107.6
West Interior (Gulf Coast Basin)		10.8	41.6
Northwest (AK)	Alaska	1.8	52.0
Northwest (WA)	Washington	1.8	18.9

Source: *Inventory of U.S. Greenhouse Gas Emissions and Sinks:1990 – 2005* April 15, 2007, U.S. Environmental Protection Agency. Annex 3, Methodological Descriptions for Additional Source or Sink Categories, Section 3.3, Table A-115, Coal Surface and Post-Mining CH4 Emission Factors (ft^3 per Short Ton). (Only Post-Mining EFs used from Table). State assignments shown from Table 113 of Annex 3.

ATTACHMENT 14: COAL MINE FUGITIVE EMISSIONS

Applicability

As part of the geological processes of coal formation, CO_2 and CH_4 may also be produced and trapped in the coal seam until the coal is exposed and broken during mining. In general, CH_4 is the predominant greenhouse gas emitted from coal mines. The following five processes are potential source categories for fugitive emissions associated with both underground and surface coal mines:

- Mining (emissions from the breakage of coal and associated strata, including ventilation air and degasification systems for underground mines);
- Post-mining operations (subsequent handling, processing, and transportation of coal);
- Low temperature oxidation (oxidation of coal when exposed to oxygen in air);
- Uncontrolled combustion (active fire caused by trapped heat and increased temperature from low temperature oxidation); and
- Abandoned mines.

The following methodology focuses solely on CH_4 mining emissions. Emissions from post-mining operations (including storage piles) are addressed in Section WCI.100. Coal oxidation occurs in both underground and surface mines; however, emissions are not expected to be significant. Uncontrolled combustion also occurs in underground and surface mines, but it is difficult to quantify and infeasible to include in the methodology. Estimation of emissions from abandoned underground mines requires the emission rate at closure/abandonment (i.e., when all active mine ventilation ceases) and "decline curves" (i.e., hyperbolic models of declining emissions as a function of time). At best, the uncertainty of estimated abandoned mine emissions is ±50 percent.

Emission Calculations

The following emission calculation methods were taken from the 2006 IPCC Guidelines, Volume 2, Section 4.1. The following methods can be used to calculate emissions:

Underground Mining

The Tier 3 method for underground mining is mine-specific measurement data based on ventilation air and degasification system measurements. The Tier 2 method relies on basin-specific emission factors that need to be obtained from sample ventilation air data or from a quantitative relationship that accounts for the gas content of the coal and the surrounding strata affected by the mining process. If Tier 3 or Tier 2 data are not available, then Tier 1 emission factors could be used. If Tier 1 or Tier 2 methods are utilized, then methane recovered and utilized for energy production or flaring should be subtracted from the emission estimates; this subtraction is not needed for the Tier 3 methodology, because the Tier 3 mine-specific measurements should take methane recovery and utilization into account.

The Tier 2 and Tier 1 equations are as follows:

$$E_{Underground-CH4} = E_{Mining-CH4} - R_{CH4}$$

Where:

$E_{Underground\text{-}CH4}$ = Total CH_4 emissions from underground coal mining (metric tons);
$E_{Mining\text{-}CH4}$ = CH_4 emissions from underground coal mining operations (metric tons);
R_{CH4} = CH_4 recovered and utilized for energy production or flared.

$$E_{Mining-CH4} = P_{Underground} \times EF_{Underground-CH4} \times 0.00067$$

Where:

$E_{Mining\text{-}CH4}$ = CH_4 emissions from underground coal mining operations (metric tons);
$P_{Underground}$ = Underground coal production (metric tons);
$EF_{Underground\text{-}CH4}$ = CH_4 emission factor (m^3 CH_4/metric ton coal);
0.00067 = Conversion factor from volume of CH_4 to mass of CH_4 (metric ton/m^3).

The Tier 1 emission factors for underground coal mining are identified as high, average, or low. The high emission factor is 25 m^3/metric ton (i.e., at depths greater than 400 meters). The average emission factor is 18 m^3/metric ton (i.e., at depths between 200 and 400 meters). The low emission factor is 10 m^3/metric ton (i.e., at depths less than 200 meters).

$$E_{Post-CH4} = P_{Underground} \times EF_{Post-CH4} \times 0.00067$$

Where:

$E_{Post\text{-}CH4}$ = CH_4 emissions from underground coal post-mining operations (metric tons);
$P_{Underground}$ = Underground coal production (metric tons);
$EF_{Post\text{-}CH4}$ = CH_4 emission factor (m^3 CH_4/metric ton coal);
0.00067 = Conversion factor from volume of CH_4 to mass of CH_4 (metric ton/m^3).

For underground mines, the uncertainty for the Tier 3 mining emission estimates ranges from ±5 percent for continuous monitoring up to ±30 percent for more infrequent monitoring. The uncertainty of the Tier 2 mining emission factors is ±50-75 percent, while the uncertainty of the Tier 1 mining emission factors is a factor of 2 greater/smaller.

Surface Mining

It is not feasible to collect mine-specific Tier 3 measurement data for mining operations at surface mines, so Tier 2 emission factors are an alternative approach for this category.

$$E_{Mining-CH4} = P_{Surface} \times EF_{Surface-CH4} \times 0.00067$$

Where:

$E_{Mining\text{-}CH4}$ = CH_4 emissions from surface coal mining operations (metric tons);

$P_{Surface}$	=	Surface coal production (metric tons);
$EF_{Surface-CH4}$	=	CH_4 emission factor (m^3 CH_4/metric ton coal);
0.00067	=	Conversion factor from volume of CH_4 to mass of CH_4 (metric ton/m^3).

The Tier 2 emission factors for surface coal mining are identified as high, average, or low. The high emission factor is 2.0 m^3/metric ton (i.e., for overburden depths greater than 50 meters). The average emission factor is 1.2 m^3/metric ton (i.e., for overburden depths between 25 and 50 meters). The low emission factor is 0.3 m^3/metric ton (i.e., for overburden depths less than 25 meters). For surface mines, the uncertainty of the Tier 2 mining emission factors is a factor of 2 greater/smaller.

Because of the high uncertainty associated with estimating emissions from mining operations at surface coal mines, these emissions will not be included in the reporting requirements at this time.

Reporting Requirements

Annual CH_4 emissions will be reported for each specific underground mine using the Tier 3 methodology.

Sampling, Analysis, and Measurement Methods

Note: The sampling, analysis, and measurement procedures will be standardized for each calculation input to reduce variation between facilities within the mining industry. Material sampling frequency and technique is distinct from material analysis conducted in a laboratory. The WCI is seeking stakeholder feedback on this topic and is specifically interested in proposals from stakeholders with expertise in this industry related to sampling, analysis and measurement procedures already in use at these mines for the material quantities and/or concentrations listed below. Those proposing procedures should include sampling frequency and technique, indicate the uncertainty associated with the procedures, and describe the application of the procedure at a mine.

Ventilation air and/or degasification system measurements will need to be taken for development of underground Tier 3 mining emission estimates. More frequent sampling (preferably continuous) will reduce the amount of uncertainty. Appropriate measurement methods are likely specified by the U.S. Mine Safety and Health Administration, although none have been identified to date.

Ventilation measurements are typically conducted on a periodic basis with air flow measurements and handheld methanometers. Drainage gas utilized for energy production is usually continuously measured with a flow meter with gas composition samples taken at a periodic basis. Drainage gas vented to the atmosphere is periodically sampled, along with the associated gas composition.

ATTACHMENT 4: ELECTRICITY GENERATION

§ WCI.40 ELECTRICITY GENERATION

WCI.41 Source Category Definition

An electricity generator is any combustion device that combusts solid, liquid, or gaseous fuel for the purpose of producing electricity either for sale or for use onsite. This source category excludes cogeneration units subject to WCI.50.

WCI.42 Greenhouse Gas Reporting Requirements

For each facility, the emissions data report shall include the following information:

(a) Annual greenhouse gas emissions in metric tons, reported as follows:

  (1) Total CO_2 emissions for fossil fuels, reported by fuel type.
  (2) Total CO_2 emissions for all biomass fuels combined.
  (3) Total CH_4 emissions for fuels combined.
  (4) Total N_2O emissions for all fuels combined.

(b) Annual fuel consumption:

  (1) For gases, report in units of million standard cubic feet or cubic meters.
  (2) For liquids, report in units of gallons or liters.
  (3) For non-biomass solids, report in units of short tons or metric tons.
  (4) For biomass-derived solid fuels, report in units of bone dry short tons or bone dry metric tons.

(c) Average carbon content of each fuel, if used to compute CO_2 emissions as specified in WCI.44.

(d) Average high heating value of each fuel, if used to compute CO_2 emissions as specified WCI.44.

(e) The nameplate generating capacity in megawatts and net power generated in the reporting year in megawatt hours.

(f) Process CO_2 emissions from acid gas scrubbers and acid gas reagent.

(g) Fugitive emissions of HFC from cooling units that support power generation.

(h) Fugitive CO_2 emissions from geothermal facilities.

(i) Fugitive CO_2 emissions from coal storage at coal-fired electricity generating facilities shall be reported as specified in section WCI.100.

WCI.43 Calculation of Greenhouse Gas Emissions

(a) Calculation of CO_2 Emissions. Operators shall use CEMS to measure CO_2 emissions if required to operate a CEMS by any other federal, state, provincial, or local regulation. Operators not required to operate a CEMS by another regulation may use either CEMS or the calculation methods specified in paragraphs (a)(1) through (a)(7). Operators using CEMS to determine CO_2 emissions shall comply with the provisions in section WCI.23(d).

(1) Natural Gas. For electric generating units combusting natural gas, use one of the following methods:

(A) If the high heat value is greater than or equal to 975 and less than or equal to 1,100 Btu/scf use either:

i. The measured carbon content of the fuel and calculation methodology 3 in section WCI.23(c); or
ii. The measured heat content of the fuel and the calculation methodology 2 in section WCI.23(b) provided the facility is not subject to the verification requirements of WCI.8.

(B) If the high heat value is less than 975 or greater than 1,100 Btu/scf, use the measured carbon content of the fuel and the calculation methodology 3 in section WCI.23(c).

(2) Coal or Petroleum Coke. For electric generating units combusting coal or petroleum coke, use the measured carbon content of the fuel and calculation methodology 3 in section WCI.23(c).

(3) Middle Distillates, Gasoline, Residual Oil, or Liquid Petroleum Gases. For electric generating units combusting middle distillates (such as diesel, fuel oil, or kerosene), gasoline, residual oil, or LPG (such as ethane, propane, isobutene, n-butane, or unspecified LPG), use one of the following methods:

(A) The measured carbon content of the fuel and calculation methodology 3 in section WCI.23(c); or
(B) The measured heat content of the fuel and calculation methodology 2 in section WCI.23(b) provided the facility is not subject to the verification requirements of WCI.8.

(4) Refinery Fuel Gas, Flexigas, or Associated Gas. For electric generating units combusting refinery fuel gas, flexigas, or associated gas, use the methods specified in section WCI.30.

(5) Landfill Gas, Biogas, or Biomass. For electric generating units combusting landfill gas, biogas, or biomass, use one of the following methods:

(A) The measured carbon content of the fuel and calculation methodology 3 provided in section WCI.23(c); or
(B) The measured heat content of the fuel and calculation methodology 2 in section WCI.23(b) provided the facility is not subject to the verification requirements of WCI.8.

(6) Municipal Solid Waste. Electric generating units combusting municipal solid waste, may use the measured steam generated, the default carbon content emission factor in Table 20-1, and the calculation methodology in section WCI.23(b)(2) provided the facility is not subject to the verification requirements of WCI.8. If the facility is subject to the verification requirements of WCI.8, the operator shall use CEMS to measure CO_2 emissions in accordance with WCI.23(d).

(7) Start-up Fuels. The operators of generating facilities that primarily combust biomass-derived fuels but combust fossil fuels during start-up, shut-down, or malfunction operating

periods only, shall calculate CO_2 emissions from fossil fuel combustion using one of the following methods:

(A) The default emission factors from Tables 20-1 and 20-2 and calculation methodology 1 provided in section WCI.23(a);
(B) The measured heat content of the fuel and calculation methodology 2 provided in section WCI.23(b);
(C) The measured carbon content of the fuel and calculation methodology 3 provided in section WCI.23(c); or
(D) For combustion of refinery fuel gas, the measured heat content and carbon content of the fuel, and the calculation methodology provided in section WCI.30.

(8) Co-fired Electricity Generating Units. For electricity generating units that combust more than one type of fuel, the operator shall calculate CO_2 emissions as follows.

(A) For co-fired electricity generators that burn only fossil fuels, CO_2 emissions shall be determined using one of the following methods:

i. A continuous emission monitoring system in accordance with calculation methodology 4 in section WCI.23(d). Operators using this method need not report emissions separately for each fossil fuel.
ii. For units not equipped with a continuous emission system, calculate the CO2 emissions separately for each fuel type using the methods specified in paragraphs (a)(1) through (a)(4) of this section.

(B) For co-fired electricity generators that burn biomass-derived fuel with a fossil fuel, CO_2 emissions shall be determined using one of the following methods:

i. A continuous emission monitoring system in accordance with calculation methodology 4 in section WCI.23(d). Operators using this method shall determine the portion of the total CO_2 emissions attributable to the biomass-derived fuel and portion of the total CO_2 emissions attributable to the fossil fuel using the methods specified in section WCI.23(d)(4).
ii. For units not equipped with a continuous emission system, calculate the CO_2 emissions separately for each fuel type using the methods specified in paragraphs (a)(1) through (a)(7) of this section.

(b) Calculation of CH_4 and N_2O Emissions. Operators of electricity generating units shall use the methods specified in section WCI.24 to calculate the annual CH_4 and N_2O emissions. For coal combustion, use the default CH_4 emission factor of 1g of CH_4/mmBtu.

(c) Calculation of CO_2 Emissions from Acid Gas Scrubbing. Operators of electricity generating units that use acid gas scrubbers or add an acid gas reagent to the combustion unit shall calculate the annual CO_2 emissions from these processes using Equation 40-1 if these emissions are not already captured in CO_2 emissions determined using a continuous emissions monitoring system.

$$CO_2 = S \times R \times \left(CO_{2\,MW} / Sorbent_{MW} \right) \qquad \textbf{Equation 40-1}$$

Where:

CO_2 = CO_2 emitted from sorbent for the report year, metric tons;

S	=	Limestone or other sorbent used in the report year, metric tons;
R	=	Ratio of moles of CO_2 released upon capture of one mole of acid gas;
$CO_{2\ MW}$	=	Molecular weight of carbon dioxide (44);
$Sorbent_{MW}$	=	Molecular weight of sorbent (if calcium carbonate, 100).

(d) Calculating Fugitive HFC Emissions from Cooling Units. Operators of electricity generating facilities shall calculate fugitive HFC emissions for each HFC compound used in cooling units that support power generation or are used in heat transfers to cool stack gases using either the methodology in paragraph (d)(1) or (d)(2). The Operator is not required to report GHG emissions from air or water cooling systems or condensers that do not contain HFCs.

(1) Use Equation 40-2 to calculate annual HFC emissions:

$$HFC = HFC_{inventory} + HFC_{purchases/acquisitions} - HFC_{sales/disbursements} + HFC_{\Delta capacity}$$ **Equation 40-2**

Where:

HFC	=	Annual fugitive HFC emission, metric tons;
$HFC_{inventory}$	=	The difference between the quantity of HFC in storage at the beginning of the year and the quantity in storage at the end of the year. Stored HFC includes HFC contained in cylinders (such as 115-pound storage cylinders), gas carts, and other storage containers. It does not include HFC gas held in operating equipment. The change in inventory will be negative if the quantity of HFC in storage increases over the course of the year.
$HFC_{purchases/acquisitions}$	=	The sum of all HFC acquired from other entities during the year either in storage containers or in equipment.
$HFC_{sales/disbursements}$	=	The sum of all the HFC sold or otherwise transferred offsite to other entities during the year either in storage containers or in equipment.
$HFC_{\Delta capacity}$	=	The net change in the total nameplate capacity (i.e. the full and proper charge) of the cooling equipment). The net change in capacity will be negative if the total nameplate capacity at the end of the year is less than the total nameplate capacity at the beginning of the year.

(2) Use service logs to document HFC usage and emissions from each cooling unit. Service logs should document all maintenance and service performed on the unit during the report year, including the quantity of HFCs added to or removed from the unit, and include a record at the beginning and end of each report year. The operator may use service log information along with the following simplified material balance equations to quantify fugitive HFCs from unit installation, servicing, and retirement, as applicable. The operator shall include the sum of HFC emissions from the applicable equations in the greenhouse gas emissions data report.

$$HFC_{Install} = R_{new} - C_{new}$$
$$HFC_{Service} = R_{recharge} - R_{Recover}$$
$$HFC_{Retire} = C_{retire} - R_{retire}$$

Where:

$HFC_{Install}$ = HFC emitted during initial charging/installation of the unit, kilograms;
$HFC_{Service}$ = HFC emitted during use and servicing of the unit for the report year, kilograms;
HFC_{Retire} = HFC emitted during the removal from service/retirement of the unit, kilograms;
R_{new} = HFC used to fill new unit (omit if unit was pre-charged by the manufacturer), kilograms;
C_{new} = Nameplate capacity of new unit (omit if unit was pre-charged by the manufacturer), kilograms;
$R_{recharge}$ = HFC used to recharge the unit during maintenance and service, kilograms;
$R_{recover}$ = HFC recovered from the unit during maintenance and service, kilograms;
C_{retire} = Nameplate capacity of the retired unit, kilograms; and
R_{retire} = HFC recovered from the retired unit, kilograms.

(e) Fugitive CO_2 Emissions from Geothermal Facilities. Operators of geothermal electricity generating facilities shall calculate the fugitive CO_2 emissions using one of the following methods:

(1) Calculate the fugitive CO_2 emissions using Equation 40-3:

$$CO_2 = 7.53 \times Heat \times 0.001$$ **Equation 40-3**

Where:

CO_2 = CO_2 emissions, metric tons per year;
7.53 = Default fugitive CO_2 emission factor for geothermal facilities, kg per mmBtu; and
Heat = Heat taken from geothermal steam and/or fluid, mmBtu/yr.

(2) Calculate CO_2 emissions using [*insert jurisdiction*] approved source specific emission factor.

WCI.44 Sampling, Analysis, and Measurement Requirements

(a) CO_2, CH_4 and N_2O Emissions from Fuel Combustion. Operators using CEMS to estimate CO_2 emissions from fuel combustion shall comply with the requirements in section WCI.23(d). Operators using methods other than CEMS shall comply with the applicable fuel sampling, fuel consumption monitoring, heat content monitoring, and carbon content monitoring specified in section WCI.25.

(b) CO_2 Emissions from Acid Gas Scrubbing. Operators of electricity generating units that use acid gas scrubbers or add an acid gas reagent to the combustion unit shall measure the

amount of limestone or other sorbent used during the reporting year using methods that comply with the measurement accuracy provisions in WCI.2(g).

(c) CO_2 Emissions from Geothermal Facilities. Operators of geothermal facilities shall measure the heat recovered from geothermal steam. If using source specific emission factor instead of the default factor, the operator shall conduct an annual test of the CO_2 emission rate using a method approved by [*insert jurisdiction*]. The operator shall submit a test plan to the [*insert jurisdiction*] for approval. Once approved, the annual tests shall be conducted in accordance with the approved test plan under the supervision of the [*insert jurisdiction*].-

ATTACHMENT 2: GENERAL STATIONARY COMBUSTION

§ WCI.20 GENERAL STATIONARY COMBUSTION

§ WCI.21 Source Category Definition

General stationary fuel combustion sources are devices that combust solid, liquid, or gaseous fuel for the purpose of generating steam (or providing useful heat or energy) for industrial, commercial, or institutional use; or reducing the volume of waste by removing combustible matter. General stationary combustion sources are boilers, combustion turbines, engines, incinerators, and process heaters, and any other stationary combustion device that is not specifically addressed under the provisions for another source category in this rule.

Note: The source category definition may need to be revised after the remaining ER sections are completed.

§ WCI.22 Greenhouse Gas Reporting Requirements

The emissions data report shall include the following information at the facility level:

(a) Annual greenhouse gas emissions in metric tons, reported as follows:

(1) Total CO_2 emissions for fossil fuels, reported by fuel type.
(2) Total CO_2 emissions for all biomass fuels combined.
(3) Total CH_4 emissions for all fuels combined.
(4) Total N_2O emissions for all fuels combined.

(b) Annual fuel consumption:

(1) For gases, report in units of million cubic meters.
(2) For liquids, report in units of liters.
(3) For non-biomass solids, report in units of metric tons.
(4) For biomass-derived solid fuels, report in units of bone dry short tons or bone dry metric tons.

(c) Average carbon content of each fuel, if used to compute CO_2 emissions.

(d) Average high heating value of each fuel, as used to compute CO_2 emissions.

(e) Annual steam generation in pounds or kilograms, for units that burn biomass or municipal solid waste.

Please note that most of the calculation methodologies in this section currently accommodate inputs in English units, only, and not SI units. The section will be revised to allow inputs in SI units, as well as to provide applicable Canadian emission factors from "National Inventory Report 1990-2006: Greenhouse Gas Sources and Sinks in Canada – The Canadian Government's Submission to the UN Framework Convention on Climate Change, April 2008." (http://www.ec.gc.ca/pdb/ghg/inventory_e.cfm)]

§ WCI.23 Calculation of CO_2 Emissions

For each fuel, calculate CO_2 mass emissions using one of the four calculation methodologies specified in this section, subject to the restrictions in §WCI.23 (e).

(a) Calculation Methodology 1. Calculate the annual CO_2 mass emissions by substituting a fuel-specific default CO_2 emission factor, a default high heating value, and the annual fuel consumption into the Equation 20-1:

$$CO_2 = Fuel \times HHV \times EF \times 0.001$$ **Equation 20-1**

Where:

CO_2	=	Annual CO_2 mass emissions for the specific fuel type (metric tons).
Fuel	=	Mass or volume of fuel combusted per year (express mass in short tons for solid fuel, volume in standard cubic feet for gaseous fuel, and volume in gallons for liquid fuel).
HHV	=	Default high heat value of the fuel, from column 3 of Table 20-1 (mmBtu per mass or mmBtu per volume, as applicable).
EF	=	Fuel-specific default CO_2 emission factor, from column 5 of Table 20-1 (kg CO_2/mmBtu).
0.001	=	Conversion factor from kilograms to metric tons.

(b) Calculation Methodology 2. Calculate the annual CO_2 mass emissions using a default CO_2 emission factor, and either Equation 20-2 or 20-3, as appropriate:

(1) Equation 20-2 of this section can be used for any type of fuel for which an emission factor is provided in Tables 20-1 or 20-2:

$$CO_2 = \sum_{p=1}^{n} Fuel_P \times HHV_P \times EF \times 0.001$$ **Equation 20-2**

Where:

CO_2	=	Annual CO_2 mass emissions for a specific fuel type (metric tons).
n	=	Number of required heat content measurements for the year as specified in WCI.25.
$Fuel_p$	=	Mass or volume of the fuel combusted during the measurement period "p" (express mass in short tons for solid fuel, volume in standard cubic feet for gaseous fuel, and volume in gallons for liquid fuel).
HHV_p	=	High heat value of the fuel for the measurement period (mmBtu per mass or volume).
EF	=	Fuel-specific default CO_2 emission factor, from column 5 of Table 20-1 or from Table 20-2 (kg CO_2/mmBtu).
0.001	=	Conversion factor from kilograms to metric tons.

(2) Equation 20-3 of this section can be used for biomass solid fuels and municipal solid waste only:

$$CO_2 = Steam \times B \times EF \times 0.001$$

Equation 20-3

Where:

CO_2	=	Annual CO_2 mass emissions from MSW combustion (metric tons).
Steam	=	Total mass of steam generated by MSW combustion during the reporting year (lb steam).
B	=	Ratio of the boiler's maximum rated heat input capacity to its design rated steam output capacity (mmBtu/lb steam).
EF	=	Default carbon content for MSW, from column 5 of Table WCI.20-1 (kg CO_2/mmBtu).
0.001	=	Conversion factor from kilograms to metric tons.

(c) Calculation Methodology 3. Calculate the annual CO_2 mass emissions by substituting measurements of fuel carbon content, molecular weight (gaseous fuels, only), and the quantity of fuel combusted into the following equations. For solid fuels, the amount of fuel combusted is obtained from company records kept as provided in this rule. For liquid and gaseous fuels, the volume of fuel combusted is measured directly, using fuel flow meters (including gas billing meters). For fuel oil, tank drop measurements may also be used.

(1) For a solid fuel, use Equation 20-4 of this section:

$$CO_2 = \sum_{i=1}^{n} Fuel_i \times CC_i \times 3.664$$

Equation 20-4

Where:

CO_2	=	Annual CO_2 mass emissions from the combustion of the specific solid fuel (metric tons).
n	=	Number of monthly carbon content determinations for the year.
$Fuel_i$	=	Mass of the solid fuel combusted in month "n" (metric tons).
CC_i	=	Carbon content of the solid fuel, from the fuel analysis results for month "n"(percent by weight, expressed as a decimal fraction, e.g., 95% = 0.95).
3.664	=	Ratio of molecular weights, CO_2 to carbon.

(2) For a liquid fuel, use Equation 20-5 of this section:

$$CO_2 = \sum_{i=1}^{n} 3.664 \times Fuel_i \times CC_i \times 0.001$$

Equation 20-5

Where:

CO_2	=	Annual CO_2 mass emissions from the combustion of the specific liquid fuel (metric tons).
n	=	Number of required carbon content determinations for the year, as specified in WCI.25.
$Fuel_i$	=	Volume of the liquid fuel combusted in month "n" (gallons).
CC_i	=	Carbon content of the liquid fuel, from the fuel analysis results for month "n" (kg C per gallon of fuel).

3.664	=	Ratio of molecular weights, CO_2 to carbon.
0.001	=	Conversion factor from kg to metric tons.

(3) For a gaseous fuel, use Equation 20-6 of this section:

$$CO_2 = \sum_{i=1}^{n} 3.664 \times Fuel_i \times CC_i \times \frac{MW}{MVC} \times 0.001 \qquad \textbf{Equation 20-6}$$

Where:

CO_2	=	Annual CO_2 mass emissions from combustion of the specific gaseous fuel (metric tons).
n	=	Number of required carbon content and molecular weight determinations for the year, as specified in WCI.25.
$Fuel_i$	=	Volume of the gaseous fuel combusted in a day or month, as applicable (scf).
CC_i	=	Average carbon content of the gaseous fuel, from the fuel analysis results for the day or month, as applicable (kg C per kg of fuel).
MW	=	Molecular weight of the gaseous fuel, from fuel analysis (kg/kg-mole).
MVC	=	Molar volume conversion factor (849.5 scf per kg-mole at standard conditions).
3.664	=	Ratio of molecular weights, CO_2 to carbon.
0.001	=	Conversion factor from kg to metric tons.

(d) Calculation Methodology 4. Calculate the annual CO_2 mass emissions from all fuels combusted in a unit, by using data from continuous emission monitoring systems (CEMS) as specified in (d)(1) through (d)(7).

(1) The operator of a facility that combusts fossil fuels or biomass and operates CEMS in response to federal, state, provincial, or local regulation, may use CO_2 or O_2 concentrations and flue gas flow measurements to determine hourly CO_2 mass emissions using methodologies provided in 40 CFR Part 75, Appendix F.

(A) The operator shall report CO_2 emissions for the report year in metric tons based on the sum of hourly CO_2 mass emissions over the year, converted to metric tons.

(B) If the operator of a facility that combusts biomass uses O_2 concentrations to calculate CO_2 concentrations, annual source testing must demonstrate that calculated CO_2 concentrations when compared to measured CO_2 concentrations meet the Relative Accuracy Test Audit (RATA) requirements in 40 CFR Part 60, Appendix B, Performance Specification 3.

(2) The operators of a facility that combusts municipal solid waste or other waste-derived fuels and operates a CEMS in response to federal, state, provincial, or local regulations must use CO_2 concentrations and flue gas flow measurements to determine hourly CO_2 mass emissions using methodologies provided in 40 CFR Part 75, Appendix F.

(A) Annual CO_2 emissions shall be reported in metric tons based on the sum of hourly CO_2 mass emissions over the year.

(B) Emissions calculations shall not be based on O_2 concentrations.

(3) The operator of a facility that combusts MSW or other waste-derived fuels and calculates CO_2 emissions using the methodology provided in WCI.23(d)(2) shall determine the

portion of emissions associated with the combustion of biomass-derived fuels using the method provided in WCI.23(f).

(4) An operator who uses CEMS data to report CO_2 emissions from a facility that co-fires fossil fuels with biomass or waste-derived fuels that are partly biomass shall determine the portion of total CO_2 emissions separately assigned to the fossil fuel and the biomass-derived fuel using the method provided in WCI.23(f), if applicable. The operator who co-fires pure biomass with fossil fuels may elect to calculate CO_2 emissions for the fossil fuels using methods designated in WCI.23(b)(3) by fuel type and then subtract the fossil fuel related emissions from the total CO_2 emissions determined using the CEMS based methodology.

(5) For any units for which CO_2 emissions are reported using CEMS data, the operator is relieved of the requirement to separately report process emissions from combustion emissions or to report emissions separately for different fossil fuels when only fossil fuels are co-fired. In this circumstance, operators shall still report fuel use by fuel type as otherwise required.

(6) If a facility is subject to requirements in 40 CFR Part 60 or 40 CFR Part 75 and the operator chooses to add devices to an existing continuous monitoring system for the purpose of measuring CO_2 concentrations or flue gas flow, the operator shall select and operate the added devices pursuant to the requirements in 40 CFR Part 60 or Part 75 that apply to the facility. If the facility is subject to both 40 CFR Part 60 and 40 CFR Part 75, the operator shall select and operate the added devices pursuant to the requirements in 40 CFR Part 75.

(7) If a facility does not have a continuous emissions monitoring system and the operator chooses to add one in order to measure CO_2 concentrations, the operator shall select and operate the CEMS pursuant to the requirements in 40 CFR Part 75.

(A) The operator shall use CO_2 concentrations and flue gas flow measurements to determine hourly CO_2 mass emissions using methodologies provided in 40 CFR Part 75, Appendix F.

(B) The operator shall report CO_2 emissions for the report year in metric tons based on the sum of hourly CO_2 mass emissions over the year, converted to metric tons.

(C) Operators who add CEMS under this article are subject to specifications in WCI.23(d)(1)-(5), if applicable.

(e) Use of the Four CO_2 Calculation Methodologies. Use of the four CO_2 emissions calculation methodologies described in paragraphs (a) through (d) of this section is subject to the following requirements and restrictions:

(1) Calculation Methodology 1 may not be used by a facility that is subject to the verification requirements of WCI.8, except for stationary combustion units that combust natural gas with a high heating value between 975 and 1,150 Btu per cubic foot. Otherwise, Calculation Methodology 1 may be used for any type of fuel for which a default CO_2 emission factor and a default high heat value for the fuel is specified in Table 20-1.

(2) Calculation Methodology 2 may not be used by a facility that is subject to the verification requirements of WCI.8, except for stationary combustion units that combust natural gas with a high heating value between 975 and 1,150 Btu per cubic foot. Otherwise, Calculation Methodology 2 may be used for any type of fuel combusted for which a default CO_2 emission factor for the fuel is specified in Table 20-1 or 20-2.

(3) Calculation Methodology 3 may be used for a unit of any size combusting any type of fuel, except when the use of Calculation Methodology 4 is required.
(4) Calculation Methodology 4 may be used for a unit of any size combusting any type of fuel, and must be used for either of the following conditions:

(i) A combustion unit with a CEMS that is required by any federal, state, provincial, or local regulation.

(ii) A municipal solid waste combustion unit that is subject to the verification requirements of WCI.8.

(f) Biogenic CO_2 emissions. The operator that combusts fuels or fuel mixtures that contain biomass shall determine the biomass-derived portion of CO_2 emissions using ASTM D6866-06a, as specified in this paragraph. This procedure is not required for fuels that contain less than 5 percent biomass by weight or for waste-derived fuels that are less than 30 percent biomass by weight on an annual basis.

(1) The operator shall conduct ASTM D6866-06a analysis at least every three months, and shall collect each gas sample for analysis during normal operating conditions over at least 24 consecutive hours.
(2) The operator shall divide total CO_2 emissions between biomass-derived emissions and non-biomass-derived emissions using the average proportionalities of the samples analyzed.
(3) If there is a common fuel source to multiple units at the facility, the operator may elect to conduct ASTM D6866-06a testing for one of the units.

§ WCI.24 Calculation of CH_4 and N_2O Emissions

Calculate the annual CH_4 and N_2O mass emissions from stationary fuel combustion sources using the procedures in paragraph (a), (b), or (c), as appropriate.

(a) If the heat content of the fuel is measured, calculate CH_4 and N_2O emissions the following Equation 20-7:

$$CH_4 \text{ or } N_2O = \sum_{1}^{n} Fuel_P \times HHV_P \times EF \times 0.001 \qquad \textbf{Equation 20-7}$$

Where:

CH_4 or N_2O	=	Combustion emissions from specific fuel type, metric tons CH_4 or N_2O per year.
n	=	Period/frequency of heat content measurements over the year (e.g. monthly n = 12).
$Fuel_P$	=	Mass or volume of fuel combusted for the measurement period specified by fuel type, units of mass or volume per unit time.
HHV_P	=	High heat value measured for the measurement period specified by fuel type, MMBtu per unit mass or volume.
EF	=	Default CH_4 or N_2O emission factor provided in Table 20-3, kg CH_4 or N_2O per MMBtu.
0.001	=	Factor to convert kg to metric tons.

(b) If the heat content of the fuel is not measured, calculate CH_4 and N_2O emissions using the following equation:

$$CH_4 \text{ or } N_2O = \sum_{1}^{n} Fuel \times HHV_D \times EF \times 0.001$$ **Equation 20-8**

Where:

CH_4 or N_2O	=	CH_4 or N_2O emissions from a specific fuel type, metric tons CH_4 or N_2O per year.
Fuel	=	Mass or volume of fuel combusted specified by fuel type, unit of mass or volume per year.
HHV_D	=	Default high heat value specified by fuel type provided in Table 20-3, MMBtu per unit of mass or volume.
EF	=	Default emission factor provided in Table 20-3, kg CH_4 or N_2O per MMBtu.
0.001	=	Factor to convert kg to metric tons.

(c) For municipal solid waste combustion, use Equation 20-9 of this section to estimate CH_4 and N_2O emissions:

$$CH_4 \text{ or } N_2O = Steam \times B \times EF \times 0.001$$ **Equation 20-9**

Where:

CH_4 or N_2O	=	Annual CH_4 or N_2O emissions from the combustion of a municipal solid waste (metric tons).
Steam	=	Total mass of steam generated by MSW combustion during the reporting year (lb steam).
B	=	Ratio of the boiler's maximum rated heat input capacity to its design rated steam output (mmBtu/lb steam).
EF	=	Fuel-specific emission factor for CH_4 or N_2O, from Table WCI.20-3 of this subpart (kg CH_4 or N_2O per mmBtu).
0.001	=	Conversion factor from kilograms to metric tons.

(d) The operator may elect to calculate CH_4 and N_2O emissions using source-specific emission factors derived from source tests conducted at least annually under the supervision of (*jurisdiction*). Upon approval of a source test plan, the source test procedures in that plan shall be repeated in each future year to update the source specific emission factors annually.

§ WCI.25 Sampling, Analysis, and Measurement Requirements

(a) Fuel Sampling Requirements. Fuel sampling must be conducted at the frequency specified in paragraph (a) (1) through (a)(4) of this section.

(1) At receipt of each new fuel shipment or delivery or on a monthly basis for middle distillates (diesel, gasoline, fuel oil, kerosene), residual oil, liquid waste-derived fuels, and LPG (ethane, propane, isobutene, n-Butane, unspecified LPG);

(2) Monthly for natural gas, associated gas, and mixtures of low Btu gas.
(3) Monthly for gases derived from biomass including landfill gas and biogas from wastewater treatment or agricultural processes.
(4) Monthly for solid fuels, as specified below:

(A) The monthly solid fuel sample shall be a composite sample of weekly samples.
(B) The solid fuel shall be sampled at a location after all fuel treatment operations and the samples shall be representative of the fuel chemical and physical characteristics immediately prior to combustion.
(C) Each weekly sub-sample shall be collected at a time (day and hour) of the week when the fuel consumption rate is representative and unbiased.
(D) Four weekly samples (or a sample collected during each week of operation during the month) of equal mass shall be combined to form the monthly composite sample.
(E) The monthly composite sample shall be homogenized and well mixed prior to withdrawal of a sample for analysis.
(F) One in twelve composite samples shall be randomly selected for additional analysis of its discreet constituent samples. This information will be used to monitor the homogeneity of the composite.

(b) Fuel Consumption Monitoring Requirements.

(1) Facilities that are subject to the verification requirements of WCI.8 must determine annual fuel consumption by direct measurement.
(2) Facilities that are not subject the verification requirements of WCI.8 may determine consumption on the basis of recorded fuel purchase or sales invoices measuring any stock change (measured in million Btu, gallons, million standard cubic feet, short tons or bone dry short, tons) using the following equation:

Fuel Consumption in the Report Year = Total Fuel Purchases – Total Fuel Sales + Amount Stored at Beginning of Year – Amount Stored at Year End

(3) Fuel consumption measured in Btu values shall be converted to the required metrics of mass or volume using heat content values that are either provided by the supplier, measured by the facility, or provided in Table 20-1.

(c) Fuel Heat Content Monitoring Requirements. High heat values shall be determined using one of the following methods:

(1) For gases, use ASTM D1826-94 (Reapproved 2003), ASTM D3588-98 (Reapproved 2003), ASTM D4891-89 (Reapproved 2006), GPA Standard 2261-00 "Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography." The operator may alternatively elect to use on-line instrumentation that determines heating value accurate to within ± 5.0 percent. Where existing on-line instrumentation provides only low heating value, the operator shall convert the value to high heating value as specified in section 95125(c)(1)(C).
(2) For middle distillates and oil, or liquid waste-derived fuels, use ASTM D240-02 (Reapproved 2007), ASTM D240-87 (Reapproved 1991), ASTM D4809-00 (Reapproved 2005).
(3) For solid biomass-derived fuels use ASTM D5865-07a.

(4) For waste-derived fuels use ASTM D5865-07a or ASTM D5468-02 (Reapproved 2007). Operators who combust waste-derived fuels that are partly but not pure biomass shall determine the biomass-derived portion of CO_2 emissions using the method specified in section WCI.23(f), if applicable

(d) Fuel Carbon Content Monitoring Requirements. Fuel carbon contents should be monitored in the following manner.

(1) For coal and coke, solid biomass-derived fuels, and waste-derived fuels; use ASTM 5373-02 (Reapproved 2007).

(2) For liquid fuels, use the following ASTM methods: For petroleum-based liquid fuels and liquid waste-derived fuels, use ASTM D5291-02 (Reapproved 2007) "Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants", ultimate analysis of oil or computations based on ASTM D3238-95 (Reapproved 2005) and either ASTM D2502-04 or ASTM D2503-92 (Reapproved 2002).

(3) For gaseous fuels, use ASTM D1945-03 or ASTM D1946-90 (Reapproved 2006).

Table 20-1. Default Carbon Content, Heat Content, and Carbon Dioxide Emission Factors from Stationary Combustion by Fuel Type				
Fuel Type	**Carbon Content**	**High Heat Value**	**CO_2 Emission Factor**	**CO_2 Emission Factor**
Coal and Coke	**kg C / MMBtu**	**MMBtu / Short Ton**	**kg CO_2 / Short Ton**	**kg CO_2 / MMBtu**
Anthracite	28.26	25.09	2,597.94	103.54
Bituminous	25.49	24.93	2,328.35	93.40
Sub-bituminous	26.48	17.25	1,673.64	97.02
Lignite	26.30	14.21	1,369.32	96.36
Unspecified (Residential/Commercial)	26.00	22.24	2,118.67	95.26
Unspecified (Industrial Coking)	25.56	26.28	2,461.17	93.65
Unspecified (Other Industrial)	25.63	22.18	2,082.89	93.91
Unspecified (Electric Power)	25.76	19.97	1,884.86	94.38
Coke	27.85	24.80	2,530.65	102.04
Natural Gas (By Heat Content)	**kg C / MMBtu**	**Btu / Standard cubic foot**	**kg CO_2 / Standard cubic ft.**	**kg CO_2 / MMBtu**
975 to 1,000 Btu / Standard cubic foot	14.73	n/a	n/a	53.97
1000 to 1,025 Btu / Std cubic foot	14.43	n/a	n/a	52.87
1025 to 1,050 Btu / Std cubic foot	14.47	n/a	n/a	53.02
1050 to 1,075 Btu / Std cubic foot	14.58	n/a	n/a	53.42
1075 to 1,100 Btu / Std cubic foot	14.65	n/a	n/a	53.68
Greater than 1,100 Btu / Std cubic foot	14.92	n/a	n/a	54.67
Unspecified (Weighted U.S. Average)	14.47	1,027	0.0544	53.02

Table 20-1. Default Carbon Content, Heat Content, and Carbon Dioxide Emission Factors from Stationary Combustion by Fuel Type (continued)

Petroleum Products	kg C / MMBtu	MMBtu / Barrel	kg CO_2 / gallon	kg CO_2 / MMBtu
Asphalt & Road Oil	20.62	6.636	11.94	75.55
Aviation Gasoline	18.87	5.048	8.31	69.14
Distillate Fuel Oil (#1, 2 & 4)	19.95	5.825	10.14	73.10
Jet Fuel	19.33	5.670	9.56	70.83
Kerosene	19.72	5.670	9.75	72.25
LPG (energy use)	17.19	3.861	5.79	62.98
Propane	17.20	3.824	5.74	63.02
Ethane	16.25	2.916	4.13	59.54
Isobutane	17.75	4.162	6.44	65.04
n-Butane	17.72	4.328	6.69	64.93
Lubricants	20.24	6.065	10.71	74.16
Motor Gasoline	19.33	5.218	8.80	70.83
Residual Fuel Oil (#5 & 6)	21.49	6.287	11.79	78.74
Crude Oil	20.33	5.800	10.29	74.49
Naphtha (<401 deg. F)	18.14	5.248	8.30	66.46
Natural Gasoline	18.24	4.620	7.35	66.83
Other Oil (>401 deg. F)	19.95	5.825	10.14	73.10
Pentanes Plus	18.24	4.620	7.35	66.83
Petrochemical Feedstocks	19.37	5.428	9.17	70.97
Petroleum Coke	27.85	6.024	14.64	102.04
Still Gas	17.51	6.000	9.17	64.16
Special Naphtha	19.86	5.248	9.09	72.77
Unfinished Oils	20.33	5.825	10.33	74.49
Waxes	19.81	5.537	9.57	72.58
Other Solid Fuels	**kg C / MMBtu**	**MMBtu / Short Ton**	**kg CO_2 / Short Ton**	**kg CO_2 / MMBtu**
Biomass Derived Fuels (Solid). Wood and Wood Waste (12% moisture content) or other solid biomass-derived fuels	25.60	15.38	1,442.62	93.80
Municipal Solid Waste (MSW)	24.74	8.7	788.7	90.65
Biomass-derived Fuels (Gas)	**kg C / MMBtu**	**Btu / Standard cubic foot**	**kg CO_2 / Standard cubic ft.**	**kg CO_2 / MMBtu**
Biogas (includes landfill gas and manure biogas)*	28.4	Varies	Varies	104.06

Note: Heat content factors are based on higher heating values (HHV).

* The emission factors for biogas include both the CO_2 from combustion and the pass-through CO_2, which are assumed to be in equal proportions.

Table 20-2. Default Carbon Dioxide Emission Factors from Stationary Combustion for Waste Derived Fuels

Fuel Type	kg CO_2 / MMBtu
Waste Oil	78
Tires	90
Plastics	79
Solvents	78
Impregnated Saw Dust	79
Other Fossil Based Wastes	84
Dried Sewage Sludge	116
Mixed Industrial Waste	88
Municipal Solid Waste	91

Note: Emission factors are based on higher heating values (HHV). Values were converted from LHV to HHV assuming that LHV are 5 percent lower than HHV for solid and liquid fuels.

Table 20-3. Default CH_4 and N_2O Emission Factors from Stationary Combustion by Fuel Type

Fuel Type	CH_4 Emission Factor (kg CH_4/ MMBtu)	N_2O Emission Factor (kg N_2O / MMBtu)
Asphalt	0.003	0.006
Aviation Gasoline	0.003	0.006
Coal	0.01	1.5
Crude Oil	0.003	0.006
Digester Gas	0.0009	0.1
Distillate	0.003	0.006
Gasoline	0.003	0.006
Jet Fuel	0.003	0.006
Kerosene	0.003	0.006
Landfill Gas	0.0009	0.1
LPG	0.001	0.1
Lubricants	0.003	0.006
MSW	0.03	0.004
Naphtha	0.003	0.006
Natural Gas	0.0009	0.1
Natural Gas Liquids	0.003	0.006
Other Biomass	0.03	0.004
Petroleum Coke	0.003	0.006
Propane	0.001	0.1
Refinery Gas	0.0009	0.1
Residual Fuel Oil	0.003	0.006
Tires	0.003	0.006
Waste Oil	0.03	0.004
Waxes	0.003	0.006
Wood (Dry)	0.03	0.004

Note: Heat content factors are based on higher heating values (HHV).

ATTACHMENT 1: GENERAL PROVISIONS

GENERAL PROVISIONS

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§ WCI.10 GLOBAL WARMING POTENTIALS

EMISSIONS QUANTIFICATION, AND SAMPLING, ANALYSIS AND MEASUREMENT

§ WCI.20 THROUGH § WCI.XX

§ WCI.0 PURPOSE

This rule requires mandatory reporting and verification of greenhouse gas (GHG) emissions data by certain facilities that directly emit GHG, by importers of electricity, and by suppliers of fossil fuels. The GHGs that must be reported under this rule are carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFC), perfluorocarbons (PFC), and sulfur hexafluoride (SF_6).

§ WCI.1 APPLICABILITY

(a) The GHG emissions reporting requirements, and related monitoring, recordkeeping, and verification requirements of this rule apply to the owners and operators *[Each jurisdiction will select the specific terminology for the regulated persons in accordance with their customary rule-writing practices]* of any facility that meets the requirements of paragraph (a)(1) of this section; and any fuel suppliers and electricity importers that meet the requirements of paragraph (a)(2), (a)(3), or (a)(4) of this section:

(1) Any facility that emits 10,000 metric tons CO_2e or more per year in combined emissions from one or more of the source categories listed in this paragraph in any calendar year starting in 2010.

[Please note that the quantification and monitoring methods for many of these source categories are currently being assessed. Only source categories for which adequate quantification methods exist will be included in the final WCI Essential Requirements for mandatory reporting.]

(A) Adipic acid manufacturing [*still being assessed*]
(B) Aluminum manufacturing
(C) Ammonia manufacturing [*still being assessed*]
(D) Carbon dioxide transfer recipients [*still being assessed*]
(E) Cement manufacturing
(F) Coal mine fugitive emissions (active and abandoned)
(G) Coal storage
(H) Cogeneration [*still being assessed*]
(I) Electricity generation
(J) Electronics Manufacturing [*still being assessed*]
(K) Ferroalloy production [*still being assessed*]
(L) General stationary fuel combustion
(M) Glass Production and other uses of carbonates [*still being assessed*]
(N) HCFC-22 production [*still being assessed*]
(O) Hydrogen production
(P) Industrial wastewater *[still being assessed for some industries]*
(Q) Iron and steel manufacturing
(R) Lead production
(S) Lime manufacturing
(T) Magnesium production *[still being assessed]*
(U) Natural gas transmission and distribution systems *[still being assessed]*
(V) Nitric acid manufacturing *[still being assessed]*
(W) Nonroad equipment at facilities *[still being assessed]*

(X) Oil and gas production & gas processing *[still being assessed]*
(Y) Petrochemical production *[still being assessed]*
(Z) Petroleum refineries
(AA) Phosphoric acid production *[still being assessed]*
(BB) Pulp and paper manufacturing
(CC) Refinery fuel gas
(DD) SF_6 from electrical equipment *[still being assessed]*
(EE) Soda ash manufacturing *[still being assessed]*
(FF) Zinc production

(2) All importers of electricity. Importers of electricity include both retail providers and marketers that import electricity into the WCI region. *[This is preliminary language, pending definition of electricity importers by another WCI Committee.]*

(3) Any supplier that within the WCI region distributes transportation fuels in quantities that when combusted would emit 10,000 metric tons CO_2e per year or more in any calendar year starting in 2010. *[This is preliminary language, pending future determination of point of regulation for transportation fuels.]*

(4) Any supplier that distributes within the WCI region residential, commercial, and industrial fuels in quantities that when combusted would emit 10,000 metric tons CO_2e per year or more in any calendar year starting in 2010. *[This is preliminary language, pending future determination of points of regulation for these fuels.]*

(b) To calculate GHG emissions for comparison to the 10,000 metric ton CO_2e per year emission threshold in paragraph (a)(1) of this section, the owner or operator shall calculate annual CO_2e emissions, as described in paragraphs (b)(1) through (b)(4) of this section.

(1) Estimate the annual emissions of CO_2, CH_4, N_2O, HFC, PFC, and SF_6 in metric tons for each unit, process, activity, or operation for which emission calculation methodologies are provided in sections WCI.20 through WCI.XX. The GHG emissions shall be calculated using methodologies specified in each applicable section.

(2) For stationary combustion units, carbon dioxide emissions from the combustion of biomass fuels shall be included in the calculations. *[WCI is considering a limited deduction of biomass fuel combustion emissions from determination of whether the reporting threshold has been met.]*

(3) Sum the total facility emissions for each GHG and calculate the metric tons of CO_2e using equation 1-1 below.

$$CO_2e = \sum_{i=1}^{n} GHG_i \times \mathrm{GWP}_i \qquad \textbf{Equation 1-1}$$

Where:

CO_2e = Carbon dioxide equivalent, metric tons/year.
GHG_i = Mass emissions of each greenhouse gas emitted, metric tons/year.
GWP_i = Global warming potential for each greenhouse gas from Table WCI.10-1 of this regulation.
n = The number of greenhouse gases emitted.

(4) For purpose of determining if an emission threshold has been exceeded, any CO_2 that is captured for on-site use, on-site storage, or transfer off-site must be included in the emissions total.

(c) To calculate GHG emissions for comparison to the 10,000 metric ton CO_2e per year emission threshold for suppliers of transportation fuels in paragraphs (a)(3) of this section, the owner or operator shall follow the procedures of paragraphs (c)(1) through (c)(2) below:

(1) Calculate the total mass in metric tons per year of CO_2, CH_4, and N_2O that would result from the complete combustion or oxidation of all transportation fuels that are distributed within the WCI region. The mass of each GHG shall be calculated using any of the applicable methodologies specified in section WCI.XX [Transportation Fuels Combustion] of this rule.

(2) Sum the emissions of each GHG and calculate total metric tons of CO_2e using Equation 1-1 of this rule.

(d) To calculate GHG emissions for comparison to the 10,000 metric ton CO_2e per year emission threshold for suppliers of residential, commercial, and industrial fuels in paragraph (a)(4) of this section, the owner or operator shall follow the procedures of paragraphs (d)(1) and (d)(2) below:

(1) Calculate the total mass in metric tons per year of CO_2, CH_4, and N_2O that would result from the complete combustion or oxidation of all residential, commercial, and industrial fuels that are distributed within the WCI region. The calculation shall exclude any fuels that are supplied to facilities that are required to report GHG emissions under section WCI.1(a)(1). *[These accounting issues will be dealt with in 2009.]* The mass of each GHG shall be calculated using any of the applicable methodologies specified in section WCI.XX [Residential, Commercial and Industrial Fuels Combustion] of this rule.

(2) Sum the emissions of each GHG and calculate total metric tons of CO_2e using Equation 1-1 of this rule.

(e) If the operations of a facility or fuel supplier that is subject to this rule change such that emissions fall below 10,000 metric tons CO_2e per year, then the following reporting requirements shall apply:

[Please note that the requirements of this subsection do not currently address reporters who emit >25,000 metric tons during 1 or more years, and then drop below 25,000 metric tons and above 10,000 metric tons in subsequent years. A provision for these reporters to cease verification after some period of time is under consideration.]

(1) If, prior to such emission reduction, the emissions report was subject to the verification requirements of this rule; then the owner or operator shall continue to submit verified emission reports until reported emissions are below 10,000 metric tons CO_2e per year for a minimum of 3 consecutive years. If reported emission are less than 10,000 metric tons CO_2 per year during 3 consecutive years, then the owner or operator shall be exempted from further reporting until CO_2e emissions again exceed 10,000 metric tons in any future calendar year.

(2) If, prior to such emission reduction, the emissions report was not subject to the verification requirements of this rule; then the owner or operator shall submit to the *[jurisdiction]* a signed statement certifying that emissions are less than 10,000 metric tons

CO_2e during the prior year. After certifying that emissions are below 10,000 metric tons CO_2e per year for 3 consecutive years, the owner or operator shall be exempted from further reporting until CO_2e emissions again exceed 10,000 metric tons in any future calendar year.

(3) Notwithstanding the requirements of paragraphs (e)(1) and (2) of this section, a facility or fuel supplier that is subject to an emissions limitation under the WCI cap-and-trade program must continue to submit verified annual reports.

(f) Upon request by the [*jurisdiction*], owner or operator of any facility or fuel supply operation must submit a demonstration that emissions have not exceeded one or more of the applicability criteria specified in this section in any year since 2010. Such demonstration shall be provided to the [*jurisdiction*] within 20 working days of receipt of a written request. *[WCI is considering whether this and other deadlines for responses provide sufficient time, and whether such deadlines should be standardized across requirements.]*

§ WCI.2 GENERAL GREENHOUSE GAS REPORTING REQUIREMENTS AND SCHEDULE

[Specific requirements of this section may change based on the future final design of the marketing trading program.]

(a) General. Owners or operators that are subject to this rule must submit an annual GHG emissions report. Owners and operators must collect data; calculate GHG emissions; and follow the procedures for quality assurance, missing data, recordkeeping, and reporting as specified in these General Provisions and in each relevant section WCI.20 through WCI.XX of this rule.

(1) A facility, fuel supplier, or electricity importer that commenced operation before January 1, 2010, must report emissions beginning in 2011 for GHGs emitted in calendar year 2010.

(2) A new facility, fuel supplier, or electricity importer that commences operation on or after January 1, 2010, must report emissions for the first calendar year in which the facility operates, beginning with the first operating month and ending on December 31 of that year. Each subsequent annual report must cover emissions for the calendar year, beginning on January 1 and ending on December 31.

(b) Reporting and Verification Schedule.

(1) Annual GHG emissions reports must be submitted to [*the jurisdiction*] by April 1 of each year for emissions in the previous calendar year.

(2) Reporters subject to the verification requirements of WCI.8, must complete their verification process, including submittal of a verification statement to [*the jurisdiction*], according to the following schedule:

(A) For reporting years 2010 through 2011, September 1 of the year following the reporting year.

(B) For reporting years 2012 and later, *[date to be determined]*.

(c) Submission of GHG Emissions Report. The annual GHG emissions report must be submitted to [*the jurisdiction*] in a format [*to be specified by each jurisdiction*].

(d) Simplified Emission Calculation Methods for De Minimis Sources. The owner or operator may elect to designate as de minimis one or more sources or pollutants that collectively emit no more than 3 percent of the facility's total CO_2e emissions, but not to exceed 20,000 metric tons CO_2e. The owner or operator may estimate emissions for these de minimis sources using alternative methods to those required to be used by this rule. If verification of the emissions report is required by this rule, then the selection of any alternative GHG calculation method is subject to the concurrence of the verification team that the use of such methods provides reasonable assurance that the emissions so designated do not exceed the applicable de minimis limits. The operator shall separately identify and include in the emissions data report the emissions from designated de minimis sources.

(e) GHG Inventory Management Plan. The owner or operator shall prepare and follow a written GHG inventory management plan that ensures that the emissions calculations and other information that is required to be reported under this rule are transparent, accurate, and independently verifiable. The owner or operator shall establish, document, implement, and maintain data acquisition and handling activities for the calculation and reporting of GHG emissions. Such activities shall include measuring, monitoring, analyzing, recording, processing and calculating the parameters specified by this rule. The owner or operator shall implement systems of internal audit, quality assurance, and quality control for the reporting program and the data reported. *[WCI is considering whether a written plan should be mandatory, or advised in guidance materials as a means of assuring a smooth verification process and a positive verification opinion.]*

(f) GHG Emissions Report Revisions.

(1) The owner or operator shall maintain documentation to support any revisions made to a previously submitted annual GHG emissions report. Documentation for all revisions shall be retained by the operator for 7 years.

(2) If, after the verification deadline, a report subject to verification is found to contain an error, or accumulation of errors, greater than 5 percent of the total CO_2e emissions reported, the owner or operator shall revise and resubmit an annual GHG emissions report within 60 days of the finding. To the extent possible, the revised report must correct all identified errors. A revised report will be accepted only if verified according to WCI.8 and approved by [*the jurisdiction*].

(3) If, after the report submittal deadline, a report not subject to verification is found to contain an error, or accumulation of errors, greater than 5 percent of the total CO_2e emissions reported, the owner or operator shall revise and resubmit an annual GHG emissions report within 30 days of the finding. To the extent possible, the revised report must correct all identified errors. A revised report will be accepted only if approved by [*the jurisdiction*].

(4) An owner or operator that voluntarily chooses to correct errors of 5 percent or less in total CO_2e emissions reported may do so according to the following requirements:

(A) For reports subject to verification, a revised report will be accepted only if verified according to WCI.8 and approved by [*the jurisdiction*].

(B) For reports not subject to verification, a revised report will be accepted if approved by [*the jurisdiction*].

(g) Fuel Use Measurement Accuracy. The operator shall use procedures to quantify fuel use (mass or volume flow) that provide data with an accuracy within ±5 percent. All fuel use measurement devices shall be maintained and calibrated in a manner and at a frequency required to maintain this level of accuracy. The operator shall make available to the verification team documentation to support this level of accuracy. The operator who measures solid fuels shall validate fuel consumption estimates with belt or conveyor scale calibrations conducted at least quarterly, and retain record of such calibrations.

(h) Where this rule specifies a choice between use of a fuel-based or mass balance-based calculation or use of a continuous emissions monitoring system (CEMS) to calculate CO_2 emissions, the operator shall make this choice and continue to use the method chosen for all future emissions data reports, unless the use of the alternative calculation method is approved in advance by *[the jurisdiction]*.

§ WCI.3 CONTENTS OF THE GREENHOUSE GAS EMISSIONS REPORT

Each annual GHG emissions report shall contain the following information:

(a) Facility name, identification number, physical address, mailing address, and NAICS code.

(b) Reporting year.

(c) Date of report submittal.

(d) Total facility emissions aggregated from all applicable source categories in subparts WCI.20 through WCI.XX expressed in metric tons of CO_2e calculated using Equation 1-1 of section WCI.1, excluding emissions from CO_2 that is captured and CO_2 emissions from the combustion of biomass and biomass-derived fuels, which are reported separately.

(e) Total facility emissions of CO_2 from the combustion of biomass and biomass-derived fuels.

(f) Total annual mass of CO_2 captured for on-site use, on-site storage, or transfer off site, in metric tons.

(g) For applicable fuel supplier categories in subparts WCI.XX [Transportation Fuels Combustion] and WCI.XX [Residential, Commercial and Industrial Fuels Combustion], total CO_2e emissions aggregated from all specified fuels.

(h) Emissions from each applicable source category or fuel supplier category in subparts WCI.20 through WCI.XX, expressed in metric tons per year of CO_2, CH_4, N_2O, HFC, PFC, and SF_6. CO_2 emissions from the combustion of biomass and biomass-derived fuels shall be reported separately.

(i) For electricity importers, the information required by WCI.XX [Electricity Imports].

(j) Emissions and other data for individual units, processes, activities, and operations as specified for each source category in sections WCI.20 through WCI.XX of this rule.

(k) Mass emissions from each designated de minimis source or pollutant, reported in metric tons per year of each GHG for which an alternative emission calculation method is used.

(l) Name and contact information including e-mail address and telephone number of the person primarily responsible for preparing and submitting the emissions report.

(m) A signed and dated statement provided by the owner or operator, or their designated representative, certifying that the report has been prepared in accordance with this rule and that, subject to verification, the statements and information contained in the emissions data report are true, accurate, and complete to the best of their knowledge.

§ WCI.4 DOCUMENT RETENTION AND RECORD KEEPING REQUIREMENTS

(a) The operator shall establish and maintain procedures for document retention and record keeping. The operator shall retain all documents regarding the design, development and maintenance of the GHG inventory in paper, electronic or other usable format for a period of not less than 7 years following submission of each emissions data report. The retained documents, including GHG emissions data, shall be sufficient to allow for the verification of each emissions data report.

(b) Upon request by *[jurisdiction]*, the operator shall provide within 10 working days all documents and data used to develop an emissions data report.

(c) In addition to information submitted as part of the emissions data report, each operator shall retain, at a minimum, the following information for at least 7 years after the submission of the report:

(1) A list of all GHG sources (i.e., units, operations, processes, and activities) included in the emission estimates.
(2) All data used to calculate emissions for each source, categorized by process and fuel or material type.
(3) Documentation of the process for collecting emissions data.
(4) Any GHG emissions calculations and methods used;
(5) All emission factors used for emission estimates, including documentation for any factors not provided in the rule.
(6) All input data used for emission estimates.
(7) Documentation of biomass fractions for specific fuels.
(8) All other data submitted to the [*jurisdiction*] under this rule, including the GHG emissions report.
(9) All computations made to gap-fill missing data.
(10) Names and documentation of key facility personnel involved in emissions calculating and reporting;
(11) Any other information that is required for the verification of the GHG emissions report.
(12) A log to be prepared for each reporting year, beginning January 1, documenting all procedural changes made in GHG accounting methods and changes to instrumentation for GHG emissions estimation.
(13) A copy of the GHG Inventory Management Plan.

(d) For measurement based methodologies, the following information also must be retained for at least 7 years after the submission of the emissions data report:

(1) List of all emission points monitored.
(2) Collected monitoring data.
(3) Quality assurance and quality control information collected under the GHG Inventory Management Plan required by section WCI.2 of this rule.

(4) A detailed technical description of the continuous measurement system, including documentation of any findings and approvals by federal, State or local agencies.
(5) Raw and aggregated data from the continuous measurement system.
(6) A log book of all system down-times, calibrations, servicing, and maintenance of the continuous measurement system.
(7) Documentation of any changes in the continuous measurement system over time.

§ WCI.5 COMPLIANCE AND ENFORCEMENT

(a) Knowing submission of false information to the *[jurisdiction*] or a verification body, shall constitute a single, separate violation of the requirements of this article for each day after the information has been received by the [*jurisdiction*].

(b) Each violation of this rule shall constitute a single, separate violation for each day beyond the specified reporting date. A violation includes failure to submit any report, failure to collect data needed to calculate GHG emissions, failure to monitor and test as required, failure to calculate GHG emissions following the methodologies specified in this rule, failure to retain required records, failure to provide all information required in the report, and failure to submit a report on time. For the purposes of this rule, "report" means any GHG emissions data report, verification statement, or other document required to be submitted by this rule.

§ WCI.6 INCORPORATION BY REFERENCE

The following documents are incorporated by reference into this rule. These materials are incorporated as they exist on the date this article is adopted.

[This list will be revised as additional calculation methods are selected. Canadian Standards Association methods equivalent to the specified ASTM methods will be identified as substitutes for these in rulemaking by Canadian jurisdictions.]

(a) American Society for Testing and Materials (ASTM) D1826-94 (Reapproved 2003), ASTM D3588-98 (Reapproved 2003), ASTM D4891-89 (Reapproved 2006), ASTM D240-02 (Reapproved 2007), ASTM D4809-00 (Reapproved 2005), ASTM 5373-02 (Reapproved 2007), ASTM D5291-02 (Reapproved 2007), ASTM D3238-95 (Reapproved 2005), ASTM D2502-04, ASTM D2503-92 (Reapproved 2002), ASTM D1945-03, ASTM D1946-90 (Reapproved 2006), ASTM D6866-06a, ASTM D388-05, ASTM D5468-02 (Reapproved 2007), ASTM D240-87 (Reapproved 1991), ASTM D5865-07a, ASTM Specification D396-07, ASTM Specification D975-07b.

(b) California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities, California Air Pollution Control Officers Association (CAPCOA) and California Air Resources Board (ARB), February 1999.

(c) Control of Emissions from Refinery Flares, Rule 118, South Coast Air Quality Management District, Amended November 4, 2005.

(d) U.S. EPA TANKS Version 4.09D, US Environmental Protection Agency, October 2005.

(e) Gas Processors Association (GPA) Standard 2261-00, Revised 2000.

§ WCI.7 DESIGNATED REPRESENTATIVE

(a) General. Each fuel supplier, electricity importer, and owner or operator of a facility that is subject to this rule, shall select a designated representative that is responsible for certifying and submitting GHG emissions reports under this reporting rule.

(b) Authorization of a Designated Representative. The designated representative of the facility shall be selected by a certificate of representation agreement that is signed by the designated representative and owners or operators of the facility. The designated representative must be an individual having responsibility for the overall operation of the facility or activity such as the position of the plant manager, operator of a well or a well field, superintendent, position of equivalent responsibility, or an individual or position having overall responsibility for environmental matters for the company.

(c) Responsibility of the Designated Representative.

(1) The designated representative of the facility shall represent and by any representations, actions, inactions, or submissions, legally bind each owner and operator in all matters pertaining to this rule.

(2) Each GHG emission report submitted under this rule must be signed by the designated representative and must contain the following certification statement: “I have been authorized to make this submission on behalf of the owners and operators of the facility (or supply operation, as appropriate). I certify under penalty of law that I have personally examined the information submitted in this document. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(d) Changing a Designated Representative. The designated representative may be changed at any time upon submission of a superseding certificate of representation. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous designated representative before time of the superseding certificate of representation shall be binding on the new designated representative and the owners and operators.

(e) Changes in Owners and Operators. In the event of any change in ownership of the facility, any new owner or operator shall be deemed to be bound by the representations, actions, inactions, and submissions of the designated representative of the facility until such time as the designated representative is changed.

(f) Certificate of Representation. A certificate of representation must be submitted to *[the jurisdiction]* and kept on location by the facility, fuel supplier, or electricity importer. The certificate shall include the following information:

(1) Identification of the facility, fuel supplier, or electricity importer for which the certificate of representation is submitted.

(2) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the designated representative.

(3) A list of the owners and operators.

(4) Certification statements that the actions of the designated representative with respect to this rule are binding on the owners and operators, and that the designated representative has the necessary authority to carry out duties and responsibilities on behalf of the owners and operators.

(5) The signature of the designated representative and owner(s) and operator(s), and the dates signed.

§WCI.8 REQUIREMENTS FOR VERIFICATION OF GREENHOUSE GAS EMISSIONS DATA REPORTS AND REQUIREMENTS APPLICABLE TO EMISSIONS DATA VERIFIERS

(a) Applicability. Owners or operators [Each jurisdiction will select the specific terminology for the regulated persons in accordance with their customary rule-writing practices] are required to obtain annual verification when the reported annual emissions of the operation subject to this rule:

(1) Are equal to 25,000 metric tons of CO_2e or more; or

(2) Are subject to an emissions limit under the WCI cap-and-trade program as required under WCI.1(e)(3); or

(3) Were verified and then fall below 10,000 metric tons of CO_2e in a subsequent year as stipulated under WCI.1(e)(1).

[WCI is considering a limited deduction of biomass fuel combustion emissions from determination of whether the verification threshold has been met.]

(b) Requirements for Annual Verification of Emissions Data Reports.

(1) Facility owners or operators, fuel suppliers, and electricity importers required to obtain annual verification shall be subject to full verification requirements in the first year that verification is required. Upon completion of a positive verification statement under full verification requirements, the facility owner or operator, fuel supplier, or electricity importer may choose to obtain two years of less intensive verification services. This cycle may be repeated in subsequent three-year cycles, but full verification requirements shall apply at least once every three years.

(2) Facility owners or operators, fuel suppliers, and electricity importers required to obtain annual verification will be required to obtain full verification services if any of the following apply:

(A) Change in the verification body from the previous year; or

(B) A verification body was not able to provide a positive verification statement for the reporters emissions report for the previous year.

(3) Facility owners or operators, fuel suppliers, or electricity importers subject to annual verification shall not use the same verification body for a period of more than six consecutive years. If a facility owner or operator, fuel supplier, or electricity importer is required or elects to contract with another verification body, they may contract verification services from the previous verification body only after not using the previous verification body for at least three years.

(c) Requirements for Verification Services. Verification services shall be subject to the following requirements.

(1) Notice of Verification Services. After the [*WCI Regional Body, jurisdiction, or other organization to be determined (TBD)*] has provided a determination that the potential for a conflict of interest is acceptable as specified in section WCI.8(e) and that verification services may proceed, the verification body shall submit a notice of verification services to [*TBD*]. The verification body may begin verification services for the operator 15 working days after the notice is received by the [*TBD*], or earlier if approved by the [*TBD*] in writing. The notice shall include the following information:

(A) A list of the staff who will be designated to provide verification services as a verification team, including the names of each designated staff member, the lead verifier, and all subcontractors, and a description of the roles and responsibilities each member will have during verification;

(B) Documentation that the verification team has the skills required to provide verification services for the reporting facility, fuel supply or electricity import operation. This shall include a demonstration that a verification team includes at least one member with source category specific skills to provide source-category specific verification services when required below:

i. For providing verification of emissions reported under WCI.60 [Electricity Importers] at least one verification team member must have demonstrated knowledge as an electricity transactions specialist.

ii. For providing verification of emissions reported under WCI.200 [Petroleum refineries] or WCI.140 [Hydrogen production], at least one verification team member must have demonstrated knowledge as a refinery specialist;

iii. For providing verification of emissions reported under WCI.90 [Cement], at least one verification team member must have demonstrated knowledge as a cement specialist.

[Note that other source-category specialist skills may be required. These requirements are being discussed by the WCI, as are any additional accreditation requirements for individual lead verifiers, general verifiers, or sector specialists.]

(C) General information on the lead verifier and the operator, including:

i. The name, office address, telephone number, and e-mail address of the lead verifier;

ii. The name of the owner or operator, and the facilities and other locations that will be subject to verification services, owner or operator contact, address, telephone number, and e-mail address;

iii. The industry sector, and the Standard Industrial Classification and North American Industry Classification System (NAICS) codes of the facility, fuel supplier, or electricity importer;

iv. The expected date(s) of on-site visits, with facility or fuel supply location address and contact information;

v. A brief description of expected verification services to be performed, including expected completion date.

(2) Verification services shall include, but are not limited to, the following:

(A) Verification Plan. The verification team shall obtain information from the owner or operator necessary to develop a verification plan. Such information shall include but is not limited to:

i. Information to allow the verification team to develop a general understanding of facility or entity boundaries, operations, emissions sources, and electricity transactions as applicable;
ii. Information regarding the training or qualifications of personnel involved in developing the GHG emissions data report;
iii. Description of the specific methodologies used to quantify and report GHG emissions, electricity transactions, and other required data as applicable;
iv. Information about the data management system used to track GHG emissions, electricity transactions, and other required data as applicable.

(B) The verification team shall develop a verification plan that includes, at a minimum:

i. Dates of proposed meetings and interviews with reporting facility, fuel supply, or electricity import personnel;
ii. Dates of proposed site visits;
iii. Types of proposed document and data reviews;
iv. Expected date for completing verification services.

(C) The verification team shall discuss with the owner or operator the scope of the verification services and request any information and documents needed for initial verification services. The verification team shall review the documents submitted and plan and conduct a review of original documents and supporting data for the emissions data report.

(D) Site visits. At least one member of the verification team shall at a minimum make one site visit, in the first year of each three-year reporting cycle or if full verification requirements are required under WCI.8(b)(3), to each facility or fuel supply location [Note that exact location of fuel supplier site visits remains TBD] for which an emissions data report is submitted. The verification team member(s) shall visit the headquarters or other location of central data management when the owner or operator is an electricity importer. During the site visit, the verification team member(s) shall conduct the following:

i. The verification team member(s) shall check that all sources specified in sections WCI.20 to WCI.XX as applicable to the owner or operator, are identified appropriately.
ii. The verification team member(s) shall review and understand the data management systems used by the owner or operator to track, quantify, and report greenhouse gas emissions and, when applicable, electricity transactions. The verification team member(s) shall evaluate the uncertainty and effectiveness of these systems.
iii. The verification team shall collect and review other information that, in the professional judgment of the team, is needed in the verification process.

(E) The verification team shall review facility, fuel supplier, or electricity importer operations to identify applicable GHG emissions sources. This shall include a review of the emissions inventory and each type of emission source to assure that all sources listed in sections WCI.20 through WCI.XX are properly included in the inventory.

(F) Owners or operators shall make available to the verification team all information and documentation used to calculate and report emissions, electricity transactions, and other information required under this rule, as applicable.

(G) As applicable for electricity importers, the verification team shall review electricity transaction records, including receipts of power attributed to the Northwest or Southwest region as verifiable via North American Electric Reliability Corporation (NERC) E-Tags, settlements data, or other information as confirmation of the region of origin. [Note that this procedure is subject to change pending WCI Electricity Committee review.]

(H) Sampling Plan. As part of confirming emissions data or electricity transactions the verification team shall develop a sampling plan that meets the following requirements:

i. The verification team shall develop a sampling plan based on a strategic analysis developed from document reviews and interviews to assess the likely nature, scale and complexity of the verification services for an owner or operator. The analysis shall review the inputs for the development of the submitted emissions data report, the rigor and appropriateness of the GHG or electricity transaction data management system, and the coordination within a facility, fuel supplier's, or electricity importer's organization to manage the operation and maintenance of equipment and systems used to develop emissions data reports.

ii. The verification team shall include in the sampling plan a ranking of emissions sources by amount of contribution to total CO_2e emissions for the owner or operator and a ranking of emissions sources with the largest calculation uncertainty. As applicable and deemed appropriate by the verification team, electricity transactions shall also be ranked or evaluated relative to the amount of power exchanged and uncertainties that may apply to data provided by the electricity importer.

iii. The verification team shall include in the sampling plan a qualitative narrative of uncertainty risk assessment in the following areas as applicable under sections WCI.20 through WCI.XX:

- Data acquisition equipment;
- Data sampling and frequency;
- Data processing and tracking;
- Emissions calculations;
- Data reporting;
- Management policies or practices in developing emissions data reports.

iv. The verification team may change the sampling plan as relevant information becomes available and potential issues emerge of material misstatement or nonconformance with the requirements of this rule.

v. The verification body shall retain the sampling plan in paper, electronic, or other format for a period of not less than five years following the submission of each verification statement. The sampling plan shall be made available to *[TBD]* upon request.

(I) Data Checks. To determine the reliability of the submitted emissions data report, the verification team shall use data checks. Such data checks shall focus first on the largest and most uncertain estimates of emissions and electricity transactions, and shall include the following:

i. The verification team shall use data checks to ensure that the appropriate methodologies and emission factors have been applied for the emissions sources and electricity transactions covered under sections WCI.20 through WCI.XX;
ii. The verification team shall choose emissions sources, and electricity transactions data as applicable, for data checks based on their relative sizes and risks of material misstatement as indicated in the sampling plan;
iii. The verification team shall use professional judgment in the number of data checks required for the team to conclude with reasonable assurance whether the reported emissions and transactions are free of material misstatement and the emissions data report otherwise conforms to the requirements of this rule.

(J) Emissions Data Report Modifications. If as a result of review by the verification team and prior to completion of a verification statement the operator chooses to make improvements or corrections to the submitted emissions data report, a revised emissions data report may be submitted to [the jurisdiction] as specified by section WCI.2(f). The operator shall maintain documentation to support any revisions made to the initial emissions data report. Documentation for all emissions data report submittals shall be retained by the operator for seven years pursuant to section WCI.4.
(K) Findings. To verify that the emissions data report is free of material misstatement, the verification team shall make its own determination of emissions for sources checked according to WCI.8(c)(1), and shall determine whether there is reasonable assurance that the reported facility, fuel supply, or electricity import emissions are within 95 percent of actual total emissions for the facility, on a CO_2e basis. To assess conformance with this rule the verification team shall review the methods and factors used to develop the emissions data report for adherence to the requirement of this rule. The verification team shall keep a log of any issues identified in the course of verification activities that may affect determinations of material misstatement and nonconformance, and how those issues were resolved.

(3) Completion of verification services shall include:

(A) Verification Statement. Upon completion of the verification services specified in section WCI.8(c)(2), the verification body shall complete a verification statement, and provide that statement to the owner or operator and [the jurisdiction] according to the schedule specified in section WCI.2(b). Before that statement is completed, the verification body shall have the verification services and findings of the verification team independently reviewed within the verification body by a lead verifier not involved in services for that operator during that year.

(B) When the verification team completes its findings:

i. The verification body shall provide to the owner or operator a detailed verification report. The verification report shall at minimum include the verification plan, the detailed comparison of the data checks with the submitted emissions data report, the log of issues identified in the course of verification activities and their resolution, and any qualifying comments on findings during verification services. The detailed verification report shall be made available to [*the jurisdiction*] upon request.

ii. The verification body shall provide the verification statement to the owner or operator and [*the jurisdiction*], attesting that the verification body has found the submitted emissions data report free of material misstatement and in conformance with the requirements of this rule or, alternatively, that the emissions data report contains material misstatement or otherwise does not conform with the requirements of this rule.

iii. The lead verifier in the verification team shall attest that the verification team has carried out all verification services as required by this rule, and the lead verifier who has conducted the independent review of verification services and findings specified in section WCI.8(c)(3)(A) shall attest to his or her independent review on behalf of the verification body and his or her concurrence with the verification findings.

(C) Prior to the verification body providing an adverse verification statement to [*the* jurisdiction], the owner or operator shall be provided at least 10 working days to modify the emissions data report to correct any material misstatement or nonconformance found by the verification team. The modified report and verification statement must be submitted to [*the jurisdiction*] before the applicable verification deadline, unless the operator makes a request to [*the jurisidiction]* as follows

i. If the owner or operator and the verification body cannot reach agreement on modifications to the emissions data report that result in a positive verification statement, the operator may petition *[TBD]* to make a final decision as to the verifiability of the submitted emissions data report.

ii. If *[TBD]* determines that the emissions data report does not meet the standards and requirements specified in this rule, the owner or operator shall have the opportunity to submit within 60 calendar days of the date of this decision [Note that this time frame may need to be changed pending details of cap-and-trade system design and needs.] any emissions data report revisions that address *[TBD's]* determination, for re-verification of the emissions data report. In re-verifying a revised emissions data report, the verification body and verification team shall be subject to the requirements in section WCI.8(c)(3).

(4) Upon provision of the verification statement to *[the jurisdiction]*, the emissions data report shall be considered final and no changes shall be made except as provided in

section WCI.2(f). All verification requirements of this rule shall be considered complete upon provision of the verification statement.

(5) If the *[TBD]* finds a high level of conflict of interest existed between a verification body and an owner or operator or an emissions data report that received a positive verification statement fails an audit by *[TBD]*, the *[TBD]* may set aside the positive verification statement submitted by the verification body.

(6) Upon request by *[TBD]*, the owner or operator shall provide the data used to generate an emissions data report, including all data available to a verifier in the conduct of verification services. *[TBD]* may also review the full verification report given by the verification body to the owner or operator. The full verification report shall be provided to the *[TBD]* upon request.

(7) Upon written notification by the *[TBD]*, the verification body shall make itself available for a verification services audit.

(d) Accreditation Requirements for Verification Bodies, Lead Verifiers, and Verifiers.

(1) The accreditation requirements specified in this subsection shall apply to all verification bodies, lead verifiers, and verifiers that wish to provide verification services under this rule.

(2) Verification bodies accredited according to the requirements of the California Air Resources Board [provide regulatory citation] or to ISO 14065 through a program developed under ISO 17011 with demonstrated knowledge of WCI reporting requirements to conduct verification activities for WCI emissions data, are qualified to conduct verification activities for the WCI.

[Note the details of WCI's specific accreditation process for verification bodies (which has yet to be developed) will be consistent with ISO 14065 through an accreditation program that will developed under ISO 17011 and will include demonstrated knowledge of the WCI reporting requirements. WCI will explore additional accreditation requirements for individual lead verifiers, general verifiers, or sector specialists.]

(3) Subcontracting. The following requirements shall apply to any verification body that elects to subcontract verification services.

(A) The verification body must assume full responsibility for verification services performed by subcontractor verifiers or verification bodies.

(B) A verification body or verifier acting as a subcontractor to another verification body shall not further subcontract or outsource verification services for an operator.

(C) A verification body that engages a subcontractor shall be responsible for demonstrating an acceptable level of conflict of interest, as provided in section WCI.8(e) between its subcontractor and the operator for which it will provide verification services.

(4) If any WCI accredited verification body is suspended in any other mandatory or voluntary GHG reporting or trading program, that verification body will not be allowed to provide any verification services under WCI until that suspension ends. If any WCI accredited verification body has their verification body accreditation revoked under any other mandatory or voluntary GHG reporting or trading program, that verification body will no longer be allowed to provide verification services under WCI.

(e) Conflict of Interest Requirements for Verification Bodies.

(1) The conflict of interest provisions of this section shall apply to the verification body, entities related to the verification body, and the verification team accredited according to the requirements of WCI.8(d) to perform verification services for the WCI cap-and-trade program. Member for purposes of this section means any employee or subcontractor of the verification body or entities related to the verification body. Member also includes any individual with a majority equity share in the verification body or entities related to the verification body.

(2) The potential for a conflict of interest shall be deemed to be high where:

(A) The verification body and owner or operator share any management staff or board of directors membership, or any of the management staff of the owner or operator have been employed by the verification body, or vice versa, within the previous three years; or

(B) Within the previous three years, any member of the verification body, any entity related to the verification body, and the verification team has provided to the owner or operator any of the following non-verification services:

i. Designing, developing, implementing, or maintaining an inventory or information or data management system for facility greenhouse gases, or, where applicable, electricity transactions;
ii. Developing greenhouse gas emission factors or other greenhouse gas-related engineering analysis;
iii. Designing energy efficiency, renewable power, or other projects which explicitly identify greenhouse gas reductions as a benefit;
iv. Preparing or producing greenhouse gas-related manuals, handbooks, or procedures specifically for the reporting facility;
v. Appraisal services of carbon or greenhouse gas liabilities or assets;
vi. Brokering in, advising on, or assisting in any way in carbon or greenhouse gas-related markets;
vii. Managing any health, environment or safety functions;
viii. Bookkeeping or other services related to the accounting records or financial statements;
ix. Any service related to information systems, unless those systems will not be part of the verification process;
x. Appraisal and valuation services, both tangible and intangible;
xi. Fairness opinions and contribution-in-kind reports in which the verification body has provided its opinion on the adequacy of consideration in a transaction, unless the resulting services shall not be part of the verification process;
xii. Any actuarially oriented advisory service involving the determination of amounts recorded in financial statements and related accounts;
xiii. Any internal audit service that has been outsourced by the operator that relates to the owner's or operator's internal accounting controls, financial systems or financial statements, unless the result of those services shall not be part of the verification process;
xiv. Acting as a broker-dealer (registered or unregistered), promoter or underwriter on behalf of the owner or operator;

xv. Any legal services;

xvi. Expert services to the owner or operator or his or her legal representative for the purpose of advocating his or her's interests in litigation or in a regulatory or administrative proceeding or investigation, unless providing factual testimony.

(C) The potential for a conflict of interest shall also be deemed to be high where any staff member of the verification body, entity related to the verification body, or the verification team has provided verification services for the owner or operator within the last three years, except within the time periods in which the owner or operator is allowed to use the same verification body as specified in sections WCI.8(b).

(D) The potential for a conflict of interest shall be deemed high where the lead verifier doing the independent review for the verification team has provided verification or non-verification services for the operator in the last year as specified in section WCI.8(b).

(3) The potential for a conflict of interest shall be deemed to be low where:

(A) No potential for a conflict of interest is found under section WCI.8(e)(2) and any non-verification services provided by all members of the verification body and the verification team to the owner or operator within the last three years are valued at less than [Percent of the fee TBD] for the proposed verification.

(B) Any non-verification services provided at any time by a member of the verification body or the verification team did not include development of a GHG inventory system still in use by the owner or operator.

(4) The potential for a conflict of interest shall be deemed to be medium where the potential for a conflict of interest is not deemed to be either high or low as specified in sections WCI.8(e)(2)-(3).

(A) If a verification body identifies a medium potential for conflict of interest and wishes to provide verification services for the owner or operator, then the verification body shall submit, in addition to the submittal requirements specified in section WCI.8(e)(5), below, a plan to avoid, neutralize, or mitigate the potential conflict of interest situation. At a minimum, the conflict of interest mitigation plan shall include:

i. A demonstration that any individuals in the verification body or team with potential conflicts have been removed and insulated from the project.

ii. An explanation of any changes to the verification body or verification team to remove the potential conflict of interest, including changes to organization structure to demonstrate that a unit with potential conflicts has been divested or moved into an insulated related entity.

iii. A description of any other circumstance that specifically addresses other sources for potential conflict of interest.

(B) As provided in section WCI.8(e)(6), below, the [TBD] shall evaluate the conflict of interest mitigation plan and determine whether verification services may proceed.

(5) Conflict of Interest Submittal Requirements for Accredited Verification Bodies.

(A) Before the start of any work related to providing verification services to an owner or operator, a verification body must first be authorized in writing by *[TBD]* to provide verification services. To obtain authorization the verification body shall submit to *[TBD]* a self-evaluation of the potential for any conflict of interest that the verification body, entities related to the verification body, and members of the verification team including, subcontractors may have with the owner or operator or their related entities for which it will perform verification services. The submittal shall include the following:

i. Identification of whether the potential for conflict of interest is high, low, or medium based on factors specified in sections WCI.8(e)(2)-(4);

ii. An organizational chart of the business structure of the verification body, including its related entities and brief description of the primary work done by the verification body and related entities;

iii. Identification of whether any member of the verification body, entities related to the verification body, or the verification team including subcontractors has previously provided verification services for the owner or operator or its related entities and, if so, the years in which such verification services were provided;

iv. Identification of whether any member of the verification body, entities related to the verification body, or the verification team or including subcontractors has engaged in any non-verification services of any nature with the owner or operator or related entities either within or outside the WCI region during the previous three years. If non-verification services have previously been provided, the following information shall also be submitted:

- Identification of the nature and location of the work performed for the owner or operator and whether the work is similar to the type of work to be performed during verification, such as emissions inventory, auditing, energy efficiency, renewable energy, or other work with implications for the operator's greenhouse gas emissions or the accounting of greenhouse gas emissions or electricity transactions;
- The nature of past, present or future relationships the verification body, entities related to the verification body, and members of the verification team including subcontractors have with the owner or operator or related entity including:
  - Instances when any member has performed or intends to perform work for the owner or operator;
  - Identification of whether work is currently being performed for the owner or operator and, if so, the nature of the work;
  - Whether any member has any contracts or other arrangements to perform work for the owner or operator or a related entity;
  - Identify how much work was performed in the last three years, as a percentage of the verification body's total gross income for the last three years;
  - Identify how much work related to greenhouse gases or electricity transactions was has performed for the owner or operator or related

entities in the last three years, as a percentage of the verification body's income for the last three years;

– Identify how much work was performed by each subcontractor for the operator in the last three years, as a percentage of each subcontractor's total gross income for the last three years.

- Explanation of how the amount and nature of work previously performed is such that any member of the verification team's credibility and lack of bias should not be under question.

v. A list of names of the staff that will perform verification services for the owner or operator and a description of any instances of personal or family relationships with management or employees of the owner or operator that potentially represent a conflict of interest; and,

vi. Identification of any other circumstances or relevant information known to the verification body or owner or operator that could result in a conflict of interest, or any situation where the appearance of impartiality could undermine confidence in the verification body's ability to asses the reported emissions.

(6) Conflict of Interest Determinations. The *[TBD]* shall review the self-evaluation submitted by the verification body and determine whether the verification body is authorized to perform verification services for the owner or operator

(A) The *[TBD]* shall notify the verification body in writing when the conflict of interest evaluation information submitted under section WCI.8(e)(5) is deemed complete. Within *[Number of days TBD]* of deeming the evaluation information complete, *[TBD]* shall determine whether the verification body is authorized to proceed with verification and shall so notify the verification body.

(B) If *[TBD]* determines the verification body or any member of the verification team meets the criteria specified in section WCI.8(e)(2), *[TBD]* shall find a high potential conflict of interest and verification services may not proceed.

(C) If *[TBD]* determines that there is a low potential conflict of interest, verification services may proceed.

(D) If *[TBD]* determines that the verification body and verification team have a medium potential for a conflict of interest, *[TBD]* shall evaluate the conflict of interest mitigation plan submitted pursuant to sections WCI.8(e)(4), and may request additional information from the applicant to complete the determination. In determining whether verification services may proceed, *[TBD]* may consider factors including, but not limited to, the nature of previous work performed, the current and past relationships between the verification body and its subcontractors with the owner or operator, and the cost of the verification services to be performed. If *[TBD]* determines that these factors when considered in combination demonstrate an acceptable level of potential conflict of interest, then *[TBD]* will authorize the verification body to provide verification services.

(f) Monitoring Conflict of Interest Situations.

(1) After commencement of verification services, the verification body shall monitor and immediately make full disclosure in writing to *[TBD]* regarding any potential for a conflict of interest situation that arises. This disclosure shall include a description of actions that the verification body has taken or proposes to take to avoid, neutralize, or mitigate the potential for a conflict of interest.
(2) The verification body shall monitor arrangements or relationships that may be present for a period of one year after the completion of verification services. During that period, within 30 calendar days of any change in arrangements or relationships with the owner or operator for which the body has provided verification services, the verification body shall notify *[TBD]* of the change and provide a description of the nature of the change.
(3) The verification body shall report to *[TBD]* any changes in its organizational structure, including mergers, acquisitions, or divestitures, for one year after completion of verification services.
(4) *[TBD]* may invalidate a verification finding if a potential conflict of interest has arisen for any member of the verification team. In such a case, the owner or operator shall be provided 180 calendar days to complete re-verification.
(5) If the verification body or its subcontractor(s) are found to have violated the conflict of interest requirements of this section, *[TBD]* may rescind accreditation of the body, its verifier staff, or its subcontractor(s) for any appropriate period of time as provided in section WCI.8(d) *[TBD – accreditation requirements]*.

§ WCI.9 DEFINITIONS

[This is a partial list of definitions. Additional definitions are under development based on the Canadian regulations come from "Section 71 of the Canadian Environmental Protection Act (CEPA) 1999"and the CARB definitions come from "Title 17, Subchapter 10, Article 2, Section 95102 of the California Code of Regulations.]

"Adverse verification statement" means a verification statement rendered by a verification body stating that the verification body cannot say with reasonable assurance that the submitted emissions data report is free of material misstatement, or that it cannot provide a qualifying statement that the emissions data report conforms to the requirements of this article.

"Biomass fuels" or "biomass-derived fuels" means fuels derived entirely from biomass.

"Carbon dioxide equivalent" or "CO_2 equivalent" or "CO_2e" means a measure for comparing carbon dioxide with other GHGs, based on the quantity of those gases multiplied by the appropriate global warming potential (GWP) factor and commonly expressed as metric tons of carbon dioxide equivalent.

"Conflict of interest" means a situation in which, because of financial or other activities or relationships with other persons or organizations, a person or body is unable or potentially unable to render an impartial verification opinion of a potential client's greenhouse gas emissions, or the person or body's objectivity in performing verification services is or might be otherwise compromised.

“Continuous emissions monitoring system” or “CEMS” means the total equipment required to obtain a continuous measurement of a gas concentration or emission rate from combustion or industrial processes.

“Electricity generating unit” or “EGU” means any combination of physically connected generator(s), reactor(s), boiler(s), combustion turbine(s), or other prime mover(s) operated together to produce electric power.

“Exporter” means…*[To be defined later for transportation and RCI fuels accounting]*

“Facility” means any property, plant, building, structure, stationary source, stationary equipment or grouping of stationary equipment or stationary sources located on one or more contiguous or adjacent properties, in actual physical contact or separated solely by a public roadway or other public right-of-way, under common operational control, and having the same first two digits of the Standard Industrial Classification (SIC) or same first three digits of the North American Industry Classification System (NAICS) code. *[Some special facilities, such as oil and gas production fields will have separate definitions.]*

“Full verification” means all verification services as provided in section WCI.8(c).

“Global warming potential” or “GWP factor” means the radiative forcing impact of one mass-based unit of a given greenhouse gas relative to an equivalent unit of carbon dioxide over a given period of time.

“Greenhouse gas”, “greenhouse gases” or “GHG” means carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), and perfluorocarbons (PFCs).

“Hydrofluorocarbons” or “HFCs” means a class of GHGs primarily used as refrigerants, consisting of hydrogen, fluorine, and carbon.

“Importer” means…*[To be defined later with input from the Electricity Subcommittee.]*

“Lead verifier” means a person that has met all of the requirements in section WCI.8 *[TBD]*, and who may act as the lead verifier of a verification team providing verification services or as a lead verifier providing an independent review of verification services rendered.

“Material misstatement” means one or more inaccuracies identified in the course of verification that result in the total reported emissions being outside the 95 percent accuracy required to receive a positive verification statement.

“Owner or operator” means any person who owns, leases, operates, controls, or supervises a facility or fuel supply operation; or who imports electricity into the WCI region.

“Perfluorocarbons” or “PFCs” means a class of greenhouse gases consisting on the molecular level of carbon and fluorine.

"Positive verification statement" means a verification statement rendered by a verification body stating that the verification body can say with reasonable assurance that the submitted emissions data report is free of material misstatement and includes a qualifying statement that the emissions data report conforms to the requirements of this article.

"Pure" means consisting of at least 97 percent by mass of a specified substance. For facilities burning biomass fuels, this means the fraction of biomass carbon accounts for at least 97 percent of the total amount of carbon in the fuel burned at the facility.

"Reasonable assurance" means a high degree of confidence that submitted data and statements are valid.

"Stationary combustion unit" means any boiler, heater, furnace, kiln, turbine, internal combustion engine, incinerator or other non-mobile source device that combusts any solid, liquid, or gaseous fuel for purposes of producing useful heat or energy for industrial, commercial, or institutional use; or for purposes of reducing the volume of waste by removing combustible material.

"Supplier" means . . . *[To be defined later for transportation and RCI fuels accounting.]*.

"Verification" means the process used to ensure that an operator's emissions data report is free of material misstatement and complies with WCI's reporting procedures and methods for calculating and reporting GHG emissions.

"Verification body" means a firm accredited by the jurisdiction or its designee, that is able to render a verification statement and provide verification services for operators subject to reporting under this article.

"Verification cycle" means one year of full verification and the next consecutive two years of less intensive verification for operators subject to annual verification. For operators subject to triennial verification, a verification cycle means one year of full verification, and if elected, the next consecutive two years of less intensive verification. A verification cycle cannot exceed three calendar years.

"Verification statement" means the final opinion rendered by a verification body attesting whether an operator's emissions data report is free of material misstatement and a qualifying statement whether the emissions data report conforms to the requirements of this article.

"Verification services" means services provided during verification as specified in section WCI.8, including but not limited to reviewing an owner's or operator's emissions data report, verifying its accuracy according to the standards specified in this section, assessing the owner's or operator's compliance with this section, and submitting a verification statement to the *[jurisdiction or its agent]*.

"Verification team" means all of those working for a verification body, including all subcontractors, to provide verification services for an operator. The lead verifier for the verification team shall be a lead verifier in the verification body.

"Verifier" means an individual accredited by the jurisdiction or its designee to carry out verification services as specified in section WCI.8.

"Waste-derived fuel" means a fuel typically derived from waste and generally used as a substitute for conventional fossil fuels. Waste-derived fuels can include fossil fuels such as waste oil, plastics, or solvents; biomass such as dried sewage or impregnated saw dust; or fractions of both fossil fuels and biomass such as municipal solid waste or tires.

§ WCI.10 Global Warming Potentials

Owners and operators must use the global warming potential (GWP) values given in Table WCI.10-1 when converting emissions of greenhouse gases to metric tons of carbon dioxide equivalent (CO_2e), using Equation 1-1.

Table WCI.10-1. Global Warming Potential Factors for Greenhouse Gases			
Common Name	**Formula**	**Chemical Name**	**GWP**
Carbon dioxide	CO_2		1
Methane	CH_4		21
Nitrous oxide	N_2O		310
Sulfur hexafluoride	SF_6		23,900
Hydrofluorocarbons (HFCs)			
HFC-23	CHF_3	trifluoromethane	11,700
HFC-32	CH_2F_2	difluoromethane	650
HFC-41	CH_3F	fluoromethane	150
HFC-43-10mee	$C_5H_2F_{10}$	1,1,1,2,3,4,4,5,5,5- decafluoropentane	1,300
HFC-125	C_2HF_5	pentafluoroethane	2,800
HFC-134	$C_2H_2F_4$	1,1,2,2-tetrafluoroethane	1,000
HFC-134a	$C_2H_2F_4$	1,1,1,2-tetrafluoroethane	1,300
HFC-143	$C_2H_3F_3$	1,1,2-trifluoroethane	300
HFC-143a	$C_2H_3F_3$	1,1,1-trifluoroethane	3,800
HFC-152	$C_2H_4F_2$	1,2-difluoroethane	43
HFC-152a	$C_2H_4F_2$	1,1-difluoroethane	140
HFC-161	C_2H_5F	fluoroethane	12
HFC-227ea	C_3HF_7	1,1,1,2,3,3,3- heptafluoropropane	2,900
HFC-236cb	$C_3H_2F_6$	1,1,1,2,2,3-hexafluoropropane	1,300
HFC-236ea	$C_3H_2F_6$	1,1,1,2,3,3-hexafluoropropane	1,200
HFC-236fa	$C_3H_2F_6$	1,1,1,3,3,3-hexafluoropropane	6,300
HFC-245ca	$C_3H_3F_5$	1,1,2,2,3-pentafluoropropane	560
HFC-245fa	$C_3H_3F_5$	1,1,1,3,3-pentafluoropropane	950
HFC-365mfc	$C_4H_5F_5$	1,1,1,3,3-pentafluorobutane	890
Perfluorocarbons (PFCs)			
Perfluoromethane	CF_4	tetrafluoromethane	6,500
Perfluoroethane	C_2F_6	hexafluoroethane	9,200
Perfluoropropane	C_3F_8	octafluoropropane	7,000
Perfluorobutane	C_4F_{10}	decafluorobutane	7,000
Perfluorocyclobutane	$c\text{-}C_4F_8$	octafluorocyclobutane	8,700
Perfluoropentane	C_5F_{12}	dodecafluoropentane	7,500
Perfluorohexane	C_6F_{14}	tetradecafluorohexane	7,400

ATTACHMENT 8: IRON AND STEEL MANUFACTURING

§ WCI.150 IRON AND STEEL MANUFACTURING

§ WCI.151 Source Category Definition

Iron and steel manufacturing comprises four categories: primary facilities that produce both iron and steel, secondary steelmaking facilities, iron production facilities, and offsite production of metallurgical coke. These processes may occur together in an "integrated" facility or they may occur in separate offsite facilities.

§ WCI.152 Greenhouse Gas Reporting Requirements

In addition to the information required by WCI.3, the annual emissions data report shall contain the following information:

(a) Total emissions of CO_2 and CH_4 in metric tons at the facility level.

(b) CO_2 and CH_4 emissions from coke production (metric tons) and the following information:

(1) Quantity of coking coal consumed in coke production (metric tons)
(2) Quantity of other process materials (e.g., natural gas, fuel oil, etc.) consumed in coke production (metric tons)
(3) Quantity of blast furnace gas consumed in coke production (metric tons)
(4) Quantity of coke produced (metric tons)
(5) Quantity of coke oven gas transferred offsite (metric tons)
(6) Quantity of other coke oven by-products (e.g., coal tar, light oil, coke breeze, etc.) transferred offsite (metric tons)
(7) Carbon content of material inputs and outputs listed in (b)(1) through (b)(6) (metric tons of C per unit of material)

(c) CO_2 and CH_4 emissions from iron and steel production (metric tons) and the following information:

(1) Quantity of coke consumed in iron and steel production (excluding sinter production) (metric tons)
(2) Quantity of on-site coke oven by-products (e.g., coal tar, light oil, coke breeze, etc.) consumed in blast furnace (metric tons)
(3) Quantity of coal directly injected into blast furnace (metric tons)
(4) Quantity of limestone directly injected into blast furnace (metric tons)
(5) Quantity of dolomite directly injected into blast furnace (metric tons)
(6) Quantity of carbon electrodes consumed in EAFs (metric tons)
(7) Quantity of other carbonaceous or process material (e.g., sinter, waste plastic, etc.) consumed in iron and steel production (metric tons)
(8) Quantity of coke oven gas consume in blast furnace (metric tons)
(9) Quantity of steel produced (metric tons)
(10) Quantity of iron production not converted to steel (metric tons)
(11) Quantity of blast furnace gas transferred offsite (metric tons)
(12) Carbon content of material inputs and outputs listed in (c)(1) through (c)(11) (metric tons of C per unit of material)

(d) Process CO_2 and CH_4 emissions from sinter production (metric tons) and the following information:

(1) Quantity of coke breeze (purchased and produced on-site) used for sinter production (metric tons)
(2) Quantity of coke oven gas consumed in blast furnace in sinter production (metric tons)
(3) Quantity of blast furnace gas consumed in sinter production (metric tons)
(4) Quantity of other process materials (e.g., natural gas, fuel oil, etc.) consumed in sinter production (metric tons)
(5) Quantity of sinter off gas transferred offsite (metric tons)
(6) Carbon content of material inputs and outputs listed in (d)(1) through (d)(5) (metric tons of C per unit of material)

(e) Process CO_2 and CH_4 emissions from direct reduced iron production (metric tons) and the following information:

(1) Energy from natural gas used in direct reduced iron production (gigajoules [GJ])
(2) Energy from coke breeze used in direct reduced iron production (GJ)
(3) Energy from metallurgical coke used in direct reduced iron production (GJ)
(4) Carbon of material inputs listed in (e)(1) through (e)(3) (metric tons of C per GJ)

§ WCI.153 Calculation of CO_2 Emissions

(a) Process CO_2 emissions. Determine process CO_2 emissions as specified under either paragraph (1) or (2) of this section.

(1) Continuous emissions monitoring systems (CEMS) as specified in WCI.23(d).
(2) Calculation methodologies specified in paragraph (b) of this section.

(b) Process CO_2 Emissions Calculation Methodology. Calculate total CO_2 process emissions using the following mass balance approach:

(1) Calculate the coke production CO_2 (either within integrated facilities or at offsite facilities) emissions using Equation 150-1 (if applicable):

$$E_{coke} = \left[(CC \times C_{CC}) + \sum_a (PM_a \times C_a) + (BG \times C_{BG}) - (CO \times C_{CO}) - (COG \times C_{COG}) - \sum_b (COB_b \times C_b) \right] \times 3.664$$

Equation 150-1

Where:

E_{coke}	=	Emissions of CO_2 from coke production (metric tons);
CC	=	Quantity of coking coal (metric tons);
PM_a	=	Quantity of other process material *a* (not included as separate terms), such as natural gas or fuel oil (metric tons);
BG	=	Quantity of blast furnace gas consumed in coke ovens (metric tons);
CO	=	Quantity of coke produced (metric tons)
COG	=	Quantity of coke oven gas transferred offsite (metric tons);
COB_b	=	Quantity of coke oven by-product *b* transferred offsite (metric tons);

C_x = Carbon content of material input or output *x* (metric tons C/metric tons of *x*);
3.664 = Conversion factor from metric tons of C to metric tons of CO_2.

(2) Calculate the iron and steel production CO_2 emissions using Equation 150-2:

$$E_{iron,steel} = \Big[(CO \times C_{CO}) + \sum_a (COB_a \times C_a) + (CI \times C_{CI}) + (L \times C_L) + (D \times C_D) + (CE \times C_{CE}) + \sum_b (O_b \times C_b) + (COG \times C_{COG}) - (S \times C_S) - (IP \times C_{IP}) - (BG \times C_{BG}) \Big] \times 3.664$$

Equation 150-2

Where:

$E_{iron,steel}$ = Emissions of CO_2 from iron and steel production (metric tons);
CO = Quantity of coke consumed (excluding sinter production) (metric tons);
COB_a = Quantity of coke oven by-product *a* consumed in blast furnace (metric tons);
CI = Quantity of coal directly injected into blast furnace (metric tons);
L = Quantity of limestone consumed (metric tons);
D = Quantity of dolomite consumed (metric tons);
CE = Quantity of carbon electrodes consumed in EAFs (metric tons);
O_b = Quantity of other carbonaceous and process material *b*, such as sinter or waste plastic (metric tons);
COG = Quantity of coke oven gas consumed in blast furnace (metric tons);
S = Quantity of steel produced (metric tons);
IP = Quantity of iron production not converted to steel (metric tons);
BG = Quantity of blast furnace gas transferred offsite (metric tons);
C_x = Carbon content of material input or output *x* (metric tons C/metric tons of *x*);
3.664 = Conversion factor from metric tons of C to metric tons of CO_2.

(3) Calculate the sinter production CO_2 emissions using Equation 150-3 (if applicable):

$$E_{sinter} = \Big[(CBR \times C_{CBR}) + (COG \times C_{COG}) + (BG \times C_{BG}) + \sum_a (PM_a \times C_a) - (SOG \times C_{SOG}) \Big] \times 3.664$$

Equation 150-3

Where:

E_{sinter} = Emissions of CO_2 from sinter production (metric tons);
CBR = Quantity of purchased and onsite produced coke breeze used for sinter production (metric tons);
COG = Quantity of coke oven gas consumed in blast furnace for sinter production (metric tons);
BG = Quantity of blast furnace gas consumed for sinter production (metric tons);
PM_a = Quantity of other process material *a* consumed for sinter production (not included as separate terms), such as natural gas or fuel oil (metric tons);
SOG = Quantity of sinter off gas transferred offsite (metric tons);
C_x = Carbon content of material input or output *x* (metric tons C/metric tons of *x*);
3.664 = Conversion factor from metric tons of C to metric tons of CO_2.

(4) Calculate the direct reduced iron production CO_2 emissions using Equation 150-4 (if applicable):

$$E_{DRI} = [(DRI_{NG} \times C_{NG}) + (DRI_{BZ} \times C_{BZ}) + (DRI_{CK} \times C_{CK})] \times 3.664$$

Equation 150-4

Where:

E_{DRI} = Emissions of CO_2 from direct reduced iron production (metric tons);
DRI_{NG} = Energy from natural gas used in direct reduced iron production (GJ);
DRI_{BZ} = Energy from coke breeze used in direct reduced iron production (GJ);
DRI_{CK} = Energy from metallurgical coke used in direct reduced iron production (GJ);
C_{NG} = Carbon content of natural gas (metric ton C/GJ);
C_{BZ} = Carbon content of coke breeze (metric ton C/GJ);
C_{CK} = Carbon content of metallurgical coke (metric ton C/GJ);
3.664 = Conversion factor from metric tons of C to metric tons of CO_2.

(5) Calculate the total CO_2 emissions using Equation 150-5:

$$E_{CO2} = E_{coke} + E_{iron,steel} + E_{sinter} + E_{DRI}$$

Equation 150-5

Where:

E_{CO2} = Total CO_2 emissions (metric tons);
E_{coke} = Emissions from coke production (metric tons);
$E_{iron,steel}$ = Emissions from iron and steel production (metric tons);
E_{sinter} = Emissions from sinter production (metric tons);
E_{DRI} = Emissions from direct reduced iron production (metric tons).

§ WCI.154 Calculation of CH_4 Emissions

(a) Process CH_4 emissions. Determine process CH_4 emissions as specified under paragraph (1) of this section.

(1) Continuous emissions monitoring systems (CEMS) as specified in WCI.23(d).

§ WCI.155 Sampling, Analysis, and Measurement Requirements

Measurements of carbon contents of the material balance input, output, and by-product materials shall be conducted as described below.

Note: The sampling, analysis, and measurement procedures will be standardized for each calculation input to reduce variation between facilities within the iron and steel industry. Material sampling frequency and technique is distinct from material analysis conducted in a laboratory. The WCI is seeking stakeholder feedback on this topic and is specifically interested in proposals from stakeholders with expertise in this industry related to sampling, analysis and measurement procedures already in use at these facilities for the material quantities and/or concentrations listed below. Those proposing procedures should include sampling frequency and technique, indicate the uncertainty associated with the procedures, and describe the application of the procedure at a facility.

(b) Fuel Carbon Content Requirements. Fuel carbon contents should be monitored in the following manner (from § WCI.25):

(1) For coal and coke, solid biomass-derived fuels, and waste-derived fuels; use ASTM 5373-02 (Reapproved 2007).
(2) For liquid fuels, use the following ASTM methods: For petroleum-based liquid fuels and liquid waste-derived fuels, use ASTM D5291-02 (Reapproved 2007) "Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants", ultimate analysis of oil or computations based on ASTM D3238-95 (Reapproved 2005) and either ASTM D2502-04 or ASTM D2503-92 (Reapproved 2002).
(3) For gaseous fuels, use ASTM D1945-03 or ASTM D1946-90 (Reapproved 2006).

(c) By-Product Carbon Content Requirements. Carbon contents of by-products (e.g., blast furnace gas, coke oven gas, coal tar, light oil, coke breeze, sinter off gas, etc.) from all iron and steel production processes should be monitored in the following manner:

(1) [Methodology to be determined.]

(d) Flux Carbon Content Requirements. Carbon contents of fluxes (i.e., limestone and dolomite) from all iron and steel production processes should be monitored in the following manner:

(1) For limestone and dolomite, use ASTM C25-06.

(e) Electrode Carbon Content Requirements. Carbon contents of carbon electrodes used in electric arc furnaces (EAFs) should be monitored in the following manner:

(1) [Methodology to be determined.]

(f) Finished Product Carbon Content Requirements. Carbon contents of finished products (i.e., steel, iron not converted to steel, and direct reduced iron) from all iron and steel production processes should be monitored in the following manner:

(1) For iron and steel, use ASTM E1019-08 or ASTM E351-93.

(g) Quantity Measurement Requirements. The quantities of process inputs, outputs, and by-products must be determined using the following methods:

(1) For solid process inputs, outputs, and by-products, quantities must be determined by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.
(2) For liquid process inputs, outputs, and by-products, quantities must be determined by direct volume measurement using the same plant instruments used for accounting purposes.
(3) For gaseous process inputs, outputs, and by-products, quantities must be determined by direct volume measurement using the same plant instruments used for accounting purposes.

ATTACHMENT 12: LEAD PRODUCTION

Applicability

There are two primary production processes used to produce lead from lead concentrates: the sintering/smelting process and the direct smelting process. In the sintering/smelting process, the lead concentrates are initially combined with recycled sinter, lime rock and silica, oxygen, and high lead content sludge to produce a sinter roast. The sinter roast is then put into a blast furnace (i.e., traditional blast or Imperial Smelting) with other metal-containing ores, air, smelter by-products, and metallurgical coke. This reduction of lead oxide in the furnace results in the production of CO_2 emissions. In the direct smelting process, the sintering step is skipped and the lead concentrates are entered directly into the furnace (i.e., Isasmelt-Ausmelt, Queneau-Schumann-Lurgi, and Kaldo for bath smelting and Kivcet for flash smelting) with reducing agents.

In addition to the sintering/smelting and direct smelting primary production processes, secondary production or recycling of lead is also conducted. Most of the recycled lead comes from scrapped lead acid batteries. The lead acid batteries are either crushed with a hammer mill or smelted whole. All of the furnaces used for primary production, as well as electric arc and electric resistance furnaces, can be used to smelt recycled scrap lead.

Emission Calculations

The following emission calculation methods are from the 2006 IPCC Guidelines, Volume 3, Section 4.6.

The Tier 3 methodology recommends using actual directly measured CO_2 emissions data, if available. Alternatively, facility-specific data regarding reducing agents and carbon contents can be used to calculate emissions for the Tier 3 methodology. The Tier 2 methodology is similar to the Tier 3 method, except that default carbon contents for the reducing agents are used instead of facility-specific carbon contents. Default carbon contents are available for the following reducing agents: blast furnace gas, charcoal, coal, coal tar, coke, coke oven gas, coking coal, electric arc furnace (EAF) carbon electrodes, EAF charge carbon, fuel oil, gas coke, natural gas, and petroleum coke.

The emission calculation equation is:

$$E_{Pb} = \sum_x (RA_x \times C_x) \times 3.664$$

Where:

E_{Pb}	=	CO_2 emissions from lead production (metric tons);
RA_x	=	Quantity of reducing agent *x* used (metric tons);
C_x	=	Carbon content of reducing agent *x* (metric tons C/metric tons of *x*);
3.664	=	Conversion factor from metric tons of C to metric tons of CO_2.

The Tier 3 method (using either actual directly measured CO_2 emissions data or facility-specific reducing agent quantities and carbon contents) is recommended to estimate emissions from lead production facilities.

The uncertainty for Tier 3 facility-specific measured CO_2 data has been estimated to be ±5 percent. The uncertainty associated with the Tier 3 facility-specific reducing agent quantities and carbon contents is also estimated to be ±5 percent. The uncertainty of the Tier 2 reducing agent carbon contents is estimated to be ±15 percent.

Reporting Requirements

Annual CO_2 emissions (measured or calculated) based on the IPCC Tier 3 method will be reported for each facility. Facility-specific quantities and carbon contents of each reducing agent used will also be reported.

Sampling, Analysis, and Measurement Methods

The Tier 3 method from the 2006 IPCC Guidelines specifies facility-specific emission measurements or facility-specific data regarding reducing agents and carbon contents. The following measurement methods should be used.

Note: The sampling, analysis, and measurement procedures will be standardized for each calculation input to reduce variation between facilities within the lead industry. Material sampling frequency and technique is distinct from material analysis conducted in a laboratory. The WCI is seeking stakeholder feedback on this topic and is specifically interested in proposals from stakeholders with expertise in this industry related to sampling, analysis and measurement procedures already in use at these facilities for the material quantities and/or concentrations listed below. Those proposing procedures should include sampling frequency and technique, indicate the uncertainty associated with the procedures, and describe the application of the procedure at a facility.

(a) Facility CO_2 emissions. Determine facility CO_2 emissions using continuous emissions monitoring systems (CEMS) as specified in WCI.23(d).

Wherever possible, measurements of carbon contents of the material balance input materials should be conducted as described below.

(b) Fuel Carbon Content Requirements. Fuel carbon contents should be measured in the following manner (from WCI.25):

(1) For coal and coke, solid biomass-derived fuels, and waste-derived fuels; use ASTM 5373-02 (Reapproved 2007).
(2) For liquid fuels, use the following ASTM methods: For petroleum-based liquid fuels and liquid waste-derived fuels, use ASTM D5291-02 (Reapproved 2007) “Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants”, ultimate analysis of oil or computations based on ASTM D3238-95 (Reapproved 2005) and either ASTM D2502-04 or ASTM D2503-92 (Reapproved 2002).
(3) For gaseous fuels, use ASTM D1945-03 or ASTM D1946-90 (Reapproved 2006).

(c) By-Product Carbon Content Monitoring Requirements. Carbon contents of by-products (e.g., blast furnace gas, coke oven gas, coal tar, light oil, coke breeze, sinter off gas, etc.) used in lead production processes should be monitored in the following manner:
[Method to be determined.]

(d) Electrode Carbon Content Requirements. Carbon contents of carbon electrodes used in lead production processes should be monitored in the following manner:
[Method to be determined.]

(e) Quantity Measurement Requirements. The quantities of process inputs, outputs, and by-products must be determined using the following methods:

- For solid process inputs, outputs, and by-products, quantities must be determined by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.
- For liquid process inputs, outputs, and by-products, quantities must be determined by direct volume measurement using the same plant instruments used for accounting purposes, such as *[Method to be determined]*.
- For gaseous process inputs, outputs, and by-products, quantities must be determined by direct volume measurement using the same plant instruments used for accounting purposes, such as *[Method to be determined]*.

ATTACHMENT 9: LIME MANUFACTURING

§ WCI.170 LIME MANUFACTURING

§ WCI.171 Source Category Definition

Lime manufacturing is comprised of all processes that are used to manufacture quick lime (i.e. calcium oxide or calcium-magnesium oxide). Lime is produced via the calcination of limestone or other highly calcareous materials such as dolomite, aragonite, chalk, coral, marble, and shell.

§ WCI.172 Greenhouse Gas Reporting Requirements

In addition to the information required by WCI.3, the annual emissions data report shall contain the following information:

(a) Total emissions of CO_2, CH_4, and N_2O in metric tons.

(b) CO_2 process emissions from quick lime production (metric tons) and the following information:

(1) Quick lime emission factor (kg CO_2/metric ton quick lime).
(A) Quantity of quick lime produced (metric tons).
(B) Total Calcium Oxide (CaO) content of quick lime (weight fraction).
(C) Total Magnesium Oxide (MgO) content of quick lime (weight fraction).
(D) Uncalcined CaO (weight fraction).
(E) Uncalcined MgO (weight fraction).

(2) Lime kiln dust (LKD) emission factor (kg CO_2/metric ton LKD).
(A) Quantity of LKD discarded (metric tons).
(B) Total Calcium Oxide (CaO) content of LKD (weight fraction).
(C) Total Magnesium Oxide (MgO) content of LKD (weight fraction).
(D) Uncalcined CaO content of LKD (weight fraction).
(E) Uncalcined MgO content of LKD (weight fraction).

(c) CO_2, CH_4, and N_2O emissions from fuel combustion in all kilns combined, following the calculation methods and reporting requirements specified in WCI.173(c) (metric tons).

(d) CO_2, CH_4, and N_2O emissions from all other fuel combustion units combined (kilns excluded), following the calculation methods and reporting requirements specified in WCI.20 (metric tons).

(e) If a continuous emissions monitor is used to measure CO_2 emissions from kilns, then the requirements of paragraphs (b) and (c) of this section do not apply for CO_2. Lime plants that measure CO_2 emissions using CEMS shall report fuel usage by fuel type for kilns.

(f) Operators of lime plants shall also comply with the reporting requirements for any other applicable source category listed at WCI.1(a), including but not limited to the following:

(1) Coal fuel storage as specified in WCI.100.

(2) Electricity generating as specified in WCI.40.

(3) Cogeneration systems as specified in WCI.XX.

§ WCI.173 Calculation of greenhouse Gas Emissions from Kilns

(a) Determine process CO_2 emissions as specified under either paragraph (a)(1) or (a)(2) of this section.

(1) Continuous emissions monitoring systems (CEMS) as specified in WCI.23(d).

(2) Calculate the sum of CO_2 process emissions from kilns and CO_2 fuel combustion emissions from kilns using the calculation methodologies specified in paragraph (b) and (c) of this section**.**

(b) Process CO_2 Emissions Calculation Methodology. Calculate total CO_2 process emissions as the sum of emissions from quick lime production, using the method specified in paragraph (b)(1) of this section.

(1) CO_2 Process Emissions. Calculate CO_2 emissions from quick lime production from each kiln using Equation 170-1 and a plant-specific quick lime emission factor and a plant-specific lime kiln dust (LKD) emission factor as specified in this section.

$$CO_2 = \sum_{I=1}^{12} [(QL) \times (EF_{QL})] + [(LKD) \times (EF_{LKD})]$$

Equation 170-1

Where:

CO_2	=	CO_2 emissions in metric tones/yr.
QL	=	Monthly Quantity of quick lime produced, metric tons.
EF_{QL}	=	Monthly Quick lime emission factor, metric tons CO_2/metric ton quick lime computed as specified in paragraph (b)(1)(A) of this section.
LKD	=	Monthly Quantity LKD discarded (i.e., not recycled to the kiln), metric tons.
EF_{LKD}	=	Monthly LKD emission factor, computed as specified in paragraph (b)(1)(B) of this section.

(A) Monthly Quick Lime Emission Factor. Calculate a plant-specific quick lime emission factor _(EF_{QL}) for each kiln and month based on the percent of measured CaO and MgO content in quick lime and using Equation 170-2.

$$EF_{QL} = [(CaO\ content - uncalcined\ CaO) \times Molecular\ ratio\ of\ CO_2 / CaO] + [(MgO\ Content - uncalcined\ MgO) \times Molecular\ ratio\ of\ CO_2 / MgO]$$

Equation 170-2

Where:

CaO Content (by weight)	=	Total CaO content of Quick Lime, including calcined and uncalcined (weight fraction).
Uncalcined CaO (by weight)	=	Uncalcined CaO content of Quick Lime (weight fraction).
Molecular ratio of CO_2/CaO	=	0.785.
MgO Content (by weight)	=	Total MgO content of Quick Lime, including calcined and uncalcined (weight fraction).
Uncalcined MgO	=	Uncalcined MgO content of Quick Lime (weight fraction).
Molecular ratio of CO_2/MgO	=	1.092.

(B) Monthly LKD Emission Factor. If LKD is generated and not recycled back to the kiln, then calculate a plant-specific LKD emission factor for each kiln and month. The LKD emission factor shall be calculated using Equation 170-3.

$$EF_{LKD} = [(CaO\ \ content - uncalcined\ \ CaO) \times Molecular\ \ ratio\ \ of\ \ CO_2 / CaO] + [(MgO\ \ Content - uncalcined\ \ MgO) \times Molecular\ \ ratio\ \ of\ \ CO_2 / MgO]$$

Equation 170-3

Where:

EF_{LKD}	=	LKD emission factor.
CaO Content (by weight)	=	Total CaO content of LKD, including calcined and uncalcined (weight fraction).
Uncalcined CaO (by weight)	=	Uncalcined CaO content of LKD (weight fraction).
Molecular ratio of CO_2/CaO	=	0.785.
MgO Content (by weight)	=	Total MgO content of LKD, including calcined and uncalcined (weight fraction).
Uncalcined MgO	=	Uncalcined MgO content of LKD (weight fraction).
Molecular ratio of CO_2/MgO	=	1.092.

(c) Fuel Combustion Emissions in Kilns. Calculate CO_2, CH_4, and N_2O emissions from stationary fuel combustion emissions following the calculation methods specified in WCI.20. Operators of lime manufacturing plants that primarily combust biomass-derived fuels and combust fossil fuels only during periods of start-up, shut-down, or malfunction may report CO_2 emissions from fossil fuels using the emission factor methodology in WCI.23(a). "Pure" means that the biomass-derived fuels account for 97 percent of the total amount of carbon in the fuels burned.

§ WCI.174 Sampling, Analysis, and Measurement Requirements

Note: The sampling, analysis, and measurement procedures will be standardized for each calculation input to reduce variation between facilities within the lime industry. Material sampling frequency and technique is distinct from material analysis conducted in a laboratory. The WCI is seeking stakeholder feedback on this topic and is specifically interested in proposals from stakeholders with expertise in this industry related to sampling, analysis and measurement *procedures already in use at these facilities for the material quantities and/or concentrations listed below. Those proposing procedures should include sampling frequency and technique, indicate the uncertainty associated with the procedures, and describe the application of the procedure at a facility.*

(a) Determine the plant-specific weight fractions of CaO, MgO, uncalcined CaO, and uncalcined MgO in quick lime from each kiln using (method to be determined). Determine the plant-specific fraction of CaO, MgO, uncalcined CaO, and uncalcined MgO in LKD not recycled to the kiln using (method to be determined). The monitoring must be conducted monthly for each kiln from samples drawn from bulk storage.

(b) The quantity of quick lime produced must be determined by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.

(c) The quantity of LKD discarded must be determined by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.

(d) The quantity of raw materials consumed (i.e. limestone, dolomite, aragonite, chalk, coral, marble, and shell.) must be determined by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.

ATTACHMENT 10: PETROLEUM REFINERIES

§ WCI.200 PETROLEUM REFINERIES

§ WCI.201 Source Category Definition

A petroleum refinery consists of all processes used to produce gasoline, aromatics, kerosene, distillate fuel oils, residual fuel oils, lubricants, asphalt, or other products through distillation of petroleum or through redistillation, cracking, rearrangement or reforming of unfinished petroleum derivatives.

WCI.202 Greenhouse Gas Reporting Requirements

The annual emissions report must contain the following information reported at the facility level:

(a) Catalyst Regeneration. Report CO_2 emissions.

(b) Process Vents. Report CO_2, N_2O, and CH_4 emissions.

(c) Asphalt Production. Report CO_2 and CH_4 emissions.

(d) Sulfur Recovery. Report CO_2 emissions.

(e) Stationary Combustion Units Other than Flares and Control Devices. Report CO_2, N_2O, and CH_4 emissions as specified in WCI.23.

(f) Flares and Other Control Devices. Report CO_2, N_2O, and CH_4 emissions.

(g) Above-Ground Storage Tanks. Report CH_4 emissions.

(h) Wastewater Treatment. Report CH_4 and N_2O emissions.

(i) Oil-Water Separators. Report CH_4 emissions.

(j) Equipment Leaks. Report CH_4 emissions.

(k) Feedstock Consumption: Report feedstock consumption by type for all feedstocks which result in GHG emissions in the reporting year (including petroleum coke) in units of million standard cubic feet for gases, gallons for liquids, short tons for non-biomass solids, and bone dry short tons for biomass-derived solid fuels.

(l) Fuel Consumption: Report fuel consumption by fuel type consumed in the reporting year in units of million standard cubic feet for gases, gallons for liquids, short tons for non-biomass solids, and bone dry short tons for biomass-derived solid fuels.

WCI.203 Calculation of Greenhouse Gas Emissions

The operator shall calculate GHG emissions using the methods in paragraphs (a) through (i) of this section.

(a) Catalyst Regeneration. For units equipped with CEMS, operators shall calculate CO_2 process emissions resulting from catalyst regeneration using CEMS in accordance with WCI.20. In the absence of CEMS data, the operator shall use the methods in paragraphs (a)(1) through (a)(3).

(1) The operator shall calculate process CO_2 emissions from the continuous regeneration of catalyst material in fluid catalytic cracking units (FCCU) and fluid cokers using Equations 200-1, 200-2, and 200-3.

$$CO_2 = \sum_{d=1}^{n} CR_d \times CF \times 3.664 \times 0.001 \qquad \textbf{Equation 200-1}$$

Where:

CO_2	=	CO_2 emissions (metric tons/yr)
n	=	number of days of operation in the report year
CR_d	=	daily average coke burn rate (kg/day)
CF	=	carbon fraction in coke burned
3.664	=	ratio of molecular weights, CO_2 to carbon
0.001	=	conversion factor – kg to metric tons

$$CR_d = \left[\sum_{i=1}^{n} [K_1 Q_r \times (\%CO_2 + \%CO) + K_2 Q_a - K_3 Q_r \times [\%CO/2 + \%CO_2 + \%O_2] + K_3 Q_{oxy} \times (\%O_{oxy})]_i \right] / n$$

Equation 200-2

Where:

CR_d	=	daily average coke burn rate (kg/day or lb/day)
K_1, K_2, K_3	=	material balance and conversion factors (K_1, K_2, and K_3 from Table 200-1
n	=	number of hours per day
Q_r	=	volumetric flow rate of exhaust gas before entering the emission control system (dscm/min or dscf/min)
Q_a	=	volumetric flow rate of air to regenerator as determined from control room instrumentation (dscm/min or dscf/min)
$\%CO_2$	=	CO_2 concentration in regenerator exhaust, percent by volume – dry basis
%CO	=	CO concentration in regenerator exhaust, percent by volume – dry basis
$\%O_2$	=	O_2 concentration in regenerator exhaust, percent by volume – dry basis
Q_{oxy}	=	volumetric flow rate of O_2 enriched air to regenerator as determined from control room instrumentation (dscm/min or dscf/min)
$\%O_{xy}$	=	O_2 concentration in O_2 enriched air stream inlet to regenerator, percent by volume – dry basis

$$Q_r = (79 \times Q_a + (100 - \%Q_{xy}) \times Q_{oxy}) / (100 - \%CO_2 - \%CO - \%O_2) \qquad \textbf{Equation 200-3}$$

Where:

Q_r = volumetric flow rate of exhaust gas from regenerator before entering the emission control system (dscm/min or dscf/min)
Q_a = volumetric flow rate of air to regenerator, as determined from control room instrumentation (dscm/min or dscf/min)
$\%Q_{xy}$ = oxygen concentration in oxygen enriched air stream, percent by volume – dry basis
Q_{oxy} = volumetric flow rate of O_2 enriched air to regenerator as determined from catalytic cracking unit control room instrumentation (dscm/min or dscf/min)
$\%CO_2$ = carbon dioxide concentration in regenerator exhaust, percent by volume – dry basis
$\%CO$ = CO concentration in regenerator exhaust, percent by volume – dry basis. When no auxiliary fuel is burned and a continuous CO monitor is not required, assume %CO to be zero
$\%O_2$ = O_2 concentration in regenerator exhaust, percent by volume – dry basis

(2) The operator shall calculate process CO_2 emissions resulting from periodic catalyst regeneration using Equation 200-4.

$$CO_2 = \sum_{i=1}^{n} CRR \times \left(CF_{spent} - CF_{regen}\right)_i \times 3.664 \times 0.001 \qquad \textbf{Equation 200-4}$$

Where:

CO_2 = CO_2 emissions (metric tons/yr)
CRR = mass of catalyst regenerated (mass/regeneration cycle)
CF_{spent} = weight fraction carbon on spent catalyst
CF_{regen} = weight fraction carbon on regenerated catalyst (default = 0)
n = number of regeneration cycles
3.664 = ratio of molecular weights, CO_2 to carbon
0.001 = conversion factor – kg to metric tons

(3) The operator shall calculate process CO_2 emissions resulting from continuous catalyst regeneration in operations other than FCCUs and fluid cokers (e.g. catalytic reforming) using Equation 200-5.

$$CO_2 = CC_{irc} \times (CF_{spent} - CF_{regen}) \times H \times 3.664 \qquad \textbf{Equation 200-5}$$

Where:

CO_2 = CO_2 emissions (metric tons/yr)
CC_{irc} = average catalyst regeneration rate (metric tons/hr)
CF_{spent} = weight carbon fraction on spent catalyst
CF_{regen} = weight carbon fraction on regenerated catalyst (default = 0)
H = hours regenerator was operational (hr/yr)
3.664 = ratio of molecular weights, CO_2 to carbon

(b) Process Vents. Except for process emissions reported under other requirements of this regulation, the operator shall calculate process emissions of CO_2, CH_4, and N_2O from process vents using Equation 200-6.

Equation 200-6

$$E_x = \sum_{i=1}^{n} VR_i \times F_{xi} \times (MW_x / MVC) \times VT_i \times 0.001$$

Where:

E_x	=	emissions of x (metric tons/yr), where x = CO_2, N_2O, or CH_4
VR_i	=	vent rate for venting event i (scf/unit time)
F_{xi}	=	molar fraction of x in vent gas stream during event i
MW_x	=	molecular weight of x (kg/kg-mole)
MVC	=	molar volume conversion (849.5 scf/kg-mole for STP of 20°C and 1 atmosphere or 836 scf/kg-mole for STP of 60°F, and 1 atmosphere)
VT_i	=	time duration of venting event i
n	=	number of venting events
0.001	=	conversion factor – kg to metric tons

(c) Asphalt Production. The operator shall calculate CO_2 and CH_4 process emissions from asphalt blowing activities using Equations 200-7 and 200-8.

Equation 200-7

$$CH_4 = (M_A \times EF \times MW_{CH4} / MVC) \times (1 - DE) \times 0.001$$

Where:

CH_4	=	CH_4 emissions (metric tons/yr)
M_A	=	mass of asphalt blown (10^3 bbl/yr)
EF	=	emission factor (EF = 2,555 scf $CH_4/10^3$ bbl)
MW_{CH4}	=	CH_4 molecular weight (16.04 kg/kg-mole)
MVC	=	molar volume conversion factor (849.5 scf/kg- mole, for STP of 20°C and 1 atmosphere)
DE	=	control measure destruction efficiency (DE = 98% expressed as 0.98)
0.001	=	conversion factor – kg to metric tons

Equation 200-8

$$CO_2 = (M_A \times EF \times MW_{CH4} / MVC) \times DE \times 2.743 \times 0.001$$

Where:

CO_2	=	CO_2 emissions (metric tons/yr)
M_A	=	mass of asphalt blown (10^3 bbl/yr)
EF	=	emission factor (EF = 2,555 scf $CH_4/10^3$ bbl)
MW_{CH4}	=	CH_4 molecular weight (16.04 kg/kg-mole)
MVC	=	molar volume conversion factor (849.5 scf/kg mole, for STP of 20°C and 1 atmosphere)
DE	=	control measure destruction efficiency (DE = 98% expressed as 0.98)

2.743	=	CH_4 to CO_2 conversion factor
0.001	=	conversion factor – kg to metric tons

(d) Sulfur Recovery. The operator shall calculate CO_2 process emissions from sulfur recovery units (SRUs) using Equation 200-9. For the molecular fraction (MF) of CO_2 in the sour gas, use either a default factor of 0.20 or a source specific molecular fraction value approved by [*insert jurisdiction*] and derived from source tests conducted at least once per calendar year under the supervision of [*insert jurisdiction*].

$$CO_2 = FR \times MW_{CO2} / MVC \times MF \times 0.001$$ **Equation 200-9**

Where:

CO_2	=	emissions of CO_2 (metric tons/yr)
FR	=	volumetric flow rate of acid gas to SRU (scf/year)
MW_{CO2}	=	molecular weight of CO_2 (44 kg/kg-mole)
MVC	=	molar volume conversion (849.5 scf/ kg-mole, for STP of 20°C and 1 atmosphere or 836 scf/kg-mole, for STP of 60°F, and 1 atmosphere)
MF	=	molecular fraction (%) of CO_2 in sour gas (default MF = 20% expressed as 0.20)
0.001	=	conversion factor – kg to metric tons

(e) Flares and Other Control Devices.

(1) The operator shall calculate and report CO_2, CH_4 and N_2O emissions resulting from the combustion of flare pilot and purge gas using the appropriate method(s) specified in sections WCI.20.

(2) The operator shall calculate and report CO_2 emissions resulting from the combustion of hydrocarbons routed to flares for destruction using Equation 200-10.

$$CO_2 = RFI \times EF_{NMHC} \times CF_{NMHC} \times 3.664 \times 0.001$$ **Equation 200-10**

Where:

CO_2	=	CO_2 emissions (metric tons/year)
RFT	=	refinery feed input (m^3/yr)
EF_{NMHC}	=	non-methane hydrocarbon emission factor (EF_{NMHC} = 0.002 kg/m^3 throughput)
CF_{NMHC}	=	conversion factor – NMHC to carbon (CF_{NMHC}= 0.6)
3.664	=	ratio of molecular weights, CO_2 to carbon 0.001 = conversion factor – kg to metric tons

(3) The operator who uses methods other than flares (e.g. incineration, combustion as a supplemental fuel in heaters or boilers) to destroy low Btu gases (e.g. coker flue gas, gases from vapor recovery systems, casing vents and product storage tanks) shall calculate CO_2 emissions using Equation 200-11. The operator shall determine CC_A and MW_A quarterly using methods specified in section WCI.20 and use the annual average values of CC_A and MW_A to calculate CO_2 emissions.

$$CO_2 = GV_A \times CC_A \times MW_A / MVC \times 3.664 \times 0.001 \quad \textbf{Equation 200-11}$$

Where:

CO_2	=	CO_2 emissions (metric tons/year)
GV_A	=	volume of gas A destroyed annually (scf/year)
CC_A	=	carbon content of gas A (kg C/kg fuel)
MW_A	=	molecular weight of gas A
MVC	=	molar volume conversion factor (849.5 scf/kg- mole for STP of 20°C and 1 atmosphere or 836 scf/kg-mole, for STP of 60°F, and 1 atmosphere)
3.664	=	ratio of molecular weights, CO_2 to carbon
0.001	=	conversion factor – kg to metric tons

(f) Storage Tanks. For above-ground storage tanks containing crude oil, asphalt, naphtha, and distillate oils that are not equipped with vapor recovery technology, the operator shall calculate CH_4 emissions using the U.S. EPA TANKS Model (Version 4.09D). For crude oil, naphtha, and distillate oils, use the default chemical databases for crude oil (RVP 5), distillate fuel oil No. 2, and jet naphtha (JP4), respectively. For asphalt, use the data in Table 200-4 to create an asphalt chemical database. The annual throughput for each storage tank must be distributed equally across the twelve months of the year and the single-component liquid option selected. The total VOC emission values generated by the model shall be converted to methane emissions using:

(1) A default conversion factor of 0.6 (CH_4 = 0.6 * VOC); or

(2) Species specific conversion factors determined by storage tank headspace vapor analysis using a sampling and analysis methodology approved by [*insert jurisdiction*].

(g) Wastewater Treatment.

(1) The operator shall calculate CH_4 emissions from wastewater treatment using Equation 200-12.

$$CH_4 = [(Q \times COD_{qave}) - S] \times B \times MCF \times 0.001 \quad \textbf{Equation 200-12}$$

Where:

CH_4	=	emission of methane (tons/yr)
Q	=	volume of wastewater treated (m^3/yr)
COD_{qave}	=	average of quarterly determinations of chemical oxygen demand of the wastewater (kg/m^3)
S	=	organic component removed as sludge (kg COD/yr)
B	=	methane generation capacity (B = 0.25 kg CH_4/kg COD)
MCF	=	methane conversion factor for anaerobic decay (0-1.0) from Table 200-2
0.001	=	conversion factor – kg to metric tons

(2) The operator shall calculate N_2O emissions from wastewater treatment using Equation 200-13.

$$N_2O = Q \times N_{qave} \times EF_{N2O} \times 1.571 \times 0.001 \quad \textbf{Equation 200-13}$$

Where:

N_2O = emissions of N_2O (metric tons/yr)
Q = volume of wastewater treated (m^3/yr)
N_{qave} = average of quarterly determinations of N in effluent (kg N/m^3)
EF_{N2O} = emission factor for N_2O from discharged wastewater (0.005 kg N_2O-N/kg N)
1.571 = conversion factor – kg N_2O-N to kg N_2O
0.001 = conversion factor – kg to metric tons

(h) Oil-Water Separators. The operator shall calculate CH_4 emissions from oil-water separators using Equation 200-14.

$$CH_4 = EF_{sep} \times V_{water} \times CF_{NMHC} \times 0.001$$ **Equation 200-14**

Where:

CH_4 = emission of methane (tons/yr)
EF_{sep} = NMHC (non methane hydrocarbon) emission factor (kg/m^3) from Table 200-3.
V_{water} = volume of waste water treated by the separator (m^3/yr)
CF_{NMHC} = NMHC to CH_4 conversion factor (CF_{NMHC} = 0.6)
0.001 = conversion factor – kg to metric tons

(i) Equipment leaks. The operator shall calculate CH_4 emissions for all components in natural gas, refinery fuel gas, and PSA off-gas systems as follows:

(1) Components shall be identified as one of the following classification types: valve, pump seal, connector, flange, open-ended line. Operators shall use the Component Identification and Counting Methodology and screening methods found in Method 3 in CAPCOA (1999), which is incorporated by reference in WCI.6. Operators shall measure and record emissions using instrumentation capable of detecting methane.

(2) The VOC emissions shall be calculated using the following methods:

(A) For components where the measured screening value (SV) is indistinguishable from zero when corrected for background, operators shall calculate VOC emissions using Equation 200-15:

$$E_{VOC-0} = \sum_{i=1}^{6} CC_i \times ZF_{i0} \times t$$ **Equation 200-15**

Where:

E_{VOC-0} = zero component VOC emission (kg/screening period)
i = component type (1 = valve, 2 = pump seal, 3 = other, 4 = connector, 5 = flange, 6 = open-ended line)
CC_i = number of i components where SV = 0
ZF_{i0} = zero VOC emission factor (kg/hr) for component i from Table 200-5
t = time (hours) since last screening

(B) For leaking components, operators shall calculate VOC emissions using the following methods:

(i) For screening values between background and 9,999 ppmv, the operator shall calculate the VOC emissions using Equation 200-16.

$$E_{VOCL-C} = \sum_{i=1}^{6} \sum_{n=1}^{n} \left(\sigma_i \times SV_n^{\beta i}\right) \times t \qquad \textbf{Equation 200-16}$$

Where:

E_{VOCL-C}	=	leaking components VOC emissions (kg/screening period)
i	=	component type (1=valve, 2=pump seal, 3=others, 4=connector, 5=flange, 6=open ended-line)
n	=	number of i components
σ_i	=	correlation equation coefficient for component type i from Table 200-5
SV_n	=	screening value for component n
βi	=	correlation equation exponent for component type i from Table 200-5
t	=	time (hours) component has been leaking – default value is time from last screening

(ii) For screening values greater than 9,999 ppmv, the operator shall calculate the VOC emissions using Equation 200-17.

$$E_{VOCP} = \sum_{i=1}^{6} CC_i \times PF_{iP} \times t \qquad \textbf{Equation 200-17}$$

Where:

E_{VOCP}	=	VOC emissions for components pegged over SV 9,999 ppmv (kg/screening period)
i	=	component type (1=valve, 2=pump seal, 3=others, 4=connector, 5=flange, 6=open-ended line)
CC_i	=	number of i components pegged over 9,999 ppmv
PF_{iP}	=	VOC emission factor (kg/hr) for component type i pegged over 9,999 ppmv from Table 200-5
t	=	time component has been leaking (hours) – default value is time since last screening

(C) The operator shall calculate CH_4 emissions using Equation 200-18. Operators shall use system specific determinations of gas composition and methane content (refinery fuel gas, natural gas, associated gas, flexigas, low Btu gas), where available, to determine a CF_{VOC} value. When representative data is not available, operators shall use the default value of 0.6 for CF_{VOC}.

$$CH_4 = \sum_{1}^{n} \left(E_{VOC-0} + E_{VOC-LC} + E_{VOCP}\right)_n \times CF_{VOC} \times 0.001 \qquad \textbf{Equation 200-18}$$

Where:

CH_4	=	methane emissions (metric tons/year)
n	=	number of screenings/year
E_{VOC-0}	=	zero component VOC emissions (kg/screening period)
E_{VOC-LC}	=	leaking component VOC emissions (kg/screening period)
E_{VOCP}	=	VOC emissions for components pegged over 9,999 ppmv (kg/screening period)
CF_{VOC}	=	VOC to CH_4 conversion factor (default CF_{VOC}=0.6)
0.001	=	conversion factor – kg to metric tons

WCI.204 Sampling, Analysis, and Measurement Requirements

(a) Catalyst Regeneration.

(1) For FCCUs and fluid coking units, the operators shall measure the following parameters using methods that comply with the measurement accuracy provisions in WCI.2(g).

(A) The daily oxygen concentration in the oxygen enriched air stream inlet to the regenerator.
(B) Continuous measurements of the volumetric flow rate of air and oxygen enriched air entering the regenerator.
(C) Continuous measurement of the volumetric flow rate of exhaust gas leaving the regenerator.
(D) Continuous measurements of the CO_2, CO and O_2 concentrations in the regenerator exhaust gas.
(E) Daily measurements of the carbon content of the coke burned.
(F) The number of days of operation.

(2) For periodic catalyst regeneration, the operators shall measure the following parameters using methods that comply with the measurement accuracy provisions in WCI.2(g).

(A) The mass of catalyst regenerated in each regeneration cycle.
(B) The weight fraction of carbon on the catalyst prior to and after catalyst regeneration.

(3) For continuous catalyst regeneration in operations other than FCCUs and fluid cokers, the operators shall measure the following parameters using methods that comply with the measurement accuracy provisions in WCI.2(g).

(A) The hourly catalyst regeneration rate.
(B) The weight fraction of carbon on the catalyst prior to and after catalyst regeneration.
(C) The number of hours of operation.

(b) Process vents. Operators shall measure the following parameters for each process vent using methods that comply with the measurement accuracy provisions in WCI.2(g).

(1) The vent flow rate for each venting event.
(2) The molar fraction of CO_2, N_2O, and CH_4 in the vent gas stream during each venting event.
(3) The duration of each venting event.

(c) Asphalt Production. Operators shall measure the mass of asphalt blown using methods that comply with the measurement accuracy provisions in WCI.2(g).

(d) Sulfur Recovery. The operator shall measure the volumetric flow rate of acid gas to the SRU using methods that comply with the measurement accuracy provisions in WCI.2(g). If using source specific molecular faction value instead of the default factor, the operator shall conduct an annual test of the CO_2 content using methods approved by [insert jurisdiction]. The operator shall submit a test plan to the [insert jurisdiction] for approval. Once approved, the annual tests shall be conducted in accordance with the approved test plan under the supervision of the [*insert jurisdiction*].

(e) Flares and Other Control Devices. The operator shall measure:

(1) The volume of gas destroyed annually determined to accuracy of ± 7.5%.
(2) The carbon content using methods that comply with the measurement accuracy provisions in WCI.2(g).

(f) Storage Tanks. The operator shall measure the annual throughput of crude oil, naphtha, distillate oil, asphalt, and gas oil for each storage tank using flow meters that comply with the measurement accuracy provisions in WCI.2(g).

(g) Wastewater Treatment. Operators shall measure the following parameters using methods that comply with the measurement accuracy provisions in WCI.2(g).

(1) The daily volume of waste water treated.
(2) The quarterly chemical oxygen demand of the wastewater.
(3) The amount of sludge removed and the organic content of the sludge.
(4) The quarterly nitrogen content of the wastewater.

(h) Oil-Water Separators. Operators shall measure the daily volume of waste water treated by the oil-water separators using methods that comply with the measurement accuracy provisions in WCI.2(g).

(i) Equipment Leaks. Operators shall measure screening values for each valve, pump seal, connector, flange, and open-ended line used in natural gas, refinery fuel gas, and PSA off-gas systems using the methods specified in CAPCOA (1999) Method 3: Correlation Equation Method and an instrument capable of detecting methane. Operators shall conduct screenings at the frequency interval required by [*insert jurisdiction*].

Note: Comparability of the Canadian regulations to the leak detection and repair r regulations under 40 CFR 63, Subpart CC and 40 CFR 60, Subpart VV is under determination. These U.S EPA regulations require initially monthly monitoring for valves and pumps, which may be reduced to quarterly, semi-annual, or annual based on the percentage of leaking components.

Table 200-1. Coke burn rate material balance and conversion factors

	(kg min)/(hr dscm %)	(lb min)/(hr dscf %)
K_1	0.2982	0.0186
K_2	2.0880	0.1303
K_3	0.0994	0.0062

Table 200-2. Default MCF Values for Industrial Wastewater			
Type of Treatment and Discharge Pathway or System	**Comments**	**MCF**	**Range**
Untreated			
Sea, river and lake discharge	Rivers with high organic loading may turn anaerobic, however this is not considered here	0.1	0 - 0.2
Treated			
Aerobic treatment plant	Well maintained, some CH_4 may be emitted from settling basins	0	0 – 0.1
Aerobic treatment plant	Not well maintained, overloaded	0.3	0.2 – 0.4
Anaerobic digester for sludge	CH_4 recovery not considered here	0.8	0.8 – 1.0
Anaerobic reactor	CH_4 recovery not considered here	0.8	0.8 – 1.0
Anaerobic shallow lagoon	Depth less than 2 meters	0.2	0 – 0.3
Anaerobic deep lagoon	Depth more than 2 meters	0.8	0.8 – 1.0

For CH_4 generation capacity (B) in kg CH_4/kg COD, use default factor of 0.25 kg CH_4/kg COD.

The emission factor for N_2O from discharged wastewater (EF_{N2O}) is 0.005 kg N_2O-N/kg-N.

MCF = methane correction factor – the fraction of waste treated anaerobically.
COD = chemical oxygen demand (kg COD/m^3).

Table 200-3. Emission Factors for Oil/Water Separators	
Separator Type	**Emission factor (EF_{sep})[a] kg NMHC/m^3 wastewater treated**
Gravity type - uncovered	1.11e-01
Gravity type - covered	3.30e-03
Gravity type – covered and connected to destruction device	0
DAF[b] of IAF[c] - uncovered	4.00e-03[d]
DAF or IAF - covered	1.20e-04[d]
DAF or Iaf – covered and connected to a destruction device	0

[a] EFs do not include ethane
[b] DAF = dissolved air flotation type
[c] IAF = induced air flotation device
[d] EFs for these types of separators apply where they are installed as secondary treatment systems

Table 200-4. Data for Preparing the Asphalt Chemical Database	
Parameter	**Database Entry**
Liquid Molecular Weight	**1000**
Vapor Molecular Weight	**105**
Liquid Density (lb/gal. at 60 ^oF)	**8.0925**
Antoine's Equation Constants (using K)	**A = 75350.06**
	B = 9.00346

Table 200-5. Gas Service Components Fugitive Emissions			
Component Type / Service Type	**Default Zero Factor (kg/hr)**	**Correlation Equation (kg/hr)**	**Pegged Factor (kg/hr)**
			10,000 ppmv
	Zf_{i0}	**σ_i and β_i**	**(SV > 9,999) PF_{iP-10}**
Valves (1)	7.8×10^{-6}	$2.27 \times 10^{-6}(SV)^{0.747}$	0.064
Pump seals (2)	1.9×10^{-5}	$5.07 \times 10^{-5}(SV)^{0.622}$	0.089
Others (3)	4.0×10^{-6}	$8.69 \times 10^{-6}(SV)^{0.642}$	0.082
Connectors (4)	7.5×10^{-6}	$1.53 \times 10^{-6}(SV)^{0.736}$	0.030
Flanges (5)	3.1×10^{-7}	$4.53 \times 10^{-6}(SV)^{0.706}$	0.095
Open-ended lines (6)	2.0×10^{-6}	$1.90 \times 10^{-6}(SV)^{0.724}$	0.033

ATTACHMENT 3: REFINERY FUEL GAS COMBUSTION

§ WCI.30 REFINERY FUEL GAS COMBUSTION

WCI.31 Source Category Definition

This source category consists of any combustion device that is located at a petroleum refinery and that combusts refinery fuel gas, still gas, flexigas, or associated gas.

WCI.32 Greenhouse Gas Reporting Requirements

In addition to the information required by WCI.3, the emissions data report shall include the following information at the facility level:

(a) Annual CO_2, CH_4, and N_2O emissions from refinery fuel gas combustion in metric tons.

(b) Annual fuel consumption in units of million standard cubic feet or cubic meters.

(c) Average carbon content of each fuel, if used to compute CO_2 emissions.

(d) Average high heating value of each fuel, if used to compute CO_2 emissions.

WCI.33 Calculation of Greenhouse Gas Emissions

(a) Calculation of CO_2 Emissions. Owners and operators shall calculate daily CO_2 emissions for each fuel gas system using any of the methods specified in paragraphs (a)(1) through (a)(5) of this section. Calculate the total annual CO_2 emissions from combustion of all fuel gas by summing the CO_2 emissions from each fuel gas system.

(1) Use a CEMS that complies with the provisions in section WCI.23(d).
(2) Calculate CO_2 emissions from each refinery fuel gas system and flexigas system using measured carbon content and molecular weight of the gas and Equation 30-1.

$$CO_2 = \sum_{i=1}^{n} Fuel_i \times CC_i \times \frac{MW}{MVC} \times 3.664 \times 0.001 \qquad \textbf{Equation 30-1}$$

Where:

CO_2	=	Carbon dioxide emissions, metric tons/year.
$Fuel_i$	=	Daily refinery fuel or flexigas combusted (scf).
CC_i	=	Daily sample of carbon content of the fuel (kg C/kg fuel).
MW	=	Daily sample of molecular weight of fuel.
MVC	=	Molar volume conversion factor (849.5 scf/kg-mole for STP of 20°C and 1 atmosphere, or 836 scf/kg-mole for STP of 60°F and 1 atmosphere).
3.664	=	Conversion factor for carbon to carbon dioxide.
0.001	=	Conversion factor for kg to metric tons.
n	=	Number of days in a year.

(A) For refinery fuel gas, the daily carbon content shall be determined a minimum of 3 times a day (once every 8 hours) using on-line instrumentation or discrete laboratory analysis using the methods specified in WCI.34.
(B) For flexigas, the daily carbon content shall be determined once per day using the methods specified in WCI.34.

(3) Calculate CO_2 emissions from each fuel gas system and flexigas system using Equation 30-2 and a daily average high heating value that is monitored using a continuous on-line instrument.

$$CO_2 = \sum_{i=1}^{n} HHV_i \times Fuel_i \times EF_{CO2,i} \times 0.000001 \qquad \textbf{Equation 30-2}$$

Where:

CO_2	=	CO_2 emissions resulting from the combustion of fuel gas from an individual fuel gas system (metric tons/yr).
HHV_i	=	Daily average high heating value of fuel gas, derived from a continuous analyzer and integrated over a 24-hour period (Btu/scf).
$Fuel_i$	=	Daily fuel consumption from all fuel combustion units burning gas from the system (scf/d).
$EF_{CO2,i}$	=	Daily CO_2 emission factor for an individual fuel gas system, developed using Equation 30-3 (metric tons CO_2/MM Btu).
0.000001	=	Conversion factor for Btu to MMBtu.
n	=	Number of days per year.

$$EF_{CO2,i} = CC/HHV \times MW/MVC \times 3.664 \times 1000 \qquad \textbf{Equation 30-3}$$

Where:

$EF_{CO2,i}$	=	Daily CO_2 emission factor for an individual fuel gas system (metric tons CO_2/MMBtu).
CC	=	Daily sample of gas carbon content for a fuel gas system, collected according to paragraph (a)(3)(A) of this section (kg carbon/kg fuel).
HHV	=	Daily sample of gas high heating value for a fuel gas system, collected according to paragraph (a)(3)(A) of this section (Btu/scf).
MW	=	Refinery fuel A molecular weight (kg/kg-mole).
MVC	=	Molar volume conversion (849.5 scf/ kg-mole, for STP of 20°C and 1 atmosphere, or 836 scf/kg-mole for STP of 60°F and 1 atmosphere).
3.664	=	Conversion factor for carbon to carbon dioxide.
1000	=	Conversion factor for kg/Btu to metric tons/MMBtu.

(A) For Equation 30-3, the carbon content shall be determined once per day by on-line instrumentation or by laboratory analysis of a representative sample using the methods specified in WCI.34. The HHV shall be determined from either the same sample used to conduct the carbon analysis or from on-line instrumentation using the hourly average value that coincides with the same hour in which the carbon content was determined.

(B) For facilities that meet the definition of a small refiner in WCI.10, the emissions measurements and calculations for Equation 30-2 and 30-3 may be conducted weekly.

(4) For associated gas, low Btu gas, or other fossil fuels; follow the requirements for general stationary source combustion sources in WCI .23(b) or (c), as appropriate for each fuel.

(5) Where individual fuels are mixed prior to combustion, the operator may choose to calculate CO_2 emissions for each fuel prior to mixing instead of using the methods in paragraphs (a)(1), (a)(2), or (a)(3) of this section. In this case, the operator must determine the fuel flow rate and appropriate fuel specific parameters (e.g. carbon content, HHV) of each fuel stream prior to mixing, calculate CO_2 emissions for each fuel stream, and sum the emissions of the individual fuel streams to determine total CO_2 emissions from the mixture. CO_2 emissions for each fuel stream must be estimated using the following methods:

(A) For natural gas and associated gas, use the appropriate methodology specified in section WCI.23(b) or (c).

(B) For refinery fuel gas and flexigas, use the methodology in either paragraph (a)(2) or (a)(3) of this section.

(C) For low Btu gas, use the methodology in paragraph (a)(2) of this section.

(b) Calculation of CH_4 and N_2O Emissions. Owners and operators shall use the methods specified in section WCI.24 to calculate the annual CH_4 and N_2O emissions.

WCI.34 Sampling, Analysis, and Measurement Requirements

(a) Measure the fuel consumption rate daily using methods specified in WCI.25(b).

(b) Measure the carbon content for fuel gas and flexigas using either ASTM D1945-03 or ASTM D1946-90 (Reapproved 2006).

(c) Measure high heating value using the monitoring requirements specified in WCI.25(c) for gaseous fuels.

ATTACHMENT 13: ZINC PRODUCTION

Applicability

There are three primary production processes used to produce zinc: electro-thermic distillation, pyrometallurgical, and electrolytic. In electro-thermic distillation, roasted concentrate and secondary zinc products are combined into a sinter feed that is then burned resulting in a zinc oxide-rich sinter. This sinter is then fed into an electric retort furnace with metallurgical coke which reduces the zinc oxide; the resultant vaporized zinc is then captured in a vacuum condenser. The pyrometallurgical process utilizes an Imperial Smelting Furnace, which allows for the simultaneous treatment of both lead and zinc concentrates (estimated emissions must be allocated to both lead and zinc production to avoid double-counting). In the electrolytic process, zinc sulfide is calcined, which results in the production of zinc oxide. The zinc oxide is leached in sulfuric acid and then drawn out of solution using electrolysis. The electrolytic process does not result in non-energy CO_2 emissions.

In addition to primary production, zinc can be recovered from various materials using more than 40 hydrometallurgical and pyrometallurgical technologies. The preferred technologies are dependent upon the zinc source and the desired end use for the recovered zinc. In general, the processes consist of zinc concentration, sintering, smelting, and refining. Many of the sintering, smelting, and refining steps are identical to the primary production process steps. Two concentration processes are the Waelz Kiln and slag reduction or fuming processes.

Emission Calculations

The following emission calculation methods are taken from the 2006 IPCC Guidelines, Volume 3, Section 4.7.

The Tier 3 methodology recommends using actual directly measured CO_2 emissions data, if available. Alternatively, facility-specific emission factors and material quantities can be used to calculate emissions for the Tier 3 methodology. The Tier 2 methodology uses country-specific emission factors developed from facility statistics regarding reducing agent use, furnace types, and other process materials. Unlike lead, default carbon contents are not provided for reducing agents used in zinc production.

The Tier 1 methodology for zinc production uses default emission factors for different zinc product types. The emission calculation equation for Tier 1 is:

$$E_{Zn} = (Zn_{ET} \times EF_{ET}) + (Zn_{PM} \times EF_{PM}) + (Zn_{Sec} \times EF_{Sec})$$

Where:

E_{Zn} = CO_2 emissions from zinc production (metric tons);
Zn_{ET} = Quantity of zinc produced by electro-thermic distillation (metric tons);
EF_{ET} = Emission factor for electro-thermic distillation (metric tons CO_2/metric tons of zinc produced);
Zn_{PM} = Quantity of zinc produced by pyrometallurgical process (Imperial Smelting Furnace Process (metric tons);
EF_{PM} = Emission factor for pyrometallurgical process (metric tons CO_2/metric tons of zinc produced);
Zn_{Sec} = Quantity of zinc produced by secondary production process (e.g., Waelz Kiln, etc.) (metric tons);
EF_{Sec} = Emission factor for secondary production process (metric tons CO_2/metric tons of zinc produced).

A default emission factor is not available for the electro-thermic distillation process because of a lack of data; emissions will be underestimated if a facility-specific emission factor for the electro-thermic distillation process is not identified and used. The default emission factor for the pyrometallurgical process (i.e., Imperial Smelting Furnace) is 0.43 metric tons CO_2/metric tons of zinc produced. The default emission factor for the secondary production process (i.e., Waelz Kiln) is 3.66 metric tons CO_2/metric tons of zinc produced.

The uncertainty for Tier 3 facility-specific measured CO_2 data has been estimated to be ±5 percent. The uncertainty associated with the Tier 3 facility-specific reducing agent quantities and carbon contents is also estimated to be ±5 percent. The uncertainty of the Tier 2 country-specific emission factors is estimated to be ±15 percent. The uncertainty of the Tier 1 default emission factors is estimated to be ±50 percent.

The Tier 3 method (using either actual directly measured CO_2 emissions data or facility-specific emission factors and material quantities) is recommended to estimate emissions from zinc production facilities.

Reporting Requirements

Annual CO_2 emissions (measured or calculated) based on the IPCC Tier 3 or Tier 2 method will be reported for each facility.

Sampling, Analysis, and Measurement Methods

(a) Facility CO_2 emissions. The Tier 3 method from the 2006 IPCC Guidelines specifies facility-specific emission measurements. Determine facility CO_2 emissions using continuous emissions monitoring systems (CEMS) as specified in WCI.23(d).
(b) Quantity Measurement Requirements. Alternatively, Tier 3 facility-specific emission factors can be used if facility-specific emission measurements are not available. For solid process outputs, quantities must be determined by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.

ATTACHMENT 7: HYDROGEN PRODUCTION

§ WCI.130 HYDROGEN PRODUCTION

§ WCI.131 Source Category Definition

A hydrogen production process produces hydrogen gas by steam hydrocarbon reforming, partial oxidation of hydrocarbons, or other transformation of hydrocarbon feedstock. The hydrogen produced may be either transferred offsite or used onsite at petrochemical, ammonia production, refineries, and other plants.

§ WCI.132 Greenhouse Gas Reporting Requirements

For each facility, the annual emissions report must contain the following information:

(a) Process CO_2 Emissions. The CO_2 process emissions from the hydrogen produced process.

(b) Feedstock Consumption. Annual feedstock consumption by feedstock type (including petroleum coke) reported in units of million standard cubic feet for gases, gallons for liquids, short tons for non-biomass solids, and bone dry short tons for biomass-derived solid fuels.

(c) Production. Annual hydrogen produced.

(d) Stationary Combustion Units. Report CO_2, N_2O, and CH_4 emissions as specified in WCI.20.

§ WCI.133 Calculation of Greenhouse Gas Emissions

The owner or operator shall calculate and report CO_2 process emissions using the methods in paragraphs (a) or (b) of this section.

(a) Continuous Emission Monitoring Systems. The owner or operator may calculate CO_2 process emissions using CEMS. The owner or operator must comply with the requirements in section WCI.20.

(b) Feedstock Material Balance. The owner or operator may calculate CO_2 process emissions using the following method. The factor S shall be used only for CO_2 and/or CH_4 emissions that are calculated and reported using applicable methods specified in this regulation. For example, carbon species in uncoverted feedstock contained in PSA off-gas and hydrogen plant product that is diverted to fuel gas systems, fed to downstream units, or diverted to flare may be included in the factor S provided the CO_2 and/or CH_4 emissions are reported using other methods in this regulation.

$$CO_2(Feedstock) = \sum_{i=1}^{n} \sum_{j=1}^{y} \left[\left(FS_j * CF_j \right) - S_j \right] * 3.664 * 0.001 \qquad \textbf{Equation 130-1}$$

Where:

CO_2 (Feedstock) = CO_2 emitted from feedstock (metric tons/year).

n	=	Days of operation per year.
FS_j	=	Feedstock b consumption rate (scf/day).
CF_j	=	Carbon content of feedstock j (kg C/scf feedstock).
y	=	Total number of feedstocks.
S_j	=	Carbon accounted for elsewhere (kg C/day).
3.664	=	ratio of molecular weights, CO_2 to carbon
0.001	=	conversion factor – kg to metric tons

WCI.134 Sampling, Analysis, and Measurement Requirements

(a) Owners or operators using CEMS to estimate CO_2 emissions shall comply with the monitoring requirements in section WCI.20.

(b) Owners or operators using the method in section WCI.103 (b) shall perform the following monitoring:

(1) The owner or operator shall measure the feedstock consumption rate daily using methods that comply with the measurement accuracy provisions in WCI.2(g).
(2) The owner or operator shall collect samples of each feedstock consumed and analyze each sample for carbon content using the methods specified in WCI.25(d). For natural gas feedstock not mixed with another feedstock prior to consumption, samples shall be collected and analyzed once per month. For all other feedstocks, samples shall be collected and analyzed daily. The samples shall be collected from a location in the feedstock handling system that provides samples representative of the feedstock consumed in the hydrogen production process.
(3) Owners or operators shall measure the hydrogen produced daily using methods that comply with the measurement accuracy provisions in WCI.2(g).
(4) Owners or operators shall measure the CO_2 and CO collected daily using methods that comply with the measurement accuracy provisions in WCI.2(g).

ATTACHMENT 15: PULP AND PAPER MANUFACTURING

Several documents were identified as having the most comprehensive estimation methods for the pulp and paper industry. In these documents, the primary authority for estimating GHG emissions from pulp and paper manufacturing is: *Calculation Tools for Estimating Greenhouse Gas Emissions from Pulp and Paper Mills, Version 1.1, July 8, 2005, a project of The Climate Change Working Group of The International Council of Forest and Paper Associations (ICFPA).* This reference is the basis of the GHG estimation methodology used by WRI and by Climate Leaders.

Applicability

The ICFPA methodology lists the following sources of GHG at pulp and paper manufacturing facilities:

1. Stationary combustion units such as fossil and biomass fired boilers and dryers (§ WCI.20)
2. Lime kilns and calciners (§ WCI.170)
3. Electric generation units (§ WCI.40)
4. Nonroad equipment (§ WCI.XX)
5. Anaerobic waste and wastewater treatment
6. Black liquor boilers

Methods for estimating emissions from sources 1 through 4 in the above list are or will be addressed under other sections of the Essential Requirements for mandatory reporting, as noted. However, most of the process CO_2 emissions from the lime kilns at pulp and paper mills is derived from organic carbon, which must be tracked separately from the fossil CO_2.

Emission Calculations – Anaerobic Treatment and Black Liquor Boilers

For purposes of reporting, WCI will likely require a method similar to that required for reporting wastewater CH_4 and N_2O emissions from refineries in WCI.203(g). WCI will examine the uncertainty of the biogenic decay models, such as those used to estimate emissions for municipal landfills and municipal wastewater treatment plants, to determine their appropriateness for estimating anaerobic treatment processes for purposes of including these emissions in the cap-and-trade program.

Black liquor boilers are a source of CO_2, CH_4 and N_2O emissions. The ICFPA reports that all CO_2 emissions from black liquor boilers are of biogenic origin and not reportable. Thus, they do not present a methodology for determining CO_2 emissions from this source. The Climate Registry (TCR) and the IPCC offer only emission factors for determining CO_2 emissions from black liquor boilers. The IPCC reports that the 95% confidence interval for their CO_2 factor ranges from 80,700 to 110,000 (± 15%) kg/TJ. Similarly, the reported IPCC factors for CH_4 and N_2O emissions from black liquor boilers range by a factor of 10 at the 95% confidence level.

Recommended Reporting Requirements (Under Development)

Methods for estimating emissions from sources 1 through 4 in the above list are or will be covered under other sections of the Essential Requirements. In January 2009, special instructions will be developed for lime kilns (source 2) to instruct reporters on how to account for biogenic and fossil process CO_2 emissions, and a specific methodology based on the refinery method (WCI.203(g)) will be prescribed for estimating wastewater emissions (source 5).

Later in 2009, a new methodology will be developed for black liquor boilers (source 6) Note that both fossil and biogenic carbon leave the black liquor boiler as both a gas (CO_2) and a solid (Na_2CO_3), thus a unique material balance methodology will be needed. As with any new methodology, it should be peer reviewed before being finalized for use in the WCI program.

Sampling, Analysis, and Measurement Methods

All further methods development will stipulate that fossil and biogenic process emissions will be reported separately, and will contain requirements pertaining to sampling, analysis, and measurements, as applicable to the specific emission quantification method input(s).

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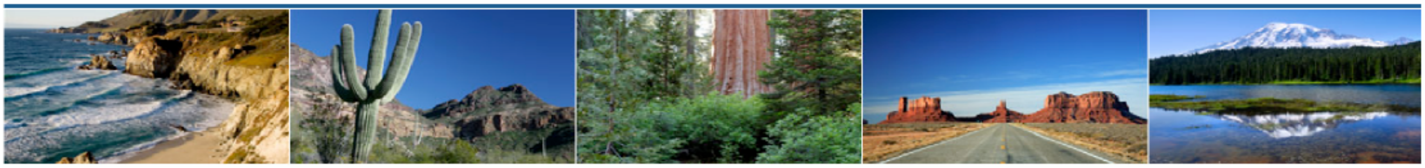


January 6, 2009

To All Interested Parties:

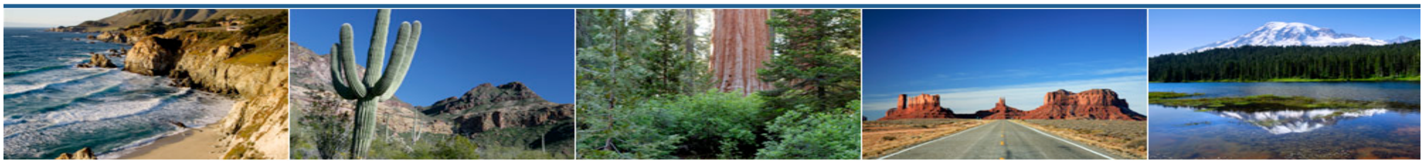
Today, the WCI is releasing their document "Background Document and Progress Report for Essential Requirements of Mandatory Reporting for the Western Climate Initiative, Third Draft." Attached to this document are the Essential Requirements of Mandatory Reporting (i.e., reporting requirements in rule language or narrative format)

You are invited to participate in a stakeholder conference call to discuss the present draft on January 12, 2009, at 12:30 PM to 2:30 PM Pacific Time. The call-in number is 800-868-1837 (direct dial 404-920-6440), access code 659-537#. We ask that written comments be submitted through the WCI Website (www.westernclimateinitiative.org) by January 20, 2009

Sincerely,

Jim Norton, Chair
WCI Reporting Committee
State of New Mexico

Western Climate Initiative



Background Document and Progress Report for Essential Requirements of Mandatory Reporting for the Western Climate Initiative, Third Draft

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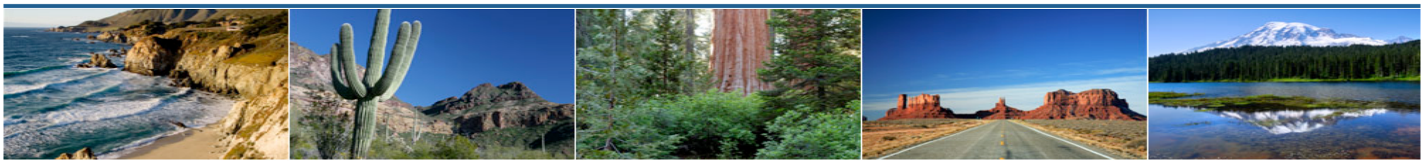
Western Climate Initiative



Background Document and Progress Report for Essential Requirements of Mandatory Reporting for the Western Climate Initiative, Third Draft

January 6, 2009

Purpose

The Background Document and Progress Report shows how the scope and design of the cap-and-trade program informs mandatory reporting requirements, discusses stakeholder comments received to date, and explains the basis for the WCI's specific recommendations on mandatory reporting. Attached to this document are the Essential Requirements of Mandatory Reporting (i.e., reporting requirements in rule language or narrative format). This document will be made available to WCI partner states and provinces for their consideration as they propose and adopt mandatory reporting rules in their jurisdictions.

This document revises and expands upon the document issued on September 30, 2008 that addressed continuing work conducted by the WCI Partners and its Reporting Subcommittee (now designated the Reporting Committee). It provides a progress report on the development of the Essential Requirements for reporting and strives to address comments made by stakeholders on previous drafts. Its purposes are similar to previous documents, namely to: 1) document the current status of WCI's consideration of Essential Requirements for reporting; 2) identify ongoing work and decisions that remain to be made; and 3) seek public comment on these reporting Essential Requirements.

Comments on this document should be submitted in writing by January 20, 2009, through the WCI Website (www.westernclimateinitiative.org).

Introduction

The "Design Recommendations for the WCI Regional Cap-and-Trade Program" (September 23, 2008) state that "prior to the start of the mandatory reporting program, the WCI Partner jurisdictions will establish the essential requirements for reporting by all entities and facilities required to report in each of the WCI Partner jurisdictions." To complete the Essential Requirements for reporting, the WCI must make numerous decisions about how it wishes to define, and structure the elements that have been identified as necessary to an effective WCI cap-and-trade program. This document and its companion document, the "Essential Requirements of Mandatory Reporting," reflect the draft recommendations made to date and offered for stakeholder comment.

This document is organized somewhat differently and has a more narrative style than previous versions. Each section contains some introductory comments that explain the content of the section and provides some background information, a recitation of the relevant WCI design recommendations made earlier a brief summary of stakeholder comments and recommendations received to date, a plain language description of WCI's recommendations on Essential Requirements for reporting with a discussion of intent and purpose, and a brief summary of any work and decisions that remain to be made.

This document has 10 sections that address the following Essential Requirements for reporting, which are also referred to as "General Provisions". These sections address: applicability, general requirements and schedule, contents of the report, document retention and record keeping, confidentiality, compliance and enforcement, designated representative, verification, definitions, and pollutants and global warming potentials. An additional section provides the background and progress toward identification of GHG emissions quantification, and sampling, analysis, and measurement methods by source category. For some source categories, the Essential Requirements provide draft language that the WCI Partner jurisdictions can use for implementing the WCI program within their jurisdiction; for other source categories, the Essential Requirements provide a narrative discussion of the adequacy of available GHG quantification and monitoring methods with recommendations for WCI reporting.

It is noted that some of the WCI recommendations on reporting requirements differ from the existing provisions of state or provincial reporting rules. The intent is for those WCI Partner jurisdictions to amend their reporting rules in 2009 to align them with WCI Essential Requirements. It is also noted that, pending final decisions on which emissions will correspond with a requirement to hold allowances, the current recommendations may require reporting and verification for some emissions that are later determined not to result in an allowance requirement. For example, in some circumstances, verification may be required for some sources to validate that their emissions are indeed below the level that would trigger allowance obligations.

Stakeholders should note that the identification of adequate quantification methods is an ongoing process. At this point the methods discussed in this document apply only for purposes of reporting. A recommended quantification method for a given combustion or non-combustion source category may need to be revised and/or updated prior to the beginning of the first compliance period. The fact that a source has a recommended quantification method does not necessarily indicate whether or not that source category will be subject to the cap.

Finally, while the WCI has tried to be as comprehensive as possible in defining reporting requirements, it is not feasible to anticipate every detail at this stage of cap-and-trade program development. Reporting requirements will be developed later in 2009 for several important source categories, including electricity importers, distributors of fuels for transportation, residential, commercial and industrial use, natural gas transmission and distribution non-combustion emissions, oil and gas production and gas processing, and others noted elsewhere in this document. Furthermore, WCI Partner jurisdictions expect to revisit and if necessary revise reporting requirements several years down the road as the WCI cap-and-trade program enters the mandatory compliance phase, if they find that changes are needed to reconcile reporting requirements with the schedule and architecture of the final compliance and trading program.

Applicability (§ WCI.1)

This section describes the facilities, electricity importers, and fuel suppliers that must report their emissions in order to support the cap-and-trade program. It contains reporting thresholds stated as metric tons of carbon dioxide equivalents (CO_2e) per year. This section also addresses the point of regulation (POR) as it pertains to reporting by each included source category. Note that current language within this section describing electricity importers and fuel suppliers should be viewed as preliminary and is subject to revision when the reporting requirements for these source categories are developed by WCI later in 2009.

Relevant Scope and Design Recommendations

The scope of the cap-and-trade program addresses sources that produce 80 to 90 percent of estimated 2005 GHG emissions in WCI Partner jurisdictions. The program design includes combustion and non-combustion emissions. These sources are included in the cap-and-trade program (i.e., will have a requirement to hold emissions allowances) in two phases. Combustion and non-combustion emissions from electrical generation, large industrial and commercial facilities, and oil and gas production and gas processing, are covered in the first compliance period, while combustion emissions from residential, smaller commercial and industrial, and transportation fuels are included in the second compliance period. Adequate quantification methods are a prerequisite to including any source of emissions in the requirements to hold emissions allowances. While source categories will be brought into the cap-and-trade program in phases, emissions reporting is required for all included source categories beginning with 2010 emissions.

The POR, and therefore the reporting requirements, vary by source category. Many sources, including electrical generation within WCI Partner jurisdictions and most industrial source categories are regulated at, and will report at, the facility level. Electrical power imported into WCI Partner jurisdictions is regulated at the first entity that receives the imported power and delivers electricity for consumption within a WCI Partner jurisdiction, over which the WCI partner jurisdiction has regulatory authority. Fuel combustion emissions from residential sources, from commercial and industrial sources with emissions below the reporting threshold, and from transportation sources are regulated upstream of the point of combustion, where the fuels enter commerce in the WCI Partner jurisdictions. This will generally be at a distributor, though the precise point may vary by jurisdiction.

Carbon dioxide emissions from the combustion of biomass and pure biofuels, including those used in blends, are subject to reporting requirements. Carbon dioxide emissions from combustion of biomass determined to be carbon neutral will not be included in the cap-and-trade program. WCI jurisdictions will address the issues of carbon neutrality and lifecycle emissions of biomass and biofuel combustion later in development of the cap-and-trade program.

The emissions threshold for inclusion in cap-and-trade is 25,000 metric tons of CO_2e on an annual basis. The facilities, electricity importers, and fuel suppliers subject to reporting are those with annual emissions equal to or greater than 10,000 metric tons of CO_2e. Nothing in the WCI program design limits any WCI Partner jurisdiction's discretion to require reporting earlier, at lower thresholds, or for entities and facilities not covered by the cap-and-trade program.

Stakeholder Input

Thresholds – Some stakeholders supported the reporting threshold of 10,000 metric tons CO_2e, a few believed it was too low, while others thought it was too high, lacked justification or would unduly burden small companies. Other comments were that the thresholds should be industry-specific, should be identical throughout the WCI region, that electrical generating facilities should report at the lower threshold level required in California, and that the burden on small sources could be reduced by phasing them in and/or by providing assistance.

Source Categories – Some stakeholders urged the WCI to minimize exclusions while others advocated including specific source categories such as oil and gas production, transportation fuels, natural gas distribution and biomass emissions. Others suggested excluding specific source categories or sources within facilities, citing various reasons. For example stakeholders suggested excluding landfills and vented and fugitive methane emissions from oil and gas sources because of inaccurate quantification methods. Other suggested exclusions for emergency engines and emergency generators, and for "accidental" emissions.

Other comments urged reporting requirements that would encourage combined heat and power installations, distinguish between biogenic and anthropogenic CO_2 emissions, and that would consider lifecycle emissions of biomass fuels.

Point of Regulation/Reporting – Stakeholders offered various views on the POR and reporting. Several industrial commenters strongly supported reporting at the corporate or facility level. A major oil and gas trade association supported facility level reporting and noted that reporting at the process unit level would add significantly to data management requirements and could expose closely held trade or business secrets. Other commenters supported developing a unique definition of reporting entity for oil and gas production fields that will aggregate small facilities, such as by production field. Stakeholders recommended uniform point of regulation for residential, commercial and industrial fuel use and transportation at all WCI jurisdictions.

Reporting Recommendations and Discussion

Thresholds – The WCI reporting threshold is 10,000 metric tons CO_2e per year, well below the 25,000 metric tons CO_2e per year threshold for inclusion in the cap-and-trade program. The reporting threshold is set lower than the cap-and-trade threshold to ensure that accurate emissions data are available to document the exclusion of those facilities and other reporting entities whose emissions are below the 25,000 metric tons threshold. Second, reporting down to a threshold of 10,000 metric tons of CO_2e will provide the information needed to determine whether the threshold for inclusion in the cap-and-trade program is set at the appropriate level. Third, the lower reporting threshold will allow the WCI to monitor potential leakage to facilities below the threshold of the cap-and-trade program. Finally, a threshold of 10,000 metric tons of CO_2e is consistent with the level being considered in potential legislation for a U.S. federal cap-and-trade program.

Stationary Combustion – Reporting requirements apply to facilities with stationary combustion units[1] that individually or in combination emit 10,000 metric tons of CO_2e on an annual basis, **even if they are not associated with one of the source categories listed below**.

Carbon dioxide emissions from the combustion of biomass fuels are to be included in the calculations for purposes of determining whether this threshold has been met or exceeded. However, the WCI is aware that this requirement may be burdensome for many small businesses (especially in northern WCI Partner jurisdictions), which are being encouraged to use wood waste as a substitute for fossil fuel. The WCI is considering whether some limited deduction of biomass combustion emissions might be appropriate for purposes of determining whether the reporting threshold has been met.

Source Categories – Reporting requirements also apply to any facility[2] that emits 10,000 metric tons CO_2e or more per calendar year in combined emissions, which includes emissions from one or more of the source categories listed in Table 1 in addition to combustion emissions. Affected facilities must report both combustion emissions and, to the extent adequate

[1] General stationary combustion units are boilers, combustion turbines, engines, incinerators, and process heaters, and any other stationary combustion device that burns any liquid, gaseous or solid fuel.

[2] "Facility" means any property, plant, building, structure, stationary source, stationary equipment or grouping of stationary equipment or stationary sources located on one or more contiguous or adjacent properties, in actual physical contact or separated solely by a public roadway or other public right-of way, and under common operational control. Some special "facilities" such as oil or gas production fields, will have separate definitions.

quantification methods are currently available and have been specified in the Essential Requirements, non-combustion emissions. If, as expected, adequate quantification methods are not currently available for some sources and activities at these facilities, these source category emissions are not included in the reporting requirements at this time.

The WCI developed the list of source categories in Table 1 in order to capture both combustion and non-combustion GHG emissions in the cap-and-trade program. Note that facilities which do not have emissions from the source categories listed in Table 1 are not thereby categorically excluded from the reporting requirements, but are required to report their combustion emissions if those emissions exceed the threshold. As part of its scope and design evaluation, the WCI developed a list of source categories by reviewing national emissions guidelines, determining whether facilities in these source categories existed in WCI Partner jurisdictions, assessing whether they are addressed in The Climate Registry (TCR) or other reporting protocols, and making a preliminary determination of whether quantification methods for these non-combustion sources might be adequate. The assessment of whether quantification methods are adequate is continuing on a source category-by-source category basis.

Table 1. Source Categories Subject to Category-Specific Reporting Requirements in Addition to General Stationary Combustion Reporting Requirements

• Adipic acid manufacturing[TBD] • Aluminum production • Ammonia manufacturing[TBD] • Carbon dioxide transfer recipients[TBD] • Cement production • Coal mines (active and abandoned) • Coal storage • Cogeneration[TBD] • Electricity generation • Electronics manufacturing[TBD] • Ferroalloy production[TBD]	• Glass production and other uses of carbonates[TBD] • HCFC-22 production[TBD] • Hydrogen production • Industrial Wastewater • Iron and steel production • Lead production • Lime manufacturing • Magnesium production[TBD] • Natural gas distribution systems[TBD] • Nitric acid manufacturing[TBD] • Nonroad equipment at facilities[TBD]	• Oil and gas production and gas processing[TBD] • Petrochemical production[TBD] • Petroleum refineries • Phosphoric acid production[TBD] • Pulp and paper manufacturing • Refinery gas combustion • SF_6 from electrical equipment[TBD] • Soda ash manufacturing[TBD] • Zinc production

TBD = To be determined. The assessment of adequate quantification and monitoring methods for this source category is on going.

In addition to the facility-based sources listed above, requirements will be developed for several other source categories to report emissions at the entity level:

- To account for the emissions of electrical generation that is located outside of, but used within WCI Partner jurisdictions, reporting requirements will be developed to apply to entities that import electricity into the WCI region.
- The largest emissions source category in the WCI-wide inventory is the combustion of transportation fuels by millions of individual motor vehicles and other mobile sources. To account for these emissions efficiently, the POR and reporting is moved upstream to fuel suppliers that distribute transportation fuels within the WCI region. Suppliers must report the expected downstream emissions from combustion of the transportation fuels they distribute within the WCI region, if when combusted the distributed fuels would emit 10,000 metric tons CO_2e per year or more. The specific point of regulation in the fuel supply system is yet to be determined, and may differ between jurisdictions.
- Cumulatively, the combustion of natural gas and fuel oil at residential units, commercial buildings, and at small industrial operations, produces considerable emissions, but it is infeasible or impractical to place the point of regulation/reporting on individual residents or owners. As a result, the POR and reporting requirements are moved somewhat upstream to fuel suppliers. Suppliers must report the expected downstream emissions from combustion of the residential, commercial, and industrial fuels they distribute, within the WCI region, if when combusted the distributed fuels would emit 10,000 metric tons CO_2e per year or more. The specific point of regulation in the fuel supply system is yet to be determined, and may differ between jurisdictions and by fuel type.

Source Categories Not Included – A number of source categories are not included in reporting at this time. Agriculture emissions are excluded because they cannot currently be calculated or measured precisely and cost-effectively at the producer or farm level. Similarly, forestry emissions cannot currently be calculated or measured precisely and cost- effectively. Also, agriculture, forestry, and land use emissions would be administratively difficult to report due to the huge number of entities that would have to report. Non-combustion emissions from municipal wastewater treatment and municipal landfills are not included at this time because of concern for the adequacy of currently available quantification methods.[3]

Discontinuing Reporting – Facilities and fuel suppliers that have an emissions limitation under the cap-and-trade program must continue to report verified emissions as long as they have such an obligation. However there are some circumstances in which a facility or fuel supplier

[3] Note that noncombustion emissions from wastewater at certain types of facilities (e.g., refineries) are required to be reported.

that does not have a compliance obligation can discontinue mandatory reporting when they reduce emissions below 10,000 metric tons CO_2e per year. Those reporting entities that are subject to verification must continue to report verified emissions data until reported emissions are below 10,000 metric tons CO_2e per year for a minimum of 3 consecutive years. The owner or operator would then be exempted from further reporting until CO_2e emissions again exceed 10,000 metric tons in any future calendar year.

If the facility or fuel supplier is ***not*** subject to verification requirements, the reporter can submit a signed statement, in lieu of the emissions report, certifying that emissions were less than 10,000 metric tons CO_2e the previous year. After certifying that emissions are below 10,000 metric tons CO_2e per year for 3 consecutive years, the owner or operator shall be exempted from further reporting unless and until CO_2e emissions again exceed 10,000 metric tons.

Sources That Do Not Report - WCI Partner jurisdictions will have the option of requesting any facility or fuel supply operation in its jurisdiction to submit, within 20 days of being requested to do so, a demonstration that the facility or supply operation has not exceeded the reporting threshold/criteria since 2010. WCI is considering whether this and other deadlines for responses provide sufficient time, and whether such deadlines should be standardized across requirements.

Carbon Dioxide Capture and Transfer – Carbon dioxide that is captured for on-site use, on-site storage, or transfer off-site is included in the emissions total for purposes of determining if an emissions threshold has been exceeded, but is to be reported separately. A source category for recipients of CO_2 captured and transferred off-site will be included to account for possible downstream emissions of such captured and transferred CO_2.

Ongoing Work

The WCI has completed some decisions on which non-combustion emissions sources within the covered source categories will be subject to mandatory reporting, and will continue to evaluate additional source categories. The decisions will be based primarily on the availability of adequate quantification methods. The WCI will also refine decisions on the point of regulation and reporting for complex source categories like oil and gas production and gas processing and distribution, and determine whether alternatives to the 10,000 metric tons CO_2e

per year threshold are appropriate for some source categories. The WCI is considering whether verification may be discontinued for sources that drop below 25,000 metric tons annual emissions, but remain above 10,000 metric tons, for a period of years.

Finally, additional work is needed to develop an accounting process to avoid double-counting and potential gaps in reporting combustion emissions from residential, commercial, industrial, and transportation fuels. This may be addressed through the reporting rule or through incorporation in a market implementation rule that WCI will develop. Finally, the WCI will determine whether some limited deduction of biomass combustion emissions might be appropriate for purposes of determining whether the reporting threshold has been met.

General Greenhouse Gas Reporting Requirements and Schedule (§ WCI.2)

This section describes the responsibilities and requirements that are common to all reporting facilities, electricity importers and fuel suppliers. The section lays out general data collection and management responsibilities, the schedule for submitting reports, where reports are to be submitted, a provision allowing the use of simplified quantification methods for de minimis sources and gases, requirements to maintain program plans, the process for making report revisions, and criteria for the accuracy of fuel use measurements.

Relevant Scope and Design Recommendations

Relevant scope and design recommendations address the schedule. The cap-and-trade program will launch January 1, 2012; that is the date on which the first 3-year compliance period begins for facilities and other entities with emissions exceeding the threshold of 25,000 metric tons of CO_2e per year. Mandatory measurement and monitoring for the six included GHG gas emissions will commence January 1, 2010 for all entities and facilities subject to reporting. Reporting of 2010 emissions will begin in 2011. During 2009, WCI Partner jurisdictions will need to incorporate these Essential Requirements into their rules, which in some cases will require modifications to their existing GHG reporting rules.

Each covered entity or facility will demonstrate compliance with the cap-and-trade program by surrendering sufficient allowances by July 1 of the year following the end of each compliance period. To ensure transparency and maintain public confidence, certain data from the emissions reports, allowances, and offsets that are used for compliance will be made public in a timely manner.

The WCI has recommended using a WCI central repository implemented by TCR for data storage.

Stakeholder Input

Schedule – Given the decision to launch the cap-and-trade program in 2012, stakeholders supported beginning data collection in 2010 with reporting in 2011. A major trade association noted however, that it would be very difficult to get complex reporting requirements in place in each state and province in that timeframe, particularly for complex source categories like oil and gas production. This stakeholder recommended allowing reporting for 2010 based on best available data.

One commenter was concerned that there would initially be problems dealing with new reporting requirements and therefore supported giving reporters later deadlines for report submission during the first years of the program. A number of stakeholders suggested that reports be submitted 6-8 months after the end of the reporting year. Several commenters supported a single reporting deadline rather than a staggered deadline. Finally, there was support for consistent reporting deadlines across the WCI region and a schedule that would be consistent with the reporting requirements of the TCR and/or other programs.

Other General Requirements – Most commenters favored reporting annually, while one thought that monthly or quarterly reporting would be appropriate to make the trading program more efficient.

Several commenters recommended setting de minimis emissions levels at 3 percent and using the same list of de minimis activities as used in the Title V program. Another commenter recommended 5 percent. One suggested that WCI rely solely on the 3 percent threshold and eliminate the additional maximum threshold of 20,000 metric tons CO_2e that is contained in the CARB rule.

Commenters held a full range of views about where reports should be submitted. One thought the option of reporting to either the TCR or the state/province was appropriate. Another supported direct reporting to the TCR's Climate Registry Information System (CRIS) with no requirement to file separate reports to individual jurisdictions. One commenter suggested that any TCR fees should be borne by the jurisdiction so, ultimately, the use of TCR would be cost neutral to regulated reporters. Finally one commenter felt that compliance would be enhanced if reports were submitted to the appropriate jurisdictions, which would then transfer the information into a regional database.

Reporting Recommendations and Discussion

Schedule for Starting Reporting – Beginning in 2011, facilities, electricity importers and fuel suppliers that commenced operation before January 1, 2010 must report annual emissions, using prescribed quantification methods, for calendar year 2010 and each subsequent calendar year. This start date is widely supported by stakeholders and needed by sources and WCI Partner jurisdictions to prepare for the start of the cap-and-trade program in 2012. These reported data will also help verify emission totals and trends as the program enters its first compliance period and may be used as one of several factors, time permitting, in setting Partner and regional allowance budgets. The WCI Partners recognize the burdens that would be created by multiple, divergent reporting programs, and will encourage national reporting programs in the U.S. and Canada to accommodate the needs of regional cap-and-trade programs that are ahead in the development process.

Reporting and Verification Deadlines - The WCI structured reporting and verification deadlines to provide reporters and verifiers with sufficient time to adjust to new requirements during the initial reporting years before phasing in the more demanding deadlines that will be necessary to provide timely and coordinated information to the public and allowance market participants, and to determine the compliance obligation of reporters subject to the cap-and-trade program.

The deadline for the submission of annual reports is April 1. The reporting date is early in the year so that verification can occur in a timely fashion and, in the case of 2011, at least one year of complete data will be available to prepare sources and WCI Partner jurisdictions for the cap–and-trade program and to verify emission totals and trends as they enter the first compliance period. In addition, verified 2010 data could be used to ensure that allowance allocations during the first compliance period do not exceed the anticipated emissions. Incorporation of this schedule into jurisdictional reporting rules will likely require modification of existing GHG reporting schedules where they already exist.

For reporting years 2010 through 2011, reporters that are subject to verification requirements must complete their verification process, including submittal of a verification statement, by September 1. This deadline provides five months after reports are submitted to allow reporters and verifiers to become accustomed to the process during the early years of mandatory reporting. However, no later than reporting year 2014, verification will need to be completed earlier than September 1. The WCI program design calls for facilities, electricity importers and fuel suppliers that are subject to the cap-and-trade program to surrender allowances by July 1, beginning in 2015, the year after the first 3-year compliance period ends. Deadlines for the 2012 and subsequent reporting years will be determined later as decisions on market functioning are made by WCI.

Early verification deadlines require a different approach in which the reporter and verifier work together throughout the year rather than after reports are developed. This approach can greatly reduce the time lapse between the end of the reporting year and the completion of verification. As an example, the European Union emissions trading program requires completion of the verification process by the end of March, just 3 months after the end of the reporting year.

New facilities that are subject to reporting requirements will begin collecting data during the first month of operation and will report emissions generated from their first month of operation through the end of the first calendar year. For subsequent years they will report on the same basis and schedule as existing facilities.

Regulated facilities and other entities subject to reporting will submit emissions reports to the WCI Partner jurisdiction in which they are located. All WCI Partner jurisdictions must submit the emissions data from their regulated facilities/sources to WCI's regional database for purposes of aggregation and analysis. The Climate Registry will manage WCI's regional database using a modified version of TCR's Climate Registry Information System (CRIS) to support mandatory reporting (CRIS Common Framework). Some WCI Partner jurisdictions may also choose to use the CRIS Common Framework to meet their individual jurisdictional database needs for emission collection, verification, and compliance. Other states and provinces will collect data through their independent reporting systems and databases and then transfer the data to WCI's regional database. Each WCI Partner jurisdiction will specify the format of the emissions report, but these formats will be compatible with eventual consolidation in TCR's CRIS Common Framework.

Reporting facilities may elect to designate as "de minimis" one or more sources or pollutants that collectively account for no more than 3 percent the facility's total CO_2e emissions, but not to exceed 20,000 metric tons CO_2e. Emissions for those sources must be reported, but the facility may use simplified, alternative quantification methods to those otherwise required. If verification of the emissions report is required, the selection of any alternative GHG calculation method is also subject to verification and must provide reasonable assurance that the emissions so designated do not exceed the applicable de minimis limits. Emissions that are calculated by alternative methods must be separately identified in the report.

In order to ensure as accurate and reliable data as possible and protect the integrity of the cap-and-trade program, all facilities and other reporting entities have a number of general administrative obligations in addition to those that are specific to their source category. In preparing their annual emissions report, they must collect emissions and other required data; calculate GHG emissions; and follow the procedures for quality assurance, missing data, and recordkeeping that are specified in the essential requirements for reporting. The facility or other reporting entity is required to prepare and follow a written GHG inventory management plan that ensures that emissions calculations and other information that is required to be reported are transparent, accurate, and independently verifiable. (WCI is considering whether a written plan should be mandatory, or advised in guidance materials as a means of assuring a smooth verification process and a positive verification statement.)

The facility or other reporting entity must also establish, document, implement, and maintain data acquisition and handling activities needed for the calculation and reporting of GHG emissions. Such activities shall include measuring, monitoring, analyzing, recording, processing and calculating the parameters specified in the reporting rule. They must implement systems of internal audit, quality assurance, and quality control for the reporting program and the data reported.

Facilities, electricity importers and fuel suppliers must revise and resubmit an annual GHG emissions report if the initial report is found to contain an error, or accumulation of errors, greater than 5 percent of reported CO_2e emissions. To the extent possible, the revised report must correct all identified errors, identified omissions and misstatements. If the original report was subject to verification, the revision must be completed within 60 days of the finding and the corrected data must also be verified.

For annual reports not subject to verification, the owner or operator shall revise and resubmit an annual GHG emissions report within 30 days of the finding. To the extent possible, the revised report must correct all identified errors. A revised report will be accepted only if approved by the state or province with jurisdiction over the reporter.

Voluntary revisions are also allowed for reporting errors of less than 5 percent, however verification is required if the original report was subject to verification, and the appropriate jurisdiction must approve the change.

The provisions described above apply during the first several years of reporting but will be revisited during the first compliance period. Since verified data is integral to the operation of a cap-and-trade program, any changes to previously verified emissions data will have consequences that must be carefully considered. The most appropriate time to do so is when the architecture and planned operation of the WCI cap-and-trade program is more advanced.

All facilities, electricity importers and fuel suppliers that are subject to mandatory reporting shall maintain documentation needed to support any revisions made to a previously submitted emissions data report for 7 years.

The measurement of fuel use is so central to the consistent and accurate reporting of all combustion emissions that it is important to have a WCI-wide standard for measurement accuracy for any situation in which a continuous emissions monitoring system (CEMS) is not in use. In these situations, facilities and other reporting entities shall use procedures to quantify fuel use (mass or volume flow) that provide data accuracy within ±5 percent. All fuel use measurement devices shall be maintained and calibrated in a manner and at a frequency required to maintain this level of accuracy. Facilities shall conduct belt or conveyor scale calibrations at least quarterly to validate fuel consumption estimates of solid fuels. The facility will maintain for seven years the documentation that allows the above level of accuracy to be independently verified.

Ongoing Work

When the architecture and planned operation of the WCI cap-and-trade program is more advanced the WCI will revisit the schedule and process for report revisions. In addition, a provision will be considered that would allow reporters that are not subject to emissions limitations, and that reduce their emissions below 25,000 metric tons of CO_2e, to cease verification after some period of time.

The WCI and TCR will work closely in 2009 to identify the system requirements necessary to design and implement the regional database for reporting so the reporting mechanism is important for WCI to continue to move forward ready for the first year of reporting in 2010.

Also, the WCI Reporting Committee will coordinate closely with the WCI Market Operations and Oversight Committee to ensure a smooth flow between the emissions reporting database and the development and implementation of the allowance tracking and offsets tracking systems.

Contents of the Greenhouse Gas Emissions Report (§ WCI.3)

This section describes the general information that must be included in every emissions report, regardless of source category.

Relevant Scope and Design Recommendations

The WCI agreed to establish the essential requirements for reporting by all facilities and other entities required to report in each of the WCI Partner jurisdictions.

Stakeholder Input

In general, stakeholders want a reporting system that is fair, easy to manage, and not costly to implement for either reporters or jurisdictions. Commenters generally support a single WCI reporting rule, citing the advantages of administrative simplicity and cost effectiveness. Stakeholders also expressed concern that a lack of consistency would undermine confidence in the use of reported data in a market system. There were a number of comments supporting the concept that WCI reporting requirements should be identical or equivalent to the forthcoming U.S. EPA and Environment Canada mandatory GHG reporting regulations.

Reporting Recommendations and Discussion

To improve reporting consistency and facilitate data management throughout the WCI region, the following information is required for each report submitted by a facility, electricity importer and fuel supplier. This includes basic information that is in addition to data and information identified in the source category-specific requirements contained in the reporting rule.

- Name of facility or other reporting entity, including identification number, physical address, mailing address and NAICS code,
- Reporting year,
- Date of report submittal,
- Total emissions aggregated from all applicable sources expressed in metric tons of CO_2e, excluding CO_2 that is captured and CO_2 emissions from the combustion of biomass fuels, which are reported separately,
- Total emissions of CO_2e from the combustion of biomass and biomass-derived fuels,
- Total annual mass of CO_2 captured for on-site use, on-site storage, or transfer off site, in metric tons,
- For applicable fuel supplier categories identified as Essential Requirements for transportation fuels combustion and residential, commercial and industrial fuels combustion, total estimated end-user CO_2e emissions aggregated from all specified fuel,
- Emissions from each applicable source category or fuel supplier category in subparts WCI.20 through WCI.XX, expressed in metric tons per year of CO_2, CH_4, N_2O, HFC, PFC, and SF_6. CO_2 emissions from the combustion of biomass and biomass-derived fuels shall be reported separately,
- For electricity importers, information required in the Essential Requirements section for this source category,
- Emissions and other data for individual units, processes, activities, and operations as specified for each source category covered in the Essential Requirements,
- Emissions from each designated de minimis source or pollutant for which an alternative emission calculation method is used,
- Name and contact information including email address and telephone number of the person primarily responsible for preparing and submitting the emissions report, and

- A signed and dated statement provided by the owner or operator, or their designated representative, certifying that the report has been prepared in accordance with this rule, and that, subject to verification, the statements and information contained in the emissions data report are to the best of their knowledge, true, accurate, and complete.

Any state or province may request additional information beyond that specified above.

Ongoing Work

As noted above, WCI is considering a provision for discontinuation of the verification requirement for sources that are not subject to an emissions limitation and that reduce emissions below the 25,000 metric tons for a sufficient number of years.

WCI will review and address any further stakeholder comments.

Document Retention and Record Keeping Requirements (§ WCI.4)

This section describes which records must be kept by each reporting entity and for how long. The purpose of recordkeeping is to ensure that reporting entities retain enough information on hand to support their emissions calculations. For those facilities subject to verification requirements, retention and record keeping requirements provide the information needed to allow verifiers to confirm their emissions reports. In addition, retained data allow internal or independent reviewers or auditors to evaluate, and if necessary, reconstruct or correct, past emissions reports. Existing reporting systems call for such records to be retained for 3-10 years depending on the jurisdiction.

Relevant Design Recommendations

WCI Partner jurisdictions will establish the essential requirements for reporting by all entities and facilities required to report in each of the WCI Partner jurisdictions.

Stakeholder Input

There were few comments directly addressing retention time and recordkeeping, but there is a general level of support for consistency across the WCI region and with other reporting systems. One commenter advocated maintaining all records indefinitely until the reporting system is running effectively.

Reporting Recommendations and Discussion

Facilities and other reporting entities must establish and maintain procedures for document retention and recordkeeping. They must retain all documents regarding the design, development and maintenance of the emissions inventory in paper, electronic or other usable format for a period of not less than seven years following submission of each emissions data report. This is longer than some other programs require because of the three-year length of compliance periods for the WCI cap-and-trade program. They must be able to produce all documents and data they are required to retain upon request within 10 working days. In general the retained documents and data shall be sufficient to allow for the verification of each emissions data report.

The following information must be retained in addition to information submitted as part of the emissions data report, for at least seven years.

- A list of all GHG sources (i.e., units, operations, processes, and activities) included in the emission estimates,
- All data used to calculate emissions for each source and gas, categorized by process and fuel or material type,
- Documentation of the process for collecting emissions data,
- Any GHG emissions calculations and methods used,
- All emission factors used for emission estimates, including documentation for any factors not provided in the rule,
- All input data used for emission estimates,
- Documentation of biomass fractions for specific fuels,
- All other data submitted under this rule, including the GHG emissions report,
- All computations made to gap-fill missing data,
- Names and documentation of key facility personnel involved in emissions calculating and reporting,
- Any other information that is required for the verification of the GHG emissions report,
- A log to be prepared for each reporting year, beginning January 1, documenting all procedural changes made in GHG accounting methods and changes to instrumentation for GHG emissions estimation, and
- A copy of the GHG Inventory Management Plan.

For quantification methodologies based on direct measurement of emissions, the following information must be retained for at least seven years after the submission of the emissions data report.

- List of all emission points monitored,
- Collected monitoring data,
- Quality assurance and quality control information collected under the GHG Inventory Management Plan required by the Essential Requirements,
- A detailed technical description of the continuous measurement system, including documentation of any findings and approvals by federal, state or local agencies,
- Raw and aggregated data from the continuous measurement system,
- A log book showing all system down-times, calibrations, servicing, and maintenance of the continuous measurement system, and
- Documentation of any changes in the continuous measurement system over time.

The Essential Requirements for quantification methods may also include some source category-specific record retention requirements.

Ongoing Work

WCI will review and address any further stakeholder comments.

Confidentiality

The challenge in dealing with public access to reported data is to strike an appropriate balance between revealing information that is important to the public interest while protecting information that if disclosed would harm the reporting entity. In general, air emissions data that are collected by public agencies are not considered confidential – in fact, transparent emissions data are essential to the successful operation of a cap-and-trade program. Nevertheless, in some cases the operational and technical information that is used to calculate emissions is sensitive and could reveal trade secrets or other facts that are damaging to the reporting entity's competitive position.

WCI Partner jurisdictions have existing laws and procedures to address the issues associated with balancing public and private interests. They generally provide for public disclosure of information that is submitted to government agencies, but allow for reporting entities to assert a claim of confidentiality on a case-by-case basis and seek to prevent disclosure of trade secrets or other confidential business information. Laws usually provide guidance or criteria that the appropriate agency must consider in evaluating confidentiality claims.

Relevant Design Recommendations

While WCI design recommendations do not directly address the balance between disclosure and confidentiality, they do prescribe the disclosure of emissions information to ensure transparency, maintain public confidence and allow the market to function properly. The WCI calls for making public in a timely manner certain data from the emissions reports, allowances, and offsets that are used for compliance. Moreover the design recommendations call for each jurisdiction to make its data available for other jurisdiction's review and consideration for possible expansion of the cap-and-trade program.

Stakeholder Input

Stakeholders have offered a range of comments with some favoring a narrow construction of confidentiality to protect the public's right to know, and others favoring a broader construction that would better protect sensitive operational information from competitors. Some have offered specific recommendations as to what types of data and information should be considered confidential, suggesting that production rates, breakouts of fuels used, process level emissions and similar information be considered confidential. There are conflicting views on who should make decisions on confidentiality, with some favoring the individual WCI Partner jurisdictions while others felt that the prospect of having to follow separate rules in each WCI Partner jurisdiction was a concern. One commenter noted that third party verification gives assurance to the public that reported emissions information is accurate without the need to reveal sensitive business information or trade secrets.

Reporting Recommendations and Discussion

In general, emissions data submitted to any WCI Partner jurisdiction under the reporting rule are public information and shall not be designated as confidential. Each state or province shall address claims of confidentiality, for information that is not emissions data, from reporting entities in their jurisdictions under that jurisdiction's laws and procedures. Therefore, confidentiality is not addressed further in the Essential Requirements.

Embargoing of emissions data until a specified public release date may be needed for proper functioning of the allowance market. This issue will be addressed later, as decisions are made on the details of market operation.

Ongoing Work

WCI will review and address any further stakeholder comments.

Compliance and Enforcement (§ WCI.5)

Mandatory reporting programs are weakened if a facility, electricity importer or fuel supplier fails to submit a report by the required deadline, submits incomplete information, fails to address missing or incorrect data, doesn't retain records as required by the rule, or intentionally submits false or misleading information. Compliance, for purposes of this discussion means the degree to which facilities and other reporting entities submit timely, complete and accurate reports. Enforcement refers to the action taken in response to a violation or non-compliance situation.

A clear definition of what actions or inactions are considered a violation not only serves notice to those subject to a regulatory requirement but it is typically considered a prerequisite to taking any enforcement action. If violations are defined consistently by WCI Partner jurisdictions, there is a better basis for members to exercise their enforcement prerogatives in an even-handed manner. Reporting violations will be defined within the Essential Requirements for reporting.

Relevant Design Recommendations

The WCI Partners' consideration of compliance and enforcement issues focused on facilities subject to cap-and-trade obligations and did not specifically address reporting compliance and enforcement.

Stakeholder Input

Few stakeholders commented on compliance or enforcement issues. One favored third-party verification and argued that verification is an important means of bolstering compliance by ensuring the accuracy of reported data. Several commenters also saw appropriate models in the

California approach, which combines verification with strong penalties, and the U.S. Acid Rain program in which traditional enforcement is minimized because of a reporting regime that includes incentives, stringent missing data provisions and automatic penalties and that serve as an incentive to complete and accurate reporting. One commenter noted that while jurisdictions must ultimately enforce the reporting rule in keeping with their own legislation, the rules of reporting should be consistently enforced across all jurisdictions. They recommended two triggers for a violation of the reporting rule, the failure to file completed emissions information as required and the failure to file by the reporting deadline.

Reporting Recommendations and Discussion

While the WCI does not see a need to achieve complete uniformity in how each WCP Partner jurisdiction reacts to reporting violations in terms of levying fines or imposing other penalties, it is important that the Essential Requirements for reporting contain a consistent definition of which acts constitute violations of the reporting rule.

It is a violation to knowingly submit false information to a state or province, or to a verification body. It is also a violation to fail to:

- Submit any report (GHG emissions data report, verification opinion, or other document) required to be submitted,
- Collect data needed to calculate GHG emissions,
- Monitor and test as required,
- Calculate GHG emissions following the methodologies specified in this rule,
- Retain required records, provide all information required in the report, and
- Submit a report on time.

Each violation of this rule shall be considered a single, separate violation for each day beyond the specified reporting date.

There are also a number of other mechanisms to encourage compliance and consistent enforcement practices that are addressed in various sections of the Essential Requirements. For example, third party verification, which serves as a key compliance assurance tool for both the overall cap-and-trade program and mandatory reporting, is addressed in some detail. The Essential Requirements for reporting also contain provisions for records retention and making report revisions.

Ongoing Work

The WCI will continue to consider whether to develop additional guidelines to promote consistent administrative practices and responses to non-compliance issues among its jurisdictions.

Designated Representative (§ WCI.7)

To ensure accountability and facilitate communication, a designated individual must be responsible for certifying and submitting GHG emissions reports. Because of the legal implications, the WCI considers detailed and consistent requirements across WCI Partner jurisdictions to be Essential Requirements.

Relevant Design Recommendations

There are no design recommendations specific to the responsibility for submitting reports.

Stakeholder Input

This is a new section in this version of the Essential Requirements, thus no comments have yet been received from stakeholders.

Reporting Recommendations and Discussion

The designated representative of the facility, electricity importer or fuel supplier shall be selected and identified in writing by an agreement that is signed by the designated representative and owners or operators of the facility or other reporting entity. The designated representative must be an individual that has responsibility for the overall operation of the facility or activity being reported, a position of equivalent responsibility, or an individual having overall responsibility for environmental matters for the company. The responsibilities of a designated representative are:

- To represent, and by any representations, actions, inactions, or submissions, legally bind each owner and operator in all matters pertaining to these Essential Requirements, and
- Sign each emission report submitted under these Essential Requirements. The signature statement must include the following certification statement or its

> equivalent: "I have been authorized to make this submission on behalf of the owners and operators of the facility (importer or supply operation, as appropriate). I certify under penalty of law that I have personally examined the information submitted in this document. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

The designated representative may be changed at any time but all prior representations, actions, inactions, and submissions by the previous designated representative are binding on the new designated representative and the facility owners and operators. In the event of any change in ownership of the facility, electricity importer or fuel supplier, the new owner or operator remains bound by the representations, actions, inactions, and submissions of the designated representative until the designated representative is changed.

A complete certificate of representation containing the following information must be kept on site at the facility:

- Identification of the facility (importer or supply operation) for which the certificate of representation is submitted,
- The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the designated representative,
- A list of the owners and operators of the facility (importer or supply operation),
- Certification statements that the actions of the designated representative with respect to this rule are binding on the owners and operators, and that the designated representative has the necessary authority to carry out duties and responsibilities on behalf of the owners and operators, and
- The signature of the designated representative and owner(s) and the dates signed.

Ongoing Work

WCI will review and address any further stakeholder comments.

Requirements for Verification of Emissions Data Reports (§ WCI.8)

This essential requirement addresses how reported information will be verified against international standards for GHG emissions data. ISO 14064-3[4] and ISO 14065[5] are international standards for greenhouse gas verification and accreditation, respectively. In an effort to promote international consistency of greenhouse gas reporting and verification, many reporting and market programs, including TCR, have based their verification programs on these standards. The key subject areas are accreditation of verifiers, core verification services, and conflict of interest requirements. The WCI verification requirements will also ensure an enforceable verification program with direct oversight. Although the development of the WCI verification program is not complete, a number of recommendations pertain to the foundation of the program and its implementation; these are described below.

Relevant Design Recommendations

WCI Partner jurisdictions will require third party verification of reported emissions from entities and facilities that will be included under the cap.

Stakeholder Input

Third party verification remains a significant issue to stakeholders. Most commenters on this topic were from industry, and most opposed it, arguing that the use of defined protocols, self-certification, and opportunity for agency audit should be sufficient to encourage accurate reporting. One commenter with experience with third-party verification argued that the actual inaccuracies identified were too small to be material. Some commenters objected to the cost, which one industry trade group estimated at $10,000 per facility per year.

A number of commenters suggested ways to reduce the cost of verification. Several supported a multiple year verification cycle as outlined in CARB regulations, with the first year of "full verification", and less intensive verification activities in the remaining years. Some

[4] ISO (2006) ISO 14064-3: Greenhouse Gases-Part 3: Specification with guidance for the validation and verification of greenhouse gas assertions, March, 2006, International Organization for Standardization, Switzerland.

[5] ISO (2007) ISO 14065: Greenhouse Gases-Requirements for greenhouse gas validation and verification bodies for use in accreditation or other forms of recognition, April, 2007. International Organization for Standardization, Switzerland.

recommended exemptions, such as combustion units with certified continuous emissions monitors (CEMs), facilities with existing Title V permits, or sources not selling credits.

A few commenters indicated support for verification and advocated a standardized approach to verification across the WCI region to protect the integrity of the market.

Reporting Recommendations and Discussion

Comprehensive mandatory and accurate reporting is especially important to a cap-and-trade program because of its focus on actual emissions performance and emission allowance trading. The WCI Partner jurisdictions have considered the advantages and disadvantages of third-party verification and jurisdictional audit and quality assurance. The WCI Partner jurisdictions note that in a cap-and-trade program, every metric ton of emissions translates into a financial obligation or benefit, whereas in existing air pollutant reporting and compliance, errors in emissions data can be inconsequential if they do not affect whether a compliance limit has been exceeded. For those facilities and entities with cap-and-trade compliance obligations (i.e., required to hold allowances), there are no inconsequential emissions totals. A high degree of accuracy and reliability for this emissions data is needed for market transparency and credibility, as well as for potential linkage to other emissions trading programs.

The goals of the WCI verification program are to root the program in international standards and best practices, to ensure high quality data, and to promote consistency across similar mandatory greenhouse gas reporting and cap-and-trade programs. The recommendations are drawn from international standards (ISO 14064-3 and ISO 14065) and other verification programs.

The recommendations listed below are divided into those intended to support the immediate needs of a credible WCI mandatory reporting program, and those that support the development of the overall verification program. Once the rules of a market have been developed, some parts of the verification requirements will need to be revised.

<u>Recommendations Directly Related to Reporting</u>

Applicability of Verification Requirements - Third party verification of reported emissions is required from all facilities and other entities with emissions of 25,000 metric tons per year or more, and any others that are covered under the cap. If, as discussed earlier, WCI establishes a limited deduction of biomass combustion emissions for purposes of determining the reporting threshold, WCI will also consider whether the deduction should affect the verification threshold.

Materiality threshold – The threshold is five percent, applied at the facility or other designated level of reporting.

Data adjustment – All misstatements in an emissions data report must be corrected if uncovered during the course of verification, even if they do not affect materiality.

Level of assurance – The WCI will require that verification bodies provide a reasonable level of assurance of reported emissions; i.e., based on the verification activities conducted (ISO 14064-3, Section A.2.3.2), the emissions data report is materially correct and was prepared according to the appropriate standard.

Verification document retention – Records and documents must be retained for seven years.

Recommendations Related to Verification Program Development

In 2009, WCI will develop the implementation structure to support third party verification. Pending these decisions, the following discussion simply refers to the implementing body as the WCI Partner jurisdiction "or their designee," which may be a regional organization. Note that the WCI is considering the formation of a Regional Body for purposes of implementation and ongoing operation of the reporting and cap-and-trade programs. A WCI Regional Body may have responsibility for implementing several reporting verification items, such as providing Conflict of Interest determinations, reporter-verifier dispute resolution, etc.

Verification cycle – During the first year (Year 1) of the verification cycle, a verification body must conduct a comprehensive verification that includes visits to the reporter's facilities at which direct emissions occur. Verification Years 2 and 3 permit a less intensive verification with data checks based on the last sampling plan that resulted in a positive verification opinion.

Enforcement and Compliance – Each WCI partner will have the responsibility for ensuring compliance with verification requirements in their jurisdiction.

Accreditation of verifiers – WCI will implement an accreditation process consistent with ISO 14065 developed under ISO 17011, and will also require verifiers to demonstrate knowledge of WCI reporting requirements. WCI will require "specialist" accreditations in order to verify emission reports for electricity importers, petroleum refineries, hydrogen production, cement, and possibly other sources categories to be determined.

Common standard – Verifications will be conducted according to ISO 14064-3.

Verification statement – WCI Partner jurisdictions will require a standard verification statement throughout the WCI region that allows verification bodies to provide comments and supplemental information.

Verification report – Verification bodies must develop and provide a detailed report that includes a verification plan, data checks, and a log of problems encountered during the verification process and how they were resolved. The report will be made available to a WCI Partner jurisdiction or its designee.

Sampling plan – To assess the likely nature, scale and complexity of verification services the verification body shall develop a sampling plan for each reporter. The plan will be based on a strategic analysis developed from document reviews and interviews. The analysis shall review the inputs for submitted emissions data, the rigor and appropriateness of the data management systems, and the coordination that is employed to manage the operation and maintenance of the equipment and systems used to develop emissions data reports. The plan must identify which areas of the emissions data report should undergo data checks. The sampling plan will be retained by the verification body and made available to the WCI Partner jurisdiction or its designee upon request.

Notice of verification services – WCI Partner jurisdictions may elect to attend selected verification meetings and site visits. To facilitate their attendance, verifiers must notify the jurisdiction or their designee at least 15 working days prior to commencement of any proposed verification services for facilities within the jurisdiction, and receive notification from the WCI jurisdiction of approval for commencement of verification services.

Conflict of interest – Before verification may proceed, a verification body must perform a conflict of interest self-assessment and provide it for the approval of the jurisdiction or its designee. This self-assessment must take place for each verification body-reporter relationship for every year that the verification body provides services.

Report of dismissal - All facilities, electricity importers, fuel suppliers and verifiers will report to the jurisdiction or their designee when a verifier has been dismissed by a facility, and the reasons for the dismissal. This information will be kept confidential to protect the interests of both parties.

Ongoing Work

The WCI will consider whether it is appropriate to structure verification requirements in a cycle during which more intensive “full verification” will occur the first year of reporting and less intensive verification is allowed in subsequent years.

Although not part of the Essential Requirements for reporting, the following additional work by the WCI is necessary for implementation of the verification system.

In 2009, the WCI will complete the design of the process for accreditation of verifiers. The WCI will specify an accreditation cycle, including frequency of surveillance audits and re-accreditation. The WCI will develop a process for revoking accreditation of any verification body found to be incompetent. Beyond the requirements of ISO 14065, the WCI will determine any additional competencies or requirements for subcontractors, verification bodies, or individual verifiers for use in the WCI program. The WCI will specify if there is any required training for individual verifiers.

The WCI will complete and make available a standardized verification statement that allows verification bodies to provide comments and supplemental information. The WCI will coordinate with other GHG programs to explore the potential for developing a universal verification statement.

The WCI will decide whether to establish a Reporting and Verification Panel, perhaps as a component of the Regional Body, to foster standardization in key elements of implementing the WCI verification program. The panel would be comprised of representatives from each of the WCI Partner jurisdictions. An alternative to creating a WCI Panel could be for WCI to contract elements of verification program administration to a third party, such as TCR. If a WCI Reporting and Verification Panel is formed one of its assignments would be adoption of a unified plan to conduct surveillance audits to ensure that all WCI Partner jurisdictions have a similar level of oversight and that the audits are carried out on a standardized basis. A central panel or designee could administer consistent audits across the WCI Partner jurisdictions, or the partners could agree to an audit plan developed and approved by all of the partners. The partners would have to adhere to the level of oversight laid out in the plan, acknowledging that the plan may go beyond auditing plans for existing air programs since it would need to support a market program. The Reporting and Verification Panel may also play a role in reviewing complaints submitted to the verification body, a jurisdiction or the WCI, in ensuring consistency in evaluating individual cases of conflict of interest, and in processing notices that verification services are about to begin. Many of these activities would reduce the administrative burden on WCI Partner jurisdictions.

The WCI will develop and make available a standardized appeals process to handle a situation in which the verification body and reporter have a dispute over an emissions report. Standardization of the appeals process is paramount for ensuring consistency across the WCI Partner jurisdictions.

A policy will be developed to address facts discovered after the verification statement has been issued that could materially affect the verification outcome. Any revisions are subject to third-party verification.

Definitions (§ WCI.9)

This essential requirement contains clear and appropriately detailed definitions of key terms used in the monitoring and reporting rule. The WCI has borrowed definitions from other jurisdictions' mandatory GHG reporting rules and relevant GHG protocols whenever appropriate. In addition to their direct regulatory application, definitions facilitate communications among WCI Partner jurisdictions and stakeholders by defining common terminology used throughout the reporting program.

This section contains a partial list of the definitions that will be used in the Essential Requirements, with a focus on terms that are important to understanding general reporting requirements. In addition, definitions of terms that are specific to individual source categories are provided in the rule sections that contain those reporting requirements.

Relevant Design Recommendations

There were no recommendations specific to Definitions.

Stakeholder Input

There were limited stakeholder comments on definitions. Several commenters supported the approach of using definitions from existing reporting programs as a starting point in order to ensure as much consistency as possible among various reporting rules. One commenter specifically advocated using definitions from the U.S. EPA mandatory reporting rule that is under development. Several stakeholders proposed the addition of specific definitions, including "process emissions", "fugitive emissions", and a number of terms associated with natural gas production and distribution. One commenter noted that natural gas pipeline facilities would not fit well under the general definition of a facility and urged the use of definitions contained in the Canadian Environmental Protection Act.

Reporting Recommendations and Discussion

The Essential Requirements for reporting provide definitions that are necessary to understanding specific reporting requirements and generally avoid definitions that are not essential. For example, terms that are used in their common English context (e.g., fence line, unit) or that explain acronyms or chemical formulae are not specifically defined. Definitions are listed in the Essential Requirements and are not repeated here. Additional definitions are under development based on the Canadian regulations from "Section 71 of the Canadian Environmental Protection Act (CEPA) 1999"and the CARB definitions from "Title 17, Subchapter 10, Article 2, Section 95102 of the California Code of Regulations.

Ongoing Work

Definitions are continuing to be developed.

Pollutants and Global Warming Potentials (§ WCI.10)

This section addresses the greenhouse gas pollutants that must be reported and their 100-year global warming potential (GWP) factors. The GWP is used to convert emissions of a greenhouse gas to metric tons of carbon dioxide equivalent (CO_2e). The technical definition of the GWP of a greenhouse gas is the ratio of the time-integrated radiative forcing from the instantaneous release of 1 kilogram (kg) of a trace substance relative to that of 1 kg of a reference gas, which is CO_2.

Relevant Design Recommendations

The greenhouse gases covered by the cap-and-trade program are carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. Both the annual emissions threshold for a compliance obligation and the threshold for reporting are stated in terms of metric tons of carbon dioxide equivalents (CO_2e) annually.

Stakeholder Input

Nearly all comments addressing GWP values recommended using the values used by the Intergovernmental Panel on Climate Change (IPCC), and some specified use of the 1995 IPCC Second Assessment Report values. None recommended use of other values.

Reporting Recommendations and Discussion

Reporting entities must use the GWP factors provided in Table WCI.10-1 of the Essential Requirements when converting emissions of greenhouse gases to metric tons of carbon dioxide equivalent values (CO_2e) for purposes of estimating emissions under the rule. These factors are the same as those used regionally and internationally and are based on the IPCC Second Assessment Report, 1995, updated to add new greenhouse gases identified in the IPCC Third Assessment Report, 2001. The table is the same as contained in the TCR General Reporting Protocol, Version 1.1, May 2008. Hydrofluorocarbons and perfluorocarbons are families of pollutants, and individual compounds within the families have different GWP factors.

Ongoing Work

In the future, the WCI will establish a mechanism for periodically updating GWP factors as the international community adopts more recent GWP values as standard practice (e.g., when reporting under the United Nations Framework Convention on Climate Change [UNFCCC]).

Emissions Quantification, and Sampling, Analysis, and Measurement (§ WCI.20 through § WCI.XX)

These sections contain source-category specific GHG emissions quantification methods, and sampling, analysis and measurement requirements.

Relevant Design Recommendations

The WCI design recommendations specify that only emission sources with adequate quantification methods will be included in the cap-and-trade program.

Stakeholder Input

Stakeholders held a variety of concerns about quantification methods and their use for reporting.

Some commenters pointed out problems or uncertainties associated with specific sources of emissions. For example one natural gas producer felt that existing methods of quantifying fugitive methane emissions from the gas industry had significant uncertainties that, unless addressed, could undermine the integrity of the cap- and-trade program. A solid waste manager noted a number of problems with current methods of quantifying landfill emissions, including a poor understanding of the variability among individual landfills and an incomplete understanding of lifecycle emissions including emission sinks. Another commenter stressed the importance of improving systems and protocols for tracking energy and carbon flows within the Western region electrical grid.

A number of stakeholders advocated the use of specific quantification protocols for their industries. For example a forestry association suggested the use of parametric estimation tools specifically developed for pulp and paper mills and sawmills and the Canadian Cement Association advocated the use of the CSI Cement CO_2 Protocol, as is proposed under the Climate Registry. One commenter specifically advocated the use of ASTM D6866 'Standard Test Methods for Determining the Biobased Content of Natural Range Materials Using Radiocarbon and Isotope Ratio Mass Spectrometry Analysis' for the measurement and verification of biogenic/biomass CO_2. The National Lime Association raised concern that the protocol that had been developed for its members by TCR would underestimate emissions and advocated the use of one they had developed instead.

Several commenters suggested additional process solutions to address problems and uncertainties. Several advocated the formation of special working groups or task forces that included industry experts, and/or the use of extended comment periods, to help the WCI develop and refine more accurate and appropriate quantification protocols. One commenter thought that the WCI reporting framework represented a significant opportunity to improve the existing capabilities to track and measure the quantities and life-cycle impacts of unconventional fuels. Some held the view that methods development could be regional effort within the WCI region while others suggested it ought to be done nationally or internationally to ensure maximum consistency. It was noted that some of the methods gathered by such reporting entities as TCR and the California Climate Action Registry (CCAR) were mainly efforts to compile existing methodologies rather than improve their accuracy to the level needed for a cap-and-trade program. In some cases a large, multi-year effort would be needed involving field tests, sampling and statistical analysis to improve methods appropriately.

Some commenters urged flexibility arguing that the WCI should not mandate the use of CEMs if alternative calculation methodologies were available to facilities and if the accuracy of alternate methods could be controlled by a materiality threshold.

One commenter suggested leaving sources of non-combustion emissions with uncertain quantification methods out of the mandatory reporting and cap-and-trade program initially, while allowing them to be used as offsets provided the proponents develop sufficiently robust methods of quantifying emissions. With the offset incentive in place, better quantification methods would be developed without expending significant state or federal funds while the integrity of cap-and-trade would be protected.

Reporting Recommendations and Discussion

To ensure that the design recommendation of including only source categories with "adequate" emission quantification methods is comprehensively implemented, the WCI assessed the adequacy of available methods for nearly all of the source categories initially identified by the WCI as having potential for inclusion in the cap-and-trade program. (Some source category quantification methods were assessed and documented in rule-like language, while others were researched and documented in a plain-English recommendation format; see below.) Without extensive analysis, however, it is not possible to determine absolute levels of accuracy (e.g., ± %) for every method, as these data are not universally available.

Therefore, for some source categories we identified the relative accuracy of available methods and recommended the methods with the greatest accuracy, with some allowances for less accurate methods. For example, methods that rely on emission factors are recommended for estimating CH_4 and N_2O emissions from stationary combustion sources, although these emission factors are relatively inaccurate as compared to the CO_2 emission factors for the same sources. The WCI considers these CH_4 and N_2O emissions factors to be adequate for purposes of reporting because CH_4 and N_2O emissions are relatively insignificant as compared to CO_2 emissions from these sources, and we are striving to be comprehensive in our requirements to address all GHGs as required by the design recommendations. However, for some categories of non-combustion emission sources (e.g., CH_4 from landfills), we determined that the existing methods are simply too inaccurate and biased at the facility level to justify including them in the reporting program at this time, when these emissions comprise a large fraction of the facility's total emissions. For these and other categories, we will conduct research and continue to request input from and work with stakeholders and industries to identify, and possibly develop, accurate methods for source categories that may be excluded from reporting and/or the cap-and-trade program in the first few years.

Table 2 lists the source categories initially identified by the WCI for reporting and potential inclusion in the cap-and-trade program and some additional source categories identified by the WCI along with our current assessment of the adequacy of available quantification and monitoring methods. Where adequate methods have been identified, specific GHG emission estimation and monitoring method recommendations are provided in attachments to this background document.

Some of the recommended estimation methods, including descriptions of the source category applicability, reporting requirements, and monitoring (e.g., fuel sampling, fuel consumption, fuel heat content, and fuel carbon content) requirements, are provided in "rule like" language. Most of these source category requirements were based on the CARB mandatory reporting rule and modified to fit the WCI requirements. Estimation methods for other source

Table 2. WCI Source Categories and Status of GHG Emission Quantification and Monitoring Methods

Source Category	*Status of Quantification Method Assessment*			*Comments*
	Recommended in Reporting ERs	***Inadequate at this Time***	***Analysis On-Going***	
Stationary Combustion Sources				
Electricity Generation	●			
Cogeneration				*Draft method pending review by WCI*
Electricity Importers (retail providers, marketers)			●	*Being developed by WCI Electricity Subcommittee*
General Stationary Combustion: Fossil and biomass fuel combustion in equipment	●			
Fuel Suppliers: Transportation fuels			●	*To be addressed in 2009*
Fuel Suppliers: Residential, commercial, industrial (RCI) fuels			●	
Petroleum refineries	●			
Refinery fuel gas combustion	●			
Noncombustion Emissions (Combustion Emissions for these and other Sources are Included in Stationary Combustion Sources, Above)				
Oil and gas production & gas processing			●	*Being developed by WRAP/TCR*
Natural gas distribution systems			●	*Being developed by CCAR/TCR*
Carbon dioxide transfers			●	*To be addressed in 2009*
Cement manufacturing	●			
Hydrogen production	●			
Lime manufacturing	●			
Glass production and other uses of carbonates			●	*Method drafted, pending review by WCI*
Soda ash manufacturing			●	
Aluminum manufacturing	●			
Ferroalloy production			●	*Method drafted, pending review by WCI*
Zinc production	●			
Lead production	●			
Pulp and paper manufacturing	●			
Iron and steel manufacturing	●			
Electronics manufacturing			●	*Method drafted, pending review by WCI*
Petrochemical production			●	
HCFC-22 production			●	*Method dratted, pending review by WCI*
Adipic acid manufacturing			●	
Ammonia manufacturing			●	
Magnesium production				*To be addressed in 2009*
Nitric acid manufacturing				
Phosphoric acid production				
SF_6 from electrical equipment			●	*Method drafted, pending review by WCI*
Coal storage	●			
Coal mines (fugitives, active and abandoned)	●			
Nonroad equipment			●	*Method drafted, pending review by WCI*
Landfills		●		
Industrial wastewater			●	
Municipal wastewater		●		

categories not contained in the CARB rule are provided in a narrative format; based on final input from the stakeholders, these will be adopted by the WCI Partner jurisdictions using their appropriate rulemaking requirements. These methods are based on a current review of emission estimation protocols used by voluntary and mandatory programs (e.g., TCR, CCAR, IPCC, EU ETS), as well as methods used by industry groups such as National Lime Association.

It is important to note that although a quantification method is recommended for a given combustion or non-combustion source category, this applies strictly to reporting and does not indicate whether or not a given source category will be under the cap. These quantification recommendations apply strictly to reporting at this time.

In addition to bracketed comments and notes within the individual sections, the following provides clarification and requests stakeholder input related to specific technical details of the GHG emissions quantification and monitoring methods:

- Electric generating units (EGUs): The Canadian Partners acknowledge the potential need to address reporting requirements related to some Canadian off-grid EGUs located in remote areas.
- Metric and English units: For many source categories, the recommended quantification methods currently use English units only, because the sources of equations and/or emission factors using these methods were available in English units and/or take English unit inputs. In the future, these will be provided in both English and metric units. The WCI requests stakeholder input on the specific metric unit inputs and/or emission factors to use (e.g., liters or cubic meters). Table 3 lists, by source category, the emission equation input parameter and current unit(s) of measure in English units. Stakeholder can use this table to provide preferred metric units.
- Sampling, Analysis and Measurement: Where methods for quantifying emissions from industrial processes rely on measurement and/or characterization of input materials, the Essential Requirements will specify the sampling, analytical, and measurement procedures for obtaining these values. The sampling, analysis and measurement procedures must be standardized for each calculation input to reduce variation between facilities within a given industry. Note that material sampling frequency and technique is distinct from the method of material analysis conducted in a laboratory.

  The WCI seeks stakeholder feedback on this topic and is specifically interested in proposals for sampling, analysis and measurement procedures already in use at facilities for the material quantities and concentrations listed in Table 4, below. Those proposed procedures should include sampling frequency and technique, indicate the uncertainty associated with the procedures, and describe the application of the procedure at the specified industry.

Table 3. Emission Estimation Input Parameters and Units of Measure

Source Category	Input Parameter	Current Units of Measure	Stakeholder Preferred Metric Units
General combustion	carbon content of liquid fuel	kg/gallon	
	carbon content of MSW	kg/MMBtu	
	CO_2, CH_4, and N_2O emission factor	kg/MMBtu	
	higher heating value of coal	MMBtu/ ton	
	higher heating value of gas	Btu/standard cubic foot (scf)	
	higher heating value of liquid fuel	MMBtu/barrel	
	mass of steam	lb	
	ratio of boiler max rated heat input capacity to design rated steam output capacity	MMBtu/lb	
	volume of gaseous fuel combusted	scf	
	volume of liquid fuel combusted	gallons	
Electric generation	default fugitive CO_2 emission factor for geothermal facilities	kg/MMBtu	
	heat taken from geothermal steam and/or fluid	MMBtu/year	
Refineries	molar volume conversion factor	scf/kg-mol	
	gas concentration	ppm	
	daily average coke burn rate	lb/day	
	emission factor	scf/10^3 bbl	
	mass of asphalt blown	10^3 bbl/year	
	mass of catalyst regenerated	mass/regeneration cycle	
	coke burn rate material balance and conversion factors (Table 200-1)	(kg-min)/(hr-dscm-%) <u>or</u> (lb-min/hr-dscf-%)	
	vent rate for venting event	scf/ unit time	
	volumetric flow rate of gas	dscm/min or dscf/min	
Refinery fuel gas	CO_2 emission factor for individual fuel system	metric tons/MMBtu	
	refinery fuel or flexigas combusted / daily fuel consumption	scf/day	
	standard temperature for gases	20ºC <u>or</u> 60ºF	
Hydrogen, Ammonia	carbon content of feedstock	kg/scf	
	feedstock consumption rate	scf/day	
Coal storage	CH_4 emission factor for coal storage	scf/ton	
	purchased coal	tons/year	

Table 4. Input Parameters for Which Stakeholder Comments on Sampling, Analysis, and Measurement Procedures are Requested

Industry	Input Parameter
Cement Manufacturing	Weight fractions: • Plant-specific weight fractions in clinker from each kiln of: CaO, MgO, uncalcined CaO, uncalcined MgO • Weight fraction of carbonate CO_2 in the CKD • Weight fraction of carbonate CO_2 in the raw material
	Total organic carbon contents of raw materials.
	Quantity of clinker produced
	Quantity of CKD discarded
	Quantity of raw materials consumed (i.e. limestone, sand, shale, iron oxide, and alumina)
Lime Manufacturing	Weight fractions: • Plant-specific weight fractions in quick lime from each kiln of: CaO, MgO, uncalcined CaO, uncalcined MgO • Plant-specific weight fractions in lime kiln dust (LKD) from each kiln of: CaO, MgO, uncalcined CaO, uncalcined MgO
	Quantity of quick lime produced
	Quantity of LKD discarded
	Quantity of raw materials consumed (i.e., limestone, dolomite, aragonite, chalk, coral, marble, and shell)
Iron and Steel Manufacturing	Carbon contents: • By-products: blast furnace gas, coke oven gas, coal tar, light oil, coke breeze, sinter off gas • Carbon electrodes Direct reduced iron inputs: natural gas, coke breeze, metallurgical coke
	Energy used in direct reduced iron production (i.e., from natural gas, coke breeze, metallurgical coke)
	Quantity of coke production inputs (i.e., coking coal, blast furnace gas, other process materials)
	Quantity of coke produced
	Quantity of other coke production outputs (i.e., coke oven gas, other by-products)
	Quantity of iron and steel production inputs (i.e., coke, coke oven by-products, directly injected coal, limestone, dolomite, carbon electrodes, other carbonaceous and process material, coke oven gas)
	Quantity of steel produced
	Quantity of iron produced (not converted to steel)
	Quantity of blast furnace gas produced
	Quantity of sinter production inputs (i.e., coke breeze, coke oven gas, blast furnace gas, other process materials) and outputs (i.e., sinter off gas)
Electronics (Semiconductor) Manufacturing[a]	Fraction of gas remaining in shipping contained (i.e., heel)
	Mass of individual gas species fed into individual processes
	Use rate (i.e., fraction destroyed or transformed) of each gas species/process
	Fraction of each gas species/process fed into process with emission control technology
	Fraction of gas destroyed by emission control technology
	By-product emission factor for amount of CF_4/C_2F_6/CHF_3/ C_3F_8 created for each gas species/process

Table 4. Continued

Industry	Input Parameter
Lead Production	Carbon contents of reducing agents: blast furnace gas, charcoal, coal, coal tar, coke, coke oven gas, coking coal, electric arc furnace (EAF) carbon electrodes, EAF charge carbon, fuel oil, gas coke, natural gas petroleum coke
	Quantity of reducing agents (i.e., blast furnace gas, charcoal, coal, coal tar, coke, coke oven gas, coking coal, electric arc furnace [EAF] carbon electrodes, EAF charge carbon, fuel oil, gas coke, natural gas petroleum coke)
Soda Ash Manufacturing[a]	Carbon contents: • Ore • Sodium carbonate-rich brine • Soda ash Waste material (i.e., collected kiln dust)
	Quantity of soda ash produced
	Quantity of waste material
	Quantity of raw materials consumed (i.e., trona ore, nacholite ore, sodium carbonate-rich brine)
Adipic Acid Manufacturing[a]	Destruction factor
	Chemical composition of feedstock (i.e., cyclohexanone, cyclohexanol)
Aluminum Manufacturing	Quantity of materials consumed (i.e., paste, carbon, anodes, coke, recovered tar, coke dust)
	Quantity of aluminum produced
	Binder content in paste
	Pitch content in anodes
	Volatile content in coke
	Smelter-specific operating parameters (i.e., current efficiency, anode effect frequency, anode effect duration, anode effect over-voltage)
Ferroalloy Production[a]	Carbon contents: • Ore • Finished product • Non-product outgoing stream Volatiles in individual reducing agents
	Quantity of inputs (i.e., ore, individual reducing agents, individual slag-forming materials)
	Mass fractions in individual reducing agents: • Fixed carbon • Volatiles • Ash
HCFC-22 Production[a]	Concentration of HFC-23 in vented gas stream
	Gas stream mass flow rate
	Current process operating rate used as proxy
	Duration of atmospheric venting (not to a destruction system)
	Quantity of HFC-23 recovered for use as a chemical feedstock
	Concentration of HFC-23 in product reactor
	Mass of HCFC-22 produced at specific concentrations of HFC-23
Coal Mines	Mine-specific methane measurements from ventilation air and/or degasification systems

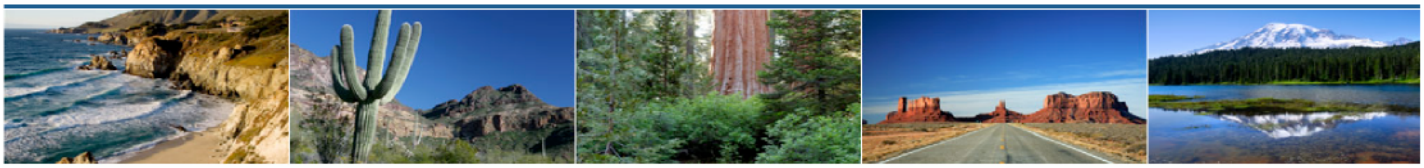
[a] Process emissions quantification method for this source category is still under development.

Ongoing Work

In the future, work will continue in these main areas related to emissions quantification and monitoring methods for mandatory reporting:

- Address any remaining stakeholder comments on quantification methods for source categories that were not prepared for public review prior to the January 12, 2009, stakeholder conference call.
- Oil and Gas Exploration and Gas Processing: Write emissions quantification and monitoring and related Essential Requirement sections (definitions, report requirements, etc.) based on interim TCR/WRAP O&G Protocol Project Task 2 output (i.e., available methods). Work will include developing "facility" or "reporting entity" definitions that will aggregate small, dispersed emissions sources, and consideration of appropriate reporting thresholds for such aggregated reporting entities.
- Natural Gas Transmission and Distribution: Write emissions quantification and monitoring and related Essential Requirement sections (definitions, report requirements, etc.) based on CCAR protocol (for eventual adoption by TCR) for process (i.e., fugitive CH_4) emissions.
- Transportation and RCI fuels GHG emission estimation methods, differences across jurisdictions, and accounting. Develop the reporting Essential Requirements for transportation fuels. Work may include identifying differences across WCI Partner jurisdictions with regard to regulating and dispensing RCI and transportation fuels, writing draft requirements, workshops with industry representatives and modification of such requirements. Update the portions of the Essential Requirements pertaining to transportation and RCI fuels to adapt decisions made by WCI with regard to transaction “accounting” to avoid double-counting of emissions and/or gaps in reported emissions by fuel suppliers, industrial sources, and jurisdictions. Current recommendations for GHG emissions quantification and monitoring methods to be included in the Essential Requirements completed in January 2009 will need to be revised.
- Pursue research to develop accurate emissions factors and/or quantification methods for the source categories for which adequate GHG emissions factors and/or quantification/monitoring methods are not currently available. This analysis would include establishing priorities, and would likely involve source testing and measurements. Some source data may be relatively inexpensive to obtain, while others will be more extensive and expensive to develop.
- The WCI Partner jurisdictions recommended the inclusion of certain emission categories in the Essential Reporting Requirements for which it was acknowledged that for specific emissions sources either quantification method uncertainties may be high or for which quantification methods are being developed. The WCI will evaluate the acceptable level of accuracy of quantification methods for inclusion in compliance reporting. Various forms of accuracy such as the level of uncertainty, bias, measurement error, sampling error and other pertinent factors (possibly

including factors other than methodological uncertainty) will be reviewed for the source categories under consideration. This will help the Partners consistently and transparently determine which emissions sources should be included and which emissions sources have justification for delayed inclusion or exclusion.



ATTACHMENT 1: GENERAL PROVISIONS

GENERAL PROVISIONS

§ WCI.0 PURPOSE

§ WCI.1 APPLICABILITY

§ WCI.2 GENERAL GREENHOUSE GAS REPORTING REQUIREMENTS AND SCHEDULE

§ WCI.3 CONTENTS OF THE GREENHOUSE GAS EMISSIONS REPORT

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§ WCI.5 COMPLIANCE AND ENFORCEMENT

§ WCI.6 INCORPORATION BY REFERENCE

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§ WCI.8 REQUIREMENTS FOR VERIFICATION OF GREENHOUSE GAS EMISSIONS DATA REPORTS AND REQUIREMENTS APPLICABLE TO EMISSIONS DATA VERIFIERS

§ WCI.9 DEFINITIONS

§ WCI.10 GLOBAL WARMING POTENTIALS

EMISSIONS QUANTIFICATION, AND SAMPLING, ANALYSIS AND MEASUREMENT

§ WCI.20 THROUGH § WCI.XX

§ WCI.0 PURPOSE

This rule requires mandatory reporting and verification of greenhouse gas (GHG) emissions data by certain facilities that directly emit GHG, by importers of electricity, and by suppliers of fossil fuels. The GHGs that must be reported under this rule are carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFC), perfluorocarbons (PFC), and sulfur hexafluoride (SF_6).

§ WCI.1 APPLICABILITY

(a) The GHG emissions reporting requirements, and related monitoring, recordkeeping, and verification requirements of this rule apply to the owners and operators *[Each jurisdiction will select the specific terminology for the regulated persons in accordance with their customary rule-writing practices]* of any facility that meets the requirements of paragraph (a)(1) of this section; and any fuel suppliers and electricity importers that meet the requirements of paragraph (a)(2), (a)(3), or (a)(4) of this section:

(1) Any facility that emits 10,000 metric tons CO_2e or more per year in combined emissions from one or more of the source categories listed in this paragraph in any calendar year starting in 2010.

[Please note that the quantification and monitoring methods for many of these source categories are currently being assessed. Only source categories for which adequate quantification methods exist will be included in the final WCI Essential Requirements for mandatory reporting.]

(A) Adipic acid manufacturing [*still being assessed*]
(B) Aluminum manufacturing
(C) Ammonia manufacturing [*still being assessed*]
(D) Carbon dioxide transfer recipients [*still being assessed*]
(E) Cement manufacturing
(F) Coal mine fugitive emissions (active and abandoned)
(G) Coal storage
(H) Cogeneration [*still being assessed*]
(I) Electricity generation
(J) Electronics Manufacturing [*still being assessed*]
(K) Ferroalloy production [*still being assessed*]
(L) General stationary fuel combustion
(M) Glass Production and other uses of carbonates [*still being assessed*]
(N) HCFC-22 production [*still being assessed*]
(O) Hydrogen production
(P) Industrial wastewater *[still being assessed for some industries]*
(Q) Iron and steel manufacturing
(R) Lead production
(S) Lime manufacturing
(T) Magnesium production *[still being assessed]*
(U) Natural gas transmission and distribution systems *[still being assessed]*
(V) Nitric acid manufacturing *[still being assessed]*
(W) Nonroad equipment at facilities *[still being assessed]*

(X) Oil and gas production & gas processing *[still being assessed]*
(Y) Petrochemical production *[still being assessed]*
(Z) Petroleum refineries
(AA) Phosphoric acid production *[still being assessed]*
(BB) Pulp and paper manufacturing
(CC) Refinery fuel gas
(DD) SF_6 from electrical equipment *[still being assessed]*
(EE) Soda ash manufacturing *[still being assessed]*
(FF) Zinc production

(2) All importers of electricity. Importers of electricity include both retail providers and marketers that import electricity into the WCI region. *[This is preliminary language, pending definition of electricity importers by another WCI Committee.]*

(3) Any supplier that within the WCI region distributes transportation fuels in quantities that when combusted would emit 10,000 metric tons CO_2e per year or more in any calendar year starting in 2010. *[This is preliminary language, pending future determination of point of regulation for transportation fuels.]*

(4) Any supplier that distributes within the WCI region residential, commercial, and industrial fuels in quantities that when combusted would emit 10,000 metric tons CO_2e per year or more in any calendar year starting in 2010. *[This is preliminary language, pending future determination of points of regulation for these fuels.]*

(b) To calculate GHG emissions for comparison to the 10,000 metric ton CO_2e per year emission threshold in paragraph (a)(1) of this section, the owner or operator shall calculate annual CO_2e emissions, as described in paragraphs (b)(1) through (b)(4) of this section.

(1) Estimate the annual emissions of CO_2, CH_4, N_2O, HFC, PFC, and SF_6 in metric tons for each unit, process, activity, or operation for which emission calculation methodologies are provided in sections WCI.20 through WCI.XX. The GHG emissions shall be calculated using methodologies specified in each applicable section.

(2) For stationary combustion units, carbon dioxide emissions from the combustion of biomass fuels shall be included in the calculations. *[WCI is considering a limited deduction of biomass fuel combustion emissions from determination of whether the reporting threshold has been met.]*

(3) Sum the total facility emissions for each GHG and calculate the metric tons of CO_2e using equation 1-1 below.

$$CO_2e = \sum_{i=1}^{n} GHG_i \times GWP_i \qquad \textbf{Equation 1-1}$$

Where:

CO_2e = Carbon dioxide equivalent, metric tons/year.
GHG_i = Mass emissions of each greenhouse gas emitted, metric tons/year.
GWP_i = Global warming potential for each greenhouse gas from Table WCI.10-1 of this regulation.
n = The number of greenhouse gases emitted.

(4) For purpose of determining if an emission threshold has been exceeded, any CO_2 that is captured for on-site use, on-site storage, or transfer off-site must be included in the emissions total.

(c) To calculate GHG emissions for comparison to the 10,000 metric ton CO_2e per year emission threshold for suppliers of transportation fuels in paragraphs (a)(3) of this section, the owner or operator shall follow the procedures of paragraphs (c)(1) through (c)(2) below:

(1) Calculate the total mass in metric tons per year of CO_2, CH_4, and N_2O that would result from the complete combustion or oxidation of all transportation fuels that are distributed within the WCI region. The mass of each GHG shall be calculated using any of the applicable methodologies specified in section WCI.XX [Transportation Fuels Combustion] of this rule.

(2) Sum the emissions of each GHG and calculate total metric tons of CO_2e using Equation 1-1 of this rule.

(d) To calculate GHG emissions for comparison to the 10,000 metric ton CO_2e per year emission threshold for suppliers of residential, commercial, and industrial fuels in paragraph (a)(4) of this section, the owner or operator shall follow the procedures of paragraphs (d)(1) and (d)(2) below:

(1) Calculate the total mass in metric tons per year of CO_2, CH_4, and N_2O that would result from the complete combustion or oxidation of all residential, commercial, and industrial fuels that are distributed within the WCI region. The calculation shall exclude any fuels that are supplied to facilities that are required to report GHG emissions under section WCI.1(a)(1). *[These accounting issues will be dealt with in 2009.]* The mass of each GHG shall be calculated using any of the applicable methodologies specified in section WCI.XX [Residential, Commercial and Industrial Fuels Combustion] of this rule.

(2) Sum the emissions of each GHG and calculate total metric tons of CO_2e using Equation 1-1 of this rule.

(e) If the operations of a facility or fuel supplier that is subject to this rule change such that emissions fall below 10,000 metric tons CO_2e per year, then the following reporting requirements shall apply:

[Please note that the requirements of this subsection do not currently address reporters who emit >25,000 metric tons during 1 or more years, and then drop below 25,000 metric tons and above 10,000 metric tons in subsequent years. A provision for these reporters to cease verification after some period of time is under consideration.]

(1) If, prior to such emission reduction, the emissions report was subject to the verification requirements of this rule; then the owner or operator shall continue to submit verified emission reports until reported emissions are below 10,000 metric tons CO_2e per year for a minimum of 3 consecutive years. If reported emission are less than 10,000 metric tons CO_2 per year during 3 consecutive years, then the owner or operator shall be exempted from further reporting until CO_2e emissions again exceed 10,000 metric tons in any future calendar year.

(2) If, prior to such emission reduction, the emissions report was not subject to the verification requirements of this rule; then the owner or operator shall submit to the *[jurisdiction]* a signed statement certifying that emissions are less than 10,000 metric tons

CO_2e during the prior year. After certifying that emissions are below 10,000 metric tons CO_2e per year for 3 consecutive years, the owner or operator shall be exempted from further reporting until CO_2e emissions again exceed 10,000 metric tons in any future calendar year.

(3) Notwithstanding the requirements of paragraphs (e)(1) and (2) of this section, a facility or fuel supplier that is subject to an emissions limitation under the WCI cap-and-trade program must continue to submit verified annual reports.

(f) Upon request by the [*jurisdiction*], owner or operator of any facility or fuel supply operation must submit a demonstration that emissions have not exceeded one or more of the applicability criteria specified in this section in any year since 2010. Such demonstration shall be provided to the [*jurisdiction*] within 20 working days of receipt of a written request. *[WCI is considering whether this and other deadlines for responses provide sufficient time, and whether such deadlines should be standardized across requirements.]*

§ WCI.2 GENERAL GREENHOUSE GAS REPORTING REQUIREMENTS AND SCHEDULE

[Specific requirements of this section may change based on the future final design of the marketing trading program.]

(a) General. Owners or operators that are subject to this rule must submit an annual GHG emissions report. Owners and operators must collect data; calculate GHG emissions; and follow the procedures for quality assurance, missing data, recordkeeping, and reporting as specified in these General Provisions and in each relevant section WCI.20 through WCI.XX of this rule.

(1) A facility, fuel supplier, or electricity importer that commenced operation before January 1, 2010, must report emissions beginning in 2011 for GHGs emitted in calendar year 2010.

(2) A new facility, fuel supplier, or electricity importer that commences operation on or after January 1, 2010, must report emissions for the first calendar year in which the facility operates, beginning with the first operating month and ending on December 31 of that year. Each subsequent annual report must cover emissions for the calendar year, beginning on January 1 and ending on December 31.

(b) Reporting and Verification Schedule.

(1) Annual GHG emissions reports must be submitted to [*the jurisdiction*] by April 1 of each year for emissions in the previous calendar year.

(2) Reporters subject to the verification requirements of WCI.8, must complete their verification process, including submittal of a verification statement to [*the jurisdiction*], according to the following schedule:

(A) For reporting years 2010 through 2011, September 1 of the year following the reporting year.

(B) For reporting years 2012 and later, *[date to be determined]*.

(c) Submission of GHG Emissions Report. The annual GHG emissions report must be submitted to [*the jurisdiction*] in a format [*to be specified by each jurisdiction*].

(d) Simplified Emission Calculation Methods for De Minimis Sources. The owner or operator may elect to designate as de minimis one or more sources or pollutants that collectively emit no more than 3 percent of the facility's total CO_2e emissions, but not to exceed 20,000 metric tons CO_2e. The owner or operator may estimate emissions for these de minimis sources using alternative methods to those required to be used by this rule. If verification of the emissions report is required by this rule, then the selection of any alternative GHG calculation method is subject to the concurrence of the verification team that the use of such methods provides reasonable assurance that the emissions so designated do not exceed the applicable de minimis limits. The operator shall separately identify and include in the emissions data report the emissions from designated de minimis sources.

(e) GHG Inventory Management Plan. The owner or operator shall prepare and follow a written GHG inventory management plan that ensures that the emissions calculations and other information that is required to be reported under this rule are transparent, accurate, and independently verifiable. The owner or operator shall establish, document, implement, and maintain data acquisition and handling activities for the calculation and reporting of GHG emissions. Such activities shall include measuring, monitoring, analyzing, recording, processing and calculating the parameters specified by this rule. The owner or operator shall implement systems of internal audit, quality assurance, and quality control for the reporting program and the data reported. *[WCI is considering whether a written plan should be mandatory, or advised in guidance materials as a means of assuring a smooth verification process and a positive verification opinion.]*

(f) GHG Emissions Report Revisions.

(1) The owner or operator shall maintain documentation to support any revisions made to a previously submitted annual GHG emissions report. Documentation for all revisions shall be retained by the operator for 7 years.

(2) If, after the verification deadline, a report subject to verification is found to contain an error, or accumulation of errors, greater than 5 percent of the total CO_2e emissions reported, the owner or operator shall revise and resubmit an annual GHG emissions report within 60 days of the finding. To the extent possible, the revised report must correct all identified errors. A revised report will be accepted only if verified according to WCI.8 and approved by [*the jurisdiction*].

(3) If, after the report submittal deadline, a report not subject to verification is found to contain an error, or accumulation of errors, greater than 5 percent of the total CO_2e emissions reported, the owner or operator shall revise and resubmit an annual GHG emissions report within 30 days of the finding. To the extent possible, the revised report must correct all identified errors. A revised report will be accepted only if approved by [*the jurisdiction*].

(4) An owner or operator that voluntarily chooses to correct errors of 5 percent or less in total CO_2e emissions reported may do so according to the following requirements:

(A) For reports subject to verification, a revised report will be accepted only if verified according to WCI.8 and approved by [*the jurisdiction*].

(B) For reports not subject to verification, a revised report will be accepted if approved by [*the jurisdiction*].

(g) Fuel Use Measurement Accuracy. The operator shall use procedures to quantify fuel use (mass or volume flow) that provide data with an accuracy within ±5 percent. All fuel use measurement devices shall be maintained and calibrated in a manner and at a frequency required to maintain this level of accuracy. The operator shall make available to the verification team documentation to support this level of accuracy. The operator who measures solid fuels shall validate fuel consumption estimates with belt or conveyor scale calibrations conducted at least quarterly, and retain record of such calibrations.

(h) Where this rule specifies a choice between use of a fuel-based or mass balance-based calculation or use of a continuous emissions monitoring system (CEMS) to calculate CO_2 emissions, the operator shall make this choice and continue to use the method chosen for all future emissions data reports, unless the use of the alternative calculation method is approved in advance by *[the jurisdiction]*.

§ WCI.3 CONTENTS OF THE GREENHOUSE GAS EMISSIONS REPORT

Each annual GHG emissions report shall contain the following information:

(a) Facility name, identification number, physical address, mailing address, and NAICS code.

(b) Reporting year.

(c) Date of report submittal.

(d) Total facility emissions aggregated from all applicable source categories in subparts WCI.20 through WCI.XX expressed in metric tons of CO_2e calculated using Equation 1-1 of section WCI.1, excluding emissions from CO_2 that is captured and CO_2 emissions from the combustion of biomass and biomass-derived fuels, which are reported separately.

(e) Total facility emissions of CO_2 from the combustion of biomass and biomass-derived fuels.

(f) Total annual mass of CO_2 captured for on-site use, on-site storage, or transfer off site, in metric tons.

(g) For applicable fuel supplier categories in subparts WCI.XX [Transportation Fuels Combustion] and WCI.XX [Residential, Commercial and Industrial Fuels Combustion], total CO_2e emissions aggregated from all specified fuels.

(h) Emissions from each applicable source category or fuel supplier category in subparts WCI.20 through WCI.XX, expressed in metric tons per year of CO_2, CH_4, N_2O, HFC, PFC, and SF_6. CO_2 emissions from the combustion of biomass and biomass-derived fuels shall be reported separately.

(i) For electricity importers, the information required by WCI.XX [Electricity Imports].

(j) Emissions and other data for individual units, processes, activities, and operations as specified for each source category in sections WCI.20 through WCI.XX of this rule.

(k) Mass emissions from each designated de minimis source or pollutant, reported in metric tons per year of each GHG for which an alternative emission calculation method is used.

(l) Name and contact information including e-mail address and telephone number of the person primarily responsible for preparing and submitting the emissions report.

(m) A signed and dated statement provided by the owner or operator, or their designated representative, certifying that the report has been prepared in accordance with this rule and that, subject to verification, the statements and information contained in the emissions data report are true, accurate, and complete to the best of their knowledge.

§ WCI.4 DOCUMENT RETENTION AND RECORD KEEPING REQUIREMENTS

(a) The operator shall establish and maintain procedures for document retention and record keeping. The operator shall retain all documents regarding the design, development and maintenance of the GHG inventory in paper, electronic or other usable format for a period of not less than 7 years following submission of each emissions data report. The retained documents, including GHG emissions data, shall be sufficient to allow for the verification of each emissions data report.

(b) Upon request by *[jurisdiction],* the operator shall provide within 10 working days all documents and data used to develop an emissions data report.

(c) In addition to information submitted as part of the emissions data report, each operator shall retain, at a minimum, the following information for at least 7 years after the submission of the report:

(1) A list of all GHG sources (i.e., units, operations, processes, and activities) included in the emission estimates.
(2) All data used to calculate emissions for each source, categorized by process and fuel or material type.
(3) Documentation of the process for collecting emissions data.
(4) Any GHG emissions calculations and methods used;
(5) All emission factors used for emission estimates, including documentation for any factors not provided in the rule.
(6) All input data used for emission estimates.
(7) Documentation of biomass fractions for specific fuels.
(8) All other data submitted to the [*jurisdiction*] under this rule, including the GHG emissions report.
(9) All computations made to gap-fill missing data.
(10) Names and documentation of key facility personnel involved in emissions calculating and reporting;
(11) Any other information that is required for the verification of the GHG emissions report.
(12) A log to be prepared for each reporting year, beginning January 1, documenting all procedural changes made in GHG accounting methods and changes to instrumentation for GHG emissions estimation.
(13) A copy of the GHG Inventory Management Plan.

(d) For measurement based methodologies, the following information also must be retained for at least 7 years after the submission of the emissions data report:

(1) List of all emission points monitored.
(2) Collected monitoring data.
(3) Quality assurance and quality control information collected under the GHG Inventory Management Plan required by section WCI.2 of this rule.

(4) A detailed technical description of the continuous measurement system, including documentation of any findings and approvals by federal, State or local agencies.
(5) Raw and aggregated data from the continuous measurement system.
(6) A log book of all system down-times, calibrations, servicing, and maintenance of the continuous measurement system.
(7) Documentation of any changes in the continuous measurement system over time.

§ WCI.5 COMPLIANCE AND ENFORCEMENT

(a) Knowing submission of false information to the *[jurisdiction*] or a verification body, shall constitute a single, separate violation of the requirements of this article for each day after the information has been received by the [*jurisdiction*].

(b) Each violation of this rule shall constitute a single, separate violation for each day beyond the specified reporting date. A violation includes failure to submit any report, failure to collect data needed to calculate GHG emissions, failure to monitor and test as required, failure to calculate GHG emissions following the methodologies specified in this rule, failure to retain required records, failure to provide all information required in the report, and failure to submit a report on time. For the purposes of this rule, "report" means any GHG emissions data report, verification statement, or other document required to be submitted by this rule.

§ WCI.6 INCORPORATION BY REFERENCE

The following documents are incorporated by reference into this rule. These materials are incorporated as they exist on the date this article is adopted.

[This list will be revised as additional calculation methods are selected. Canadian Standards Association methods equivalent to the specified ASTM methods will be identified as substitutes for these in rulemaking by Canadian jurisdictions.]

(a) American Society for Testing and Materials (ASTM) D1826-94 (Reapproved 2003), ASTM D3588-98 (Reapproved 2003), ASTM D4891-89 (Reapproved 2006), ASTM D240-02 (Reapproved 2007), ASTM D4809-00 (Reapproved 2005), ASTM 5373-02 (Reapproved 2007), ASTM D5291-02 (Reapproved 2007), ASTM D3238-95 (Reapproved 2005), ASTM D2502-04, ASTM D2503-92 (Reapproved 2002), ASTM D1945-03, ASTM D1946-90 (Reapproved 2006), ASTM D6866-06a, ASTM D388-05, ASTM D5468-02 (Reapproved 2007), ASTM D240-87 (Reapproved 1991), ASTM D5865-07a, ASTM Specification D396-07, ASTM Specification D975-07b.

(b) California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities, California Air Pollution Control Officers Association (CAPCOA) and California Air Resources Board (ARB), February 1999.

(c) Control of Emissions from Refinery Flares, Rule 118, South Coast Air Quality Management District, Amended November 4, 2005.

(d) U.S. EPA TANKS Version 4.09D, US Environmental Protection Agency, October 2005.

(e) Gas Processors Association (GPA) Standard 2261-00, Revised 2000.

§ WCI.7 DESIGNATED REPRESENTATIVE

(a) General. Each fuel supplier, electricity importer, and owner or operator of a facility that is subject to this rule, shall select a designated representative that is responsible for certifying and submitting GHG emissions reports under this reporting rule.

(b) Authorization of a Designated Representative. The designated representative of the facility shall be selected by a certificate of representation agreement that is signed by the designated representative and owners or operators of the facility. The designated representative must be an individual having responsibility for the overall operation of the facility or activity such as the position of the plant manager, operator of a well or a well field, superintendent, position of equivalent responsibility, or an individual or position having overall responsibility for environmental matters for the company.

(c) Responsibility of the Designated Representative.

(1) The designated representative of the facility shall represent and by any representations, actions, inactions, or submissions, legally bind each owner and operator in all matters pertaining to this rule.

(2) Each GHG emission report submitted under this rule must be signed by the designated representative and must contain the following certification statement: "I have been authorized to make this submission on behalf of the owners and operators of the facility (or supply operation, as appropriate). I certify under penalty of law that I have personally examined the information submitted in this document. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(d) Changing a Designated Representative. The designated representative may be changed at any time upon submission of a superseding certificate of representation. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous designated representative before time of the superseding certificate of representation shall be binding on the new designated representative and the owners and operators.

(e) Changes in Owners and Operators. In the event of any change in ownership of the facility, any new owner or operator shall be deemed to be bound by the representations, actions, inactions, and submissions of the designated representative of the facility until such time as the designated representative is changed.

(f) Certificate of Representation. A certificate of representation must be submitted to *[the jurisdiction]* and kept on location by the facility, fuel supplier, or electricity importer. The certificate shall include the following information:

(1) Identification of the facility, fuel supplier, or electricity importer for which the certificate of representation is submitted.

(2) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the designated representative.

(3) A list of the owners and operators.

(4) Certification statements that the actions of the designated representative with respect to this rule are binding on the owners and operators, and that the designated representative has the necessary authority to carry out duties and responsibilities on behalf of the owners and operators.
(5) The signature of the designated representative and owner(s) and operator(s), and the dates signed.

§WCI.8 REQUIREMENTS FOR VERIFICATION OF GREENHOUSE GAS EMISSIONS DATA REPORTS AND REQUIREMENTS APPLICABLE TO EMISSIONS DATA VERIFIERS

(a) Applicability. Owners or operators [Each jurisdiction will select the specific terminology for the regulated persons in accordance with their customary rule-writing practices] are required to obtain annual verification when the reported annual emissions of the operation subject to this rule:

(1) Are equal to 25,000 metric tons of CO_2e or more; or
(2) Are subject to an emissions limit under the WCI cap-and-trade program as required under WCI.1(e)(3); or
(3) Were verified and then fall below 10,000 metric tons of CO_2e in a subsequent year as stipulated under WCI.1(e)(1).

[WCI is considering a limited deduction of biomass fuel combustion emissions from determination of whether the verification threshold has been met.]

(b) Requirements for Annual Verification of Emissions Data Reports.

(1) Facility owners or operators, fuel suppliers, and electricity importers required to obtain annual verification shall be subject to full verification requirements in the first year that verification is required. Upon completion of a positive verification statement under full verification requirements, the facility owner or operator, fuel supplier, or electricity importer may choose to obtain two years of less intensive verification services. This cycle may be repeated in subsequent three-year cycles, but full verification requirements shall apply at least once every three years.
(2) Facility owners or operators, fuel suppliers, and electricity importers required to obtain annual verification will be required to obtain full verification services if any of the following apply:

(A) Change in the verification body from the previous year; or
(B) A verification body was not able to provide a positive verification statement for the reporters emissions report for the previous year.

(3) Facility owners or operators, fuel suppliers, or electricity importers subject to annual verification shall not use the same verification body for a period of more than six consecutive years. If a facility owner or operator, fuel supplier, or electricity importer is required or elects to contract with another verification body, they may contract verification services from the previous verification body only after not using the previous verification body for at least three years.

(c) Requirements for Verification Services. Verification services shall be subject to the following requirements.

(1) Notice of Verification Services. After the [*WCI Regional Body, jurisdiction, or other organization to be determined (TBD)*] has provided a determination that the potential for a conflict of interest is acceptable as specified in section WCI.8(e) and that verification services may proceed, the verification body shall submit a notice of verification services to [*TBD*]. The verification body may begin verification services for the operator 15 working days after the notice is received by the [*TBD*], or earlier if approved by the [*TBD*] in writing. The notice shall include the following information:

(A) A list of the staff who will be designated to provide verification services as a verification team, including the names of each designated staff member, the lead verifier, and all subcontractors, and a description of the roles and responsibilities each member will have during verification;

(B) Documentation that the verification team has the skills required to provide verification services for the reporting facility, fuel supply or electricity import operation. This shall include a demonstration that a verification team includes at least one member with source category specific skills to provide source-category specific verification services when required below:

i. For providing verification of emissions reported under WCI.60 [Electricity Importers] at least one verification team member must have demonstrated knowledge as an electricity transactions specialist.

ii. For providing verification of emissions reported under WCI.200 [Petroleum refineries] or WCI.140 [Hydrogen production], at least one verification team member must have demonstrated knowledge as a refinery specialist;

iii. For providing verification of emissions reported under WCI.90 [Cement], at least one verification team member must have demonstrated knowledge as a cement specialist.

[Note that other source-category specialist skills may be required. These requirements are being discussed by the WCI, as are any additional accreditation requirements for individual lead verifiers, general verifiers, or sector specialists.]

(C) General information on the lead verifier and the operator, including:

i. The name, office address, telephone number, and e-mail address of the lead verifier;

ii. The name of the owner or operator, and the facilities and other locations that will be subject to verification services, owner or operator contact, address, telephone number, and e-mail address;

iii. The industry sector, and the Standard Industrial Classification and North American Industry Classification System (NAICS) codes of the facility, fuel supplier, or electricity importer;

iv. The expected date(s) of on-site visits, with facility or fuel supply location address and contact information;

v. A brief description of expected verification services to be performed, including expected completion date.

(2) Verification services shall include, but are not limited to, the following:

(A) Verification Plan. The verification team shall obtain information from the owner or operator necessary to develop a verification plan. Such information shall include but is not limited to:

i. Information to allow the verification team to develop a general understanding of facility or entity boundaries, operations, emissions sources, and electricity transactions as applicable;
ii. Information regarding the training or qualifications of personnel involved in developing the GHG emissions data report;
iii. Description of the specific methodologies used to quantify and report GHG emissions, electricity transactions, and other required data as applicable;
iv. Information about the data management system used to track GHG emissions, electricity transactions, and other required data as applicable.

(B) The verification team shall develop a verification plan that includes, at a minimum:

i. Dates of proposed meetings and interviews with reporting facility, fuel supply, or electricity import personnel;
ii. Dates of proposed site visits;
iii. Types of proposed document and data reviews;
iv. Expected date for completing verification services.

(C) The verification team shall discuss with the owner or operator the scope of the verification services and request any information and documents needed for initial verification services. The verification team shall review the documents submitted and plan and conduct a review of original documents and supporting data for the emissions data report.

(D) Site visits. At least one member of the verification team shall at a minimum make one site visit, in the first year of each three-year reporting cycle or if full verification requirements are required under WCI.8(b)(3), to each facility or fuel supply location [Note that exact location of fuel supplier site visits remains TBD] for which an emissions data report is submitted. The verification team member(s) shall visit the headquarters or other location of central data management when the owner or operator is an electricity importer. During the site visit, the verification team member(s) shall conduct the following:

i. The verification team member(s) shall check that all sources specified in sections WCI.20 to WCI.XX as applicable to the owner or operator, are identified appropriately.
ii. The verification team member(s) shall review and understand the data management systems used by the owner or operator to track, quantify, and report greenhouse gas emissions and, when applicable, electricity transactions. The verification team member(s) shall evaluate the uncertainty and effectiveness of these systems.
iii. The verification team shall collect and review other information that, in the professional judgment of the team, is needed in the verification process.

(E) The verification team shall review facility, fuel supplier, or electricity importer operations to identify applicable GHG emissions sources. This shall include a review of the emissions inventory and each type of emission source to assure that all sources listed in sections WCI.20 through WCI.XX are properly included in the inventory.

(F) Owners or operators shall make available to the verification team all information and documentation used to calculate and report emissions, electricity transactions, and other information required under this rule, as applicable.

(G) As applicable for electricity importers, the verification team shall review electricity transaction records, including receipts of power attributed to the Northwest or Southwest region as verifiable via North American Electric Reliability Corporation (NERC) E-Tags, settlements data, or other information as confirmation of the region of origin. [Note that this procedure is subject to change pending WCI Electricity Committee review.]

(H) Sampling Plan. As part of confirming emissions data or electricity transactions the verification team shall develop a sampling plan that meets the following requirements:

i. The verification team shall develop a sampling plan based on a strategic analysis developed from document reviews and interviews to assess the likely nature, scale and complexity of the verification services for an owner or operator. The analysis shall review the inputs for the development of the submitted emissions data report, the rigor and appropriateness of the GHG or electricity transaction data management system, and the coordination within a facility, fuel supplier's, or electricity importer's organization to manage the operation and maintenance of equipment and systems used to develop emissions data reports.

ii. The verification team shall include in the sampling plan a ranking of emissions sources by amount of contribution to total CO_2e emissions for the owner or operator and a ranking of emissions sources with the largest calculation uncertainty. As applicable and deemed appropriate by the verification team, electricity transactions shall also be ranked or evaluated relative to the amount of power exchanged and uncertainties that may apply to data provided by the electricity importer.

iii. The verification team shall include in the sampling plan a qualitative narrative of uncertainty risk assessment in the following areas as applicable under sections WCI.20 through WCI.XX:

- Data acquisition equipment;
- Data sampling and frequency;
- Data processing and tracking;
- Emissions calculations;
- Data reporting;
- Management policies or practices in developing emissions data reports.

iv. The verification team may change the sampling plan as relevant information becomes available and potential issues emerge of material misstatement or nonconformance with the requirements of this rule.

v. The verification body shall retain the sampling plan in paper, electronic, or other format for a period of not less than five years following the submission of each verification statement. The sampling plan shall be made available to *[TBD]* upon request.

(I) Data Checks. To determine the reliability of the submitted emissions data report, the verification team shall use data checks. Such data checks shall focus first on the largest and most uncertain estimates of emissions and electricity transactions, and shall include the following:

i. The verification team shall use data checks to ensure that the appropriate methodologies and emission factors have been applied for the emissions sources and electricity transactions covered under sections WCI.20 through WCI.XX;
ii. The verification team shall choose emissions sources, and electricity transactions data as applicable, for data checks based on their relative sizes and risks of material misstatement as indicated in the sampling plan;
iii. The verification team shall use professional judgment in the number of data checks required for the team to conclude with reasonable assurance whether the reported emissions and transactions are free of material misstatement and the emissions data report otherwise conforms to the requirements of this rule.

(J) Emissions Data Report Modifications. If as a result of review by the verification team and prior to completion of a verification statement the operator chooses to make improvements or corrections to the submitted emissions data report, a revised emissions data report may be submitted to [the jurisdiction] as specified by section WCI.2(f). The operator shall maintain documentation to support any revisions made to the initial emissions data report. Documentation for all emissions data report submittals shall be retained by the operator for seven years pursuant to section WCI.4.
(K) Findings. To verify that the emissions data report is free of material misstatement, the verification team shall make its own determination of emissions for sources checked according to WCI.8(c)(1), and shall determine whether there is reasonable assurance that the reported facility, fuel supply, or electricity import emissions are within 95 percent of actual total emissions for the facility, on a CO_2e basis. To assess conformance with this rule the verification team shall review the methods and factors used to develop the emissions data report for adherence to the requirement of this rule. The verification team shall keep a log of any issues identified in the course of verification activities that may affect determinations of material misstatement and nonconformance, and how those issues were resolved.

(3) Completion of verification services shall include:

(A) Verification Statement. Upon completion of the verification services specified in section WCI.8(c)(2), the verification body shall complete a verification statement, and provide that statement to the owner or operator and [the jurisdiction] according to the schedule specified in section WCI.2(b). Before that statement is completed, the verification body shall have the verification services and findings of the verification team independently reviewed within the verification body by a lead verifier not involved in services for that operator during that year.

(B) When the verification team completes its findings:

i. The verification body shall provide to the owner or operator a detailed verification report. The verification report shall at minimum include the verification plan, the detailed comparison of the data checks with the submitted emissions data report, the log of issues identified in the course of verification activities and their resolution, and any qualifying comments on findings during verification services. The detailed verification report shall be made available to [*the jurisdiction*] upon request.

ii. The verification body shall provide the verification statement to the owner or operator and [*the jurisdiction*], attesting that the verification body has found the submitted emissions data report free of material misstatement and in conformance with the requirements of this rule or, alternatively, that the emissions data report contains material misstatement or otherwise does not conform with the requirements of this rule.

iii. The lead verifier in the verification team shall attest that the verification team has carried out all verification services as required by this rule, and the lead verifier who has conducted the independent review of verification services and findings specified in section WCI.8(c)(3)(A) shall attest to his or her independent review on behalf of the verification body and his or her concurrence with the verification findings.

(C) Prior to the verification body providing an adverse verification statement to [*the* jurisdiction], the owner or operator shall be provided at least 10 working days to modify the emissions data report to correct any material misstatement or nonconformance found by the verification team. The modified report and verification statement must be submitted to [*the jurisdiction*] before the applicable verification deadline, unless the operator makes a request to [*the jurisidiction]* as follows

i. If the owner or operator and the verification body cannot reach agreement on modifications to the emissions data report that result in a positive verification statement, the operator may petition *[TBD]* to make a final decision as to the verifiability of the submitted emissions data report.

ii. If *[TBD]* determines that the emissions data report does not meet the standards and requirements specified in this rule, the owner or operator shall have the opportunity to submit within 60 calendar days of the date of this decision [Note that this time frame may need to be changed pending details of cap-and-trade system design and needs.] any emissions data report revisions that address *[TBD's]* determination, for re-verification of the emissions data report. In re-verifying a revised emissions data report, the verification body and verification team shall be subject to the requirements in section WCI.8(c)(3).

(4) Upon provision of the verification statement to *[the jurisdiction]*, the emissions data report shall be considered final and no changes shall be made except as provided in

section WCI.2(f). All verification requirements of this rule shall be considered complete upon provision of the verification statement.

(5) If the *[TBD]* finds a high level of conflict of interest existed between a verification body and an owner or operator or an emissions data report that received a positive verification statement fails an audit by *[TBD]*, the *[TBD]* may set aside the positive verification statement submitted by the verification body.

(6) Upon request by *[TBD]*, the owner or operator shall provide the data used to generate an emissions data report, including all data available to a verifier in the conduct of verification services. *[TBD]* may also review the full verification report given by the verification body to the owner or operator. The full verification report shall be provided to the *[TBD]* upon request.

(7) Upon written notification by the *[TBD]*, the verification body shall make itself available for a verification services audit.

(d) Accreditation Requirements for Verification Bodies, Lead Verifiers, and Verifiers.

(1) The accreditation requirements specified in this subsection shall apply to all verification bodies, lead verifiers, and verifiers that wish to provide verification services under this rule.

(2) Verification bodies accredited according to the requirements of the California Air Resources Board [provide regulatory citation] or to ISO 14065 through a program developed under ISO 17011 with demonstrated knowledge of WCI reporting requirements to conduct verification activities for WCI emissions data, are qualified to conduct verification activities for the WCI.

[Note the details of WCI's specific accreditation process for verification bodies (which has yet to be developed) will be consistent with ISO 14065 through an accreditation program that will developed under ISO 17011 and will include demonstrated knowledge of the WCI reporting requirements. WCI will explore additional accreditation requirements for individual lead verifiers, general verifiers, or sector specialists.]

(3) Subcontracting. The following requirements shall apply to any verification body that elects to subcontract verification services.

(A) The verification body must assume full responsibility for verification services performed by subcontractor verifiers or verification bodies.

(B) A verification body or verifier acting as a subcontractor to another verification body shall not further subcontract or outsource verification services for an operator.

(C) A verification body that engages a subcontractor shall be responsible for demonstrating an acceptable level of conflict of interest, as provided in section WCI.8(e) between its subcontractor and the operator for which it will provide verification services.

(4) If any WCI accredited verification body is suspended in any other mandatory or voluntary GHG reporting or trading program, that verification body will not be allowed to provide any verification services under WCI until that suspension ends. If any WCI accredited verification body has their verification body accreditation revoked under any other mandatory or voluntary GHG reporting or trading program, that verification body will no longer be allowed to provide verification services under WCI.

(e) Conflict of Interest Requirements for Verification Bodies.

(1) The conflict of interest provisions of this section shall apply to the verification body, entities related to the verification body, and the verification team accredited according to the requirements of WCI.8(d) to perform verification services for the WCI cap-and-trade program. Member for purposes of this section means any employee or subcontractor of the verification body or entities related to the verification body. Member also includes any individual with a majority equity share in the verification body or entities related to the verification body.

(2) The potential for a conflict of interest shall be deemed to be high where:

(A) The verification body and owner or operator share any management staff or board of directors membership, or any of the management staff of the owner or operator have been employed by the verification body, or vice versa, within the previous three years; or

(B) Within the previous three years, any member of the verification body, any entity related to the verification body, and the verification team has provided to the owner or operator any of the following non-verification services:

i. Designing, developing, implementing, or maintaining an inventory or information or data management system for facility greenhouse gases, or, where applicable, electricity transactions;
ii. Developing greenhouse gas emission factors or other greenhouse gas-related engineering analysis;
iii. Designing energy efficiency, renewable power, or other projects which explicitly identify greenhouse gas reductions as a benefit;
iv. Preparing or producing greenhouse gas-related manuals, handbooks, or procedures specifically for the reporting facility;
v. Appraisal services of carbon or greenhouse gas liabilities or assets;
vi. Brokering in, advising on, or assisting in any way in carbon or greenhouse gas-related markets;
vii. Managing any health, environment or safety functions;
viii. Bookkeeping or other services related to the accounting records or financial statements;
ix. Any service related to information systems, unless those systems will not be part of the verification process;
x. Appraisal and valuation services, both tangible and intangible;
xi. Fairness opinions and contribution-in-kind reports in which the verification body has provided its opinion on the adequacy of consideration in a transaction, unless the resulting services shall not be part of the verification process;
xii. Any actuarially oriented advisory service involving the determination of amounts recorded in financial statements and related accounts;
xiii. Any internal audit service that has been outsourced by the operator that relates to the owner's or operator's internal accounting controls, financial systems or financial statements, unless the result of those services shall not be part of the verification process;
xiv. Acting as a broker-dealer (registered or unregistered), promoter or underwriter on behalf of the owner or operator;

xv. Any legal services;
xvi. Expert services to the owner or operator or his or her legal representative for the purpose of advocating his or her's interests in litigation or in a regulatory or administrative proceeding or investigation, unless providing factual testimony.

(C) The potential for a conflict of interest shall also be deemed to be high where any staff member of the verification body, entity related to the verification body, or the verification team has provided verification services for the owner or operator within the last three years, except within the time periods in which the owner or operator is allowed to use the same verification body as specified in sections WCI.8(b).
(D) The potential for a conflict of interest shall be deemed high where the lead verifier doing the independent review for the verification team has provided verification or non-verification services for the operator in the last year as specified in section WCI.8(b).

(3) The potential for a conflict of interest shall be deemed to be low where:

(A) No potential for a conflict of interest is found under section WCI.8(e)(2) and any non-verification services provided by all members of the verification body and the verification team to the owner or operator within the last three years are valued at less than [Percent of the fee TBD] for the proposed verification.
(B) Any non-verification services provided at any time by a member of the verification body or the verification team did not include development of a GHG inventory system still in use by the owner or operator.

(4) The potential for a conflict of interest shall be deemed to be medium where the potential for a conflict of interest is not deemed to be either high or low as specified in sections WCI.8(e)(2)-(3).

(A) If a verification body identifies a medium potential for conflict of interest and wishes to provide verification services for the owner or operator, then the verification body shall submit, in addition to the submittal requirements specified in section WCI.8(e)(5), below, a plan to avoid, neutralize, or mitigate the potential conflict of interest situation. At a minimum, the conflict of interest mitigation plan shall include:

i. A demonstration that any individuals in the verification body or team with potential conflicts have been removed and insulated from the project.
ii. An explanation of any changes to the verification body or verification team to remove the potential conflict of interest, including changes to organization structure to demonstrate that a unit with potential conflicts has been divested or moved into an insulated related entity.
iii. A description of any other circumstance that specifically addresses other sources for potential conflict of interest.

(B) As provided in section WCI.8(e)(6), below, the [TBD] shall evaluate the conflict of interest mitigation plan and determine whether verification services may proceed.

(5) Conflict of Interest Submittal Requirements for Accredited Verification Bodies.

(A) Before the start of any work related to providing verification services to an owner or operator, a verification body must first be authorized in writing by *[TBD]* to provide verification services. To obtain authorization the verification body shall submit to *[TBD]* a self-evaluation of the potential for any conflict of interest that the verification body, entities related to the verification body, and members of the verification team including, subcontractors may have with the owner or operator or their related entities for which it will perform verification services. The submittal shall include the following:

i. Identification of whether the potential for conflict of interest is high, low, or medium based on factors specified in sections WCI.8(e)(2)-(4);
ii. An organizational chart of the business structure of the verification body, including its related entities and brief description of the primary work done by the verification body and related entities;
iii. Identification of whether any member of the verification body, entities related to the verification body, or the verification team including subcontractors has previously provided verification services for the owner or operator or its related entities and, if so, the years in which such verification services were provided;
iv. Identification of whether any member of the verification body, entities related to the verification body, or the verification team or including subcontractors has engaged in any non-verification services of any nature with the owner or operator or related entities either within or outside the WCI region during the previous three years. If non-verification services have previously been provided, the following information shall also be submitted:

- Identification of the nature and location of the work performed for the owner or operator and whether the work is similar to the type of work to be performed during verification, such as emissions inventory, auditing, energy efficiency, renewable energy, or other work with implications for the operator's greenhouse gas emissions or the accounting of greenhouse gas emissions or electricity transactions;
- The nature of past, present or future relationships the verification body, entities related to the verification body, and members of the verification team including subcontractors have with the owner or operator or related entity including:
  - Instances when any member has performed or intends to perform work for the owner or operator;
  - Identification of whether work is currently being performed for the owner or operator and, if so, the nature of the work;
  - Whether any member has any contracts or other arrangements to perform work for the owner or operator or a related entity;
  - Identify how much work was performed in the last three years, as a percentage of the verification body's total gross income for the last three years;
  - Identify how much work related to greenhouse gases or electricity transactions was has performed for the owner or operator or related

entities in the last three years, as a percentage of the verification body's income for the last three years;
  - Identify how much work was performed by each subcontractor for the operator in the last three years, as a percentage of each subcontractor's total gross income for the last three years.

- Explanation of how the amount and nature of work previously performed is such that any member of the verification team's credibility and lack of bias should not be under question.

v. A list of names of the staff that will perform verification services for the owner or operator and a description of any instances of personal or family relationships with management or employees of the owner or operator that potentially represent a conflict of interest; and,

vi. Identification of any other circumstances or relevant information known to the verification body or owner or operator that could result in a conflict of interest, or any situation where the appearance of impartiality could undermine confidence in the verification body's ability to asses the reported emissions.

(6) Conflict of Interest Determinations. The *[TBD]* shall review the self-evaluation submitted by the verification body and determine whether the verification body is authorized to perform verification services for the owner or operator

(A) The *[TBD]* shall notify the verification body in writing when the conflict of interest evaluation information submitted under section WCI.8(e)(5) is deemed complete. Within *[Number of days TBD]* of deeming the evaluation information complete, *[TBD]* shall determine whether the verification body is authorized to proceed with verification and shall so notify the verification body.

(B) If *[TBD]* determines the verification body or any member of the verification team meets the criteria specified in section WCI.8(e)(2), *[TBD]* shall find a high potential conflict of interest and verification services may not proceed.

(C) If *[TBD]* determines that there is a low potential conflict of interest, verification services may proceed.

(D) If *[TBD]* determines that the verification body and verification team have a medium potential for a conflict of interest, *[TBD]* shall evaluate the conflict of interest mitigation plan submitted pursuant to sections WCI.8(e)(4), and may request additional information from the applicant to complete the determination. In determining whether verification services may proceed, *[TBD]* may consider factors including, but not limited to, the nature of previous work performed, the current and past relationships between the verification body and its subcontractors with the owner or operator, and the cost of the verification services to be performed. If *[TBD]* determines that these factors when considered in combination demonstrate an acceptable level of potential conflict of interest, then *[TBD]* will authorize the verification body to provide verification services.

(f) Monitoring Conflict of Interest Situations.

(1) After commencement of verification services, the verification body shall monitor and immediately make full disclosure in writing to *[TBD]* regarding any potential for a conflict of interest situation that arises. This disclosure shall include a description of actions that the verification body has taken or proposes to take to avoid, neutralize, or mitigate the potential for a conflict of interest.
(2) The verification body shall monitor arrangements or relationships that may be present for a period of one year after the completion of verification services. During that period, within 30 calendar days of any change in arrangements or relationships with the owner or operator for which the body has provided verification services, the verification body shall notify *[TBD]* of the change and provide a description of the nature of the change.
(3) The verification body shall report to *[TBD]* any changes in its organizational structure, including mergers, acquisitions, or divestitures, for one year after completion of verification services.
(4) *[TBD]* may invalidate a verification finding if a potential conflict of interest has arisen for any member of the verification team. In such a case, the owner or operator shall be provided 180 calendar days to complete re-verification.
(5) If the verification body or its subcontractor(s) are found to have violated the conflict of interest requirements of this section, *[TBD]* may rescind accreditation of the body, its verifier staff, or its subcontractor(s) for any appropriate period of time as provided in section WCI.8(d) *[TBD – accreditation requirements]*.

§ WCI.9 DEFINITIONS

[This is a partial list of definitions. Additional definitions are under development based on the Canadian regulations come from "Section 71 of the Canadian Environmental Protection Act (CEPA) 1999"and the CARB definitions come from "Title 17, Subchapter 10, Article 2, Section 95102 of the California Code of Regulations.]

"Adverse verification statement" means a verification statement rendered by a verification body stating that the verification body cannot say with reasonable assurance that the submitted emissions data report is free of material misstatement, or that it cannot provide a qualifying statement that the emissions data report conforms to the requirements of this article.

"Biomass fuels" or "biomass-derived fuels" means fuels derived entirely from biomass.

"Carbon dioxide equivalent" or "CO_2 equivalent" or "CO_2e" means a measure for comparing carbon dioxide with other GHGs, based on the quantity of those gases multiplied by the appropriate global warming potential (GWP) factor and commonly expressed as metric tons of carbon dioxide equivalent.

"Conflict of interest" means a situation in which, because of financial or other activities or relationships with other persons or organizations, a person or body is unable or potentially unable to render an impartial verification opinion of a potential client's greenhouse gas emissions, or the person or body's objectivity in performing verification services is or might be otherwise compromised.

"Continuous emissions monitoring system" or "CEMS" means the total equipment required to obtain a continuous measurement of a gas concentration or emission rate from combustion or industrial processes.

"Electricity generating unit" or "EGU" means any combination of physically connected generator(s), reactor(s), boiler(s), combustion turbine(s), or other prime mover(s) operated together to produce electric power.

"Exporter" means…*[To be defined later for transportation and RCI fuels accounting]*

"Facility" means any property, plant, building, structure, stationary source, stationary equipment or grouping of stationary equipment or stationary sources located on one or more contiguous or adjacent properties, in actual physical contact or separated solely by a public roadway or other public right-of-way, under common operational control, and having the same first two digits of the Standard Industrial Classification (SIC) or same first three digits of the North American Industry Classification System (NAICS) code. *[Some special facilities, such as oil and gas production fields will have separate definitions.]*

"Full verification" means all verification services as provided in section WCI.8(c).

"Global warming potential" or "GWP factor" means the radiative forcing impact of one mass-based unit of a given greenhouse gas relative to an equivalent unit of carbon dioxide over a given period of time.

"Greenhouse gas", "greenhouse gases" or "GHG" means carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), and perfluorocarbons (PFCs).

"Hydrofluorocarbons" or "HFCs" means a class of GHGs primarily used as refrigerants, consisting of hydrogen, fluorine, and carbon.

"Importer" means…*[To be defined later with input from the Electricity Subcommittee.]*

"Lead verifier" means a person that has met all of the requirements in section WCI.8 *[TBD]*, and who may act as the lead verifier of a verification team providing verification services or as a lead verifier providing an independent review of verification services rendered.

"Material misstatement" means one or more inaccuracies identified in the course of verification that result in the total reported emissions being outside the 95 percent accuracy required to receive a positive verification statement.

"Owner or operator" means any person who owns, leases, operates, controls, or supervises a facility or fuel supply operation; or who imports electricity into the WCI region.

"Perfluorocarbons" or "PFCs" means a class of greenhouse gases consisting on the molecular level of carbon and fluorine.

"Positive verification statement" means a verification statement rendered by a verification body stating that the verification body can say with reasonable assurance that the submitted emissions data report is free of material misstatement and includes a qualifying statement that the emissions data report conforms to the requirements of this article.

"Pure" means consisting of at least 97 percent by mass of a specified substance. For facilities burning biomass fuels, this means the fraction of biomass carbon accounts for at least 97 percent of the total amount of carbon in the fuel burned at the facility.

"Reasonable assurance" means a high degree of confidence that submitted data and statements are valid.

"Stationary combustion unit" means any boiler, heater, furnace, kiln, turbine, internal combustion engine, incinerator or other non-mobile source device that combusts any solid, liquid, or gaseous fuel for purposes of producing useful heat or energy for industrial, commercial, or institutional use; or for purposes of reducing the volume of waste by removing combustible material.

"Supplier" means . . . *[To be defined later for transportation and RCI fuels accounting.]*.

"Verification" means the process used to ensure that an operator's emissions data report is free of material misstatement and complies with WCI's reporting procedures and methods for calculating and reporting GHG emissions.

"Verification body" means a firm accredited by the jurisdiction or its designee, that is able to render a verification statement and provide verification services for operators subject to reporting under this article.

"Verification cycle" means one year of full verification and the next consecutive two years of less intensive verification for operators subject to annual verification. For operators subject to triennial verification, a verification cycle means one year of full verification, and if elected, the next consecutive two years of less intensive verification. A verification cycle cannot exceed three calendar years.

"Verification statement" means the final opinion rendered by a verification body attesting whether an operator's emissions data report is free of material misstatement and a qualifying statement whether the emissions data report conforms to the requirements of this article.

"Verification services" means services provided during verification as specified in section WCI.8, including but not limited to reviewing an owner's or operator's emissions data report, verifying its accuracy according to the standards specified in this section, assessing the owner's or operator's compliance with this section, and submitting a verification statement to the *[jurisdiction or its agent]*.

"Verification team" means all of those working for a verification body, including all subcontractors, to provide verification services for an operator. The lead verifier for the verification team shall be a lead verifier in the verification body.

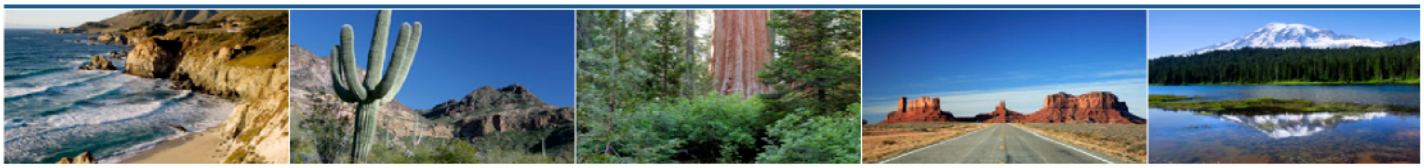
"Verifier" means an individual accredited by the jurisdiction or its designee to carry out verification services as specified in section WCI.8.

"Waste-derived fuel" means a fuel typically derived from waste and generally used as a substitute for conventional fossil fuels. Waste-derived fuels can include fossil fuels such as waste oil, plastics, or solvents; biomass such as dried sewage or impregnated saw dust; or fractions of both fossil fuels and biomass such as municipal solid waste or tires.

§ WCI.10 Global Warming Potentials

Owners and operators must use the global warming potential (GWP) values given in Table WCI.10-1 when converting emissions of greenhouse gases to metric tons of carbon dioxide equivalent (CO_2e), using Equation 1-1.

Table WCI.10-1. Global Warming Potential Factors for Greenhouse Gases			
Common Name	**Formula**	**Chemical Name**	**GWP**
Carbon dioxide	CO_2		1
Methane	CH_4		21
Nitrous oxide	N_2O		310
Sulfur hexafluoride	SF_6		23,900
Hydrofluorocarbons (HFCs)			
HFC-23	CHF_3	trifluoromethane	11,700
HFC-32	CH_2F_2	difluoromethane	650
HFC-41	CH_3F	fluoromethane	150
HFC-43-10mee	$C_5H_2F_{10}$	1,1,1,2,3,4,4,5,5,5- decafluoropentane	1,300
HFC-125	C_2HF_5	pentafluoroethane	2,800
HFC-134	$C_2H_2F_4$	1,1,2,2-tetrafluoroethane	1,000
HFC-134a	$C_2H_2F_4$	1,1,1,2-tetrafluoroethane	1,300
HFC-143	$C_2H_3F_3$	1,1,2-trifluoroethane	300
HFC-143a	$C_2H_3F_3$	1,1,1-trifluoroethane	3,800
HFC-152	$C_2H_4F_2$	1,2-difluoroethane	43
HFC-152a	$C_2H_4F_2$	1,1-difluoroethane	140
HFC-161	C_2H_5F	fluoroethane	12
HFC-227ea	C_3HF_7	1,1,1,2,3,3,3- heptafluoropropane	2,900
HFC-236cb	$C_3H_2F_6$	1,1,1,2,2,3-hexafluoropropane	1,300
HFC-236ea	$C_3H_2F_6$	1,1,1,2,3,3-hexafluoropropane	1,200
HFC-236fa	$C_3H_2F_6$	1,1,1,3,3,3-hexafluoropropane	6,300
HFC-245ca	$C_3H_3F_5$	1,1,2,2,3-pentafluoropropane	560
HFC-245fa	$C_3H_3F_5$	1,1,1,3,3-pentafluoropropane	950
HFC-365mfc	$C_4H_5F_5$	1,1,1,3,3-pentafluorobutane	890
Perfluorocarbons (PFCs)			
Perfluoromethane	CF_4	tetrafluoromethane	6,500
Perfluoroethane	C_2F_6	hexafluoroethane	9,200
Perfluoropropane	C_3F_8	octafluoropropane	7,000
Perfluorobutane	C_4F_{10}	decafluorobutane	7,000
Perfluorocyclobutane	$c\text{-}C_4F_8$	octafluorocyclobutane	8,700
Perfluoropentane	C_5F_{12}	dodecafluoropentane	7,500
Perfluorohexane	C_6F_{14}	tetradecafluorohexane	7,400



ATTACHMENT 2: GENERAL STATIONARY COMBUSTION

§ WCI.20 GENERAL STATIONARY COMBUSTION

§ WCI.21 Source Category Definition

General stationary fuel combustion sources are devices that combust solid, liquid, or gaseous fuel for the purpose of generating steam (or providing useful heat or energy) for industrial, commercial, or institutional use; or reducing the volume of waste by removing combustible matter. General stationary combustion sources are boilers, combustion turbines, engines, incinerators, and process heaters, and any other stationary combustion device that is not specifically addressed under the provisions for another source category in this rule.

Note: The source category definition may need to be revised after the remaining ER sections are completed.

§ WCI.22 Greenhouse Gas Reporting Requirements

The emissions data report shall include the following information at the facility level:

(a) Annual greenhouse gas emissions in metric tons, reported as follows:

(1) Total CO_2 emissions for fossil fuels, reported by fuel type.
(2) Total CO_2 emissions for all biomass fuels combined.
(3) Total CH_4 emissions for all fuels combined.
(4) Total N_2O emissions for all fuels combined.

(b) Annual fuel consumption:

(1) For gases, report in units of million cubic meters.
(2) For liquids, report in units of liters.
(3) For non-biomass solids, report in units of metric tons.
(4) For biomass-derived solid fuels, report in units of bone dry short tons or bone dry metric tons.

(c) Average carbon content of each fuel, if used to compute CO_2 emissions.

(d) Average high heating value of each fuel, as used to compute CO_2 emissions.

(e) Annual steam generation in pounds or kilograms, for units that burn biomass or municipal solid waste.

Please note that most of the calculation methodologies in this section currently accommodate inputs in English units, only, and not SI units. The section will be revised to allow inputs in SI units, as well as to provide applicable Canadian emission factors from "National Inventory Report 1990-2006: Greenhouse Gas Sources and Sinks in Canada – The Canadian

Government's Submission to the UN Framework Convention on Climate Change, April 2008." *(http://www.ec.gc.ca/pdb/ghg/inventory_e.cfm)]*

§ WCI.23 Calculation of CO_2 Emissions

For each fuel, calculate CO_2 mass emissions using one of the four calculation methodologies specified in this section, subject to the restrictions in §WCI.23 (e).

(a) Calculation Methodology 1. Calculate the annual CO_2 mass emissions by substituting a fuel-specific default CO_2 emission factor, a default high heating value, and the annual fuel consumption into the Equation 20-1:

$$CO_2 = Fuel \times HHV \times EF \times 0.001$$ **Equation 20-1**

Where:

CO_2 = Annual CO_2 mass emissions for the specific fuel type (metric tons).
Fuel = Mass or volume of fuel combusted per year (express mass in short tons for solid fuel, volume in standard cubic feet for gaseous fuel, and volume in gallons for liquid fuel).
HHV = Default high heat value of the fuel, from column 3 of Table 20-1 (mmBtu per mass or mmBtu per volume, as applicable).
EF = Fuel-specific default CO_2 emission factor, from column 5 of Table 20-1 (kg CO_2/mmBtu).
0.001 = Conversion factor from kilograms to metric tons.

(b) Calculation Methodology 2. Calculate the annual CO_2 mass emissions using a default CO_2 emission factor, and either Equation 20-2 or 20-3, as appropriate:

(1) Equation 20-2 of this section can be used for any type of fuel for which an emission factor is provided in Tables 20-1 or 20-2:

$$CO_2 = \sum_{p=1}^{n} Fuel_P \times HHV_P \times EF \times 0.001$$ **Equation 20-2**

Where:

CO_2 = Annual CO_2 mass emissions for a specific fuel type (metric tons).
n = Number of required heat content measurements for the year as specified in WCI.25.
$Fuel_p$ = Mass or volume of the fuel combusted during the measurement period "p" (express mass in short tons for solid fuel, volume in standard cubic feet for gaseous fuel, and volume in gallons for liquid fuel).
HHV_p = High heat value of the fuel for the measurement period (mmBtu per mass or volume).
EF = Fuel-specific default CO_2 emission factor, from column 5 of Table 20-1 or from Table 20-2 (kg CO_2/mmBtu).
0.001 = Conversion factor from kilograms to metric tons.

(2) Equation 20-3 of this section can be used for biomass solid fuels and municipal solid waste only:

$$CO_2 = Steam \times B \times EF \times 0.001$$ **Equation 20-3**

Where:

CO_2	=	Annual CO_2 mass emissions from MSW combustion (metric tons).
Steam	=	Total mass of steam generated by MSW combustion during the reporting year (lb steam).
B	=	Ratio of the boiler's maximum rated heat input capacity to its design rated steam output capacity (mmBtu/lb steam).
EF	=	Default carbon content for MSW, from column 5 of Table WCI.20-1 (kg CO_2/mmBtu).
0.001	=	Conversion factor from kilograms to metric tons.

(c) Calculation Methodology 3. Calculate the annual CO_2 mass emissions by substituting measurements of fuel carbon content, molecular weight (gaseous fuels, only), and the quantity of fuel combusted into the following equations. For solid fuels, the amount of fuel combusted is obtained from company records kept as provided in this rule. For liquid and gaseous fuels, the volume of fuel combusted is measured directly, using fuel flow meters (including gas billing meters). For fuel oil, tank drop measurements may also be used.

(1) For a solid fuel, use Equation 20-4 of this section:

$$CO_2 = \sum_{i=1}^{n} Fuel_i \times CC_i \times 3.664$$ **Equation 20-4**

Where:

CO_2	=	Annual CO_2 mass emissions from the combustion of the specific solid fuel (metric tons).
n	=	Number of monthly carbon content determinations for the year.
$Fuel_i$	=	Mass of the solid fuel combusted in month "n" (metric tons).
CC_i	=	Carbon content of the solid fuel, from the fuel analysis results for month "n"(percent by weight, expressed as a decimal fraction, e.g., 95% = 0.95).
3.664	=	Ratio of molecular weights, CO_2 to carbon.

(2) For a liquid fuel, use Equation 20-5 of this section:

$$CO_2 = \sum_{i=1}^{n} 3.664 \times Fuel_i \times CC_i \times 0.001$$ **Equation 20-5**

Where:

CO_2	=	Annual CO_2 mass emissions from the combustion of the specific liquid fuel (metric tons).
n	=	Number of required carbon content determinations for the year, as specified in WCI.25.

$Fuel_i$ = Volume of the liquid fuel combusted in month "n" (gallons).
CC_i = Carbon content of the liquid fuel, from the fuel analysis results for month "n" (kg C per gallon of fuel).
3.664 = Ratio of molecular weights, CO_2 to carbon.
0.001 = Conversion factor from kg to metric tons.

(3) For a gaseous fuel, use Equation 20-6 of this section:

$$CO_2 = \sum_{i=1}^{n} 3.664 \times Fuel_i \times CC_i \times \frac{MW}{MVC} \times 0.001 \qquad \textbf{Equation 20-6}$$

Where:

CO_2 = Annual CO_2 mass emissions from combustion of the specific gaseous fuel (metric tons).
n = Number of required carbon content and molecular weight determinations for the year, as specified in WCI.25.
$Fuel_i$ = Volume of the gaseous fuel combusted in a day or month, as applicable (scf).
CC_i = Average carbon content of the gaseous fuel, from the fuel analysis results for the day or month, as applicable (kg C per kg of fuel).
MW = Molecular weight of the gaseous fuel, from fuel analysis (kg/kg-mole).
MVC = Molar volume conversion factor (849.5 scf per kg-mole at standard conditions).
3.664 = Ratio of molecular weights, CO_2 to carbon.
0.001 = Conversion factor from kg to metric tons.

(d) Calculation Methodology 4. Calculate the annual CO_2 mass emissions from all fuels combusted in a unit, by using data from continuous emission monitoring systems (CEMS) as specified in (d)(1) through (d)(7).

(1) The operator of a facility that combusts fossil fuels or biomass and operates CEMS in response to federal, state, provincial, or local regulation, may use CO_2 or O_2 concentrations and flue gas flow measurements to determine hourly CO_2 mass emissions using methodologies provided in 40 CFR Part 75, Appendix F.

(A) The operator shall report CO_2 emissions for the report year in metric tons based on the sum of hourly CO_2 mass emissions over the year, converted to metric tons.
(B) If the operator of a facility that combusts biomass uses O_2 concentrations to calculate CO_2 concentrations, annual source testing must demonstrate that calculated CO_2 concentrations when compared to measured CO_2 concentrations meet the Relative Accuracy Test Audit (RATA) requirements in 40 CFR Part 60, Appendix B, Performance Specification 3.

(2) The operators of a facility that combusts municipal solid waste or other waste-derived fuels and operates a CEMS in response to federal, state, provincial, or local regulations must use CO_2 concentrations and flue gas flow measurements to determine hourly CO_2 mass emissions using methodologies provided in 40 CFR Part 75, Appendix F.

(A) Annual CO_2 emissions shall be reported in metric tons based on the sum of hourly CO_2 mass emissions over the year.

(B) Emissions calculations shall not be based on O_2 concentrations.

(3) The operator of a facility that combusts MSW or other waste-derived fuels and calculates CO_2 emissions using the methodology provided in WCI.23(d)(2) shall determine the portion of emissions associated with the combustion of biomass-derived fuels using the method provided in WCI.23(f).

(4) An operator who uses CEMS data to report CO_2 emissions from a facility that co-fires fossil fuels with biomass or waste-derived fuels that are partly biomass shall determine the portion of total CO_2 emissions separately assigned to the fossil fuel and the biomass-derived fuel using the method provided in WCI.23(f), if applicable. The operator who co-fires pure biomass with fossil fuels may elect to calculate CO_2 emissions for the fossil fuels using methods designated in WCI.23(b)(3) by fuel type and then subtract the fossil fuel related emissions from the total CO_2 emissions determined using the CEMS based methodology.

(5) For any units for which CO_2 emissions are reported using CEMS data, the operator is relieved of the requirement to separately report process emissions from combustion emissions or to report emissions separately for different fossil fuels when only fossil fuels are co-fired. In this circumstance, operators shall still report fuel use by fuel type as otherwise required.

(6) If a facility is subject to requirements in 40 CFR Part 60 or 40 CFR Part 75 and the operator chooses to add devices to an existing continuous monitoring system for the purpose of measuring CO_2 concentrations or flue gas flow, the operator shall select and operate the added devices pursuant to the requirements in 40 CFR Part 60 or Part 75 that apply to the facility. If the facility is subject to both 40 CFR Part 60 and 40 CFR Part 75, the operator shall select and operate the added devices pursuant to the requirements in 40 CFR Part 75.

(7) If a facility does not have a continuous emissions monitoring system and the operator chooses to add one in order to measure CO_2 concentrations, the operator shall select and operate the CEMS pursuant to the requirements in 40 CFR Part 75.

(A) The operator shall use CO_2 concentrations and flue gas flow measurements to determine hourly CO_2 mass emissions using methodologies provided in 40 CFR Part 75, Appendix F.

(B) The operator shall report CO_2 emissions for the report year in metric tons based on the sum of hourly CO_2 mass emissions over the year, converted to metric tons.

(C) Operators who add CEMS under this article are subject to specifications in WCI.23(d)(1)-(5), if applicable.

(e) Use of the Four CO_2 Calculation Methodologies. Use of the four CO_2 emissions calculation methodologies described in paragraphs (a) through (d) of this section is subject to the following requirements and restrictions:

(1) Calculation Methodology 1 may not be used by a facility that is subject to the verification requirements of WCI.8, except for stationary combustion units that combust natural gas with a high heating value between 975 and 1,150 Btu per cubic foot. Otherwise, Calculation Methodology 1 may be used for any type of fuel for which a default CO_2 emission factor and a default high heat value for the fuel is specified in Table 20-1.

(2) Calculation Methodology 2 may not be used by a facility that is subject to the verification requirements of WCI.8, except for stationary combustion units that combust natural gas with a high heating value between 975 and 1,150 Btu per cubic foot. Otherwise, Calculation Methodology 2 may be used for any type of fuel combusted for which a default CO_2 emission factor for the fuel is specified in Table 20-1 or 20-2.
(3) Calculation Methodology 3 may be used for a unit of any size combusting any type of fuel, except when the use of Calculation Methodology 4 is required.
(4) Calculation Methodology 4 may be used for a unit of any size combusting any type of fuel, and must be used for either of the following conditions:

(i) A combustion unit with a CEMS that is required by any federal, state, provincial, or local regulation.

(ii) A municipal solid waste combustion unit that is subject to the verification requirements of WCI.8.

(f) Biogenic CO_2 emissions. The operator that combusts fuels or fuel mixtures that contain biomass shall determine the biomass-derived portion of CO_2 emissions using ASTM D6866-06a, as specified in this paragraph. This procedure is not required for fuels that contain less than 5 percent biomass by weight or for waste-derived fuels that are less than 30 percent biomass by weight on an annual basis.

(1) The operator shall conduct ASTM D6866-06a analysis at least every three months, and shall collect each gas sample for analysis during normal operating conditions over at least 24 consecutive hours.
(2) The operator shall divide total CO_2 emissions between biomass-derived emissions and non-biomass-derived emissions using the average proportionalities of the samples analyzed.
(3) If there is a common fuel source to multiple units at the facility, the operator may elect to conduct ASTM D6866-06a testing for one of the units.

§ WCI.24 Calculation of CH_4 and N_2O Emissions

Calculate the annual CH_4 and N_2O mass emissions from stationary fuel combustion sources using the procedures in paragraph (a), (b), or (c), as appropriate.

(a) If the heat content of the fuel is measured, calculate CH_4 and N_2O emissions the following Equation 20-7:

$$CH_4 \ or \ N_2O = \sum_{1}^{n} Fuel_P \times HHV_P \times EF \times 0.001 \qquad \textbf{Equation 20-7}$$

Where:

CH_4 or N_2O	=	Combustion emissions from specific fuel type, metric tons CH_4 or N_2O per year.
n	=	Period/frequency of heat content measurements over the year (e.g. monthly n = 12).
$Fuel_P$	=	Mass or volume of fuel combusted for the measurement period specified by fuel type, units of mass or volume per unit time.

HHV_P	=	High heat value measured for the measurement period specified by fuel type, MMBtu per unit mass or volume.
EF	=	Default CH_4 or N_2O emission factor provided in Table 20-3, kg CH_4 or N_2O per MMBtu.
0.001	=	Factor to convert kg to metric tons.

(b) If the heat content of the fuel is not measured, calculate CH_4 and N_2O emissions using the following equation:

$$CH_4 \ or \ N_2O = \sum_{1}^{n} Fuel \times HHV_D \times EF \times 0.001$$ **Equation 20-8**

Where:

CH_4 or N_2O	=	CH_4 or N_2O emissions from a specific fuel type, metric tons CH_4 or N_2O per year.
Fuel	=	Mass or volume of fuel combusted specified by fuel type, unit of mass or volume per year.
HHV_D	=	Default high heat value specified by fuel type provided in Table 20-3, MMBtu per unit of mass or volume.
EF	=	Default emission factor provided in Table 20-3, kg CH_4 or N_2O per MMBtu.
0.001	=	Factor to convert kg to metric tons.

(c) For municipal solid waste combustion, use Equation 20-9 of this section to estimate CH_4 and N_2O emissions:

$$CH_4 \ or \ N_2O = Steam \times B \times EF \times 0.001$$ **Equation 20-9**

Where:

CH_4 or N_2O	=	Annual CH_4 or N_2O emissions from the combustion of a municipal solid waste (metric tons).
Steam	=	Total mass of steam generated by MSW combustion during the reporting year (lb steam).
B	=	Ratio of the boiler's maximum rated heat input capacity to its design rated steam output (mmBtu/lb steam).
EF	=	Fuel-specific emission factor for CH_4 or N_2O, from Table WCI.20-3 of this subpart (kg CH_4 or N_2O per mmBtu).
0.001	=	Conversion factor from kilograms to metric tons.

(d) The operator may elect to calculate CH_4 and N_2O emissions using source-specific emission factors derived from source tests conducted at least annually under the supervision of (*jurisdiction*). Upon approval of a source test plan, the source test procedures in that plan shall be repeated in each future year to update the source specific emission factors annually.

§ WCI.25 Sampling, Analysis, and Measurement Requirements

(a) Fuel Sampling Requirements. Fuel sampling must be conducted at the frequency specified in paragraph (a) (1) through (a)(4) of this section.

(1) At receipt of each new fuel shipment or delivery or on a monthly basis for middle distillates (diesel, gasoline, fuel oil, kerosene), residual oil, liquid waste-derived fuels, and LPG (ethane, propane, isobutene, n-Butane, unspecified LPG);
(2) Monthly for natural gas, associated gas, and mixtures of low Btu gas.
(3) Monthly for gases derived from biomass including landfill gas and biogas from wastewater treatment or agricultural processes.
(4) Monthly for solid fuels, as specified below:

(A) The monthly solid fuel sample shall be a composite sample of weekly samples.
(B) The solid fuel shall be sampled at a location after all fuel treatment operations and the samples shall be representative of the fuel chemical and physical characteristics immediately prior to combustion.
(C) Each weekly sub-sample shall be collected at a time (day and hour) of the week when the fuel consumption rate is representative and unbiased.
(D) Four weekly samples (or a sample collected during each week of operation during the month) of equal mass shall be combined to form the monthly composite sample.
(E) The monthly composite sample shall be homogenized and well mixed prior to withdrawal of a sample for analysis.
(F) One in twelve composite samples shall be randomly selected for additional analysis of its discreet constituent samples. This information will be used to monitor the homogeneity of the composite.

(b) Fuel Consumption Monitoring Requirements.

(1) Facilities that are subject to the verification requirements of WCI.8 must determine annual fuel consumption by direct measurement.
(2) Facilities that are not subject the verification requirements of WCI.8 may determine consumption on the basis of recorded fuel purchase or sales invoices measuring any stock change (measured in million Btu, gallons, million standard cubic feet, short tons or bone dry short, tons) using the following equation:

Fuel Consumption in the Report Year = Total Fuel Purchases – Total Fuel Sales + Amount Stored at Beginning of Year – Amount Stored at Year End

(3) Fuel consumption measured in Btu values shall be converted to the required metrics of mass or volume using heat content values that are either provided by the supplier, measured by the facility, or provided in Table 20-1.

(c) Fuel Heat Content Monitoring Requirements. High heat values shall be determined using one of the following methods:

(1) For gases, use ASTM D1826-94 (Reapproved 2003), ASTM D3588-98 (Reapproved 2003), ASTM D4891-89 (Reapproved 2006), GPA Standard 2261-00 "Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography." The operator may alternatively elect to use on-line instrumentation that determines heating value accurate to

within ± 5.0 percent. Where existing on-line instrumentation provides only low heating value, the operator shall convert the value to high heating value as specified in section 95125(c)(1)(C).

(2) For middle distillates and oil, or liquid waste-derived fuels, use ASTM D240-02 (Reapproved 2007), ASTM D240-87 (Reapproved 1991), ASTM D4809-00 (Reapproved 2005).

(3) For solid biomass-derived fuels use ASTM D5865-07a.

(4) For waste-derived fuels use ASTM D5865-07a or ASTM D5468-02 (Reapproved 2007). Operators who combust waste-derived fuels that are partly but not pure biomass shall determine the biomass-derived portion of CO_2 emissions using the method specified in section WCI.23(f), if applicable

(d) Fuel Carbon Content Monitoring Requirements. Fuel carbon contents should be monitored in the following manner.

(1) For coal and coke, solid biomass-derived fuels, and waste-derived fuels; use ASTM 5373-02 (Reapproved 2007).

(2) For liquid fuels, use the following ASTM methods: For petroleum-based liquid fuels and liquid waste-derived fuels, use ASTM D5291-02 (Reapproved 2007) "Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants", ultimate analysis of oil or computations based on ASTM D3238-95 (Reapproved 2005) and either ASTM D2502-04 or ASTM D2503-92 (Reapproved 2002).

(3) For gaseous fuels, use ASTM D1945-03 or ASTM D1946-90 (Reapproved 2006).

Table 20-1. Default Carbon Content, Heat Content, and Carbon Dioxide Emission Factors from Stationary Combustion by Fuel Type				
Fuel Type	**Carbon Content**	**High Heat Value**	**CO_2 Emission Factor**	**CO_2 Emission Factor**
Coal and Coke	**kg C / MMBtu**	**MMBtu / Short Ton**	**kg CO_2 / Short Ton**	**kg CO_2 / MMBtu**
Anthracite	28.26	25.09	2,597.94	103.54
Bituminous	25.49	24.93	2,328.35	93.40
Sub-bituminous	26.48	17.25	1,673.64	97.02
Lignite	26.30	14.21	1,369.32	96.36
Unspecified (Residential/Commercial)	26.00	22.24	2,118.67	95.26
Unspecified (Industrial Coking)	25.56	26.28	2,461.17	93.65
Unspecified (Other Industrial)	25.63	22.18	2,082.89	93.91
Unspecified (Electric Power)	25.76	19.97	1,884.86	94.38
Coke	27.85	24.80	2,530.65	102.04
Natural Gas (By Heat Content)	**kg C / MMBtu**	**Btu / Standard cubic foot**	**kg CO_2 / Standard cubic ft.**	**kg CO_2 / MMBtu**
975 to 1,000 Btu / Standard cubic foot	14.73	n/a	n/a	53.97
1000 to 1,025 Btu / Std cubic foot	14.43	n/a	n/a	52.87
1025 to 1,050 Btu / Std cubic foot	14.47	n/a	n/a	53.02
1050 to 1,075 Btu / Std cubic foot	14.58	n/a	n/a	53.42
1075 to 1,100 Btu / Std cubic foot	14.65	n/a	n/a	53.68
Greater than 1,100 Btu / Std cubic foot	14.92	n/a	n/a	54.67
Unspecified (Weighted U.S. Average)	14.47	1,027	0.0544	53.02

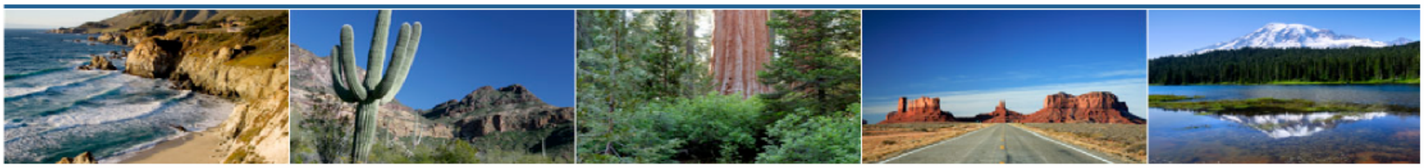
Table 20-1. Default Carbon Content, Heat Content, and Carbon Dioxide Emission Factors from Stationary Combustion by Fuel Type (continued)				
Petroleum Products	**kg C / MMBtu**	**MMBtu / Barrel**	**kg CO_2 / gallon**	**kg CO_2 / MMBtu**
Asphalt & Road Oil	20.62	6.636	11.94	75.55
Aviation Gasoline	18.87	5.048	8.31	69.14
Distillate Fuel Oil (#1, 2 & 4)	19.95	5.825	10.14	73.10
Jet Fuel	19.33	5.670	9.56	70.83
Kerosene	19.72	5.670	9.75	72.25
LPG (energy use)	17.19	3.861	5.79	62.98
Propane	17.20	3.824	5.74	63.02
Ethane	16.25	2.916	4.13	59.54
Isobutane	17.75	4.162	6.44	65.04
n-Butane	17.72	4.328	6.69	64.93
Lubricants	20.24	6.065	10.71	74.16
Motor Gasoline	19.33	5.218	8.80	70.83
Residual Fuel Oil (#5 & 6)	21.49	6.287	11.79	78.74
Crude Oil	20.33	5.800	10.29	74.49
Naphtha (<401 deg. F)	18.14	5.248	8.30	66.46
Natural Gasoline	18.24	4.620	7.35	66.83
Other Oil (>401 deg. F)	19.95	5.825	10.14	73.10
Pentanes Plus	18.24	4.620	7.35	66.83
Petrochemical Feedstocks	19.37	5.428	9.17	70.97
Petroleum Coke	27.85	6.024	14.64	102.04
Still Gas	17.51	6.000	9.17	64.16
Special Naphtha	19.86	5.248	9.09	72.77
Unfinished Oils	20.33	5.825	10.33	74.49
Waxes	19.81	5.537	9.57	72.58
Other Solid Fuels	**kg C / MMBtu**	**MMBtu / Short Ton**	**kg CO_2 / Short Ton**	**kg CO_2 / MMBtu**
Biomass Derived Fuels (Solid). Wood and Wood Waste (12% moisture content) or other solid biomass-derived fuels	25.60	15.38	1,442.62	93.80
Municipal Solid Waste (MSW)	24.74	8.7	788.7	90.65
Biomass-derived Fuels (Gas)	**kg C / MMBtu**	**Btu / Standard cubic foot**	**kg CO_2 / Standard cubic ft.**	**kg CO_2 / MMBtu**
Biogas (includes landfill gas and manure biogas)*	28.4	Varies	Varies	104.06

Note: Heat content factors are based on higher heating values (HHV).

* The emission factors for biogas include both the CO_2 from combustion and the pass-through CO_2, which are assumed to be in equal proportions.

Table 20-2. Default Carbon Dioxide Emission Factors from Stationary Combustion for Waste Derived Fuels	
Fuel Type	**kg CO_2 / MMBtu**
Waste Oil	78
Tires	90
Plastics	79
Solvents	78
Impregnated Saw Dust	79
Other Fossil Based Wastes	84
Dried Sewage Sludge	116
Mixed Industrial Waste	88
Municipal Solid Waste	91
Note: Emission factors are based on higher heating values (HHV). Values were converted from LHV to HHV assuming that LHV are 5 percent lower than HHV for solid and liquid fuels.	

Table 20-3. Default CH_4 and N_2O Emission Factors from Stationary Combustion by Fuel Type		
Fuel Type	**CH_4 Emission Factor (kg CH_4/ MMBtu)**	**N_2O Emission Factor (kg N_2O / MMBtu)**
Asphalt	0.003	0.006
Aviation Gasoline	0.003	0.006
Coal	0.01	1.5
Crude Oil	0.003	0.006
Digester Gas	0.0009	0.1
Distillate	0.003	0.006
Gasoline	0.003	0.006
Jet Fuel	0.003	0.006
Kerosene	0.003	0.006
Landfill Gas	0.0009	0.1
LPG	0.001	0.1
Lubricants	0.003	0.006
MSW	0.03	0.004
Naphtha	0.003	0.006
Natural Gas	0.0009	0.1
Natural Gas Liquids	0.003	0.006
Other Biomass	0.03	0.004
Petroleum Coke	0.003	0.006
Propane	0.001	0.1
Refinery Gas	0.0009	0.1
Residual Fuel Oil	0.003	0.006
Tires	0.003	0.006
Waste Oil	0.03	0.004
Waxes	0.003	0.006
Wood (Dry)	0.03	0.004
Note: Heat content factors are based on higher heating values (HHV).		



ATTACHMENT 3: REFINERY FUEL GAS COMBUSTION

§ WCI.30 REFINERY FUEL GAS COMBUSTION

WCI.31 Source Category Definition

This source category consists of any combustion device that is located at a petroleum refinery and that combusts refinery fuel gas, still gas, flexigas, or associated gas.

WCI.32 Greenhouse Gas Reporting Requirements

In addition to the information required by WCI.3, the emissions data report shall include the following information at the facility level:

(a) Annual CO_2, CH_4, and N_2O emissions from refinery fuel gas combustion in metric tons.

(b) Annual fuel consumption in units of million standard cubic feet or cubic meters.

(c) Average carbon content of each fuel, if used to compute CO_2 emissions.

(d) Average high heating value of each fuel, if used to compute CO_2 emissions.

WCI.33 Calculation of Greenhouse Gas Emissions

(a) Calculation of CO_2 Emissions. Owners and operators shall calculate daily CO_2 emissions for each fuel gas system using any of the methods specified in paragraphs (a)(1) through (a)(5) of this section. Calculate the total annual CO_2 emissions from combustion of all fuel gas by summing the CO_2 emissions from each fuel gas system.

(1) Use a CEMS that complies with the provisions in section WCI.23(d).

(2) Calculate CO_2 emissions from each refinery fuel gas system and flexigas system using measured carbon content and molecular weight of the gas and Equation 30-1.

$$CO_2 = \sum_{i=1}^{n} Fuel_i \times CC_i \times \frac{MW}{MVC} \times 3.664 \times 0.001 \qquad \textbf{Equation 30-1}$$

Where:

CO_2 = Carbon dioxide emissions, metric tons/year.
$Fuel_i$ = Daily refinery fuel or flexigas combusted (scf).
CC_i = Daily sample of carbon content of the fuel (kg C/kg fuel).
MW = Daily sample of molecular weight of fuel.
MVC = Molar volume conversion factor (849.5 scf/kg-mole for STP of 20°C and 1 atmosphere, or 836 scf/kg-mole for STP of 60°F and 1 atmosphere).
3.664 = Conversion factor for carbon to carbon dioxide.
0.001 = Conversion factor for kg to metric tons.
n = Number of days in a year.

(A) For refinery fuel gas, the daily carbon content shall be determined a minimum of 3 times a day (once every 8 hours) using on-line instrumentation or discrete laboratory analysis using the methods specified in WCI.34.

(B) For flexigas, the daily carbon content shall be determined once per day using the methods specified in WCI.34.

(3) Calculate CO_2 emissions from each fuel gas system and flexigas system using Equation 30-2 and a daily average high heating value that is monitored using a continuous on-line instrument.

$$CO_2 = \sum_{i=1}^{n} HHV_i \times Fuel_i \times EF_{CO2,i} \times 0.000001 \qquad \textbf{Equation 30-2}$$

Where:

CO_2	=	CO_2 emissions resulting from the combustion of fuel gas from an individual fuel gas system (metric tons/yr).
HHV_i	=	Daily average high heating value of fuel gas, derived from a continuous analyzer and integrated over a 24-hour period (Btu/scf).
$Fuel_i$	=	Daily fuel consumption from all fuel combustion units burning gas from the system (scf/d).
$EF_{CO2,i}$	=	Daily CO_2 emission factor for an individual fuel gas system, developed using Equation 30-3 (metric tons CO_2/MM Btu).
0.000001	=	Conversion factor for Btu to MMBtu.
n	=	Number of days per year.

$$EF_{CO2,i} = CC/HHV \times MW/MVC \times 3.664 \times 1000 \qquad \textbf{Equation 30-3}$$

Where:

$EF_{CO2,i}$	=	Daily CO_2 emission factor for an individual fuel gas system (metric tons CO_2/MMBtu).
CC	=	Daily sample of gas carbon content for a fuel gas system, collected according to paragraph (a)(3)(A) of this section (kg carbon/kg fuel).
HHV	=	Daily sample of gas high heating value for a fuel gas system, collected according to paragraph (a)(3)(A) of this section (Btu/scf).
MW	=	Refinery fuel A molecular weight (kg/kg-mole).
MVC	=	Molar volume conversion (849.5 scf/ kg-mole, for STP of 20°C and 1 atmosphere, or 836 scf/kg-mole for STP of 60°F and 1 atmosphere).
3.664	=	Conversion factor for carbon to carbon dioxide.
1000	=	Conversion factor for kg/Btu to metric tons/MMBtu.

(A) For Equation 30-3, the carbon content shall be determined once per day by on-line instrumentation or by laboratory analysis of a representative sample using the methods specified in WCI.34. The HHV shall be determined from either the same sample used to conduct the carbon analysis or from on-line instrumentation using the hourly average value that coincides with the same hour in which the carbon content was determined.

(B) For facilities that meet the definition of a small refiner in WCI.10, the emissions measurements and calculations for Equation 30-2 and 30-3 may be conducted weekly.

(4) For associated gas, low Btu gas, or other fossil fuels; follow the requirements for general stationary source combustion sources in WCI .23(b) or (c), as appropriate for each fuel.

(5) Where individual fuels are mixed prior to combustion, the operator may choose to calculate CO_2 emissions for each fuel prior to mixing instead of using the methods in paragraphs (a)(1), (a)(2), or (a)(3) of this section. In this case, the operator must determine the fuel flow rate and appropriate fuel specific parameters (e.g. carbon content, HHV) of each fuel stream prior to mixing, calculate CO_2 emissions for each fuel stream, and sum the emissions of the individual fuel streams to determine total CO_2 emissions from the mixture. CO_2 emissions for each fuel stream must be estimated using the following methods:

(A) For natural gas and associated gas, use the appropriate methodology specified in section WCI.23(b) or (c).

(B) For refinery fuel gas and flexigas, use the methodology in either paragraph (a)(2) or (a)(3) of this section.

(C) For low Btu gas, use the methodology in paragraph (a)(2) of this section.

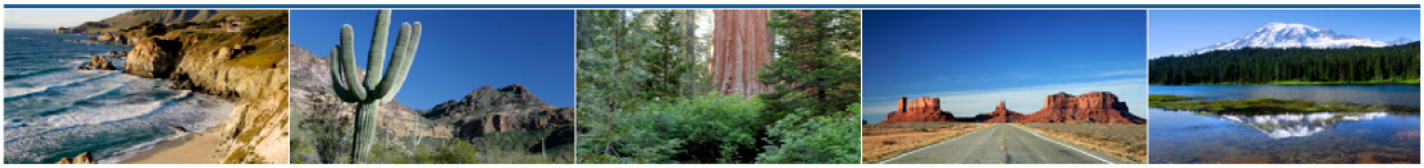
(b) Calculation of CH_4 and N_2O Emissions. Owners and operators shall use the methods specified in section WCI.24 to calculate the annual CH_4 and N_2O emissions.

WCI.34 Sampling, Analysis, and Measurement Requirements

(a) Measure the fuel consumption rate daily using methods specified in WCI.25(b).

(b) Measure the carbon content for fuel gas and flexigas using either ASTM D1945-03 or ASTM D1946-90 (Reapproved 2006).

(c) Measure high heating value using the monitoring requirements specified in WCI.25(c) for gaseous fuels.



ATTACHMENT 4: ELECTRICITY GENERATION

§ WCI.40 ELECTRICITY GENERATION

WCI.41 Source Category Definition

An electricity generator is any combustion device that combusts solid, liquid, or gaseous fuel for the purpose of producing electricity either for sale or for use onsite. This source category excludes cogeneration units subject to WCI.50.

WCI.42 Greenhouse Gas Reporting Requirements

For each facility, the emissions data report shall include the following information:

(a) Annual greenhouse gas emissions in metric tons, reported as follows:

(1) Total CO_2 emissions for fossil fuels, reported by fuel type.
(2) Total CO_2 emissions for all biomass fuels combined.
(3) Total CH_4 emissions for fuels combined.
(4) Total N_2O emissions for all fuels combined.

(b) Annual fuel consumption:

(1) For gases, report in units of million standard cubic feet or cubic meters.
(2) For liquids, report in units of gallons or liters.
(3) For non-biomass solids, report in units of short tons or metric tons.
(4) For biomass-derived solid fuels, report in units of bone dry short tons or bone dry metric tons.

(c) Average carbon content of each fuel, if used to compute CO_2 emissions as specified in WCI.44.

(d) Average high heating value of each fuel, if used to compute CO_2 emissions as specified WCI.44.

(e) The nameplate generating capacity in megawatts and net power generated in the reporting year in megawatt hours.

(f) Process CO_2 emissions from acid gas scrubbers and acid gas reagent.

(g) Fugitive emissions of HFC from cooling units that support power generation.

(h) Fugitive CO_2 emissions from geothermal facilities.

(i) Fugitive CO_2 emissions from coal storage at coal-fired electricity generating facilities shall be reported as specified in section WCI.100.

WCI.43 Calculation of Greenhouse Gas Emissions

(a) Calculation of CO_2 Emissions. Operators shall use CEMS to measure CO_2 emissions if required to operate a CEMS by any other federal, state, provincial, or local regulation. Operators not required to operate a CEMS by another regulation may use either CEMS or the calculation methods specified in paragraphs (a)(1) through (a)(7). Operators using CEMS to determine CO_2 emissions shall comply with the provisions in section WCI.23(d).

(1) Natural Gas. For electric generating units combusting natural gas, use one of the following methods:

(A) If the high heat value is greater than or equal to 975 and less than or equal to 1,100 Btu/scf use either:

i. The measured carbon content of the fuel and calculation methodology 3 in section WCI.23(c); or
ii. The measured heat content of the fuel and the calculation methodology 2 in section WCI.23(b) provided the facility is not subject to the verification requirements of WCI.8.

(B) If the high heat value is less than 975 or greater than 1,100 Btu/scf, use the measured carbon content of the fuel and the calculation methodology 3 in section WCI.23(c).

(2) Coal or Petroleum Coke. For electric generating units combusting coal or petroleum coke, use the measured carbon content of the fuel and calculation methodology 3 in section WCI.23(c).

(3) Middle Distillates, Gasoline, Residual Oil, or Liquid Petroleum Gases. For electric generating units combusting middle distillates (such as diesel, fuel oil, or kerosene), gasoline, residual oil, or LPG (such as ethane, propane, isobutene, n-butane, or unspecified LPG), use one of the following methods:

(A) The measured carbon content of the fuel and calculation methodology 3 in section WCI.23(c); or
(B) The measured heat content of the fuel and calculation methodology 2 in section WCI.23(b) provided the facility is not subject to the verification requirements of WCI.8.

(4) Refinery Fuel Gas, Flexigas, or Associated Gas. For electric generating units combusting refinery fuel gas, flexigas, or associated gas, use the methods specified in section WCI.30.

(5) Landfill Gas, Biogas, or Biomass. For electric generating units combusting landfill gas, biogas, or biomass, use one of the following methods:

(A) The measured carbon content of the fuel and calculation methodology 3 provided in section WCI.23(c); or
(B) The measured heat content of the fuel and calculation methodology 2 in section WCI.23(b) provided the facility is not subject to the verification requirements of WCI.8.

(6) Municipal Solid Waste. Electric generating units combusting municipal solid waste, may use the measured steam generated, the default carbon content emission factor in Table 20-1, and the calculation methodology in section WCI.23(b)(2) provided the facility is not subject to the verification requirements of WCI.8. If the facility is subject to the

verification requirements of WCI.8, the operator shall use CEMS to measure CO_2 emissions in accordance with WCI.23(d).

(7) Start-up Fuels. The operators of generating facilities that primarily combust biomass-derived fuels but combust fossil fuels during start-up, shut-down, or malfunction operating periods only, shall calculate CO_2 emissions from fossil fuel combustion using one of the following methods:

(A) The default emission factors from Tables 20-1 and 20-2 and calculation methodology 1 provided in section WCI.23(a);
(B) The measured heat content of the fuel and calculation methodology 2 provided in section WCI.23(b);
(C) The measured carbon content of the fuel and calculation methodology 3 provided in section WCI.23(c); or
(D) For combustion of refinery fuel gas, the measured heat content and carbon content of the fuel, and the calculation methodology provided in section WCI.30.

(8) Co-fired Electricity Generating Units. For electricity generating units that combust more than one type of fuel, the operator shall calculate CO_2 emissions as follows.

(A) For co-fired electricity generators that burn only fossil fuels, CO_2 emissions shall be determined using one of the following methods:

i. A continuous emission monitoring system in accordance with calculation methodology 4 in section WCI.23(d). Operators using this method need not report emissions separately for each fossil fuel.
ii. For units not equipped with a continuous emission system, calculate the CO2 emissions separately for each fuel type using the methods specified in paragraphs (a)(1) through (a)(4) of this section.

(B) For co-fired electricity generators that burn biomass-derived fuel with a fossil fuel, CO_2 emissions shall be determined using one of the following methods:

i. A continuous emission monitoring system in accordance with calculation methodology 4 in section WCI.23(d). Operators using this method shall determine the portion of the total CO_2 emissions attributable to the biomass-derived fuel and portion of the total CO_2 emissions attributable to the fossil fuel using the methods specified in section WCI.23(d)(4).
ii. For units not equipped with a continuous emission system, calculate the CO_2 emissions separately for each fuel type using the methods specified in paragraphs (a)(1) through (a)(7) of this section.

(b) Calculation of CH_4 and N_2O Emissions. Operators of electricity generating units shall use the methods specified in section WCI.24 to calculate the annual CH_4 and N_2O emissions. For coal combustion, use the default CH_4 emission factor of 1g of CH_4/mmBtu.

(c) Calculation of CO_2 Emissions from Acid Gas Scrubbing. Operators of electricity generating units that use acid gas scrubbers or add an acid gas reagent to the combustion unit shall calculate the annual CO_2 emissions from these processes using Equation 40-1 if these emissions are not already captured in CO_2 emissions determined using a continuous emissions monitoring system.

$$CO_2 = S \times R \times \left(CO_{2\,MW} / Sorbent_{MW} \right) \qquad \textbf{Equation 40-1}$$

Where:

CO_2 = CO_2 emitted from sorbent for the report year, metric tons;
S = Limestone or other sorbent used in the report year, metric tons;
R = Ratio of moles of CO_2 released upon capture of one mole of acid gas;
$CO_{2\ MW}$ = Molecular weight of carbon dioxide (44);
$Sorbent_{MW}$ = Molecular weight of sorbent (if calcium carbonate, 100).

(d) Calculating Fugitive HFC Emissions from Cooling Units. Operators of electricity generating facilities shall calculate fugitive HFC emissions for each HFC compound used in cooling units that support power generation or are used in heat transfers to cool stack gases using either the methodology in paragraph (d)(1) or (d)(2). The Operator is not required to report GHG emissions from air or water cooling systems or condensers that do not contain HFCs.

(1) Use Equation 40-2 to calculate annual HFC emissions:

$$HFC = HFC_{inventory} + HFC_{purchases/acquisitions} - HFC_{sales/disbursements} + HFC_{\Delta capacity}$$ **Equation 40-2**

Where:

HFC = Annual fugitive HFC emission, metric tons;
$HFC_{inventory}$ = The difference between the quantity of HFC in storage at the beginning of the year and the quantity in storage at the end of the year. Stored HFC includes HFC contained in cylinders (such as 115-pound storage cylinders), gas carts, and other storage containers. It does not include HFC gas held in operating equipment. The change in inventory will be negative if the quantity of HFC in storage increases over the course of the year.
$HFC_{purchases/acquisitions}$ = The sum of all HFC acquired from other entities during the year either in storage containers or in equipment.
$HFC_{sales/disbursements}$ = The sum of all the HFC sold or otherwise transferred offsite to other entities during the year either in storage containers or in equipment.
$HFC_{\Delta capacity}$ = The net change in the total nameplate capacity (i.e. the full and proper charge) of the cooling equipment). The net change in capacity will be negative if the total nameplate capacity at the end of the year is less than the total nameplate capacity at the beginning of the year.

(2) Use service logs to document HFC usage and emissions from each cooling unit. Service logs should document all maintenance and service performed on the unit during the report year, including the quantity of HFCs added to or removed from the unit, and include a record at the beginning and end of each report year. The operator may use service log information along with the following simplified material balance equations to quantify fugitive HFCs from unit installation, servicing, and retirement, as applicable. The operator shall include the sum of HFC emissions from the applicable equations in the greenhouse gas emissions data report.

$$HFC_{Install} = R_{new} - C_{new}$$
$$HFC_{Service} = R_{recharge} - R_{Recover}$$
$$HFC_{Retire} = C_{retire} - R_{retire}$$

Where:

$HFC_{Install}$	=	HFC emitted during initial charging/installation of the unit, kilograms;
$HFC_{Service}$	=	HFC emitted during use and servicing of the unit for the report year, kilograms;
HFC_{Retire}	=	HFC emitted during the removal from service/retirement of the unit, kilograms;
R_{new}	=	HFC used to fill new unit (omit if unit was pre-charged by the manufacturer), kilograms;
C_{new}	=	Nameplate capacity of new unit (omit if unit was pre-charged by the manufacturer), kilograms;
$R_{recharge}$	=	HFC used to recharge the unit during maintenance and service, kilograms;
$R_{recover}$	=	HFC recovered from the unit during maintenance and service, kilograms;
C_{retire}	=	Nameplate capacity of the retired unit, kilograms; and
R_{retire}	=	HFC recovered from the retired unit, kilograms.

(e) Fugitive CO_2 Emissions from Geothermal Facilities. Operators of geothermal electricity generating facilities shall calculate the fugitive CO_2 emissions using one of the following methods:

(1) Calculate the fugitive CO_2 emissions using Equation 40-3:

$$CO_2 = 7.53 \times Heat \times 0.001$$ **Equation 40-3**

Where:

CO_2	=	CO_2 emissions, metric tons per year;
7.53	=	Default fugitive CO_2 emission factor for geothermal facilities, kg per mmBtu; and
Heat	=	Heat taken from geothermal steam and/or fluid, mmBtu/yr.

(2) Calculate CO_2 emissions using [*insert jurisdiction*] approved source specific emission factor.

WCI.44 Sampling, Analysis, and Measurement Requirements

(a) CO_2, CH_4 and N_2O Emissions from Fuel Combustion. Operators using CEMS to estimate CO_2 emissions from fuel combustion shall comply with the requirements in section WCI.23(d). Operators using methods other than CEMS shall comply with the applicable fuel sampling, fuel consumption monitoring, heat content monitoring, and carbon content monitoring specified in section WCI.25.

(b) CO_2 Emissions from Acid Gas Scrubbing. Operators of electricity generating units that use acid gas scrubbers or add an acid gas reagent to the combustion unit shall measure the

amount of limestone or other sorbent used during the reporting year using methods that comply with the measurement accuracy provisions in WCI.2(g).

(c) CO_2 Emissions from Geothermal Facilities. Operators of geothermal facilities shall measure the heat recovered from geothermal steam. If using source specific emission factor instead of the default factor, the operator shall conduct an annual test of the CO_2 emission rate using a method approved by [*insert jurisdiction*]. The operator shall submit a test plan to the [*insert jurisdiction*] for approval. Once approved, the annual tests shall be conducted in accordance with the approved test plan under the supervision of the [*insert jurisdiction*].-

ATTACHMENT 5: CEMENT MANUFACTURING

§ WCI.90 CEMENT MANUFACTURING

§ WCI.91 Source Category Definition

Cement manufacturing is comprised of all processes that are used to manufacture Portland, natural, masonry, pozzolanic, or other hydraulic cements.

§ WCI.92 Greenhouse Gas Reporting Requirements

In addition to the information required by WCI.3, the annual emissions data report shall contain the following information:

(a) Total emissions of CO_2, CH_4, and N_2O in metric tons.

(b) CO_2 process emissions from calcination (metric tons) and the following information:

(1) Clinker emission factor (kg CO_2/metric ton clinker).
(A) Quantity of clinker produced (metric tons).
(B) Total lime (CaO) content of clinker (wt. fraction).
(C) Total magnesium Oxide (MgO) content of clinker (wt. fraction).
(D) Uncalcined CaO (wt. fraction).
(E) Uncalcined MgO (wt. fraction).

(2) Cement kiln dust (CKD) emission factor (kg CO_2/metric ton CKD discarded).
(A) Plant specific CKD calcination rate (unitless ratio).
(B) Quantity of CKD discarded (metric tons).

(c) CO_2 process emissions from organic carbon oxidation (metric tons) and the following information:

(A) Amount of raw material consumed in the report year (metric tons).
(B) Organic carbon content of raw material (wt. fraction).

(d) CO_2, CH_4, and N_2O emissions from fuel combustion in all kilns combined, following the calculation methods and reporting requirements specified in WCI.93(c) (metric tons).

(e) CO_2, CH_4, and N_2O emissions from all other fuel combustion units combined (kilns excluded), following the calculation methods and reporting requirements specified in WCI.20 (metric tons).

(f) If a continuous emissions monitor is used to measure CO_2 emissions from kilns, then the requirements of paragraphs (b), (c), and (d) of this section do not apply for CO_2. Cement plants that measure CO_2 emissions using CEMS shall report fuel usage by fuel type for kilns.

(g) Operators of cement plants shall also comply with the reporting requirements for any other applicable source category listed at WCI.1(a), including but not limited to the following:

(1) Coal fuel storage as specified in WCI.100.

(2) Electricity generating as specified in WCI.40.
(3) Cogeneration systems as specified in WCI.50.

§ WCI.93 Calculation of Greenhouse Gas Emissions From Kilns

(a) Determine CO_2 emissions as specified under either paragraph (a)(1) or (a)(2) of this section.

(1) Use a continuous emissions monitoring system (CEMS) as specified in WCI.23(d).
(2) Calculate the sum of CO_2 process emissions from kilns and CO_2 fuel combustion emissions from kilns using the calculation methodologies specified in paragraph (b) and (c) of this section.

(b) Process CO_2 Emissions Calculation Methodology. Calculate total CO_2 process emissions as the sum of emissions from calcination, using the method specified in paragraph (b)(1) of this section; and from organic carbon oxidation, using the method specified in paragraph (b)(2) of this section (Equation 90-0).

$$CO_2\ process = CO_2\ calcination + CO_2\ raw\ material$$ **Equation 90-0**

(1) <u>Calcination Emissions</u>. Calculate CO_2 process emissions from calcination using Equation 90-1 and a plant-specific clinker emission factor and a plant-specific cement kiln dust (CKD) emission factor as specified in this section.

$$CO_{2-C} = \sum_{i=1}^{12} [(Cli) \times (EF_{Cli})] + [(Q_{CKD}) \times (EF_{CKD})]$$ **Equation 90-1**

Where:

CO_{2-C} = CO_2 emissions from calcination, metric tones.
Cli = Monthly quantity of clinker produced, metric tons.
EF_{Cli} = Monthly clinker emission factor, metric tons CO_2/metric ton clinker computed as specified in paragraph (b)(1)(A) of this section.
Q_{CKD} = Monthly quantity CKD discarded (i.e., not recycled to the kiln), metric tons.
EF_{CKD} = Monthly CKD emission factor, computed as specified in paragraph (b)(1)(B) of this section.

(A) Monthly Clinker Emission Factor. Calculate a monthly plant-specific clinker emission factor (EF_{Cli}) for each report year based on the percent of measured CaO and MgO content in the clinker and using Equation 90-2.

$$EF_{Cli} = [(CaO\ content - uncalcined\ CaO) \times Molecular\ ratio\ of\ CO_2/CaO] + [(MgO\ Content - uncalcined\ MgO) \times Molecular\ ratio\ of\ CO_2/MgO]$$ **Equation 90-2**

Where:

CaO Content (by weight) = Total CaO content of Clinker (including calcined and uncalcined) (wt. fraction).
Non-carbonate CaO (by weight) = Uncalcined CaO of Clinker (wt. fraction).

Molecular ratio of CO_2/CaO = 0.785.
MgO Content (by weight) = Total MgO content of Clinker (including calcined and uncalcined) (wt. fraction).
Non-carbonate MgO = Uncalcined MgO of Clinker (wt. fraction).
Molecular ratio of CO_2/MgO = 1.092.

(B) Monthly CKD Emission Factor. If CKD is generated and not recycled back to the kiln, then calculate a monthly plant-specific CKD emission factor. The CKD emission factor shall be calculated using Equation 90-3 and a plant-specific CKD calcination rate as specified in Equation 90-4.

$$EF_{CKD} = \frac{\frac{EF_{Cli}}{1 + EF_{Cli}} \times d}{1 - \left(\frac{EF_{Cli}}{1 + EF_{Cli}} \times d\right)} \qquad \textbf{Equation 90-3}$$

Where:

EF_{CKD} = Monthly CKD emission factor, kg CO_2/metric ton CKD discarded.
EF_{Cli} = Clinker emission factor, determined according to Equation 90-2.
d = CKD calcination rate, determined according to Equation 90-4.

$$d = 1 - \frac{fCO_{2CKD} \times (1 - fCO_{2RM})}{(1 - fCO_{2CKD}) \times fCO_{2RM}} \qquad \textbf{Equation 90-4}$$

Where:

d = CKD calcination rate (unitless ratio).
fCO_{2CKD} = Weight fraction of carbonate CO_2 in the CKD.
fCO_{2RM} = Weight fraction of carbonate CO_2 in the raw material.

(2) Organic Carbon Oxidation Emissions. Calculate CO_2 process emissions from the total organic content in raw materials by using Equation 90-5.

$$CO_{2-RM} = TOC_{RM} \times RM \times 3.664 \qquad \textbf{Equation 90-5}$$

Where:

CO_{2-RM} = CO_2 emissions from raw material oxidation, metric tons.
TOC_{RM} = Total organic carbon content in raw material (wt. fraction), measured using the method in WCI.94(c) or using a default of 0.002 (0.2%).
RM = Amount of raw material consumed (metric tons/yr).
3.664 = The CO_2 to carbon molar ratio.

(c) Fuel Combustion Emissions in Kilns. Calculate CO_2, CH_4, and N_2O emissions from stationary fuel combustion following the calculation methods specified in WCI.20. Cement plants that combust pure biomass-derived fuels and combust fossil fuels only during periods of start-up, shut-down, or malfunction may report CO_2 emissions from fossil fuels using the emission factor methodology in WCI.23(a). "Pure" means that the biomass-derived fuels account for 97 percent of the total amount of carbon in the fuels burned.

§ WCI.94 Sampling, Analysis, and Measurement Requirements

Note: The sampling, analysis, and measurement procedures will be standardized for each calculation input to reduce variation between facilities within the cement industry. Material sampling frequency and technique is distinct from material analysis conducted in a laboratory. The WCI is seeking stakeholder feedback on this topic and is specifically interested in proposals from stakeholders with expertise in this industry related to sampling, analysis and measurement procedures already in use at these facilities for the material quantities and/or concentrations listed below. Those proposing procedures should include sampling frequency and technique, indicate the uncertainty associated with the procedures, and describe the application of the procedure at a facility.

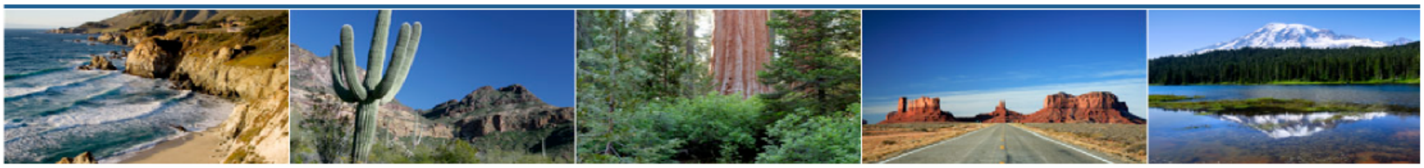
(a) Determine the plant-specific weight fractions of CaO, MgO, uncalcined CaO, and uncalcined MgO in clinker from each kiln using *(method to be determined).* Determine the weight fraction of carbonate CO_2 in the CKD and the weight fraction of carbonate CO_2 in the raw material. The monitoring must be conducted monthly for each kiln from a clinker sample drawn from bulk clinker storage.

(b) If not using the default value of 0.002 for TOC_{RM} in Equation 90-5, the total organic carbon contents of raw materials must be determined annually *[monthly?]* using ASTM Method C114-07. The analysis must be conducted on sample material drawn from bulk raw material storage for each category of raw material.

(c) The quantity of clinker produced must be determined by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.

(d) The quantity of CKD discarded must be determined by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.

(e) The quantity of raw materials consumed (i.e. limestone, sand, shale, iron oxide, and alumina) must be determined by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.



ATTACHMENT 6: COAL STORAGE

§ WCI.100 COAL STORAGE

§ WCI.101 Source Category Definition

Coal storage piles are located at any facilities that combust coal. Coal storage piles release fugitive CH_4 emissions. Within natural coal deposits, CH_4 is either trapped under pressure within porous void spaces or adsorbed to the coal. Coal mining, post-mining activities, and coal-handling activities release pressurized CH_4 to the atmosphere; adsorbed CH_4 is also released until the CH_4 coal reaches equilibrium with the surrounding atmospheric conditions.

§ WCI.102 Greenhouse Gas Reporting Requirements

The emissions data report shall include the following information at the facility level:

(a) Annual greenhouse gas emissions in metric tons, reported as follows:

  (1) Total CH_4 emissions.

(b) Annual coal purchases in tons.

(c) Source of coal purchases:

  (1) Coal basin.
  (2) State/province.
  (3) Coal mine type (surface or underground).

§ WCI.103 Calculation of CH_4 Emissions

Note that this methodology for calculation of methane emissions uses emission factors for post-mining operations including all processes occurring after mining at the coal deposit and prior to combustion (e.g., preparation, handling, processing, transportation, storage, etc.) even though coal storage piles are only a subset of the overall post-mining operations. This follows the approach in the California Climate Action Registry, attributing all post-mining fugitive methane emissions to the facility combusting the coal, which is ultimately responsible for the coal having been processed and delivered to the facility. The Reporting Subcommittee is considering whether to require reporting of these emissions as indicated below, and whether to include these emissions in the total emissions of the coal-combusting facility. Stakeholder comment is requested.

Canadian-specific default fugitive methane emissions (i.e., a Canadian version of Table 100-1) will be developed.

Calculate fugitive CH_4 emissions from coal storage piles using the following equation:

$$CH_4 = \sum_i \left(PC \times EF\right) \times 0.04228 / 2,204.6$$ **Equation 100-1**

Where:

CH_4	=	Fugitive emissions from coal storage piles for each coal category *i*, metric tons CH_4 per year.
PC	=	Purchased coal, tons per year.
EF	=	Default CH_4 emission factor specified by location and mine type that coal originated from provided in Table 100-1, scf CH_4 per ton of coal.
0.04228	=	Methane conversion factor to convert scf to lbs.
2,204.6	=	Factor to convert lbs to metric tons.

Table 100-1 provides default CH_4 emission factors for U.S. post-mining operations.

These post-mining operation emission factors were used to estimate emissions from coal storage piles in the CARB rule.

The uncertainty associated with the U.S.-specific emission factors in Table 100-1 emission factors is unknown. Emission factors from U.S. underground mining activities were developed from mine-level emissions measurements; however, the surface mining and post-mining activity emission factors were estimated based upon an average in situ CH_4 content of 32.5%.

Canada-specific coal storage pile or post-mining operation emission factors could not be identified. The Canada National Inventory contains Canada-specific emission factors for coal production from underground and surface mines. Post-mining operations are included within these emission factors, but are not specifically disaggregated.

§ WCI.105 Sampling, Analysis, and Measurement Requirements

(a) Fuel Consumption Monitoring Requirements.

(1) Facilities may determine consumption on the basis of recorded fuel purchase or sales invoices measuring any stock change (short tons) using the following equation:

Fuel Consumption in the Report Year = Total Fuel Purchases – Total Fuel Sales + Amount Stored at Beginning of Year – Amount Stored at Year End

Table 100-1. U.S. Default Fugitive Methane Emission Factors from Post-Mining Coal Storage and Handling (CH_4 ft^3 per Short Ton)

Coal Origin		Coal Mine Type	
Coal Basin	**States**	**Surface Post-Mining Factors**	**Underground Post-Mining Factors**
Northern Appalachia	Maryland, Ohio, Pennsylvania, West Virginia North	19.3	45.0
Central Appalachia (WV)	Tennessee, West Virginia South	8.1	44.5
Central Appalachia (VA)	Virginia	8.1	129.7
Central Appalachia (E KY)	East Kentucky	8.1	20.0
Warrior	Alabama, Mississippi	10.0	86.7
Illinois	Illinois, Indiana, Kentucky West	11.1	20.9
Rockies (Piceance Basin)	Arizona, California, Colorado, New Mexico, Utah	10.8	63.8
Rockies (Uinta Basin)		5.2	32.3
Rockies (San Juan Basin)		2.4	34.1
Rockies (Green River Basin)		10.8	80.3
Rockies (Raton Basin)		10.8	41.6
N. Great Plains	Montana, North Dakota, Wyoming	1.8	5.1
West Interior (Forest City, Cherokee Basins)	Arkansas, Iowa, Kansas, Louisiana, Missouri, Oklahoma, Texas	11.1	20.9
West Interior (Arkoma Basin)		24.2	107.6
West Interior (Gulf Coast Basin)		10.8	41.6
Northwest (AK)	Alaska	1.8	52.0
Northwest (WA)	Washington	1.8	18.9

Source: *Inventory of U.S. Greenhouse Gas Emissions and Sinks:1990 – 2005*
April 15, 2007, U.S. Environmental Protection Agency. Annex 3, Methodological Descriptions for Additional Source or Sink Categories, Section 3.3, Table A-115, Coal Surface and Post-Mining CH4 Emission Factors (ft^3 per Short Ton). (Only Post-Mining EFs used from Table). State assignments shown from Table 113 of Annex 3.

ATTACHMENT 7: HYDROGEN PRODUCTION

§ WCI.130 HYDROGEN PRODUCTION

§ WCI.131 Source Category Definition

A hydrogen production process produces hydrogen gas by steam hydrocarbon reforming, partial oxidation of hydrocarbons, or other transformation of hydrocarbon feedstock. The hydrogen produced may be either transferred offsite or used onsite at petrochemical, ammonia production, refineries, and other plants.

§ WCI.132 Greenhouse Gas Reporting Requirements

For each facility, the annual emissions report must contain the following information:

(a) Process CO_2 Emissions. The CO_2 process emissions from the hydrogen produced process.

(b) Feedstock Consumption. Annual feedstock consumption by feedstock type (including petroleum coke) reported in units of million standard cubic feet for gases, gallons for liquids, short tons for non-biomass solids, and bone dry short tons for biomass-derived solid fuels.

(c) Production. Annual hydrogen produced.

(d) Stationary Combustion Units. Report CO_2, N_2O, and CH_4 emissions as specified in WCI.20.

§ WCI.133 Calculation of Greenhouse Gas Emissions

The owner or operator shall calculate and report CO_2 process emissions using the methods in paragraphs (a) or (b) of this section.

(a) Continuous Emission Monitoring Systems. The owner or operator may calculate CO_2 process emissions using CEMS. The owner or operator must comply with the requirements in section WCI.20.

(b) Feedstock Material Balance. The owner or operator may calculate CO_2 process emissions using the following method. The factor S shall be used only for CO_2 and/or CH_4 emissions that are calculated and reported using applicable methods specified in this regulation. For example, carbon species in uncoverted feedstock contained in PSA off-gas and hydrogen plant product that is diverted to fuel gas systems, fed to downstream units, or diverted to flare may be included in the factor S provided the CO_2 and/or CH_4 emissions are reported using other methods in this regulation.

$$CO_2(Feedstock) = \sum_{i=1}^{n} \sum_{j=1}^{y} \left[\left(FS_j * CF_j \right) - S_j \right] * 3.664 * 0.001 \qquad \textbf{Equation 130-1}$$

Where:

CO_2 (Feedstock)	=	CO_2 emitted from feedstock (metric tons/year).
n	=	Days of operation per year.
FS_j	=	Feedstock b consumption rate (scf/day).
CF_j	=	Carbon content of feedstock j (kg C/scf feedstock).
y	=	Total number of feedstocks.
S_j	=	Carbon accounted for elsewhere (kg C/day).
3.664	=	ratio of molecular weights, CO_2 to carbon
0.001	=	conversion factor – kg to metric tons

WCI.134 Sampling, Analysis, and Measurement Requirements

(a) Owners or operators using CEMS to estimate CO_2 emissions shall comply with the monitoring requirements in section WCI.20.

(b) Owners or operators using the method in section WCI.103 (b) shall perform the following monitoring:

(1) The owner or operator shall measure the feedstock consumption rate daily using methods that comply with the measurement accuracy provisions in WCI.2(g).
(2) The owner or operator shall collect samples of each feedstock consumed and analyze each sample for carbon content using the methods specified in WCI.25(d). For natural gas feedstock not mixed with another feedstock prior to consumption, samples shall be collected and analyzed once per month. For all other feedstocks, samples shall be collected and analyzed daily. The samples shall be collected from a location in the feedstock handling system that provides samples representative of the feedstock consumed in the hydrogen production process.
(3) Owners or operators shall measure the hydrogen produced daily using methods that comply with the measurement accuracy provisions in WCI.2(g).
(4) Owners or operators shall measure the CO_2 and CO collected daily using methods that comply with the measurement accuracy provisions in WCI.2(g).

ATTACHMENT 8: IRON AND STEEL MANUFACTURING

§ WCI.150 IRON AND STEEL MANUFACTURING

§ WCI.151 Source Category Definition

Iron and steel manufacturing comprises four categories: primary facilities that produce both iron and steel, secondary steelmaking facilities, iron production facilities, and offsite production of metallurgical coke. These processes may occur together in an "integrated" facility or they may occur in separate offsite facilities.

§ WCI.152 Greenhouse Gas Reporting Requirements

In addition to the information required by WCI.3, the annual emissions data report shall contain the following information:

(a) Total emissions of CO_2 and CH_4 in metric tons at the facility level.

(b) CO_2 and CH_4 emissions from coke production (metric tons) and the following information:

(1) Quantity of coking coal consumed in coke production (metric tons)
(2) Quantity of other process materials (e.g., natural gas, fuel oil, etc.) consumed in coke production (metric tons)
(3) Quantity of blast furnace gas consumed in coke production (metric tons)
(4) Quantity of coke produced (metric tons)
(5) Quantity of coke oven gas transferred offsite (metric tons)
(6) Quantity of other coke oven by-products (e.g., coal tar, light oil, coke breeze, etc.) transferred offsite (metric tons)
(7) Carbon content of material inputs and outputs listed in (b)(1) through (b)(6) (metric tons of C per unit of material)

(c) CO_2 and CH_4 emissions from iron and steel production (metric tons) and the following information:

(1) Quantity of coke consumed in iron and steel production (excluding sinter production) (metric tons)
(2) Quantity of on-site coke oven by-products (e.g., coal tar, light oil, coke breeze, etc.) consumed in blast furnace (metric tons)
(3) Quantity of coal directly injected into blast furnace (metric tons)
(4) Quantity of limestone directly injected into blast furnace (metric tons)
(5) Quantity of dolomite directly injected into blast furnace (metric tons)
(6) Quantity of carbon electrodes consumed in EAFs (metric tons)
(7) Quantity of other carbonaceous or process material (e.g., sinter, waste plastic, etc.) consumed in iron and steel production (metric tons)
(8) Quantity of coke oven gas consume in blast furnace (metric tons)
(9) Quantity of steel produced (metric tons)
(10) Quantity of iron production not converted to steel (metric tons)

(11) Quantity of blast furnace gas transferred offsite (metric tons)
(12) Carbon content of material inputs and outputs listed in (c)(1) through (c)(11) (metric tons of C per unit of material)

(d) Process CO_2 and CH_4 emissions from sinter production (metric tons) and the following information:

(1) Quantity of coke breeze (purchased and produced on-site) used for sinter production (metric tons)
(2) Quantity of coke oven gas consumed in blast furnace in sinter production (metric tons)
(3) Quantity of blast furnace gas consumed in sinter production (metric tons)
(4) Quantity of other process materials (e.g., natural gas, fuel oil, etc.) consumed in sinter production (metric tons)
(5) Quantity of sinter off gas transferred offsite (metric tons)
(6) Carbon content of material inputs and outputs listed in (d)(1) through (d)(5) (metric tons of C per unit of material)

(e) Process CO_2 and CH_4 emissions from direct reduced iron production (metric tons) and the following information:

(1) Energy from natural gas used in direct reduced iron production (gigajoules [GJ])
(2) Energy from coke breeze used in direct reduced iron production (GJ)
(3) Energy from metallurgical coke used in direct reduced iron production (GJ)
(4) Carbon of material inputs listed in (e)(1) through (e)(3) (metric tons of C per GJ)

§ WCI.153 Calculation of CO_2 Emissions

(a) Process CO_2 emissions. Determine process CO_2 emissions as specified under either paragraph (1) or (2) of this section.

(1) Continuous emissions monitoring systems (CEMS) as specified in WCI.23(d).
(2) Calculation methodologies specified in paragraph (b) of this section.

(b) Process CO_2 Emissions Calculation Methodology. Calculate total CO_2 process emissions using the following mass balance approach:

(1) Calculate the coke production CO_2 (either within integrated facilities or at offsite facilities) emissions using Equation 150-1 (if applicable):

$$E_{coke} = \left[(CC \times C_{CC}) + \sum_a (PM_a \times C_a) + (BG \times C_{BG}) - (CO \times C_{CO}) - (COG \times C_{COG}) - \sum_b (COB_b \times C_b) \right] \times 3.664$$

Equation 150-1

Where:

E_{coke}	=	Emissions of CO_2 from coke production (metric tons);
CC	=	Quantity of coking coal (metric tons);
PM_a	=	Quantity of other process material *a* (not included as separate terms), such as natural gas or fuel oil (metric tons);

BG	=	Quantity of blast furnace gas consumed in coke ovens (metric tons);
CO	=	Quantity of coke produced (metric tons)
COG	=	Quantity of coke oven gas transferred offsite (metric tons);
COB_b	=	Quantity of coke oven by-product *b* transferred offsite (metric tons);
C_x	=	Carbon content of material input or output *x* (metric tons C/metric tons of *x*);
3.664	=	Conversion factor from metric tons of C to metric tons of CO_2.

(2) Calculate the iron and steel production CO_2 emissions using Equation 150-2:

$$E_{iron,steel} = \Big[(CO \times C_{CO}) + \sum_a (COB_a \times C_a) + (CI \times C_{CI}) + (L \times C_L) + (D \times C_D) + (CE \times C_{CE}) + \sum_b (O_b \times C_b) + (COG \times C_{COG}) - (S \times C_S) - (IP \times C_{IP}) - (BG \times C_{BG})\Big] \times 3.664$$

Equation 150-2

Where:

$E_{iron,steel}$	=	Emissions of CO_2 from iron and steel production (metric tons);
CO	=	Quantity of coke consumed (excluding sinter production) (metric tons);
COB_a	=	Quantity of coke oven by-product *a* consumed in blast furnace (metric tons);
CI	=	Quantity of coal directly injected into blast furnace (metric tons);
L	=	Quantity of limestone consumed (metric tons);
D	=	Quantity of dolomite consumed (metric tons);
CE	=	Quantity of carbon electrodes consumed in EAFs (metric tons);
O_b	=	Quantity of other carbonaceous and process material *b*, such as sinter or waste plastic (metric tons);
COG	=	Quantity of coke oven gas consumed in blast furnace (metric tons);
S	=	Quantity of steel produced (metric tons);
IP	=	Quantity of iron production not converted to steel (metric tons);
BG	=	Quantity of blast furnace gas transferred offsite (metric tons);
C_x	=	Carbon content of material input or output *x* (metric tons C/metric tons of *x*);
3.664	=	Conversion factor from metric tons of C to metric tons of CO_2.

(3) Calculate the sinter production CO_2 emissions using Equation 150-3 (if applicable):

$$E_{sinter} = \Big[(CBR \times C_{CBR}) + (COG \times C_{COG}) + (BG \times C_{BG}) + \sum_a (PM_a \times C_a) - (SOG \times C_{SOG})\Big] \times 3.664$$

Equation 150-3

Where:

E_{sinter} = Emissions of CO_2 from sinter production (metric tons);
CBR = Quantity of purchased and onsite produced coke breeze used for sinter production (metric tons);
COG = Quantity of coke oven gas consumed in blast furnace for sinter production (metric tons);
BG = Quantity of blast furnace gas consumed for sinter production (metric tons);
PM_a = Quantity of other process material *a* consumed for sinter production (not included as separate terms), such as natural gas or fuel oil (metric tons);
SOG = Quantity of sinter off gas transferred offsite (metric tons);
C_x = Carbon content of material input or output *x* (metric tons C/metric tons of *x*);
3.664 = Conversion factor from metric tons of C to metric tons of CO_2.

(4) Calculate the direct reduced iron production CO_2 emissions using Equation 150-4 (if applicable):

$$E_{DRI} = [(DRI_{NG} \times C_{NG}) + (DRI_{BZ} \times C_{BZ}) + (DRI_{CK} \times C_{CK})] \times 3.664$$

Equation 150-4

Where:

E_{DRI} = Emissions of CO_2 from direct reduced iron production (metric tons);
DRI_{NG} = Energy from natural gas used in direct reduced iron production (GJ);
DRI_{BZ} = Energy from coke breeze used in direct reduced iron production (GJ);
DRI_{CK} = Energy from metallurgical coke used in direct reduced iron production (GJ);
C_{NG} = Carbon content of natural gas (metric ton C/GJ);
C_{BZ} = Carbon content of coke breeze (metric ton C/GJ);
C_{CK} = Carbon content of metallurgical coke (metric ton C/GJ);
3.664 = Conversion factor from metric tons of C to metric tons of CO_2.

(5) Calculate the total CO_2 emissions using Equation 150-5:

$$E_{CO2} = E_{coke} + E_{iron,steel} + E_{sinter} + E_{DRI}$$

Equation 150-5

Where:

E_{CO2} = Total CO_2 emissions (metric tons);
E_{coke} = Emissions from coke production (metric tons);
$E_{iron,steel}$ = Emissions from iron and steel production (metric tons);
E_{sinter} = Emissions from sinter production (metric tons);
E_{DRI} = Emissions from direct reduced iron production (metric tons).

§ WCI.154 Calculation of CH_4 Emissions

(a) Process CH_4 emissions. Determine process CH_4 emissions as specified under paragraph (1) of this section.

(1) Continuous emissions monitoring systems (CEMS) as specified in WCI.23(d).

§ WCI.155 Sampling, Analysis, and Measurement Requirements

Measurements of carbon contents of the material balance input, output, and by-product materials shall be conducted as described below.

Note: The sampling, analysis, and measurement procedures will be standardized for each calculation input to reduce variation between facilities within the iron and steel industry. Material sampling frequency and technique is distinct from material analysis conducted in a laboratory. The WCI is seeking stakeholder feedback on this topic and is specifically interested in proposals from stakeholders with expertise in this industry related to sampling, analysis and measurement procedures already in use at these facilities for the material quantities and/or concentrations listed below. Those proposing procedures should include sampling frequency and technique, indicate the uncertainty associated with the procedures, and describe the application of the procedure at a facility.

(b) Fuel Carbon Content Requirements. Fuel carbon contents should be monitored in the following manner (from § WCI.25):

(1) For coal and coke, solid biomass-derived fuels, and waste-derived fuels; use ASTM 5373-02 (Reapproved 2007).
(2) For liquid fuels, use the following ASTM methods: For petroleum-based liquid fuels and liquid waste-derived fuels, use ASTM D5291-02 (Reapproved 2007) "Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants", ultimate analysis of oil or computations based on ASTM D3238-95 (Reapproved 2005) and either ASTM D2502-04 or ASTM D2503-92 (Reapproved 2002).
(3) For gaseous fuels, use ASTM D1945-03 or ASTM D1946-90 (Reapproved 2006).

(c) By-Product Carbon Content Requirements. Carbon contents of by-products (e.g., blast furnace gas, coke oven gas, coal tar, light oil, coke breeze, sinter off gas, etc.) from all iron and steel production processes should be monitored in the following manner:

(1) [Methodology to be determined.]

(d) Flux Carbon Content Requirements. Carbon contents of fluxes (i.e., limestone and dolomite) from all iron and steel production processes should be monitored in the following manner:

(1) For limestone and dolomite, use ASTM C25-06.

(e) Electrode Carbon Content Requirements. Carbon contents of carbon electrodes used in electric arc furnaces (EAFs) should be monitored in the following manner:

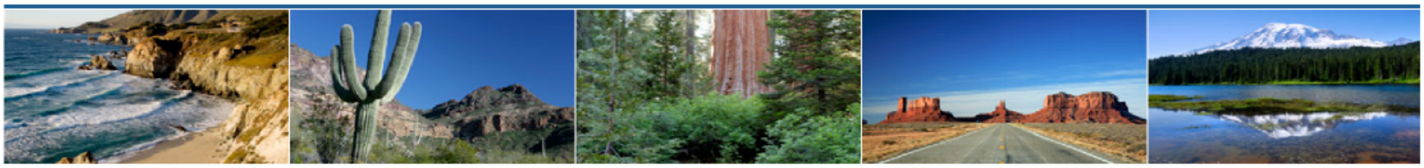
(1) [Methodology to be determined.]

(f) Finished Product Carbon Content Requirements. Carbon contents of finished products (i.e., steel, iron not converted to steel, and direct reduced iron) from all iron and steel production processes should be monitored in the following manner:

   (1) For iron and steel, use ASTM E1019-08 or ASTM E351-93.

(g) Quantity Measurement Requirements. The quantities of process inputs, outputs, and by-products must be determined using the following methods:

   (1) For solid process inputs, outputs, and by-products, quantities must be determined by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.
   (2) For liquid process inputs, outputs, and by-products, quantities must be determined by direct volume measurement using the same plant instruments used for accounting purposes.
   (3) For gaseous process inputs, outputs, and by-products, quantities must be determined by direct volume measurement using the same plant instruments used for accounting purposes.



ATTACHMENT 9: LIME MANUFACTURING

§ WCI.170 LIME MANUFACTURING

§ WCI.171 Source Category Definition

Lime manufacturing is comprised of all processes that are used to manufacture quick lime (i.e. calcium oxide or calcium-magnesium oxide). Lime is produced via the calcination of limestone or other highly calcareous materials such as dolomite, aragonite, chalk, coral, marble, and shell.

§ WCI.172 Greenhouse Gas Reporting Requirements

In addition to the information required by WCI.3, the annual emissions data report shall contain the following information:

(a) Total emissions of CO_2, CH_4, and N_2O in metric tons.

(b) CO_2 process emissions from quick lime production (metric tons) and the following information:

(1) Quick lime emission factor (kg CO_2/metric ton quick lime).
(A) Quantity of quick lime produced (metric tons).
(B) Total Calcium Oxide (CaO) content of quick lime (weight fraction).
(C) Total Magnesium Oxide (MgO) content of quick lime (weight fraction).
(D) Uncalcined CaO (weight fraction).
(E) Uncalcined MgO (weight fraction).

(2) Lime kiln dust (LKD) emission factor (kg CO_2/metric ton LKD).
(A) Quantity of LKD discarded (metric tons).
(B) Total Calcium Oxide (CaO) content of LKD (weight fraction).
(C) Total Magnesium Oxide (MgO) content of LKD (weight fraction).
(D) Uncalcined CaO content of LKD (weight fraction).
(E) Uncalcined MgO content of LKD (weight fraction).

(c) CO_2, CH_4, and N_2O emissions from fuel combustion in all kilns combined, following the calculation methods and reporting requirements specified in WCI.173(c) (metric tons).

(d) CO_2, CH_4, and N_2O emissions from all other fuel combustion units combined (kilns excluded), following the calculation methods and reporting requirements specified in WCI.20 (metric tons).

(e) If a continuous emissions monitor is used to measure CO_2 emissions from kilns, then the requirements of paragraphs (b) and (c) of this section do not apply for CO_2. Lime plants that measure CO_2 emissions using CEMS shall report fuel usage by fuel type for kilns.

(f) Operators of lime plants shall also comply with the reporting requirements for any other applicable source category listed at WCI.1(a), including but not limited to the following:

(1) Coal fuel storage as specified in WCI.100.

(2) Electricity generating as specified in WCI.40.

(3) Cogeneration systems as specified in WCI.XX.

§ WCI.173 Calculation of greenhouse Gas Emissions from Kilns

(a) Determine process CO_2 emissions as specified under either paragraph (a)(1) or (a)(2) of this section.

(1) Continuous emissions monitoring systems (CEMS) as specified in WCI.23(d).

(2) Calculate the sum of CO_2 process emissions from kilns and CO_2 fuel combustion emissions from kilns using the calculation methodologies specified in paragraph (b) and (c) of this section**.**

(b) Process CO_2 Emissions Calculation Methodology. Calculate total CO_2 process emissions as the sum of emissions from quick lime production, using the method specified in paragraph (b)(1) of this section.

(1) CO_2 Process Emissions. Calculate CO_2 emissions from quick lime production from each kiln using Equation 170-1 and a plant-specific quick lime emission factor and a plant-specific lime kiln dust (LKD) emission factor as specified in this section.

$$CO_2 = \sum_{I=1}^{12} [(QL) \times (EF_{QL})] + [(LKD) \times (EF_{LKD})]$$ **Equation 170-1**

Where:

CO_2	=	CO_2 emissions in metric tones/yr.
QL	=	Monthly Quantity of quick lime produced, metric tons.
EF_{QL}	=	Monthly Quick lime emission factor, metric tons CO_2/metric ton quick lime computed as specified in paragraph (b)(1)(A) of this section.
LKD	=	Monthly Quantity LKD discarded (i.e., not recycled to the kiln), metric tons.
EF_{LKD}	=	Monthly LKD emission factor, computed as specified in paragraph (b)(1)(B) of this section.

(A) Monthly Quick Lime Emission Factor. Calculate a plant-specific quick lime emission factor _(EF_{QL}) for each kiln and month based on the percent of measured CaO and MgO content in quick lime and using Equation 170-2.

$$EF_{QL} = [(CaO\ content - uncalcined\ \ CaO) \times Molecular\ ratio\ of\ CO_2 / CaO] + [(MgO\ Content - uncalcined\ \ MgO) \times Molecular\ ratio\ of\ CO_2 / MgO]$$ **Equation 170-2**

Where:

CaO Content (by weight)	=	Total CaO content of Quick Lime, including calcined and uncalcined (weight fraction).
Uncalcined CaO (by weight)	=	Uncalcined CaO content of Quick Lime (weight fraction).
Molecular ratio of CO_2/CaO	=	0.785.
MgO Content (by weight)	=	Total MgO content of Quick Lime, including calcined and uncalcined (weight fraction).
Uncalcined MgO	=	Uncalcined MgO content of Quick Lime (weight fraction).
Molecular ratio of CO_2/MgO	=	1.092.

(B) Monthly LKD Emission Factor. If LKD is generated and not recycled back to the kiln, then calculate a plant-specific LKD emission factor for each kiln and month. The LKD emission factor shall be calculated using Equation 170-3.

$$EF_{LKD} = [(CaO\ content - uncalcined\ \ CaO) \times Molecular\ ratio\ of\ CO_2 / CaO] + [(MgO\ Content - uncalcined\ \ MgO) \times Molecular\ ratio\ of\ CO_2 / MgO]$$

Equation 170-3

Where:

EF_{LKD}	=	LKD emission factor.
CaO Content (by weight)	=	Total CaO content of LKD, including calcined and uncalcined (weight fraction).
Uncalcined CaO (by weight)	=	Uncalcined CaO content of LKD (weight fraction).
Molecular ratio of CO_2/CaO	=	0.785.
MgO Content (by weight)	=	Total MgO content of LKD, including calcined and uncalcined (weight fraction).
Uncalcined MgO	=	Uncalcined MgO content of LKD (weight fraction).
Molecular ratio of CO_2/MgO	=	1.092.

(c) Fuel Combustion Emissions in Kilns. Calculate CO_2, CH_4, and N_2O emissions from stationary fuel combustion emissions following the calculation methods specified in WCI.20. Operators of lime manufacturing plants that primarily combust biomass-derived fuels and combust fossil fuels only during periods of start-up, shut-down, or malfunction may report CO_2 emissions from fossil fuels using the emission factor methodology in WCI.23(a). "Pure" means that the biomass-derived fuels account for 97 percent of the total amount of carbon in the fuels burned.

§ WCI.174 Sampling, Analysis, and Measurement Requirements

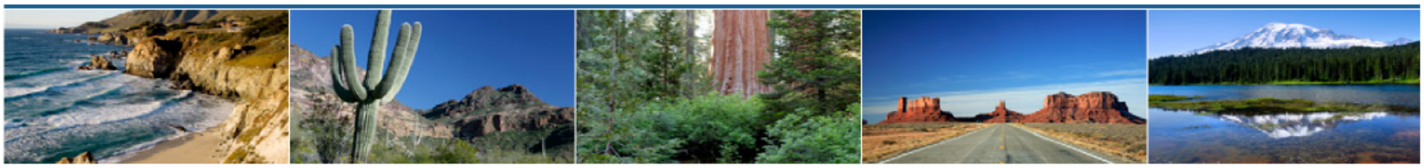
Note: The sampling, analysis, and measurement procedures will be standardized for each calculation input to reduce variation between facilities within the lime industry. Material sampling frequency and technique is distinct from material analysis conducted in a laboratory. The WCI is seeking stakeholder feedback on this topic and is specifically interested in proposals from stakeholders with expertise in this industry related to sampling, analysis and measurement *procedures already in use at these facilities for the material quantities and/or concentrations listed below. Those proposing procedures should include sampling frequency and technique, indicate the uncertainty associated with the procedures, and describe the application of the procedure at a facility.*

(a) Determine the plant-specific weight fractions of CaO, MgO, uncalcined CaO, and uncalcined MgO in quick lime from each kiln using (method to be determined). Determine the plant-specific fraction of CaO, MgO, uncalcined CaO, and uncalcined MgO in LKD not recycled to the kiln using (method to be determined). The monitoring must be conducted monthly for each kiln from samples drawn from bulk storage.

(b) The quantity of quick lime produced must be determined by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.

(c) The quantity of LKD discarded must be determined by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.

(d) The quantity of raw materials consumed (i.e. limestone, dolomite, aragonite, chalk, coral, marble, and shell.) must be determined by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.



ATTACHMENT 10: PETROLEUM REFINERIES

§ WCI.200 PETROLEUM REFINERIES

§ WCI.201 Source Category Definition

A petroleum refinery consists of all processes used to produce gasoline, aromatics, kerosene, distillate fuel oils, residual fuel oils, lubricants, asphalt, or other products through distillation of petroleum or through redistillation, cracking, rearrangement or reforming of unfinished petroleum derivatives.

WCI.202 Greenhouse Gas Reporting Requirements

The annual emissions report must contain the following information reported at the facility level:

(a) Catalyst Regeneration. Report CO_2 emissions.

(b) Process Vents. Report CO_2, N_2O, and CH_4 emissions.

(c) Asphalt Production. Report CO_2 and CH_4 emissions.

(d) Sulfur Recovery. Report CO_2 emissions.

(e) Stationary Combustion Units Other than Flares and Control Devices. Report CO_2, N_2O, and CH_4 emissions as specified in WCI.23.

(f) Flares and Other Control Devices. Report CO_2, N_2O, and CH_4 emissions.

(g) Above-Ground Storage Tanks. Report CH_4 emissions.

(h) Wastewater Treatment. Report CH_4 and N_2O emissions.

(i) Oil-Water Separators. Report CH_4 emissions.

(j) Equipment Leaks. Report CH_4 emissions.

(k) Feedstock Consumption: Report feedstock consumption by type for all feedstocks which result in GHG emissions in the reporting year (including petroleum coke) in units of million standard cubic feet for gases, gallons for liquids, short tons for non-biomass solids, and bone dry short tons for biomass-derived solid fuels.

(l) Fuel Consumption: Report fuel consumption by fuel type consumed in the reporting year in units of million standard cubic feet for gases, gallons for liquids, short tons for non-biomass solids, and bone dry short tons for biomass-derived solid fuels.

WCI.203 Calculation of Greenhouse Gas Emissions

The operator shall calculate GHG emissions using the methods in paragraphs (a) through (i) of this section.

(a) Catalyst Regeneration. For units equipped with CEMS, operators shall calculate CO_2 process emissions resulting from catalyst regeneration using CEMS in accordance with WCI.20. In

the absence of CEMS data, the operator shall use the methods in paragraphs (a)(1) through (a)(3).

(1) The operator shall calculate process CO_2 emissions from the continuous regeneration of catalyst material in fluid catalytic cracking units (FCCU) and fluid cokers using Equations 200-1, 200-2, and 200-3.

$$CO_2 = \sum_{d=1}^{n} CR_d \times CF \times 3.664 \times 0.001$$ **Equation 200-1**

Where:

CO_2	=	CO_2 emissions (metric tons/yr)
n	=	number of days of operation in the report year
CR_d	=	daily average coke burn rate (kg/day)
CF	=	carbon fraction in coke burned
3.664	=	ratio of molecular weights, CO_2 to carbon
0.001	=	conversion factor – kg to metric tons

$$CR_d = \left[\sum_{i=1}^{n} [K_1 Q_r \times (\%CO_2 + \%CO) + K_2 Q_a - K_3 Q_r \times [\%CO/2 + \%CO_2 + \%O_2] + K_3 Q_{oxy} \times (\%O_{oxy})]_i \right] / n$$

Equation 200-2

Where:

CR_d	=	daily average coke burn rate (kg/day or lb/day)
K_1, K_2, K_3	=	material balance and conversion factors (K_1, K_2, and K_3 from Table 200-1
n	=	number of hours per day
Q_r	=	volumetric flow rate of exhaust gas before entering the emission control system (dscm/min or dscf/min)
Q_a	=	volumetric flow rate of air to regenerator as determined from control room instrumentation (dscm/min or dscf/min)
$\%CO_2$	=	CO_2 concentration in regenerator exhaust, percent by volume – dry basis
%CO	=	CO concentration in regenerator exhaust, percent by volume – dry basis
$\%O_2$	=	O_2 concentration in regenerator exhaust, percent by volume – dry basis
Q_{oxy}	=	volumetric flow rate of O_2 enriched air to regenerator as determined from control room instrumentation (dscm/min or dscf/min)
$\%O_{xy}$	=	O_2 concentration in O_2 enriched air stream inlet to regenerator, percent by volume – dry basis

$$Q_r = (79 \times Q_a + (100 - \%Q_{xy}) \times Q_{oxy}) / (100 - \%CO_2 - \%CO - \%O_2)$$ **Equation 200-3**

Where:

Q_r	=	volumetric flow rate of exhaust gas from regenerator before entering the emission control system (dscm/min or dscf/min)
Q_a	=	volumetric flow rate of air to regenerator, as determined from control room instrumentation (dscm/min or dscf/min)
$\%Q_{xy}$	=	oxygen concentration in oxygen enriched air stream, percent by volume – dry basis
Q_{oxy}	=	volumetric flow rate of O_2 enriched air to regenerator as determined from catalytic cracking unit control room instrumentation (dscm/min or dscf/min)
$\%CO_2$	=	carbon dioxide concentration in regenerator exhaust, percent by volume – dry basis
%CO	=	CO concentration in regenerator exhaust, percent by volume – dry basis. When no auxiliary fuel is burned and a continuous CO monitor is not required, assume %CO to be zero
$\%O_2$	=	O_2 concentration in regenerator exhaust, percent by volume – dry basis

(2) The operator shall calculate process CO_2 emissions resulting from periodic catalyst regeneration using Equation 200-4.

$$CO_2 = \sum_{i=1}^{n} CRR \times \left(CF_{spent} - CF_{regen}\right)_i \times 3.664 \times 0.001 \qquad \textbf{Equation 200-4}$$

Where:

CO_2	=	CO_2 emissions (metric tons/yr)
CRR	=	mass of catalyst regenerated (mass/regeneration cycle)
CF_{spent}	=	weight fraction carbon on spent catalyst
CF_{regen}	=	weight fraction carbon on regenerated catalyst (default = 0)
n	=	number of regeneration cycles
3.664	=	ratio of molecular weights, CO_2 to carbon
0.001	=	conversion factor – kg to metric tons

(3) The operator shall calculate process CO_2 emissions resulting from continuous catalyst regeneration in operations other than FCCUs and fluid cokers (e.g. catalytic reforming) using Equation 200-5.

$$CO_2 = CC_{irc} \times (CF_{spent} - CF_{regen}) \times H \times 3.664 \qquad \textbf{Equation 200-5}$$

Where:

CO_2	=	CO_2 emissions (metric tons/yr)
CC_{irc}	=	average catalyst regeneration rate (metric tons/hr)
CF_{spent}	=	weight carbon fraction on spent catalyst
CF_{regen}	=	weight carbon fraction on regenerated catalyst (default = 0)
H	=	hours regenerator was operational (hr/yr)
3.664	=	ratio of molecular weights, CO_2 to carbon

(b) Process Vents. Except for process emissions reported under other requirements of this regulation, the operator shall calculate process emissions of CO_2, CH_4, and N_2O from process vents using Equation 200-6.

Equation 200-6

$$E_x = \sum_{i=1}^{n} VR_i \times F_{xi} \times (MW_x / MVC) \times VT_i \times 0.001$$

Where:

E_x	=	emissions of x (metric tons/yr), where x = CO_2, N_2O, or CH_4
VR_i	=	vent rate for venting event i (scf/unit time)
F_{xi}	=	molar fraction of x in vent gas stream during event i
MW_x	=	molecular weight of x (kg/kg-mole)
MVC	=	molar volume conversion (849.5 scf/kg-mole for STP of 20°C and 1 atmosphere or 836 scf/kg-mole for STP of 60°F, and 1 atmosphere)
VT_i	=	time duration of venting event i
n	=	number of venting events
0.001	=	conversion factor – kg to metric tons

(c) Asphalt Production. The operator shall calculate CO_2 and CH_4 process emissions from asphalt blowing activities using Equations 200-7 and 200-8.

$$CH_4 = (M_A \times EF \times MW_{CH4} / MVC) \times (1 - DE) \times 0.001$$

Equation 200-7

Where:

CH_4	=	CH_4 emissions (metric tons/yr)
M_A	=	mass of asphalt blown (10^3 bbl/yr)
EF	=	emission factor (EF = 2,555 scf $CH_4/10^3$ bbl)
MW_{CH4}	=	CH_4 molecular weight (16.04 kg/kg-mole)
MVC	=	molar volume conversion factor (849.5 scf/kg- mole, for STP of 20°C and 1 atmosphere)
DE	=	control measure destruction efficiency (DE = 98% expressed as 0.98)
0.001	=	conversion factor – kg to metric tons

$$CO_2 = (M_A \times EF \times MW_{CH4} / MVC) \times DE \times 2.743 \times 0.001$$

Equation 200-8

Where:

CO_2	=	CO_2 emissions (metric tons/yr)
M_A	=	mass of asphalt blown (10^3 bbl/yr)
EF	=	emission factor (EF = 2,555 scf $CH_4/10^3$ bbl)
MW_{CH4}	=	CH_4 molecular weight (16.04 kg/kg-mole)
MVC	=	molar volume conversion factor (849.5 scf/kg mole, for STP of 20°C and 1 atmosphere)
DE	=	control measure destruction efficiency (DE = 98% expressed as 0.98)

2.743 = CH_4 to CO_2 conversion factor
0.001 = conversion factor – kg to metric tons

(d) Sulfur Recovery. The operator shall calculate CO_2 process emissions from sulfur recovery units (SRUs) using Equation 200-9. For the molecular fraction (MF) of CO_2 in the sour gas, use either a default factor of 0.20 or a source specific molecular fraction value approved by [*insert jurisdiction*] and derived from source tests conducted at least once per calendar year under the supervision of [*insert jurisdiction*].

$$CO_2 = FR \times MW_{CO2} / MVC \times MF \times 0.001$$ **Equation 200-9**

Where:

CO_2	=	emissions of CO_2 (metric tons/yr)
FR	=	volumetric flow rate of acid gas to SRU (scf/year)
MW_{CO2}	=	molecular weight of CO_2 (44 kg/kg-mole)
MVC	=	molar volume conversion (849.5 scf/ kg-mole, for STP of 20°C and 1 atmosphere or 836 scf/kg-mole, for STP of 60°F, and 1 atmosphere)
MF	=	molecular fraction (%) of CO_2 in sour gas (default MF = 20% expressed as 0.20)
0.001	=	conversion factor – kg to metric tons

(e) Flares and Other Control Devices.

(1) The operator shall calculate and report CO_2, CH_4 and N_2O emissions resulting from the combustion of flare pilot and purge gas using the appropriate method(s) specified in sections WCI.20.

(2) The operator shall calculate and report CO_2 emissions resulting from the combustion of hydrocarbons routed to flares for destruction using Equation 200-10.

$$CO_2 = RFI \times EF_{NMHC} \times CF_{NMHC} \times 3.664 \times 0.001$$ **Equation 200-10**

Where:

CO_2	=	CO_2 emissions (metric tons/year)
RFT	=	refinery feed input (m^3/yr)
EF_{NMHC}	=	non-methane hydrocarbon emission factor (EF_{NMHC} = 0.002 kg/m^3 throughput)
CF_{NMHC}	=	conversion factor – NMHC to carbon (CF_{NMHC}= 0.6)
3.664	=	ratio of molecular weights, CO_2 to carbon 0.001 = conversion factor – kg to metric tons

(3) The operator who uses methods other than flares (e.g. incineration, combustion as a supplemental fuel in heaters or boilers) to destroy low Btu gases (e.g. coker flue gas, gases from vapor recovery systems, casing vents and product storage tanks) shall calculate CO_2 emissions using Equation 200-11. The operator shall determine CC_A and MW_A quarterly using methods specified in section WCI.20 and use the annual average values of CC_A and MW_A to calculate CO_2 emissions.

$$CO_2 = GV_A \times CC_A \times MW_A / MVC \times 3.664 \times 0.001$$ **Equation 200-11**

Where:

CO_2	=	CO_2 emissions (metric tons/year)
GV_A	=	volume of gas A destroyed annually (scf/year)
CC_A	=	carbon content of gas A (kg C/kg fuel)
MW_A	=	molecular weight of gas A
MVC	=	molar volume conversion factor (849.5 scf/kg- mole for STP of 20°C and 1 atmosphere or 836 scf/kg-mole, for STP of 60°F, and 1 atmosphere)
3.664	=	ratio of molecular weights, CO_2 to carbon
0.001	=	conversion factor – kg to metric tons

(f) Storage Tanks. For above-ground storage tanks containing crude oil, asphalt, naphtha, and distillate oils that are not equipped with vapor recovery technology, the operator shall calculate CH_4 emissions using the U.S. EPA TANKS Model (Version 4.09D). For crude oil, naphtha, and distillate oils, use the default chemical databases for crude oil (RVP 5), distillate fuel oil No. 2, and jet naphtha (JP4), respectively. For asphalt, use the data in Table 200-4 to create an asphalt chemical database. The annual throughput for each storage tank must be distributed equally across the twelve months of the year and the single-component liquid option selected. The total VOC emission values generated by the model shall be converted to methane emissions using:

(1) A default conversion factor of 0.6 (CH_4 = 0.6 * VOC); or
(2) Species specific conversion factors determined by storage tank headspace vapor analysis using a sampling and analysis methodology approved by [*insert jurisdiction*].

(g) Wastewater Treatment.

(1) The operator shall calculate CH_4 emissions from wastewater treatment using Equation 200-12.

$$CH_4 = [(Q \times COD_{qave}) - S] \times B \times MCF \times 0.001$$ **Equation 200-12**

Where:

CH_4	=	emission of methane (tons/yr)
Q	=	volume of wastewater treated (m^3/yr)
COD_{qave}	=	average of quarterly determinations of chemical oxygen demand of the wastewater (kg/m^3)
S	=	organic component removed as sludge (kg COD/yr)
B	=	methane generation capacity (B = 0.25 kg CH_4/kg COD)
MCF	=	methane conversion factor for anaerobic decay (0-1.0) from Table 200-2
0.001	=	conversion factor – kg to metric tons

(2) The operator shall calculate N_2O emissions from wastewater treatment using Equation 200-13.

$$N_2O = Q \times N_{qave} \times EF_{N2O} \times 1.571 \times 0.001$$ **Equation 200-13**

Where:

N_2O = emissions of N_2O (metric tons/yr)
Q = volume of wastewater treated (m^3/yr)
N_{qave} = average of quarterly determinations of N in effluent (kg N/m^3)
EF_{N2O} = emission factor for N_2O from discharged wastewater (0.005 kg N_2O-N/kg N)
1.571 = conversion factor – kg N_2O-N to kg N_2O
0.001 = conversion factor – kg to metric tons

(h) Oil-Water Separators. The operator shall calculate CH_4 emissions from oil-water separators using Equation 200-14.

$$CH_4 = EF_{sep} \times V_{water} \times CF_{NMHC} \times 0.001$$ **Equation 200-14**

Where:

CH_4 = emission of methane (tons/yr)
EF_{sep} = NMHC (non methane hydrocarbon) emission factor (kg/m^3) from Table 200-3.
V_{water} = volume of waste water treated by the separator (m^3/yr)
CF_{NMHC} = NMHC to CH_4 conversion factor (CF_{NMHC} = 0.6)
0.001 = conversion factor – kg to metric tons

(i) Equipment leaks. The operator shall calculate CH_4 emissions for all components in natural gas, refinery fuel gas, and PSA off-gas systems as follows:

(1) Components shall be identified as one of the following classification types: valve, pump seal, connector, flange, open-ended line. Operators shall use the Component Identification and Counting Methodology and screening methods found in Method 3 in CAPCOA (1999), which is incorporated by reference in WCI.6. Operators shall measure and record emissions using instrumentation capable of detecting methane.

(2) The VOC emissions shall be calculated using the following methods:

(A) For components where the measured screening value (SV) is indistinguishable from zero when corrected for background, operators shall calculate VOC emissions using Equation 200-15:

$$E_{VOC-0} = \sum_{i=1}^{6} CC_i \times ZF_{i0} \times t$$ **Equation 200-15**

Where:

E_{VOC-0} = zero component VOC emission (kg/screening period)
i = component type (1 = valve, 2 = pump seal, 3 = other, 4 = connector, 5 = flange, 6 = open-ended line)
CC_i = number of i components where SV = 0
ZF_{i0} = zero VOC emission factor (kg/hr) for component i from Table 200-5
t = time (hours) since last screening

(B) For leaking components, operators shall calculate VOC emissions using the following methods:

(i) For screening values between background and 9,999 ppmv, the operator shall calculate the VOC emissions using Equation 200-16.

$$E_{VOCL-C} = \sum_{i=1}^{6} \sum_{n=1}^{n} \left(\sigma_i \times SV_n^{\beta i} \right) \times t \qquad \textbf{Equation 200-16}$$

Where:

E_{VOCL-C}	=	leaking components VOC emissions (kg/screening period)
i	=	component type (1=valve, 2=pump seal, 3=others, 4=connector, 5=flange, 6=open ended-line)
n	=	number of i components
σ_i	=	correlation equation coefficient for component type i from Table 200-5
SV_n	=	screening value for component n
βi	=	correlation equation exponent for component type i from Table 200-5
t	=	time (hours) component has been leaking – default value is time from last screening

(ii) For screening values greater than 9,999 ppmv, the operator shall calculate the VOC emissions using Equation 200-17.

$$E_{VOCP} = \sum_{i=1}^{6} CC_i \times PF_{iP} \times t \qquad \textbf{Equation 200-17}$$

Where:

E_{VOCP}	=	VOC emissions for components pegged over SV 9,999 ppmv (kg/screening period)
i	=	component type (1=valve, 2=pump seal, 3=others, 4=connector, 5=flange, 6=open-ended line)
CC_i	=	number of i components pegged over 9,999 ppmv
PF_{iP}	=	VOC emission factor (kg/hr) for component type i pegged over 9,999 ppmv from Table 200-5
t	=	time component has been leaking (hours) – default value is time since last screening

(C) The operator shall calculate CH_4 emissions using Equation 200-18. Operators shall use system specific determinations of gas composition and methane content (refinery fuel gas, natural gas, associated gas, flexigas, low Btu gas), where available, to determine a CF_{VOC} value. When representative data is not available, operators shall use the default value of 0.6 for CF_{VOC}.

$$CH_4 = \sum_{1}^{n} \left(E_{VOC-0} + E_{VOC-LC} + E_{VOCP} \right)_n \times CF_{VOC} \times 0.001 \qquad \textbf{Equation 200-18}$$

Where:

CH_4	=	methane emissions (metric tons/year)
n	=	number of screenings/year
E_{VOC-0}	=	zero component VOC emissions (kg/screening period)
E_{VOC-LC}	=	leaking component VOC emissions (kg/screening period)
E_{VOCP}	=	VOC emissions for components pegged over 9,999 ppmv (kg/screening period)
CF_{VOC}	=	VOC to CH_4 conversion factor (default CF_{VOC}=0.6)
0.001	=	conversion factor – kg to metric tons

WCI.204 Sampling, Analysis, and Measurement Requirements

(a) Catalyst Regeneration.

(1) For FCCUs and fluid coking units, the operators shall measure the following parameters using methods that comply with the measurement accuracy provisions in WCI.2(g).

(A) The daily oxygen concentration in the oxygen enriched air stream inlet to the regenerator.
(B) Continuous measurements of the volumetric flow rate of air and oxygen enriched air entering the regenerator.
(C) Continuous measurement of the volumetric flow rate of exhaust gas leaving the regenerator.
(D) Continuous measurements of the CO_2, CO and O_2 concentrations in the regenerator exhaust gas.
(E) Daily measurements of the carbon content of the coke burned.
(F) The number of days of operation.

(2) For periodic catalyst regeneration, the operators shall measure the following parameters using methods that comply with the measurement accuracy provisions in WCI.2(g).

(A) The mass of catalyst regenerated in each regeneration cycle.
(B) The weight fraction of carbon on the catalyst prior to and after catalyst regeneration.

(3) For continuous catalyst regeneration in operations other than FCCUs and fluid cokers, the operators shall measure the following parameters using methods that comply with the measurement accuracy provisions in WCI.2(g).

(A) The hourly catalyst regeneration rate.
(B) The weight fraction of carbon on the catalyst prior to and after catalyst regeneration.
(C) The number of hours of operation.

(b) Process vents. Operators shall measure the following parameters for each process vent using methods that comply with the measurement accuracy provisions in WCI.2(g).

(1) The vent flow rate for each venting event.
(2) The molar fraction of CO_2, N_2O, and CH_4 in the vent gas stream during each venting event.
(3) The duration of each venting event.

(c) Asphalt Production. Operators shall measure the mass of asphalt blown using methods that comply with the measurement accuracy provisions in WCI.2(g).

(d) Sulfur Recovery. The operator shall measure the volumetric flow rate of acid gas to the SRU using methods that comply with the measurement accuracy provisions in WCI.2(g). If using source specific molecular faction value instead of the default factor, the operator shall conduct an annual test of the CO_2 content using methods approved by [insert jurisdiction]. The operator shall submit a test plan to the [insert jurisdiction] for approval. Once approved, the annual tests shall be conducted in accordance with the approved test plan under the supervision of the [*insert jurisdiction*].

(e) Flares and Other Control Devices. The operator shall measure:

(1) The volume of gas destroyed annually determined to accuracy of ± 7.5%.
(2) The carbon content using methods that comply with the measurement accuracy provisions in WCI.2(g).

(f) Storage Tanks. The operator shall measure the annual throughput of crude oil, naphtha, distillate oil, asphalt, and gas oil for each storage tank using flow meters that comply with the measurement accuracy provisions in WCI.2(g).

(g) Wastewater Treatment. Operators shall measure the following parameters using methods that comply with the measurement accuracy provisions in WCI.2(g).

(1) The daily volume of waste water treated.
(2) The quarterly chemical oxygen demand of the wastewater.
(3) The amount of sludge removed and the organic content of the sludge.
(4) The quarterly nitrogen content of the wastewater.

(h) Oil-Water Separators. Operators shall measure the daily volume of waste water treated by the oil-water separators using methods that comply with the measurement accuracy provisions in WCI.2(g).

(i) Equipment Leaks. Operators shall measure screening values for each valve, pump seal, connector, flange, and open-ended line used in natural gas, refinery fuel gas, and PSA off-gas systems using the methods specified in CAPCOA (1999) Method 3: Correlation Equation Method and an instrument capable of detecting methane. Operators shall conduct screenings at the frequency interval required by [*insert jurisdiction*].

Note: Comparability of the Canadian regulations to the leak detection and repair r regulations under 40 CFR 63, Subpart CC and 40 CFR 60, Subpart VV is under determination. These U.S EPA regulations require initially monthly monitoring for valves and pumps, which may be reduced to quarterly, semi-annual, or annual based on the percentage of leaking components.

Table 200-1. Coke burn rate material balance and conversion factors

	(kg min)/(hr dscm %)	**(lb min)/(hr dscf %)**
K_1	0.2982	0.0186
K_2	2.0880	0.1303
K_3	0.0994	0.0062

Table 200-2. Default MCF Values for Industrial Wastewater			
Type of Treatment and Discharge Pathway or System	**Comments**	**MCF**	**Range**
Untreated			
Sea, river and lake discharge	Rivers with high organic loading may turn anaerobic, however this is not considered here	0.1	0 - 0.2
Treated			
Aerobic treatment plant	Well maintained, some CH_4 may be emitted from settling basins	0	0 – 0.1
Aerobic treatment plant	Not well maintained, overloaded	0.3	0.2 – 0.4
Anaerobic digester for sludge	CH_4 recovery not considered here	0.8	0.8 – 1.0
Anaerobic reactor	CH_4 recovery not considered here	0.8	0.8 – 1.0
Anaerobic shallow lagoon	Depth less than 2 meters	0.2	0 – 0.3
Anaerobic deep lagoon	Depth more than 2 meters	0.8	0.8 – 1.0

For CH_4 generation capacity (B) in kg CH_4/kg COD, use default factor of 0.25 kg CH_4/kg COD.

The emission factor for N_2O from discharged wastewater (EF_{N2O}) is 0.005 kg N_2O-N/kg-N.

MCF = methane correction factor – the fraction of waste treated anaerobically.
COD = chemical oxygen demand (kg COD/m^3).

Table 200-3. Emission Factors for Oil/Water Separators	
Separator Type	**Emission factor (EF_{sep})[a] kg NMHC/m^3 wastewater treated**
Gravity type - uncovered	1.11e-01
Gravity type - covered	3.30e-03
Gravity type – covered and connected to destruction device	0
DAF[b] of IAF[c] - uncovered	4.00e-03[d]
DAF or IAF - covered	1.20e-04[d]
DAF or Iaf – covered and connected to a destruction device	0

[a] EFs do not include ethane
[b] DAF = dissolved air flotation type
[c] IAF = induced air flotation device
[d] EFs for these types of separators apply where they are installed as secondary treatment systems

Table 200-4. Data for Preparing the Asphalt Chemical Database	
Parameter	**Database Entry**
Liquid Molecular Weight	**1000**
Vapor Molecular Weight	**105**
Liquid Density (lb/gal. at 60 ^oF)	**8.0925**
Antoine's Equation Constants (using K)	**A = 75350.06**
	B = 9.00346

Table 200-5. Gas Service Components Fugitive Emissions			
Component Type / Service Type	**Default Zero Factor (kg/hr)**	**Correlation Equation (kg/hr)**	**Pegged Factor (kg/hr)**
			10,000 ppmv
	Zf_{i0}	**σ_i and β_i**	**(SV > 9,999) PF_{iP-10}**
Valves (1)	7.8×10^{-6}	$2.27 \times 10^{-6}(SV)^{0.747}$	0.064
Pump seals (2)	1.9×10^{-5}	$5.07 \times 10^{-5}(SV)^{0.622}$	0.089
Others (3)	4.0×10^{-6}	$8.69 \times 10^{-6}(SV)^{0.642}$	0.082
Connectors (4)	7.5×10^{-6}	$1.53 \times 10^{-6}(SV)^{0.736}$	0.030
Flanges (5)	3.1×10^{-7}	$4.53 \times 10^{-6}(SV)^{0.706}$	0.095
Open-ended lines (6)	2.0×10^{-6}	$1.90 \times 10^{-6}(SV)^{0.724}$	0.033

ATTACHMENT 11: ALUMINUM PRODUCTION

Applicability

These methodologies apply to all facilities that convert raw alumina mineral (Al_2O_3) to raw aluminum metal by an electrolytic process. Emissions must be reported for the following processes:

- CO_2 from anode consumption,
- CO_2 from anode and cathode baking,
- PFC from anode effects,
- CO_2 from green coke calcination, and
- SF_6 from cover gas consumption,

Primary aluminum smelting facilities can emit GHG from other activities that are not directly part of the aluminum smelting process. GHG emissions from the following activities are covered under other sections of the reporting Essential Requirements:

- Stationary combustion emissions from boilers, heaters, furnaces (§ WCI.20),
- Nonroad equipment (§ WCI.XX),
- Lime calcination (§ WCI.170), and
- SF_6 use in electrical equipment (§WCI.XX).

HFC use for refrigeration and cooling and not associated with the aluminum processes is not included in this category, nor is bauxite calcination to alumina and raw coke production which are assumed to be performed at other locations.

Emission Calculations

The following emission calculation methods were taken from the *Aluminum Production-Guidance Manual for Estimating Greenhouse Gas Emissions, Environment Canada, March 2004*. Other organizations are recommending very similar methodologies, including the International Aluminum Institute, WRI, IPCC and The Climate Registry.

Emissions will be calculated monthly using the following methods:

Pre-baked Anode Consumption:

To calculate emissions from pre-baked anode consumption, use the following equation:

$$Emissions_{CO_2} = NCC \times MP \times \frac{(100 - \%S_a - \%Ash_a - \%Imp_a)}{100} \times 3.664$$

Where:

Emissions $_{CO2}$ = carbon dioxide emissions (metric tons per year)
NCC = net annode consumption per metric ton of aluminum;(metric ton/ metric ton Al)
MP = annual aluminum production (metric ton);
S_a = sulphur content in baked anodes (wt %);
Ash_a = ash content in baked anodes (wt %);
Imp_a = content of fluorine and other impurities in baked anodes (wt %);
3.664 = conversion factor from carbon to CO_2.

Søderberg Anode Consumption:

To calculate emissions from Søderberg anode consumption, use the following equation:

$$Emissions_{CO_2} = \left[\begin{array}{l} (PC \times MP) - \left(BSM \times \frac{MP}{1000} \right) - \left(\frac{\%BC}{100} \times PC \times MP \times \left(\frac{\%S_p + \%Ash_p + \%H_p}{100} \right) \right) \\ - \left(\frac{100 - \%BC}{100} \times PC \times MP \times \frac{\%S_c + \%Ash_c}{100} \right) \end{array} \right] \times 3.664$$

Where:

Emissions $_{CO2}$ = carbon dioxide emissions (metric tons per year)
PC = paste consumption (metric tons paste/metric ton aluminum);
MP = annual aluminum production (metric tons);
BSM = emissions of benzene-soluble matter (kilograms benzene-soluble matter/metric ton aluminum);
BC = average binder (pitch) content in paste (wt %);
S_p = sulphur content in pitch (wt %);
Ash_p = ash content in pitch (wt %);
H_p = hydrogen content in pitch (wt %);
S_c = sulphur content in calcinated coke (wt %);
Ash_c = ash content in calcinated coke (wt %);
3.664 = conversion factor from carbon to CO_2.

Anode/Cathode Baking:

CO_2 emissions result from the baking of (pre-bake) anodes and cathodes. In cases where baking of anodes and cathodes occurs on-site, emissions should be calculated for both packing coke and pitch coking. The calculations require information on the net rate of raw material used for baked anode/cathode production, plus material composition information. To calculate emissions from packing coke for anodes, use the following equation:

$$Emissions_{CO_2} = \left(PCC \times BAP \times \frac{100 - \%Ash_{pc} - \%S_{pc} - \%Imp}{100} \right) \times 3.664$$

Where:

Emissions $_{CO2}$	=	carbon dioxide emissions (metric tons per year)
PCC	=	packing coke consumption per metric ton of baked anode (metric tons coke/metric ton anodes);
BAP	=	annual baked anode production (metric tons);
Ash_{pc}	=	ash content in packing coke (wt %);
S_{pc}	=	sulphur content in packing coke (wt %);
Imp	=	content of other impurities (wt %);
3.664	=	conversion factor from carbon to CO_2.

To calculate emissions that occur from oxidation of pitch volatile matter in ***pitch coking***, use the following equation:

$$Emissions_{CO_2} = \left(GAW - BAP - \left(\frac{\%H_p}{100} \times \frac{\%PC}{100} \times GAW \right) - RT \right) \times 3.664$$

Where:

Emissions $_{CO2}$	=	carbon dioxide emissions (metric tons per year)
GAW	=	annual green anode tonnage (metric tons);
BAP	=	annual baked anode production (metric tons).
H_p	=	hydrogen content in pitch (wt %);
PC	=	average pitch content (wt %) in green anode;
RT	=	annual recovered tar (metric tons);
3.664	=	conversion factor from carbon to CO_2.

To calculate similar emissions from the baking of cathodes, the methodology follows the above methodology for anodes, where values for baked cathode production, green cathode tonnage and cathode composition data are substituted into the equations for packing coke and pitch coking.

<u>Emissions from Anode Effects:</u>

The two PFCs known to be emitted from the occurrence of anode effects (also termed anode events) during primary aluminum smelting are CF_4 and C_2F_6. The most accurate estimates of these PFC emissions from anode effects are based on either continuous monitoring of emissions or development of smelter-specific relationships for emissions based on measured values and operating conditions. This requires both a comprehensive measurement program to establish the smelter-specific relationship as well as on-going collection of operating parameter data (e.g. frequency and duration of anode effects, anode effect over-voltage) and production data.

If continuous monitoring of PFC emissions is not selected, there are two approaches that may be used to relate monitored emissions, typically obtained from field measurements, to process data in order to develop smelter-specific relationships that can be used to estimate emissions. The two approaches are the Slope method or the Pechiney method, which are described below.

Slope Method - The **Slope** method uses a linear least squares relationship between anode effect frequency and duration and emissions, such that emissions can be calculated using the following equation:

$$Emissions_{CF_4,C_2F_6} = slope_{CF_4,C_2F_6} \times AEF \times AED \times MP$$

Where:

$Emissions_{CF4,\ C2F6}$	=	Emissions of CF_4 or C_2F_6 (metric tons/yr)
$slope_{CF4,\ C2F6}$	=	slope of the emissions relationship- measured ([Metric tons of CF_4 or C_2F_6 /metric ton Al]/[anode effect minutes/pot-days]);
AEF	=	anode effect frequency (number of anode effects per pot per day);
AED	=	anode effect duration (minutes per anode effect);
MP	=	total aluminum production (metric tons).

Note that the product of the anode effect frequency and duration can be expressed as "anode effect minutes per pot-day."

Pechiney Method - The **Pechiney** method (or over-voltage method) uses the anode effect over-voltage as the process parameter in combination with the quantity of aluminum produced to calculate PFC emissions. The anode effect over-voltage (AEO) represents the sum of the differences between the total cell voltage and the equilibrium voltage for each second during an anode event divided by the total number of seconds in the chosen period (e.g. one day). This calculation is carried out once the cell voltage exceeds 8 volts and continues until the voltage returns to the equilibrium point. The over-voltage coefficient is determined from the measurement of PFC emissions. The full calculation is:

$$Emission_{CF_4,C_2F_6} = Over - voltage \quad coefficient_{CF_4,C_2F_6} \times \frac{AEO}{CE} \times MP$$

Where:

$Emissions_{CF4,\ C2F6}$	=	Emissions of CF_4 or C_2F_6 (metric tons/yr)
Over-voltage coefficient $_{CF4,\ C2F6}$	=	experimentally measured ([Metric tons of CF_4 or C_2F_6/metric ton Al]/ mV)
AEO	=	anode effect over-voltage (millivolts per pot per day);
CE	=	current efficiency of aluminum production process, expressed as a fraction;
MP	=	annual aluminum production (metric tons).

Under either approach, the calculation is to be completed for each of the PFC gases emitted (CF_4 and C_2F_6) and for each operating pot line at the facility.

Note: It has been recommended that facilities be allowed to use a technology based emission factor in place of measuring either the slope coefficient or the over-voltage coefficient required *by the above two methods. This approach is equivalent to the IPCC Tier 2 method which has a reported uncertainty of +/-6% to +/-44%, depending on the process. The IPCC Tier 3 method requires the use of site measured values for greater accuracy. The WCI seeks stakeholder comments regarding the practicalities of requiring the IPCC Tier 3 method as opposed to allowing a Tier 2 method as well.*

CO_2 Emissions from Green Coke Calcination

The process of coke calcination, where coke is heated to high temperatures in order to drive off volatile matter, results in emissions of CO_2. The facility may purchase coke materials in the calcined state, or it may operate a calcining furnace. If coke calcination is conducted on-site at the facility, the following equation can be used to calculate the CO_2 emissions from this process:

$$Emissions_{CO_2} = \left[\left[GC \times \frac{(100 - \%H_2O_{gc} - \%V_{gc} - \%S_{gc})}{100} - (CC + UCC + DE) \times \frac{(100 - \%S_{cc})}{100}\right] \times 3.664\right] + \left[GC \times 0.035 \times \frac{44}{16}\right]$$

Where:

$Emissions_{CO2}$	=	carbon dioxide emissions (metric tons prr year)
GC	=	annual green coke feed (metric tons);
H_2O_{gc}	=	humidity in green coke feed (wt %);
V_{gc}	=	volatiles in green coke feed (wt %);
S_{gc}	=	sulphur content in green coke feed (wt %);
S_{cc}	=	sulphur content in calcinated coke (wt %);
CC	=	annual calcinated coke produced (metric tons);
UCC	=	annual under-calcinated coke produced (metric tons);
DE	=	annual coke dust emissions (metric tons);
3.664	=	conversion factor from carbon to CO_2;
0.035	=	Assumed CH4 and tar content in coke volatiles, contributing to CO_2 emissions
44/16	=	conversion factor from methane to CO_2.

For the composition parameters in the above equation, facility-specific values should be used for the coke input and output streams of the calcining operation to ensure accuracy of the emission estimates.

SF_6 Emissions from Use as a Cover Gas

For some specialized applications, SF_6 may be used as a cover gas at aluminum facilities. SF_6 is essentially non-reactive during this process. If this SF_6 use occurs, emissions are calculated based on the quantity of SF_6 consumed:

$$Emissions_{SF_6} = Consumption_{SF_6}$$

The consumption of SF_6 may be determined by:

- measured weight difference of gas cylinders used at the facility for this purpose;
- accounting of delivered purchases and inventory changes of SF6 used for this purpose; and
- metering of flow rates at the point used.

The first two methods based on weight are generally more accurate. When using measured weights, it is important to account for any gas in the heels of the cylinders returned to the supplier. If accounting or delivery records are used over an annual time period, beginning and end of year inventories must be taken into account.

Reporting Requirements

Annual emissions will be reported by emission source (i.e. emissions from prebaked anode consumption or from anode effect) and by GHG.

Sampling, Analysis, and Measurement Methods

Issue: Sampling, analysis, and measurement methods have not been specified in the available methodologies for the aluminum industry.

Note: The sampling, analysis, and measurement procedures will be standardized for each calculation input to reduce variation between facilities within the aluminum industry. Material sampling frequency and technique is distinct from material analysis conducted in a laboratory. The WCI is seeking stakeholder feedback on this topic and is specifically interested in proposals from stakeholders with expertise in this industry related to sampling, analysis and measurement procedures already in use at these facilities for the material quantities and/or concentrations listed below. Those proposing procedures should include sampling frequency and technique, indicate the uncertainty associated with the procedures, and describe the application of the procedure at a facility.

There are several possible approaches to specifying monitoring methods:

- Specify the accuracy required for each datum and allow the source to select their own methodologies that meet the accuracy requirements, and require the verifiers to certify the accuracy requirements were achieved, [*This approach is especially useful for monitoring that is currently being made with a wide variety of instruments and are likely being made with high accuracy, such as monitoring of raw material flows and product flows; however, much burden is placed on verifiers to ensure the accuracy of the methods used. This approach is used for monitoring fuel flow for combustion sources.*]
- Specify the accuracy required for each datum and require the source to submit a monitoring plan that meets the accuracy requirements, and require the verifiers to certify the source followed the approved plan. [*This approach places significant burden on WCI to approve individual monitoring plans.*]

- Specify the methodologies that should be followed, selecting them from available ASTM, ISO, U.S. EPA, and EC methodologies; however, there are not established methods for all parameters. Listed below are examples of the available methodologies for monitoring the aluminum industry.

ISO 9055:1988. Carbonaceous materials for the production of aluminum -- Pitch for electrodes -- Determination of sulfur content by the bomb method.

ISO 10238:1999. Carbonaceous materials used in the production of aluminum -- Pitch for electrodes -- Determination of sulfur content by an instrumental method.

ISO 8006:1985. Carbonaceous materials used in the production of aluminum -- Pitch for electrodes -- Determination of ash.

ISO 8005-2005. Carbonaceous materials used in the production of aluminum -- Green and calcined coke -- Determination of ash content

ISO 10237-1997. Carbonaceous materials for use in the production of aluminum -- Calcined coke -- Determination of residual-hydrogen content.

ISO 5931:2000. Carbonaceous materials used in the production of aluminum -- Calcined coke and calcined carbon products -- Determination of total sulfur by the Eschka method.

Slope and Over-voltage Coefficient: *Protocol for Measurement of Tetrafluoromethane and Hexafluoroethane Emissions from Primary Aluminum Production.* U.S. Environmental Protection Agency and International Aluminum Institute. April 2008.

ASTM D3173 Test Method for Moisture in the Analysis Sample of Coal and Coke

The following parameters are not covered by a specific ASTM or ISO methodology. They are candidates for being addressed using one of the first two approaches listed above:

- Mass flow rates or consumption of aluminum, paste, carbon, anodes, coke, recovered tar, and coke dust,
- Emissions of benzene soluble matter,
- Binder content in paste,
- Pitch content in anodes,
- Current efficiency,
- Anode effect frequency,
- Anode effect duration,
- Anode effect over-voltage,
- Current efficiency,
- Volatile content in coke

ATTACHMENT 12: LEAD PRODUCTION

Applicability

There are two primary production processes used to produce lead from lead concentrates: the sintering/smelting process and the direct smelting process. In the sintering/smelting process, the lead concentrates are initially combined with recycled sinter, lime rock and silica, oxygen, and high lead content sludge to produce a sinter roast. The sinter roast is then put into a blast furnace (i.e., traditional blast or Imperial Smelting) with other metal-containing ores, air, smelter by-products, and metallurgical coke. This reduction of lead oxide in the furnace results in the production of CO_2 emissions. In the direct smelting process, the sintering step is skipped and the lead concentrates are entered directly into the furnace (i.e., Isasmelt-Ausmelt, Queneau-Schumann-Lurgi, and Kaldo for bath smelting and Kivcet for flash smelting) with reducing agents.

In addition to the sintering/smelting and direct smelting primary production processes, secondary production or recycling of lead is also conducted. Most of the recycled lead comes from scrapped lead acid batteries. The lead acid batteries are either crushed with a hammer mill or smelted whole. All of the furnaces used for primary production, as well as electric arc and electric resistance furnaces, can be used to smelt recycled scrap lead.

Emission Calculations

The following emission calculation methods are from the 2006 IPCC Guidelines, Volume 3, Section 4.6.

The Tier 3 methodology recommends using actual directly measured CO_2 emissions data, if available. Alternatively, facility-specific data regarding reducing agents and carbon contents can be used to calculate emissions for the Tier 3 methodology. The Tier 2 methodology is similar to the Tier 3 method, except that default carbon contents for the reducing agents are used instead of facility-specific carbon contents. Default carbon contents are available for the following reducing agents: blast furnace gas, charcoal, coal, coal tar, coke, coke oven gas, coking coal, electric arc furnace (EAF) carbon electrodes, EAF charge carbon, fuel oil, gas coke, natural gas, and petroleum coke.

The emission calculation equation is:

$$E_{Pb} = \sum_{x} (RA_x \times C_x) \times 3.664$$

Where:

E_{Pb} = CO_2 emissions from lead production (metric tons);
RA_x = Quantity of reducing agent *x* used (metric tons);
C_x = Carbon content of reducing agent *x* (metric tons C/metric tons of *x*);
3.664 = Conversion factor from metric tons of C to metric tons of CO_2.

The Tier 3 method (using either actual directly measured CO_2 emissions data or facility-specific reducing agent quantities and carbon contents) is recommended to estimate emissions from lead production facilities.

The uncertainty for Tier 3 facility-specific measured CO_2 data has been estimated to be ±5 percent. The uncertainty associated with the Tier 3 facility-specific reducing agent quantities and carbon contents is also estimated to be ±5 percent. The uncertainty of the Tier 2 reducing agent carbon contents is estimated to be ±15 percent.

Reporting Requirements

Annual CO_2 emissions (measured or calculated) based on the IPCC Tier 3 method will be reported for each facility. Facility-specific quantities and carbon contents of each reducing agent used will also be reported.

Sampling, Analysis, and Measurement Methods

The Tier 3 method from the 2006 IPCC Guidelines specifies facility-specific emission measurements or facility-specific data regarding reducing agents and carbon contents. The following measurement methods should be used.

Note: The sampling, analysis, and measurement procedures will be standardized for each calculation input to reduce variation between facilities within the lead industry. Material sampling frequency and technique is distinct from material analysis conducted in a laboratory. The WCI is seeking stakeholder feedback on this topic and is specifically interested in proposals from stakeholders with expertise in this industry related to sampling, analysis and measurement procedures already in use at these facilities for the material quantities and/or concentrations listed below. Those proposing procedures should include sampling frequency and technique, indicate the uncertainty associated with the procedures, and describe the application of the procedure at a facility.

(a) Facility CO_2 emissions. Determine facility CO_2 emissions using continuous emissions monitoring systems (CEMS) as specified in WCI.23(d).

Wherever possible, measurements of carbon contents of the material balance input materials should be conducted as described below.

(b) Fuel Carbon Content Requirements. Fuel carbon contents should be measured in the following manner (from WCI.25):

(1) For coal and coke, solid biomass-derived fuels, and waste-derived fuels; use ASTM 5373-02 (Reapproved 2007).
(2) For liquid fuels, use the following ASTM methods: For petroleum-based liquid fuels and liquid waste-derived fuels, use ASTM D5291-02 (Reapproved 2007) "Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants", ultimate analysis of oil or computations based on ASTM D3238-95 (Reapproved 2005) and either ASTM D2502-04 or ASTM D2503-92 (Reapproved 2002).
(3) For gaseous fuels, use ASTM D1945-03 or ASTM D1946-90 (Reapproved 2006).

(c) By-Product Carbon Content Monitoring Requirements. Carbon contents of by-products (e.g., blast furnace gas, coke oven gas, coal tar, light oil, coke breeze, sinter off gas, etc.) used in lead production processes should be monitored in the following manner:
[Method to be determined.]

(d) Electrode Carbon Content Requirements. Carbon contents of carbon electrodes used in lead production processes should be monitored in the following manner:
[Method to be determined.]

(e) Quantity Measurement Requirements. The quantities of process inputs, outputs, and by-products must be determined using the following methods:

- For solid process inputs, outputs, and by-products, quantities must be determined by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.
- For liquid process inputs, outputs, and by-products, quantities must be determined by direct volume measurement using the same plant instruments used for accounting purposes, such as *[Method to be determined]*.
- For gaseous process inputs, outputs, and by-products, quantities must be determined by direct volume measurement using the same plant instruments used for accounting purposes, such as *[Method to be determined]*.

ATTACHMENT 13: ZINC PRODUCTION

Applicability

There are three primary production processes used to produce zinc: electro-thermic distillation, pyrometallurgical, and electrolytic. In electro-thermic distillation, roasted concentrate and secondary zinc products are combined into a sinter feed that is then burned resulting in a zinc oxide-rich sinter. This sinter is then fed into an electric retort furnace with metallurgical coke which reduces the zinc oxide; the resultant vaporized zinc is then captured in a vacuum condenser. The pyrometallurgical process utilizes an Imperial Smelting Furnace, which allows for the simultaneous treatment of both lead and zinc concentrates (estimated emissions must be allocated to both lead and zinc production to avoid double-counting). In the electrolytic process, zinc sulfide is calcined, which results in the production of zinc oxide. The zinc oxide is leached in sulfuric acid and then drawn out of solution using electrolysis. The electrolytic process does not result in non-energy CO_2 emissions.

In addition to primary production, zinc can be recovered from various materials using more than 40 hydrometallurgical and pyrometallurgical technologies. The preferred technologies are dependent upon the zinc source and the desired end use for the recovered zinc. In general, the processes consist of zinc concentration, sintering, smelting, and refining. Many of the sintering, smelting, and refining steps are identical to the primary production process steps. Two concentration processes are the Waelz Kiln and slag reduction or fuming processes.

Emission Calculations

The following emission calculation methods are taken from the 2006 IPCC Guidelines, Volume 3, Section 4.7.

The Tier 3 methodology recommends using actual directly measured CO_2 emissions data, if available. Alternatively, facility-specific emission factors and material quantities can be used to calculate emissions for the Tier 3 methodology. The Tier 2 methodology uses country-specific emission factors developed from facility statistics regarding reducing agent use, furnace types, and other process materials. Unlike lead, default carbon contents are not provided for reducing agents used in zinc production.

The Tier 1 methodology for zinc production uses default emission factors for different zinc product types. The emission calculation equation for Tier 1 is:

$$E_{Zn} = (Zn_{ET} \times EF_{ET}) + (Zn_{PM} \times EF_{PM}) + (Zn_{Sec} \times EF_{Sec})$$

Where:

E_{Zn} = CO_2 emissions from zinc production (metric tons);
Zn_{ET} = Quantity of zinc produced by electro-thermic distillation (metric tons);
EF_{ET} = Emission factor for electro-thermic distillation (metric tons CO_2/metric tons of zinc produced);
Zn_{PM} = Quantity of zinc produced by pyrometallurgical process (Imperial Smelting Furnace Process (metric tons);
EF_{PM} = Emission factor for pyrometallurgical process (metric tons CO_2/metric tons of zinc produced);
Zn_{Sec} = Quantity of zinc produced by secondary production process (e.g., Waelz Kiln, etc.) (metric tons);
EF_{Sec} = Emission factor for secondary production process (metric tons CO_2/metric tons of zinc produced).

A default emission factor is not available for the electro-thermic distillation process because of a lack of data; emissions will be underestimated if a facility-specific emission factor for the electro-thermic distillation process is not identified and used. The default emission factor for the pyrometallurgical process (i.e., Imperial Smelting Furnace) is 0.43 metric tons CO_2/metric tons of zinc produced. The default emission factor for the secondary production process (i.e., Waelz Kiln) is 3.66 metric tons CO_2/metric tons of zinc produced.

The uncertainty for Tier 3 facility-specific measured CO_2 data has been estimated to be ±5 percent. The uncertainty associated with the Tier 3 facility-specific reducing agent quantities and carbon contents is also estimated to be ±5 percent. The uncertainty of the Tier 2 country-specific emission factors is estimated to be ±15 percent. The uncertainty of the Tier 1 default emission factors is estimated to be ±50 percent.

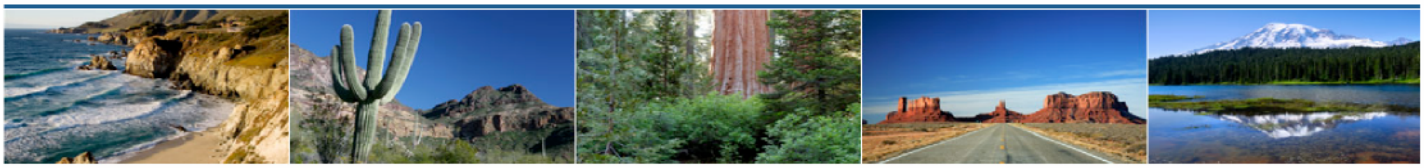
The Tier 3 method (using either actual directly measured CO_2 emissions data or facility-specific emission factors and material quantities) is recommended to estimate emissions from zinc production facilities.

Reporting Requirements

Annual CO_2 emissions (measured or calculated) based on the IPCC Tier 3 or Tier 2 method will be reported for each facility.

Sampling, Analysis, and Measurement Methods

(a) Facility CO_2 emissions. The Tier 3 method from the 2006 IPCC Guidelines specifies facility-specific emission measurements. Determine facility CO_2 emissions using continuous emissions monitoring systems (CEMS) as specified in WCI.23(d).
(b) Quantity Measurement Requirements. Alternatively, Tier 3 facility-specific emission factors can be used if facility-specific emission measurements are not available. For solid process outputs, quantities must be determined by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.



ATTACHMENT 14: COAL MINE FUGITIVE EMISSIONS

Applicability

As part of the geological processes of coal formation, CO_2 and CH_4 may also be produced and trapped in the coal seam until the coal is exposed and broken during mining. In general, CH_4 is the predominant greenhouse gas emitted from coal mines. The following five processes are potential source categories for fugitive emissions associated with both underground and surface coal mines:

- Mining (emissions from the breakage of coal and associated strata, including ventilation air and degasification systems for underground mines);
- Post-mining operations (subsequent handling, processing, and transportation of coal);
- Low temperature oxidation (oxidation of coal when exposed to oxygen in air);
- Uncontrolled combustion (active fire caused by trapped heat and increased temperature from low temperature oxidation); and
- Abandoned mines.

The following methodology focuses solely on CH_4 mining emissions. Emissions from post-mining operations (including storage piles) are addressed in Section WCI.100. Coal oxidation occurs in both underground and surface mines; however, emissions are not expected to be significant. Uncontrolled combustion also occurs in underground and surface mines, but it is difficult to quantify and infeasible to include in the methodology. Estimation of emissions from abandoned underground mines requires the emission rate at closure/abandonment (i.e., when all active mine ventilation ceases) and "decline curves" (i.e., hyperbolic models of declining emissions as a function of time). At best, the uncertainty of estimated abandoned mine emissions is ±50 percent.

Emission Calculations

The following emission calculation methods were taken from the 2006 IPCC Guidelines, Volume 2, Section 4.1. The following methods can be used to calculate emissions:

Underground Mining

The Tier 3 method for underground mining is mine-specific measurement data based on ventilation air and degasification system measurements. The Tier 2 method relies on basin-specific emission factors that need to be obtained from sample ventilation air data or from a quantitative relationship that accounts for the gas content of the coal and the surrounding strata affected by the mining process. If Tier 3 or Tier 2 data are not available, then Tier 1 emission factors could be used. If Tier 1 or Tier 2 methods are utilized, then methane recovered and utilized for energy production or flaring should be subtracted from the emission estimates; this subtraction is not needed for the Tier 3 methodology, because the Tier 3 mine-specific measurements should take methane recovery and utilization into account.

The Tier 2 and Tier 1 equations are as follows:

$$E_{Underground-CH4} = E_{Mining-CH4} - R_{CH4}$$

Where:

$E_{Underground-CH4}$ = Total CH_4 emissions from underground coal mining (metric tons);
$E_{Mining-CH4}$ = CH_4 emissions from underground coal mining operations (metric tons);
R_{CH4} = CH_4 recovered and utilized for energy production or flared.

$$E_{Mining-CH4} = P_{Underground} \times EF_{Underground-CH4} \times 0.00067$$

Where:

$E_{Mining-CH4}$ = CH_4 emissions from underground coal mining operations (metric tons);
$P_{Underground}$ = Underground coal production (metric tons);
$EF_{Underground-CH4}$ = CH_4 emission factor (m^3 CH_4/metric ton coal);
0.00067 = Conversion factor from volume of CH_4 to mass of CH_4 (metric ton/m^3).

The Tier 1 emission factors for underground coal mining are identified as high, average, or low. The high emission factor is 25 m^3/metric ton (i.e., at depths greater than 400 meters). The average emission factor is 18 m^3/metric ton (i.e., at depths between 200 and 400 meters). The low emission factor is 10 m^3/metric ton (i.e., at depths less than 200 meters).

$$E_{Post-CH4} = P_{Underground} \times EF_{Post-CH4} \times 0.00067$$

Where:

$E_{Post-CH4}$ = CH_4 emissions from underground coal post-mining operations (metric tons);
$P_{Underground}$ = Underground coal production (metric tons);
$EF_{Post-CH4}$ = CH_4 emission factor (m^3 CH_4/metric ton coal);
0.00067 = Conversion factor from volume of CH_4 to mass of CH_4 (metric ton/m^3).

For underground mines, the uncertainty for the Tier 3 mining emission estimates ranges from ±5 percent for continuous monitoring up to ±30 percent for more infrequent monitoring. The uncertainty of the Tier 2 mining emission factors is ±50-75 percent, while the uncertainty of the Tier 1 mining emission factors is a factor of 2 greater/smaller.

Surface Mining

It is not feasible to collect mine-specific Tier 3 measurement data for mining operations at surface mines, so Tier 2 emission factors are an alternative approach for this category.

$$E_{Mining-CH4} = P_{Surface} \times EF_{Surface-CH4} \times 0.00067$$

Where:

$E_{Mining-CH4}$	=	CH_4 emissions from surface coal mining operations (metric tons);
$P_{Surface}$	=	Surface coal production (metric tons);
$EF_{Surface-CH4}$	=	CH_4 emission factor (m^3 CH_4/metric ton coal);
0.00067	=	Conversion factor from volume of CH_4 to mass of CH_4 (metric ton/m^3).

The Tier 2 emission factors for surface coal mining are identified as high, average, or low. The high emission factor is 2.0 m^3/metric ton (i.e., for overburden depths greater than 50 meters). The average emission factor is 1.2 m^3/metric ton (i.e., for overburden depths between 25 and 50 meters). The low emission factor is 0.3 m^3/metric ton (i.e., for overburden depths less than 25 meters). For surface mines, the uncertainty of the Tier 2 mining emission factors is a factor of 2 greater/smaller.

Because of the high uncertainty associated with estimating emissions from mining operations at surface coal mines, these emissions will not be included in the reporting requirements at this time.

Reporting Requirements

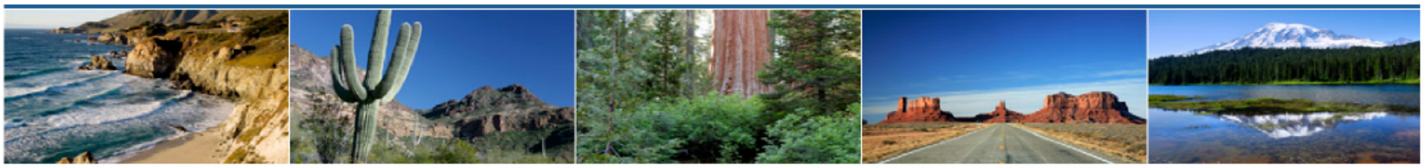
Annual CH_4 emissions will be reported for each specific underground mine using the Tier 3 methodology.

Sampling, Analysis, and Measurement Methods

Note: The sampling, analysis, and measurement procedures will be standardized for each calculation input to reduce variation between facilities within the mining industry. Material sampling frequency and technique is distinct from material analysis conducted in a laboratory. The WCI is seeking stakeholder feedback on this topic and is specifically interested in proposals from stakeholders with expertise in this industry related to sampling, analysis and measurement procedures already in use at these mines for the material quantities and/or concentrations listed below. Those proposing procedures should include sampling frequency and technique, indicate the uncertainty associated with the procedures, and describe the application of the procedure at a mine.

Ventilation air and/or degasification system measurements will need to be taken for development of underground Tier 3 mining emission estimates. More frequent sampling (preferably continuous) will reduce the amount of uncertainty. Appropriate measurement methods are likely specified by the U.S. Mine Safety and Health Administration, although none have been identified to date.

Ventilation measurements are typically conducted on a periodic basis with air flow measurements and handheld methanometers. Drainage gas utilized for energy production is usually continuously measured with a flow meter with gas composition samples taken at a periodic basis. Drainage gas vented to the atmosphere is periodically sampled, along with the associated gas composition.



ATTACHMENT 15: PULP AND PAPER MANUFACTURING

Several documents were identified as having the most comprehensive estimation methods for the pulp and paper industry. In these documents, the primary authority for estimating GHG emissions from pulp and paper manufacturing is: *Calculation Tools for Estimating Greenhouse Gas Emissions from Pulp and Paper Mills, Version 1.1, July 8, 2005, a project of The Climate Change Working Group of The International Council of Forest and Paper Associations (ICFPA).* This reference is the basis of the GHG estimation methodology used by WRI and by Climate Leaders.

Applicability

The ICFPA methodology lists the following sources of GHG at pulp and paper manufacturing facilities:

1. Stationary combustion units such as fossil and biomass fired boilers and dryers (§ WCI.20)
2. Lime kilns and calciners (§ WCI.170)
3. Electric generation units (§ WCI.40)
4. Nonroad equipment (§ WCI.XX)
5. Anaerobic waste and wastewater treatment
6. Black liquor boilers

Methods for estimating emissions from sources 1 through 4 in the above list are or will be addressed under other sections of the Essential Requirements for mandatory reporting, as noted. However, most of the process CO_2 emissions from the lime kilns at pulp and paper mills is derived from organic carbon, which must be tracked separately from the fossil CO_2.

Emission Calculations – Anaerobic Treatment and Black Liquor Boilers

For purposes of reporting, WCI will likely require a method similar to that required for reporting wastewater CH_4 and N_2O emissions from refineries in WCI.203(g). WCI will examine the uncertainty of the biogenic decay models, such as those used to estimate emissions for municipal landfills and municipal wastewater treatment plants, to determine their appropriateness for estimating anaerobic treatment processes for purposes of including these emissions in the cap-and-trade program.

Black liquor boilers are a source of CO_2, CH_4 and N_2O emissions. The ICFPA reports that all CO_2 emissions from black liquor boilers are of biogenic origin and not reportable. Thus, they do not present a methodology for determining CO_2 emissions from this source. The Climate Registry (TCR) and the IPCC offer only emission factors for determining CO_2 emissions from black liquor boilers. The IPCC reports that the 95% confidence interval for their CO_2 factor ranges from 80,700 to 110,000 (± 15%) kg/TJ. Similarly, the reported IPCC factors for CH_4 and N_2O emissions from black liquor boilers range by a factor of 10 at the 95% confidence level.

Recommended Reporting Requirements (Under Development)

Methods for estimating emissions from sources 1 through 4 in the above list are or will be covered under other sections of the Essential Requirements. In January 2009, special instructions will be developed for lime kilns (source 2) to instruct reporters on how to account for biogenic and fossil process CO_2 emissions, and a specific methodology based on the refinery method (WCI.203(g)) will be prescribed for estimating wastewater emissions (source 5).

Later in 2009, a new methodology will be developed for black liquor boilers (source 6) Note that both fossil and biogenic carbon leave the black liquor boiler as both a gas (CO_2) and a solid (Na_2CO_3), thus a unique material balance methodology will be needed. As with any new methodology, it should be peer reviewed before being finalized for use in the WCI program.

Sampling, Analysis, and Measurement Methods

All further methods development will stipulate that fossil and biogenic process emissions will be reported separately, and will contain requirements pertaining to sampling, analysis, and measurements, as applicable to the specific emission quantification method input(s).

§ WCI.40 ELECTRICITY GENERATION

WCI.41 Source Category Definition

An electricity generator is any combustion device that combusts solid, liquid, or gaseous fuel for the purpose of producing electricity either for sale or for use onsite. This source category excludes cogeneration units subject to WCI.50.

WCI.42 Greenhouse Gas Reporting Requirements

For each facility, the emissions data report shall include the following information:

(a) Annual greenhouse gas emissions in metric tons, reported as follows:

(1) Total CO_2 emissions for fossil fuels, reported by fuel type.
(2) Total CO_2 emissions for all biomass fuels combined.
(3) Total CH_4 emissions for fuels combined.
(4) Total N_2O emissions for all fuels combined.

(b) Annual fuel consumption:

(1) For gases, report in units of million standard cubic feet or cubic meters.
(2) For liquids, report in units of gallons or liters.
(3) For non-biomass solids, report in units of short tons or metric tons.
(4) For biomass-derived solid fuels, report in units of bone dry short tons or bone dry metric tons.

(c) Average carbon content of each fuel, if used to compute CO_2 emissions as specified in WCI.44.

(d) Average high heating value of each fuel, if used to compute CO_2 emissions as specified WCI.44.

(e) The nameplate generating capacity in megawatts and net power generated in the reporting year in megawatt hours.

(f) Process CO_2 emissions from acid gas scrubbers and acid gas reagent.

(g) Fugitive emissions of HFC from cooling units that support power generation.

(h) Fugitive CO_2 emissions from geothermal facilities.

(i) Fugitive CO_2 emissions from coal storage at coal-fired electricity generating facilities shall be reported as specified in section WCI.100.

WCI.43 Calculation of GHG Emissions

(a) **Calculation of CO_2 Emissions.** Operators shall use CEMS to measure CO_2 emissions if required to operate a CEMS by any other federal, state, provincial, or local regulation. Operators not required to operate a CEMS by another regulation may use either CEMS or the calculation methods specified in paragraphs (a)(1) through (a)(7). Operators using CEMS to determine CO_2 emissions shall comply with the provisions in section WCI.23(d).

(1) **Natural Gas.** For electric generating units combusting natural gas, use one of the following methods:

(A) If the high heat value is greater than or equal to 975 and less than or equal to 1,100 Btu/scf use either:

i. The measured carbon content of the fuel and calculation methodology 3 in section WCI.23(c); or

ii. The measured heat content of the fuel and the calculation methodology 2 in section WCI.23(b) provided the facility is not subject to the verification requirements of WCI.8.

(B) If the high heat value is less than 975 or greater than 1,100 Btu/scf, use the measured carbon content of the fuel and the calculation methodology 3 in section WCI.23(c).

(2) **Coal or Petroleum Coke.** For electric generating units combusting coal or petroleum coke, use the measured carbon content of the fuel and calculation methodology 3 in section WCI.23(c).

(3) **Middle Distillates, Gasoline, Residual Oil, or Liquid Petroleum Gases.** For electric generating units combusting middle distillates (such as diesel, fuel oil, or kerosene), gasoline, residual oil, or LPG (such as ethane, propane, isobutene, n-butane, or unspecified LPG), use one of the following methods:

(A) The measured carbon content of the fuel and calculation methodology 3 in section WCI.23(c); or

(B) The measured heat content of the fuel and calculation methodology 2 in section WCI.23(b) provided the facility is not subject to the verification requirements of WCI.8.

(4) **Refinery Fuel Gas, Flexigas, or Associated Gas.** For electric generating units combusting refinery fuel gas, flexigas, or associated gas, use the methods specified in section WCI.30.

(5) **Landfill Gas, Biogas, or Biomass.** For electric generating units combusting landfill gas, biogas, or biomass, use one of the following methods:

(A) The measured carbon content of the fuel and calculation methodology 3 provided in section WCI.23(c); or

(B) The measured heat content of the fuel and calculation methodology 2 in section WCI.23(b) provided the facility is not subject to the verification requirements of WCI.8.

(6) **Municipal Solid Waste.** Electric generating units combusting municipal solid waste, may use the measured steam generated, the default carbon content emission factor in Table 20-1, and the calculation methodology in section WCI.23(b)(2) provided the facility is not subject to the verification requirements of WCI.8. If the facility is subject to the verification requirements of WCI.8, the operator shall use CEMS to measure CO_2 emissions in accordance with WCI.23(d).

(7) **Start-up Fuels.** The operators of generating facilities that primarily combust biomass-derived fuels but combust fossil fuels during start-up, shut-down, or malfunction operating periods only, shall calculate CO_2 emissions from fossil fuel combustion using one of the following methods:

(A) The default emission factors from Tables 20-1 and 20-2 and calculation methodology 1 provided in section WCI.23(a);
(B) The measured heat content of the fuel and calculation methodology 2 provided in section WCI.23(b);
(C) The measured carbon content of the fuel and calculation methodology 3 provided in section WCI.23(c); or
(D) For combustion of refinery fuel gas, the measured heat content and carbon content of the fuel, and the calculation methodology provided in section WCI.30.

(8) **Co-fired Electricity Generating Units.** For electricity generating units that combust more than one type of fuel, the operator shall calculate CO_2 emissions as follows.

(A) For co-fired electricity generators that burn only fossil fuels, CO_2 emissions shall be determined using one of the following methods:

i. A continuous emission monitoring system in accordance with calculation methodology 4 in section WCI.23(d). Operators using this method need not report emissions separately for each fossil fuel.
ii. For units not equipped with a continuous emission system, calculate the CO2 emissions separately for each fuel type using the methods specified in paragraphs (a)(1) through (a)(4) of this section.

(B) For co-fired electricity generators that burn biomass-derived fuel with a fossil fuel, CO_2 emissions shall be determined using one of the following methods:

i. A continuous emission monitoring system in accordance with calculation methodology 4 in section WCI.23(d). Operators using this method shall determine the portion of the total CO_2 emissions attributable to the biomass-derived fuel and portion of the total CO_2 emissions attributable to the fossil fuel using the methods specified in section WCI.23(d)(4).
ii. For units not equipped with a continuous emission system, calculate the CO_2 emissions separately for each fuel type using the methods specified in paragraphs (a)(1) through (a)(7) of this section.

(b) **Calculation of CH_4 and N_2O Emissions.** Operators of electricity generating units shall use the methods specified in section WCI.24 to calculate the annual CH_4 and N_2O emissions. For coal combustion, use the default CH_4 emission factor of 1g of CH_4/mmBtu.

(c) **Calculation of CO_2 Emissions from Acid Gas Scrubbing.** Operators of electricity generating units that use acid gas scrubbers or add an acid gas reagent to the combustion unit shall calculate the annual CO_2 emissions from these processes using Equation 40-1 if these emissions are not already captured in CO_2 emissions determined using a continuous emissions monitoring system.

$$CO_2 = S \times R \times \left(CO_{2\,MW} / Sorbent_{MW}\right)$$ **Equation 40-1**

Where:

CO_2	=	CO_2 emitted from sorbent for the report year, metric tons;
S	=	Limestone or other sorbent used in the report year, metric tons;
R	=	Ratio of moles of CO_2 released upon capture of one mole of acid gas;
$CO_{2\ MW}$	=	Molecular weight of carbon dioxide (44);
$Sorbent_{MW}$	=	Molecular weight of sorbent (if calcium carbonate, 100).

(d) Calculating Fugitive HFC Emissions from Cooling Units. Operators of electricity generating facilities shall calculate fugitive HFC emissions for each HFC compound used in cooling units that support power generation or are used in heat transfers to cool stack gases using either the methodology in paragraph (d)(1) or (d)(2). The Operator is not required to report GHG emissions from air or water cooling systems or condensers that do not contain HFCs.

(1) Use Equation 40-2 to calculate annual HFC emissions:

$$HFC = HFC_{inventory} + HFC_{purchases/acquisitions} - HFC_{sales/disbursements} + HFC_{\Delta capacity} \qquad \textbf{Equation 40-2}$$

Where:

HFC	=	Annual fugitive HFC emission, metric tons;
$HFC_{inventory}$	=	The difference between the quantity of HFC in storage at the beginning of the year and the quantity in storage at the end of the year. Stored HFC includes HFC contained in cylinders (such as 115-pound storage cylinders), gas carts, and other storage containers. It does not include HFC gas held in operating equipment. The change in inventory will be negative if the quantity of HFC in storage increases over the course of the year.
$HFC_{purchases/acquisitions}$	=	The sum of all HFC acquired from other entities during the year either in storage containers or in equipment.
$HFC_{sales/disbursements}$	=	The sum of all the HFC sold or otherwise transferred offsite to other entities during the year either in storage containers or in equipment.
$HFC_{\Delta capacity}$	=	The net change in the total nameplate capacity (i.e. the full and proper charge) of the cooling equipment). The net change in capacity will be negative if the total nameplate capacity at the end of the year is less than the total nameplate capacity at the beginning of the year.

(2) Use service logs to document HFC usage and emissions from each cooling unit. Service logs should document all maintenance and service performed on the unit during the report year, including the quantity of HFCs added to or removed from the unit, and include a record at the beginning and end of each report year. The operator may use service log information along with the following simplified material balance equations to quantify fugitive HFCs from unit installation, servicing, and retirement, as applicable. The operator shall include the sum of HFC emissions from the applicable equations in the greenhouse gas emissions data report.

$$HFC_{Install} = R_{new} - C_{new}$$

$$HFC_{Service} = R_{recharge} - R_{Recover}$$

$$HFC_{Retire} = C_{retire} - R_{retire}$$

Where:

$HFC_{Install}$	=	HFC emitted during initial charging/installation of the unit, kilograms;
$HFC_{Service}$	=	HFC emitted during use and servicing of the unit for the report year, kilograms;
HFC_{Retire}	=	HFC emitted during the removal from service/retirement of the unit, kilograms;
R_{new}	=	HFC used to fill new unit (omit if unit was pre-charged by the manufacturer), kilograms;
C_{new}	=	Nameplate capacity of new unit (omit if unit was pre-charged by the manufacturer), kilograms;
$R_{recharge}$	=	HFC used to recharge the unit during maintenance and service, kilograms;
$R_{recover}$	=	HFC recovered from the unit during maintenance and service, kilograms;
C_{retire}	=	Nameplate capacity of the retired unit, kilograms; and
R_{retire}	=	HFC recovered from the retired unit, kilograms.

(e) **Fugitive CO_2 Emissions from Geothermal Facilities.** Operators of geothermal electricity generating facilities shall calculate the fugitive CO_2 emissions using one of the following methods:

(1) Calculate the fugitive CO_2 emissions using Equation 40-3:

$$CO_2 = 7.53 \times Heat \times 0.001 \qquad \textbf{Equation 40-3}$$

Where:

CO_2	=	CO_2 emissions, metric tons per year;
7.53	=	Default fugitive CO_2 emission factor for geothermal facilities, kg per mmBtu; and
Heat	=	Heat taken from geothermal steam and/or fluid, mmBtu/yr.

(2) Calculate CO_2 emissions using [*insert jurisdiction*] approved source specific emission factor.

WCI.44 Monitoring Requirements

(a) **CO_2, CH_4 and N_2O Emissions from Fuel Combustion.** Operators using CEMS to estimate CO_2 emissions from fuel combustion shall comply with the requirements in section WCI.23(d). Operators using methods other than CEMS shall comply with the applicable fuel sampling, fuel consumption monitoring, heat content monitoring, and carbon content monitoring specified in section WCI.25.

(b) **CO_2 Emissions from Acid Gas Scrubbing.** Operators of electricity generating units that use acid gas scrubbers or add an acid gas reagent to the combustion unit shall measure the

amount of limestone or other sorbent used during the reporting year using methods that comply with the measurement accuracy provisions in WCI.2(g).

(c) **CO_2 Emissions from Geothermal Facilities.** Operators of geothermal facilities shall measure the heat recovered from geothermal steam. If using source specific emission factor instead of the default factor, the operator shall conduct an annual test of the CO_2 emission rate using a method approved by [*insert jurisdiction*]. The operator shall submit a test plan to the [*insert jurisdiction*] for approval. Once approved, the annual tests shall be conducted in accordance with the approved test plan under the supervision of the [*insert jurisdiction*].-

§ WCI.20 GENERAL STATIONARY COMBUSTION

§ WCI.21 Source Category Definition

General stationary fuel combustion sources are devices that combust solid, liquid, or gaseous fuel for the purpose of generating steam (or providing useful heat or energy) for industrial, commercial, or institutional use; or reducing the volume of waste by removing combustible matter. General stationary combustion sources are boilers, combustion turbines, engines, incinerators, and process heaters, and any other stationary combustion device that is not specifically addressed under the provisions for another source category in this rule.

[The source category definition may need to be revised after the remaining ER sections are completed.]

§ WCI.22 Greenhouse Gas Reporting Requirements

The emissions data report shall include the following information at the facility level:

(a) Annual greenhouse gas emissions in metric tons, reported as follows:

(1) Total CO_2 emissions for fossil fuels, reported by fuel type.
(2) Total CO_2 emissions for all biomass fuels combined.
(3) Total CH_4 emissions for all fuels combined.
(4) Total N_2O emissions for all fuels combined.

(b) Annual fuel consumption:

(1) For gases, report in units of million cubic meters.
(2) For liquids, report in units of liters.
(3) For non-biomass solids, report in units of metric tons.
(4) For biomass-derived solid fuels, report in units of bone dry short tons or bone dry metric tons.

(c) Average carbon content of each fuel, if used to compute CO_2 emissions.

(d) Average high heating value of each fuel, as used to compute CO_2 emissions.

(e) Annual steam generation in pounds or kilograms, for units that burn biomass or municipal solid waste.

[Please note that most of the calculation methodologies in this section currently accommodate inputs in English units, only, and not SI units. The section will be revised to allow inputs in SI units, as well as to provide applicable Canadian emission factors from "National Inventory Report 1990-2006: Greenhouse Gas Sources and Sinks in Canada – The Canadian Government's Submission to the UN Framework Convention on Climate Change, April 2008." (http://www.ec.gc.ca/pdb/ghg/inventory_e.cfm)]

§ WCI.23 Calculation of CO_2 Emissions

For each fuel, calculate CO_2 mass emissions using one of the four calculation methodologies specified in this section, subject to the restrictions in §WCI.23 (e).

(a) **Calculation Methodology 1**. Calculate the annual CO_2 mass emissions by substituting a fuel-specific default CO_2 emission factor, a default high heating value, and the annual fuel consumption into the Equation 20-1:

$$CO_2 = Fuel \times HHV \times EF \times 0.001$$ **Equation 20-1**

Where:

CO_2 = Annual CO_2 mass emissions for the specific fuel type (metric tons).
Fuel = Mass or volume of fuel combusted per year (express mass in short tons for solid fuel, volume in standard cubic feet for gaseous fuel, and volume in gallons for liquid fuel).
HHV = Default high heat value of the fuel, from column 3 of Table 20-1 (mmBtu per mass or mmBtu per volume, as applicable).
EF = Fuel-specific default CO_2 emission factor, from column 5 of Table 20-1 (kg CO_2/mmBtu).
0.001 = Conversion factor from kilograms to metric tons.

(b) **Calculation Methodology 2**. Calculate the annual CO_2 mass emissions using a default CO_2 emission factor, and either Equation 20-2 or 20-3, as appropriate:

(1) Equation 20-2 of this section can be used for any type of fuel for which an emission factor is provided in Tables 20-1 or 20-2:

Equation 20-2

$$CO_2 = \sum_{p=1}^{n} Fuel_P \times HHV_P \times EF \times 0.001$$

Where:

CO_2 = Annual CO_2 mass emissions for a specific fuel type (metric tons).
n = Number of required heat content measurements for the year as specified in WCI.25.
$Fuel_p$ = Mass or volume of the fuel combusted during the measurement period "p" (express mass in short tons for solid fuel, volume in standard cubic feet for gaseous fuel, and volume in gallons for liquid fuel).
HHV_p = High heat value of the fuel for the measurement period (mmBtu per mass or volume).
EF = Fuel-specific default CO_2 emission factor, from column 5 of Table 20-1 or from Table 20-2 (kg CO_2/mmBtu).
0.001 = Conversion factor from kilograms to metric tons.

(2) Equation 20-3 of this section can be used for biomass solid fuels and municipal solid waste only:

$$CO_2 = Steam \times B \times EF \times 0.001$$ **Equation 20-3**

Where:

CO_2 = Annual CO_2 mass emissions from MSW combustion (metric tons).
Steam = Total mass of steam generated by MSW combustion during the reporting year (lb steam).
B = Ratio of the boiler's maximum rated heat input capacity to its design rated steam output capacity (mmBtu/lb steam).
EF = Default carbon content for MSW, from column 5 of Table WCI.20-1 (kg CO_2/mmBtu).
0.001 = Conversion factor from kilograms to metric tons.

(c) **Calculation Methodology 3**. Calculate the annual CO_2 mass emissions by substituting measurements of fuel carbon content, molecular weight (gaseous fuels, only), and the quantity of fuel combusted into the following equations. For solid fuels, the amount of fuel combusted is obtained from company records kept as provided in this rule. For liquid and gaseous fuels, the volume of fuel combusted is measured directly, using fuel flow meters (including gas billing meters). For fuel oil, tank drop measurements may also be used.

(1) For a solid fuel, use Equation 20-4 of this section:

$$CO_2 = \sum_{i=1}^{n} Fuel_i \times CC_i \times 3.664$$ **Equation 20-4**

Where:
CO_2 = Annual CO_2 mass emissions from the combustion of the specific solid fuel (metric tons).
n = Number of monthly carbon content determinations for the year.
$Fuel_i$ = Mass of the solid fuel combusted in month "n" (metric tons).
CC_i = Carbon content of the solid fuel, from the fuel analysis results for month "n"(percent by weight, expressed as a decimal fraction, e.g., 95% = 0.95).
3.664 = Ratio of molecular weights, CO_2 to carbon.

(2) For a liquid fuel, use Equation 20-5 of this section:

$$CO_2 = \sum_{i=1}^{n} 3.664 \times Fuel_i \times CC_i \times 0.001$$ **Equation 20-5**

Where:
CO_2 = Annual CO_2 mass emissions from the combustion of the specific liquid fuel (metric tons).
n = Number of required carbon content determinations for the year, as specified in WCI.25.
$Fuel_i$ = Volume of the liquid fuel combusted in month "n" (gallons).
CC_i = Carbon content of the liquid fuel, from the fuel analysis results for month "n" (kg C per gallon of fuel).
3.664 = Ratio of molecular weights, CO_2 to carbon.
0.001 = Conversion factor from kg to metric tons.

(3) For a gaseous fuel, use Equation 20-6 of this section:

$$CO_2 = \sum_{i=1}^{n} 3.664 \times Fuel_i \times CC_i \times \frac{MW}{MVC} \times 0.001 \qquad \textbf{Equation 20-6}$$

Where:

CO_2 = Annual CO_2 mass emissions from combustion of the specific gaseous fuel (metric tons).
n = Number of required carbon content and molecular weight determinations for the year, as specified in WCI.25.
$Fuel_i$ = Volume of the gaseous fuel combusted in a day or month, as applicable (scf).
CC_i = Average carbon content of the gaseous fuel, from the fuel analysis results for the day or month, as applicable (kg C per kg of fuel).
MW = Molecular weight of the gaseous fuel, from fuel analysis (kg/kg-mole).
MVC = Molar volume conversion factor (849.5 scf per kg-mole at standard conditions).
3.664 = Ratio of molecular weights, CO_2 to carbon.
0.001 = Conversion factor from kg to metric tons.

(d) **Calculation Methodology 4**. Calculate the annual CO_2 mass emissions from all fuels combusted in a unit, by using data from continuous emission monitoring systems (CEMS) as specified in (d)(1) through (d)(7).

(1) The operator of a facility that combusts fossil fuels or biomass and operates CEMS in response to federal, state, provincial, or local regulation, may use CO_2 or O_2 concentrations and flue gas flow measurements to determine hourly CO_2 mass emissions using methodologies provided in 40 CFR Part 75, Appendix F.

(A) The operator shall report CO_2 emissions for the report year in metric tons based on the sum of hourly CO_2 mass emissions over the year, converted to metric tons.

(B) If the operator of a facility that combusts biomass uses O_2 concentrations to calculate CO_2 concentrations, annual source testing must demonstrate that calculated CO_2 concentrations when compared to measured CO_2 concentrations meet the Relative Accuracy Test Audit (RATA) requirements in 40 CFR Part 60, Appendix B, Performance Specification 3.

(2) The operators of a facility that combusts municipal solid waste or other waste-derived fuels and operates a CEMS in response to federal, state, provincial, or local regulations must use CO_2 concentrations and flue gas flow measurements to determine hourly CO_2 mass emissions using methodologies provided in 40 CFR Part 75, Appendix F.

(A) Annual CO_2 emissions shall be reported in metric tons based on the sum of hourly CO_2 mass emissions over the year.

(B) Emissions calculations shall not be based on O_2 concentrations.

(3) The operator of a facility that combusts MSW or other waste-derived fuels and calculates CO_2 emissions using the methodology provided in WCI.23(d)(2) shall determine the portion of emissions associated with the combustion of biomass-derived fuels using the method provided in WCI.23(f).

(4) An operator who uses CEMS data to report CO_2 emissions from a facility that co-fires fossil fuels with biomass or waste-derived fuels that are partly biomass shall determine the portion of total CO_2 emissions separately assigned to the fossil fuel and the biomass-derived fuel using the method provided in WCI.23(f), if applicable. The operator who co-fires pure biomass with fossil fuels may elect to calculate CO_2 emissions for the fossil fuels using methods designated in WCI.23(b)(3) by fuel type and then subtract the fossil fuel related emissions from the total CO_2 emissions determined using the CEMS based methodology.

(5) For any units for which CO_2 emissions are reported using CEMS data, the operator is relieved of the requirement to separately report process emissions from combustion emissions or to report emissions separately for different fossil fuels when only fossil fuels are co-fired. In this circumstance, operators shall still report fuel use by fuel type as otherwise required.

(6) If a facility is subject to requirements in 40 CFR Part 60 or 40 CFR Part 75 and the operator chooses to add devices to an existing continuous monitoring system for the purpose of measuring CO_2 concentrations or flue gas flow, the operator shall select and operate the added devices pursuant to the requirements in 40 CFR Part 60 or Part 75 that apply to the facility. If the facility is subject to both 40 CFR Part 60 and 40 CFR Part 75, the operator shall select and operate the added devices pursuant to the requirements in 40 CFR Part 75.

(7) If a facility does not have a continuous emissions monitoring system and the operator chooses to add one in order to measure CO_2 concentrations, the operator shall select and operate the CEMS pursuant to the requirements in 40 CFR Part 75.

(A) The operator shall use CO_2 concentrations and flue gas flow measurements to determine hourly CO_2 mass emissions using methodologies provided in 40 CFR Part 75, Appendix F.

(B) The operator shall report CO_2 emissions for the report year in metric tons based on the sum of hourly CO_2 mass emissions over the year, converted to metric tons.

(C) Operators who add CEMS under this article are subject to specifications in WCI.23(d)(1)-(5), if applicable.

(e) **Use of the Four CO_2 Calculation Methodologies**. Use of the four CO_2 emissions calculation methodologies described in paragraphs (a) through (d) of this section is subject to the following requirements and restrictions:

(1) Calculation Methodology 1 may not be used by a facility that is subject to the verification requirements of WCI.8, except for stationary combustion units that combust natural gas with a high heating value between 975 and 1,150 Btu per cubic foot. Otherwise, Calculation Methodology 1 may be used for any type of fuel for which a default CO_2 emission factor and a default high heat value for the fuel is specified in Table 20-1.

(2) Calculation Methodology 2 may not be used by a facility that is subject to the verification requirements of WCI.8, except for stationary combustion units that combust natural gas with a high heating value between 975 and 1,150 Btu per cubic foot. Otherwise, Calculation Methodology 2 may be used for any type of fuel combusted for which a default CO_2 emission factor for the fuel is specified in Table 20-1 or 20-2.

(3) Calculation Methodology 3 may be used for a unit of any size combusting any type of fuel, except when the use of Calculation Methodology 4 is required.

(4) Calculation Methodology 4 may be used for a unit of any size combusting any type of fuel, and must be used for either of the following conditions:

(i) A combustion unit with a CEMS that is required by any federal, state, provincial, or local regulation.

(ii) A municipal solid waste combustion unit that is subject to the verification requirements of WCI.8.

(f) **Biogenic CO_2 emissions**. The operator that combusts fuels or fuel mixtures that contain biomass shall determine the biomass-derived portion of CO_2 emissions using ASTM D6866-06a, as specified in this paragraph. This procedure is not required for fuels that contain less than 5 percent biomass by weight or for waste-derived fuels that are less than 30 percent biomass by weight on an annual basis.

(1) The operator shall conduct ASTM D6866-06a analysis at least every three months, and shall collect each gas sample for analysis during normal operating conditions over at least 24 consecutive hours.

(2) The operator shall divide total CO_2 emissions between biomass-derived emissions and non-biomass-derived emissions using the average proportionalities of the samples analyzed.

(3) If there is a common fuel source to multiple units at the facility, the operator may elect to conduct ASTM D6866-06a testing for one of the units.

§ WCI.24 Calculation of CH_4 and N_2O Emissions

Calculate the annual CH_4 and N_2O mass emissions from stationary fuel combustion sources using the procedures in paragraph (a), (b), or (c), as appropriate.

(a) If the heat content of the fuel is measured, calculate CH_4 and N_2O emissions the following Equation 20-7:

$$CH_4 \text{ or } N_2O = \sum_{1}^{n} Fuel_P \times HHV_P \times EF \times 0.001 \qquad \textbf{Equation 20-7}$$

Where:

CH_4 or N_2O	=	Combustion emissions from specific fuel type, metric tons CH_4 or N_2O per year.
n	=	Period/frequency of heat content measurements over the year (e.g. monthly n = 12).
$Fuel_P$	=	Mass or volume of fuel combusted for the measurement period specified by fuel type, units of mass or volume per unit time .
HHV_P	=	High heat value measured for the measurement period specified by fuel type, MMBtu per unit mass or volume.
EF	=	Default CH_4 or N_2O emission factor provided in Table 20-3, kg CH_4 or N_2O per MMBtu.
0.001	=	Factor to convert kg to metric tons.

(b) If the heat content of the fuel is not measured, calculate CH_4 and N_2O emissions using the following equation:

$$CH_4 \ or \ N_2O = \sum_{1}^{n} Fuel \times HHV_D \times EF \times 0.001 \quad \textbf{Equation 20-8}$$

Where:

CH_4 or N_2O	=	CH_4 or N_2O emissions from a specific fuel type, metric tons CH_4 or N_2O per year.
Fuel	=	Mass or volume of fuel combusted specified by fuel type, unit of mass or volume per year.
HHV_D	=	Default high heat value specified by fuel type provided in Table 20-3, MMBtu per unit of mass or volume.
EF	=	Default emission factor provided in Table 20-3, kg CH_4 or N_2O per MMBtu.
0.001	=	Factor to convert kg to metric tons.

(c) For municipal solid waste combustion, use Equation 20-9 of this section to estimate CH_4 and N_2O emissions:

$$CH_4 \ or \ N_2O = Steam \times B \times EF \times 0.001 \quad \textbf{Equation 20-9}$$

Where:

CH_4 or N_2O	=	Annual CH_4 or N_2O emissions from the combustion of a municipal solid waste (metric tons).
Steam	=	Total mass of steam generated by MSW combustion during the reporting year (lb steam).
B	=	Ratio of the boiler's maximum rated heat input capacity to its design rated steam output (mmBtu/lb steam).
EF	=	Fuel-specific emission factor for CH_4 or N_2O, from Table WCI.20-3 of this subpart (kg CH_4 or N_2O per mmBtu).
0.001	=	Conversion factor from kilograms to metric tons.

(d) The operator may elect to calculate CH_4 and N_2O emissions using source-specific emission factors derived from source tests conducted at least annually under the supervision of (*jurisdiction*). Upon approval of a source test plan, the source test procedures in that plan shall be repeated in each future year to update the source specific emission factors annually.

§ WCI.25 Monitoring and QA/QC Requirements

(a) **Fuel Sampling Requirements**. Fuel sampling must be conducted at the frequency specified in paragraph (a) (1) through (a)(4) of this section.

(1) At receipt of each new fuel shipment or delivery or on a monthly basis for middle distillates (diesel, gasoline, fuel oil, kerosene), residual oil, liquid waste-derived fuels, and LPG (ethane, propane, isobutene, n-Butane, unspecified LPG);

(2) Monthly for natural gas, associated gas, and mixtures of low Btu gas.

(3) Monthly for gases derived from biomass including landfill gas and biogas from wastewater treatment or agricultural processes.

(4) Monthly for solid fuels, as specified below:

(A) The monthly solid fuel sample shall be a composite sample of weekly samples.

(B) The solid fuel shall be sampled at a location after all fuel treatment operations and the samples shall be representative of the fuel chemical and physical characteristics immediately prior to combustion.

(C) Each weekly sub-sample shall be collected at a time (day and hour) of the week when the fuel consumption rate is representative and unbiased.

(D) Four weekly samples (or a sample collected during each week of operation during the month) of equal mass shall be combined to form the monthly composite sample.

(E) The monthly composite sample shall be homogenized and well mixed prior to withdrawal of a sample for analysis.

(F) One in twelve composite samples shall be randomly selected for additional analysis of its discreet constituent samples. This information will be used to monitor the homogeneity of the composite.

(b) Fuel Consumption Monitoring Requirements.

(1) Facilities that are subject to the verification requirements of WCI.8 must determine annual fuel consumption by direct measurement.

(2) Facilities that are not subject the verification requirements of WCI.8 may determine consumption on the basis of recorded fuel purchase or sales invoices measuring any stock change (measured in million Btu, gallons, million standard cubic feet, short tons or bone dry short, tons) using the following equation:

Fuel Consumption in the Report Year = Total Fuel Purchases – Total Fuel Sales + Amount Stored at Beginning of Year – Amount Stored at Year End

(3) Fuel consumption measured in Btu values shall be converted to the required metrics of mass or volume using heat content values that are either provided by the supplier, measured by the facility, or provided in Table 20-1.

(c) **Fuel Heat Content Monitoring Requirements.** High heat values shall be determined using one of the following methods:

(1) For gases, use ASTM D1826-94 (Reapproved 2003), ASTM D3588-98 (Reapproved 2003), ASTM D4891-89 (Reapproved 2006), GPA Standard 2261-00 "Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography." The operator may alternatively elect to use on-line instrumentation that determines heating value accurate to within ± 5.0 percent. Where existing on-line instrumentation provides only low heating value, the operator shall convert the value to high heating value as specified in section 95125(c)(1)(C).

(2) For middle distillates and oil, or liquid waste-derived fuels, use ASTM D240-02 (Reapproved 2007), ASTM D240-87 (Reapproved 1991), ASTM D4809-00 (Reapproved 2005).

(3) For solid biomass-derived fuels use ASTM D5865-07a.

(4) For waste-derived fuels use ASTM D5865-07a or ASTM D5468-02 (Reapproved 2007). Operators who combust waste-derived fuels that are partly but not pure biomass shall determine the biomass-derived portion of CO_2 emissions using the method specified in section WCI.23(f), if applicable

(d) **Fuel Carbon Content Monitoring Requirements.** Fuel carbon contents should be monitored in the following manner.

(1) For coal and coke, solid biomass-derived fuels, and waste-derived fuels; use ASTM 5373-02 (Reapproved 2007).

(2) For liquid fuels, use the following ASTM methods: For petroleum-based liquid fuels and liquid waste-derived fuels, use ASTM D5291-02 (Reapproved 2007) "Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants", ultimate analysis of oil or computations based on ASTM D3238-95 (Reapproved 2005) and either ASTM D2502-04 or ASTM D2503-92 (Reapproved 2002).

(3) For gaseous fuels, use ASTM D1945-03 or ASTM D1946-90 (Reapproved 2006).

Table 20-1. Default Carbon Content, Heat Content, and Carbon Dioxide Emission Factors from Stationary Combustion by Fuel Type				
Fuel Type	**Carbon Content**	**High Heat Value**	**CO_2 Emission Factor**	**CO_2 Emission Factor**
Coal and Coke	**kg C / MMBtu**	**MMBtu / Short Ton**	**kg CO_2 / Short Ton**	**kg CO_2 / MMBtu**
Anthracite	28.26	25.09	2,597.94	103.54
Bituminous	25.49	24.93	2,328.35	93.40
Sub-bituminous	26.48	17.25	1,673.64	97.02
Lignite	26.30	14.21	1,369.32	96.36
Unspecified (Residential/Commercial)	26.00	22.24	2,118.67	95.26
Unspecified (Industrial Coking)	25.56	26.28	2,461.17	93.65
Unspecified (Other Industrial)	25.63	22.18	2,082.89	93.91
Unspecified (Electric Power)	25.76	19.97	1,884.86	94.38
Coke	27.85	24.80	2,530.65	102.04
Natural Gas (By Heat Content)	**kg C / MMBtu**	**Btu / Standard cubic foot**	**kg CO_2 / Standard cubic ft.**	**kg CO_2 / MMBtu**
975 to 1,000 Btu / Standard cubic foot	14.73	n/a	n/a	53.97
1000 to 1,025 Btu / Std cubic foot	14.43	n/a	n/a	52.87
1025 to 1,050 Btu / Std cubic foot	14.47	n/a	n/a	53.02
1050 to 1,075 Btu / Std cubic foot	14.58	n/a	n/a	53.42
1075 to 1,100 Btu / Std cubic foot	14.65	n/a	n/a	53.68
Greater than 1,100 Btu / Std cubic foot	14.92	n/a	n/a	54.67
Unspecified (Weighted U.S. Average)	14.47	1,027	0.0544	53.02

Table 20-1. Default Carbon Content, Heat Content, and Carbon Dioxide Emission Factors from Stationary Combustion by Fuel Type (continued)

Petroleum Products	kg C / MMBtu	MMBtu / Barrel	kg CO_2 / gallon	kg CO_2 / MMBtu
Asphalt & Road Oil	20.62	6.636	11.94	75.55
Aviation Gasoline	18.87	5.048	8.31	69.14
Distillate Fuel Oil (#1, 2 & 4)	19.95	5.825	10.14	73.10
Jet Fuel	19.33	5.670	9.56	70.83
Kerosene	19.72	5.670	9.75	72.25
LPG (energy use)	17.19	3.861	5.79	62.98
Propane	17.20	3.824	5.74	63.02
Ethane	16.25	2.916	4.13	59.54
Isobutane	17.75	4.162	6.44	65.04
n-Butane	17.72	4.328	6.69	64.93
Lubricants	20.24	6.065	10.71	74.16
Motor Gasoline	19.33	5.218	8.80	70.83
Residual Fuel Oil (#5 & 6)	21.49	6.287	11.79	78.74
Crude Oil	20.33	5.800	10.29	74.49
Naphtha (<401 deg. F)	18.14	5.248	8.30	66.46
Natural Gasoline	18.24	4.620	7.35	66.83
Other Oil (>401 deg. F)	19.95	5.825	10.14	73.10
Pentanes Plus	18.24	4.620	7.35	66.83
Petrochemical Feedstocks	19.37	5.428	9.17	70.97
Petroleum Coke	27.85	6.024	14.64	102.04
Still Gas	17.51	6.000	9.17	64.16
Special Naphtha	19.86	5.248	9.09	72.77
Unfinished Oils	20.33	5.825	10.33	74.49
Waxes	19.81	5.537	9.57	72.58
Other Solid Fuels	**kg C / MMBtu**	**MMBtu / Short Ton**	**kg CO_2 / Short Ton**	**kg CO_2 / MMBtu**
Biomass Derived Fuels (Solid). Wood and Wood Waste (12% moisture content) or other solid biomass-derived fuels	25.60	15.38	1,442.62	93.80
Municipal Solid Waste (MSW)	24.74	8.7	788.7	90.65
Biomass-derived Fuels (Gas)	**kg C / MMBtu**	**Btu / Standard cubic foot**	**kg CO_2 / Standard cubic ft.**	**kg CO_2 / MMBtu**
Biogas (includes landfill gas and manure biogas)*	28.4	Varies	Varies	104.06

Note: Heat content factors are based on higher heating values (HHV).
* The emission factors for biogas include both the CO_2 from combustion and the pass-through CO_2, which are assumed to be in equal proportions.

Table 20-2. Default Carbon Dioxide Emission Factors from Stationary Combustion for Waste Derived Fuels	
Fuel Type	**kg CO_2 / MMBtu**
Waste Oil	78
Tires	90
Plastics	79
Solvents	78
Impregnated Saw Dust	79
Other Fossil Based Wastes	84
Dried Sewage Sludge	116
Mixed Industrial Waste	88
Municipal Solid Waste	91
Note: Emission factors are based on higher heating values (HHV). Values were converted from LHV to HHV assuming that LHV are 5 percent lower than HHV for solid and liquid fuels.	

Table 20-3. Default CH_4 and N_2O Emission Factors from Stationary Combustion by Fuel Type		
Fuel Type	**CH_4 Emission Factor (kg CH_4/ MMBtu)**	**N_2O Emission Factor (kg N_2O / MMBtu)**
Asphalt	0.003	0.006
Aviation Gasoline	0.003	0.006
Coal	0.01	1.5
Crude Oil	0.003	0.006
Digester Gas	0.0009	0.1
Distillate	0.003	0.006
Gasoline	0.003	0.006
Jet Fuel	0.003	0.006
Kerosene	0.003	0.006
Landfill Gas	0.0009	0.1
LPG	0.001	0.1
Lubricants	0.003	0.006
MSW	0.03	0.004
Naphtha	0.003	0.006
Natural Gas	0.0009	0.1
Natural Gas Liquids	0.003	0.006
Other Biomass	0.03	0.004
Petroleum Coke	0.003	0.006
Propane	0.001	0.1
Refinery Gas	0.0009	0.1
Residual Fuel Oil	0.003	0.006
Tires	0.003	0.006
Waste Oil	0.03	0.004
Waxes	0.003	0.006
Wood (Dry)	0.03	0.004
Note: Heat content factors are based on higher heating values (HHV).		

ESSENTIAL REQUIREMENTS OF MANDATORY REPORTING FOR THE WCI

DRAFT

GENERAL PROVISIONS

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§ WCI.0 PURPOSE

This rule requires mandatory reporting and verification of greenhouse gas (GHG) emissions data by certain facilities that directly emit GHG, by importers of electricity, and by suppliers of fossil fuels. The GHGs that must be reported under this rule are carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFC), perfluorocarbons (PFC), and sulfur hexafluoride (SF_6).

§ WCI.1 APPLICABILITY

(a) The GHG emissions reporting requirements, and related monitoring, recordkeeping, and verification requirements of this rule apply to the owners and operators *[Each jurisdiction will select the specific terminology for the regulated persons in accordance with their customary rule-writing practices]* of any facility that meets the requirements of paragraph (a)(1)of this section; and any fuel suppliers and electricity importers that meet the requirements of paragraph (a)(2), (a)(3), or (a)(4) of this section:

(1) Any facility that emits 10,000 metric tons CO_2e or more per year in combined emissions from one or more of the source categories listed in this paragraph in any calendar year starting in 2010.

[Please note that the quantification and monitoring methods for most of these source categories are currently being assessed. Only source categories for which adequate quantification methods exist will be included in the final WCI Essential Requirements for mandatory reporting.]

(A) Adipic acid manufacturing
(B) Aluminum production
(C) Ammonia manufacturing
(D) Cement production
(E) Coal mine fugitive emissions (active and abandoned)
(F) Cogeneration
(G) Electricity generation
(H) Electronics Manufacturing
(I) Ferroalloy production
(J) Glass Production and other uses of carbonates
(K) HCFC-22 production
(L) Hydrogen production
(M) Industrial wastewater
(N) Iron and steel production
(O) Lead production
(P) Lime manufacturing
(Q) Magnesium production
(R) Natural gas distribution systems
(S) Nitric acid manufacturing
(T) Nonroad equipment at facilities
(U) Oil and gas production & gas processing

(V) Petrochemical production
(W) Petroleum refineries
(X) Phosphoric acid production
(Y) Pulp and paper manufacturing
(Z) SF6 from electrical equipment
(AA) Soda ash manufacturing
(BB) Stationary fuel combustion
(CC) Zinc production

(2) All importers of electricity. Importers of electricity include both retail providers and marketers that import electricity into the WCI region.
(3) Any supplier that within the WCI region distributes gasoline and diesel transportation fuels in quantities that when combusted would emit 10,000 metric tons CO2e per year or more in any calendar year starting in 2010.
(4) Any supplier that distributes within the WCI region residential, commercial, and industrial fuels in quantities that when combusted would emit 10,000 metric tons CO_2e per year or more in any calendar year starting in 2010.

(b) To calculate GHG emissions for comparison to the 10,000 metric ton CO_2e per year emission threshold in paragraph (a)(1) of this section, the owner or operator shall calculate annual CO_2e emissions, as described in paragraphs (b)(1) through (b)(4)of this section.

(1) Estimate the annual emissions of CO_2, CH_4, N_2O, HFC, PFC, and SF_6 in metric tons for each unit, process, activity, or operation for which emission calculation methodologies are provided in sections WCI.20 through WCI.XX. The GHG emissions shall be calculated using methodologies specified in each applicable section.
(2) For stationary combustion units, carbon dioxide emissions from the combustion of biomass fuels shall be included in the calculations.
(3) Sum the total facility emissions for each GHG and calculate the metric tons of CO_2e using equation 1-1 below.

$$CO_2e = \sum_{i=1}^{n} GHG_i \text{ x } GWP_i \qquad \textbf{Equation 1-1}$$

Where:

CO_2e = Carbon dioxide equivalent, metric tons/year.
GHG_i = Mass emissions of each greenhouse gas emitted, metric tons/year.
GWP_i = Global warming potential for each greenhouse gas from Table 10 of this regulation.
n = The number of greenhouse gases emitted.

(4) For purpose of determining if an emission threshold has been exceeded, any CO_2 that is captured for on-site use, on-site storage, or transfer off-site must be included in the emissions total.

(c) To calculate GHG emissions for comparison to the 10,000 metric ton CO_2e per year emission threshold for suppliers of liquid transportation fuels in paragraphs (a)(3) of this section, the owner or operator shall follow the procedures of paragraphs (c)(1) through (c)(3) below:

(1) Calculate the total mass in metric tons per year of CO2, CH4, and N2O that would result from the complete combustion or oxidation of all gasoline and diesel transportation fuels that are distributed within the WCI region. The mass of each GHG shall be calculated using any of the applicable methodologies specified in section WCI.250 of this rule.

(2) Sum the emissions of each GHG and calculate total metric tons of CO2e using Equation 1-1 of this rule.

(d) To calculate GHG emissions for comparison to the 10,000 metric ton CO_2e per year emission threshold for suppliers of residential, commercial, and industrial fuels in paragraph (a)(4) of this section, the owner or operator shall follow the procedures of paragraphs (d)(1) and (d)(2) below:

(1) Calculate the total mass in metric tons per year of CO_2, CH_4, and N_2O that would result from the complete combustion or oxidation of all residential, commercial, and industrial fuels that are distributed within the WCI region. The calculation shall exclude any fuels that are supplied to facilities that are required to report GHG emissions under section WCI.1(a)(1). *[These accounting issues will be dealt with in 2009.]* The mass of each GHG shall be calculated using any of the applicable methodologies specified in section WCI.260 of this rule.

(2) Sum the emissions of each GHG and calculate total metric tons of CO_2e using Equation 1-1 of this rule.

(e) If the operations of a facility or fuel supplier that is subject to this rule change such that emissions fall below 10,000 metric tons CO_2 per year, then the following reporting requirements shall apply:

[Please note that the requirements of this subsection do not currently address reporters who emit >25,000 metric tons during 1 or more years, and then drop below 25,000 metric tons and above 10,000 metric tons in subsequent years. A provision for these reporters to cease verification after some period of time is under consideration.]

(1) If, prior to such emission reduction, the emissions report was subject to the verification requirements of this rule; then the owner or operator shall continue to submit verified emission reports until reported emissions are below 10,000 metric tons CO_2e per year for a minimum of 3 consecutive years. If reported emission are less than 10,000 metric tons CO_2 per year during 3 consecutive years, then the owner or operator shall be exempted from further reporting until CO_2e emissions again exceed 10,000 metric tons in any future calendar year.

(2) If, prior to such emission reduction, the emissions report was not subject to the verification requirements of this rule; then the owner or operator shall submit to the *[jurisdiction]* a signed statement certifying that emissions are less than 10,000 metric tons CO_2e during the prior year. After certifying that emissions are below 10,000 metric tons CO_2e per year for 3 consecutive years, the owner or operator shall be exempted from further reporting until CO_2e emissions again exceed 10,000 metric tons in any future calendar year.

(3) Notwithstanding the requirements of paragraphs (e)(1) and (2) of this section, a facility or fuel supplier that is subject to an emissions limitation under the WCI cap and trade program must continue to submit verified annual reports.

(f) Upon request by the *jurisdiction*], owner or operator of any facility or fuel supply operation must submit a demonstration that emissions have not exceeded one or more of the applicability criteria specified in this section in any year since 2010. Such demonstration shall be provided to the [*jurisdiction*] within 20 working days of receipt of a written request.

§ WCI.2 GENERAL GREENHOUSE GAS REPORTING REQUIREMENTS AND SCHEDULE

[Please note that the specific requirements of this section may change based on the future final design of the marketing trading program.]

(a) **General**. Owners or operators that are subject to this rule must submit an annual GHG emissions report. Owners and operators must collect emissions data; calculate GHG emissions; and follow the procedures for quality assurance, missing data, recordkeeping, and reporting as specified in these General Provisions and in each relevant section WCI.20 through WCI.XX of this rule.

(1) A facility, fuel supplier, or electricity importer that commenced operation before January 1, 2010, must report emissions beginning in 2011 for GHGs emitted in calendar year 2010.

(2) A new facility, fuel supplier, or electricity importer that commences operation on or after January 1, 2010, must report emissions for the first calendar year in which the facility operates, beginning with the first operating month and ending on December 31 of that year. Each subsequent annual report must cover emissions for the calendar year, beginning on January 1 and ending on December.

(b) **Reporting and Verification Schedule**.

(1) Annual GHG emissions reports must be submitted to [*the jurisdiction*] by April 1 of each year for emissions in the previous calendar year.

(2) Reporters subject to the verification requirements of WCI.8, must complete their verification process, including submittal of a verification statement to [*the jurisdiction*], according to the following schedule:

(A) For reporting years 2010 through 2011, September 1 of the year following the reporting year.

(B) For reporting years 2012 and later, *[date to be determined]* .

(c) **Submission of GHG Emissions Report**. The annual GHG emissions report must be submitted to [*the jurisdiction*] in a format [*to be specified by each jurisdiction*].

(d) **Simplified Emission Calculation Methods for De Minimis Sources**. The owner or operator may elect to designate as de minimis one or more sources or pollutants that collectively emit no more than 3 percent of the facility's total CO2e emissions, but not to exceed 20,000 metric tons CO_2e. The owner or operator may estimate emissions for these de minimis sources using alternative methods to those required to be used by this rule. If verification of the emissions report is required by this rule, then the selection of any alternative GHG calculation method is subject to the concurrence of the verification team that the use of such methods provides reasonable assurance that the emissions so designated do not exceed the applicable de minimis limits. The operator shall separately identify and include in the emissions data report the emissions from designated de minimis sources.

(e) **GHG Inventory Management Plan**. The owner or operator shall prepare and follow a written GHG inventory management plan that ensures that the emissions calculations and other information that is required to be reported under this rule are transparent, accurate, and independently verifiable. The owner or operator shall establish, document, implement, and maintain data acquisition and handling activities for the calculation and reporting of GHG emissions. Such activities shall include measuring, monitoring, analyzing, recording, processing and calculating the parameters specified by this rule. The owner or operator shall implement systems of internal audit, quality assurance, and quality control for the reporting program and the data reported.

(f) **GHG Emissions Report Revisions**.

(1) The owner or operator shall maintain documentation to support any revisions made to a previously submitted annual GHG emissions report. Documentation for all revisions shall be retained by the operator for 7 years.

(2) If, after the verification deadline, a report subject to verification is found to contain an error, or accumulation of errors, greater than 5 percent of the total CO_2e emissions reported, the owner or operator shall revise and resubmit an annual GHG emissions report within 60 days of the finding. To the extent possible, the revised report must correct all identified errors. A revised report will be accepted only if verified according to WCI.8 and approved by [*the jurisdiction*].

(3) If, after the report submittal deadline, a report not subject to verification is found to contain an error, or accumulation of errors, greater than 5 percent of the total CO_2e emissions reported, the owner or operator shall revise and resubmit an annual GHG emissions report within 30 days of the finding. To the extent possible, the revised report must correct all identified errors. A revised report will be accepted only if approved by [*the jurisdiction*].

(4) An owner or operator that voluntarily chooses to correct errors of 5 percent or less in total CO_2e emissions reported may do so according to the following requirements:

(A) For reports subject to verification, a revised report will be accepted only if verified according to WCI.8 and approved by [*the jurisdiction*].

(B) For reports not subject to verification, a revised report will be accepted if approved by [*the jurisdiction*].

(g) **Fuel Use Measurement Accuracy.** The operator shall use procedures to quantify fuel use (mass or volume flow) that provide data with an accuracy within ±5 percent. All fuel use measurement devices shall be maintained and calibrated in a manner and at a frequency required to maintain this level of accuracy. The operator shall make available to the verification team documentation to support this level of accuracy. The operator who measures solid fuels shall validate fuel consumption estimates with belt or conveyor scale calibrations conducted at least quarterly, and retain record of such calibrations.

(h) Where this rule specifies a choice between use of a fuel-based calculation or use of a continuous emissions monitoring system (CEMS) to calculate CO2 emissions, the operator shall make this choice and continue to use the method chosen for all future emissions data reports, unless the use of the alternative calculation method is approved in advance by *[the jurisdiction]*.

§ WCI.3 CONTENTS OF THE GREENHOUSE GAS EMISSIONS REPORT

Each annual GHG emissions report shall contain the following information:

(a) Facility name, identification number, physical address, mailing address, and NAICS code.

(b) Reporting year.

(c) Date of report submittal.

(d) Total facility emissions aggregated from all applicable source categories in subparts WCI.20 through WCI.XX expressed in metric tons of CO_2e calculated using Equation 1-1 of section WCI.1, excluding emissions from CO_2 that is captured and CO_2 emissions from the combustion of biomass and biomass-derived fuels, which are reported separately.

(e) Total facility emissions of CO_2 from the combustion of biomass and biomass-derived fuels.

(f) Total annual mass of CO_2 captured for on-site use, on-site storage, or transfer off site, in metric tons.

(g) For applicable fuel supplier categories in subparts WCI.250 and WCI.260, total CO_2e emissions aggregated from all specified fuels.

(h) Emissions from each applicable source category or fuel supplier category in subparts WCI.20 through WCI.XX, expressed in metric tons per year of CO_2, CH_4, N_2O, HFC, PFC, and SF_6. CO_2 emissions from the combustion of biomass and biomass-derived fuels shall be reported separately.

(i) For electricity importers, the information required by WCI.60.

(j) Emissions and other data for individual units, processes, activities, and operations as specified for each source category in sections WCI.20 through WCI.XX of this rule.

(k) Mass emissions from each designated de minimis source or pollutant, reported in metric tons per year of each GHG for which an alternative emission calculation method is used.

(l) Name and contact information including e-mail address and telephone number of the person primarily responsible for preparing and submitting the emissions report.

(m) A signed and dated statement provided by the owner or operator, or their designated representative, certifying that the report has been prepared in accordance with this rule and that, subject to verification, the statements and information contained in the emissions data report are true, accurate, and complete to the best of their knowledge.

§ WCI.4 DOCUMENT RETENTION AND RECORD KEEPING REQUIREMENTS

(a) The operator shall establish and maintain procedures for document retention and record keeping. The operator shall retain all documents regarding the design, development and maintenance of the GHG inventory in paper, electronic or other usable format for a period of not less than 7 years following submission of each emissions data report. The retained documents, including GHG emissions data, shall be sufficient to allow for the verification of each emissions data report.

(b) Upon request by *[jurisdiction],* the operator shall provide within 10 working days all documents and data used to develop an emissions data report.

(c) In addition to information submitted as part of the emissions data report, each operator shall retain, at a minimum, the following information for at least 7 years after the submission of the report:

(1) A list of all GHG sources (i.e., units, operations, processes, and activities) included in the emission estimates.
(2) All data used to calculate emissions for each source, categorized by process and fuel or material type.
(3) Documentation of the process for collecting emissions data.
(4) Any GHG emissions calculations and methods used;
(5) All emission factors used for emission estimates, including documentation for any factors not provided in the rule.
(6) All input data used for emission estimates.
(7) Documentation of biomass fractions for specific fuels.
(8) All other data submitted to the [*jurisdiction*] under this rule, including the GHG emissions report.
(9) All computations made to gap-fill missing data.
(10) Names and documentation of key facility personnel involved in emissions calculating and reporting;
(11) Any other information that is required for the verification of the GHG emissions report.
(12) A log to be prepared for each reporting year, beginning January 1, documenting all procedural changes made in GHG accounting methods and changes to instrumentation for GHG emissions estimation.
(13) A copy of the GHG Inventory Management Plan.

(d) For measurement based methodologies, the following information also must be retained for at least 7 years after the submission of the emissions data report:

(1) List of all emission points monitored.
(2) Collected monitoring data.
(3) Quality assurance and quality control information collected under the GHG Inventory Management Plan required by section WCI.2 of this rule.
(4) A detailed technical description of the continuous measurement system, including documentation of any findings and approvals by federal, State or local agencies.
(5) Raw and aggregated data from the continuous measurement system.
(6) A log book of all system down-times, calibrations, servicing, and maintenance of the continuous measurement system.
(7) Documentation of any changes in the continuous measurement system over time.

§ WCI.5 COMPLIANCE AND ENFORCEMENT

(a) Knowing submission of false information to the *[jurisdiction*] or a verification body, shall constitute a single, separate violation of the requirements of this article for each day after the information has been received by the [*jurisdiction*].

(b) Each violation of this rule shall constitute a single, separate violation for each day beyond the specified reporting date. A violation includes failure to submit any report, failure to collect data needed to calculate GHG emissions, failure to monitor and test as required, failure to calculate GHG emissions following the methodologies specified in this rule, failure to retain required records, failure to provide all information required in the report, and failure to submit a report on time. For the purposes of this rule, "report" means any GHG emissions data report, verification opinion, or other document required to be submitted by this rule.

§ WCI.6 INCORPORATION BY REFERENCE

The following documents are incorporated by reference into this rule. These materials are incorporated as they exist on the date this article is adopted.

[This list will be revised as additional calculation methods are selected.]

(a) American Society for Testing and Materials (ASTM) D1826-94 (Reapproved 2003), ASTM D3588-98 (Reapproved 2003), ASTM D4891-89 (Reapproved 2006), ASTM D240-02 (Reapproved 2007), ASTM D4809-00 (Reapproved 2005), ASTM 5373-02 (Reapproved 2007), ASTM D5291-02 (Reapproved 2007), ASTM D3238-95 (Reapproved 2005), ASTM D2502-04, ASTM D2503-92 (Reapproved 2002), ASTM D1945-03, ASTM D1946-90 (Reapproved 2006), ASTM D6866-06a, ASTM D388-05, ASTM D5468-02 (Reapproved 2007), ASTM D240-87 (Reapproved 1991), ASTM D5865-07a, ASTM Specification D396-07, ASTM Specification D975-07b.

(b) California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities, California Air Pollution Control Officers Association (CAPCOA) and California Air Resources Board (ARB), February 1999.

(c) Control of Emissions from Refinery Flares, Rule 118, South Coast Air Quality Management District, Amended November 4, 2005.

(d) U.S. EPA TANKS Version 4.09D, US Environmental Protection Agency, October 2005.

(e) Gas Processors Association (GPA) Standard 2261-00, Revised 2000.

§ WCI.7 DESIGNATED REPRESENTATIVE

(a) **General**. Each fuel supplier, electricity importer, and owner or operator of a facility that is subject to this rule, shall select a designated representative that is responsible for certifying and submitting GHG emissions reports under this reporting rule.

(b) **Authorization of a Designated Representative**. The designated representative of the facility shall be selected by a certificate of representation agreement that is signed by the designated representative and owners or operators of the facility. The designated representative must be an individual having responsibility for the overall operation of the facility or activity such as the position of the plant manager, operator of a well or a well field, superintendent, position of equivalent responsibility, or an individual or position having overall responsibility for environmental matters for the company.

(c) **Responsibility of the Designated Representative**.

(1) The designated representative of the facility shall represent and by any representations, actions, inactions, or submissions, legally bind each owner and operator in all matters pertaining to this rule.

(2) Each GHG emission report submitted under this rule must be signed by the designated representative and must contain the following certification statement: "I have been

authorized to make this submission on behalf of the owners and operators of the facility (or supply operation, as appropriate). I certify under penalty of law that I have personally examined the information submitted in this document. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(d) **Changing a Designated Representative**. The designated representative may be changed at any time upon submission of a superseding certificate of representation. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous designated representative before time of the superseding certificate of representation shall be binding on the new designated representative and the owners and operators.

(e) **Changes in Owners and Operators**. In the event of any change in ownership of the facility, any new owner or operator shall be deemed to be bound by the representations, actions, inactions, and submissions of the designated representative of the facility until such time as the designated representative is changed.

(f) **Certificate of Representation**. A certificate of representation must be submitted to *[the jurisdiction]* and kept on location by the facility, fuel supplier, or electricity importer. The certificate shall include the following information:

(1) Identification of the facility, fuel supplier, or electricity importer for which the certificate of representation is submitted.
(2) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the designated representative.
(3) A list of the owners and operators.
(4) Certification statements that the actions of the designated representative with respect to this rule are binding on the owners and operators, and that the designated representative has the necessary authority to carry out duties and responsibilities on behalf of the owners and operators.
(5) The signature of the designated representative and owner(s) and operator(s), and the dates signed.

§ WCI.8 REQUIREMENTS FOR VERIFICATION OF EMISSIONS DATA REPORTS

[To be added later]

§ WCI.9 DEFINITIONS

[Partial list of definitions. Additional definitions are under development.]

"Adverse verification statement" means a verification statement rendered by a verification body stating that the verification body cannot say with reasonable assurance that the submitted emissions data report is free of material misstatement, or that it cannot provide a qualifying statement that the emissions data report conforms to the requirements of this article.

"Biomass fuels" or "biomass-derived fuels" means fuels derived entirely from biomass.

“Carbon dioxide equivalent" or “CO_2 equivalent” or "CO_2e" means a measure for comparing carbon dioxide with other GHGs, based on the quantity of those gases multiplied by the appropriate global warming potential (GWP) factor and commonly expressed as metric tons of carbon dioxide equivalent.

“Conflict of interest” means a situation in which, because of financial or other activities or relationships with other persons or organizations, a person or body is unable or potentially unable to render an impartial verification opinion of a potential client’s greenhouse gas emissions, or the person or body’s objectivity in performing verification services is or might be otherwise compromised.

“Continuous emissions monitoring system” or “CEMS” means the total equipment required to obtain a continuous measurement of a gas concentration or emission rate from combustion or industrial processes.

“Electricity generating unit” or “EGU” means any combination of physically connected generator(s), reactor(s), boiler(s), combustion turbine(s), or other prime mover(s) operated together to produce electric power.

“Exporter” means…*[To be defined later for liquid transportation and RCI fuels accounting]*

“Facility” means any property, plant, building, structure, stationary source, stationary equipment or grouping of stationary equipment or stationary sources located on one or more contiguous or adjacent properties, in actual physical contact or separated solely by a public roadway or other public right-of way, under common operational control, and having the same first two digits of the Standard Industrial Classification (SIC) or same first three digits of the North American

Industry Classification System (NAICS) code. *[Some special facilities, such as oil and gas production fields will have separate definitions.]*

“Global warming potential” or “GWP factor” means the radiative forcing impact of one mass-based unit of a given greenhouse gas relative to an equivalent unit of carbon dioxide over a given period of time.

“Greenhouse gas”, “greenhouse gases” or “GHG” means carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), and perfluorocarbons (PFCs).

“Hydrofluorocarbons” or “HFCs” means a class of GHGs primarily used as refrigerants, consisting of hydrogen, fluorine, and carbon.

“Importer” means…*[To be defined later with input from the Electricity Subcommittee.]*

“Lead verifier” means a person that has met all of the requirements in section WCI.9 [TBD], and who may act as the lead verifier of a verification team providing verification services or as a lead verifier providing an independent review of verification services rendered.

“Material misstatement” means one or more inaccuracies identified in the course of verification that result in the total reported emissions being outside the 95 percent accuracy required to receive a positive verification opinion.

“Owner or operator” means any person who owns, leases, operates, controls, or supervises a facility or fuel supply operation; or who imports electricity into the WCI region.

“Perfluorocarbons” or “PFCs” means a class of greenhouse gases consisting on the molecular level of carbon and fluorine.

“Positive verification opinion” means a verification opinion rendered by a verification body stating that the verification body can say with reasonable assurance that the submitted emissions data report is free of material misstatement and includes a qualifying statement that the emissions data report conforms to the requirements of this article.

“Reasonable assurance” means a high degree of confidence that submitted data and statements are valid.

“Stationary combustion unit” means any boiler, heater, furnace, kiln, turbine, internal combustion engine, incinerator or other non-mobile source device that combusts any solid, liquid, or gaseous fuel for purposes of producing useful heat or energy for industrial, commercial, or institutional use; or for purposes of reducing the volume of waste by removing combustible material.

“Supplier” means . . . [To *be defined later for liquid transportation and RCI fuels accounting.]*.

“Verification” means the process used to ensure that an operator’s emissions data report is free of material misstatement and complies with WCI’s reporting procedures and methods for calculating and reporting GHG emissions.

“Verification body” means a firm accredited by WCI or its agent, that is able to render a verification opinion and provide verification services for operators subject to reporting under this article.

“Verification cycle” means one year of full verification and the next consecutive two years of less intensive verification for operators subject to annual verification. For operators subject to triennial verification, a verification cycle means one year of full verification, and if elected, the next consecutive two years of less intensive verification. A verification cycle cannot exceed three calendar years.

“Verification statement” means the final opinion rendered by a verification body attesting whether an operator’s emissions data report is free of material misstatement and a qualifying statement whether the emissions data report conforms to the requirements of this article.

“Verification services” means services provided during verification as specified in section WCI.9, including but not limited to reviewing an owner’s or operator’s emissions data report, verifying its accuracy according to the standards specified in this section, assessing the owner’s or operator's compliance with this section, and submitting a verification opinion to the *[jurisdiction or its agent].*

"Verification team" means all of those working for a verification body, including all subcontractors, to provide verification services for an operator. The lead verifier for the verification team shall be a lead verifier in the verification body.

"Verifier" means an individual accredited by WCI or its agent to carry out verification services as specified in section WCI.9.

"Waste-derived fuel" means a fuel typically derived from waste and generally used as a substitute for conventional fossil fuels. Waste-derived fuels can include fossil fuels such as waste oil, plastics, or solvents; biomass such as dried sewage or impregnated saw dust; or fractions of both fossil fuels and biomass such as municipal solid waste or tires.

§ WCI.10 Global Warming Potentials

Owners and operators must use the global warming potential (GWP) values given in Table WCI.10-1 when converting emissions of greenhouse gases to metric tons of carbon dioxide equivalent (CO_2e).

Table WCI.10-1. Global Warming Potential Factors for Greenhouse Gases			
Common Name	**Formula**	**Chemical Name**	**GWP**
Carbon dioxide	CO_2		1
Methane	CH_4		21
Nitrous oxide	N_2O		310
Sulfur hexafluoride	SF_6		23,900
Hydrofluorocarbons (HFCs)			
HFC-23	CHF_3	trifluoromethane	11,700
HFC-32	CH_2F_2	difluoromethane	650
HFC-41	CH_3F	fluoromethane	150
HFC-43-10mee	$C_5H_2F_{10}$	1,1,1,2,3,4,4,5,5,5- decafluoropentane	1,300
HFC-125	C_2HF_5	pentafluoroethane	2,800
HFC-134	$C_2H_2F_4$	1,1,2,2-tetrafluoroethane	1,000
HFC-134a	$C_2H_2F_4$	1,1,1,2-tetrafluoroethane	1,300
HFC-143	$C_2H_3F_3$	1,1,2-trifluoroethane	300
HFC-143a	$C_2H_3F_3$	1,1,1-trifluoroethane	3,800
HFC-152	$C_2H_4F_2$	1,2-difluoroethane	43
HFC-152a	$C_2H_4F_2$	1,1-difluoroethane	140
HFC-161	C_2H_5F	fluoroethane	12
HFC-227ea	C_3HF_7	1,1,1,2,3,3,3- heptafluoropropane	2,900
HFC-236cb	$C_3H_2F_6$	1,1,1,2,2,3-hexafluoropropane	1,300
HFC-236ea	$C_3H_2F_6$	1,1,1,2,3,3-hexafluoropropane	1,200
HFC-236fa	$C_3H_2F_6$	1,1,1,3,3,3-hexafluoropropane	6,300
HFC-245ca	$C_3H_3F_5$	1,1,2,2,3-pentafluoropropane	560
HFC-245fa	$C_3H_3F_5$	1,1,1,3,3-pentafluoropropane	950
HFC-365mfc	$C_4H_5F_5$	1,1,1,3,3-pentafluorobutane	890
Perfluorocarbons (PFCs)			
Perfluoromethane	CF_4	tetrafluoromethane	6,500
Perfluoroethane	C_2F_6	hexafluoroethane	9,200
Perfluoropropane	C_3F_8	octafluoropropane	7,000
Perfluorobutane	C_4F_{10}	decafluorobutane	7,000
Perfluorocyclobutane	$c\text{-}C_4F_8$	octafluorocyclobutane	8,700
Perfluoropentane	C_5F_{12}	dodecafluoropentane	7,500
Perfluorohexane	C_6F_{14}	tetradecafluorohexane	7,400

§ WCI.200 PETROLEUM REFINERIES

§ WCI.201 Source Category Definition

A petroleum refinery consists of all processes used to produce gasoline, aromatics, kerosene, distillate fuel oils, residual fuel oils, lubricants, asphalt, or other products through distillation of petroleum or through redistillation, cracking, rearrangement or reforming of unfinished petroleum derivatives.

WCI.202 Greenhouse Gas Reporting Requirements

The annual emissions report must contain the following information reported at the facility-level:

(a) Catalyst Regeneration. Report CO_2 emissions.

(b) Process Vents. Report CO_2, N_2O, and CH_4 emissions.

(c) Asphalt Production. Report CO_2 and CH_4 emissions.

(d) Sulfur Recovery. Report CO_2 emissions.

(e) Stationary Combustion Units Other than Flares and Control Devices. Report CO_2, N_2O, and CH_4 emissions as specified in WCI.23.

(f) Flares and Other Control Devices. Report CO_2, N_2O, and CH_4 emissions.

(g) Above-Ground Storage Tanks. Report CH_4 emissions.

(h) Wastewater Treatment. Report CH_4 and N_2O emissions.

(i) Oil-Water Separators. Report CH_4 emissions.

(j) Equipment Leaks. Report CH_4 emissions.

(k) Feedstock Consumption: Report feedstock consumption by type for all feedstocks which result in GHG emissions in the reporting year (including petroleum coke) in units of million standard cubic feet for gases, gallons for liquids, short tons for non-biomass solids, and bone dry short tons for biomass-derived solid fuels.

(l) Fuel Consumption: Report fuel consumption by fuel type consumed in the reporting year in units of million standard cubic feet for gases, gallons for liquids, short tons for non-biomass solids, and bone dry short tons for biomass-derived solid fuels.

WCI.203 Calculation of GHG Emissions

The operator shall calculate GHG emissions using the methods in paragraphs (a) through (i) of this section.

(a) ***Catalyst Regeneration.*** For units equipped with CEMS, operators shall calculate CO_2 process emissions resulting from catalyst regeneration using CEMS in accordance with WCI.20. In the absence of CEMS data, the operator shall use the methods in paragraphs (a)(1) through (a)(3).

(1) The operator shall calculate process CO_2 emissions from the continuous regeneration of catalyst material in fluid catalytic cracking units (FCCU) and fluid cokers using Equations 200-1, 200-2, and 200-3.

$$CO_2 = \sum_{d=1}^{n} CR_d \times CF \times 3.664 \times 0.001$$ **Equation 200-1**

Where:

CO_2	=	CO_2 emissions (metric tons/yr)
n	=	number of days of operation in the report year
CR_d	=	daily average coke burn rate (kg/day)
CF	=	carbon fraction in coke burned
3.664	=	ratio of molecular weights, CO_2 to carbon
0.001	=	conversion factor – kg to metric tons

$$CR_d = \left[\sum_{i=1}^{n} [K_1 Q_r \times (\%CO_2 + \%CO) + K_2 Q_a - K_3 Q_r \times [\%CO/2 + \%CO_2 + \%O_2] + K_3 Q_{oxy} \times (\%O_{oxy})]_i \right] / n$$

Equation 200-2

Where:

CR_d	=	daily average coke burn rate (kg/day or lb/day)
K_1, K_2, K_3	=	material balance and conversion factors (K_1, K_2, and K_3 from Table 200-1
n	=	number of hours per day
Q_r	=	volumetric flow rate of exhaust gas before entering the emission control system (dscm/min or dscf/min)
Q_a	=	volumetric flow rate of air to regenerator as determined from control room instrumentation (dscm/min or dscf/min)
$\%CO_2$	=	CO_2 concentration in regenerator exhaust, percent by volume – dry basis
%CO	=	CO concentration in regenerator exhaust, percent by volume – dry basis
$\%O_2$	=	O_2 concentration in regenerator exhaust, percent by volume – dry basis
Q_{oxy}	=	volumetric flow rate of O_2 enriched air to regenerator as determined from control room instrumentation (dscm/min or dscf/min)
$\%O_{xy}$	=	O_2 concentration in O_2 enriched air stream inlet to regenerator, percent by volume – dry basis

$$Q_r = (79 \times Q_a + (100 - \%Q_{xy}) \times Q_{oxy}) / (100 - \%CO_2 - \%CO - \%O_2)$$ **Equation 200-3**

Where:

Q_r	=	volumetric flow rate of exhaust gas from regenerator before entering the emission control system (dscm/min or dscf/min)
Q_a	=	volumetric flow rate of air to regenerator, as determined from control room instrumentation (dscm/min or dscf/min)

$\%Q_{xy}$	=	oxygen concentration in oxygen enriched air stream, percent by volume – dry basis
Q_{oxy}	=	volumetric flow rate of O_2 enriched air to regenerator as determined from catalytic cracking unit control room instrumentation (dscm/min or dscf/min)
$\%CO_2$	=	carbon dioxide concentration in regenerator exhaust, percent by volume – dry basis
%CO	=	CO concentration in regenerator exhaust, percent by volume – dry basis. When no auxiliary fuel is burned and a continuous CO monitor is not required, assume %CO to be zero
$\%O_2$	=	O_2 concentration in regenerator exhaust, percent by volume – dry basis

(2) The operator shall calculate process CO_2 emissions resulting from periodic catalyst regeneration using Equation 200-4.

$$CO_2 = \sum_{i=1}^{n} CRR \times \left(CF_{spent} - CF_{regen}\right)_i \times 3.664 \times 0.001 \qquad \textbf{Equation 200-4}$$

Where:

CO_2	=	CO_2 emissions (metric tons/yr)
CRR	=	mass of catalyst regenerated (mass/regeneration cycle)
CF_{spent}	=	weight fraction carbon on spent catalyst
CF_{regen}	=	weight fraction carbon on regenerated catalyst (default = 0)
n	=	number of regeneration cycles
3.664	=	ratio of molecular weights, CO_2 to carbon
0.001	=	conversion factor – kg to metric tons

(3) The operator shall calculate process CO_2 emissions resulting from continuous catalyst regeneration in operations other than FCCUs and fluid cokers (e.g. catalytic reforming) using Equation 200-5.

$$CO_2 = CC_{irc} \times (CF_{spent} - CF_{regen}) \times H \times 3.664 \qquad \textbf{Equation 200-5}$$

Where:

CO_2	=	CO_2 emissions (metric tons/yr)
CC_{irc}	=	average catalyst regeneration rate (metric tons/hr)
CF_{spent}	=	weight carbon fraction on spent catalyst
CF_{regen}	=	weight carbon fraction on regenerated catalyst (default = 0)
H	=	hours regenerator was operational (hr/yr)
3.664	=	ratio of molecular weights, CO_2 to carbon

(b) ***Process Vents.*** Except for process emissions reported under other requirements of this regulation, the operator shall calculate process emissions of CO_2, CH_4, and N_2O from process vents using Equation 200-6.

$$E_x = \sum_{i=1}^{n} VR_i \times F_{xi} \times (MW_x / MVC) \times VT_i \times 0.001 \qquad \textbf{Equation 200-6}$$

Where:

E_x	=	emissions of x (metric tons/yr), where x = CO_2, N_2O, or CH_4
VR_i	=	vent rate for venting event i (scf/unit time)
F_{xi}	=	molar fraction of x in vent gas stream during event i
MW_x	=	molecular weight of x (kg/kg-mole)
MVC	=	molar volume conversion (849.5 scf/kg-mole for STP of 20°C and 1 atmosphere or 836 scf/kg-mole for STP of 60°F, and 1 atmosphere)
VT_i	=	time duration of venting event i
n	=	number of venting events
0.001	=	conversion factor – kg to metric tons

(c) ***Asphalt Production:*** The operator shall calculate CO_2 and CH_4 process emissions from asphalt blowing activities using Equations 200-7 and 200-8.

$$CH_4 = (M_A \times EF \times MW_{CH4} / MVC) \times (1 - DE) \times 0.001$$ **Equation 200-7**

Where:

CH_4	=	CH_4 emissions (metric tons/yr)
M_A	=	mass of asphalt blown (10^3 bbl/yr)
EF	=	emission factor (EF = 2,555 scf $CH_4/10^3$ bbl)
MW_{CH4}	=	CH_4 molecular weight (16.04 kg/kg-mole)
MVC	=	molar volume conversion factor (849.5 scf/kg- mole, for STP of 20°C and 1 atmosphere)
DE	=	control measure destruction efficiency (DE = 98% expressed as 0.98)
0.001	=	conversion factor – kg to metric tons

$$CO_2 = (M_A \times EF \times MW_{CH4} / MVC) \times DE \times 2.743 \times 0.001$$ **Equation 200-8**

Where:

CO_2	=	CO_2 emissions (metric tons/yr)
M_A	=	mass of asphalt blown (10^3 bbl/yr)
EF	=	emission factor (EF = 2,555 scf $CH_4/10^3$ bbl)
MW_{CH4}	=	CH_4 molecular weight (16.04 kg/kg-mole)
MVC	=	molar volume conversion factor (849.5 scf/kg mole, for STP of 20°C and 1 atmosphere)
DE	=	control measure destruction efficiency (DE = 98% expressed as 0.98)
2.743	=	CH_4 to CO_2 conversion factor
0.001	=	conversion factor – kg to metric tons

(d) ***Sulfur Recovery.*** The operator shall calculate CO_2 process emissions from sulfur recovery units (SRUs) using Equation 200-9. For the molecular fraction (MF) of CO_2 in the sour gas, use either a default factor of 0.20 or a source specific molecular fraction value approved by [*insert jurisdiction*] and derived from source tests conducted at least once per calendar year under the supervision of [*insert jurisdiction*].

$$CO_2 = FR \times MW_{CO2} / MVC \times MF \times 0.001 \qquad \textbf{Equation 200-9}$$

Where:

CO_2	=	emissions of CO_2 (metric tons/yr)
FR	=	volumetric flow rate of acid gas to SRU (scf/year)
MW_{CO2}	=	molecular weight of CO_2 (44 kg/kg-mole)
MVC	=	molar volume conversion (849.5 scf/ kg-mole, for STP of 20°C and 1 atmosphere or 836 scf/kg-mole, for STP of 60°F, and 1 atmosphere)
MF	=	molecular fraction (%) of CO_2 in sour gas (default MF = 20% expressed as 0.20)
0.001	=	conversion factor – kg to metric tons

(e) ***Flares and Other Control Devices.***

(1) The operator shall calculate and report CO_2, CH_4 and N_2O emissions resulting from the combustion of flare pilot and purge gas using the appropriate method(s) specified in sections WCI.20.

(2) The operator shall calculate and report CO_2 emissions resulting from the combustion of hydrocarbons routed to flares for destruction using Equation 200-10.

$$CO_2 = RFI \times EF_{NMHC} \times CF_{NMHC} \times 3.664 \times 0.001 \qquad \textbf{Equation 200-10}$$

Where:

CO_2	=	CO_2 emissions (metric tons/year)
RFT	=	refinery feed input (m^3/yr)
EF_{NMHC}	=	non-methane hydrocarbon emission factor (EF_{NMHC} = 0.002 kg/m^3 throughput)
CF_{NMHC}	=	conversion factor – NMHC to carbon (CF_{NMHC}= 0.6)
3.664	=	ratio of molecular weights, CO_2 to carbon0.001 = conversion factor – kg to metric tons

(3) The operator who uses methods other than flares (e.g. incineration, combustion as a supplemental fuel in heaters or boilers) to destroy low Btu gases (e.g. coker flue gas, gases from vapor recovery systems, casing vents and product storage tanks) shall calculate CO_2 emissions using Equation 200-11. The operator shall determine CC_A and MW_A quarterly using methods specified in section WCI.20 and use the annual average values of CC_A and MW_A to calculate CO_2 emissions.

$$CO_2 = GV_A \times CC_A \times MW_A / MVC \times 3.664 \times 0.001 \qquad \textbf{Equation 200-11}$$

Where:

CO_2	=	CO_2 emissions (metric tons/year)
GV_A	=	volume of gas A destroyed annually (scf/year)
CC_A	=	carbon content of gas A (kg C/kg fuel)
MW_A	=	molecular weight of gas A
MVC	=	molar volume conversion factor (849.5 scf/kg- mole for STP of 20°C and 1 atmosphere or 836 scf/kg-mole, for STP of 60°F, and 1 atmosphere)
3.664	=	ratio of molecular weights, CO_2 to carbon
0.001	=	conversion factor – kg to metric tons

(f) ***Storage Tanks.*** For above-ground storage tanks containing crude oil, asphalt, naphtha, and distillate oils that are not equipped with vapor recovery technology, the operator shall calculate CH_4 emissions using the U.S. EPA TANKS Model (Version 4.09D). For crude oil, naphtha, and distillate oils, use the default chemical databases for crude oil (RVP 5), distillate fuel oil No. 2, and jet naphtha (JP4), respectively. For asphalt, use the data in Table 200-4 to create an asphalt chemical database. The annual throughput for each storage tank must be distributed equally across the twelve months of the year and the single-component liquid option selected. The total VOC emission values generated by the model shall be converted to methane emissions using:

(1) A default conversion factor of 0.6 (CH_4 = 0.6 * VOC); or
(2) Species specific conversion factors determined by storage tank headspace vapor analysis using a sampling and analysis methodology approved by [*insert jurisdiction*].

(g) ***Wastewater Treatment****.*

(1) The operator shall calculate CH_4 emissions from wastewater treatment using Equation 200-12.

$$CH_4 = [(Q \times COD_{qave}) - S] \times B \times MCF \times 0.001 \qquad \textbf{Equation 200-12}$$

Where:

CH_4	=	emission of methane (tons/yr)
Q	=	volume of wastewater treated (m^3/yr)
COD_{qave}	=	average of quarterly determinations of chemical oxygen demand of the wastewater (kg/m^3)
S	=	organic component removed as sludge (kg COD/yr)
B	=	methane generation capacity (B = 0.25 kg CH_4/kg COD)
MCF	=	methane conversion factor for anaerobic decay (0-1.0) from Table 200-2
0.001	=	conversion factor – kg to metric tons

(2) The operator shall calculate N_2O emissions from wastewater treatment using Equation 200-13.

$$N_2O = Q \times N_{qave} \times EF_{N2O} \times 1.571 \times 0.001 \qquad \textbf{Equation 200-13}$$

Where:

N_2O	=	emissions of N_2O (metric tons/yr)
Q	=	volume of wastewater treated (m^3/yr)
N_{qave}	=	average of quarterly determinations of N in effluent (kg N/m^3)
EF_{N2O}	=	emission factor for N_2O from discharged wastewater (0.005 kg N_2O-N/kg N)
1.571	=	conversion factor – kg N_2O-N to kg N_2O
0.001	=	conversion factor – kg to metric tons

(h) ***Oil-Water Separators.*** The operator shall calculate CH_4 emissions from oil-water separators using Equation 200-14.

$$CH_4 = EF_{sep} \times V_{water} \times CF_{NMHC} \times 0.001 \qquad \textbf{Equation 200-14}$$

Where:

CH_4	=	emission of methane (tons/yr)
EF_{sep}	=	NMHC (non methane hydrocarbon) emission factor (kg/m^3) from Table 200-3.
V_{water}	=	volume of waste water treated by the separator (m^3/yr)
CF_{NMHC}	=	NMHC to CH_4 conversion factor (CF_{NMHC} = 0.6)
0.001	=	conversion factor – kg to metric tons

(i) ***Equipment leaks***. The operator shall calculate CH_4 emissions for all components in natural gas, refinery fuel gas, and PSA off-gas systems as follows:

(1) Components shall be identified as one of the following classification types: valve, pump seal, connector, flange, open-ended line. Operators shall use the Component Identification and Counting Methodology and screening methods found in Method 3 in CAPCOA (1999), which is incorporated by reference in WCI.6. Operators shall measure and record emissions using instrumentation capable of detecting methane.

(2) The VOC emissions shall be calculated using the following methods:

(A) For components where the measured screening value (SV) is indistinguishable from zero when corrected for background, operators shall calculate VOC emissions using Equation 200-15:

$$E_{VOC-0} = \sum_{i=1}^{6} CC_i \times ZF_{i0} \times t \qquad \textbf{Equation 200-15}$$

Where:

E_{VOC-0}	=	zero component VOC emission (kg/screening period)
i	=	component type (1 = valve, 2 = pump seal, 3 = other, 4 = connector, 5 = flange, 6 = open-ended line)
CC_i	=	number of i components where SV = 0
ZF_{i0}	=	zero VOC emission factor (kg/hr) for component i from Table 200-5

t = time (hours) since last screening

(B) For leaking components, operators shall calculate VOC emissions using the following methods:

(i) For screening values between background and 9,999 ppmv, the operator shall calculate the VOC emissions using Equation 200-16.

$$E_{VOCL-C} = \sum_{i=1}^{6} \sum_{n=1}^{n} \left(\sigma_i \times SV_n^{\beta i}\right) \times t$$ **Equation 200-16**

Where:

$E_{VOCL\text{-}C}$ = leaking components VOC emissions (kg/screening period)
i = component type (1=valve, 2=pump seal, 3=others, 4=connector, 5=flange, 6=open ended-line)
n = number of i components
σ_i = correlation equation coefficient for component type i from Table 200-5
SV_n = screening value for component n
βi = correlation equation exponent for component type i from Table 200-5
t = time (hours) component has been leaking – default value is time from last screening

(ii) For screening values greater than 9,999 ppmv, the operator shall calculate the VOC emissions using Equation 200-17.

$$E_{VOCP} = \sum_{i=1}^{6} CC_i \times PF_{iP} \times t$$ **Equation 200-17**

Where:

E_{VOCP} = VOC emissions for components pegged over SV 9,999 ppmv (kg/screening period)
i = component type (1=valve, 2=pump seal, 3=others, 4=connector, 5=flange, 6=open-ended line)
CC_i = number of i components pegged over 9,999 ppmv
PF_{iP} = VOC emission factor (kg/hr) for component type i pegged over 9,999 ppmv from Table 200-5
t = time component has been leaking (hours) – default value is time since last screening

(C) The operator shall calculate CH_4 emissions using Equation 200-18. Operators shall use system specific determinations of gas composition and methane content (refinery fuel gas, natural gas, associated gas, flexigas, low Btu gas), where available, to determine a

CF_{VOC} value. When representative data is not available, operators shall use the default value of 0.6 for CF_{VOC}.

$$CH_4 = \sum_{1}^{n} \left(E_{VOC-0} + E_{VOC-LC} + E_{VOCP}\right)_n \times CF_{VOC} \times 0.001 \qquad \textbf{Equation 200-18}$$

Where:

CH_4	=	methane emissions (metric tons/year)
n	=	mumber of screenings/year
E_{VOC-0}	=	zero component VOC emissions (kg/screening period)
E_{VOC-LC}	=	leaking component VOC emissions (kg/screening period)
E_{VOCP}	=	VOC emissions for components pegged over 9,999 ppmv (kg/screening period)
CF_{VOC}	=	VOC to CH_4 conversion factor (default CF_{VOC}=0.6)
0.001	=	conversion factor – kg to metric tons

WCI.204 Monitoring Requirements:

(a) ***Catalyst Regeneration***.

(1) For FCCUs and fluid coking units, the operators shall measure the following parameters using methods that comply with the measurement accuracy provisions in WCI.2(g).

(A) The daily oxygen concentration in the oxygen enriched air stream inlet to the regenerator.
(B) Continuous measurements of the volumetric flow rate of air and oxygen enriched air entering the regenerator.
(C) Continuous measurement of the volumetric flow rate of exhaust gas leaving the regenerator.
(D) Continuous measurements of the CO_2, CO and O_2 concentrations in the regenerator exhaust gas.
(E) Daily measurements of the carbon content of the coke burned.
(F) The number of days of operation.

(2) For periodic catalyst regeneration, the operators shall measure the following parameters using methods that comply with the measurement accuracy provisions in WCI.2(g).

(A) The mass of catalyst regenerated in each regeneration cycle.
(B) The weight fraction of carbon on the catalyst prior to and after catalyst regeneration.

(3) For continuous catalyst regeneration in operations other than FCCUs and fluid cokers, the operators shall measure the following parameters using methods that comply with the measurement accuracy provisions in WCI.2(g).

(A) The hourly catalyst regeneration rate.
(B) The weight fraction of carbon on the catalyst prior to and after catalyst regeneration.
(C) The number of hours of operation.

(b) ***Process vents.*** Operators shall measure the following parameters for each process vent using methods that comply with the measurement accuracy provisions in WCI.2(g).

(1) The vent flow rate for each venting event.
(2) The molar fraction of CO_2, N_2O, and CH_4 in the vent gas stream during each venting event.
(3) The duration of each venting event.

(c) ***Asphalt Production.*** Operators shall measure the mass of asphalt blown using methods that comply with the measurement accuracy provisions in WCI.2(g).

(d) ***Sulfur Recovery.*** The operator shall measure the volumetric flow rate of acid gas to the SRU using methods that comply with the measurement accuracy provisions in WCI.2(g). If using source specific molecular faction value instead of the default factor, the operator shall conduct an annual test of the CO_2 content using methods approved by [insert jurisdiction]. The operator shall submit a test plan to the [insert jurisdiction] for approval. Once approved, the annual tests shall be conducted in accordance with the approved test plan under the supervision of the [*insert jurisdiction*].

(e) ***Flares and Other Control Devices.*** The operator shall measure:

(1) The volume of gas destroyed annually determined to accuracy of ± 7.5%.
(2) The carbon content using methods that comply with the measurement accuracy provisions in WCI.2(g).

(f) ***Storage Tanks.*** The operator shall measure the annual throughput of crude oil, naphtha, distillate oil, asphalt, and gas oil for each storage tank using flow meters that comply with the measurement accuracy provisions in WCI.2(g).

(g) ***Wastewater Treatment.*** Operators shall measure the following parameters using methods that comply with the measurement accuracy provisions in WCI.2(g).

(1) The daily volume of waste water treated.
(2) The quarterly chemical oxygen demand of the wastewater.
(3) The amount of sludge removed and the organic content of the sludge.
(4) The quarterly nitrogen content of the wastewater.

(h) ***Oil-Water Separators.*** Operators shall measure the daily volume of waste water treated by the oil-water separators using methods that comply with the measurement accuracy provisions in WCI.2(g).

(i) ***Equipment Leaks.*** Operators shall measure screening values for each valve, pump seal, connector, flange, and open-ended line used in natural gas, refinery fuel gas, and PSA off-gas systems using the methods specified in CAPCOA (1999) Method 3: Correlation Equation Method and an instrument capable of detecting methane. Operators shall conduct screenings at the frequency interval required by [*insert jurisdiction*].

[Comparability of the Canadian regulations to the leak detection and repair r regulations under 40 CFR 63, Subpart CC and 40 CFR 60, Subpart VV is under determination. These U.S EPA regulations require initially monthly monitoring for valves and pumps, which may be reduced to quarterly, semi-annual, or annual based on the percentage of leaking components.]

Table 200-1. Coke burn rate material balance and conversion factors		
	(kg min)/(hr dscm %)	**(lb min)/(hr dscf %)**
K_1	0.2982	0.0186
K_2	2.0880	0.1303
K_3	0.0994	0.0062

Table 200-2. Default MCF Values for Industrial Wastewater			
Type of Treatment and Discharge Pathway or System	**Comments**	**MCF**	**Range**
Untreated			
Sea, river and lake discharge	Rivers with high organic loading may turn anaerobic, however this is not considered here	0.1	0 - 0.2
Treated			
Aerobic treatment plant	Well maintained, some CH_4 may be emitted from settling basins	0	0 – 0.1
Aerobic treatment plant	Not well maintained, overloaded	0.3	0.2 – 0.4
Anaerobic digester for sludge	CH_4 recovery not considered here	0.8	0.8 – 1.0
Anaerobic reactor	CH_4 recovery not considered here	0.8	0.8 – 1.0
Anaerobic shallow lagoon	Depth less than 2 meters	0.2	0 – 0.3
Anaerobic deep lagoon	Depth more than 2 meters	0.8	0.8 – 1.0

For CH_4 generation capacity (B) in kg CH_4/kg COD, use default factor of 0.25 kg CH_4/kg COD.

The emission factor for N_2O from discharged wastewater (EF_{N2O}) is 0.005 kg N_2O-N/kg-N.

MCF = methane correction factor – the fraction of waste treated anaerobically.
COD = chemical oxygen demand (kg COD/m^3).

Table 200-3. Emission Factors for Oil/Water Separators	
Separator Type	**Emission factor (EF_{sep})[a] kg NMHC/m^3 wastewater treated**
Gravity type - uncovered	1.11e-01
Gravity type - covered	3.30e-03
Gravity type – covered and connected to destruction device	0
DAF[b] of IAF[c] - uncovered	4.00e-03[d]
DAF or IAF - covered	1.20e-04[d]
DAF or Iaf – covered and connected to a destruction device	0

a. EFs do not include ethane
b. DAF = dissolved air flotation type
c. IAF = induced air flotation device
d. EFs for these types of separators apply where they are installed as secondary treatment systems

Table 200-4. Data for Preparing the Asphalt Chemical Database	
Parameter	**Database Entry**
Liquid Molecular Weight	**1000**
Vapor Molecular Weight	**105**
Liquid Density (lb/gal. at 60 ^oF)	**8.0925**
Antoine's Equation Constants (using K)	**A = 75350.06**
	B = 9.00346

Table 200-5. Gas Service Components Fugitive Emissions			
Component Type / Service Type	**Default Zero Factor (kg/hr)**	**Correlation Equation (kg/hr)**	**Pegged Factor (kg/hr)**
			10,000 ppmv
	Zf_{i0}	**σ_i and β_i**	**(SV > 9,999) $PF_{iP\text{-}10}$**
Valves (1)	7.8×10^{-6}	$2.27 \times 10^{-6}(SV)^{0.747}$	0.064
Pump seals (2)	1.9×10^{-5}	$5.07 \times 10^{-5}(SV)^{0.622}$	0.089
Others (3)	4.0×10^{-6}	$8.69 \times 10^{-6}(SV)^{0.642}$	0.082
Connectors (4)	7.5×10^{-6}	$1.53 \times 10^{-6}(SV)^{0.736}$	0.030
Flanges (5)	3.1×10^{-7}	$4.53 \times 10^{-6}(SV)^{0.706}$	0.095
Open-ended lines (6)	2.0×10^{-6}	$1.90 \times 10^{-6}(SV)^{0.724}$	0.033

ATTACHMENT 5: CEMENT MANUFACTURING

§ WCI.90 CEMENT MANUFACTURING

§ WCI.91 Source Category Definition

Cement manufacturing is comprised of all processes that are used to manufacture Portland, natural, masonry, pozzolanic, or other hydraulic cements.

§ WCI.92 Greenhouse Gas Reporting Requirements

In addition to the information required by WCI.3, the annual emissions data report shall contain the following information:

(a) Total emissions of CO_2, CH_4, and N_2O in metric tons.

(b) CO_2 process emissions from calcination (metric tons) and the following information:

(1) Clinker emission factor (kg CO_2/metric ton clinker).
(A) Quantity of clinker produced (metric tons).
(B) Total lime (CaO) content of clinker (wt. fraction).
(C) Total magnesium Oxide (MgO) content of clinker (wt. fraction).
(D) Uncalcined CaO (wt. fraction).
(E) Uncalcined MgO (wt. fraction).

(2) Cement kiln dust (CKD) emission factor (kg CO_2/metric ton CKD discarded).
(A) Plant specific CKD calcination rate (unitless ratio).
(B) Quantity of CKD discarded (metric tons).

(c) CO_2 process emissions from organic carbon oxidation (metric tons) and the following information:

(A) Amount of raw material consumed in the report year (metric tons).
(B) Organic carbon content of raw material (wt. fraction).

(d) CO_2, CH_4, and N_2O emissions from fuel combustion in all kilns combined, following the calculation methods and reporting requirements specified in WCI.93(c) (metric tons).

(e) CO_2, CH_4, and N_2O emissions from all other fuel combustion units combined (kilns excluded), following the calculation methods and reporting requirements specified in WCI.20 (metric tons).

(f) If a continuous emissions monitor is used to measure CO_2 emissions from kilns, then the requirements of paragraphs (b), (c), and (d) of this section do not apply for CO_2. Cement plants that measure CO_2 emissions using CEMS shall report fuel usage by fuel type for kilns.

(g) Operators of cement plants shall also comply with the reporting requirements for any other applicable source category listed at WCI.1(a), including but not limited to the following:

(1) Coal fuel storage as specified in WCI.100.
(2) Electricity generating as specified in WCI.40.
(3) Cogeneration systems as specified in WCI.50.

§ WCI.93 Calculation of Greenhouse Gas Emissions From Kilns

(a) Determine CO_2 emissions as specified under either paragraph (a)(1) or (a)(2) of this section.

(1) Use a continuous emissions monitoring system (CEMS) as specified in WCI.23(d).
(2) Calculate the sum of CO_2 process emissions from kilns and CO_2 fuel combustion emissions from kilns using the calculation methodologies specified in paragraph (b) and (c) of this section**.**

(b) Process CO_2 Emissions Calculation Methodology. Calculate total CO_2 process emissions as the sum of emissions from calcination, using the method specified in paragraph (b)(1) of this section; and from organic carbon oxidation, using the method specified in paragraph (b)(2) of this section (Equation 90-0).

$$CO_2\text{ process} = CO_2\text{ calcination} + CO_2\text{ raw material} \qquad \textbf{Equation 90-0}$$

(1) Calcination Emissions. Calculate CO_2 process emissions from calcination using Equation 90-1 and a plant-specific clinker emission factor and a plant-specific cement kiln dust (CKD) emission factor as specified in this section.

$$CO_{2-C} = \sum_{i=1}^{12} [(Cli)\times(EF_{Cli})]+[(Q_{CKD})\times(EF_{CKD})] \qquad \textbf{Equation 90-1}$$

Where:

$CO_{2\text{-}C}$	=	CO_2 emissions from calcination, metric tones.
Cli	=	Monthly quantity of clinker produced, metric tons.
EF_{Cli}	=	Monthly clinker emission factor, metric tons CO_2/metric ton clinker computed as specified in paragraph (b)(1)(A) of this section.
Q_{CKD}	=	Monthly quantity CKD discarded (i.e., not recycled to the kiln), metric tons.
EF_{CKD}	=	Monthly CKD emission factor, computed as specified in paragraph (b)(1)(B) of this section.

(A) Monthly Clinker Emission Factor. Calculate a monthly plant-specific clinker emission factor (EF_{Cli}) for each report year based on the percent of measured CaO and MgO content in the clinker and using Equation 90-2.

$$\begin{aligned} EF_{Cli} &= [(CaO\ content - uncalcined\ CaO)\times Molecular\ ratio\ of\ CO_2/CaO] \\ &+ [(MgO\ Content - uncalcined\ MgO)\times Molecular\ ratio\ of\ CO_2/MgO] \end{aligned} \qquad \textbf{Equation 90-2}$$

Where:

CaO Content (by weight)	=	Total CaO content of Clinker (including calcined and uncalcined) (wt. fraction).
Non-carbonate CaO (by weight)	=	Uncalcined CaO of Clinker (wt. fraction).
Molecular ratio of CO_2/CaO	=	0.785.
MgO Content (by weight)	=	Total MgO content of Clinker (including calcined and uncalcined) (wt. fraction).

Non-carbonate MgO = Uncalcined MgO of Clinker (wt. fraction).
Molecular ratio of CO_2/MgO = 1.092.

(B) Monthly CKD Emission Factor. If CKD is generated and not recycled back to the kiln, then calculate a monthly plant-specific CKD emission factor. The CKD emission factor shall be calculated using Equation 90-3 and a plant-specific CKD calcination rate as specified in Equation 90-4.

$$EF_{CKD} = \frac{\frac{EF_{Cli}}{1 + EF_{Cli}} \times d}{1 - \left(\frac{EF_{Cli}}{1 + EF_{Cli}} \times d\right)} \qquad \textbf{Equation 90-3}$$

Where:

EF_{CKD} = Monthly CKD emission factor, kg CO_2/metric ton CKD discarded.
EF_{Cli} = Clinker emission factor, determined according to Equation 90-2.
d = CKD calcination rate, determined according to Equation 90-4.

$$d = 1 - \frac{fCO_{2CKD} \times (1 - fCO_{2RM})}{(1 - fCO_{2CKD}) \times fCO_{2RM}} \qquad \textbf{Equation 90-4}$$

Where:

d = CKD calcination rate (unitless ratio).
fCO_{2CKD} = Weight fraction of carbonate CO_2 in the CKD.
fCO_{2RM} = Weight fraction of carbonate CO_2 in the raw material.

(2) Organic Carbon Oxidation Emissions. Calculate CO_2 process emissions from the total organic content in raw materials by using Equation 90-5.

$$CO_{2-RM} = TOC_{RM} \times RM \times 3.664 \qquad \textbf{Equation 90-5}$$

Where:

CO_{2-RM} = CO_2 emissions from raw material oxidation, metric tons.
TOC_{RM} = Total organic carbon content in raw material (wt. fraction), measured using the method in WCI.94(c) or using a default of 0.002 (0.2%).
RM = Amount of raw material consumed (metric tons/yr).
3.664 = The CO_2 to carbon molar ratio.

(c) Fuel Combustion Emissions in Kilns. Calculate CO_2, CH_4, and N_2O emissions from stationary fuel combustion following the calculation methods specified in WCI.20. Cement plants that combust pure biomass-derived fuels and combust fossil fuels only during periods of start-up, shut-down, or malfunction may report CO_2 emissions from fossil fuels using the emission factor methodology in WCI.23(a). "Pure" means that the biomass-derived fuels account for 97 percent of the total amount of carbon in the fuels burned.

§ WCI.94 Sampling, Analysis, and Measurement Requirements

Note: The sampling, analysis, and measurement procedures will be standardized for each calculation input to reduce variation between facilities within the cement industry. Material sampling frequency and technique is distinct from material analysis conducted in a laboratory. The WCI is seeking stakeholder feedback on this topic and is specifically interested in proposals from stakeholders with expertise in this industry related to sampling, analysis and measurement procedures already in use at these facilities for the material quantities and/or concentrations listed below. Those proposing procedures should include sampling frequency and technique, indicate the uncertainty associated with the procedures, and describe the application of the procedure at a facility.

(a) Determine the plant-specific weight fractions of CaO, MgO, uncalcined CaO, and uncalcined MgO in clinker from each kiln using *(method to be determined).* Determine the weight fraction of carbonate CO_2 in the CKD and the weight fraction of carbonate CO_2 in the raw material. The monitoring must be conducted monthly for each kiln from a clinker sample drawn from bulk clinker storage.

(b) If not using the default value of 0.002 for TOC_{RM} in Equation 90-5, the total organic carbon contents of raw materials must be determined annually *[monthly?]* using ASTM Method C114-07. The analysis must be conducted on sample material drawn from bulk raw material storage for each category of raw material.

(c) The quantity of clinker produced must be determined by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.

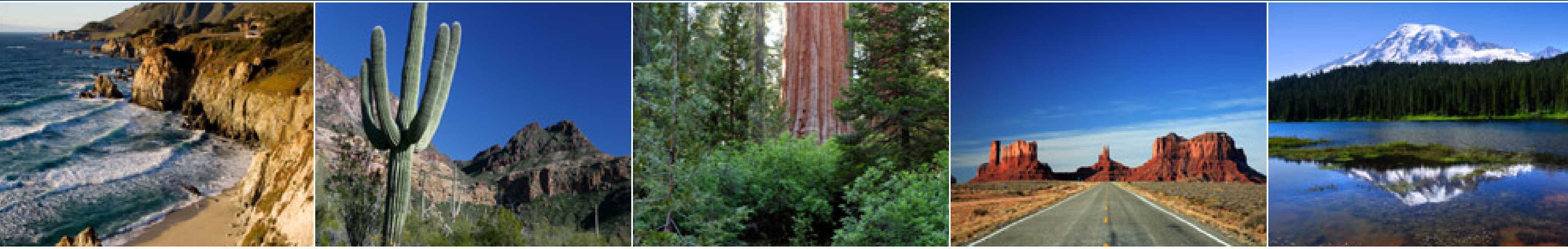
(d) The quantity of CKD discarded must be determined by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.

(e) The quantity of raw materials consumed (i.e. limestone, sand, shale, iron oxide, and alumina) must be determined by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.

January 13, 2009 Economic Modeling Stakeholder Teleconference

List of Commenters

WEST Associates



Economic Modeling – Next Steps

Economic Modeling Team

January 13, 2009
Conference Call

Outline of Presentation

- Status of economic modeling
- Discussion of suggestions from stakeholders on revisions to model and assumptions
- Input on priorities for sensitivity analysis in next round of modeling
- Additional comments and questions

Status of Economic Modeling

- Plans call for:
  - Expanding the model to include Manitoba, Ontario, and Quebec.
  - Addressing issues identified with the previous analysis
  - Repeating and updating analyses released in September to include all partners
  - Conducting additional sensitivity analyses
- Aim to complete and release in March
- Outcome of 3-Dec. San Francisco workshop

Summary of Decisions To Date Regarding Stakeholder Suggestions

- Conform model to 2-stage scope, 2012-2014 and 2015-2020
- Extend the model to 2030
- Update macroeconomic and/or energy price forecast
- Examine interaction of the complementary policies and cap-and-trade system
- Revise offsets and banking provisions

Summary of Decisions To Date Regarding Stakeholder Suggestions (Cont.)

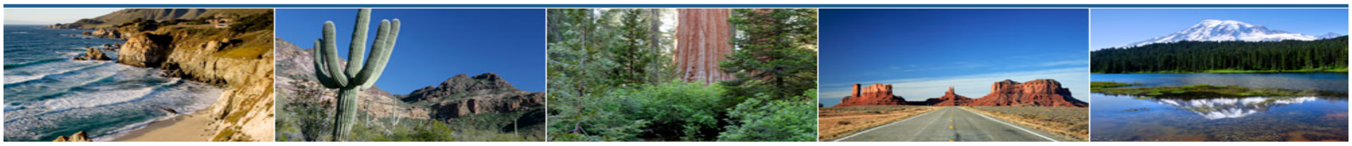
- Examine a variety of combinations of auctioned and free allocations of allowances
- Expand reporting of inputs and outputs from modeling to provide more detail on power sector, transportation sector, and effects of energy efficiency complementary policy

Input on Priorities for Sensitivity Analysis in Next Round of Modeling

- *Time did not allow this topic to be discussed at S.F. workshop*
- *Moderator will solicit participant input*

Comments and Questions

Western Climate Initiative



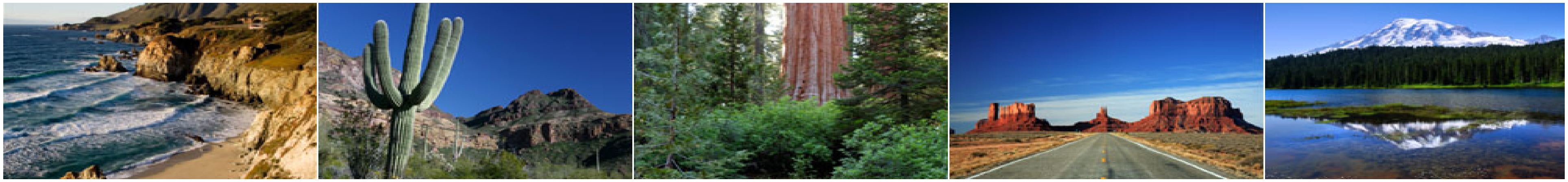
ELECTRICITY SUBCOMMITTEE
TECHNICAL WORKING SESSION

Phoenix, Arizona
January 15, 2009
9:00 a.m. to 5:00 p.m. Mountain

Location:
Sheraton Hotel Downtown
Phoenix, Arizona

AGENDA

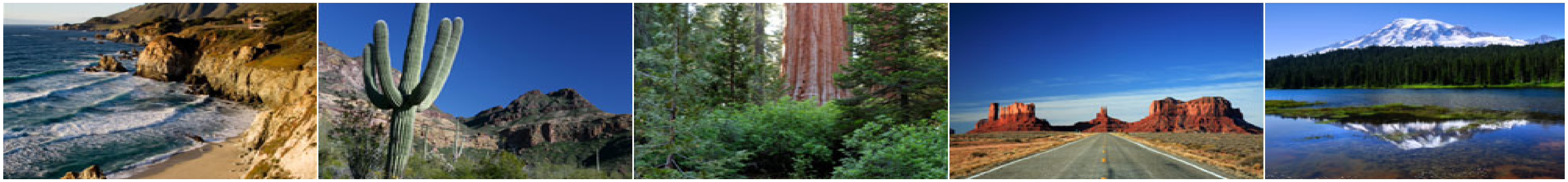
1.	**9:00 am**	**Welcome and Introductions** **David Van't Hof, Chair, WCI Electricity Subcommittee**
2.	**9:15**	**Review of the Process and Agenda**
3.	**9:30**	**Distributing Allowances and the Electricity Sector** **Scott Murtishaw, CA PUC** • **What are the distribution options?** • **What happens when states/provinces differ in their approaches to distributing allowances?**
4.	**10:00**	**Comments and Suggestions from TAG and Stakeholders**
7.	**12:00 pm**	**Lunch (On Your Own)**
8.	**1:00**	**Discussion on Allocations, continued.**
9.	**2:30 pm**	**Recap of Recent TAG Conference Calls** • **Renewable Energy Credits (RECs)** • **Common Boundary Approach** • **Default Rates**
10.	**4:15**	**Next Steps for the Electricity TAG Process**
11.	**4:45**	**Public Comment Session**
12.	**5:00**	**Adjourn**



GHG Allowance Allocation Options in the Electricity Sector

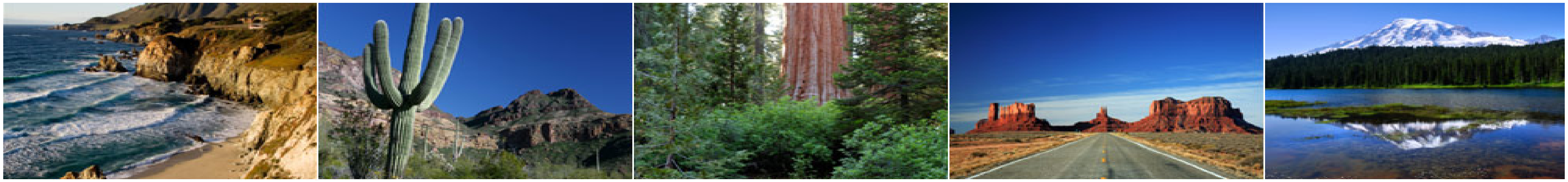
Scott Murtishaw
California Public Utilities Commission

WCI Technical Working Session
Phoenix, Arizona
January 15, 2009



Outline of Presentation

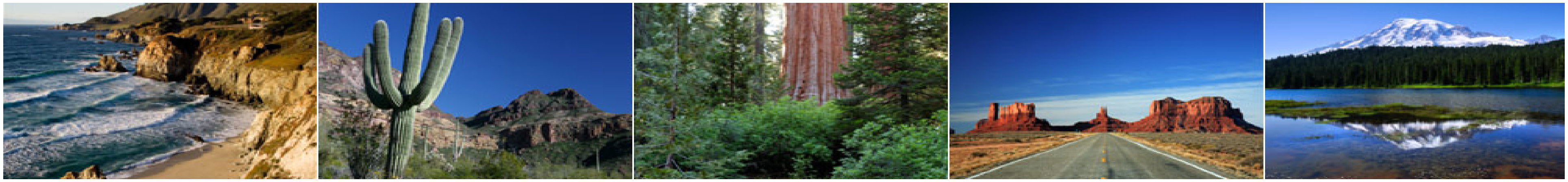
- Suggested Evaluation Criteria
- Overview of Basic Allocation Options
- Windfall Profits
  - Why and how they occur
  - Rough calculation of potential consumer losses for some WCI Partners
- Mechanics and Evaluation of Basic Allocation Options and Variants
- Possible Effects of Non-Harmonized Allocation Policies



Some WCI Allocation Purposes and Objectives

<u>From the WCI Design Recommendations:</u>

- Funding energy efficiency and renewable energy incentives
- Funding RDD&D of carbon capture, renewable and efficiency technologies
- Reducing consumer impacts, especially for low-income consumers;
- Providing for worker transition and green jobs;
- Achieving emission reductions in communities that experience disproportionate environmental impacts;
- Providing transition assistance to industries;
- Recognizing early actions to reduce emissions and/or;
- Promoting economic efficiency



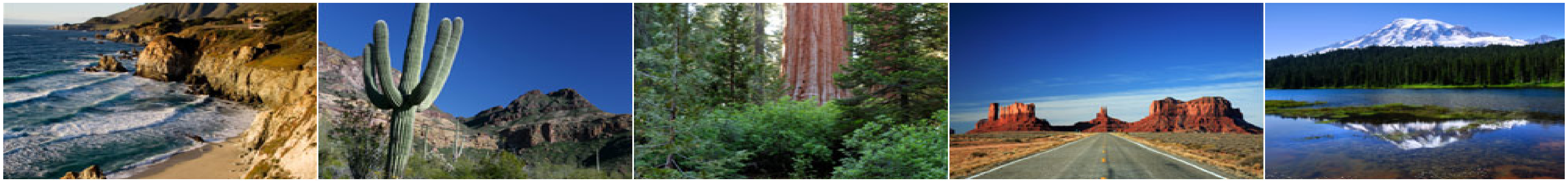
Suggested Evaluation Criteria

Principal Criteria

- Total consumer costs: Impacts on retail electricity customers
- Distribution of consumer costs: Equity among customers of retail providers

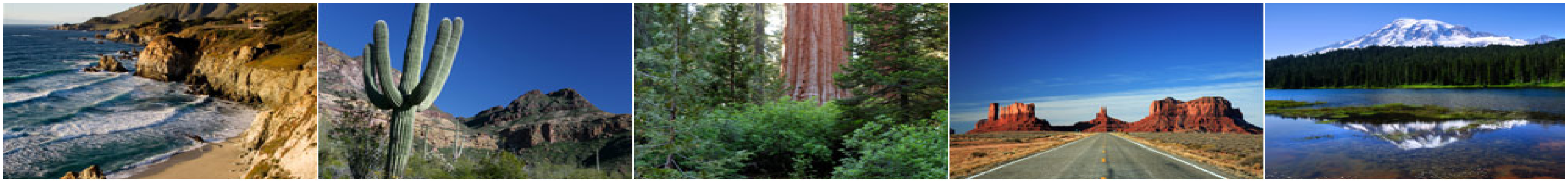
Additional Criteria

- Administrative simplicity/transparency
- Accommodation of new entrants



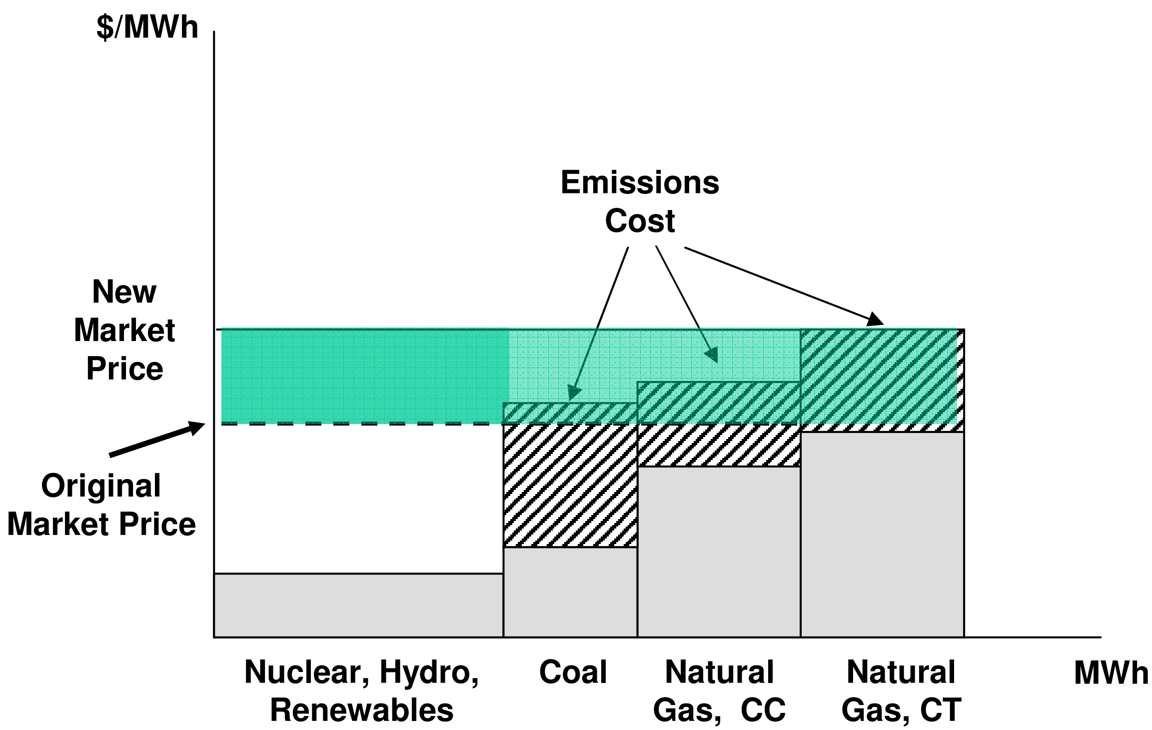
Basic Allocation Options

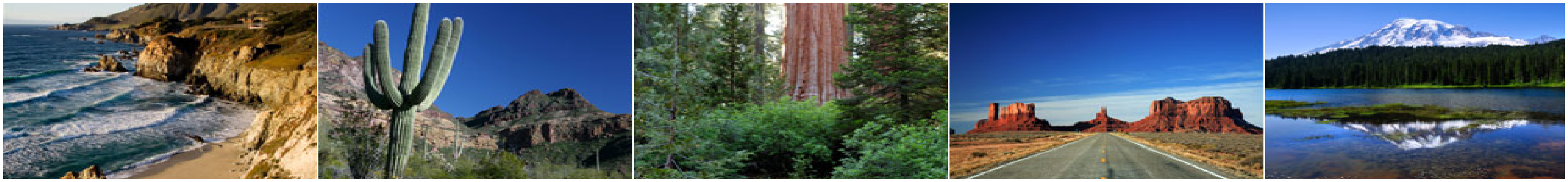
- Administrative (usually free) allocation
  - Emission-based, historic base year(s) ("grandfathering")
  - Output-based, usually with updating
  - Input-based, usually with updating
- Auctioning
- Hybrids that combine one or more options



Explanation of Windfall Profits

…in situations where retail providers make market purchases from independent generators or deliverers

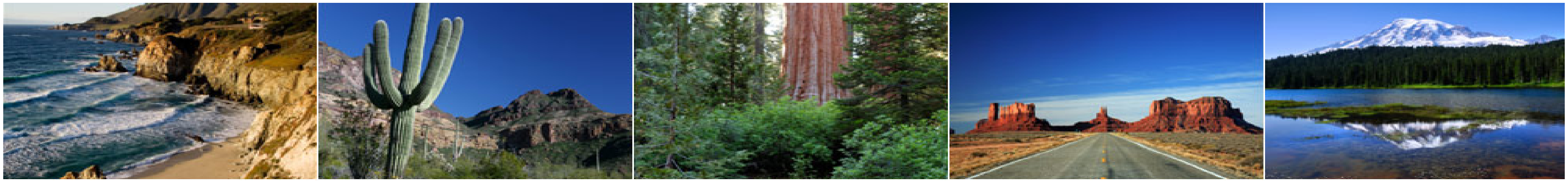




Rough Estimates of Potential Windfalls

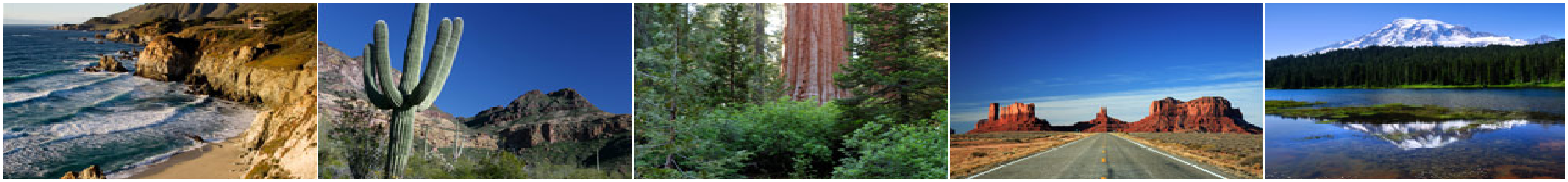
	Generation to Serve Load, TWh	Market Purchases, TWh	Market Purchase Share	Windfall Potential, Million US $
CA	295	170	58%	$1,700
WA	95	10	11%	$100
ON	165	60	36%	$600
BC	55	8	15%	$80
NM	23	2	9%	$20

Assumptions: \$20/tonne allowance price, gas on margin at 500 kg CO_2/MWh, and full pass-through of opportunity costs



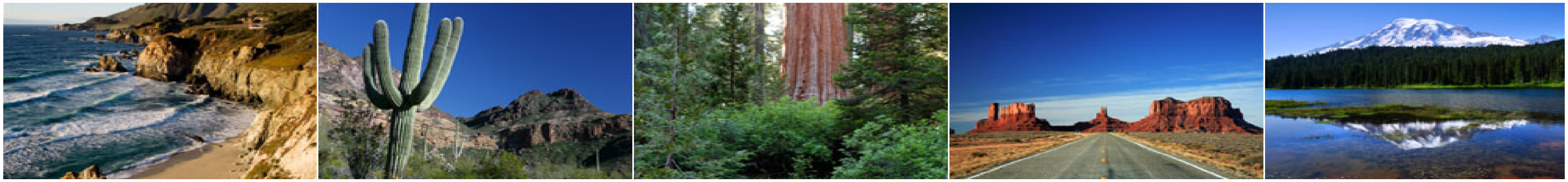
Allocation Options in this Analysis

- Administrative allocation to deliverers
  - Emission-Based Allocation (EBA)
  - Output-Based Allocation (OBA): delivered MWh
- Auctioning: Allocation of allowances or auction revenue rights to retail providers with subsequent auctioning
  - Emission-Based: emissions of sources used to serve load
  - Sales-Based



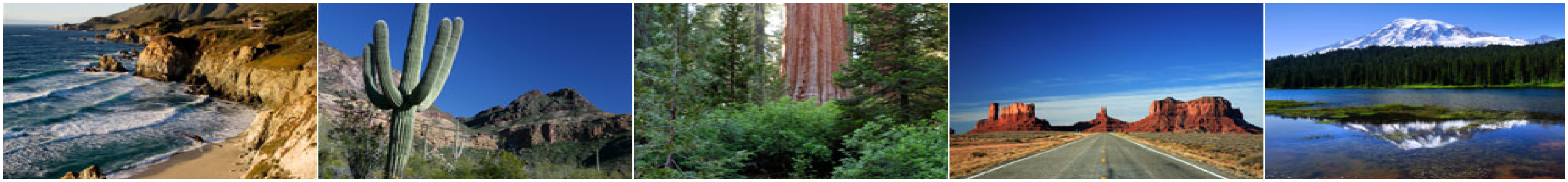
Emission-Based Allocation Mechanics

- Provide allowances to deliverers on an historic emissions basis
- Possible multi-year baseline to smooth variations due to hydro production and weather
- All deliverers receive proportional declining allowances
- Awarded in perpetuity based on historic period
- Administrative determination of baseline and historic emissions from unspecified purchases



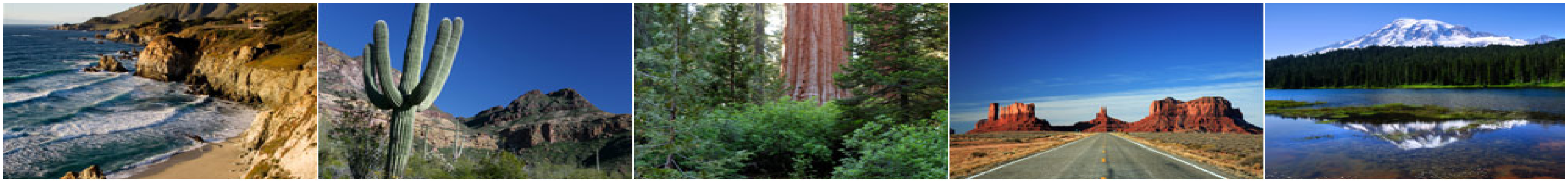
Evaluation of Emission-Based Allocation

- **Total Consumer Cost:** Higher costs for market-dependent customers; for fully-resourced, it depends on provider decision of how to use allowance value
- **Distribution of Costs**: Limited distributional impacts among customers
- **Administrative Simplicity:** Simple, except administrative decision on baseline
- **New Entrants**: Discriminates against them without set-aside provision



Output-Based Allocation Mechanics

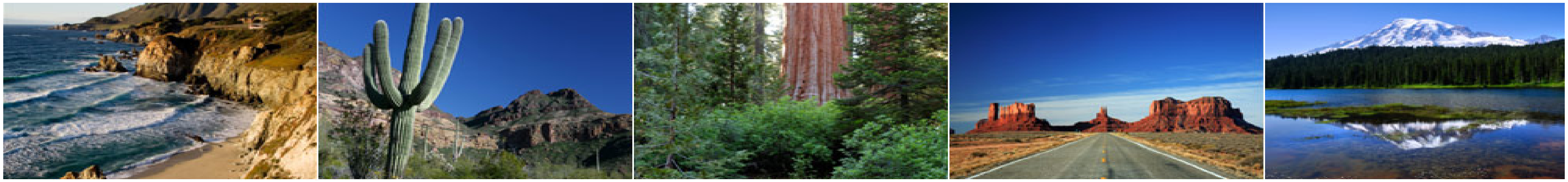
- Freely Allocate Allowances on a Per MWh Basis
- Measurement of Output Updated Regularly
- Benchmarking vs. Fixed-Cap
  - Benchmarking is allocating at a fixed rate per unit of output
  - Total number of allowances allocated cannot be known in advance
  - Fixed-cap output-based allocation distributes a fixed number of allowances based on shares of a prior year’s output



Hypothetical Fixed-Cap OBA

Assumes 100 Million Ton Cap in 2012

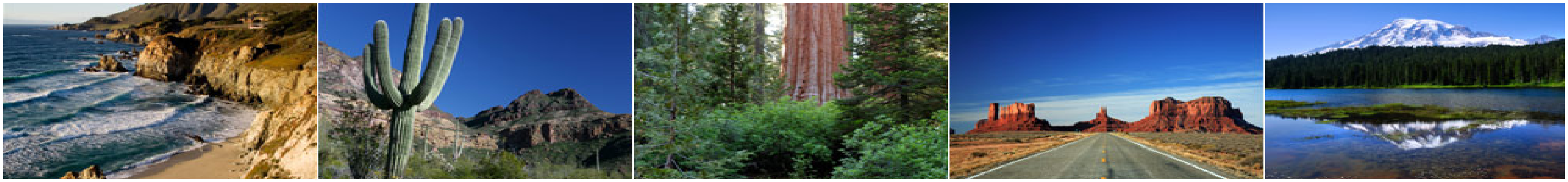
	Deliveries in 2011, Million MWh	Share of 2011 Deliveries, Million MWh	2012 Allowances Received, Millions
Deliverer A	100	50%	50
Deliverer B	75	37.5%	37.5
Deliverer C	25	12.5%	12.5
Total	**200**	**100%**	**100**



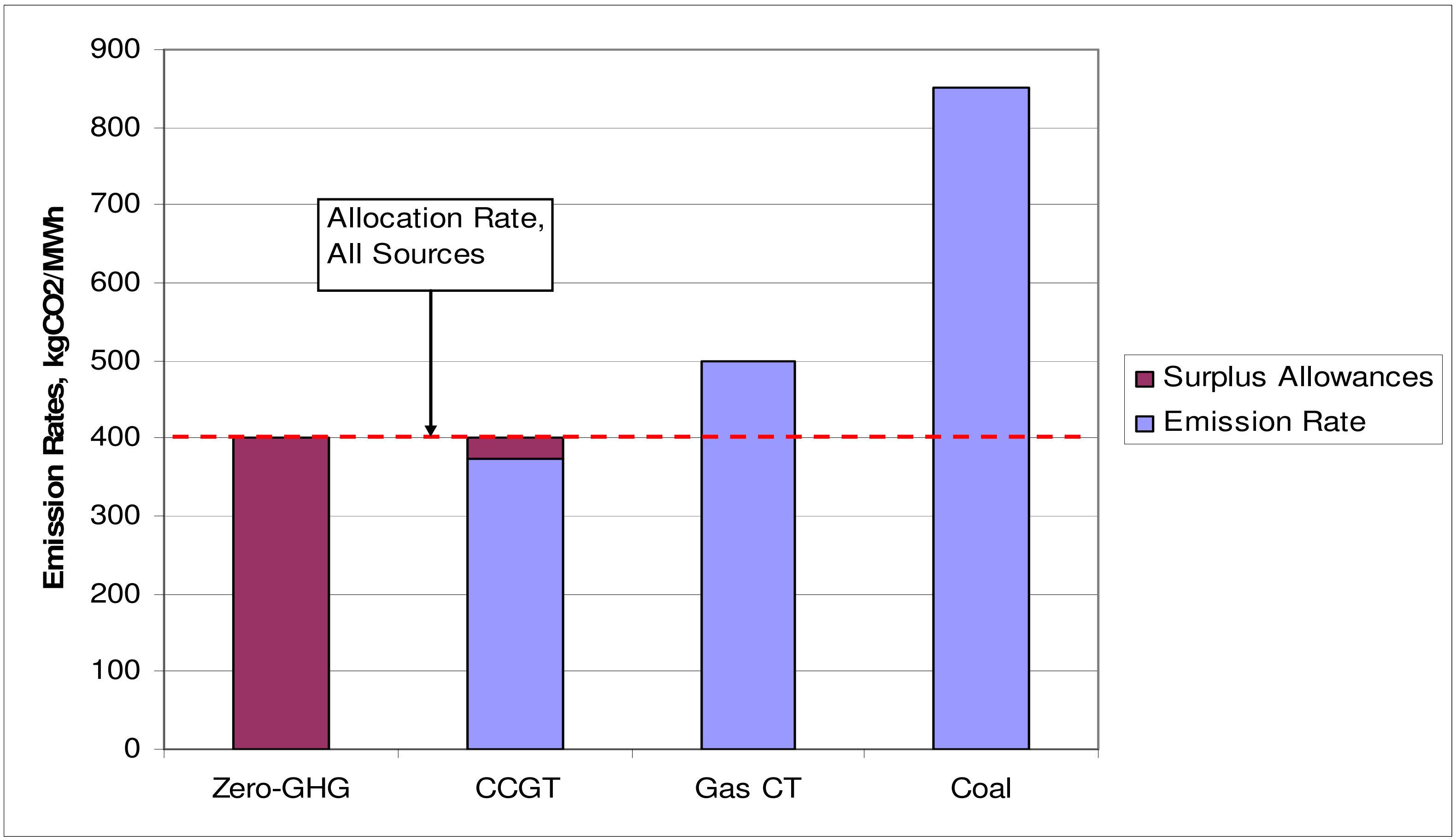
Pure Output-Based Allocation

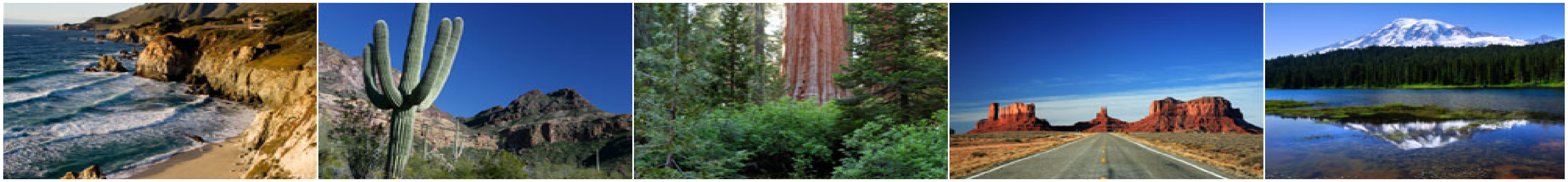
- Allocation to all generation
- Uniform level of allowances provided to deliverers for each unit of generation

$$\frac{\text{(Total Capped Emission Level in 2012, tons CO2e)}}{\text{(Total Generation in 2011, MWh)}} = \text{Allowances per MWh}$$



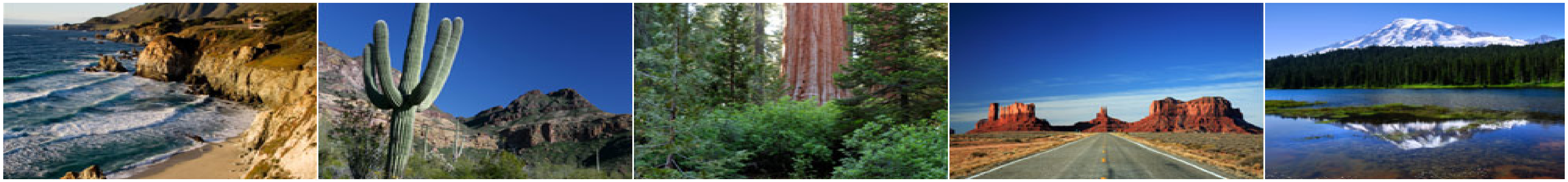
Pure OBA, Impact by Resource Type





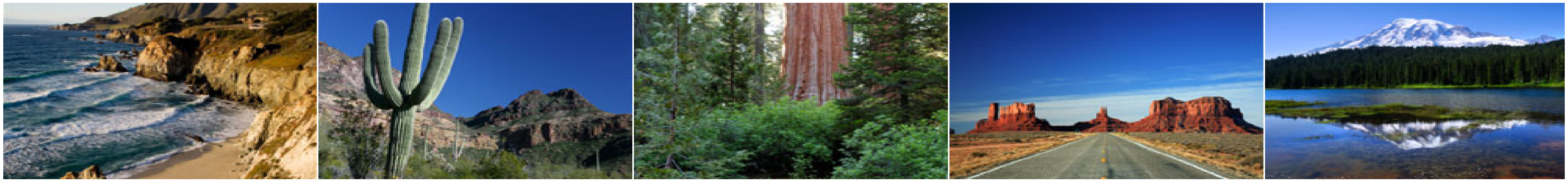
Evaluation of Pure OBA

- **Total Consumer Cost:** Dampens energy price increases, but economic efficiency losses and higher allowance prices
- **Distribution of Costs**: Disadvantages customers of retail providers with high GHG portfolios
- **Administrative Simplicity:** Transparent, simple formula for allocating allowances
- **New Entrants**: With frequent updating, easily accommodates new entrants



Variations of OBA

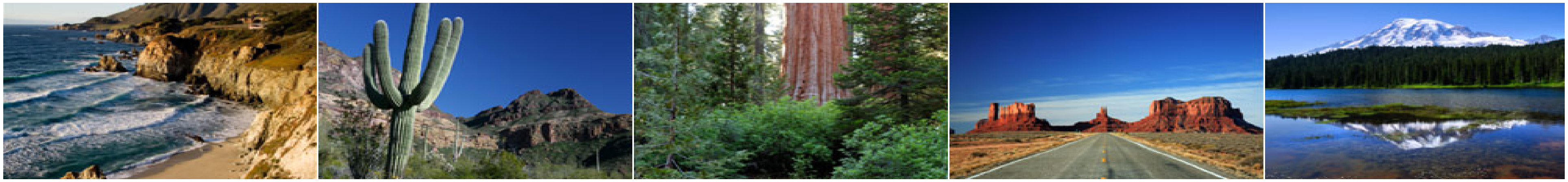
- Restricting Generator Eligibility
  - Exclude all, or a subset of, zero-GHG deliverers
- Fuel Differentiated Output Weighting
  - Higher per MWh allocation rate to high emitters



Hypothetical Fuel-Differentiated OBA

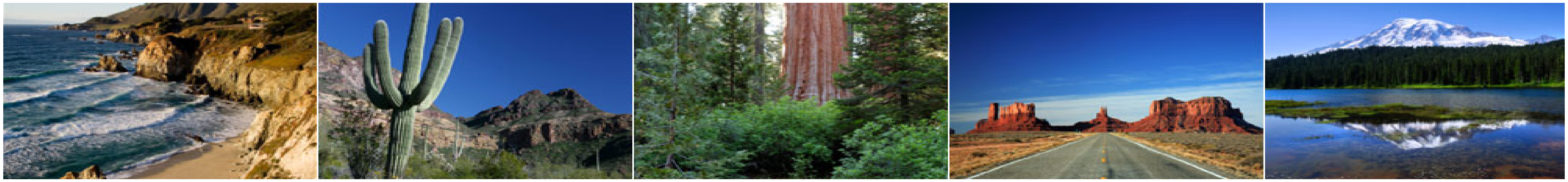
Weighting Factor: Gas-Fired = 1, Coal-Fired = 2

	Unweighted Generation			Weighted Generation		
Generation Fuel Type	**Deliveries in 2011, (million MWh)**	**Share of 2011 Deliveries**	**2012 Allowances Received, (In million tons)**	**Weighted Deliveries in 2011, (million MWh)**	**Share of 2011 Weighted Deliveries**	**2012 Allowance Received, (in million tons)**
Gas-Fired	**100**	**66.7%**	**66.7**	**100**	**50%**	**50**
Coal-Fired	**50**	**33.3%**	**33.3**	**100**	**50%**	**50**



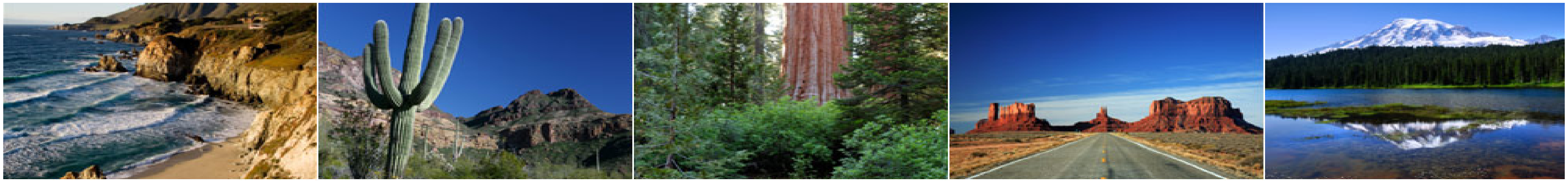
Evaluation of Fuel-Differentiated OBA

- **Total Consumer Cost:** Dampens energy price increases, but economic efficiency losses and higher allowance prices
- **Distribution of Costs**: Minimizes distributive effects
- **Administrative Simplicity:** Relatively simple, but necessitates determination of weighting factors
- **New Entrants**: With frequent updating, easily accommodates new entrants



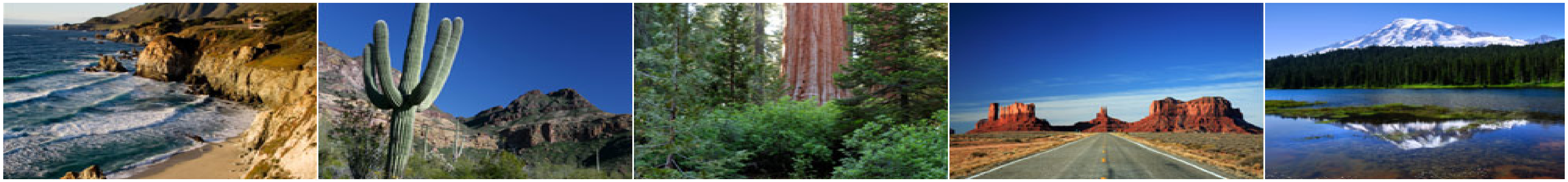
Auctioning Mechanics

- Auctions of GHG allowances conducted by state/provincial agencies or their agents
- Entities with a compliance obligation buy allowances according to anticipated need from the auction and/or the secondary market



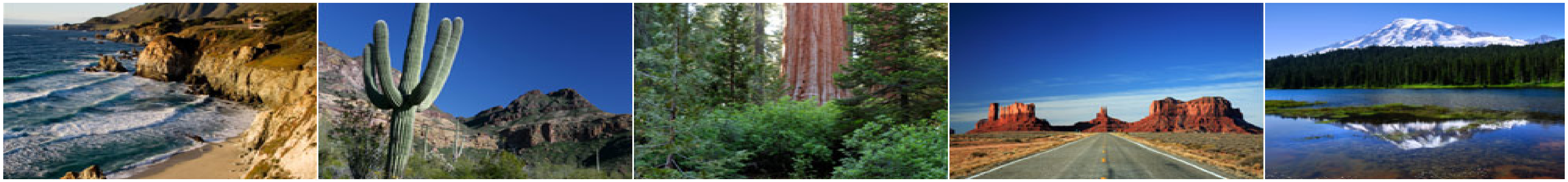
Description of a Pure Auction Allocation

- All allowances are distributed by auction
- Assumes no direct refund of auction revenues for electricity customer benefit
- Assumes auctions revenues provide benefits relatively evenly across jurisdiction



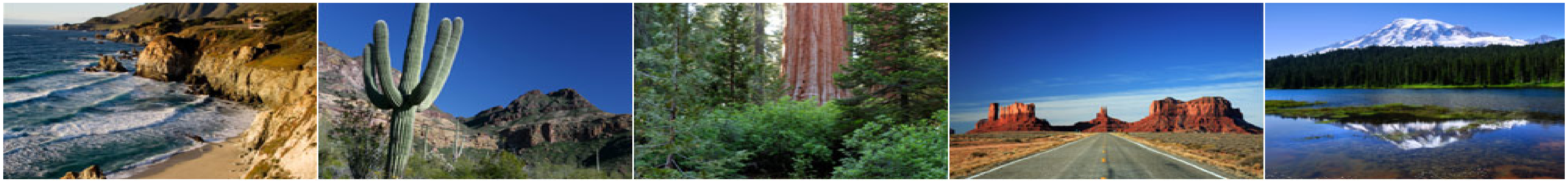
Evaluation of Pure Auction

- **Total Consumer Cost**: The need for deliverers to recover allowance costs raises the cost of electricity to consumers
- **Distribution of Costs**: Customers of high-GHG retail providers experience larger cost increases than customers of low-GHG retail providers
- **Administrative Simplicity**: Requires no baselines for deliverers or retail providers
- **New Entrants**: No barrier to market entry for new deliverers



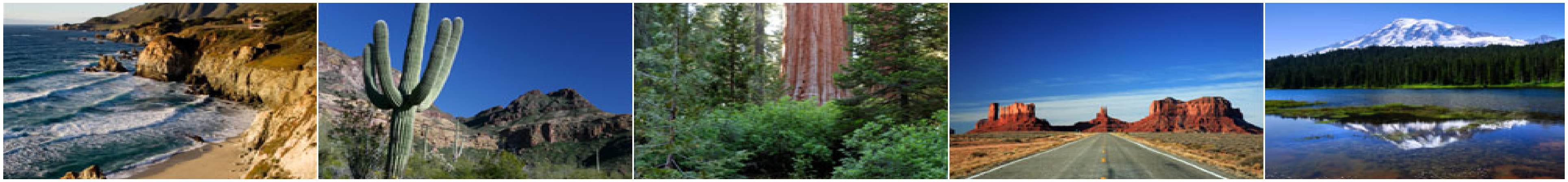
Mechanics for Recycling Auction Revenue to Retail Providers

- A certain number of allowances per vintage are reserved for the electricity sector
- Either allowances or auction revenue rights are allocated to retail providers
- Retail providers must auction allowances received through this mechanism in the centralized auction



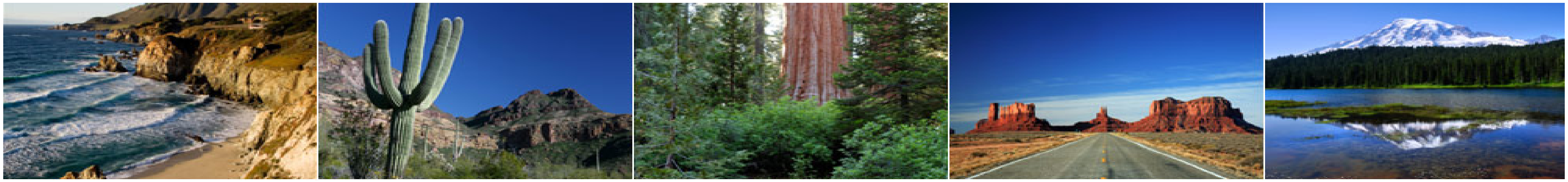
Variations on Auctioning with Revenue Recycling

- **Emission-Based**: Auction revenue given to retail providers on the basis of emissions associated with serving load in a fixed, historical base period
- **Sales-Based**: Auction revenue given to retail providers on the basis of retail sales
  - Verified energy savings could also qualify for auction revenues



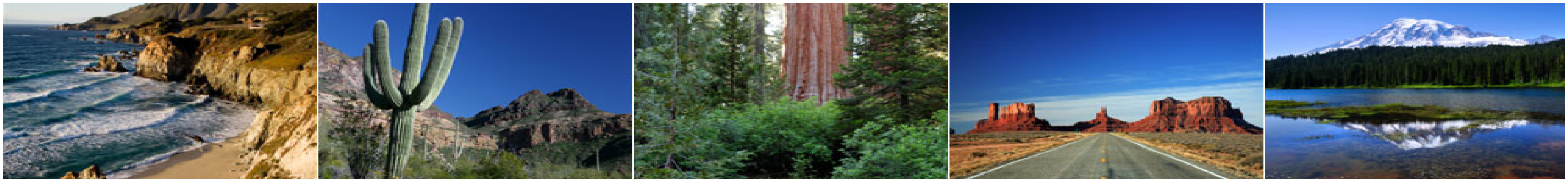
Evaluation of Emission-Based Revenue Recycling

- **Total Consumer Cost**: Relatively low cost to consumers
- **Distribution of Costs**: Minimizes distributive effects
  - In the long-run, retail providers with fast-growing loads would be disadvantaged
- **Administrative Simplicity**: Need to calculate base period emissions for all retail providers adds some additional complexity
- **New Entrants**: Disadvantages new retail providers (ESPs or new utilities carved from existing territories) without reallocation of allowance revenues



Evaluation of Sales-Based Revenue Recycling

- **Total Consumer Cost**: Relatively low cost to consumers
- **Distribution of Costs**: High-GHG retail providers spend much more on allowances (whether directly or embedded in market prices) than they receive in auction revenue
  - Distribution of revenue on “net” load (subtraction of load served by utility-owned nuclear and hydro resources) is one method to consider
- **Administrative Simplicity**: Allocating on a sales basis is administratively simple
- **New Entrants**: Without a set-aside mechanism, dis-advantages new retail providers until allocation update

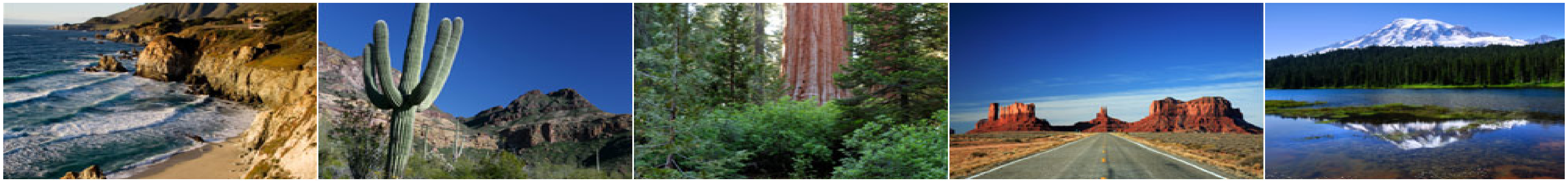


Summary of Options

✓ = performs well, ✗ = performs poorly

Allocation Method	Total Consumer Cost	Distribution of Costs	Admin Simplicity	New Entrants
Pure Emission-Based	✗/✓[1]	✓	✓	✗
Pure Output-Based	✓	✗	✓	✓
Fuel-Diff'd Output-Based	✓	✓	✗	✓
Pure Auction	✗[2]	✗[2]	✓	✓
Emission-Based Recycling	✓	✓	✗	✗/✓[3]
Sales-Based Recycling	✓	✗	✓	✓

1 Depends on whether retail provider is market-dependent or vertically integrated
2 Depends on how the issuing jurisdiction uses the revenues
3 Performs well for new generators but not new retail providers



Consequences of Non-Harmonization

- Auctioning and EBA send the same marginal price signal to generators
- Under either auctioning or EBA, new entrants face full marginal cost
- OBA reduces the marginal price signal for both existing and new deliverers
- Generation will tend to gravitate to jurisdictions using OBA

January 15, 2009 Stakeholder Meeting, Electricity Subcommittee Technical Working Session, Phoenix, Arizona

List of Commenters

Association of Power Producers of Ontario

Arizona Utilities (APS, SRP, TEP & AEPCO)

Center for Resource Solutions

Environmental Defense Fund

Ontario Independent Electricity System Operator

Independent Energy Producers Association

NextEra Energy Resources

Northern California Power Agency

NW Energy

Pacific Gas & Electric Company

PNGC Power Cooperative

Powerex Corporation

Public Power Council

Renewable Energy Marketers Association

Sacramento Municipal Utility District

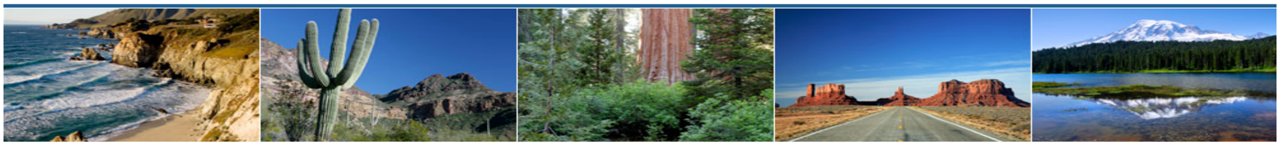
Southern California Edison

Southern California Public Power Authority

Western Climate Action Network

Western Power Trading Forum

Western Climate Initiative



ELECTRICITY COMMITTEE DISCUSSION PAPER ON FJD BOUNDARY OPTIONS FOR REGULATING ELECTRICITY IMPORTS

January 12, 2009

Scott Murtishaw, California PUC[1]

1 Introduction

This discussion paper reviews various boundary, monitoring, and enforcement options for regulating electricity imported from non-WCI locations. The WCI Design Recommendations released on September 23 define the point of regulation for imported power imported as:

> For power that is generated outside the WCI jurisdictions (or generated by a federal entity or on tribal lands) for consumption within a WCI Partner jurisdiction, the FJD [first jurisdictional deliverer] is the first entity that delivers that electricity over which the consuming WCI partner jurisdiction has regulatory authority.[2]

The Electricity Committee and stakeholders in the electricity sector have determined that this approach to implementing the FJD point of regulation could negatively affect liquidity in the wholesale power market. Other approaches to implementing the FJD point of regulation may maintain a high degree of liquidity

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[1] The author wishes to acknowledge the extensive comments received on a previous draft from Clare Breidenich, WPTF; Rob Campbell, Powerex; Mark Meldgin, PG&E; and Kevin Nordt, Grant County PUD.

[2] Western Climate Initiative, 2008. Design Recommendations for the WCI Regional Cap-and-Trade Program. http://www.westernclimateinitiative.org/ewebeditpro/items/O104F20432.PDF

in the power market and simplify the reporting and tracking procedures for electricity market participants.

The Electricity Committee has identified four basic options to regulating the emissions associated with imports from non-WCI locations.[3] The first option is an individual boundary approach as envisioned in the WCI Design Recommendations. The rest are variants of a common boundary approach that eliminates regulation of transmission paths crossing intra-WCI borders. These options are described below.

1. Option 1 is an individual boundary approach whereby the purchasing/selling entity (PSE) holding title to non-WCI generated power when it is imported into the consuming jurisdiction (state or province) is financially liable for GHG allowances regardless of who first imported the non-WCI power into the WCI.[4] The party that imports the non-WCI generated power into the consuming jurisdiction must surrender the appropriate quantity of GHG allowances to that jurisdiction. Each jurisdiction is responsible for monitoring transmission paths crossing its own borders and is responsible for collecting GHG allowances from liable entities.

2. Option 2 is a common boundary approach whereby the entity holding title to non-WCI generated power when it is initially imported into any WCI jurisdiction is financially liable for GHG allowances regardless of where within the WCI the power is ultimately consumed. The entity holding title to the non-WCI generated power when it is imported into the WCI must surrender the appropriate quantity of GHG allowances to the WCI jurisdiction where the power is consumed. The jurisdiction where the power is consumed is responsible for monitoring power delivered to its jurisdiction and is responsible for collecting GHG allowances from liable entities.

3. Option 3 is a common boundary approach whereby the entity holding title to non-WCI generated power when it is initially imported into any WCI jurisdiction is financially liable for GHG allowances regardless of where within the WCI the power is ultimately consumed. The entity holding title to the non-WCI generated power when it is imported into the WCI must surrender the appropriate quantity of GHG allowances to the WCI jurisdiction where the power is consumed. Unlike Option 2, the jurisdiction into which the power is initially imported into the WCI is responsible for

[3] Power that originates outside the WCI, is wheeled through the WCI, and then exported from the WCI is exempt under all scenarios.
[4] Power shall be deemed to have been consumed in a jurisdiction when an e-tag (or other transmission record) lists a final point of delivery in that jurisdiction.

monitoring whether non-WCI power has been delivered to a WCI jurisdiction, while the jurisdiction where the power is ultimately consumed is responsible for enforcing the collection of allowances associated with that power delivery.

4. Option 4 is a common boundary approach whereby the entity holding title to non-WCI generated power when it is initially imported into any WCI jurisdiction is financially liable for GHG allowances regardless of where within the WCI the power is ultimately consumed. The entity holding title to the non-WCI generated power when it is imported into the WCI must surrender the appropriate quantity of GHG allowances to the WCI jurisdiction into which the power is initially imported. The state/province where the power is initially imported is responsible for monitoring whether non-WCI power has been delivered to a WCI jurisdiction and is responsible for collecting GHG allowances from liable entities.

These four options are explored more fully below. Section 2 provides background information on certain aspects of wholesale power markets that are relevant to the boundary option decision. Section 3 gives a hypothetical wholesale power transaction that is used as a concrete example to ground the subsequent description of how the options could work in practice. Section 4 describes the four options in more detail using the hypothetical scenario as a common example. In addition, this section explains how the choice between an individual boundary approach and a common boundary approach could potentially impact wholesale power market liquidity. Finally, Section 5 offers some concluding thoughts on the interaction between the boundary approach and allowance apportionment as well as initial ideas on existing tools that could facilitate monitoring of non-WCI imports.

2 Power Market Attributes that Impact the Policy Discussion

Before analyzing the four approaches, it is useful to describe a few attributes of power markets that are particularly important when evaluating the options. These include the following:

1. A large share of power, at least in the Western Electricity Coordinating Council (WECC) area, is bought and sold in the forward markets. A forward market transaction can occur anywhere from one month ahead of delivery up to many years before delivery. For some entities, more than 80 percent of their power purchases and sales are done in the forward markets.

2. The power markets cannot be represented by a simplified model of a generator selling to a consumer. Typically, there are many intermediaries taking title to power between the point of generation and the point of consumption. Some of these entities may be wheeling power while others

may simply be buying and selling at one location. It is common to have five or more entities in the delivery chain.

3. The vast majority of forward power market transactions are executed through brokers or electronic exchanges. When executing trades through brokers or electronic exchanges, the buyer and seller are anonymous until the transaction is executed.

4. Power scheduling is the process by which energy trades that are completed in the forward and spot markets are converted into physical flows of electricity. The scheduling process identifies where the power is being generated, which transmission lines the power is moving on, and where the power is being consumed. The scheduling process also identifies which entity holds title to the power on every transmission link.

5. The scheduling process results in the creation of an e-tag that is submitted to each entity in the transaction chain and the balancing authorities that are involved in the physical path. All e-tags in the WECC area are also submitted to WECC. An example of an e-tag is contained in Appendix 1.

6. Since trading always precedes scheduling, it is impossible for an entity to know the generator, transmitter, or consumer of the electricity it is buying/selling at the time the trade is executed. That information can only be obtained through the scheduling process, which may be months or years after the energy trade was executed.

3 Hypothetical Example of a Wholesale Power Transaction

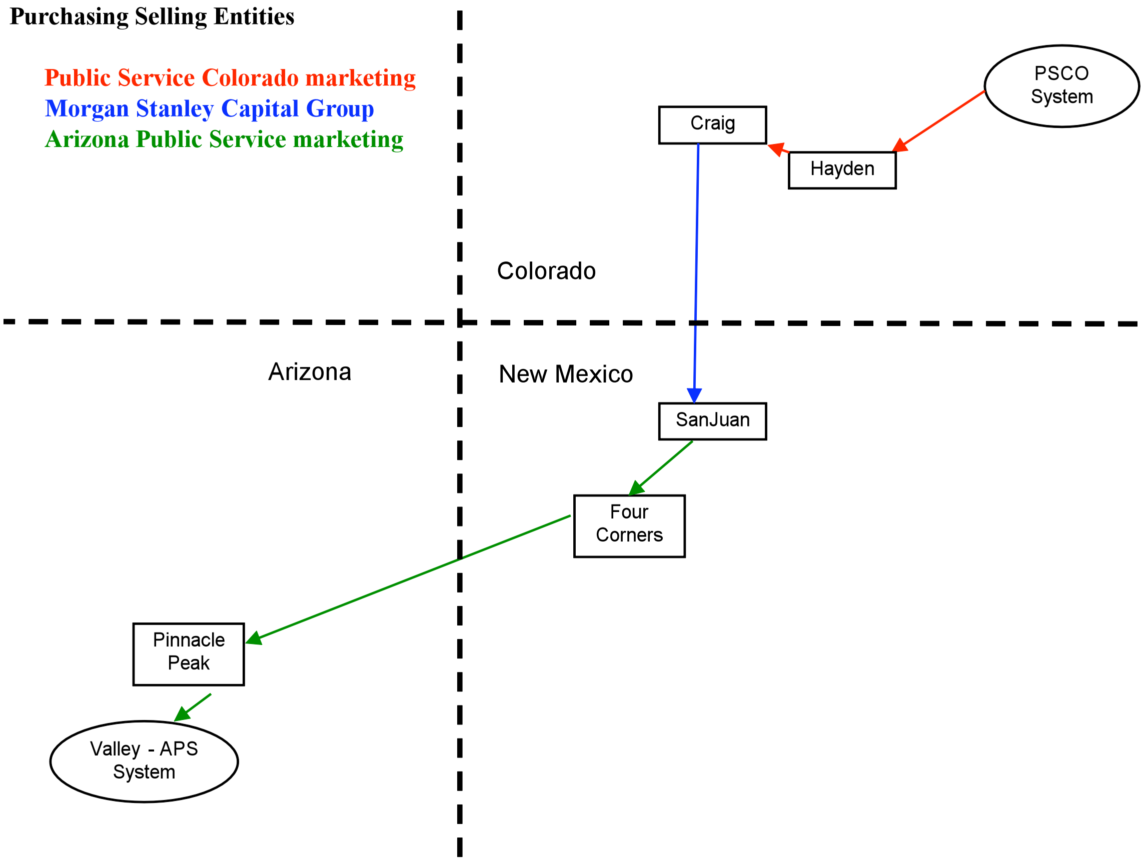
In order to help ground discussion of the four boundary options, the following scenario will be used to provide an illustrative example of how each option could work in practice. This discussion assumes that the entire physical chain is captured and reported on a single e-tag. Splitting the chain into separate e-tags could result in a different outcome. In this example, Morgan Stanley Capital Group (MSCG) purchases power from Public Service Company of Colorado (PSC). PSC generates and delivers the power to MSCG at the Craig substation located in Colorado where MSCG takes title. MSCG arranges for transmission from Craig to the San Juan substation located in New Mexico. Since MSCG held title to the power and arranged for the transmission from Craig to San Juan, MSCG is the PSE of record when the power entered the WCI jurisdiction in New Mexico. MSCG sells the power to Public Service of New Mexico (PNM) at the San Juan substation. PNM resells the power to Arizona Public Service (APS) at San Juan. APS schedules transmission from the San Juan substation to the Pinnacle Peak substation in Arizona. APS is the PSE of record when the power is transmitted from New Mexico to Arizona since APS held title of the power when it was transmitted from San Juan to Pinnacle Peak. APS is the sink for the power at the Valley substation.

Table 1. Summary of Hypothetical Wholesale Power Transaction

Action	Location
PSC generates	PSC System (CO)
PSC transmits	PSC System (CO) to Craig (CO)
PSC sells to MSCG	Craig (CO)
MSCG transmits	Craig (CO) to San Juan (NM)
MSCG sells to PNM	San Juan (NM)
PNM sells to APS	San Juan (NM)
APS transmits	San Juan (NM) to Pinnacle Peak (AZ)
APS sinks	Valley (AZ)

Note: PSC = Public Service of Colorado, MSCG = Morgan Stanley Capital Group, PNM = Public Service of New Mexico, APS = Arizona Public Service.

Figure 1. Illustration of Hypothetical Wholesale Power Transaction



Note: A detailed view of this path is included in Appendix 2.

Table 1 summarizes this transaction, and Figure 1 provides a graphical representation. Note that PNM does not appear in Figure 1 because PNM participates only as a financial participant. In other words, PNM is not a PSE on any physical portion of the transmission path. The following section describes how each FJD boundary option applies to the transaction example.

4 Application of the Four Boundary Options to the Hypothetical Power Transaction

4.1 Option 1: Individual State and Provincial Boundaries

Under this option, the consuming jurisdiction monitors each transmission path that crosses its border with any other jurisdiction, including tribal lands. Any power consumed in that jurisdiction and generated in a non-WCI location triggers a compliance obligation. The entity that assumes the compliance obligation is the PSE holding title to the power as it crosses the consuming jurisdiction's border.

Using Arizona as an example, Arizona would monitor the transmission paths connecting it to California, Nevada, Utah, Navajo Nation, and New Mexico. E-tags showing a final point of delivery in Arizona and a first point of receipt in a non-WCI location trigger a compliance obligation. The entity with the compliance obligation is the entity holding title to the power on the path that crosses the Arizona border. Referring to the illustrative example, APS would be the entity with the compliance obligation since APS held title to the power when it was transmitted into Arizona along the San Juan/Pinnacle Peak path. The state of Arizona would be responsible for monitoring APS' obligation and collecting the appropriate GHG allowances.

This approach is problematic for a number of reasons described below.

1. The central problem associated with Option 1 is that it is impossible for an entity to know its GHG allowance liability at the time of the transaction. For example, when APS purchased power from PNM at San Juan, there was no way of knowing that the power at San Juan would be sourced from a non-WCI generator in Colorado. This stems from the fact that many power trades occur in the forward markets while scheduling isn't done until a day before delivery. This will result in an unknown potential future allowance liability for any entity intending to wheel power across any intra-WCI state line. Price certainty and transaction-finality are key attributes of a liquid and efficient power market.

2. This could result in a game of allowance liability "pass the buck." As soon as the transaction is scheduled, APS will realize that it has an allowance liability associated with its purchase from PNM and will try to mitigate that liability. APS did nothing to incur this liability and has no way to reduce this liability except to try to pass it along to someone else downstream. There are numerous ways for APS to accomplish this. For example, a

scheduler at APS could try to switch the non-WCI upstream generator path with an intra-WCI upstream generator path.

Table 2. APS Transmission Schedules before Passing Allowance Liability

APS Schedule 1 - Before

Action	Location
PSC Generates	PSC System (CO)
PSC Sells To MSCG	Craig (CO)
MSCG Transmits	Craig (CO) to San Juan (NM)
MSCG Sells to PNM	San Juan (NM)
PNM Sells to APS	San Juan (NM)
APS Transmits	San Juan (NM) to PP (AZ)
APS Transmits	PP (AZ) to Valley (AZ)
APS Sinks	Valley (AZ)

APS Schedule 2 – Before

Action	Location
PNM Generates	PNM System (NM)
PNM Sells to APS	San Juan (NM)
APS Sells to SRP	San Juan (NM)
SRP Transmits	San Juan (NM) to PV (AZ)
SRP Sells to Barclays	Palo Verde (AZ)
Barclays Transmits	PV (AZ) to SP15 (CA)
Barclays Sells to SCE	SP15 (CA)
SCE / CAISO Sinks	SP15 (CA)

Shading indicates entity liable for GHG allowances.
PP = Pinnacle Peak, PV = Palo Verde, SP15 = South of Path 15

Table 3. APS Transmission Schedules after Passing Allowance Liability

APS Schedule 1 – After

Action	Location
PNM Generates	PNM System (NM)
PNM Sells to APS	San Juan (NM)
APS Transmits	San Juan (NM) to PP (AZ)
APS Transmits	PP (AZ) to Valley (AZ)
APS Sinks	Valley (AZ)

APS Schedule 2 – After

Action	Location
PSC Generates	PSC System (CO)
PSC Sells To MSCG	Craig (CO)
MSCG Transmits	Craig (CO) to San Juan (NM)
MSCG Sells to PNM	San Juan (NM)
PNM Sells to APS	San Juan (NM)
APS Sells to SRP	San Juan (NM)
SRP Transmits	San Juan (NM) to PV (AZ)
SRP Sells to Barclays	PV (AZ)
Barclays Transmits	PV (AZ) to SP15 (CA)
Barclays Sells to SCE	SP15 (CA)
SCE / CAISO Sinks	SP15 (CA)

Shading indicates entity liable for GHG allowances.
PP = Pinnacle Peak, PV = Palo Verde, SP15 = South of Path 15

The entity with the allowance liability is highlighted in yellow in the above example. In Table 2 APS is saddled with the allowance liability in Schedule 1. No entity downstream from the generator faces any potential allowance liability in Schedule 2 since the generator within WCI faces the allowance liability. In Table 3, the "After" case, APS is able to shift the allowance liability from itself in Schedule 1 to Barclays in Schedule 2.

This is accomplished by adjusting the transmission schedules. An APS scheduler notices that it has two purchases at San Juan – one from MSCG which came with an allowance liability and one from PNM without an allowance liability (since the generator within WCI faces the allowance liability). The APS scheduler simply chooses the other upstream path, directing the PNM-generated power to its own load ("After" Schedule 1) and directing the non-WCI generated power to APS' sale to Salt River Project (SRP) at San Juan. The non-WCI power ultimately ends up with Barclays who imports it into California where Southern California Edison (SCE) is the sink. Barclays now has the allowance liability since it imports the power into California and the power is consumed in California. Just as APS had done nothing to bring this allowance liability on itself in the "Before" case, Barclays has done nothing to bring this allowance liability upon itself in the "After" case.

Although the allowance liability has been shifted from one unwitting market participant to another, it's important to note that nothing has changed in the physical system. The same generators are running and the same amount of power is being transmitted across the same lines. The only difference is that the allowance liability has been passed from APS to Barclays. Barclays will in turn attempt to pass the allowance liability the next day (easily accomplished by choosing not to move the power across state lines and simply selling at Palo Verde). Through this game of pass the carbon buck, the non-WCI allowance liability will shift from one entity to the next based on scheduling acumen.

3. At the time MSCG decides to purchase power at a non-WCI location (Craig) it doesn't know whether it will ultimately have a GHG allowance liability or not. If MSCG doesn't price the potential GHG allowance liability into the price at which it sells to PNM, it can easily lose money if it ends up importing the power into New Mexico and the power is ultimately consumed in New Mexico. As a result, most prudent traders would price the potential liability into the transaction, leaving open the possibility that it will earn extra profit should the GHG allowance liability end up with another party. In this example MSCG was lucky and earned extra profit equal to the amount of GHG allowance liability it had originally priced into the transaction with PNM just as APS ("Before" case) and then Barclays ("After" case) suffered unanticipated GHG allowance liability losses.

4. In addition to market liquidity and efficiency concerns, Option 1 will likely result in higher administrative costs. Option 3 and Option 4 require market participants and regulators to monitor a relatively small number of transmission paths linking non-WCI jurisdictions with WCI jurisdictions. Option 1 creates the added burden for market participants and regulators to monitor all internal WCI paths that connect two WCI jurisdictions.

5. Due to the nature of the scheduling process, the allowance liability buck will typically be passed further downstream, just as APS did in the example. As a result, much of the non-WCI generated power will be scheduled into California as the furthest downstream geographic point and the region with the highest prices. Traders who schedule power into California may be particularly wary of accepting any power generated outside WCI.

6. The likely result of this will be a bifurcated market within WCI with two products types – "WCI generated power" and "non-WCI generated power."

Markets for the two separate products will have less liquidity than a market that can encompass both products. Very few entities will be willing to purchase non-WCI generated power from brokers or pooled markets because of the uncertain liability and the inability to manage this uncertainty in a systematic way. Only those entities who are buying non-WCI power to transmit all the way to their service territory to serve load will have certainty about who has allowance liability (since they would have it and could price it at the time of the transaction). This outcome could make non-WCI power extremely illiquid and difficult to trade. Transfers between regions will be reduced and more efficient plants in non-WCI regions may not run when they should due to the lack of a market for their product. This runs counter to the longstanding benefits that have been gained through inter-regional trade.

4.2 Option 2: Common Boundary with Monitoring and Enforcement by Consuming Jurisdiction

Under this option the entity holding title to non-WCI generated power when it is initially imported into any WCI jurisdiction is financially liable for GHG allowances. The jurisdiction where the power is ultimately consumed is responsible for monitoring whether non-WCI power has been consumed in its jurisdiction and for collecting GHG allowances from liable entities. As with all options, wheel through transactions are exempt since the power is not generated or consumed within the WCI.

Let's examine how the sample transaction plays out under Option 2. Table 4 depicts two schedules used in the discussion of Option 1: "APS Schedule 1 – Before" with the initial schedule and "APS Schedule 2 – After" the result of APS passing the allowance liability downstream.

Table 4. APS Schedules with Common Boundary

APS Schedule 1 - Before

Action	Location
PSC Generates	PSC System (CO)
PSC Sells To MSCG	Craig (CO)
MSCG Transmits	Craig (CO) to San Juan (NM)
MSCG Sells to PNM	San Juan (NM)
PNM Sells to APS	San Juan (NM)
APS Transmits	San Juan (NM) to PP (AZ)
APS Transmits	PP (AZ) to Valley (AZ)
APS Sinks	Valley (AZ)

Yellow shading indicates entity liable for GHG allowances.
Blue shading indicates reporting and enforcement jurisdiction.
PP = Pinnacle Peak, PV = Palo Verde, SP15 = South of Path 15

APS Schedule 2 – After

Action	Location
PSC Generates	PSC System (CO)
PSC Sells To MSCG	Craig (CO)
MSCG Transmits	Craig (CO) to San Juan (NM)
MSCG Sells to PNM	San Juan (NM)
PNM Sells to APS	San Juan (NM)
APS Sells to SRP	San Juan (NM)
SRP Transmits	San Juan (NM) to PV (AZ)
SRP Sells to Barclays	PV (AZ)
Barclays Transmits	PV (AZ) to SP15 (CA)
Barclays Sells to SCE	SP15 (CA)
SCE / CAISO Sink	SP15 (CA)

The entity with the GHG allowance liability is highlighted in yellow and the portion of the schedule that dictates which jurisdiction is responsible for monitoring and collecting GHG allowances is highlighted in blue. In both schedules MSCG has the allowance liability since MSCG made the decision to import non-WCI power into the WCI. Option 2 (and the other common boundary approaches) does not create an opportunity to pass the allowance liability buck – the buck starts and stops with the entity that chose to import the non-WCI power into the WCI. The state of Arizona will be responsible for monitoring the schedules in "APS Schedule 1 – Before" and collecting the GHG allowances from MSCG since the power was consumed by APS in Arizona. The state of California will be responsible for monitoring the schedules in "APS Schedule 2 – After" and collecting the GHG allowances from MSCG since the power was consumed by SCE in California.

This system has the following advantages:

1. The entity that decides to import the power does so knowing exactly the number of GHG allowances that it will be liable for. Because the compliance obligation does not change, MSCG can incorporate the compliance cost into its sales prices.

2. The entity that creates the GHG allowance liability is responsible for procuring the allowances to meet the liability. In this example, MSCG made the decision to import the non-WCI power into the WCI and is responsible for procuring GHG allowances under all scenarios. The allowance liability cannot be passed and is not assigned through the scheduling process to unwitting downstream entities. Downstream participants (e.g., APS and Barclays in Option 1) do not have to worry about having the compliance obligation shift to them based on the final point of delivery.

3. Once non-WCI power is imported into WCI, it can be traded interchangeably with WCI-generated power. Liquidity and efficiency are maximized as a result.

4.3 Option 3: Common Boundary with Monitoring by Boundary Jurisdiction and Enforcement by Consuming Jurisdiction

Option 3 will create the same outcome as Option 2 with respect to GHG allowance liability. That is, MSCG as the importer of non-WCI power into the WCI would always be liable for the GHG allowances. The difference between Option 2 and Option 3 pertains to the reporting function. Under Option 2, both monitoring and enforcement are performed by the WCI jurisdiction where the power sinks. In Option 3, the monitoring is performed by the jurisdiction where the power is initially imported (in this example, New Mexico) while the enforcement is performed by the jurisdiction where the power is consumed (Arizona). Under this option, each WCI jurisdiction would monitor only those transmission paths that connect it to non-WCI jurisdictions.

4.4 Option 4: Common Boundary with Monitoring and Enforcement by Boundary Jurisdiction

Under this option the allowance liability is the same as in Option 2 or Option 3. The only difference is the determination of which jurisdiction is responsible for monitoring the transactions and collecting the GHG allowances. The jurisdiction where the non-WCI power is initially imported bears the monitoring and GHG allowance collection responsibilities under Option 4.

MSCG has the allowance liability since it is the initial importer of non-WCI power into the WCI. MSCG reports the transaction to New Mexico and is obligated to surrender allowances to New Mexico since the non-WCI power was first imported into the WCI at the San Juan substation. As in Option 3, each WCI jurisdiction would monitor only those transmission paths that connect it to non-WCI jurisdictions.

4.5 Summary of Boundary Options

Table 5 summarizes the four boundary options and shows how they apply to the hypothetical example. Note that while Option 1 is the option envisioned in the Design Recommendations, Option 2 preserves the same assignment of monitoring and enforcement responsibilities while offering the potential benefits of a common boundary approach. Options 3 and 4 may potentially reduce administrative costs by narrowing the set of transmission paths that must be monitored.

Table 5. Summary of Four Boundary Options

Boundary Option	Regulated Entity (First Jurisdictional Deliverer)	State/Province		
		Consuming	Monitoring	Enforcing
Option 1	Consuming State Importer – APS	AZ	AZ	AZ
Option 2	First WCI Importer – MSCG	AZ	AZ	AZ
Option 3	First WCI Importer – MSCG	AZ	NM	AZ
Option 4	First WCI Importer – MSCG	AZ	NM	NM

5 Discussion

5.1 Interaction among Boundary Options, GHG Inventories and Apportionment

One question that has arisen regarding Options 3 and 4 concerns the effect it would have on each Partner jurisdiction's inventory. For example, would the emissions associated with Arizona's imports count against New Mexico's inventory or Arizona's? Because the emissions fall under WCI jurisdiction as a result of Arizona's consumption, it seems reasonable that the emissions would continue to count as part of Arizona's inventory. The boundary states and provinces that monitor, or monitor and enforce, on behalf of other Partner jurisdictions would simply provide the information on emissions associated with imports to the consuming jurisdictions for inclusion in their inventories.

A related concern is that Options 3 and 4 could be interpreted as being inconsistent with the WCI Design Recommendations regarding apportionment of the regional target among participating jurisdictions. The WCI regional goal includes emissions from non-WCI electricity imports. The Design Recommendations state that apportionment of allowances is to be based on the individual goals set by each jurisdiction. Together, these WCI decisions imply that the allowances associated with imports from non-WCI sources will be apportioned to the states or provinces on the basis of the historical pattern of consumption since the emissions associated with imports comprise a part of the consuming jurisdiction's GHG inventory. In other words, each jurisdiction's apportionment would be set relative to its in-jurisdiction emissions (with possible adjustments due to intra-WCI power flows and other factors) plus emissions associated with non-WCI power imports in the base year. Each jurisdiction would then be responsible for distributing (via direct allocation or auction) allowances to capped entities up to the level of its apportionment. In the scenario above, the emissions associated with the power imported from Colorado count against the regional goal by dint of Arizona's consumption (and assuming that there has been an historical pattern of Arizona importing power from Colorado), Arizona would issue the allowances covering these emissions.

Moving the point of regulation upstream to the common boundary point need not affect the apportionment of allowances related to non-WCI imports. The compliance obligation is still triggered by the fact that the power transaction terminates in the consuming state. Moreover, Arizona's consumers of imported power will bear the brunt of the embedded GHG compliance cost because the GHG cost will be included in the price of the power imported from Colorado, regardless of whether compliance is enforced by Arizona or by New Mexico on Arizona's behalf.

5.2 Use of a Centralized Tool for Monitoring

Another question is how monitoring and enforcement will work under each of the boundary options. Under the proposed WCI reporting rules, each non-WCI FJD would report power imports to individual WCI jurisdictions (either the common boundary or consuming jurisdiction). While this self-reported information will be important for transparency, it will not be sufficient for identifying all FJDs and enforcing compliance due to the opportunities and incentives to under- or misreport imports. For this reason, an additional source of information will be required.

Fortunately, most of the data that is required to enforce any of these options is contained in e-tags. One option is to collect e-tag data from balancing authorities. However, this approach may be administratively burdensome since it would require each WCI jurisdiction to collect data from the numerous balancing authorities in that jurisdiction and to compare the data to that collected by other jurisdictions. A preferable approach for WECC transactions is to access the data already collected by WECC's Western Interchange Tool (WIT).

If WIT schedule data is available to the WCI regulators, then either the WIT administrators or another organization could develop queries for the e-tag data to identify entities with GHG liabilities for each individual WCI jurisdiction. This would simplify monitoring and enforcement of imports because there is no need for each jurisdiction to build its own computer system to track e-tags. It is possible that using WIT could effectively equalize the boundary options' administrative costs. While WIT does not capture all of the information needed for monitoring and verification of intra-balancing authority imports (e.g., within the PacifiCorp East balancing authority), it can identify the FJD for the majority of non-WCI imports.

Appendix 1: Sample E-Tag

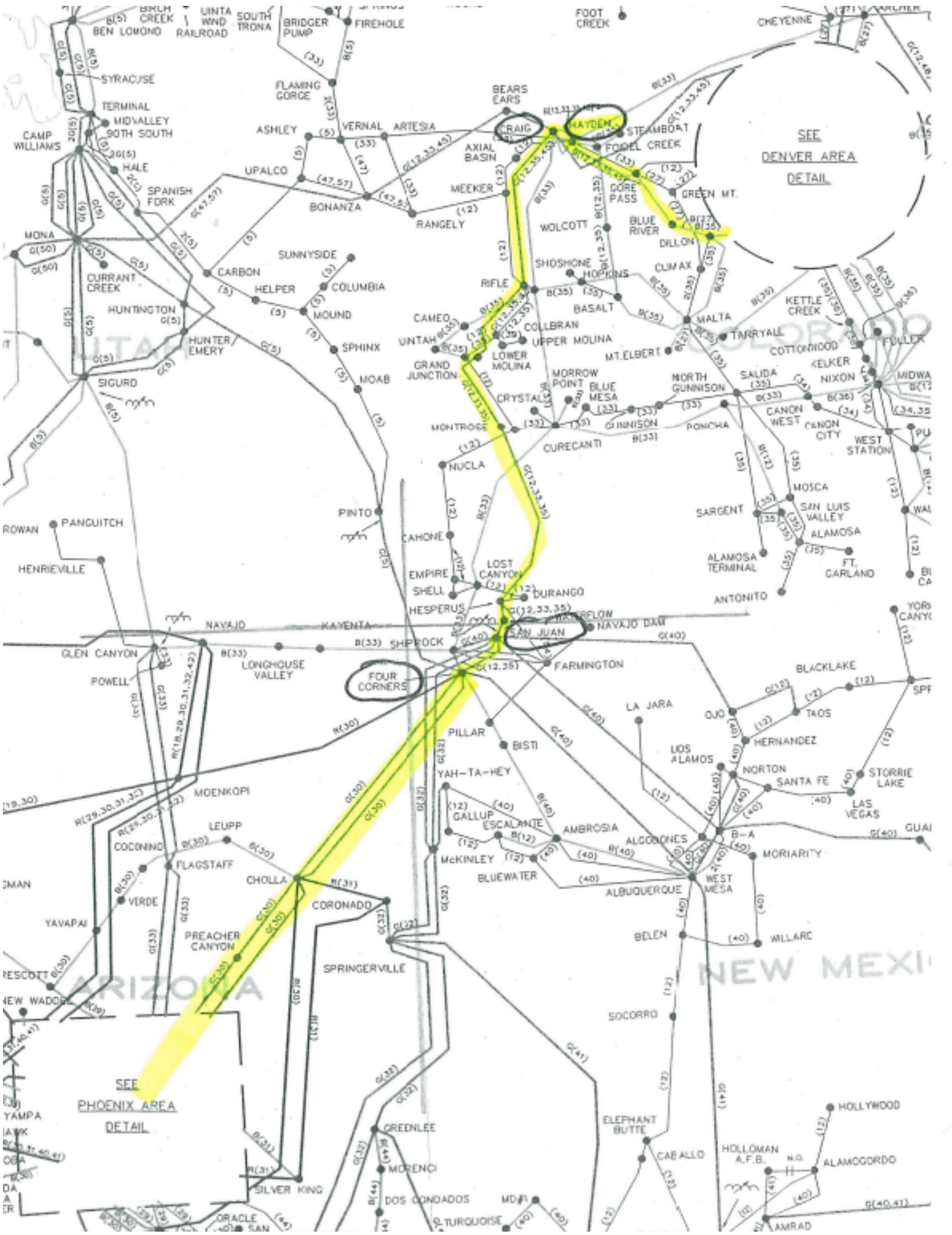
Sample Transaction Tag Example

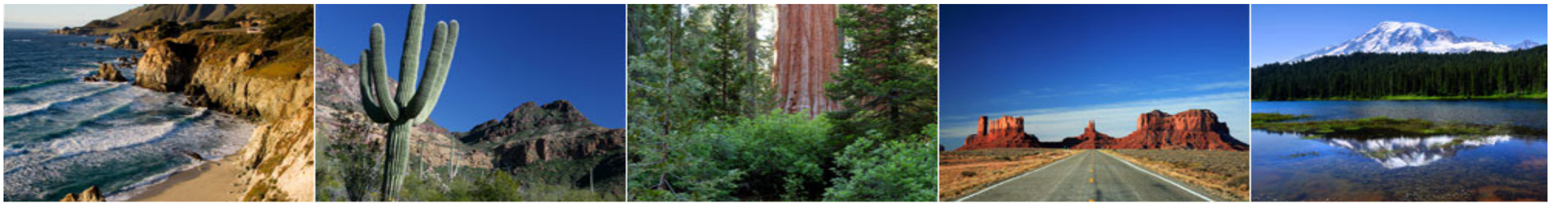
	Market Path			
Line	PSE	Product	Contract	Misc(Token/Value)
1	PSCMPS	G-FS		
2	MSCG01			
3	PNMMS1			
4	APS01	L		

	Physical Path							
Line	CA	TP	PSE	POR	POD	Sched Entities	Contract	Misc(Token/Value)
5	PSCO		PSCMPS	PSCM				
6		PSCO	PSCMPS	PSCO	HDN	PSCO		
7		PSCO	PSCMPS	HDN	CRG	WACM		
8		PSCO	MSCG01	CRG	SJ345	WACM		
9		PNM	APS01	SJ345	FOURCORNE345	PNM		
10		PNM	APS01	FOURCORNE345	FOURCORNE345	AZPS		
11		AZPS	APS01	FOURCORNE345	PINPKAPS230	AZPS		
12	AZPS		APS01	VALLEY-APS				

		Jurisdiction	
Description		Start	End
1-4	Lines 1-4 show the "Market Path" of the tag, i.e. each entities contractal relationship for delivery of energy is limited to the adjacent entity in the market path		
1	Title to the energy starts with Public Service Colorado's marketing entity (PSCMPS)		
2	Title transfers to Morgan Stanley Capital Group (MSCG01)		
3	Title transfer to Public Service New Mexico's marketing entity (PNMMS1)		
4	Title transfer to Arizona Public Service's marketing entity (APS01)		
5-12	Lines 5-12 show the "Physical Path" that the energy follows - the specific transmission lines one which the energy is scheduled.		
5	Public Service Colorado (PSCO) Generating	CO	
6	PSCO Scheduling on PSCo transmission from PSCO system to Hayden (in Colorado)	CO	CO
7	PSCO Scheduling on PSCO owned transmission - (that is managed by WAPA Western Area Power Admin - Colorado Missouri) from Hayden to Craig	CO	CO
8	Morgan Stanley Capital Group (MSCG01) Scheduling from Craig to SanJuan 345kV bus on PSCo Transmission (Colorado into New Mexico) - (WAPA Colorado Missouri Schedules on behalf of PSCo Transmission) - Passes title to PNM Marketing as shown in line 3 of the market section of the tag	CO	NM
9	PNM passes title to Arizona Public Service at San Juan 345 (as shown as line 3 in the market section of the tag), then APS wheels from SanJuan 345kV bus and to Four Corners 345 KV bus (inside New Mexico)	NM	NM
10	APS01 wheels energy from SanJuan 345kV substation to Four Corners substation	NM	NM
11	APS wheels energy from Four Courners to Pinnacle Peak on APS transmission	NM	AZ
12	Arizona Public Service consumes energy at its system		AZ

Appendix 2: Detailed View of Sample Transmission Path





Western Climate Initiative

2009-10 Work Plan

February 19, 2009

Updated June 23, 2009 to include the Complementary Policies Work Plan

This document describes the content and timing of the work that the Western Climate Initiative anticipates will move forward in 2009 and 2010. This information, including the schedule, is subject to change and modification, as necessary.

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Introduction

This *2009-10 Work Plan* describes the approach to operating the Western Climate Initiative (WCI) over the next 12 to 18 months. The WCI is a cooperative effort of U.S. states and Canadian provinces that are collaborating to identify policies to reduce greenhouse gas (GHG) emissions, including the design and implementation of a regional cap-and-trade program. The WCI began in February 2007 with the governors of Arizona, California, New Mexico, Oregon, and Washington, who have since been joined by the premiers of British Columbia, Manitoba, Ontario, and Quebec, and the governors of Montana and Utah. Participation in the WCI reflects the strong commitment of each Partner jurisdiction to take cooperative actions to reduce GHG emissions.

After 18 months of extensive analysis, stakeholder consultation, and deliberation, the WCI released its *Design Recommendations for the WCI Regional Cap-and-Trade Program* on September 23, 2008.[1] The design for the WCI cap-and-trade program is comprehensive. When it is fully implemented in 2015, the WCI program will cover up to 90 percent of the GHG emissions in WCI Partner states and provinces. Through its broad scope, the WCI program will reduce compliance costs while reducing emissions across the economy. It will also help spur growth in new green technologies, help build a strong clean-energy economy, and enhance North American energy security.

Over the past few months as we have seen the world economy falter, questions have been raised as to whether this is the right time to be moving forward with a cap-and-trade program. We believe that it is important to move forward with the cap-and-trade program, while acknowledging the need for flexibility in the short term due to the current economic situation. This will provide policy certainty over the longer term to guide investments in lower emitting technologies during the economic recovery period. We cannot ignore the far greater costs associated with failing to achieve the carbon reductions science says must be made. The longer we wait, the more we delay, the higher those costs and the steeper the reductions we and our children will have to make. If delayed, those reductions will be costlier to make with less flexibility than we have today as they will need to be made over a much shorter time line. Now is the time to plan and prepare; the WCI program does not begin until January of 2012, by which time the North American and world economies will have certainly turned around. Our goal is not to further burden an already struggling economy, but to help pave the way to build the new economy on a clean energy platform.

Stakeholder Engagement

The WCI Partner jurisdictions want to ensure that the WCI process continues to promote an effective dialogue between the WCI Partner jurisdictions and all stakeholders. Through this dialogue the WCI Partner jurisdictions receive the benefit of stakeholder perspectives and expertise, while stakeholders have access to the information they need to understand the

[1] For more information on WCI and to access the design recommendations, visit www.westernclimateinitiative.org.

work of the WCI and provide timely and meaningful input into the deliberations of the WCI Partner jurisdictions. Stakeholder engagement consists of: 1) stakeholder processes conducted by individual WCI Partners within their jurisdiction; 2) stakeholder engagement opportunities with all WCI Partner jurisdictions (similar to the workshops held in 2008); and 3) stakeholder engagement activities conducted by WCI Committees. The final section in this *2009-10 Work Plan* provides a brief description of the major deliverables and milestones for each WCI Committee. In the near future, a more detailed timeline of WCI stakeholder activities will be available. The purpose of these activities is to ensure that stakeholders have the opportunity to review and provide comments on draft documents and recommendations, and to provide feedback at working sessions. Stakeholders are also involved within WCI jurisdictions as the Legislative branches hold hearings and otherwise consider proposals from these efforts.

2009 WCI Committees

The WCI is led by designated representatives from each member state and province. The WCI Partners lead and direct the overall effort by recommending policy for the implementation of the WCI program; developing and approving work plans, budgets and work products; and providing direction to advisors and support staff to achieve the objectives of the WCI. As necessary to accomplish the purposes of the WCI, the WCI Partners will form working Committees. Each Committee is or will be chaired or co-chaired by a WCI Partner or Partners. Each WCI Partner jurisdiction may designate representatives to serve as members on each Committee. Governors or premiers who have formally requested official observer status in the WCI, and whose request has been approved by consensus of the WCI Partners, may designate representatives to participate as observers to the WCI. Observers are also invited to participate on the Committees. Advisors and contractors may be enlisted to provide Committee members with policy and technical guidance and assistance. Committees may form task groups as needed to accomplish specific work of the Committee, and will be responsible for determining the members, scope, and outcomes of these task groups.

This *2009-10 Work Plan* contains a description of the anticipated activities, tasks and deliverables that will be accomplished by the six working Committees of the WCI to further develop the WCI cap-and-trade program and should be considered a work in progress:

- **Reporting Committee:** The Reporting Committee will develop a GHG-emissions reporting system that will support the WCI cap-and-trade program by ensuring that WCI jurisdictions receive necessary and accurate emissions data in a timely manner. A reporting system will be designed to coordinate the use of a common set of functionally-equivalent jurisdictional reporting rules, standardized reporting tools, and a regional GHG emissions database.
- **Cap Setting and Allowance Distribution Committee (CSAD):** The CSAD Committee will recommend methodologies for establishing each WCI Partner jurisdiction's allowance budgets, including the one-time budget adjustment in 2012. Additionally, the Committee will examine harmonization of allowance distribution, offsets compliance limits, and will develop the approach for issuing Early Reduction Allowances.

- **Markets Committee:** The Markets Committee will develop recommendations on common elements needed to guide the proper development and operation of a robust and transparent allowance and offset credit trading market. The Markets Committee will coordinate with other Committees to develop elements for implementing a WCI cap-and-trade program that is effectively similar and that provides a uniform measure of environmental integrity across jurisdictions. The Committee will examine compliance verification and enforcement; oversight of the primary, secondary and derivatives markets; auction design, and tracking systems and related infrastructure. It will also assess the design and operation of a regional administrative body to support the implementation of the cap-and-trade program.
- **Electricity Committee:** The WCI Electricity Committee addresses issues specific to the electric sector related to the design and implementation of the WCI cap-and-trade program. Over the past year, the Electricity Committee has assessed policy mechanisms for addressing electricity sector emissions, consulting with stakeholders on conference calls, in public meetings, and through the release of written documents for review and comment. In 2009, the Electricity Committee will continue to examine technical issues related to the First Jurisdictional Deliverer (FJD) approach and issues concerning reliability and electricity market efficiency.
- **Offset Committee:** The Offset Committee will make recommendations on the design and operation of the offset system, including the process for issuing offset credits and the criteria necessary for offset projects to be used to meet compliance obligations within the WCI cap-and-trade program.
- **Complementary Policies Committee:** The WCI Partner jurisdictions recognize that it will take other policies working in concert with cap-and-trade to achieve the regional reduction goal. The purpose of the Complementary Policies Committee is to recommend other policies that will aid in achieving individual and regional emissions reductions goals, for both capped and uncapped sectors.
- **Economic Modeling Team:** The Economic Modeling Team will provide economic analysis to inform the development of the WCI cap-and-trade program policy and design options. The Team serves as a resource for WCI Partners and other Committees.

Collaboration

The WCI Partner jurisdictions recognize the importance of collaborating with the other regional initiatives currently underway (i.e., the Regional Greenhouse Gas Initiative in the Northeast U.S. and the Midwest Greenhouse Gas Accord in Midwest North America) and with the U.S. and Canadian federal governments. To facilitate collaboration and communication, the WCI Partner jurisdictions have designated one U.S. and one Canadian representative to serve in the position of WCI Liaison. The WCI Liaisons are the primary but not sole WCI contacts for interaction with federal governments and other state, provincial, and regional efforts.

Reporting Committee

The purpose of the Reporting Committee is to develop a GHG-emissions reporting system that will support the WCI cap-and-trade program by ensuring that WCI Partner jurisdictions receive necessary and accurate emissions data in a timely manner. Elements of the reporting system will need to include jurisdictional reporting rules, reporting tools, and a regional emissions database. Jurisdictional reporting rules will need to include, at a minimum, a common set of functionally equivalent requirements sufficient to ensure that "a metric ton is a metric ton" across the WCI Partner jurisdictions.

Completion of the initial version of the essential requirements for reporting, which will serve as the basis for jurisdictional rules, is scheduled for the end of February 2009. The Reporting Committee will divide its work into five tasks in 2009:

Task 1: Provide ongoing guidance to WCI Partner jurisdictions as they undertake stakeholder processes in the course of adopting reporting rules in conformance with the essential requirements for reporting.

Task 2: Work with The Climate Registry (TCR) to develop the regional emissions reporting database.

Tasks 3–4: Augment the essential requirements for reporting by developing reporting requirements (i.e., applicability, quantification and monitoring methods, and report content requirements) for additional source categories that, due to the need to conduct detail analyses of points of regulation (PORs), a lack of adequate quantification or monitoring methods, and other factors, were not included in the initial essential requirements for reporting. Determine criteria for verifier accreditation and conflict of interest determination.

Task 5: Provide WCI comments on the proposed U.S. EPA GHG reporting rule and possibly the anticipated Environment Canada GHG reporting rule.

Description of Tasks and Deliverables

TASK 1: ONGOING TECHNICAL SUPPORT AND GUIDANCE IN SUPPORT OF JURISDICTIONAL RULEMAKING

As jurisdictions undertake their rulemaking processes in 2009, stakeholder comments and involvement will likely increase, and new or unforeseen issues will be discovered. Jurisdictions may also need WCI assistance in interpreting or communicating reporting requirements internally within their agencies. The Reporting Committee will respond to comments and conduct research on which to base changes to methods, reporting requirements, etc. The Committee will also provide jurisdiction support, as necessary.

Task	Deliverables	Dates
1	Response to stakeholder comments received in 2009	Throughout 2009
	Technical support to jurisdictions	Throughout 2009
	Status report on types of technical support provided to each jurisdiction and WCI	Quarterly in 2009

TASK 2: DEVELOP WCI REPORTING DATABASE WITH THE CLIMATE REGISTRY (TCR)

WCI Partner jurisdictions have agreed that the emissions reporting component of the cap-and-trade program should rely as heavily as possible on the infrastructure developed by TCR. Emissions data will be reported to jurisdictions. Some states and provinces will collect data through their independent reporting systems and databases and then transfer the data to WCI's regional database; other jurisdictions will use a customized segment of TCR's "Common Framework" data platform. WCI will need to move forward with development of the reporting mechanism in 2009 in order to be ready for the first year of reporting, when 2010 emissions are reported in 2011. The WCI will develop a regional emissions data repository to store and manage GHG data across the region. The database will use a modified version of TCR's Climate Registry Information System (CRIS) to serve as the technical back end of this regional repository. The Reporting Committee will work with TCR to develop the requirements for the regional emissions data repository; the requirements for data transfer into and out of the regional emissions database; the report needs; and the design of the user interface of the regional emissions repository. In addition, the Reporting Committee will participate in beta-testing the application, and will provide feedback and direction throughout the development process.

The scope of work for developing the emissions reporting and database infrastructure will include development of:

- WCI Program Module, incorporating the WCI's essential requirements for reporting, which will be used as the basis for collection and management of reported emissions data by WCI jurisdictions that adopt the Common Framework.
- WCI Regional Emissions Database, which will consolidate WCI emissions data and support data analysis for the cap-and-trade program and emissions inventory.
- Data Collection from WCI Partner jurisdictions, which is the transfer of emissions reporting data from jurisdictions to the regional emissions database, either via the Common Framework or through the transfer of data from independent jurisdictional databases.
- Analysis, report presentation, and user interface tools, which will provide access to specified emissions data by WCI Staff and Partners, regulated parties, and the public.

Development of the Regional Emissions Database will be in two phases. Phase 1, to be completed June 1, 2009, will include the preparation of a scope of work, the development of a white paper to outline different options for how WCI structures its emissions reporting process, a detailed requirements analysis document, and an executive summary of the proposed requirements for the WCI Partner jurisdictions.

Phase 2, to be completed by December 31, 2009, will include design and development of the application, systems testing, and application deployment with beta testing and education. At the end of Phase 1, TCR will develop a detailed timeline for each component of Phase 2, as well as a Phase 2 budget.

Development of the emissions reporting system and emissions database is closely related to the Markets Committee's task 4 (development of tracking systems and related infrastructure). The Reporting and Markets Committees will work closely together to ensure a smooth flow of emissions data from the emissions database to the allowance tracking system.

Additional effort may be needed by those jurisdictions that choose to work with TCR to modify the CRIS application to meet their individual jurisdictional reporting and database needs.

Task	Deliverables	Dates
2	Reporting Options White Paper	mid-March 2009
	Database Requirements Analysis	June 1, 2009
	Database Design	Oct. 1, 2009
	System Testing Complete	Nov. 15, 2009
	Beta Testing and Education Complete	Dec. 31, 2009

TASK 3: SOURCE CATEGORY-SPECIFIC EMISSIONS QUANTIFICATION REQUIREMENTS

3.1. Source Category-Specific Support

Some work will need to be conducted during 2009 to address outstanding issues related to source category specific methods that could not be completely resolved during 2008. These outstanding issues fall into three areas:

- Finalizing quantification and/or sampling, analysis, and measurement methods for certain source categories, such as those listed in Table 4 of the January 9, 2009 Reporting Committee background document (cement, lime, iron and steel, electronics, etc.), including development of all equations, emission factors, etc., in metric units.
- Addressing stakeholder comments on the essential requirements for reporting after they are finalized in January 2009.
- Developing rule-format language for the source category methods that were previously developed in "narrative" format.

Most of this work will be completed by the end of March 2009, and all work can be completed by the end of June 2009.

3.2. Oil and Gas Exploration and Production, and Gas Processing

Write emissions quantification and monitoring and related essential requirements sections (definitions, report requirements, etc.) based on the TCR/Western Regional Air Partnership (WRAP) Oil and Gas Protocol Project's Task 2 output (technical review of high-tier emissions quantification methods).[2] The TCR/WRAP Technical Review, which will likely build on existing methodologies, such as the American Petroleum Institute's "Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry" (2004) and those developed for use by industry in Canada, will be available in March 2009.

3.3. Natural Gas Transmission and Distribution (methane and other non-combustion GHGs directly emitted by these facilities)

Address non-combustion direct emissions from facilities in the source category sectors. The work will consist of writing emissions quantification and monitoring and related essential requirement sections (definitions, report requirements, etc.) based on 1) CCAR protocol (for eventual adoption by TCR) for this source category (scheduled for completion sometime in 2009), and on 2) any Environment Canada protocol available during 2009.

3.4. Transportation and RCI Fuels GHG Methods, POR, and Accounting

Develop the essential requirements for reporting liquid transportation fuels. Work will include writing draft requirements for emissions quantification methodologies, engaging with industry representatives, and subsequent modification of the draft requirements. The appropriate point of regulation (POR) is an issue that differs across jurisdictions and will need to be addressed; however, the Committee will not identify the jurisdiction-specific PORs, recognizing that the POR may vary across jurisdictions. Appropriate quantification methodologies are likely to depend on the POR, so it will likely be necessary to identify a variety of POR-specific methodologies. The Committee will need to update the portions of the essential requirements pertaining to reporting transportation and RCI fuels to incorporate decisions made by WCI with regard to transaction "accounting," to avoid double-counting of emissions and/or gaps in reported emissions by fuel suppliers, industrial sources, and jurisdictions. This work would occur after the WCI has made decisions within the Markets Committee, or other Committees—which could be in either calendar year 2009 or beyond.

3.5. Development of New Emissions Factors and Quantification Methods

Develop an RFP and pursue research to develop accurate emissions factors and/or quantification methods for source categories where adequate GHG emissions factors and/or quantification/monitoring methods are not currently available. This analysis would include establishing priorities, and would likely involve source testing and measurements. Some source data may be relatively inexpensive to obtain, while others will be more extensive and expensive to develop. Based on methods developed, the essential requirements for reporting would be updated.

[2] Information on this project is available at http://www.wrapair.org/ClimateChange/GHGProtocol/.

3.6. Evaluation of Monitoring Protocols for Cap-and-Trade Compliance

The WCI Partner jurisdictions recommended the inclusion of certain emission categories in the essential requirements for reporting, for which either quantification method uncertainties may be high or quantification methods are being developed. The Reporting Committee will evaluate the acceptable level of accuracy of quantification methods for inclusion in compliance reporting. Various forms of accuracy such as the level of uncertainty, bias, measurement error, sampling error, and other pertinent factors (possibly including factors other than methodological uncertainty) will be reviewed for the source categories under consideration. This work will be done in close cooperation with TCR's protocol development processes. This will help the WCI Partner jurisdictions to consistently and transparently determine which emissions sources should be included and which emissions sources have justification for delayed inclusion or exclusion.

Task	Deliverables	Dates
3.1	Changes in reporting essential requirements, based on comments received from stakeholders in the first quarter of 2009.	June 2009
3.2	Documentation of reporting essential requirements pertaining to oil and gas exploration and gas processing POR, and GHG emissions quantification and monitoring method	July 2009
3.3	Documentation of reporting essential requirements pertaining to natural gas transmission and distribution	December 2009
3.4	Documentation of reporting essential requirements pertaining to transportation and RCI fuels	June 2010
3.5	Development of GHG emission factors and quantification methods	December 2009
3.6	Defining acceptable level of accuracy of quantification and monitoring methods	June 2010

TASK 4: DETERMINE CRITERIA FOR VERIFIER ACCREDITATION AND CONFLICT OF INTEREST DETERMINATION

The Reporting Committee will develop criteria for verifier accreditation. Accreditation will be consistent with international standards (ISO 14065) through an accreditation program to be developed under ISO 17011, and will include a requirement to demonstrate knowledge of the WCI reporting requirements. Other aspects of the verifier accreditation that will be specified include the accreditation cycle, the criteria and process for revoking accreditation, insurance requirements, required technical competencies, and subcontracting issues. Requirements will also be developed for determining conflict of interest (COI) between verifiers and reporters.

This work will build upon recognized international standards and the verifier standards developed by the California Air Resources Board (CARB) and TCR. WCI will work closely with CARB and TCR in developing these criteria.

The completion date for this Task will allow for implementation/accreditation to occur in 2010, to ensure that a pool of verifiers is ready for 2011, the first year that reports will be submitted and verified.

Task	Deliverables	Dates
4	Documented verifier accreditation and COI requirements as a revision to the reporting essential requirements	September 2009 (to complete essential requirements)

TASK 5: RECOMMEND WCI COMMENTS ON PROPOSED U.S. EPA GHG REPORTING RULE AND ENVIRONMENT CANADA GHG REPORTING RULE

The Reporting Committee will review the proposed U.S. EPA GHG reporting rule, which is anticipated to be published in the first quarter of 2009. The Committee will prepare a summary of the proposed rule, compare it to the WCI essential requirements for reporting, and make recommendations on formal comments that WCI may submit to U.S. EPA. In addition, Environment Canada is expected to promulgate a mandatory GHG reporting rule. The Committee will seek opportunities to provide input into this federal reporting rule as well.

Task	Deliverables	Dates
5	Documented WCI comments on proposed U.S. EPA GHG mandatory reporting rule	Exact date TBD, but prior to closure of the 60 day public comment deadline to allow for Partner review
	Comparison of Environment Canada GHG reporting rule and WCI essential requirements	Exact date TBD, within 2 months after the first notice of the proposed federal regulations being published in the *Canada Gazette*

Cap Setting and Allowance Distribution Committee

The Cap Setting and Allowance Distribution Committee (CSAD) has been formed to recommend methodologies for establishing the regional WCI GHG emissions cap, each WCI Partner jurisdiction's allowance budgets, and allowance distribution guidelines. The work of CSAD will help to ensure that the data being used to inform these decisions are as accurate as possible, that the approach taken addresses competitiveness issues, and that methodologies are applied consistently to achieve each WCI Partner jurisdiction's specific goal as well as the WCI regional goal.

As described below, CSAD has divided its work into the following six tasks:

Task 1: Data Review and Collection
Task 2: Cap and Budget Setting
Task 3: Competitiveness Analysis
Task 4: 2012 One-Time Budget Adjustments
Task 5: Offsets Compliance Limit
Task 6: Early Reduction Allowances (ERA)

Description of Tasks and Deliverables

TASK 1: DATA REVIEW AND COLLECTION

CSAD, with the collaboration of each WCI Partner jurisdiction, will:

- Perform data review and recommend to the WCI Partner jurisdictions how to improve and harmonize historical data used to inform cap and budget[3] setting.
- Collect and review economic and demographic data, and develop and recommend a common, consistent emission projection methodology and assumptions to enable 2012 and 2015 best estimates of actual emissions that will be used in setting caps and budgets.
- Assess the implications of differences between the inventory methodologies used to collect historical data and reporting methodologies that will be used for compliance, and recommend any adjustments that may be needed to account for reasonably anticipated differences.

[3] The term "budget" refers to the total number of allowances to be issued by a WCI Partner jurisdiction in a given year or compliance period. The term "cap" refers to the sum of all WCI Partner jurisdictions' budgets in a given year or compliance period.

1.1. Prepare CSAD's Preliminary Information

- Organize the historical jurisdictional emissions data to distinguish emissions categories that are currently expected to be covered and not covered by the cap-and-trade system.
- Update the historical jurisdictional emissions data with any inventories updated since January 2008, as identified by the WCI Partner jurisdictions.
- Identify emissions data and appropriate information that will be coming from other Committees, such as the Electricity and Reporting Committees.

1.2. Perform Historical Data and Projected Emissions Review and Analysis

Each WCI Partner jurisdiction will work with CSAD to review and analyze data and projected emissions of:

- WCI Partner jurisdictions' historical data for both covered and non-covered source categories.
- WCI Partner jurisdictions' 2012 and 2015 projected emissions for covered source categories.
- WCI Partner jurisdictions' 2020 projected emissions for non-covered source categories.

1.3. Compare and Assess Differences Between Inventory Methodologies and Reporting Methodologies

- Analyze the differences between the inventory methodologies used to collect historical emissions data and reporting methodologies that will be used for compliance.
- Identify covered source categories where significant differences may be reasonably anticipated, and any adjustments that may be needed to account for them.

1.4. Develop and Present a Work Plan for Harmonizing WCI Partner Jurisdictions' Data and Projected 2012 and 2015 Emissions

Each WCI Partner jurisdiction will work with CSAD to:

- Recommend adjustments that may be needed to improve historical data, as well as procedures to fill any data gaps.
- Develop a consistent methodology for projecting 2012 and 2015 emissions for capped source categories.
- Develop an approach for estimating emissions from sources in source categories covered under the cap, but below 25,000 $MMTCO_2e$, in order to inform the setting of caps to meet the 2020 goals.
- Develop a consistent methodology for projecting 2020 emissions for uncapped source categories, in order to inform the setting of caps to meet the 2020 goals.

1.5. Provide an Emissions Data Set, Including Projections, for WCI Partner Jurisdiction Use in Cap Setting and Other Tasks Noted Below, and Establish Procedures for any Future Adjustments

- Implement a work plan for harmonizing data and projections.
- Produce, in collaboration with every WCI Partner jurisdiction, a report containing tables with each WCI Partner jurisdiction's emissions data and projections by covered source category for the 1990–2012 and 2015 period, and non-covered source categories for the 1990–2020 period, along with supporting documentation.
- Produce, in collaboration with every WCI Partner jurisdiction, an Annex to the report assessing the level of uncertainty/quality associated with the data.
- Establish a procedure for updating the data set and correcting it for errors over time;
- Post the data set on the WCI website for stakeholder review.
- Obtain WCI Partner jurisdiction approval for use of the data set as the basis for cap setting and other analysis.

Task	Deliverables	Dates
1.1	Assemble and update existing data and data needs	2009 Q1
1.2	Historical data and project emissions methodology review and analysis	2009 Q2
1.3	Compare reporting and inventory methods and assess implications	2009 Q2
1.4	Work plan for harmonizing WCI Partner jurisdiction's data	2009 Q3
1.5	Provide an emissions data set and data report[4]	2009 Q4

TASK 2: CAP AND BUDGET SETTING

CSAD, in collaboration with each WCI Partner jurisdiction, will:

- Recommend a methodology for establishing the aggregate regional cap for 2012 and then yearly to 2020.
- Recommend a methodology for establishing each WCI Partner jurisdiction's emissions allowance budget for 2012 and then yearly to 2020.
- Recommend a process and a methodology to review each WCI Partner jurisdiction's upcoming overall and yearly emissions allowance budget, and aggregate regional cap to 2020, prior to the beginning of each new compliance period. This will provide flexibility to make adjustments to the program at the end of each compliance period particularly in response to the current economic situation.

[4] To complete this task, CSAD will need the information from the Electricity Committee on the emissions from the FJDs.

2.1. Prepare CSAD's Preliminary Information Needs

- Identify specific source categories to be included in 2012 and 2015 (Reporting Committee).
- Identify other factors that may affect cap and budget setting, such as early reduction allowances.

2.2. Propose a Methodology and/or Guidelines for Establishing WCI Partner Jurisdiction Caps and Yearly Allowance Budgets

- Develop a proposal on the methodology or guidelines for each WCI Partner jurisdiction to follow in creating their respective allowance budgets.
- Develop a white paper on options to deal with new entrants and plant shut-downs.

2.3. Review WCI Partner Jurisdiction Budgets, the Regional Cap, and the 2020 Regional Goal

- Each WCI Partner jurisdiction will work in collaboration with CSAD to calculate the WCI Partner jurisdictions' preliminary 2012–2020 yearly allowance budgets based on the methodology and/or guidelines developed as part of subtask 2.2. The preliminary WCI Partner jurisdiction budgets will then be reviewed by all WCI Partner jurisdictions prior to being finalized by each WCI Partner jurisdiction.
- Calculate the preliminary regional cap as the sum of each WCI Partner jurisdiction's preliminary budget.

2.4. Develop a Process and Methodology to Review WCI Partner Jurisdiction Budgets and Performance of the Cap-and-Trade Program

Develop a process and methodology to:

- Review each WCI Partner jurisdiction's emission allowance budget prior to the beginning of each new compliance period, taking into account the latest reported emissions for covered sources as well as new sources, including new entrants.
- Review and report past compliance period data, cap, budget, and allowances relative to the stated WCI regional goals to assess overall performance of the cap-and-trade program, and to also provide possible cap and allowance adjustment options for consideration for future compliance periods.

Task	Deliverables	Dates
2.1	Assessment of information needed and factors that may affect budget-setting	2009 Q2
2.2	Methodology for budget calculations	2009 Q2
2.3	Preliminary budgets and cap	2010 Q1
2.4	Cap/budget review process	2010 Q1

TASK 3: COMPETITIVENESS ANALYSIS

The purpose of this task is for CSAD to:

- Seek, receive, review and perform analyses on competitiveness issues, from sectors or sources that have been identified and/or that self-identify as having competitiveness issues related to cap-and-trade.
- Assess how WCI Partner jurisdictions should address competitiveness issues 1) among the identified industries, and 2) within each identified industry. If a common allowance distribution method is recommended, CSAD will recommend a distribution method or methods for consideration by the WCI Partner jurisdictions.

3.1. Develop a Statement of Principle on the Evaluation of Competitiveness Issues
CSAD will develop a statement of principle that describes how competitiveness issues will be evaluated. This statement will include an evaluation grid under which competitiveness issues will be evaluated, as well as the specific circumstances under which CSAD will undertake its own analysis. It will also include policy options for WCI Partner jurisdictions to address competitiveness issues. The statement of principle will be posted on the WCI website for stakeholder review.

3.2. Solicit Information to Elucidate Competitiveness Issues
The purpose for this subtask is to:

- Ask emitters/sectors with potential compliance obligations to provide information about their competitiveness issues.
- Initiate, conduct and/or review independent analysis to assess competitiveness issues in specific sector as per the principles defined in subtask 3.1.

The Committee will initiate this process with a stakeholder consultation where the statement of principle will be presented.

3.3. Create Workgroups
CSAD will create workgroups that will review the information provided by each sector and other relevant data and analyses. The workgroups will assess the need for an ongoing dialog with stakeholders that submitted competitiveness information.

3.4. Competitiveness Analysis
The workgroups will review the information provided, assess competitiveness issues, and perform or oversee any additional required analysis. It is expected that stakeholder consultation will be required to discuss the information provided.

3.5. Options to Address Competitiveness
For each sector identified as having competitiveness issues, the workgroups will provide recommendations for addressing those issues. The recommendations will contain:

- A review of the submitted information based on the published parameters (see subtask 3.1).

- A literature review.
- Any necessary additional analysis.
- Options for the treatment of the sector/sources to address the competitiveness issues raised based on the options (tools) identified in subtask 3.1.

Task	Deliverables	Dates
3.1	Competitiveness evaluation and statement of principle	2009 Q2
3.2	Solicit proposals	2009 Q2
3.3	Create a workgroups	2009 Q2
3.4	Competitiveness analysis	2010 Q1
3.5	Options to address competitiveness	2010 Q2

TASK 4: 2012 ONE-TIME BUDGET ADJUSTMENTS

The purpose of this task is to develop and recommend a methodology for the distribution of the one-time, one percent contribution by WCI Partner jurisdictions' of their 2012 budgets. This one-time one percent contribution will account for:

- Production and consumption of electricity in megawatt hours.
- Population growth.
- Share of total WCI Partner jurisdictions' emissions in 2001 through 2005.

4.1. Data Collection

To calculate the distribution of the one-time one percent WCI Partner jurisdictions' budget contribution, CSAD will use the data set put together by CSAD task 1, Data Review. Preliminary adjustments (subtask 4.3) will be based on the existing data compiled by CSAD subtask 1.1 and the Final Adjustment (subtask 4.4) will be based on the Final Data Set provided by CSAD subtask 1.5.

4.2. Adjustment Proposal

The Committee will produce a methodology for the distribution of the one-time one percent contribution by WCI Partner jurisdictions' of their 2012 budget. Each of the three distribution criteria (population, electricity production/consumption, and emission share) will be treated separately. More than one methodology might be proposed for each criterion. The weight to attribute to each criterion will also be addressed separately. As part of this subtask, the Committee will recommend a common definition for each criterion. Also, it is presumed that where possible, common data sources (assembled in CSAD task 1) and/or methodologies will be used for all jurisdictions for each criterion.

4.3. Preliminary Adjustments to WCI Partner Jurisdictions' 2012 Budgets

Each WCI Partner jurisdiction will work in collaboration with the Committee to calculate the preliminary adjustments to their 2012 budgets based on the preliminary data received from subtask 4.1 and the distribution method chosen by WCI Partner jurisdictions.

4.4. Final Adjustments to WCI Partner Jurisdictions' 2012 Budgets

Each WCI Partner jurisdiction will work in collaboration with the Committee to calculate and present the final adjustments to their 2012 budgets. This adjustment will be calculated based on the final emission and socio-economic data.

Task	Deliverables	Dates
4.1	Data collection (performed as part of task 1)	2009 Q2
4.2	Adjustment proposal	2009 Q3
4.3	Preliminary adjustments to WCI Partner jurisdictions' 2012 budgets	2009 Q4
4.4	Final adjustments to WCI Partner jurisdictions' 2012 budgets	2010 Q1

TASK 5: OFFSETS COMPLIANCE LIMIT

The purpose of this task is to develop and recommend a methodology for implementing the offset limit of no more than 49 percent of the total emission reductions from 2012–2020 in order to ensure that a majority of emission reductions occur at WCI covered entities and facilities.

5.1. Background Paper

CSAD, in collaboration with the Markets and Offsets Committees, will identify and evaluate options for implementing the offset limit. As part of assembling background information and developing a background paper, CSAD will review offset limiting processes from other trading schemes. The background paper will be posted on the WCI website for stakeholder review and comments.

5.2. Draft Recommendation

Based on the comments received in subtask 5.1, CSAD will recommend options on implementing the offset limit. This recommendation will be posted on the WCI website for stakeholder review and comments.

5.3. Final Recommendation

Based on comments received in subtask 5.2, CSAD will review the recommended options on implementing the offset limit and present a final set of options.

5.4. Calculate the Offset Limit

CSAD will calculate the offset limit based on the option chosen by WCI Partner jurisdictions and the allowance budgets (CSAD task 2).

Task	Deliverables	Dates
5.1	Background paper	2009 Q2
5.3	Draft recommendations for stakeholder comments	2009 Q2
5.4	Final recommendations	2009 Q3
5.5	Calculate offset limit	2009 Q4

TASK 6: EARLY REDUCTION ALLOWANCES (ERA)

The purpose of this task is to develop the Early Reduction Allowances (ERA) element of the program, including the process and criteria for awarding ERAs.[5]

CSAD will:

- Review existing approaches for ERA in other jurisdictions and/or existing trading systems.
- Develop the criteria for determining eligibility for ERAs including voluntary, additional, verifiable, permanent, and enforceable.
- Develop recommendations for the entities that are eligible for ERAs.
- Develop recommendations on a process for issuing ERAs and administration of ERAs.

ERAs must be developed and adopted within a timeframe that allows the WCI Partner jurisdictions to establish the number of allowances that will be issued in 2012, and be adopted as provisions in the essential elements. The proposed deadline for the completion of the task is October 2009.

An administrative process is needed to enable the implementation of ERAs, along with supporting capacity.

The ERAs should be designed to be: 1) simple to implement, 2) transparent to all parties, 3) fair for all covered sources, and should 4) provide consistency in the approach for all sectors.

<u>6.1. Background Paper on Approaches to Recognizing Early Reductions</u>
Review, assess and consider approaches taken by other jurisdictions to recognize early reductions (RGGI, EU-ETS, etc.), including criteria for determining eligibility for ERAs.

<u>6.2. Develop the Criteria for Determining Eligibility for ERAs</u>
Evaluate the range of possible criteria for determining eligibility for ERAs, and define the meaning for each criterion. Consider possible criteria such as voluntary, additional, verifiable, permanent, and enforceable, and provide guidance on how these criteria could be implemented in ERAs. Develop options and recommendations on the criteria, taking into consideration factors such as simplicity in implementation, fairness, verifiability, transparency and consistency, and others as needed.

<u>6.3. Develop Recommendations for Entity Eligibility for ERAs</u>
ERAs could be issued to a range of entities including the facility, a corporation or company, a municipal government, a government agency, and even perhaps the government of a WCI Partner jurisdiction. While many ERA projects may take place at a single facility or process, in other instances, industries or utilities may replace older facilities with a new facility at the

[5] ERAs are described in Section 8.11 of the *Design Recommendations for the WCI Regional Cap-and-Trade Program*.

same or different sites. CSAD will review possible type of projects that could qualify for ERAs and will evaluate which entities could be eligible to receive the ERAs. In addition, CSAD will consider how ERAs could be distributed by the WCI Partner jurisdictions.

6.4. Develop Recommendations on a Process for Issuing ERAs

Identify major steps needed to administer ERAs, including application for ERAs, evaluation of applications, determination of ERAs to be issued, notification of entities and WCI of eligible ERAs for each WCI Partner jurisdiction, and coordinating issuance of ERAs with issuance of allowances under the cap. Evaluate and recommend an administrative structure to implement ERAs, and linkage to other programs such as offsets.

Task	Deliverables	Dates
6.1	Background paper on approaches to ERAs	2009 Q1
6.2	Develop the criteria for determining eligibility for ERAs	2009 Q2
6.3	Develop recommendations for entity eligibility for ERAs	2009 Q2
6.4	Develop recommendations on a process for issuing ERAs and administration ERAs	2009 Q3

Markets Committee

The WCI has formed the Markets Committee to coordinate the development of recommendations on issues and elements needed to guide the proper development and operation of a robust allowance and offset credit trading market.

As described in this work plan, the Markets Committee has divided its work into the following six tasks:

Task 1: Cap-and-Trade Essential Elements
Task 2: Compliance Verification and Enforcement
Task 3: Market Oversight
Task 4: Tracking Systems and Related Infrastructure
Task 5: Regional Administrative Body
Task 6: Auction Design

As described below, each task proposes a plan to incorporate stakeholder input, including white papers, workshops, conference calls, and written comments. In addition, the Committee proposes that the Co-Chairs hold regular stakeholder conference calls to provide updates on the status of the Committee activities. Through these regular updates, stakeholders will be able to track the overall progress of the Committee's activities.

Description of Tasks and Deliverables

TASK 1: CAP-AND-TRADE ESSENTIAL ELEMENTS

The purpose of this task is to coordinate the writing of essential elements for the WCI regional cap-and-trade program. The essential elements will be available to WCI Partners for review and adoption in the development of each jurisdiction's cap–and-trade rules.

The functions performed under this task are:

- Create the framework for the essential provisions that each Partner is expected to adopt, to ensure effectively consistent implementation of the cap-and-trade program among the WCI Partner jurisdictions.
- Integrate the products from the other task groups within this Committee and from the other Committees into a coherent suite of essential elements. As part of this integration, identify inconsistencies or conflicts among products or recommendations from other task groups and Committees that need to be resolved.
- Identify any gaps in the inputs to the essential elements, and recommend an approach for filling the gaps.

The cap-and-trade essential element must be developed and approved by the WCI Partners jurisdictions within a timeframe that allows the WCI Partners to adopt regulations consistent with jurisdictional statutory and regulatory requirements before the 2012 program start date.

The following are the proposed subtasks for task 1:

<u>1.1. Determine appropriate level of detail for final work product</u>

<u>1.2. Develop time line for completing task work product so that program can begin on January 1, 2012</u>

The task group will:

- Identify the time frame needed by each jurisdiction to adopt rules given each jurisdiction's administrative procedure requirements.
- Identify the elements that will come from other task groups and Committees and their time frame for delivery. Based on work plan design, identify gaps in essential elements being developed by task groups and Committees.
- Identify and develop a coordination process with other task groups and Committees as needed.
- Based on WCI design and needs of individual Partner jurisdictions, determine if any elements need to be completed on an expedited timeline.
- Develop a stakeholder process that at a minimum includes the stakeholder processes included in this work plan. The WCI's stakeholder process will supplement each jurisdiction's informal and formal rulemaking processes, and take into account the minimum time frame jurisdictions may require for public review and comment.

<u>1.3. After completion of subtasks 1.1 and 1.2, prepare an outline of the cap-and-trade essential elements</u>
The outline shall identify or explain in brief the issues that will be covered in each section or subsection. Provide this draft for stakeholder review and comment no later than the beginning of the third quarter of 2009.

<u>1.4. Continue to draft and refine language for final work product</u>
Provide a draft for stakeholder review in the fourth quarter of 2009.

<u>1.5. Provide the final draft for stakeholder review by the end of the second quarter of 2010</u>

Task	Deliverables	Dates
1.1-1.2	Determine appropriate level of detail. Develop time line for completing task work product.	Jan–May 2009
1.3	Prepare outline of the final work product for stakeholder comment.	May–July 2009
1.4	Develop and release draft of work product for stakeholder comment	August–December 2009

Task	Deliverables	Dates
1.5	Develop and release final draft of model work product for stakeholder comment.	January–June 2010

TASK 2: COMPLIANCE VERIFICATION AND ENFORCEMENT

The purpose of this task is to develop recommendations related to compliance verification and enforcement requirements to ensure compliance by the regulated community and define linkages across WCI Partner jurisdictions. The task will address the consistency/uniformity needed across jurisdictions and the degree of flexibility warranted. This task will also address what elements would be needed to ensure equivalent treatment and stringency among WCI Partner jurisdictions as well as issues related to inter-state, inter-provincial, and international linkages.

The recommendations will focus on:

- Creating a consistent and coordinated framework for compliance verification and enforcement that can be used within the individual WCI Partner jurisdictions, including recommendations for harmonizing elements of enforcement to ensure credibility and similar stringency across Partner jurisdictions.
- Identifying, evaluating, and recommending any agreements, instruments, or other mechanisms needed to support cooperative enforcement across WCI Partner jurisdictions.
- Developing and recommending options for reporting on the consistency of compliance verification and enforcement.

The proposed timeline for preparing recommendations for WCI Partner consideration is March 2010 to enable inclusion in the cap-and-trade program regulations.

The following steps will be performed:

- Establish Goals: Determine the criteria for recommendations and definition of successful completion of the task.
- Identify Issues: Clearly identify the issues for which the Committee recommendations will be needed as part of the essential elements.
- Produce a white paper to provide background information. The white paper will describe compliance verification and enforcement issues and propose a framework for subsequent assessment and recommendations.
- Options: Identify and evaluate the options for compliance verification and enforcement provisions and establishing linkages.
- Recommendations: Recommend the options for consideration and approval.

Task	Deliverables	Dates
2	Establish goals	2009 Q1
	Identify issues	2009 Q2
	White paper and stakeholder comment	2009 Q3
	Draft recommendations released, stakeholder comment	2010 Q1
	Final recommendations released	2010 Q1

TASK 3: MARKET OVERSIGHT

The purpose of this task is to provide recommendations that are designed to ensure that the allowance and offset credit trading market is organized properly to operate reliably and prevent or minimize manipulation. The recommendations will cover four main areas:

- Market architecture, including the relationship between the program and external organizations that comprise the market (such as exchanges).
- Program design elements (such as transaction tracking and disclosure) to prevent improper market activity.
- Market surveillance activities (such as jurisdictional and market roles in data collection and analysis) to detect improper market activity, considering primary, secondary and derivatives markets.
- Enforcement responsibilities and authorities for each jurisdiction to investigate and enforce against suspected improper market activity.

To enable the appropriate pieces of the recommendations to be included in cap-and-trade program regulations, the proposed deadline for preparing recommendations for WCI Partner consideration is March 2010.

The Committee anticipates that there are important differences between U.S. and Canadian requirements, particularly for enforcement responsibilities. Consequently, this task must carefully examine requirements in both countries (and Mexico in the event that Mexican States implement the program), and assess any cross-border issues that may arise.

- Stakeholder Involvement: Stakeholders have expressed interest that the allowance and offset trading markets have appropriate safeguards and oversight and function efficiently. This task should be completed in as open and transparent manner as possible to ensure stakeholder confidence in the market oversight function. A stakeholder workshop will be held early in the execution of this task, and subsequent stakeholder events will be used to create dialogue and participation among stakeholders. In particular, the initial stakeholder workshop will be used to help identify issues to be examined in the task, and help frame the process for developing recommendations.

The following steps will be performed as part of this task:

- Define Objectives: Define the objectives of the market architecture and the market oversight function, including prevention, surveillance, and enforcement.

- White paper: Identify and evaluate options for market oversight, including program rules, market data collection and analysis, and involvement of appropriate enforcement agencies and institutions. Assemble background information on the market oversight function, identifying previous examples and expertise required. As part of assembling background information, review trading provisions, rules, and oversight processes from other environmental programs (such as acid rain, EU ETS, and RGGI) and financial markets. Review characteristics of financial instruments and literature on environmental markets and trading. Identify if any proposed essential elements may have the potential to create barriers to future trading across systems. Produce a draft white paper that describes market oversight and proposes a framework for subsequent assessment and recommendations. Distribute to stakeholders for comments.
- Recommendations: Recommend the options for consideration and adoption by the WCI Partner jurisdictions.

This task requires specialized expertise in existing and potential market architecture and how to prevent, detect, and enforce against improper market activity.

Task	Deliverables	Dates
3	Stakeholder workshop	2009 Q2
	White paper and stakeholder comment	2009 Q2
	Draft recommendations released, stakeholder comment	2010 Q1
	Final recommendations released	2010 Q1

TASK 4: TRACKING SYSTEMS AND RELATED INFRASTRUCTURE

The purpose of this task is to provide recommendations adoption regarding specification for a tracking system(s) and for how the tracking system will be created and maintained. Work on this task will identify issues that will need to be addressed in developing a tracking system, which include defining its functional requirements and business rules. The recommendations will cover the following areas:

- How the tracking system could be created/adapted from another system, structured, and administered.
- How the tracking system could record and track emissions, allowances, and offsets. (Note: The Reporting Committee has identified TCR as a repository of GHG emissions data.)
- How the tracking system could manage the import and export of allowances and offsets credits with other compliance systems.
- How the tracking system could demonstrate compliance, or the amount of non-compliance, at the end of compliance periods, including what information should be made public through the system.

The timelines for this task assume that a tracking system needs to be in place in by mid-2011 at the latest to support tracking of allowances and offset credits in the cap-and-trade programs.

This task will integrate with other tasks that may rely on the capabilities of the tracking system, including compliance verification and enforcement across jurisdictions, market oversight mechanisms, and regional administrative activities. The task will also require input and communication with the Reporting and Offsets Committees.

The following steps will be performed as part of this task:

- Objectives: Lay out a set of objectives—what a tracking system would be expected to accomplish and the standards it would be expected to meet.
- Definitions: Create working definitions of what a tracking system is, and what the main components of it could be, in order to start working from a set of common terminology.
- Consolidation of Current Knowledge: Examine what types of tracking systems are currently operational, and identify components that they have in common as well as their differences.
- Stakeholder Engagement: Input is needed both from stakeholders who will be using the tracking system and with those who have experience and can communicate lessons learned with existing tracking systems.
- White paper: Produce a white paper to provide information on what a tracking system is, and what capabilities it could have, in order to develop a basis for the development of options and recommendations for the task group, and to give the broader working group an understanding of the issues. Bring together an analysis of existing emissions, allowance and offset credit tracking systems, stakeholder input and feedback from within the task group into a working document that will serve as a basis for development of recommendations.
- Recommendations: Prepare recommendations on a WCI tracking system.

Task	Deliverables	Dates
4	White paper and stakeholder comment	2009 Q2
	Draft recommendations released, stakeholder comment	2009 Q4
	Final recommendations released	2010 Q1

TASK 5: REGIONAL ADMINISTRATIVE BODY

The purpose of this task is to provide recommendations regarding the design and operation of a regional administrative body to support the implementation of the WCI cap-and-trade program. The recommendations will cover three main areas:

- Functions to be performed by the regional administrative body.
- Organization of the regional administrative body.

- Governance, funding, and oversight of the regional administrative body, and planning for bringing it into existence.

The recommendations must be developed and adopted within a timeframe that allows the WCI Partner jurisdictions to adopt the recommendations and bring the body into existence in time to use it to initiate the program. At the latest, the WCI Partner recommendations may be required by September 2010, so that the body can be brought into existence by April 2011. This timing would enable the regional body to support the start of the cap-and-trade program with allowance tracking and auction execution.

The following may be potential roles for a regional administrative organization:

- Coordinate the regional auction of allowances.
- Track emissions and provide public information on progress towards the WCI regional goal.
- Monitor and report on market activity, including any potential market manipulation.
- Serve as a forum for WCI Partner jurisdictions to update one another on program progress.
- Coordinate review and adoption of protocols for offsets.
- Coordinate review and adoption of updated reporting protocols.
- Coordinate review and issuing of offset credits.
- Suggest criteria and means to accredit service providers to deliver validation and verification services.
- Disclose allowance and offset prices.

Also of note is that this task requires as input the results of other tasks, including recommendations on tracking systems and related infrastructure that could potentially be operated and maintained by the regional administrative body; recommendations on market oversight functions that could potentially be undertaken by the regional administrative body; and understanding of potential roles of other entities, such as TCR.

Successfully completing this task first requires defining the function of the regional administrative body:

- <u>Functions</u>: Identify options for the scope of the functions that a regional administrative body could perform to support the regionally coordinated program. Consider length of time and quantity of staff time required by each function. Review examples.

- <u>Criteria</u>: Adopt and apply criteria to identify the functions and appropriate scope of functions to be considered for the regional administrative body.

Based on these steps, a fully defined scope of responsibility for regional administrative body can be recommended to the WCI Partner jurisdictions for consideration. Once the WCI Partner jurisdictions have approved the organizational scope, the design of the organization itself can be initiated, along with the plan for governance, funding, and oversight.

The following subtasks are proposed:

5.1. Recommended Functions
Identify, evaluate, and recommend functions to be performed by the regional administrative body. As part of this subtask: review examples, confer with the Legal Team, and assess the relevance and importance of organizational functions being considered.

5.2. Organizational Design
Design an organization to carry out the functions selected and defined in subtask 5.1, and describe the WCI Partner jurisdictions' goals for successful execution of those tasks. The Organizational Design will include an organization chart; proposed staffing levels with draft position descriptions, task statements, and funding requirements; and a detailed timeline outlining the necessary legal and logistical steps required to bring the organization into existence.

5.3. Governance, Funding, Oversight
Recommend approaches for governance, funding, and oversight. Additionally, this subtask will include identifying steps required by the WCI Partner jurisdictions to engage the body to provide services.

Task	Deliverables	Dates
5.1	White paper and stakeholder comment	2009 Q3
	Draft recommendations released, stakeholder comment	2009 Q4
	Final recommendations released	2010 Q1
5.2	White paper and stakeholder comment	2010 Q2
	Final recommendations released	2010 Q3
5.3	White paper and stakeholder comment	2010 Q1
	Draft recommendations released, stakeholder comment	2010 Q2
	Final recommendations released	2010 Q3

TASK 6: AUCTION DESIGN

The purpose of this task is to provide recommendations to the WCI Partner jurisdictions on the design of the auction that will be used to auction emission allowances in a regionally coordinated manner consistent with applicable state and provincial law. To enable the recommendations to be included in WCI Partner jurisdictions' cap-and-trade program rules, the proposed deadline for preparing recommendations is May 2010.

In approaching this task, the task group recognizes that auction design requires specialized expertise. Additionally, the WCI Partners and stakeholders insist that the auction include appropriate safeguards and oversight. This task should be completed in as open and transparent manner as possible to ensure stakeholder confidence in the market function.

The following steps will be performed:

- Goals of auction design: Define success and performance metrics for the cap-and-trade program auctions.
- White paper: Considerable work has been done to design government auctions for environmental products (RGGI, EU ETS, Acid Rain) and other assets (financial and commodity). The auction design process should start by considering previous examples; expertise required; and experts who the WCI Partner jurisdictions may consider for providing advice and assistance. Review of the RGGI auction design is recommended as an important element. The white paper will create a framework for informing decisions on auction design, including a catalog of the decisions to be made and assessment of their inherent tradeoffs.
- Technical Analysis: Technical analysis of auction design options may inform and support design recommendations. The scope of the analysis depends on what the WCI Partner jurisdictions find is needed to make a decision regarding the auction design. If the WCI Partner jurisdictions find that the existing literature addresses the critical design questions to their satisfaction, then limited additional analyses may be required. Alternatively, if fundamental questions remain to be addressed, or in the least applied to WCI Partner jurisdiction conditions, then more in-depth analyses may be needed. The extent of the analyses required will be determined following the preparation of the white paper and the response of stakeholders to it.

Task	Deliverables	Dates
6	White paper and stakeholder comment	2009 Q3
	Technical analysis	TBD
	Draft recommendations released, stakeholder comment	2010 Q1
	Final recommendations released	2010 Q1

Electricity Committee

The purpose of the WCI Electricity Committee is to address issues specific to the electric sector related to the design and implementation of the WCI Partner jurisdictions' cap-and-trade program. The WCI Electricity Committee has assessed policy mechanisms for addressing electricity sector emissions, consulting with stakeholders on conference calls, in public meetings and through the release of written documents for review and comment. Among the issues examined have been technical issues regarding the First Jurisdictional Deliverer (FJD) approach and issues concerning reliability and electricity market efficiency. The Electricity Committee is continuing its examination of issues, and will provide input to other WCI committees on electricity sector issues.

The Electricity Committee proposes to divide its work into the following five tasks:

Task 1: Provide Essential Elements for Reporting for the Electric Sector
Task 2: Assess FJD Boundary Options for WCI Partner jurisdictions
Task 3: Attributing Emissions to Imported Electricity
Task 4: Allowance Set-Asides for Voluntary Renewable Energy Products
Task 5: Competitiveness and Reliability Issues Related to Distribution of Allowance and Allowance Value

Description of Tasks and Deliverables

TASK 1: PROVIDE ESSENTIAL ELEMENTS FOR REPORTING FOR THE ELECTRIC SECTOR

The purpose of this task is to provide input to the Reporting Committee on the essential elements of mandatory reporting requirements for the electric sector, including reporting requirements for electricity imports. A draft version will be issued for stakeholder comment in February, and the Electricity Committee will prepare a final version for the Reporting Committee in March.

Task	Deliverables	Dates
1	Draft essential elements	2009 Q1
	Final essential elements	2009 Q1

TASK 2: ASSESS FJD BOUNDARY OPTIONS FOR WCI PARTNER JURISDICTIONS

The Electricity Committee and its Technical Advisory Group examined issues associated with the implementation of First Jurisdictional Deliverer (FJD) as the point of regulation, including potential impacts on the efficiency of wholesale power markets. The Committee has produced a discussion paper and held a conference call with stakeholders to consider other alternatives. The findings of the FJD options assessment will be released for stakeholder review and comment in Q2 2009. The recommendations from the Committee will also be provided to the Markets Committee.

Task	Deliverable	Date
2	FJD Assessment for Stakeholders	2009 Q2
	Recommendation to Market Committee	2009 Q4

TASK 3: ATTRIBUTING EMISSIONS TO IMPORTED ELECTRICITY

The purpose of this task is to prepare a report that addresses several issues related to emissions associated with imported electricity, focusing particularly on default emission rates for unspecified power imports. The assessment will examine options for defining default emission rates, and the implications for contract shuffling and leakage. The potential role of Renewable Energy Certificates (RECs) used for Renewable Portfolio Standards will also be examined. The report will discuss options and methodologies for setting default rates with a recommendation planned by Q4 2009. The Committee will also work with the CSAD Committee to develop base year estimates of emissions associated with power imported from non-WCI locations to assist in the cap setting process.

Task	Deliverables	Dates
3	Draft Report on Emission Attribution	2009 Q2
	Stakeholder Workshop	2009 Q2
	Final Report on Emission Attribution	2009 Q2
	Recommended Data Set and Methodology for Base Year Estimates to CSAD Committee	2009 Q4
	Draft Default Rates for Stakeholders	2009 Q4
	Final Default Rates	2009 Q4

TASK 4: ALLOWANCE SET-ASIDE FOR VOLUNTARY RENEWABLE ENERGY PRODUCTS

The purpose of this task is to examine issues regarding the role of a set-aside of allowances in some states or provinces that could be retired when consumers purchase renewable energy certificates (or RECs) in the voluntary market. Without a set-aside or alternative mechanism for retiring allowances, renewable energy marketers and developers are concerned that under cap-and-trade, demand for voluntary renewable energy (VRE) will fall significantly as consumers realize that their purchases no longer contribute to GHG emission reductions. A set-aside would allow the VRE market to continue to make GHG emission reduction claims. Recognizing that the use of set asides is left to the discretion of each Partner jurisdiction, the Committee will identify the issues associated with creating a set aside for this purpose for Partners' information.

Task	Deliverables	Dates
4	Issue Discussion Paper on VRE Set-Asides	2009 Q3

	Convene Stakeholder Call	2009 Q3
	Draft Report on VRE Set-Asides	2009 Q3
	Final Report on VRE Set-Asides	2009 Q4

TASK 5: COMPETITIVENESS AND RELIABILITY ISSUES RELATED TO DISTRIBUTION OF ALLOWANCE AND ALLOWANCE VALUE

The purpose of this task is to examine allowance distribution issues that are specific to the electric sector, with particular emphasis on competitiveness and reliability impacts. The electricity sector in WCI jurisdictions includes a mix of competitive wholesale markets and many vertically integrated, rate regulated utilities as well as large regional differences in GHG intensity. The implications of allowance distribution policies may differ markedly compared to other sectors. Additionally, stakeholders have expressed concerns that certain aspects of cap-and-trade design could undermine grid reliability. The Electricity Committee will provide an assessment of these issues in a report to the CSAD Committee and the WCI Partners.

Task	Deliverables	Dates
5	Draft Report on Allowance Distribution in Electric Sector	2009 Q3
	Convene Stakeholder Call	2009 Q3
	Final Report/Proposal on Allowance and Allowance Value Distribution in Electric Sector	2009 Q4

Offset Committee

The purpose of the Offset Committee is to make recommendations to the WCI Partner jurisdictions on the design and operation of the offset system as part of the WCI cap-and-trade program, including the criteria necessary for offset projects to be used to meet compliance obligations within the regional program.

The Committee will:

- Recommend and define the essential elements for the offsets system, including the necessary rules and infrastructure, to create and operate the offset system as part of the cap-and-trade program.
- Recommend standards and a process for accepting offset credits from other GHG trading programs and recognizing emission allowances from other GHG trading systems.
- Coordinate the joint review, development, and approval of offset protocols and initiate the establishment of a process to coordinate the review and recommendation of protocols proposed by project developers.
- In conjunction with any further economic modeling, provide input to the Economic Modeling Team on projected offset supply (tonnes CO_2e/year) and costs.

The Offsets Committee will collaborate with the CSAD Committee on accounting methods for ERAs.

The Offsets Committee proposes to divide its work into the following four tasks:

Task 1: Offset System Essential Elements
Task 2: Offsets and Allowances from Systems Other than the WCI
Task 3: Offset Protocols
Task 4: Offset Supply Analysis

Description of Tasks and Deliverables

TASK 1: OFFSET SYSTEM ESSENTIAL ELEMENTS

The Offsets Committee will recommend essential elements and infrastructure to create and operate the offset system as part of the cap-and-trade program.

The deliverables are a suite of recommendations that will enable the efficient and effective creation and operation of the offset system. The recommendations will be developed in conjunction with the Markets, CSAD, and Reporting Committees and will accompany the recommended cap-and-trade essential elements being developed as part of Task 1 in the Markets Committee.

The deliverables include:

- The definition of a WCI GHG offset
- Detailed eligibility criteria for GHG offset projects for compliance purposes under the cap-and-trade system.
- Detailed requirements for the registration, validation, monitoring, quantification, reporting, verification, certification, and issuance of offsets.
- Recommended aspects of the regulation and enforcement of offset project activities that should be included in the cap-and-trade essential elements.
- Recommended functions of the regional administrative body and tracking system related to the offset system.

Task	Deliverables	Dates
1	Define a WCI GHG offset	2009 Q1
	Develop detailed eligibility criteria for GHG offset projects for compliance purposes under the cap-and-trade system	2009 Q3
	Develop detailed requirements for the registration, validation, monitoring, quantification, reporting, verification, certification, and issuance of offsets	2009 Q3
	Recommend aspects of regulation and enforcement related to offsets that should be included in the cap-and-trade essential elements	2009 Q3
	Recommend functions of the regional administrative body and tracking system related to the offset system	2009 Q3
	Final recommendation of essential elements for the offsets system	2009 Q4

TASK 2: OFFSETS AND ALLOWANCES FROM SYSTEMS OTHER THAN THE WCI

The Offsets Committee will recommend standards for evaluating and, if appropriate, accepting tradable units (offset credits and allowances) from programs other than the WCI cap-and-trade program. The Committee may recommend added criteria to ensure similar rigor to WCI approved/certified offset projects or other requirements appropriate to enable use of these offset credits in the cap-and-trade program.

The Committee will monitor the ongoing development of the United Nations Framework Convention on Climate Change (UNFCCC) negotiations as they pertain to the future design of the Clean Development Mechanism (CDM) and any new carbon finance mechanisms. The Committee will also follow International Carbon Action Partnership deliberations with respect to the use of international offsets and the linking of emission trading systems. The Committee will prepare comments for the WCI on these processes.

Task	Deliverables	Dates
2	Perform an analysis on the standards which could be used to evaluate and, if appropriate, accept tradable units from programs other than the WCI	2009 Q3
	Recommend standards for evaluating and, if appropriate, accepting tradable units from programs other than WCI	2009 Q4
	Monitor ongoing development of international offset mechanisms and the linking of emission trading systems, and prepare comments for the WCI, as needed	Ongoing

TASK 3: OFFSET PROTOCOLS

WCI protocols will be detailed, project-type specific instructions for project developers that describe standard approaches, equipment, procedures, and requirements for project development, operation, monitoring, calculation, reporting and verification. Protocols must meet the criteria and requirements that are identified in task 1.

The Offsets Committee will review existing organizations and institutions which may have the capacity or structures to perform the protocol review and recommendation process. An analysis of these bodies' strengths and weaknesses will be conducted and compared to the internal capabilities of the WCI.

Upon completion of eligibility criteria under task 1, evaluation and review of existing offset protocols, and, if and as needed, the development of new offset protocols will begin. The Committee will also initiate the establishment of a process to coordinate the review and recommendation of project types and protocols proposed by project developers.

Evaluation and adaptation of existing protocols will be the focus of Committee work for during 2009, and will begin with the following project types:

- Agriculture
  - Soil sequestration
  - Manure management
  - Anaerobic digestion
  - Rangeland management
- Forestry
  - Afforestation
  - Reforestation
  - Forest management
  - Forest preservation/conservation
  - Forest products
  - Urban forestry
- Waste management
  - Landfill gas
  - Waste and wastewater treatment

The WCI Partner jurisdictions have chosen to begin evaluating the project types on the previous list because they are interested in understanding if they are suitable for the offset system, if they will meet the criteria for environmental integrity, and if adequate protocols/methodologies for their quantification and monitoring exist or can be adapted or developed. Project types that appear on the previous list are not guaranteed to be in an offset system. Similarly, omission of project types from this list does not preclude additional project types from being evaluated by the Committee. The Committee will recommend additional opportunities to the WCI Partner jurisdictions for protocols that are not identified in the previous list of project types.

Offset protocols benefit greatly from collaborative review and development by experts, academics, project developers, government agencies, and the public with reasonable oversight from the regulator or program authority to guide the process and ensure the protocol meets all of the criteria of the offset system. Interest in protocol review, development, and adaption exists across the continent and it is expected that large numbers of stakeholders will want to be involved in the WCI protocol review and development process. The Committee will aim to identify those stakeholders with knowledge, experience and resources to be directly involved in the appropriate protocol task teams.

Additional project types for which substantial high quality protocol development work has been conducted may also be considered during 2009.

The Committee will ensure protocol task groups are formed as appropriate in order to:

- Identify existing offset protocols applicable to the project type.
- Evaluate each applicable protocol against the eligibility criteria identified in task 1, including monitoring, quantification, and verification components.
- Recommend candidate protocols for adaptation to the WCI offset system.
- Adapt project-specific components of each candidate protocol, such as site-specific or regional quantification factors and project specific verification requirements, to the WCI offset system.
- Recommend adapted protocols for approval.

These steps may be taken in conjunction with other organizations or jurisdictions engaged in protocol development or the use of offset protocols.

Where no suitable protocol exists, the Committee may examine the feasibility of developing a new protocol and if approved, will recommend a course of review for that protocol.

Task	Deliverables	Dates
3	Review existing organizations and institutions which may have capacity/structure to perform protocol review and recommendation, and identify options for selecting/developing offset protocols from other programs	2009 Q1
	Form protocol task groups	As needed

Task	Deliverables	Dates
	Evaluate and adapt existing protocols	2009
	Issue draft and final WCI protocol language	2009
	Where no suitable protocol exists, recommend a course of development for that protocol	As needed

TASK 4: OFFSET SUPPLY ANALYSIS

In conjunction with any further economic modeling, provide input to the Economic Modeling Team on projected offset supply (tonnes CO_2e/year) and costs.

The estimates will:

- Cover the period 2010 through 2020.
- Be derived from offset supply scenarios developed by the Committee, incorporating the conditions of the reference case and policy case of the existing economic modeling and potential state, regional, national, continental and international regulatory outcomes.
- Be delivered to the Economic Modeling Team in a form suitable for incorporation in the existing economic modeling being undertaken.

The Committee will review and assess existing scenario analyses and offset cost and supply information for the three regions. If suitable information is not available, the Committee will recommend internal and/or contract resources to develop or deliver the information.

Task	Deliverables	Dates
4	Develop offset supply estimates	To be scheduled per economic modeling timing requirements

Complementary Policies Committee

(Included June 23, 2009)

The WCI Partners recognize that it will take numerous policies working in concert with cap-and-trade to achieve the regional GHG reduction goals in a cost-effective manner. These "complementary" policies achieve a variety of additional common goals and objectives:

- Remove market barriers to lower emissions (e.g., competing incentives, regulatory disincentives and financial barriers)
- Reach beyond actions that respond to a direct carbon price
- Achieve reductions outside (or below) the cap
- Encourage investments in low-carbon technologies
- Lower the cost per metric ton of reductions in GHG emissions in the cap-and-trade program
- Lower the cost of transitioning to a low-carbon economy
- Prevent emissions and economic leakage
- Create and retain green jobs

As used within the WCI, "complementary policies" includes policies that will reduce GHG emissions outside the cap and will assist with the transition to a low-carbon economy. The Complementary Policies Committee will focus on and recommend to the WCI Partners policies where harmonization would be useful to both achieve the regional emission reduction goal and assist with the transition to a low-carbon economy. This process will examine policies to reduce emissions from capped and uncapped sectors. The Committee will:

- Examine GHG reduction policies implemented in Partner jurisdictions and other GHG reduction policies that could be more effective and achieve additional benefits if harmonized across WCI jurisdictions
- Engage with states and provinces outside of WCI to harmonize the design or implementation of certain complementary policies
- Examine the most effective manner for interaction between state/provincial and federal complementary policies
- Develop a list of policies to consider for harmonization across the WCI Partner jurisdictions, also noting any barriers to those policies
- Work with agencies that have an authority in the area of labor and/or training to identify potential issues where other types of policies may be needed to transition to a low-carbon economy, including worker training and other workforce transition needs
- Recommend, in conjunction with the appropriate agencies, the principles or outcomes for programs that may assist with workforce transition, job creation or retention or the revitalization of local communities that depend on energy-intensive industries

Where appropriate, the Committee will work with WCI Partners and other Committees to incorporate the impacts of the selected complementary policies in other WCI analytical work such as economic modeling.

To the extent non-WCI states and provinces begin to participate with the WCI on one or more complementary policies, that state or province is included in the work indicated below as a "WCI Partner jurisdiction."

The Complementary Policies Committee proposes to divide its work into the following five tasks:

Task 1: Evaluation of Greenhouse Gas Reduction Policies
Task 2: Alternative Ways to Obtain Stakeholder Views and Involvement and Engaging Non-WCI States and Provinces
Task 3: Other Policies to Assist In the Transition to a Low-Carbon Economy
Task 4: Evaluation and Recommendations for Harmonized Policies
Task 5: Inventory of Inter-Jurisdictional Adaptation Work Groups, Committees and Other Collaborations

Description of Tasks and Deliverables

TASK 1: EVALUATION OF GREENHOUSE GAS REDUCTION POLICIES

Deliverable: A white paper that describes the complementary policies the Committee believes could be more effective and achieve additional benefits if harmonized across WCI jurisdictions and the criteria to be used for further evaluations.

Each of the WCI Partner jurisdictions has a climate change plan that, in addition to cap-and-trade, includes other policy instruments needed to achieve the jurisdiction's own emissions reduction goals or targets and to achieve emission reductions outside the cap. The first step in evaluating and recommending policies is to identify policies already underway or recommended for adoption in each Partner jurisdiction for further analysis. The Complementary Policies Committee also may identify other complementary policies implemented outside the WCI jurisdictions.

<u>1.1. Compile a list of WCI complementary policies</u>
Using a matrix format, each Partner will identify complementary policies already underway or recommended for adoption within their jurisdictions.

<u>1.2. Select policies for further evaluation</u>
Develop a subset of complementary policies from an assessment of the policies identified under Task 1.1 and policies from existing regional and national databases with the potential for substantial benefits if implementation is harmonized.

1.3. Develop criteria for further evaluation of these policies, such as:

- Effectiveness at mitigating greenhouse gas emissions (e.g., cost per metric ton)
- Ease and cost effectiveness for both implementation (government) and compliance (regulated entity)
- Effects on low-income communities or small businesses
- Barriers to harmonizing implementation
- Collateral benefits and costs (e.g., conserving water, increase use of electricity) or collateral detriments (e.g. increased fine particulate or air toxics pollution)
- Prevention of leakage outside the cap
- The potential to create or retain green jobs or otherwise transition to a low-carbon economy

1.4. Prepare white paper that describes:

- Why and when policies complementary to a cap-and-trade program are useful
- How complementary policies help achieve the WCI greenhouse gas reduction goal
- Each of the policies the Committee recommends for further evaluation under Task 4 and the benefits the Committee believes would accrue to the Partner jurisdictions if implementation was harmonized
- Which policies affect emissions under the cap and which do not
- The criteria the Committee will use for further evaluation

1.5. Submit white paper to stakeholders for review and comment
Seek stakeholder comment specifically on benefits that would result from harmonized implementation, the criteria to use to for further evaluation, issues the Committee should consider, and the types of policies that are needed to accompany the transition to a low-carbon economy, such as economic leakage, workforce development and community revitalization. Amend the white paper as necessary; finalize and prepare responses to comments received from stakeholders.

Task	Deliverables	Dates
1.1	Compile a list of WCI complementary policies	2009 Q2
1.2	Select policies for further evaluation	2009 Q3
1.3	Develop criteria for further evaluation of these policies	2009 Q3
1.4	Prepare white paper	First draft of white paper 2009 Q3
1.5	Submit white paper to stakeholders for review and comment	Paper available to stakeholders: 2009 Q4; Final Paper and response to comments 2010 Q1

TASK 2: ALTERNATIVE WAYS TO OBTAIN STAKEHOLDER VIEWS AND INVOLVEMENT AND ENGAGING NON-WCI STATES AND PROVINCES

Deliverables: Possible outreach plan; recommendations using other mediums for stakeholder comments

2.1. Possible Outreach Plan

To the extent the Committee identifies successful complementary policies being implemented in non-WCI jurisdictions or has identified benefits that could increase if a given policy was harmonized across more states and provinces, the Committee will develop an outreach plan for those states and provinces to join in this aspect of the WCI work.

2.2. Stakeholder Engagement Analysis

The Committee will evaluate methods for how the Committee and possibly the WCI Partners could engage stakeholders in a more open dialogue.

Task	Deliverables	Dates
2.1	Possible Outreach Plan	2010 Q1
2.2	Stakeholder Engagement Analysis	2009 Q2 and ongoing

TASK 3: OTHER POLICIES TO ASSIST IN THE TRANSITION TO A LOW-CARBON ECONOMY

Deliverable: Report on the principles that should guide workforce transition and community revitalization programs.

As a carbon price is built into the global economy, low-carbon opportunities will gain a competitive advantage. Transitioning to a low-carbon economy will change the workforce and training needs within the WCI jurisdictions and may impact communities that are dependent on energy-intensive industries. It is important that as the Committee identifies the programs and policies that will be necessary to achieve the emission reduction goals. The Committee will also consider the possible workforce and communities programs and policies so that the transition to a low-carbon economy will happen in a smooth and supportive manner.

3.1. Issues identification and communication

Assist in identifying and communicating workforce issues such as the type of trained workforce that will be needed to implement the complementary policies.

3.2. Create inventory

Working with appropriate agencies in the Partner jurisdictions, inventory the types of programs that could be used to assist with transitioning the workforce or communities to a low carbon economy.

3.3. Develop recommendations

Develop recommendations on the outcomes of these types of programs and policies in order to successfully position the WCI in a low carbon economy, providing green opportunities for our workers and communities.

3.4. Submit recommendations

Submit recommendations to stakeholder for review and comment; amend recommendations as necessary; finalize recommendation and prepare response to comments received from stakeholders

3.5. Make recommendations for additional analyses

Based on a review of available studies and in consultation with subject matter expert agencies, recommend where additional analyses may be necessary to evaluate the resources likely to be required for effective workforce transition and community revitalization programs associated with climate protection programs and policies.

Task	Deliverables	Dates
3.1	Issues identification and communication	2009 Q3 and Q4
3.2	Create inventory	2010 Q1 and Q2
3.3	Develop recommendations	2010 Q2
3.4	Submit recommendations	To stakeholders 2010 Q2; final recommendations and response to comments 2010 Q3
3.5	Make recommendations for additional analyses	2010 Q3 and Q4

TASK 4. EVALUATION AND RECOMMENDATIONS FOR HARMONIZED POLICIES

The Committee will recommend specific policies for regional harmonization.
Deliverable: White paper on the evaluation of and recommended policies for regional harmonization.

4.1. Evaluation and selection of policies for harmonization; design recommendations for selected policies

Evaluate the subset of policies from Task 1 against the adopted criteria from Task 1. Based on this evaluation, recommend which policies are most appropriate for regional harmonization. Identify any barriers to harmonizing these policies across the region. Include any needs related to job creation or retention or community needs associated with the specific policies. Develop design recommendations to facilitate regional harmonization of the selected policies.

4.2. Prepare white paper

Prepare white paper of the results of the analysis for inter-jurisdictional work on the selected policies.

4.3. Stakeholder review and comment

Request stakeholder review and comment; amend paper as needed, and prepare response to comments received

Task	Deliverables	Dates
4.1	Evaluation and selection of policies for harmonization; design recommendations for	2010 Q1

	selected policies	
4.2	Prepare white paper	First draft 2010 Q2 Final draft 2010 Q2
4.3	Stakeholder review and comment	Final draft to stakeholder 2010 Q3; Final recommendations with response to comments 2010 Q3

TASK 5: INVENTORY OF INTER-JURISDICTIONAL ADAPTATION WORK GROUPS, COMMITTEES AND OTHER COLLABORATIONS

The Committee will inventory the work that is currently taking place on adaptation issues. The WCI Partners may at that time make any further recommendations to the Committee for continued work in this area.

Task	Deliverables	Dates
5	Report on where WCI jurisdictions are working together on adaptation issues	2009 Q4

Economic Modeling Team

The Economic Modeling Team was formed in 2008 to provide WCI Partner jurisdictions with economic analysis to inform the development of the regional, multi-sector cap-and-trade program. In 2009, the Team will continue to serve as a resource to the WCI Partners and other Committees, and inform the development of cap-and-trade policy and design options.

The work of the Economic Modeling Team, continuing from 2008, is divided into the following tasks:

Task 8: Expand the WCI Version of ENERGY 2020
Task 9: Phase 3 Policy and Sensitivity Cases

Description of Tasks and Deliverables

TASK 8: EXPAND THE WCI VERSION OF ENERGY 2020

The purpose of this task is to expand the WCI version of ENERGY 2020 to include all the WCI Partner jurisdictions (including the three Canadian provinces omitted from the Phase 2 analyses) in a manner that enables subsequent expansion to additional states and provinces.

8.1. Expanded Model
The Economic Modeling Team will work with the contractor to expand the Phase 2 model to incorporate the three Canadian province partners: Manitoba, Quebec, and Ontario. The expanded model will be capable of being expanded to additional WCI partners in the U.S. and Canada.

8.2. Model Outputs
Prepare standard model output spreadsheets that incorporate the necessary model results for each of the WCI Partner jurisdictions and geographic regions. Model output will be provided to WCI Partner jurisdictions requesting it to conduct macroeconomic analyses.

8.3. Reference Case
Develop and provide the Reference Case for the expanded model. The Team will run the Reference Case, provide the Reference Case outputs, and address any questions or anomalies in the outputs. The Assumptions Book will be updated to reflect the expanded model and its inputs.

Task	Deliverables	Dates
8.1	Expanded model	2009 Q1
8.2	Updated output spreadsheets	2009 Q1
8.3	Reference Case outputs	2009 Q1

Task	Deliverables	Dates
	Update the Assumptions Book for Phase 3	2009 Q1

TASK 9: PHASE 3 POLICY AND SENSITIVITY CASES

The purpose of this task is to analyze policy and sensitivity cases using the expanded WCI version of ENERGY 2020, and includes the following.

9.1. Complementary Policies
The Economic Modeling Team will work to define how the complementary policies will be represented for the three newly included provinces; update the Phase 2 complementary policy specifications; and create sensitivity cases of the complementary policies for use in the sensitivity analysis.

9.2. Policy Cases
Specify the policy cases that will be used in the policy analyses. The policy cases will be based on the Phase 2 policy cases, and may include refinements in the specification of the program scope to reflect the phase in of coverage, the limit on offsets to reflect the limit on offset usage, banking parameters, and other policy inputs.

9.3. Sensitivity Cases
Specify the sensitivity cases that will be used in the sensitivity analyses. The sensitivity cases will be based on the Phase 2 sensitivity cases, but will include additional sensitivities as defined by the Economic Modeling Team, including complementary policy sensitivity, offset price sensitivity (including incorporating an offset supply curve), impacts of key assumptions such as no new coal plant construction (with and without FJD), and other factors.

9.4. Other Updates
Complete any other model updates necessary to perform the policy and sensitivity cases. These updates may include specification of additional technologies (e.g., plug-in hybrid vehicles) or other factors required to conduct the analyses.

9.5. Model Runs and Results
Conduct the policy and sensitivity analyses using the expanded model, and to provide the model results.

9.6. Assumptions Book
Update the Assumptions Book to reflect any model updates that were conducted to support the policy and sensitivity cases.

9.7. Analysis Follow Up
Address stakeholder questions that may arise from the analysis. Written explanations of the reasons for the observed results will be provided to questions regarding the analysis.

Task	Deliverables	Dates
9.1–9.4	Specification of the complementary policies, policy cases, and suggested sensitivity cases for Phase 3	2009 Q1
9.5	Model results publicly available	2009 Q2
9.6	Updated Assumptions Book for Phase 3	2009 Q2
9.7	Analysis follow-up	As requested

Stakeholder Engagement

The process that led to the *Design Recommendations for the WCI Regional Cap-and-Trade Program* released September 23, 2008 was careful and deliberate. At each step of design development, there were many opportunities and methods for stakeholder input on a regional level. These opportunities supplemented and did not replace extensive stakeholder consultations at the state and provincial levels. In addition, states and provinces have continued to conduct extensive stakeholder consultations directly in their jurisdictions. The decisions reached throughout the design process benefited greatly from stakeholder input.

The regional stakeholder process for the Design Recommendations included a number of important avenues for the sharing of information and input. Among them:

- Stakeholder Workshops
- Stakeholder Conference Calls
- Written Review and Comment
- The WCI Website (www.westernclimateinitiative.org)

The WCI Partner jurisdictions will continue to engage in regular consultation with stakeholders throughout the next phase of cap-and-trade program design through face-to-face meetings, webinars, video conferences, webcasts, teleconferences, and by releasing documents for stakeholder review and comment. A complete calendar of stakeholder engagement activities is being developed for the WCI website, and will be available in March 2009. The WCI Partner jurisdictions will be working to further improve the stakeholder process by coordinating the release of documents to stakeholders (e.g., a once-a-month release), coordinating stakeholder events such as calls/webinars (e.g., once a month, following the release of documents), and coordinating face to face events to reduce incremental travel (face to face events will also continue to have a call-in option).

Each WCI Committee anticipates soliciting public input on specific topics and work products, as described briefly below. Feedback will inform the development of Committee recommendations. For the most current information, stakeholders are encouraged to check the WCI website and/or join the WCI list serve to receive regular announcements about stakeholder activities.

Cap Setting and Allowances Committee

The CSAD Committee will engage stakeholders in reviewing the historical and projected emission data set that will be used to define Partner budgets. Through concept papers and release of draft material, stakeholders will be involved in the definition and criteria for Early Reduction Program and Offset Limit as well as in the criteria and policy options for Competitiveness Analysis. Once the criteria and policy options for Competitiveness Analysis are determined, the committee will seek the participation of stakeholders in providing information about their competitiveness issues. Workgroups will be created to review the information provided. It is expected that stakeholder consultation will be required to discuss the information provided.

Markets Committee

The Markets Committee will provide opportunity for written stakeholder feedback on the draft cap-and-trade essential elements. It will develop a stakeholder process that will supplement (not replace) each jurisdiction's administrative procedure requirements. For the remaining tasks under the Markets Committee, including Compliance Verification and Enforcement, Market Oversight, Tracking Systems and Related Infrastructure, Regional Administrative Body, and Auction Design, overview papers will be circulated for review and comment to help frame the issues. Stakeholder meetings will be held via teleconference early in the development of draft recommendations papers and face-to-face or teleconference meetings will be held with stakeholders to solicit input for final recommendations. For Market Oversight, a stakeholder workshop will be held early in the execution of this task to help identify issues to be examined in the task, and help frame the process for developing recommendations

Reporting Committee

The Reporting Committee will seek stakeholder review and comment on the additional sector-specific essential requirements for emissions reporting as proposals are developed throughout 2009. Proposed reporting requirements will be developed for oil and gas production, gas processing, and methane emissions from natural gas transmission and distribution. In addition, the point of regulation and definition of the reporting entity will be addressed for oil and gas production and for distribution of transportation fuels and residential, commercial and industrial fuels. Stakeholder feedback will be solicited via written comments and sector-specific conference calls. In addition, stakeholders will have the opportunity to review and comment on the design of the user interface for electronic submission of emissions reports, and a web demonstration of the system will be provided.

Electricity Committee

The Electricity Committee will continue to solicit stakeholder feedback on issues specific to the electric sector. Stakeholders will be asked to review written documents and provide comments on the essential elements of mandatory reporting requirements for the electric sector, options for the implementation of FJD, issues related to emissions associated with imported electricity, the role of set-aside allowances for renewable energy products, and allowance distribution issues specific to the electricity sector. Stakeholders will also be able to provide feedback at technical working sessions and through conference calls.

Economic Modeling

The Economic Modeling Team will provide opportunity for stakeholder input on the next phase of economic analysis being conducted to inform the development of cap-and-trade policy and design options. The Team plans to hold calls and meetings to preview results of the policy cases and sensitivity runs using the expanded WCI version of the ENERGY 2020 model. Written explanations for the observed results will be provided to stakeholder questions regarding the analysis. Comments provided by stakeholders will also be reflected in the updated Assumptions Book.

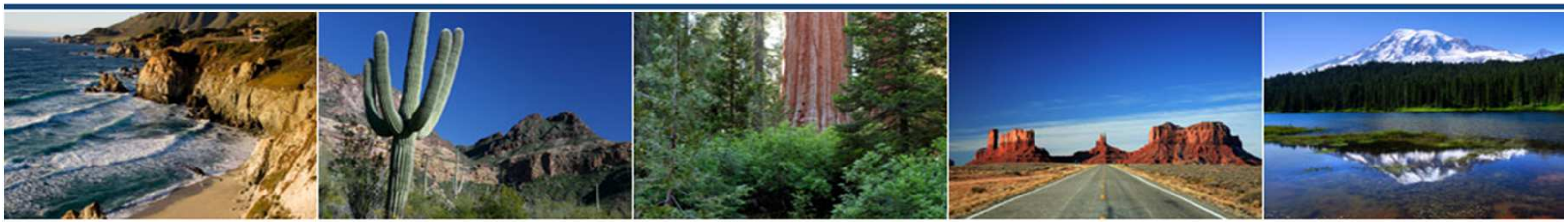
Complementary Policies

The Complementary Policies Committee will solicit input from stakeholders to inform its analysis of complementary policy options, including the selection of an initial set of policies to be examined. Stakeholders will have opportunities to review written drafts of the Committee's work and to participate in discussions with the Committee.

Offset Committee

The Offset Committee will engage stakeholders in the definition and criteria for offsets through concept papers and release of draft material related to recommendations on the essential elements of the offset system. The Committee plans to engage regional, national and international stakeholders in the analysis of options for integrating tradable units and linking with other GHG trading programs by releasing concept papers and engagement in conferences related to these topics. As the essential elements of the offset system become clear, the Offset Committee will seek the participation of stakeholders in the identification of standard protocols suitable for use in the WCI and will ensure expert advice and regional characteristics are incorporated into protocols where appropriate.

Western Climate Initiative



2009-10 Work Plan
Presentation to Stakeholders

Thursday, February 26
12:30 – 2:00 pm PST

Toll Free: 1-800-868-1837
Direct/International: 1-404-920-6440
Participant Code: 659537#

Reporting Committee

- "Background Document and Progress Report for Essential Requirements of Mandatory Reporting, Third Draft" released January 6, 2009 for stakeholder comment
  - Over 50 stakeholders provided comments
- Fourth Draft of Essential Requirements expected to be released late March-early April
  - Additional source category methods and reporting requirements
  - Revisions to previous draft
  - Responses to stakeholder comments
  - Stakeholder conference call to be scheduled

Reporting Committee

- Develop emissions reporting & database infrastructure
  - The Climate Registry will build repository for regional emissions database
  - Options for WCI jurisdictions:
    - Stand-alone reporting tool - data transfer to regional database
    - Customized reporting tool hosted by TCR - internal transfer to regional database
  - Mar.-Jun. 2009: System requirements analysis
  - Jun.-Nov. 2009: Design development
  - Nov.-Dec. 2009: Beta testing and training

- Spring 2009 (anticipated): Develop WCI comments on U.S. EPA proposed GHG reporting rule

Cap Setting and Allowance Distribution

- Develop and recommend methodologies for establishing the regional WCI GHG emission cap, each WCI Partner jurisdiction's allowance budget, and allowance distribution guidelines.

- Work divided into six tasks:
  – Task 1: Data Review and Collection
  – Task 2: Cap and Budget Setting
  – Task 3: Competitiveness Analysis
  – Task 4: 2012 One-time Budget Adjustment
  – Task 5: Offset Compliance Limit
  – Task 6: Early Reduction Allowances (ERA)

Cap Setting and Allowance Distribution

- Task 1 – Improve and harmonize historical data used to inform cap and budget setting
- Task 2 – Develop and recommend a methodology for establishing aggregate regional cap and Partner emission allowance budgets
- Task 3 – Evaluate competitiveness issues that may arise from implementation of the cap and trade program and develop options to address them
- Task 4 – Develop and recommend a methodology for the distribution of the one-time, one percent contribution by WCI Partner jurisdictions of their 2012 budget
- Task 5 – Develop and recommend a methodology for implementing the offset limit
- Task 6 – Develop the process and criteria for awarding Early Reduction Allowances

Markets Committee - Organization

- Support development and operation of robust and transparent allowance and offset credit trading market
- Work divided into six tasks:
  - Task 1: Cap-and-Trade Essential Elements
  - Task 2: Compliance Verification and Enforcement
  - Task 3: Market Oversight
  - Task 4: Tracking Systems and Related Infrastructure
  - Task 5: Regional Administrative Body
  - Task 6: Auction Design

Markets Committee - Outputs

- Task 1 – coordinate with other committees on essential elements for the cap-and-trade program
- Task 2 – compliance verification and enforcement requirements to ensure compliance by regulated community and define linkages across WCI Partner jurisdictions.
- Task 3 – oversight to ensure allowance and offset credit trading market operates reliably and prevent or minimize manipulation.
- Task 4 – specification for tracking system(s) including how created and maintained
- Task 5 – design and operation of regional administrative body to support implementation of WCI cap-and-trade program.
- Task 6 – design of auction of emission allowances in regionally coordinated manner consistent with applicable state and provincial law

Electricity Committee

- Stakeholder Technical Advisory Group process has examined a number of issues related to implementation of the First Jurisdictional Deliverer approach

- The Electricity Committee work plan for 2009 builds on and incorporates the learning from the TAG process

Electricity Committee

- The committee will focus on the following tasks in 2009:
  - Essential elements for reporting electricity emissions (Q1)
  - Written assessment of the FJD boundary issues to stakeholders (Q2); Final recommendation to Markets Committee (Q4)
  - Examine emission attribution for imported electricity, including the role of RECs in GHG accounting - draft report (Q2); then convene a workshop (Q2) and issue a final report on options and methodologies (Q2)
  - Continue work on default rates and recommend default emission rates applicable to imported power (Q4)
  - Examine with stakeholders the appropriate treatment of voluntary renewable energy in the cap-and-trade, including possible set-aside (Q3)
  - Issue report on treatment of voluntary renewable energy (Q4)
  - Examine with stakeholders allowance allocation issues in the electricity sector as they relate to competitiveness (Q3)
  - Issue draft allowance allocation report (Q3) and final report (Q4)

Offset Committee

Make recommendations to the WCI Partners on the design and operation of the offset system as part of the regional cap and trade program.

- Work divided into four tasks:
  - Task 1: Offset System Essential Elements
  - Task 2: Offsets & Allowances from other Systems
  - Task 3: Offset Protocols
  - Task 4: Offset Supply Analysis

Offset Committee

- Task 1 – develop a suite of recommendations for Partner consideration that will enable the efficient and effective creation and operation of the offset system
- Task 2 – recommend standards for evaluating and, if appropriate, accepting tradable units (offset credits and allowances) from programs other than the WCI cap and trade program
- Task 3 – recommend process to coordinate the review and recommendation of protocols
- Task 4 – in conjunction with any further economic modeling, provide input to the Economic Modeling Team, on projected offset supply (tonnes CO_2e/year) and costs

Complementary Policies

- Purpose: To recommend other policies for capped and uncapped sectors that will aid in achieving individual and regional emissions reductions goals, as well as policies related to the transition to a low-carbon economy

Tasks:

- Compile an inventory of complementary policies
- Select a subset of policies for further evaluation
- Evaluate the benefits of and barriers to harmonizing selected policies
- Final product –Policies that will work in concert with cap-and-trade to achieve regional reduction goals.

Economic Modeling

- Expanded Energy 2020 Model
  - Adding Manitoba, Ontario, and Quebec
  - Revising Reference Case: economic growth; fuel prices
  - Updating model output tables based on stakeholder feedback
    - Adding electric sector detail

- Updating Assumptions Book

Economic Modeling

- Policy Cases
  - Improving complementary policy modeling based on stakeholder input and further review by WCI team
    - Revising energy efficiency program assumptions: device vs. process improvements; economies of scale
  - Improving banking/offsets modeling based on stakeholder input and efforts of the Economic Modeling Team

- Sensitivity Cases
  - Defining cases to address stakeholder requests and program needs given limited resources
    - Examples include: energy efficiency effectiveness; auction vs. free allocation, price/availability of offsets

Stakeholder Engagement

- Ongoing stakeholder engagement is critical to the success of WCI
  - Stakeholder engagement activities will be coordinated across WCI committees
  - Opportunities to provide written comment and to participate in calls and workshops
  - Partner jurisdictions will continue their individual stakeholder processes

Stakeholder Engagement

- Monthly Status Report
  - Last Friday of each month beginning in March
  - Will highlight key activities of WCI and provide a calendar of upcoming stakeholder engagement opportunities

- Conference Calls / Webinars
  - First Thursday of every other month beginning in April (12:30 – 2:00 p.m. Pacific Time)

- Workshops
  - At least one major workshop in Fall 2009
  - Committees may hold additional workshops

Western Climate Initiative News

March 27, 2009

Upcoming Events

April 9: Markets Committee Workshop
The Markets Committee will host a stakeholder workshop on April 9 from 9:30 a.m. - 3:30 p.m. (Pacific) in Seattle, WA. The workshop is free, but registration is required. Teleconferencing/ webinar access is provided for those who cannot attend in person; registration is also required to participate in the webinar. Click here for further details and to register.

April 20: 4th Draft of Essential Requirements of Mandatory Reporting Release for Comment
The release of this document will be followed by a stakeholder conference call. Details on the call will be provided with the release via the WCI listserv and website.

April 30: Stakeholder Update Call
The next call to provide stakeholders with a status update of WCI activities will be Thursday, April 30, from 12:30 - 2:00 p.m. (Pacific). Details will be provided via the WCI listserv and website.

In This Issue

This is the first in a series of status reports that the WCI Partner jurisdictions intend to provide to all interested stakeholders. This and future reports are being issued on the last Friday of each month via the WCI listserv and website.

2009-2010 WCI Work Plan Available

On February 19, the WCI Partner jurisdictions released a detailed plan describing the work that they anticipate will move forward in 2009 and 2010. A call was hosted by the WCI Partners on February 26 to summarize the plan and address any questions.

3rd Draft of Essential Requirements of Mandatory GHG Reporting Issued

On January 6 the Reporting Committee released its third draft of the "Background Document and Progress Report for Essential Requirements of Mandatory Reporting for the WCI." At the request of stakeholders, the comment period was extended to February 3. Fifty-four commenters provided over 1,000 individual comments. The Committee is currently reviewing comments and revising the draft where appropriate. The final draft, including sections for additional source categories, is scheduled to be released for final stakeholder review and comment on April 20, and a final version will be available in late June.

Evaluating U.S. EPA Mandatory Draft GHG Reporting Rule

The Reporting Committee is evaluating the U.S. EPA's proposed rule for mandatory GHG reporting, and analyzing it for similarities and differences with the WCI draft requirements. The WCI Partner jurisdictions expect to submit public comments to EPA by the end of the public comment period based on this evaluation.

Committee Updates

- The **Economic Modeling Team** is working on a new round of analyses to incorporate the latest Partners to WCI (Ontario, Quebec and Manitoba) and to build in stakeholder recommendations received at the December 2, 2008 workshop. The updated analysis will be released for stakeholder review and comment later this spring.
- The new **Cap Setting & Allowance Distribution Committee** is working on each of its six tasks as described in the WCI

2009-2010 WCI Work Plan

3rd Draft of Essential Reporting Requirements

Evaluating U.S. EPA Proposed GHG Rule

Committee Updates

Corrections to the Design Recommendations Issued

New Website Coming

To subscribe or unsubscribe from the WCI listserv, click here.

Work Plan. As part of this work, the Committee plans to release a white paper addressing limits on the supply or use of offsets, and a white paper addressing early reduction allowances. Both papers are expected to be released by late May, and will be the subject of a webinar or meeting, followed by a period for submitting written public comments.

- In April, the **Offsets Committee** will invite stakeholders to participate in informational presentations from organizations and institutions with experience reviewing offset protocols. A listserv and website announcement will provide call in details.

Corrections to the WCI Cap-and-Trade Program Design Recommendations

Three corrections were made to the Design Recommendations to clarify the scope and point of regulation of transportation fuels, and the amount of auctioned allowances subject to a reserve price. These corrections to the Design Recommendations were posted to the WCI website on March 13.

New WCI Website Coming this Spring

The WCI website is currently being updated to improve the stakeholder comment process, access to documents, and awareness of upcoming products and events.

Agenda for April 9, 2009 Markets Committee Stakeholder Workshop
Seattle, Washington

9:30 – 10:30 a.m. (all times Pacific)	WCI Overview Markets Committee Overview Introduction to Market Concepts
10:30 – 11:00 a.m.	Task 6 Principles and Discussion
11:00 – 11:30 a.m.	Task 3 Principles and Discussion
11:30 – Noon	Task 2 Principles and Discussion
Noon – 1:30 p.m.	Lunch
1:30 – 3:30 p.m.	Task 3 Principles and Questions and Discussion

Markets Committee Draft Principles

The WCI Partner jurisdictions have formed the Markets Committee to coordinate the development of recommendations on issues and elements needed to guide the proper development and operation of a robust allowance and offset credit trading market. The WCI Partner jurisdictions and stakeholders want appropriate safeguards and oversight of the allowance and offset credit trading markets and want them to function efficiently. The Markets Committee is seeking stakeholder involvement to help achieve these goals.

To help guide the research, analysis, and deliberations of the Committee, the Committee is developing a set of principles that define the desired outcomes for three tasks described in the Committee work plan:

- Task 2: Compliance verification and enforcement;
- Task 3: Market oversight; and
- Task 6: Auction design.

Compliance verification and enforcement is part of the relationship between the Partner jurisdictions and the emitters and others who are required to surrender allowances or offset credits to satisfy a compliance obligation ("covered entities"). Market oversight is part of the Partner jurisdictions' relationship with all market participants, which may include covered entities and others who choose to buy and sell allowances and offset credits or their derivatives.

As guidelines, the principles will help inform how to weigh the multiple objectives inherent in providing effective oversight while also enabling the market to function efficiently and effectively. The principles also acknowledge differences in the legal and regulatory environment in WCI Partner jurisdictions.

The following draft principles will be discussed at a workshop on April 9, 2009 in Seattle, Washington. You may register to participate in the workshop in person or via teleconference (http://www.regonline.com/Checkin.asp?EventId=715231). The Committee will also invite written comments on these draft principles through the WCI website between April 20 – May 1, 2009 (www.westernclimateinitiative.org). The Committee may revise the principles based on the workshop discussion and comments received, as well as other information and suggestions received throughout the process.

Thank you in advance for your comments on these materials and your participation in the April 9, 2009 workshop.

Auction Design Draft Principles
(March 31, 2009 Draft)

These draft principles are proposed as guidelines for developing the auction design.

- **Fairness:** All market participants, especially covered entities, have fair and equal access to markets.

- **Efficiency:** The market is designed to operate efficiently so that greenhouse gas emission reductions can be achieved at the least cost. An efficient market means that allowance and offset credit prices reflect supply and demand, and accurately reveal the value of allowances and offset credits.

- **Effective Oversight:** The design and oversight of the allowance auction are effective in preventing or minimizing fraud, manipulation, and speculative excess. Auction participants have the capacity to execute the transactions when their bids win.

- **Transparency and the Reporting and Disclosure of Relevant Information:** Transparency in the design and the operation of the allowance auction builds and retains public confidence.

    - Reporting of relevant information to regulatory authorities and public disclosure of information has important benefits. It enables regulatory authorities to conduct effective oversight and ensure compliance. It also helps to ensure market efficiency, effective oversight, and compliance and enforcement. Coordinated and consistent release of market-relevant information allows all market participants have equal access to public information.
    - The reporting and disclosure requirements for compliance verification and enforcement balance these benefits against the need for entities to protect certain sensitive information. The potential to disclose certain information that could be used to manipulate the market is also considered. This balancing is consistent with applicable law relating to the disclosure of information.

- **Administrative Simplicity and Cost:** The auction is designed to be as simple as possible for participants and administrators. Administrative costs and transaction costs are minimized for all parties, consistent with the need to provide effective oversight.

- **Accountability:** All entities involved in the allowance and offset credit market, as regulators of the market or as participants in it, are accountable for their actions. The responsibility, authority, and capacity to conduct the necessary oversight and take appropriate action are fully defined for all agencies charged with compliance verification and enforcement.

- **Conflicts of Interest:** Conflicts of interest between market participants, monitors, and regulators are prevented.

- **Compatibility with Other Markets:** Entities that participate in allowance auctions may also be participants in other markets, such as the secondary market where allowances are traded or electricity wholesale markets. The auction design considers potential consequences of interactions between the operation of the auction and the operation of other markets and mitigates potential impacts.

Market Oversight Draft Principles
(March 31, 2009 Draft):

These draft principles are proposed as guidelines for developing oversight of the allowance and offset credit and associated derivatives trading market.

- **Fairness:** All market participants, especially covered entities, have fair and equal access to the market.

- **Efficiency:** The market is designed to operate efficiently so that greenhouse gas emission reductions can be achieved at the least cost. An efficient market means that allowance and offset credit prices reflect supply and demand, and accurately reveal the value of allowances and offset credits.

- **Effective Oversight:** The design and oversight of the market is effective in preventing or minimizing fraud, manipulation, and speculative excess.

- **Transparency and the Reporting and Disclosure of Relevant Information:** Transparency in the design and the operation of the allowance and offset credit market builds and retains public confidence.

    - Reporting of relevant information to regulatory authorities and public disclosure of information has important benefits. It enables regulatory authorities to conduct effective oversight and ensure compliance. It also helps to ensure market efficiency, effective oversight, and compliance and enforcement. Coordinated and consistent release of market-relevant information allows all market participants have equal access to public information.
    - The reporting and disclosure requirements for compliance verification and enforcement balance these benefits against the need for entities to protect certain sensitive information. The potential to disclose certain information that could be used to manipulate the market is also considered. This balancing is consistent with applicable law relating to the disclosure of information.

- **Administrative Simplicity and Cost:** Proposed rules are designed to be understood and enable entities to have a clear compliance path. Administrative costs and transaction costs are minimized for all parties, consistent with the need to provide effective oversight.

- **Accountability:** All entities involved in the allowance and offset credit market, as regulators of the market or as participants in it, are accountable for their actions. The responsibility, authority, and capacity to conduct the necessary oversight and take appropriate action are fully defined for all agencies charged with compliance verification and enforcement.

- **Conflicts of Interest:** Conflicts of interest between market participants, monitors, and regulators are prevented.

Compliance Verification and Enforcement Draft Principles
(March 31, 2009 Draft)

These draft principles are proposed as guidelines for developing compliance verification and enforcement requirements.

- **Harmonization Among Partner Jurisdictions:** To the extent permissible by law and in order to maintain the integrity of the program, compliance verification and enforcement are implemented by the Partner jurisdictions to achieve consistent regulation across jurisdictions. Enforcement and consistent regulation help to maintain a level playing field for entities. Harmonization includes:
    - Consequences for noncompliance: The consequences for non-compliance in one Partner jurisdiction are substantially the same as they would be if the non-compliance occurred in any other Partner jurisdiction.
    - Data submission by covered parties: Requirements for data submissions are consistent and timing is coordinated across Partner jurisdictions.
    - Compliance Verification: Compliance verification is consistent and timely across Partner jurisdictions.

- **Compliance:** Partner jurisdictions' policies lead to maximum compliance with regulatory requirements.

- **Transparency and the Reporting and Disclosure of Relevant Information:** Transparency in compliance verification and enforcement builds and retains public confidence.

    - Reporting of relevant information to regulatory authorities and public disclosure of information has important benefits. It enables regulatory authorities to conduct effective oversight and ensure compliance. It also helps to ensure market efficiency, effective oversight, and compliance and enforcement. Coordinated and consistent release of market-relevant information allows all market participants have equal access to public information.
    - The reporting and disclosure requirements for compliance verification and enforcement balance these benefits against the need for entities to protect certain sensitive information. The potential to disclose certain information that could be used to manipulate the market is also considered. This balancing is consistent with applicable law relating to the disclosure of information.

- **Administrative Simplicity and Cost:** Proposed rules are designed to be understood and enable entities to have a clear compliance path. Administrative costs and transaction costs are minimized for all parties, consistent with the need to provide effective compliance verification and enforcement.

- **Accountability:** All entities involved in the allowance and offset credit market, as regulators of the market or as participants in it, are accountable for their actions. The responsibility, authority, and capacity to conduct the necessary oversight and take appropriate action are fully defined for all agencies charged with compliance verification and enforcement.

Markets Committee Questions for Stakeholder Input

The WCI has formed the Markets Committee to coordinate the development of recommendations on issues and elements needed to guide the proper development and operation of a robust allowance and offset credit trading market. The WCI Partner jurisdictions and stakeholders want an allowance and offset trading market that has appropriate safeguards and oversight and that will function efficiently. The Markets Committee is seeking stakeholder involvement to help achieve these goals.

To help guide the research, analysis, and deliberations of the Market Oversight task of the Committee, the Committee is soliciting input on the attached questions. The Committee will be using these questions to motivate a discussion of market oversight issues at a workshop on April 9, 2009 in Seattle, Washington, and solicits input from stakeholders in response to them. The Committee will also be inviting written comments through the WCI website at www.westernclimateinitiative.org between April 20 – May 1, 2009.

Thank you in advance for your comments on these materials and your participation in the April 9, 2009 workshop.

<u>Market Oversight Questions for the April 9, 2009 Workshop</u>

1) Who should have the opportunity to purchase, own, and sell WCI Partner jurisdiction allowances and offset credits and under what conditions, if any, in the
   a) primary market?
   b) secondary markets?
2) What is your primary concern about how this market can be manipulated and by whom? Is there something peculiar to a market for greenhouse gases that could lead to excessive speculation?
3) What is the role you see for speculators in this market? Is it different than the role played in other markets?
4) How should WCI Partner jurisdictions monitor the WCI cap-and-trade markets? What tools and capacity should the WCI Partner jurisdictions develop?
5) What information should be collected by regulatory authorities for use in the oversight of WCI cap-and-trade primary, secondary, and derivatives markets? Of the information collected by regulatory authorities on the WCI cap-and-trade market, what information should be made public, in what form (e.g., aggregate form only), and at what frequency (e.g., daily, weekly)?
6) What financial instruments (e.g., derivative products) would you find important to manage risk and why?
7) What form should WCI Partner jurisdictions' interaction take with each other, with a WCI regional administrative organization, US and Canadian government institutions, and other external bodies (such as exchanges) to provide oversight of the primary, secondary, and derivatives markets, such as Memoranda of Agreement? What information should they exchange with these institutions?
8) What specific potential do you see for interaction between the markets for WCI Partner jurisdiction allowances and offset credits, markets for their derivatives, and other markets, e.g., renewable energy credits, that might create opportunities for, or exacerbate the effects of, fraud, manipulation, or speculative excess?
9) What trading rules would you like to see for WCI cap-and-trade market participants to ensure accountability, transparency, prevention of fraud, manipulation and excessive speculation?
10) What other market oversight issues, not covered in these questions, should the WCI Partner jurisdictions be looking at?

April 9, 2009 Stakeholder Meeting, Markets Committee Stakeholder Workshop, Seattle, Washington

List of Commenters

J.P. Morgan

Monitoring Analytics, LLC

Morgan Stanley Capital Group

Pacific Gas and Electric Company

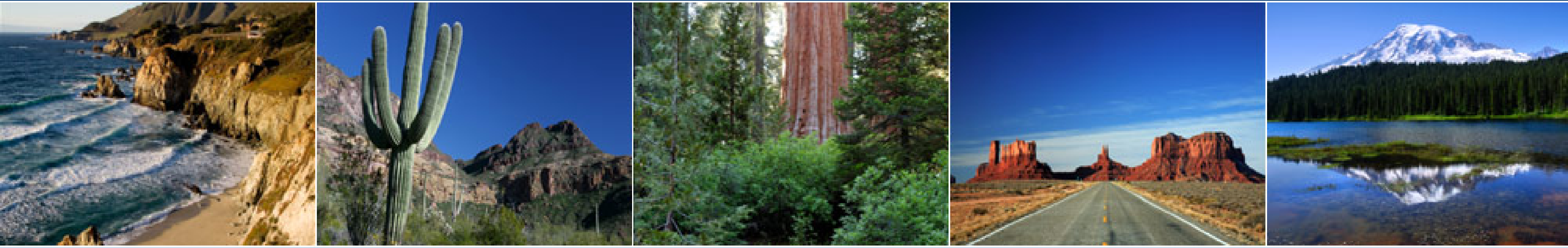
Western Climate Advocates Network (WeCAN)

Western Power Trading Forum

Weyerhaeuser

Zini, Gian

Western Climate Initiative



Markets Committee Stakeholder Workshop

Markets Committee Overview

April 9, 2009
Seattle, Washington

Markets Committee Mission

- Coordinate the development of recommendations on issues and elements needed to guide the proper development and operation of a robust allowance and offset credit trading market.

Markets Committee Tasks

- Task 1: Cap-and-Trade Essential Elements
- Task 2: Compliance Verification and Enforcement (CV&E)
- Task 3: Market Oversight
- Task 4: Tracking Systems and Related Infrastructure
- Task 5: Regional Administrative Organization
- Task 6: Auction Design

Markets Committee Output

- Essential elements of cap-and-trade program rule, including CV&E and Auction Design recommendations.
- Recommendations for market oversight.
- Design of necessary infrastructure.
  - Tracking systems.
  - Regional Administrative Organization.

Stakeholder Interaction

- Workshops:
  - Draft Principles
- Conference calls and webinars
- Joint educational opportunities
- Written comment:
  - White papers
  - Draft recommendations
- Individual jurisdictions' stakeholder processes

Remainder of Today’s Workshop

- Markets Committee Terms
- Role of Principles
- Draft Principles and Discussion
  - Auction Design
  - Market Oversight
  - Compliance Verification and Enforcement
- Market Oversight Discussion

Cap and Trade Terms (1)

Covered Facilities and Entities

Emission Allowances:

- WCI Partner jurisdictions issue emission allowances, or tradable permits.
- Declining number of allowances issued over time ensuring emission reductions.
- Allowances can be bought and sold (traded).

Cap and Trade Terms (2)

Offset Credits:

- WCI Partner jurisdictions issue or recognize offset credits for emissions reductions/removals that satisfy specific criteria.
- Offset credits can be bought and sold (traded).

Compliance Period:

- Three-year period during which facilities and entities have a compliance obligation.

Cap and Trade Terms (3)

Compliance Obligation:

- Covered facilities and entities must report their emissions annually.
- Covered facilities and entities must surrender a combination of emission allowances and offset credits equal to their emissions during the compliance period.
- Limits on the use of offset credits.

CV&E Terms

Compliance Verification:

- The process by which a WCI Partner jurisdiction determines whether a covered facility or entity has met its compliance obligation.

Enforcement:

- The steps taken by a WCI Partner jurisdiction when it believes a covered facility or entity has failed to meet its compliance obligation.

Market Terms (1)

Market Design:

- Market architecture
- Market rules
- Market oversight

Market Terms (2)

Market Architecture:

- Market participants and institutions that make up a market.
  - Covered facilities and entities
  - Regulatory authorities
  - Exchanges, brokers
  - Registry
  - Others
- Processes and tools used by the participants and institutions.

Market Terms (3)

Market Rules:

- Requirements of the market participants.
  - Reporting
  - Disclosure
  - Demonstrations of capability
  - Free of conflict of interest
  - Other
- Required processes and tools used by the participants and institutions.

Market Terms (4)

Market Oversight:

- Activities performed to ensure the proper operation of the markets.
  - Collection and release of market-relevant information.
  - Verification of compliance with market rules.
  - Data collection and analysis to detect violations of rules or laws.
  - Enforcement actions in response to suspected violations of rules or laws.

Market Terms (5)

Market Oversight (continued):

- Examples of potential violations:
  - Failure to Disclose: Failure to comply with mandatory disclosure requirements.
  - Fraud: Such as selling “allowances” that do not exist.
  - Manipulation: Attempt to interfere with the operation of a market.
  - Excessive Speculation: Commodity Exchange Act prohibits excessive speculation to prevent “sudden or unreasonable fluctuations or unwarranted changes in the price of commodities traded on an exchange.” [Reference :“Excessive Speculation in the Natural Gas Market,” U.S. Senate, 2007.]
  - Various trading violations, such as insider trading.

Market Terms (6)

Markets:

- **Primary:** Sale of allowances by issuing Partner jurisdictions, or offset credits by developers, through auctions, direct sales or other means.
- **Secondary:** Trading of allowances or offset credits between market participants.
- **Derivatives:** Instruments for which the value is "derived" from an underlying value for allowances or offset credits. Examples: forward, future, option, and swap contracts. Often used to manage risk.

Auction Context (1)

Auction is one means of distributing allowances

- Part of the primary market.
- May provide price discovery (especially early in the program).

WCI design goals

- 2012: auction at least 10% of allowances.
- 2020: increase proportion sold to 25%.
- Long-term goal: Aspire to a higher auction percentage over time, possibly to 100%.

Auction Context (2)

Auction design parameters:

- Auction type
- Frequency
- Participation
- Financial capability
- Lot Size
- Maximum purchase
- Reserve price (floor price)
- Others

Questions Regarding Markets Committee Terms?

Role of Principles

- Define desired outcomes.
- Guide data collection, analyses, and deliberations toward how to achieve the desired outcomes.
- Help identify tradeoffs required among desired outcomes.
- Acknowledge differences in the legal and regulatory environments in WCI Partner jurisdictions.

Status of Draft Principles

Principles	CV&E	Market Oversight	Auction Design
Fairness		✓	✓
Efficiency		✓	✓
Effective Oversight		✓	✓
Transparency	✓	✓	✓
Administrative Simplicity and Cost	✓	✓	✓
Accountability	✓	✓	✓
Conflicts of Interest		✓	✓
Compatibility with Other Markets			✓
Harmonization	✓		
Compliance	✓		

Principle Questions

- Anything unclear?
- Anything missing?
- Anything that does not belong?
- Comments on relative importance?

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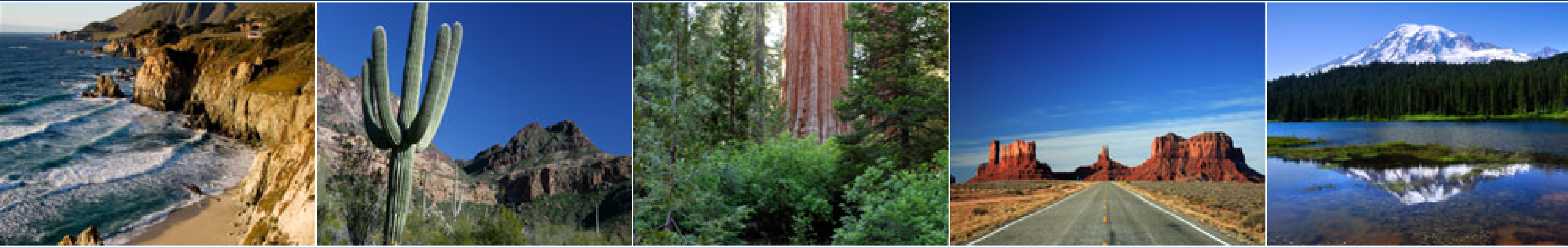

Markets Committee Stakeholder Workshop

Auction Design

April 9, 2009
Seattle, Washington

Task 6: Auction Design

- Mission: Provide recommendations on the design of the auction that will be used to auction emission allowances in a regionally coordinated manner consistent with applicable state and provincial law.

Draft Auction Design Principles:
Fairness

- All market participants, especially covered entities, have fair and equal access to markets.

Draft Auction Design Principles:
Efficiency

- The market is designed to operate efficiently so that greenhouse gas emission reductions can be achieved at the least cost. An efficient market means that allowance and offset credit prices reflect supply and demand, and accurately reveal the value of allowances and offset credits.

Draft Auction Design Principles:

Effective Oversight

- The design and oversight of the allowance auction are effective in preventing or minimizing fraud, manipulation, and speculative excess. Auction participants have the capacity to execute the transactions when their bids win.

Draft Auction Design Principles:

Transparency and the Reporting and Disclosure of Relevant Information

- Transparency in the design and the operation of the allowance auction builds and retains public confidence.
  - Reporting of relevant information to regulatory authorities and public disclosure of information has important benefits. It enables regulatory authorities to conduct effective oversight and ensure compliance. It also helps to ensure market efficiency, effective oversight, and compliance and enforcement. Coordinated and consistent release of market-relevant information allows all market participants have equal access to public information.
  - The reporting and disclosure requirements for auction design balance these benefits against the need for entities to protect certain sensitive information. The potential to disclose certain information that could be used to manipulate the market is also considered. This balancing is consistent with applicable law relating to the disclosure of information.

Draft Auction Design Principles:

Administrative Simplicity and Cost

- The auction is designed to be as simple as possible for participants and administrators. Administrative costs and transaction costs are minimized for all parties, consistent with the need to provide effective oversight.

Draft Auction Design Principles:

Accountability

- All entities involved in the allowance and offset credit market, as regulators of the market or as participants in it, are accountable for their actions. The responsibility, authority, and capacity to conduct the necessary oversight and take appropriate action are fully defined for all agencies charged with compliance verification and enforcement.

Draft Auction Design Principles:

Conflicts of Interest

- Conflicts of interest between market participants, monitors, and regulators are prevented.

Draft Auction Design Principles:

Compatibility with Other Markets

- Entities that participate in allowance auctions may also be participants in other markets, such as the secondary market where allowances are traded or electricity wholesale markets. The auction design considers potential consequences of interactions between the operation of the auction and the operation of other markets and mitigates potential impacts.

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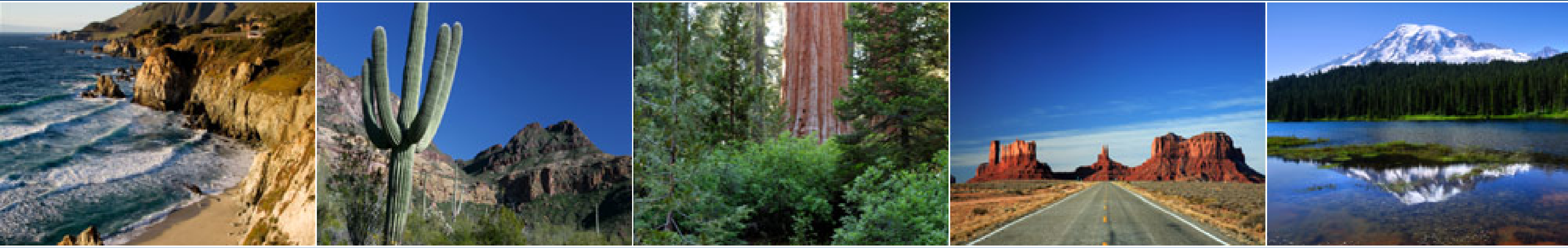


Markets Committee Stakeholder Workshop

Market Oversight

April 9, 2009
Seattle, Washington

Task 3: Market Oversight

- Mission: Provide recommendations that are designed to ensure that the allowance and offset credit trading markets are organized properly to operate reliably and prevent or minimize manipulation.

Draft Market Oversight Principles:
Fairness

- All market participants, especially covered entities, have fair and equal access to markets.

Draft Market Oversight Principles:

Efficiency

- The market is designed to operate efficiently so that greenhouse gas emission reductions can be achieved at the least cost. An efficient market means that allowance and offset credit prices reflect supply and demand, and accurately reveal the value of allowances and offset credits.

Draft Market Oversight Principles:

Effective Oversight

- The design and oversight of the market is effective in preventing or minimizing fraud, manipulation, and speculative excess

Draft Market Oversight Principles:

Transparency and the Reporting and Disclosure of Relevant Information

- Transparency in the design and the operation of the allowance and offset credit market builds and retains public confidence.
  - Reporting of relevant information to regulatory authorities and public disclosure of information has important benefits. It enables regulatory authorities to conduct effective oversight and ensure compliance. It also helps to ensure market efficiency, effective oversight, and compliance and enforcement. Coordinated and consistent release of market-relevant information allows all market participants have equal access to public information.
  - The reporting and disclosure requirements for market oversight balance these benefits against the need for entities to protect certain sensitive information. The potential to disclose certain information that could be used to manipulate the market is also considered. This balancing is consistent with applicable law relating to the disclosure of information.

Draft Auction Design Principles:

Administrative Simplicity and Cost

- The auction is designed to be as simple as possible for participants and administrators. Administrative costs and transaction costs are minimized for all parties, consistent with the need to provide effective oversight.

Draft Market Oversight Principles:

Accountability

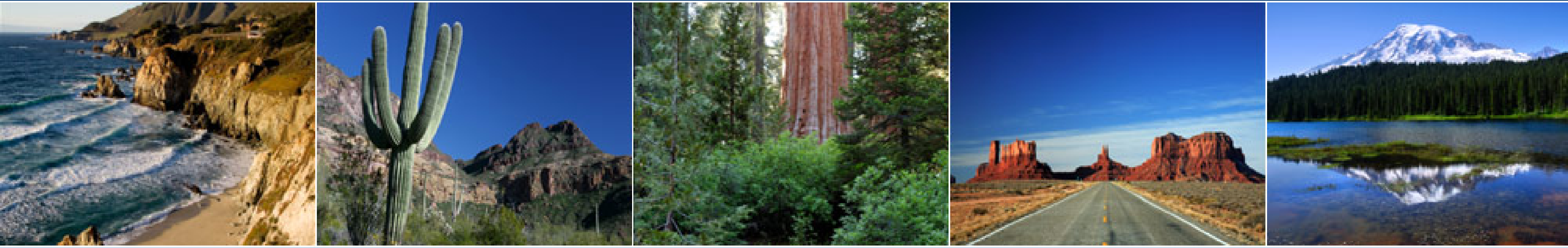
- All entities involved in the allowance and offset credit market, as regulators of the market or as participants in it, are accountable for their actions. The responsibility, authority, and capacity to conduct the necessary oversight and take appropriate action are fully defined for all agencies charged with compliance verification and enforcement.

Draft Market Oversight Principles:

Conflicts of Interest

- Conflicts of interest between market participants, monitors, and regulators are prevented.

Western Climate Initiative



Markets Committee Stakeholder Workshop

Compliance Verification and Enforcement

April 9, 2009
Seattle, Washington

Task 2: CV&E

- Mission: Develop recommendations related to compliance verification and enforcement requirements to ensure compliance by the regulated community and define linkages across WCI Partner jurisdictions.
  - Consistency/uniformity needed across jurisdictions and the degree of flexibility warranted.
  - Ensure equivalent treatment and stringency among WCI Partner jurisdictions.

Draft Compliance Verification and Enforcement Principles:

Harmonization Among Partner Jurisdictions

- To the extent permissible by law and in order to maintain the integrity of the program, compliance verification and enforcement are implemented by the Partner jurisdictions to achieve consistent regulation across jurisdictions. Enforcement and consistent regulation help to maintain a level playing field for entities.

Draft Compliance Verification and Enforcement Principles:

Harmonization Among Partner Jurisdictions

- Harmonization includes:
  - Consequences for noncompliance: The consequences for non-compliance in one Partner jurisdiction are substantially the same as they would be if the non-compliance occurred in any other Partner jurisdiction.
  - Data submission by covered parties: Requirements for data submissions are consistent and timing is coordinated across Partner jurisdictions.
  - Compliance Verification: Compliance verification is consistent and timely across Partner jurisdictions.

Draft Compliance Verification and Enforcement Principles:

Compliance

- Partner jurisdictions' policies lead to maximum compliance with regulatory requirements.

Draft Compliance Verification and Enforcement Principles:

Transparency and the Reporting and Disclosure of Relevant Information

- Transparency in compliance verification and enforcement builds and retains public confidence.
  - Reporting of relevant information to regulatory authorities and public disclosure of information has important benefits. It enables regulatory authorities to conduct effective oversight and ensure compliance. It also helps to ensure market efficiency, effective oversight, and compliance and enforcement. Coordinated and consistent release of market-relevant information allows all market participants have equal access to public information.
  - The reporting and disclosure requirements for compliance verification and enforcement balance these benefits against the need for entities to protect certain sensitive information. The potential to disclose certain information that could be used to manipulate the market is also considered. This balancing is consistent with applicable law relating to the disclosure of information.

Draft Compliance Verification and Enforcement Principles:

Administrative Simplicity and Cost

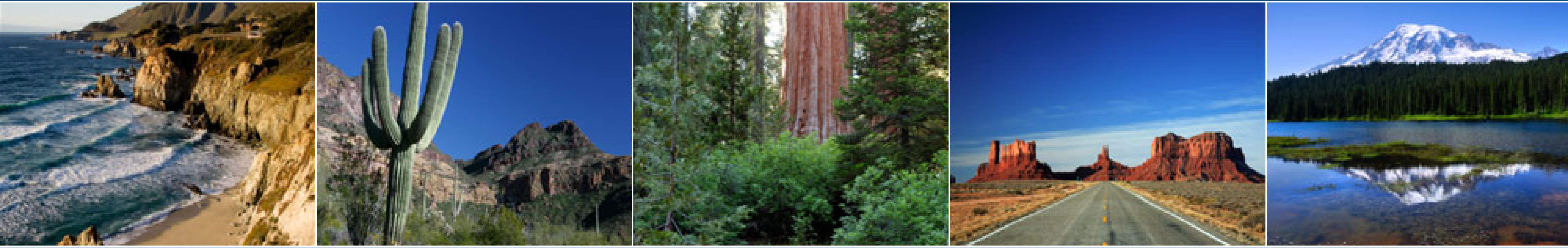
- Proposed rules are designed to be understood and enable entities to have a clear compliance path. Administrative costs and transaction costs are minimized for all parties, consistent with the need to provide effective compliance verification and enforcement.

Draft Compliance Verification and Enforcement Principles:

Accountability

- All entities involved in the allowance and offset credit market, as regulators of the market or as participants in it, are accountable for their actions. The responsibility, authority, and capacity to conduct the necessary oversight and take appropriate action are fully defined for all agencies charged with compliance verification and enforcement.

Western Climate Initiative



Markets Committee Stakeholder Workshop

Market Oversight Questions for Discussion

April 9, 2009
Seattle, Washington

Oversight of Allowance and Offset Credit Markets

- Market Architecture, Rules and Oversight
- Guided by principles

- Seek recommendations of “best practices”
- Review existing structures and practices
- Consider legal and regulatory frameworks in Partner jurisdictions

Oversight of Existing Markets for Financial Instruments (1)

Existing oversight might:

1. Provide models for WCI Partner jurisdictions to consider
2. Allow Partner jurisdictions to consider definitions of allowances and offset credits that place them into existing regulatory structures

Oversight of Existing Markets for Financial Instruments (2)

Canada

- Securities, commodities futures, and derivatives regulated by provincial securities commissions (AMF, MSC, BCSC, OSC, etc.)

U.S.

- Securities regulation shared by Securities Exchange Commission and state agencies
- Commodities regulation primarily under Commodity Futures Trading Commission (CFTC); oversight of energy commodities shared with the Federal Energy Regulatory Commission (FERC)

Oversight of Existing Markets for Financial Instruments (3)

Type of oversight depends on type of trade

- e.g., "Over-the-counter," or OTC, customized bilateral trades, are regulated differently from exchange-traded contracts, standardized contracts with anonymous counterparties;
- Primary, secondary, derivatives markets are treated differently

Oversight of Existing Markets for Financial Instruments (4)

Regional Greenhouse Gas Initiative

- Contracts with outside firm to provide market oversight services
- Requires reporting of prices with transfers

US EPA Acid Rain Program

- All allowance transfers and compliance accounts visible in online database
- Price data not collected

Market Oversight Questions for Discussion

1. Who should have the opportunity to purchase, own, and sell WCI Partner jurisdiction allowances and offset credits and under what conditions, if any, in the
   a) primary market?
   b) secondary markets?
2. What is your primary concern about how this market can be manipulated and by whom? Is there something peculiar to a market for greenhouse gases that could lead to excessive speculation?
3. What is the role you see for speculators in this market? Is it different than the role played in other markets?
4. How should WCI Partner jurisdictions monitor the WCI cap-and-trade markets? What tools and capacity should the WCI Partner jurisdictions develop?

Market Oversight Questions for Discussion

5. What information should be collected by regulatory authorities for use in the oversight of WCI cap-and-trade primary, secondary, and derivatives markets? Of the information collected by regulatory authorities on the WCI cap-and-trade market, what information should be made public, in what form (e.g., aggregate form only), and at what frequency (e.g., daily, weekly)?
6. What financial instruments (e.g., derivative products) would you find important to manage risk and why?
7. What form should WCI Partner jurisdictions' interaction take with each other, with a WCI regional administrative organization, US and Canadian government institutions, and other external bodies (such as exchanges) to provide oversight of the primary, secondary, and derivatives markets, such as Memoranda of Agreement? What information should they exchange with these institutions?

Market Oversight Questions for Discussion

8. What specific potential do you see for interaction between the markets for WCI Partner jurisdiction allowances and offset credits, markets for their derivatives, and other markets, e.g., renewable energy credits, that might create opportunities for, or exacerbate the effects of, fraud, manipulation, or speculative excess?
9. What trading rules would you like to see for WCI cap-and-trade market participants to ensure accountability, transparency, prevention of fraud, manipulation and excessive speculation?
10. What other market oversight issues, not covered in these questions, should the WCI Partner jurisdictions be looking at?

Western Climate Initiative

Overview: Western Climate Initiative

Markets Committee Meeting
Seattle, WA
April 9, 2009

www.westernclimateinitiative.org

WCI History

- Logical extension of West Coast and Southwest Governor's climate initiatives
- February 2007 – MOU signed by Governors of Arizona, California, New Mexico, Oregon and Washington
- British Columbia, Manitoba, Montana, Ontario, Quebec and Utah have since signed the Initiative
- Observers
  - U.S. states: AK, ID, CO, KS, NV, WY
  - Canadian provinces: Saskatchewan
  - Mexican states: Baja California, Chihuahua, Coahuila, Nuevo Leon, Sonora, Tamaulipas

Western Climate Initiative

Manitoba
GDP .... 48,586 Million C$
Population 1,186,700
Largest City.............. Winnipeg

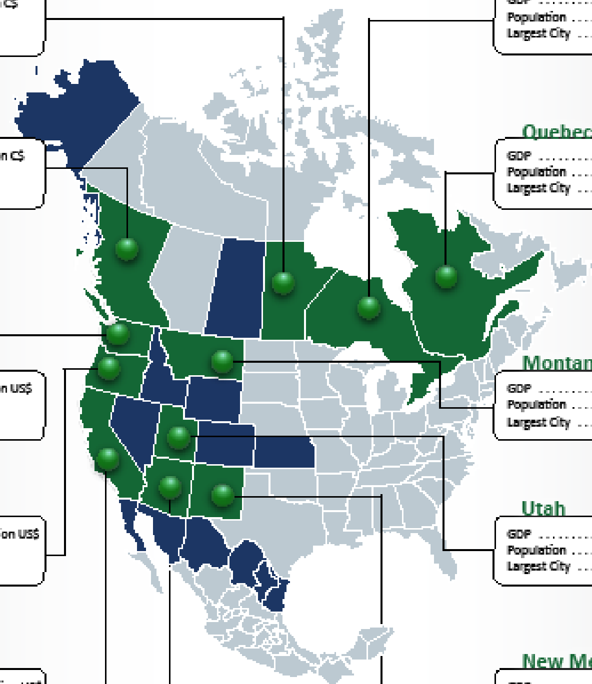
British Columbia
GDP .... 190,214 Million C$
Population 4,380,300
Largest City .... Vancouver

Washington
GDP .... 311,270 Million US$
Population 6,468,424
Largest City .... Seattle

Oregon
GDP .... 158,233 Million US$
Population 3,747,455
Largest City .... Portland

California
GDP .... 1,812,968 Million US$
Population 36,553,215
Largest City .... Los Angeles

Arizona
GDP .... 247,028 Million US$
Population 6,338,755
Largest City .... Phoenix



Ontario
GDP .... 582,019 Million C$
Population 12,803,900
Largest City .... Toronto

Quebec
GDP .... 298,157 Million C$
Population 7,700,800
Largest City .... Montreal

Montana
GDP .... 34,253 Million US$
Population 957,861
Largest City .... Billings

Utah
GDP .... 105,658 Million US$
Population 2,645,330
Largest City .... Salt Lake City

New Mexico
GDP .... 76,178 Million US$
Population 1,969,915
Largest City .... Albuquerque

Partners Observers

WCI OBSERVERS

CANADA
Saskatchewan

UNITED STATES
Alaska
Colorado
Idaho
Kansas
Nevada
Wyoming

MEXICO
Baja California
Chihuahua
Coahuila
Nuevo Leon
Sonora
Tamaulipas

All figures for 2007
Source for US data: US Census Bureau and US Bureau of Economic Analysis
Source for Canadian data: Statistics Canada

Initiative Collaboration Includes

Three specific directives:

- Set a regional emissions reduction goal
- Join a multi-state registry to track, manage and credit reductions
- *Design a regional multi-sector market-based mechanism*

Joint work to:

- *Promote clean and renewable energy in the region*
- *Increase energy efficiency*
- *Advocate for regional and national climate policies that are in the interest of western states*
- Identify measures to adapt to climate change impact

Cap-and-Trade Design Starting Point

- Firm 2020 emissions limit
  - Based on individual state and provincial emissions goals
- Common approach to quantifying emissions
- Individual state/provincial programs
  - Each state/province adopts own rules
  - Harmonized around essential elements
  - Linked to create a regional trading market
  - All allowances and offset credits have same value

Most Expansive Program Designed To-Date

- All 6 primary GHGs from all major sources, including transportation and other fuels
  - RGGI = CO_2 from electricity only
  - EU ETS = CO_2 from electricity, industrial combustion, and process emissions
- Will cover nearly 90% of the region's emissions by 2015
  - RGGI = ~28% of emissions
  - EU ETS = ~40% of emissions

WCI DESIGN

AND

2009 – 10 WORK PLAN

Cap-and-Trade
What Can Be Different

- State and provincial decisions:
  - Allocation of allowances within states and provinces
    - May standardize between sectors/jurisdictions
  - *Greater* percent of allowances auctioned than minimum
  - Use of most of the value of the allowances
  - *Fewer* offset credits than maximum allowed
  - Allowance set-asides
  - Recognition of early reductions (other than ERA)

Cap-and-Trade
What Has To Be the Same

- Basic reporting requirements
- Sectors, gases and thresholds (generally)
- Points of regulation
- Quantification methods
- Setting regional caps
- Establishing partner budgets
- Compliance periods; banking; borrowing

What Has To Be the Same, *cont.*

- Early reductions allowance (ERA) criteria
- Maximum offset credits allowed
- Offset criteria and protocols
- Auction design and implementation
- Linkage with other systems
- Participation in regional administrative organization

2009 – 10 WCI Organization

- US and Canadian Co-Chairs
  - One year staggered terms; rotates between jurisdictions
- Committee of the Whole
- Federal Liaisons
- Legal Team
- Continuing and New Committees and Task Groups:
  - Reporting Committee
  - Electricity Committee
  - Offset Committee
  - Cap Setting and Allowance Distribution Committee:
  - Markets Committee
  - Complementary Policies Committee
  - Economic Modeling Team

Stakeholder Input

- Ongoing stakeholder engagement is critical to the success of WCI
  - Stakeholder engagement activities are coordinated across WCI committees
  - Individual Partner jurisdictions will continue their own stakeholder work
- Materials posted on website for written comment
- Regular calls, workshops and list serv announcements
- Monthly newsletter

Reporting Committee

- "Background Document and Progress Report for Essential Requirements of Mandatory Reporting"
  - Third draft released January 6, 2009 for stakeholder comment
- Final draft currently under development
  - Revisions to previous draft in response to stakeholder comments
  - Sections for additional source category methods and reporting requirements
  - Scheduled to be released for stakeholder review and comment on April 20
  - Final version available in late June
- Develop emissions reporting & database infrastructure

Electricity Committee

- Stakeholder Technical Advisory Group process
  - Examined a number of issues related to implementation of the First Jurisdictional Deliverer approach
- Will now build on and incorporate the learning from the TAG process
- Work includes:
  - Essential elements for reporting electricity emissions
  - Assessment of the FJD boundary issues
  - Examine emission attribution for imported electricity, including the role of RECs in GHG accounting, treatment of voluntary renewable energy, and continued work on default rates
  - Examination of allowance allocation issues in the electricity sector, and their relation to competitiveness

Offset Committee

- Make recommendations on the design and operation of the offset system
- Work divided into four tasks:
  - Task 1: Offset System Essential Elements
  - Task 2: Offsets & Allowances from other Systems
  - Task 3: Offset Protocols
  - Task 4: Offset Supply Analysis

Cap Setting and Allowance Distribution

- Develop and recommend methodologies for establishing the regional emission cap, each Partner’s allowance budget
- Work divided into six tasks:
  - Task 1: Data Review and Collection
  - Task 2: Cap and Budget Setting
  - Task 3: Competitiveness Analysis
  - Task 4: 2012 One-time Budget Adjustment
  - Task 5: Offset Compliance Limit
  - Task 6: Early Reduction Allowances (ERA)

Markets Committee

- Support development and operation of robust and transparent allowance and offset credit trading market
- Work divided into six tasks:
  - Task 1: Cap-and-Trade Essential Elements
  - Task 2: Compliance Verification and Enforcement
  - Task 3: Market Oversight
  - Task 4: Tracking Systems and Related Infrastructure
  - Task 5: Regional Administrative Body
  - Task 6: Auction Design

Complementary Policies

- Response to directive in Initiative on clean energy and energy efficiency
- All WCI Partner jurisdictions have complementary policies in their climate action plans
- Economic analysis suggests complementary policies reduce the cost of cap-and-trade
  - Remove market barriers (such as split incentives)
  - Help with actions that do not fully respond to price
  - Ensures that all sectors are engaged in achieving reductions

Economic Modeling

- Expanded Energy 2020 Model
  - Adding Manitoba, Ontario, and Quebec
  - Revising Reference Case: economic growth; fuel prices
  - Updating model output tables based on stakeholder feedback (adding electric sector detail)
- Updating Assumptions Book
- Improving Policy Cases, banking/offsets analysis
- Adding Sensitivity Cases

National Context

- WCI Partner jurisdictions support a national approach for cap-and-trade
- WCI Partner jurisdictions are continuing to work on the details of its cap-and-trade design
- The Partners have and will continue to share what we've learned with Congressional staff and EPA
- The Partners are also working on identifying where national and regional complementary policies may be needed
- WCI program – cap-and-trade working together with other policies – serves as national model

Federal Proposals: Waxman-Markey Discussion Draft

- Title One: Clean Energy
  - Renewable Electricity (Portfolio) Standard
  - Carbon Capture and Storage
  - Low Carbon Fuel Standard
- Title Two: Energy Efficiency
  - Buildings, Lighting and Appliance, Utilities, Industrial Plants, Public Facilities, Mobile Sources
  - Transportation Planning
- Title Three: Reducing Global Warming Pollution
  - Federal cap-and-trade program
- Title Four: Transitioning to a Clean Energy Economy
  - Preserving domestic competitiveness
  - Green jobs
  - Adaptation

For More Information

- Contact WCI Partner representatives from your state or province

- Website and WCI listserv – www.westernclimateinitiative.org

- WCI Project Manager

    Patrick Cummins, WGA

    970-884-4770

    pcummins@westgov.org

Climate Action Reserve Overview

Presentation to the Western Climate Initiative
Offsets Subcommittee Meeting
April 21, 2009

CLIMATE
ACTION
RESERVE

What is the Climate Action Reserve?

- National not-for-profit environmental organization headquartered in California, operating a registry for carbon offset projects throughout the U.S.

- Open and transparent:
  - protocol development
  - verification oversight
  - project registration & tracking

Standardized Protocols

- Reserve protocols assess industry practice as a whole, rather than individual project activities
  - Industry studies are conducted upfront
  - Additionality determined through standard and objective eligibility criteria
  - Baselines estimated using standard parameters and default factors to the extent practical and appropriate

Standardized Protocols

- Advantages
  - Less subjective determinations of eligibility
  - More certainty, less risk for developers and investors
  - Faster project processing
  - Greater transparency

Protocol Development Process

- Developed with broad public input
- Goal is to create a uniform standard that is widely recognized and builds on best practice
  - We incorporate the best elements of other protocols
  - We do not accept projects developed under other protocols (i.e. CDM, Gold Standard, VCS)
- Step-by-step quantification and verification instructions
- Conformant with ISO 14064 and GHG Protocol

Protocol Development Process

1. Literature review
2. Scoping/kick-off meeting
3. Multi-stakeholder workgroup formation
4. Draft protocol to workgroup
5. Revised draft released for public comment
6. Public workshop
7. Solicit public comments and respond
8. Adoption by Climate Action Reserve Board in public session

Project Types

- **Current**
  - – Forestry (improved forest management, avoided conversion, reforestation)
  - – Landfill gas capture
  - – Livestock (agricultural methane capture)
  - – Urban forestry
- **Under Development**
  - – Co-digestion, coalmine methane, industrial gases, and others forthcoming.

Project Eligibility Rules

- Additionality
  - Regulatory screen – not legally required
  - Project started operation after 1/1/2001
    - This will be changing with new protocols
  - Performance standards or other standard criteria for additionality
- Location – must be in the United States
  - Mexico and Canada coming soon
- Material compliance – must meet all applicable environmental regulations

Protocol Revision Process

- Protocols are updated to reflect public comments, practical experience, and new technical or regulatory developments
  - *Policy Revisions* involve changes to eligibility definitions or significant changes in baseline estimation methods
  - *Technical Revisions* involve editorial changes or technical changes to quantification & monitoring methods

Verification System

- The Reserve trains, accredits and oversees verifiers
  - Working with ANSI to ensure compliance with ISO
- Developer selects an accredited verifier
- The Reserve reviews conflict of interest (COI)
- Developer hires verifier
  - Verifier makes determination of eligibility (1st visit) and how many tonnes of reduction have taken place
  - Project documents, verification report and verification opinion submitted to and approved by the Reserve

Registry System

- Project developers have individual accounts
  – Reserve software is operated by APX
- The Reserve issues credits (“CRTs”) into accounts based on approved verification reports
  – Project documents are visible to the public
- Each CRT has a unique serial number for tracking
  – Includes embedded information about the project, project type, vintage and location
- CRTs can be transferred or retired

Focused and Limited Mission

- The Reserve focuses only on protocol development, verification, and registration
  - Does not fund or develop projects or solicit project proposals
  - Does not take ownership of offsets or retire them on behalf of others
  - Is not an exchange

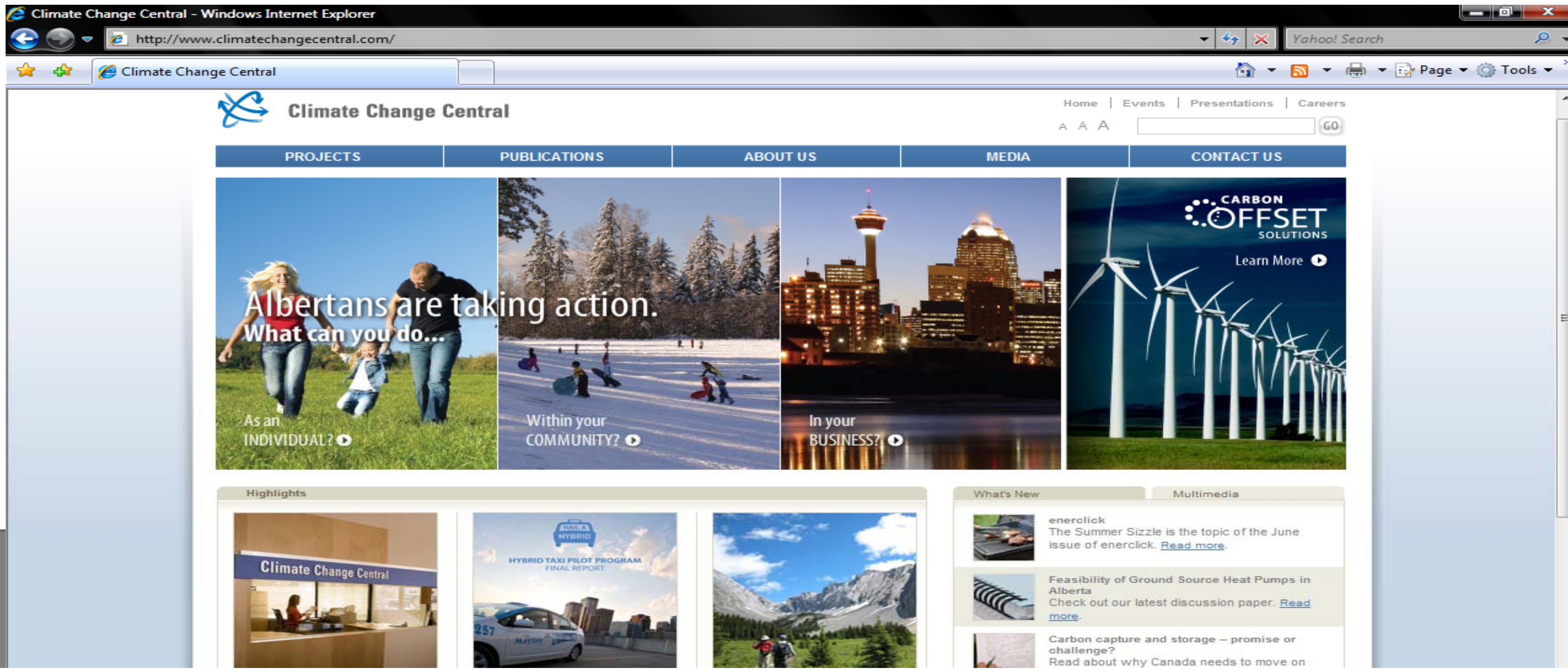
PROTOCOL REVIEW AND RECOMMENDATION PROCESS

WCI Offsets Committee Presentation
April 21, 2009

Climate Change Central

Who is Climate Change Central?

- Formed in 2000,Triple P Partnership – Not for Profit
- Goal - Advance Action that Accelerates Mitigation and Adaptation to Climate Change
  - Policy Analysis, Energy Efficiency, Clean tech deployment, environmental communications
- Facilitated development of the Carbon Offset Market in Alberta
- Active in several Provincial and National Fora in Canada



C3 Offset Program Function

- Advice and Input on a Well-Designed Offset System
  - On the ground experience in a Compliance-Based System; analysis of interactions/coherence between offsets and other policy measures
- Guidance Document Development – Project, Verification, Validation, Protocols
- Coordinating Transparent, Well-documented Evaluation, Review and Recommendation Process for Protocols, with Government Oversight
  - Based on ISO14064-2 principles and framework
- Science and Stakeholder Coordination for New Protocol Development
  - Tried and true method of standards development; ISO 14064-2 based;
  - Offset Registry Services
  - Audited system – Alberta Auditor General
- Subject Matter Experts in Agriculture and Forestry quantification
- Education and Awareness to Support the Market
- Evaluation Frameworks – feeds into Gov't Adaptive Management Process

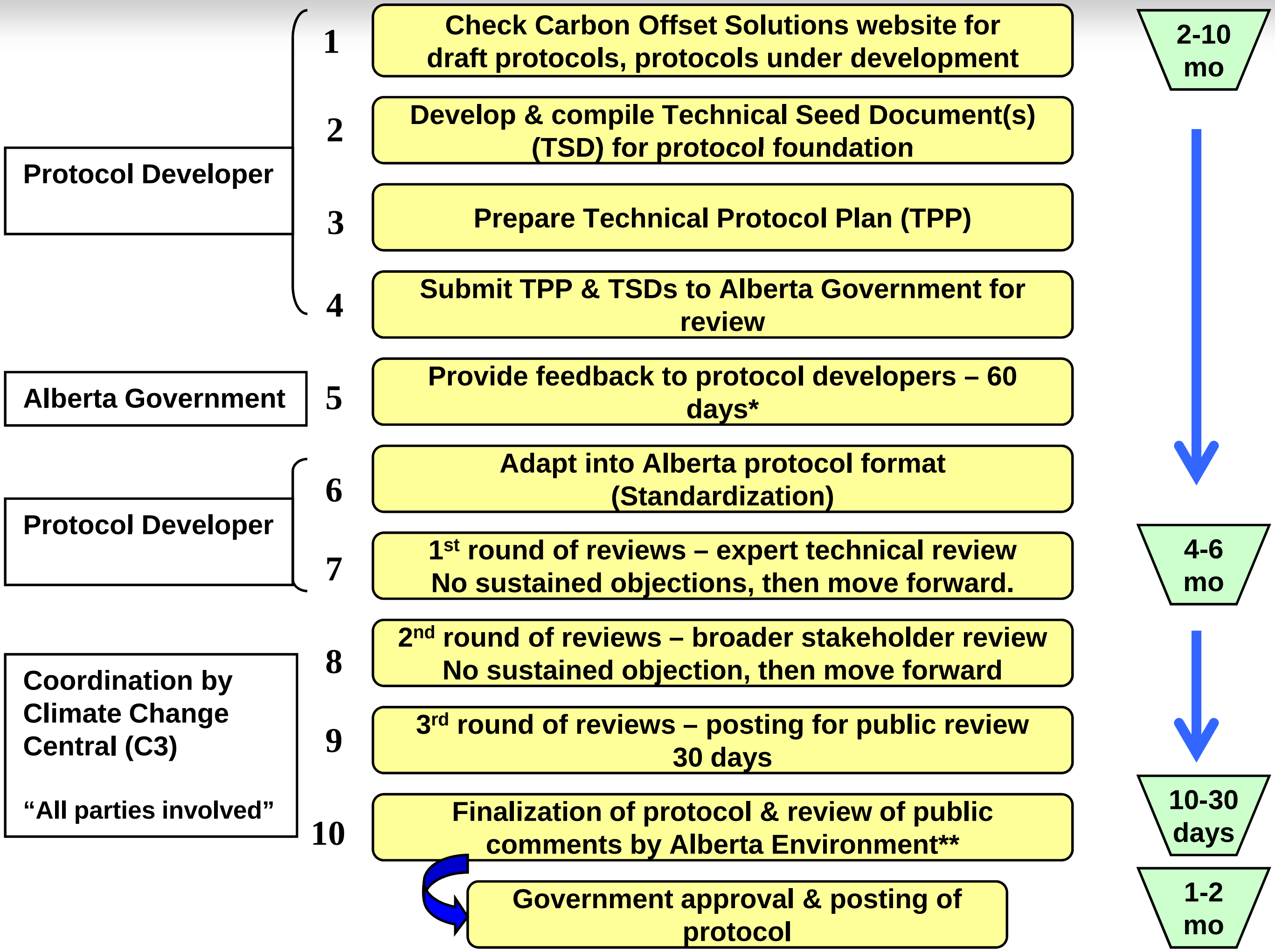
C3 Offset Experience

- Active at both the Federal and Provincial levels
- National/Federal Context
  - Secretariat to Canadian Federal-Provincial-Territorial Quantification Protocol Working Group (NOQT; 2003-'06)
  - Coordinated review of 200+ protocols/standards/methodologies ('07-'08)
    - Based on 1st and 2nd order screening criteria – adaptability of protocols
    - Environment Canada's Fast Track List of 46 eligible protocols
  - Coordinating protocol development for Ducks Unlimited and Canadian/American Fertiliser Institutes
    - Wetlands and Agricultural N_20 reduction protocols
- Industry-Provincial Offsets Group (IPOG) – input to Federal Government
  - Coordinating 10+ working groups; web-based collaboration tools
  - Coordinating Additionality, Permanence, Ownership/Eligibility Policy Papers

C3's Offset Experience

- Provincial Context – SK, AB and some ON input
  - Alberta's Government (Offset System)
    - Guidance Documents (Project, Verification, Protocols, Validation)
    - Protocol Review and Recommendation Process
      - Evaluation and adaptation process for pre-existing
      - Coordination of review for new protocols by project developers
    - Offset Registry
      - House and operate the Alberta Emission Offset Registry on www.carbonoffsetsolutions.ca
    - Education and Information
- Saskatchewan Government – Design, Advice and Technical Support
- Ontario – Preliminary technical and design advice on Offset System

Alberta Protocol Development and Review Process



Protocols – Types Identified/Approved for Development

- Guide to Protocol Developers (draft)/COS Website – initial scoping
  - Contact email, phone conversations, web displayed intentions
  - Coordination of interested parties – reduces duplication of effort
- Submission of Technical Seed Documents/Technical Protocol Plan
  - Escalating commitment/ internal review by Government
  - Manages resource risk for protocol developers/government
  - Coordinate the internal review – 60 day turnaround
- Submission deadlines to manage Protocol Review Process
- TPPs displayed on www.carbonoffsetsolutions.ca

Private Sector shares in development costs; innovation driven

APPROVED

- Afforestation
- Beef (3)
- Biofuels
- Biogas
- Biomass
- Energy Efficiency
- Pork
- Tillage Systems
- Waste Heat
- Landfill Gas/Landfill Bioreactor
- Renewables (3)
- Enhanced Oil Recovery
- Acid Gas Injection
- Intermodal Switching
- Road Rehabilitation
- Compost
- Energy Efficiency
- Wastewater Treatment

IN REVIEW/DEVELOPMENT

- FlyAsh Blending
- Engine Fuel Mgmt/Vent Gas Capture
- Pulp Sludge Application (forestry/agriculture
- Fugitive CH4 Emissions
- Energy Efficiency – Commercial/Insitutional
- Compressor Sation Retrofits
- Buildings (3)
- N20 Abatement - agriculture and industry
- Wetlands Management
- Reduced Summerfallow
- Residual Feed Intake in Beef
- Conversion to Perennial Forages
- Native Rangelands
- Pasture Management
- Soil Amendment

Protocol Review and Milestones

Protocol Developer

1 Check Carbon Offset Solutions website for draft protocols, protocols under development

2 Develop & compile Technical Seed Document(s) (TSD) for protocol foundation

3 Prepare Technical Protocol Plan (TPP)

4 Submit TPP & TSDs to Alberta Government for review

Alberta Government

5 Provide feedback to protocol developers – 60 days*

Protocol Developer

6 Adapt into Alberta protocol format (Standardization)

7 1st round of reviews – expert technical review No sustained objections, then move forward.

Coordination by Climate Change Central (C3)

“All parties involved”

8 2nd round of reviews – broader stakeholder review No sustained objection, then move forward

9 3rd round of reviews – posting for public review 30 days

10 Finalization of protocol & review of public comments by Alberta Environment

Government approval & posting of protocol

2-10 mo

4-6 mo

10-30 days

1-2 mo

C3 New Protocol Development Process

Science Coordination/Dvpmt of the Technical Seed Document

- Phase 1 – Planning and Compilation Science Discussion Document
  - Based on transparent, science-based standards and definitions, best practice guidance, with extensive literature reviews, scientific input/review from leading researchers and technical experts globally
  - ISO 14064-2 Framework
- Phase 2 – Science Coordination / Consultation
  - Discussion paper - primary vehicle for coordinating science, fostering discussion, suggesting options and building consensus on key protocol factors
  - Consensus Building Workshop / Science Coordination Workshop
  - 80% Consensus to advance options
- *Phase 3 – Development of a Technical Seed Document*
- *Phase 4 – Standardize into Alberta Protocol Template*

May take up to 12 - 18 mos. –enters Alberta Protocol Review Process

(http://www.carbonoffsetsolutions.ca/offsetprotocols/workshops.html

Recommendation/Approval Process

- Protocol Developers submit TSDs and TPPs – internal review
- 1st Round of Technical Review – C3/Government on 1st Round
- (http://www.carbonoffsetsolutions.ca/offsetprotocols/abprotocolReviewProcess.html
- C3 manages 2nd Round of 'Market Review'
  - Government attends; all issues posted; no sustained objection*
- 3rd Round – Public Posting
  - All submissions summarised and posted; post-process review with C3 and Government – recommendations reviewed
- Facilitate follow-up with Protocol Sponsors and Government, if needed
- Government makes ultimate decision
- Decisions Posted for maximum transparency

Ongoing Amendments

- Government gives credit duration period of 8 years (maybe 5+)
  - ‘Sink’ Protocols longer
- Protocols reviewed every 5 years – based on Best Available Science of the Day
- Grandfathering of Projects with “Protocol of the Day”
- But – if a direct problem in quantification – amendments immediate
  - If impacts existing projects – stakeholder consultation
- Anticipate protocol reviews will be a collaborative, transparent process

Design Criteria -Stage 1

- Eligibility – laid out in Regulation
- Design Criteria – First Cut – Technical Protocol Plan
  - *Description of the Project Type and How Reductions will be Achieved*
  - *Description of Background Information/Best Practice Guidance*
  - *Regulatory, Legal Requirements and/or Incentive/Grant Programs*
  - *Barriers to Implementation (risks)*
  - *Review of Technology – penetration levels*
  - *Review of Existing Projects -activity levels*
  - *Summary of Quantification Approaches used in the Proposed Protocol*
  - *Other Impacts (assuring permanence methods)*
  - *Assessment of Baseline Scenarios*
  - *Selection of Baseline Scenario*
  - *Definition of the Project Condition*
  - *Functional Equivalence*
  - *Flexibility Mechanisms*

Policy Criteria – Stage 2

- ISO 14064-2 Standard
  - Real, Measurable, Quantifiable, Verifiable
  - Promotes consistency and transparency in GHG quantification, monitoring, reporting and verification
  - Streamlined LCA assessment and on-site, upstream and downstream allows for scalability, stackability and ultimately fungibility
  - Functional Equivalence requirements (carbon intensity)
- Clear Guidance on Ownership

Policy Criteria – Stage 2

- Additionality
  - Designated by the Regulatory Authority (date, beyond BAU, regulations/other measures)
  - Process (ISO; transparency; technical review) – scalable to any measure of additionality (Ontario adaptation initiative)
- Permanence
  - Government policy enabled buffer reserve
  - Market-based approaches are evolving
- Registry Requirement
  - Mandatory – serialization and retirement for compliance

Subject Matter Experts

- Engaged Agriculture and Forestry Inventory Scientists
- Academia, industry technical experts, research institute scientists, provincial/federal scientists
- Developed tried and true science coordination process
  - Provide a ‘peer review’ IPCC style format
  - First Day – common understanding of Design Criteria
  - Remote/Anonymous voting by Technical Experts – comfort
  - Used successfully by Alberta Government, Ontario Government, Research Community in standards setting exercise and science consensus forming processes

Stakeholder/Market Review

- 600+ Email Group of Offset Stakeholders
- Face to Face Workshops – held 4 to date
  - Post 1st round results
  - Send out invites; draft protocols few weeks in advance
  - All 1st round technical providers; broader representation
  - Participants in Carbon Value Chain
  - Protocol Developers present approach
  - Facilitated Discussion by C3
  - No sustained objection to move a protocol forward to next stage

Public Round

- 600+ Email Group of Offset Stakeholders - notification
- Numbered Draft Protocol – submission email
- 30 Day public posting
- Comments compiled and displayed
- Two email notifications

Other Programs

- Coordinating IPOG Protocol Working Groups
  - Adaptation of 20 Alberta protocols – deviations
  - Provide solid analysis of the pros and cons of the various approaches, unique to the jurisdiction at hand
- Good policy decisions need robust technical analyses of the options…
- Ontario – adapted 16 protocols in
  - Process and format makes them scalable; adaptable with the documented, transparent history
- Saskatchewan – will likely do the same
- USDA-USEPA interested in understanding the process

Thoughts…

- Decide whether industry can bring forward new protocols – and at what stage
  - More opportunity than existing Ag, Forestry and Waste Protocols
  - Qualitative Limits?
- Systematic, Robust, Transparent Review Process – Scalable, Stackable and Fungible
  - Predefine the extent of the scope of review – the farther upstream and downstream the quantification goes - increased difficulty/uncertainty in identifying and quantifying primary and secondary effects
  - Consider adjusted baselines to accommodate differing regulatory scopes in jurisdictions –after analysis of coherence/interactions with other policy measures
- Agree on Coverage of Key Policy/Technical Issues
  - Design and Policy Criteria to assist protocol review and recommendation process

More Information?

Climate Change Central

karenhk@climatechangecentral.com

www.climatechangecentral.com

www.carbonoffsetsolutions.ca

Daniele Violetti

Manager, CDM Process Management

James Grabert

Manager, Joint Implementation

Moderator:
David Abbass

CDM Public Information Officer

UNFCCC secretariat

CDM & JI

How they work, why they work

Presentation to

WCI Offsets Committee

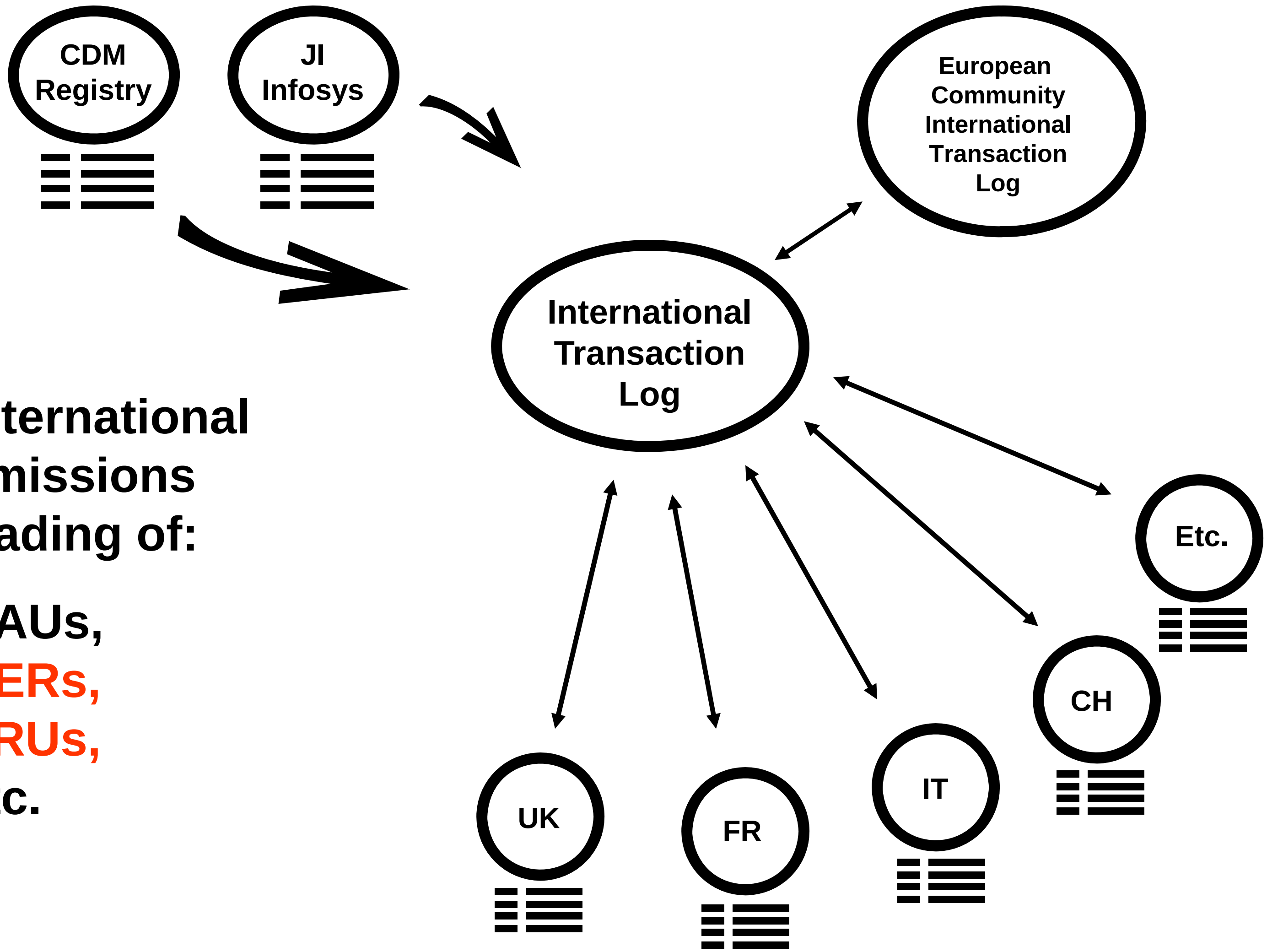
22 April 2009

Three market-based mechanisms

- International emissions trading (Article 17)
- Clean Development Mechanism (Article 12)
  - Emission reduction projects in developing countries
- Joint Implementation (Article 6)
  - Emission reduction projects in any country with a commitment under the Kyoto Protocol

Emissions trading | Essential market architecture in place

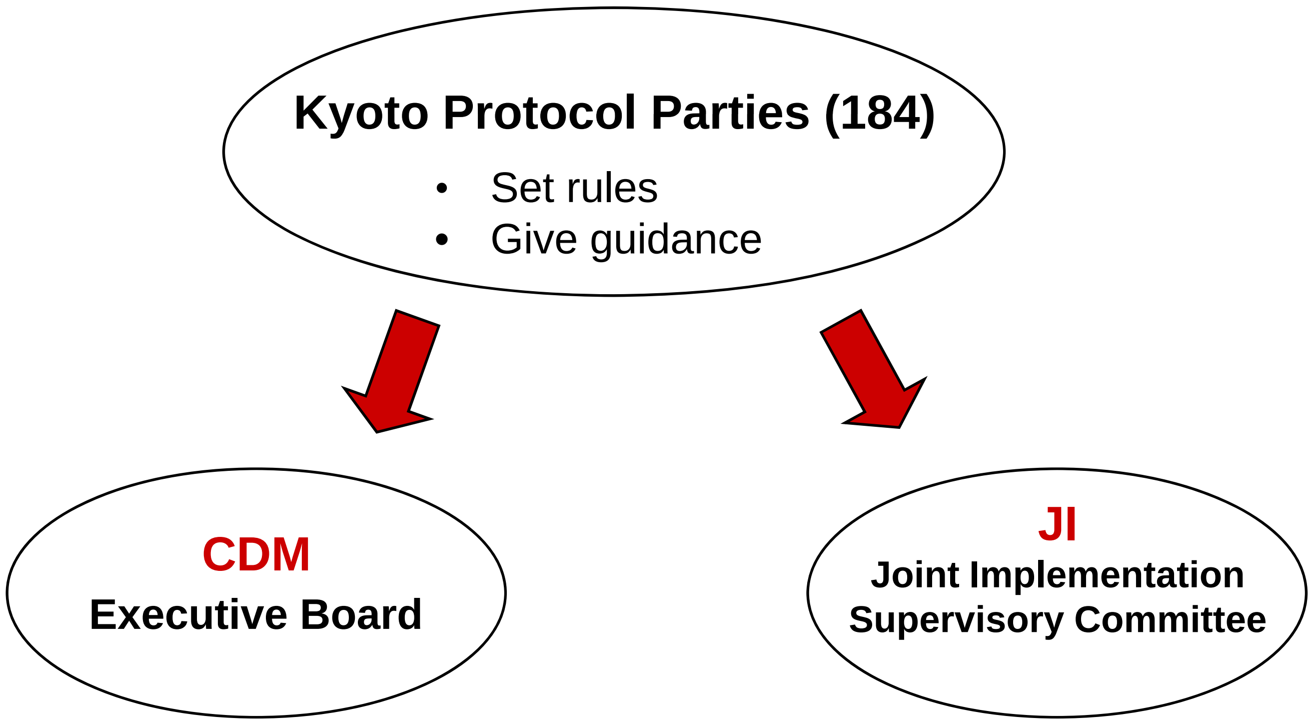
- International emissions trading (Article 17)



International emissions trading of:

AAUs,
CERs,
ERUs,
etc.

Project-based mechanisms | Background



Project-based mechanisms | Background

CDM and JI

- **Mechanisms implemented according to modalities, procedures, guidelines set by KP**

- **Continually improving, evolving based on "further guidance" by KP Parties**

- **Projects vetted by accredited, third-party certifiers – the extended arm of the regulators**

- **Regulators supported by panels, working groups, experts, secretariat**

Quality

- Real, measurable, verifiable, additional (units = 1 tonne CO_2)
- Continual improvement

Transparency

- Every document about every project available

Public input

- Regular calls for public input
- Periods for public review built in to registration, issuance processes
- Public input sought, e.g. in methodology development

CDM | Background

- Clean Development Mechanism (CDM) (Article 12)

  Emission reduction projects in developing countries

  - CDM assists countries to achieve sustainable development goals, creates incentive for investment, provides additional support for adaptation
  - CDM projects produce certified emission reductions (CERs)
  - CERs are saleable/tradable units that can be used for compliance with KP targets

Regulated mechanism overseen by

Executive Board

10 members, 10 alternate members who serve in their private and personal capacity

assisted by:

Methodology Panel

Accreditation Panel

Working groups (a/reforestation, small scale)

Registration and issuance team (roster of experts)

UNFCCC secretariat

CDM | A mechanism with global reach

1588 registered projects in

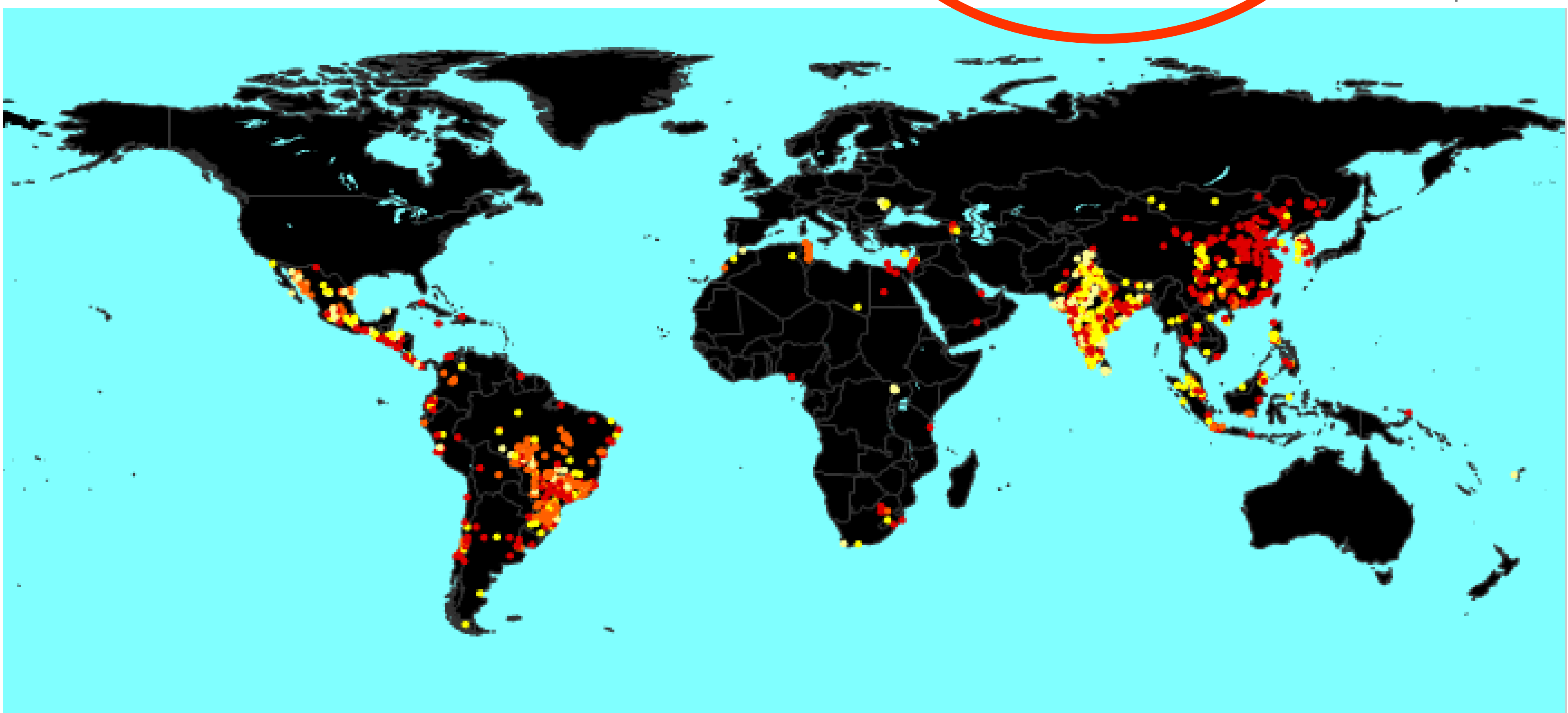
55 countries

Plus > 2600 more projects in pipeline

277 million CERs issued to date

>2.9 billion certified emission reductions expected to the end of 2012

Status: 22 April 2009



CDM | **Project cycle**

1. Project design: PP

Project participant prepares project design document, making use of approved emissions baseline and monitoring methodology. Secures letter of approval from host Party

6. CER issuance

5. Verification: DOE

4. Monitoring: PP

3. Registration: EB

2. Validation: DOE

1. Project design: PP

CDM | Project cycle

2. Validation: DOE

Project design document validated by accredited designated operational entity, private third-party certifier

6. CER issuance

5. Verification: DOE

4. Monitoring: PP

3. Registration: EB

2. Validation: DOE

1. Project design: PP

CDM | **Project cycle**

3. Registration: EB

Valid project submitted by DOE
to the Executive Board
with request for registration

6. CER issuance

5. Verification: DOE

4. Monitoring: PP

3. Registration: EB

2. Validation: DOE

1. Project design: PP

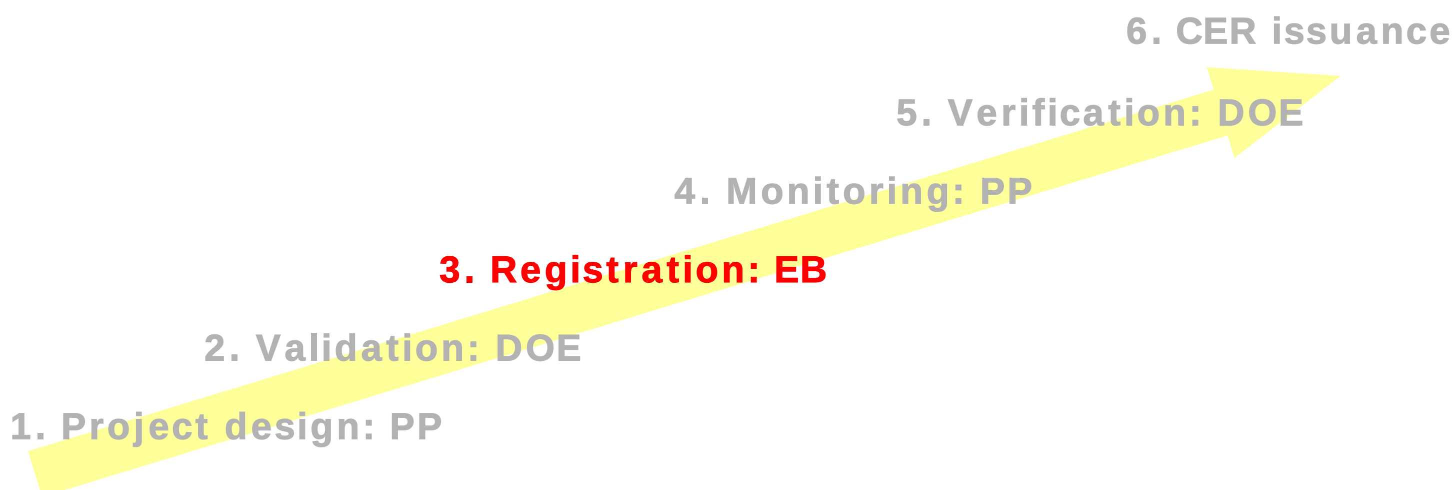
Registration step in detail

First: Completeness check by secretariat

Second: Work of certifier checked by expert from registration and issuance team (RIT)

Third: Work of RIT checked by secretariat

Fourth: If a Party or three members of Executive Board request review, project undergoes review, otherwise proceeds to registration



CDM | Project cycle

4. Monitoring: PP

Project participant responsible for monitoring actual emissions according to approved methodology

6. CER issuance

5. Verification: DOE

4. Monitoring: PP

3. Registration: EB

2. Validation: DOE

1. Project design: PP

5. Verification: DOE

Designated operational entity verifies that emission reductions took place, in the amount claimed, according to approved monitoring plan

6. CER issuance

5. Verification: DOE

4. Monitoring: PP

3. Registration: EB

2. Validation: DOE

1. Project design: PP

CDM | Project cycle

6. CER issuance: EB

Designated operational entity submits verification report with request for issuance to Executive Board

6. CER issuance

5. Verification: DOE

4. Monitoring: PP

3. Registration: EB

2. Validation: DOE

1. Project design: PP

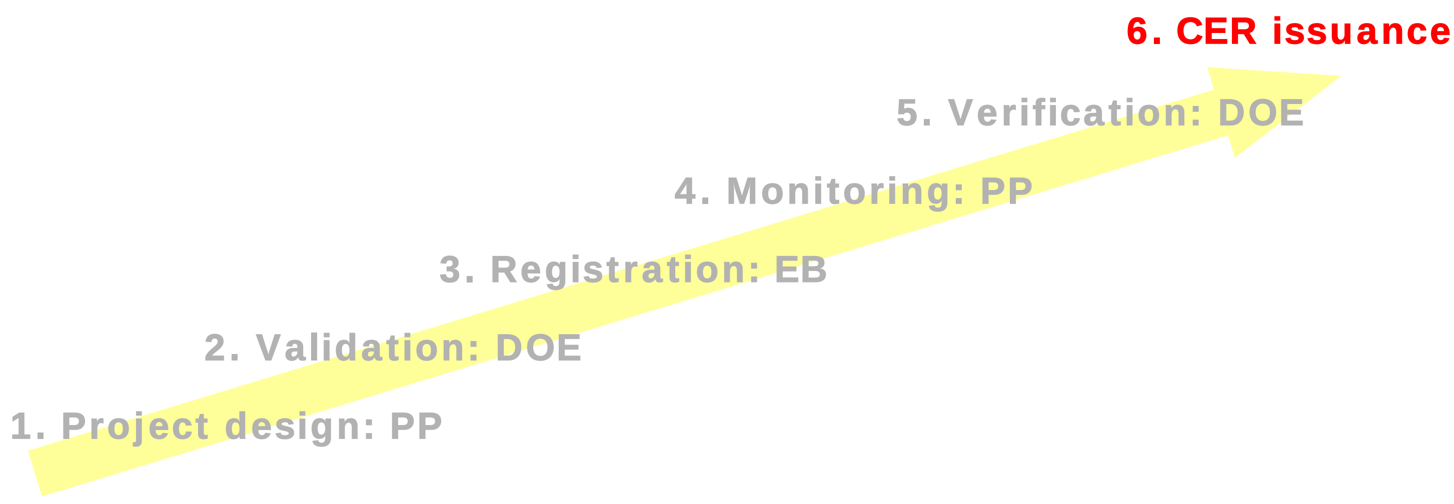
CER issuance step in detail

First: Completeness check by secretariat

Second: Work of certifier checked by expert from registration and issuance team (RIT)

Third: Work of RIT checked by secretariat

Fourth: If a Party or three members of Executive Board request review, issuance request undergoes review, otherwise proceeds to issuance



JI Track 2 | On the cusp?

- Joint Implementation (Article 6)

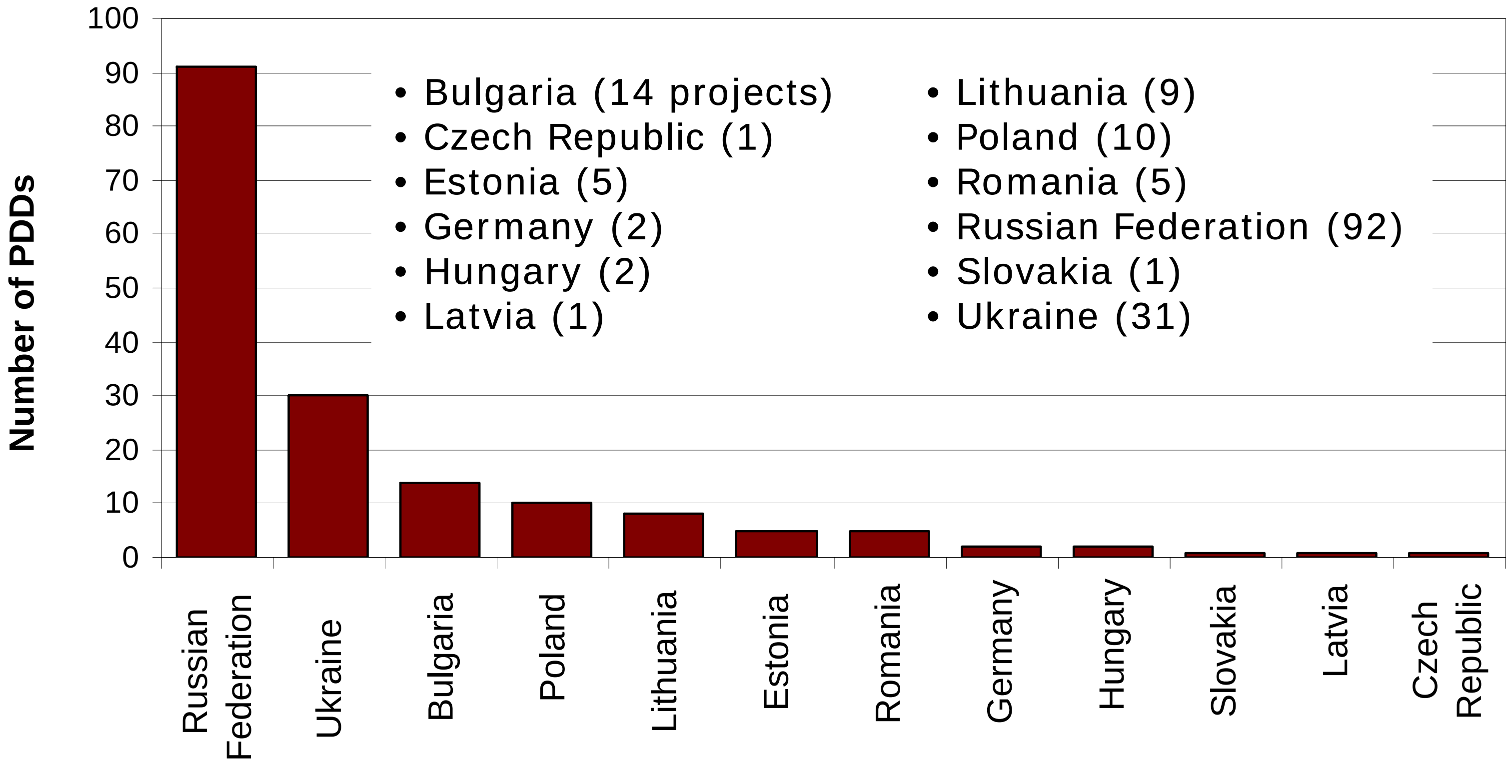
Emission reduction projects in <u>any country with a commitment under the Kyoto Protocol</u>

- Projects in capped environment
- Projects earn emission reduction units (ERUs)
- ERUs are created by conversion of existing assigned amount units (AAUs) held by the country
- ERUs are saleable/tradable units that can be used for compliance with KP targets

JI Track 2 | Project design documents

- **33 Parties have named designated focal points**
- **26 Parties have submitted procedures**
- **12 Parties hosting projects**

- **177 PDDs published for comment**



All published PDDs available on **UNFCCC JI website**: http://ji.unfccc.int

The 177 Project design documents represent

- **Emission reductions ~300 million t CO_2 eq. (2008-2012)**
  - Renewable energy (biomass, wind, hydro)
  - Methane avoidance (gas distribution, landfills, coal mine)
  - Destruction of nitrous oxide from chemical processes (nitric acid production)
  - Energy efficiency (manufacturing industries, district heating)
  - Fuel switch (manufacturing industries, transportation, power generation)
  - Power generation (modernization of power plants)

JI | **Project cycle**

1. Project design: PP

Project participant prepares PDD, making use of approved emissions baseline and monitoring methodology

6. ERU issuance

5. Verification: AIE

4. Monitoring: PP

3. Acceptance: JISC

2. Determination: AIE

1. Project design: PP

JI | Project cycle

2. Determination: AIE

Accredited independent entity (AIE), private third-party certifier, prepares and publishes PDD for public comment, and subsequently submits determination report to JISC

6. ERU issuance

5. Verification: AIE

4. Monitoring: PP

3. Acceptance: JISC

2. Determination: AIE

1. Project design: PP

JI | **Project cycle**

3. Acceptance: JISC

Project submitted by AIE to the Joint Implementation Supervisory Committee with request for determination. If letter of approval received, determination accepted (deemed final).

6. ERU issuance

5. Verification: AIE

4. Monitoring: PP

3. Acceptance: JISC

2. Determination: AIE

1. Project design: PP

Determination publication step in detail

First: Completeness check by secretariat

Second: Independent expert assigned to check determination report, two JISC members named to take lead in checking the determination

Third: Work of expert checked by secretariat

Fourth: If three members of JISC request review, or one Party, project undergoes review, otherwise project accepted

JI | **Project cycle**

4. Monitoring: PP

Project participant responsible for monitoring actual emissions according to approved methodology

6. ERU issuance

5. Verification: AIE

4. Monitoring: PP

3. Acceptance: JISC

2. Determination: AIE

1. Project design: PP

JI | Project cycle

5. Verification: AIE

Accredited independent entity verifies that emission reductions took place, in the amount claimed, according to approved monitoring plan

6. ERU issuance

5. Verification: AIE

4. Monitoring: PP

3. Acceptance: JISC

2. Determination: AIE

1. Project design: PP

JI | Project cycle

6. ERU issuance: Host Country

AIE submits verification report to JISC. If it is deemed to be in order, JISC approves emission reductions and host country is requested to proceed with issuance (i.e. convert equivalent number of AAUs into ERUs)

6. ERU issuance

5. Verification: AIE

4. Monitoring: PP

3. Acceptance: JISC

2. Determination: AIE

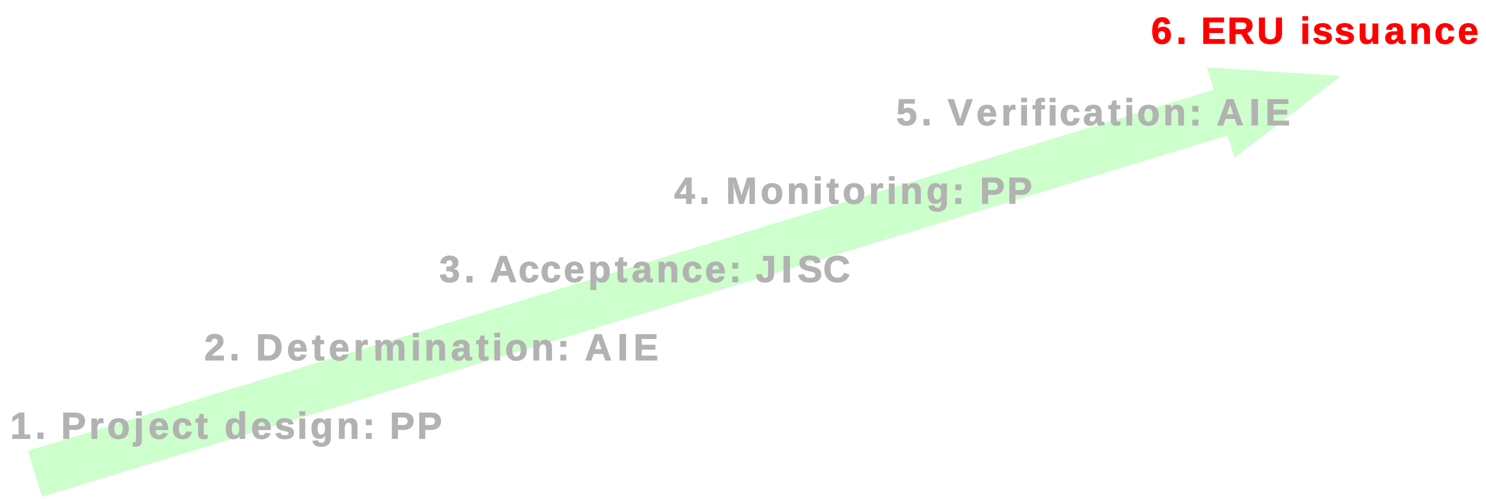
1. Project design: PP

ERU issuance step in detail

__First__: **Completeness check** by secretariat

__Second__: **Two JISC members** named to take lead in checking the verification

__Third__: If three members of JISC request review, or one Party, project undergoes **review**, otherwise **emission reductions approved**



More information

cdm.unfccc.int

ji.unfccc.int

CDM Bazaar

http://www.cdmbazaar.net/

Monitoring Emissions Allowance Markets

Pallas LeeVanSchaick, Ph.D.
Potomac Economics

Western Climate Initiative
Markets Committee Meeting
April 22, 2009

Introduction

- As the market monitor for the RGGI allowance market, Potomac Economics assists the RGGI States with market oversight. Potomac Economics also serves as the market monitor for several wholesale electricity markets in the U.S.
- This presentation provides an overview of market monitoring and how it contributes to market oversight:
  - ✓ Goal of market oversight
  - ✓ Primary objectives of market monitoring
  - ✓ Responsibilities of market monitors
  - ✓ Overview of the market monitoring process
  - ✓ Other market oversight issues
- Most aspects of market oversight are applicable to both emission allowance markets and electricity markets.

Goal of Market Oversight

- Cap-and-trade is an efficient mechanism for limiting CO2 emissions because it minimizes the cost impacts of emissions reductions.
  - ✓ CO2 allowance prices provide end-users and emitters with incentives to reduce emissions by adopting new technologies, improving energy efficiency, etc.
  - ✓ Such investment decisions are driven by price signals in the CO2 allowance market, making it important for the market to function efficiently.
- The goal of market oversight is to promote competition by:
  - ✓ Providing disincentives for anticompetitive conduct,
  - ✓ Reducing inefficient barriers to participation. Robust competition makes the market resistant to manipulation.
  - ✓ Identifying market rules or design issues that reduce the efficiency of the market.
- When there is uncertainty about whether a new market will be competitive, a well-designed market monitoring program helps ensure the market will be efficient.

Objectives of Market Monitoring

- Market monitors regularly analyze market outcomes in order to:
  - ✓ Identify and address anticompetitive behavior, which would distort the market outcomes and undermine confidence in the market.
  - ✓ Deter anticompetitive behavior by reducing the likelihood that such behavior will be profitable.
  - ✓ Identify inefficient market rules and recommend market design improvements.
    - – The market monitor is well positioned to identify factors that create barriers to entry, raise the cost of participation, or provide inefficient incentives.
    - – The best protection from anticompetitive conduct is robust competition.
  - ✓ Provide information about the market to policy makers, regulators, market participants, and the public. Such information is helpful in evaluating whether the market is functioning as intended.

Responsibilities of Market Monitors

- Market monitors have no regulatory authority.
  - ✓ Market monitors generally cannot impose remedies such as financial penalties.
  - ✓ Market monitors may request information from market participants, although such requests are only as compulsory as the participation agreements specify.
  - ✓ Market monitors investigate suspicious behavior and, if warranted, report findings to the appropriate entities, including state and federal regulators.
    - – The CFTC has jurisdiction over public commodities exchanges, and various agencies enforce state and federal antitrust laws.
- Market monitors should not be limited to addressing illegal conduct, but rather any issue that undermines market efficiency. When such conduct is identified, it can typically be addressed by:
  - ✓ Modifying the market rules.
  - ✓ Publishing information that makes the market more resistant to certain anticompetitive conduct.
  - ✓ Advising against the publication of information that could facilitate anticompetitive conduct.

Responsibilities of Market Monitor (cont.)

- Market monitors should collect information from the following sources:
  - ✓ Confidential information from the bidder qualification process, the auctions, and the allowance registry.
  - ✓ Public sources provide information that can be used to model the incentives of firms participating in the allowance market. (Some sources require a subscription.)
  - ✓ Confidential information from public exchanges and OTC transactions may not be available to the monitor (except what is obtained in an investigation).
- The market monitor should provide useful information to the public, regulators, and policy makers.
  - ✓ Information release should always balance concerns about transparency and other benefits of publication against concerns about confidentiality and facilitating anticompetitive conduct and confidentiality.
- Market monitors must avoid all potential conflicts of interest.
  - ✓ The market monitor's credibility requires it to be independent of any market participant, contractor, or other interested party.
  - ✓ Strict policies are needed to avoid financial or functional dependence on monitored entities.

Overview of the Market Monitoring Process

- We monitor the auction and the secondary market, screening the conduct of participants using competitive benchmarks. The competitive benchmarks are based on models of conduct that would be expected in a competitive and efficient market.
  - ✓ These expectations are based on the estimated value of allowances to each participant for compliance purposes or other business purposes. This requires classifying each participant as a compliance entity, a non-compliance entity, or a hybrid.
- To the extent that a market participant's conduct departs substantially from competitive expectations, we assess whether the conduct is likely:
  - ✓ A response to an inefficient market rule, or
  - ✓ An attempt to exercise market power or otherwise manipulate prices.
- If the conduct is potentially an exercise of market power or manipulation, we:
  - ✓ Use models to determine whether the conduct could have substantially affected the market.
  - ✓ Contact the market participant and request an explanation for the conduct.
- If warranted, we conduct a more detailed investigation and report findings to the appropriate entities.

Other Market Oversight Issues

- Participation in the market by non-compliance entities is beneficial for many reasons, including the following:
  - ✓ Non-compliance entities increase competition, reducing the potential exercise of market power by large compliance entities.
  - ✓ Brokers can assist smaller compliance entities in procuring allowances by providing advice and flexibility.
  - ✓ Non-compliance entities can help compliance entities hedge future compliance costs.
  - ✓ Not allowing their participation may discourage investment in offset projects and other efforts to reduce emissions.

Other Market Oversight Issues (cont.)

- Policies on information disclosure should balance the benefits of public disclosure against the likely costs.
  - ✓ The potential benefits of disclosure include:
    - – Transparency – information can help the public evaluate whether the market is working as intended.
    - – Information can reduce the cost of participation, increase certainty about expected future prices, or increase competition.
  - ✓ The potential harm from disclosure includes:
    - – Certain information that may facilitate collusion in the auction or unilateral market power.
    - – To avoid disclosure of confidential information, some firms may conceal their activity in the market. This would have the unintended effect of reducing the information available to the market monitor.
  - ✓ Hence, it is important to be selective about the information that is disclosed.

Other Market Oversight Issues (cont.)

- Policies on information collection:
  - ✓ Information could be collected from the auction process, the allowance registry, and/or the derivative market.
  - ✓ The collection of information should not impose undue cost on firms that participate in the auction or that hold allowances in the registry.
    - – Onerous reporting requirements can be circumvented, ultimately reducing the information available and increasing the difficulty of monitoring.
  - ✓ It would be difficult to collect information on derivatives (particularly OTC), since these would not be administered by WCI.
    - – It may be possible to obtain information on transactions in public exchanges. In this regard, there may be potential to develop a way to share information with the CFTC.
    - – Collecting information on OTC derivative transactions would likely be costly for market participants and the market monitor. Furthermore, such requirements could be difficult to enforce.

Western Climate Initiative News

April 24, 2009

This status report is issued on the last Friday of each month from WCI Partner jurisdictions to all interested stakeholders via the WCI listserv and website.

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Upcoming Events

April 30: Stakeholder Update Call

The WCI's next bimonthly teleconference to update and hear from stakeholders will be on Thursday, April 30, from 12:30 to 2:00 pm (Pacific Time). To join the call, dial 1.800.868.1837 (toll free) or 1.404.920.6440 (direct dial), and enter participant code 659537#. A reminder and agenda for the call will be posted to the WCI website and sent to the listserv next week. (If you received this newsletter directly from the WCI, then you are on the listserv. If not, please go to the WCI website and join our listserv.)

Week of May 4: Release of Final Draft Essential Requirements of Mandatory Reporting for the WCI

Originally scheduled for release on April 20, the WCI will release its final draft of the essential requirements for mandatory reporting the week of May 4. A stakeholder conference call will be held on May 19 (see below) and a one-month period for written comment will be provided.

WCI Educational Opportunities Open to Stakeholders

The WCI is further extending its stakeholder engagement process to include opportunities for stakeholders to attend some of the teleconferences and webinars routinely conducted by WCI committees and task groups. Specifically, stakeholders will be invited to attend events in which experts share knowledge pertaining to various elements of the WCI cap-and-trade program design. Five such events, with stakeholder attendance, occurred the week of April 20 (see below). Future events will be posted on the WCI website and announced through the WCI listserv. Typically, there will be no opportunity on these teleconferences and webinars for stakeholders to make comments or ask questions, but stakeholder feedback can be provided at any time on the submit comments page of the WCI website, or during the bi-monthly stakeholder update calls. (See "Upcoming Events" to the left for information on the next stakeholder update call.)

In addition, a portion of each in-person meeting of the WCI Partners will be open to the public. These meetings generally occur every other month. The next WCI meeting which will be open to the public will occur on the afternoon of May 27 followed by a workshop on offset limits, early reduction allowances, and competitiveness issues on the morning of May 28 (see "Upcoming Events" to the left for additional information).

WCI Comments on the American Clean Energy

May 19: Stakeholder Call on Final Draft Essential Requirements

The Reporting Committee will host a teleconference to update and hear from stakeholders regarding the final draft essential requirements. The call will be held on Tuesday, May 19 from 12:00 pm to 2:00 pm (Pacific Time). Details for the call will be sent to the listserv and posted to the WCI website.

May 27: Partners Meeting, Seattle, WA

The WCI Partners will be meeting at the Grand Hyatt Hotel in Seattle, WA on May 27. Stakeholders and members of the public are invited to attend from 1:00 pm - 5:00 pm. There will be some time at the end of the day dedicated to public comments and questions. An informal reception will be hosted by the WCI Partners upon adjournment. The agenda and other meeting details will be posted to the WCI website and issued to the WCI listserv when available.

May 28: Cap Setting and Allowance Distribution (CSAD) Committee Workshop, Seattle, WA

Following on the WCI

and Security Act of 2009

On April 17, the WCI provided comments to the U.S. House of Representatives Energy and Commerce Committee regarding the Waxman-Markey discussion draft of The American Clean Energy and Security Act of 2009. A copy of these comments is available on the WCI website.

WCI Testifies on EPA's Proposed Mandatory GHG Reporting Rule

The WCI provided oral testimony to the US EPA at its April 16 public hearing in Sacramento on its proposed mandatory GHG reporting rule. A copy of the testimony is available on the WCI website. WCI expects to provide a complete set of written comments to US EPA prior to the close of the 60-day public comment period on June 9.

Markets Committee Taking Comments on Draft Principles and Market Oversight Questions

To help guide its research, analysis, and deliberations, the WCI Markets Committee is developing a set of principles that define the desired outcomes for three tasks described in the Committee work plan (Task 2: Compliance Verification and Enforcement; Task 3: Market Oversight; and Task 6: Auction Design). The draft principles, as well as market oversight questions intended to motivate a discussion of market oversight issues, are available for review and comment on the WCI website. These draft principles and questions were discussed at a stakeholder meeting in Seattle on April 9. The Markets Committee also hosted a teleconference on April 22 to gather information on market monitoring and oversight. The presentation from the April 22 teleconference is available on the WCI website.

Offsets Committee Teleconferences on Organizations and Institutions Which Conduct Offset Protocol Reviews

Per Task 3.1 of the WCI Offsets Committee's work plan, the Committee asked five organizations which may have the capacity or structures to perform the protocol review and recommendation process to make a presentation to the Committee and interested stakeholders. Teleconferences with four of the organizations occurred on April 21 and 22. The fifth and final presentation will occur April 28 at 10:00 am Pacific (see WCI website for details). The presentation from each organization will be posted to the WCI website.

Partners meeting, the CSAD Committee will host a workshop to discuss offset limits, early reduction allowances, and competiveness issues on the morning of May 28. This workshop will also be held at the Grand Hyatt Hotel in downtown Seattle. Further details will be posted to the WCI website and sent to the listserv soon, including draft white papers on offset limits and early reduction allowances.

Nova Scotia Joins the WCI as an Observer

The province of Nova Scotia has joined the WCI as an Observer. WCI Observers now include two Canadian provinces, six U.S. states, and six Mexican states.

To subscribe or unsubscribe from the WCI listserv, click here.

The Climate Trust Project and Methodology Experience

Presented to

WCI Offsets Committee

April 28, 2009

The Climate Trust

Introduction to The Climate Trust

- Non-profit based in Portland, Oregon
- Only state-recognized supplier of regulatory-grade offsets
- Experienced offset practitioner: Since 1999
- Portfolio: 18 projects, $9 million, 3 million tons CO_2
- Quality reputation with regulators, business, and environmental groups

The Climate Trust

Regulatory Programs

- Oregon
  - Only qualified organization under state CO_2 Standard for power plants
- Washington State
  - Recognized Independent Qualified Organization under CO_2 Standard
- Massachusetts
  - Department of Environmental Protection
- Montana
  - Department of Environmental Quality

The Climate Trust

Voluntary Programs

- Colorado Carbon Fund
  - Initiated by the Governor's Energy Office
  - Focused on in-state offset projects
- Northwest Natural Smart Energy Program
  - Portland's natural gas utility
  - Focused on regional livestock methane projects
- Responsible for program design, project acquisition, fund management

The Climate Trust

Sampling of Project Portfolio

Oregon CO_2 Standard

- New power plants must offset a significant portion (~17%) of their CO2 emissions
- Climate Trust has unique non-profit role
- Developer can comply by paying a per-ton fee to The Climate Trust
- Trust reports to Energy Facility Siting Council

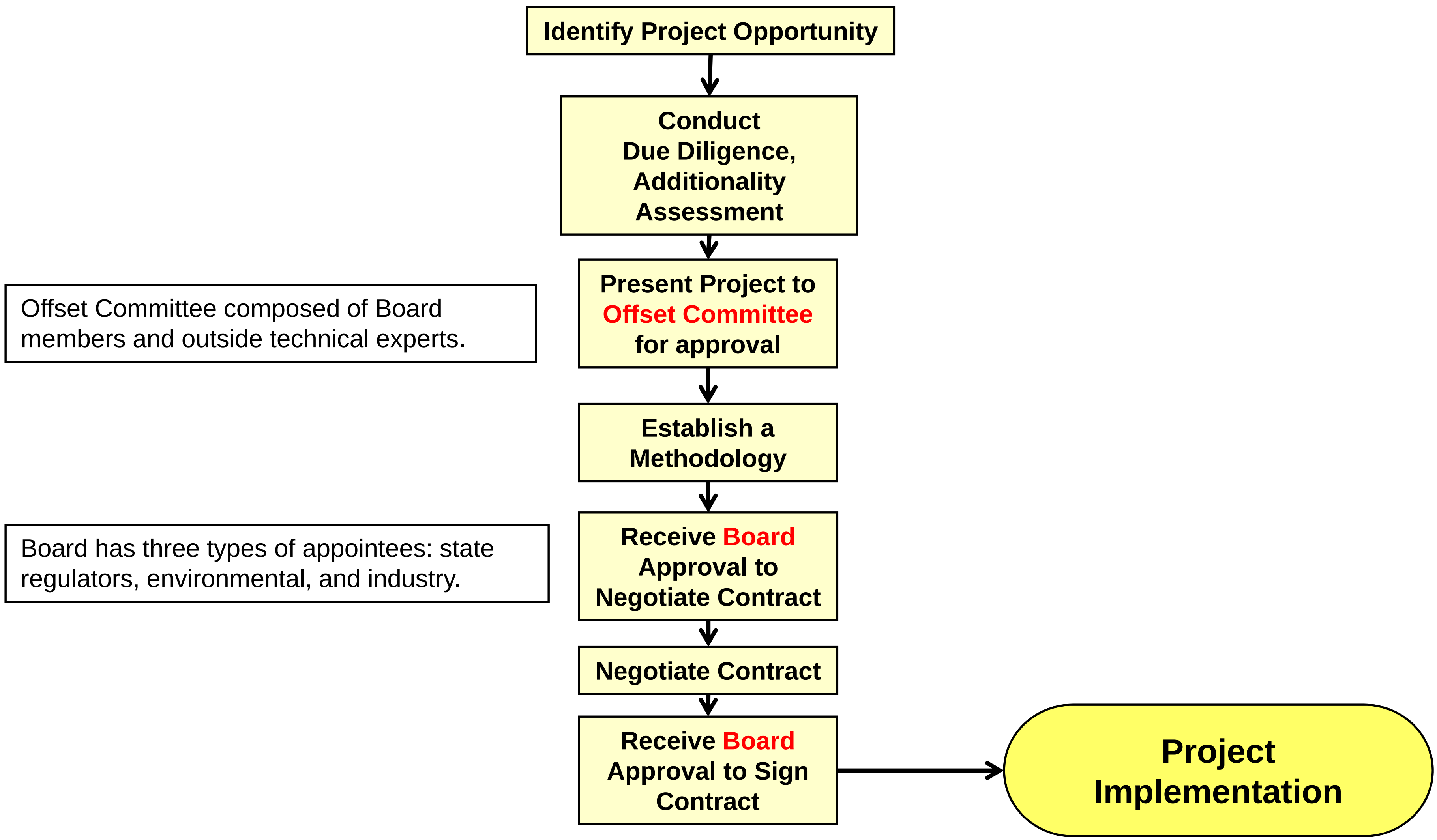
The Climate Trust

Capabilities/Capacity

- Offset project acquisition
- Offset project development
- Project management
- Methodology development
- Carbon contracting

The Climate Trust

Project Acquisition Process



Methodology Development

- **Methodologies developed in coordination with:**
  - **Outside technical experts**
  - **Climate Trust Offset Committee**
  - **Climate Trust Board of Directors**
- **Majority of existing portfolio pre-dates existing methodologies**
- **Outside methodologies used when available**

The Climate Trust

Project to Protocol

- Priority is identification of high-quality offset projects
- Project-specific methodology developed
- Most similar to CDM, VCS process
- Allows for market-based project solutions
- Can work in concert with sector methodologies

The Climate Trust

Developing an Offset Program Administrator

- Develop and evaluate methodologies and protocols
- Project to protocol process
- Early action implementation
- Evaluate projects or operate a third-party certifier system
- Administer project registry

The Climate Trust

Thank you

Sean Clark

Director of Offset Programs

Tel: 503.238.1915 x203

Email: swclark@climatetrust.org

The Climate Trust

Attachment 5: Adipic Acid Manufacturing

§ WCI.XX0 ADIPIC ACID MANUFACTURING

§ WCI.XX1 Source Category Definition

Adipic acid ($HOOC(CH_2)_4COOH$) is a dicarboxylic acid used in the production of a large number of products including synthetic fibers (primarily nylon 6,6), coatings, plastics, urethane foams, and synthetic lubricants. Adipic acid is produced by oxidizing a mixture of cyclohexanone ($(CH_2)_5CO$) and cyclohexanol ($(CH_2)_5CHOH$) with nitric acid in the presence of a catalyst; nitrous oxide (N_2O) is formed as an unwanted by-product.

§ WCI.XX2 Greenhouse Gas Reporting Requirements

In addition to the information required by WCI.3, the annual emissions data report shall contain the following information:

(a) Total emissions of N_2O at the facility level (metric tons)

(b) Total quantity of adipic acid production (metric tons)

(c) Facility-specific N_2O emission factor derived from periodic emissions monitoring or irregular emissions sampling (metric tons N_2O per metric ton of adipic acid)

(d) Destruction factor for facility-specific abatement technology (e.g., catalytic destruction, thermal destruction, nitric acid recycling, adipic acid recycling, etc.)

(e) Abatement system utilization factor for facility-specific abatement technology

(f) CO_2, N_2O, and CH_4 emissions from stationary combustion units as specified in WCI.20

§ WCI.XX3 Calculation of N_2O Emissions

(a) Process N_2O emissions. Determine process N_2O emissions as specified under either paragraph (1) or (2) of this section.

(1) Continuous emissions monitoring systems (CEMS).
(2) Calculation methodologies specified in paragraph (b) of this section.

(b) Process N_2O Emissions Calculation Methodology. Calculate total N_2O process emissions using the following equation:

$$E_{N2O} = EF \times AAP \times (1 - DF \times ASUF)$$

Equation XX0-1

Where:

E_{N2O}	=	Emissions of N_2O from adipic acid production (metric tons);
EF	=	N_2O emission factor (metric tons N_2O/metric ton of adipic acid produced) derived from periodic emissions monitoring or irregular emissions sampling;
AAP	=	Adipic acid production (metric tons);
DF	=	Destruction factor (dimensionless);
ASUF	=	Abatement system utilization factor (dimensionless).

§ WCI.XX4 Sampling, Analysis, and Measurement Requirements

The following measurement methods shall be used.

(a) Facility N_2O emissions tests. All facilities must conduct testing using:

(1) U.S. EPA Method 320 (40 CFR part 63, Appendix A) or ASTM D6348-03; or
(This is a possible change for WCI based on §98.54 of the Mandatory Reporting Rule);

(2) Continuous emissions monitor system (CEMS) to determine either the uncontrolled emissions to derive an emission factor (for use with the documented abator destruction efficiency), or the controlled emissions. The CEMS shall be operated in accordance with quality assurance and quality control program approved by the [jurisdiction].

(b) Adipic acid production rates. Production rates may be determined through sales records, or through direct measurement using flow meters or weigh scales.

Attachment 6: Primary Aluminum Production

§ WCI.70 PRIMARY ALUMINUM PRODUCTION

§ WCI.71 Source Category Definition

A primary aluminum production process converts alumina mineral to aluminum metal using electrolysis.

§ WCI.72 Greenhouse Gas Reporting Requirements

For each facility that includes a primary aluminum production process, the emissions data report must contain the following information:

(a) CO_2 emissions from anode consumption from prebaked and Søderberg electrolysis cells.

(b) CO_2 emissions from anode and cathode baking.

(c) CF_4 and C_2F_6 emissions for anode effects.

(d) CO_2 emissions from green coke calcination.

(e) SF_6 emissions from cover gas consumption.

(f) CO_2, N_2O, and CH_4 emissions from stationary combustion units as specified in WCI.20.

(g) Annual aluminum production.

§ WCI.73 Calculation of GHG Emissions

(a) Calculate CO_2 emissions from anode consumption using either Equation 70-1 or 70-2, as applicable.

(1) For Prebaked Anodes:

$$E_{CO_2} = \sum_{i=1}^{12} [NCC \times MP \times \frac{(100 - S_a - Ash_a - Imp_a)}{100} \times 3.664]_i$$

Equation 70-1

Where:

E_{CO2}	=	Annual CO_2 emissions (metric tons).
NCC	=	Net anode consumption per metric ton of aluminum for month i (metric ton/ metric ton aluminum).
MP	=	Aluminum production for month i (metric ton).
S_a	=	Sulfur content in baked anodes for month i (wt %).
Ash_a	=	Ash content in baked anodes for month i (wt %).
Imp_a	=	Content of fluorine and other impurities in baked anodes for month i (wt %).
3.664	=	Conversion factor from carbon to CO_2.

(2) For Søderberg Anodes:

$$E_{CO_2} = \sum_{i=1}^{12} \left[\begin{array}{l} (PC \times MP) - \left(BSM \times \frac{MP}{1000} \right) - \left(\frac{BC}{100} \times PC \times MP \times \left(\frac{S_p + Ash_p + H_p}{100} \right) \right) \\ - \left(\frac{100 - BC}{100} \times PC \times MP \times \frac{S_c + Ash_c}{100} \right) \end{array} \right]_i \times 3.664$$

Equation 70-2

Where:

E_{CO2}	=	Annual CO_2 emissions (metric tons).
PC	=	Paste consumption for month i (metric tons paste/metric ton aluminum).
MP	=	Aluminum production for month i (metric tons).
BSM	=	Emissions of benzene-soluble matter (kilograms benzene-soluble matter/metric ton aluminum).
BC	=	Average binder (pitch) content in paste for month i (wt %).
S_p	=	Sulfur content in pitch for month i (wt %).
Ash_p	=	Ash content in pitch (wt %).
H_p	=	Hydrogen content in pitch (wt %).
S_c	=	Sulfur content in calcinated coke (wt %).
Ash_c	=	Ash content in calcinated coke (wt %).
3.664	=	Conversion factor from carbon to CO_2.

(b) If anode or cathode baking is performed onsite, calculate CO_2 emissions as specified in paragraphs (b)(1) or (2) as applicable. Total emissions as specified in paragraph (b)(3) if both (b)(1) and (2) are applicable.

(1) Calculate CO_2 emissions from packing coke using Equation 70-3.

$$EC_{CO_2} = \sum_{i=1}^{12} \left(PCC \times BAP \times \frac{100 - Ash_{pc} - S_{pc} - Imp}{100} \right)_i \times 3.664$$

Equation 70-3

Where:

EC_{CO2}	=	Annual CO_2 emissions (metric tons pre year).
PCC	=	Packing coke consumption per metric ton of baked anode for month i (metric tons coke/metric ton anodes).
BAP	=	Baked anode production for month i (metric tons).
Ash_{pc}	=	Ash content in packing coke for month i (wt %).
S_{pc}	=	Sulfur content in packing coke for month i (wt %).
Imp	=	Content of other impurities for month i (wt %).
3.664	=	Conversion factor from carbon to CO_2.

(2) Calculate CO_2 emissions from pitch coking using Equation 70-4.

$$EP_{CO_2} = \sum_{i=1}^{12} \left(GAW - BAP - \left(\frac{H_p}{100} \times \frac{PC}{100} \times GAW \right) - RT \right)_i \times 3.664$$ **Equation 70-4**

Where:

EP_{CO2}	=	CO_2 emissions (metric tons pre year).
GAW	=	Green anode consumption for month i (metric tons).
BAP	=	Baked anode production for month i (metric tons).
H_p	=	Hydrogen content in pitch for moth i (wt %).
PC	=	Pitch content in green anode for month i (wt %).
RT	=	Recovered tar for month i (metric tons).
3.664	=	Conversion factor from carbon to CO_2.

(3) Calculate total CO_2 emissions for anode baking using Equation 70-5.

$$E_{anodebaking} = EC_{CO2} + EP_{CO2}$$ **Equation 70-5**

Where:

$E_{anodebaking}$	=	Total annual CO_2 emissions from anode baking (metric tons).
EC_{CO2}	=	Annual CO_2 emissions from packing coke (metric tons).
EP_{CO2}	=	Annual CO_2 emissions from pitch coking (metric tons).

(c) Calculate CF_4 and C_2F_6 emissions from anode effects for each pot line using either the Slope Method in paragraph (c)(1) or the Pechiney Method in paragraph (c)(2).

(1) **Slope Method:** Calculate the CF_4 and C_2F_6 emissions using Equation 70-6.

$$E_{CF_4,C_2F_6} = \sum_{i=1}^{n} [slope_{CF_4,C_2F_6} \times AEF \times AED \times MP]_i$$ **Equation 70-6**

Where:

$E_{CF4,\ C2F6}$	=	Annual emissions of CF_4 or C_2F_6 (metric tons/yr).
$slope_{CF4,\ C2F6}$	=	Measured slope coefficient ([Metric tons of CF_4 or C_2F_6 /metric ton Aluminum]/[anode effect minutes/pot-days]).
AEF	=	Anode effect frequency (number of anode effects per pot per day).
AED	=	Anode effect duration (minutes per anode effect).
MP	=	Aluminum production per day (metric tons).
n	=	Number of operating days per year.

(2) **Pechiney Method:** Calculate the CF_4 and C_2F_6 emissions using Equation 70-7.

$$E_{CF_4,C_2F_6} = \sum_{i=1}^{n}[Over-voltage \quad coefficient_{CF_4,C_2F_6} \times \frac{AEO}{CE} \times MP]_i$$ **Equation 70-8**

Where:

$Emission_{CF4,\ C2F6}$	=	Emissions of CF_4 or C_2F_6 (metric tons/yr).
Over-voltage $coefficient_{CF4,\ C2F6}$	=	Experimentally measured ([Metric tons of CF_4 or C_2F_6 /metric ton Aluminum]/mV).
AEO	=	Anode effect over-voltage (millivolts per pot per day).
CE	=	Current efficiency of aluminum production process, expressed as a fraction.
MP	=	Aluminum production per day (metric tons).
n	=	Number of operating days per year.

(d) Calculate CO_2 emissions from onsite green coke calcination furnaces using Equation 70-9.

$$E_{CO_2} = \sum_{n=1}^{12}\left[\left[GC \times \frac{(100 - H_2O_{gc} - V_{gc} - S_{gc})}{100} - (CC + UCC + DE) \times \frac{(100 - S_{cc})}{100}\right] \times 3.664\right]_i + \left[GC \times 0.035 \times \frac{44}{16}\right]_i$$ **Equation 70-9**

Where:

E_{CO2}	=	CO_2 emissions (metric tons pre year).
GC	=	Green coke feed for month i (metric tons).
H_2O_{gc}	=	Humidity in green coke feed for month i (wt %).
V_{gc}	=	Volatiles in green coke feed for month i (wt %).
S_{gc}	=	Sulfur content in green coke feed in month i (wt %).
S_{cc}	=	Sulfur content in calcinated coke in month i (wt %).
CC	=	Calcinated coke produced in month i (metric tons).
UCC	=	Under-calcinated coke produced in month i (metric tons).
DE	=	Coke dust emissions for month i (metric tons).
3.664	=	Conversion factor from carbon to CO_2.
0.035	=	Assumed CH_4 and tar content in coke volatiles, contributing to CO_2 emissions.
44/16	=	Conversion factor from methane to CO_2.

(e) Calculate SF_6 emissions from cover gas consumption using one of the following methods:

(1) Calculate the annual SF_6 emissions using inventory records and Equation 70-10:

$$E_{SF6} = S_{Inv-Begin} - S_{Inv-End} + S_{Purchased} - S_{Shipped}$$ **Equation 70-10**

Where:

E_{SF6}	=	SF_6 emissions from cover gas (metric tons).

$S_{Purchased}$ = Quantity of SF_6 purchased (metric tons).
$S_{Shipped}$ = Quantity of SF_6 shipped offsite (metric tons).
$S_{Inv\text{-}Begin}$ = Quantity of SF_6 in storage at the beginning of the year, (metric tons).
$S_{Inv\text{-}End}$ = Quantity of SF_6 in storage at the end of the year (metric tons).

(2) Calculate the annual SF_6 emissions using Equation 70-11 and direct measurement of the SF6 input to electrolysis cells and the SF6 waste gases collected and transferred off-site:

$$E_{SF6} = \sum_{i=1}^{12} [(Q_{Input} \times C_{Input}) - (Q_{Output} \times C_{Output})]_i \qquad \textbf{Equation 70-11}$$

Where:
E_{SF6} = SF_6 emissions from cover gas (metric tons).
$Q_{in;put}$ = Quantity of SF_6 input to the electrolysis cell for month i (metric tons).
C_{Input} = Concentration of SF_6 input to the electrolysis cell for month i (metric tons).
Q_{Output} = Quantity of SF_6 gas collected during month i (if applicable) (metric tons).
C_{Output} = Concentration of SF_6 gas collected and sent off-site during month i (metric tons).

WCI.74 Monitoring Requirements

(a) Except as specified in paragraphs (b) through (c) of this section, all parameters must be measured monthly using methods that comply with the measurement accuracy provisions in WCI.2(g).

(b) Conduct performance tests once every 36 months to determine the slope or Pechiney coefficients for each pot line using the *Protocol for Measurement of Tetrafluoromethane and Hexafluoroethane Emissions from Primary Aluminum Production*, U.S. Environmental Protection Agency and International Aluminum Institute. April 2008. The test must be repeat whenever:

(1) Thirty-six months have passed since the last measurements;
(2) A change occurs in the control algorithm that affects the mix of types of anode effects or the nature of the anode effect termination routine; or
(3) Changes occur in the distribution of duration of anode effects (e.g. when the percentage of manual kills changes or if, over time, the number of anode effects decreases and results in a fewer number of longer anode effects) or, for Rio Tinto Alcan control technology, when the algorithm for bridge movements and anode effect overvoltage accounting changes.

(c) If using the direct measurement approach in WCI.73(e)(2) to calculate SF_6 emissions from cover gas consumption, you must measure the quantity of SF_6 gas input to the electrolysis cell month and the quantity and SF_6 concentration of any waste gas collected and sent off-site.

Monitoring methods have not been specified in the available methodologies for the aluminum industry. There are several possible approaches to specifying monitoring methods:

- *Specify the accuracy required for each datum and allow the source to select their own methodologies that meet the accuracy requirements, and require the* *verifiers to certify the accuracy requirements were achieved, [This approach is especially useful for monitoring that is currently being made with a wide variety of instruments and are likely being made with high accuracy, such as monitoring of raw material flows and product flows; however, much burden is placed on verifiers to ensure the accuracy of the methods used. This approach is used for monitoring fuel flow for combustion sources.]*

- *Specify the accuracy required for each datum and require the source to submit a monitoring plan that meets the accuracy requirements, and require the verifiers to certify the source followed the approved plan. [This approach places a lot of burden on WCI to approve individual monitoring plans.]*
- *Specify the methodologies that should be followed, selecting them from available ASTM, ISO, U.S. EPA, and EC methodologies; however, there are not e*stablished methods for all parameters. Listed below are examples of the available methodologies for monitoring the aluminum industry.

ISO 9055:1988. Carbonaceous materials for the production of aluminum -- Pitch for electrodes -- Determination of sulfur content by the bomb method.

ISO 10238:1999. Carbonaceous materials used in the production of aluminum -- Pitch for electrodes -- Determination of sulfur content by an instrumental method.

ISO 8006:1985. Carbonaceous materials used in the production of aluminum -- Pitch for electrodes -- Determination of ash.

ISO 8005-2005. Carbonaceous materials used in the production of aluminum -- Green and calcined coke -- Determination of ash content

ISO 10237-1997. Carbonaceous materials for use in the production of aluminum -- Calcined coke -- Determination of residual-hydrogen content.

ISO 5931:2000. Carbonaceous materials used in the production of aluminum -- Calcined coke and calcined carbon products -- Determination of total sulfur by the Eschka method.

Slope and Over-voltage Coefficient: *Protocol for Measurement of Tetrafluoromethane and Hexafluoroethane Emissions from Primary Aluminum Production.* U.S. Environmental Protection Agency and International Aluminum Institute. April 2008.

ASTM D3173 Test Method for Moisture in the Analysis Sample of Coal and Coke

The following parameters are not covered by a specific ASTM or ISO methodology. They are candidates for being addressed using one of the first two approaches listed above.

- Mass flow rates or consumption of aluminum, paste, carbon, anodes, coke, recovered tar, and coke dust,
- Emissions of benzene soluble matter,
- Binder content in paste,
- Pitch content in anodes,

- Current efficiency,
- Anode effect frequency,
- Anode effect duration,
- Anode effect over-voltage,
- Current efficiency,
- Volatile content in coke.

Attachment 3: General Stationary Combustion

(UNDERLINE/STRIKEOUT VERSION SHOWING CHANGES FROM JANUARY 6, 2009 RELEASE, FOLLOWED BY INTEGRATED VERSION)

§ WCI.20 GENERAL STATIONARY COMBUSTION

§ WCI.21 Source Category Definition

General stationary fuel combustion sources are devices that combust solid, liquid, or gaseous fuel for the purpose of generating steam (or providing useful heat or energy) for industrial, commercial, or institutional use; or reducing the volume of waste by removing combustible matter. General stationary combustion sources are boilers, combustion turbines, engines, incinerators, and process heaters, and any other stationary combustion device that is not specifically addressed under the provisions for another source category in this rule.

Note: The source category definition may need to be revised after the remaining ER sections are completed.

§ WCI.22 Greenhouse Gas Reporting Requirements

The emissions data report shall include the following information at the facility level:

(a) Annual greenhouse gas emissions in metric tons, reported as follows:

(1) Total CO_2 emissions for fossil and biomass fuels, reported by fuel type.
~~(2) Total CO_2 emissions for all biomass fuels combined.~~
(2) Total CH_4 emissions ~~for all fuels combined~~, reported by fuel type.
(3) Total N_2O emissions ~~for all fuels combined~~, reported by fuel type.

(b) Annual fuel consumption:

(4) For gases, report in units of ~~million cubic meters~~ standard cubic feet.
(5) For liquids, report in units of ~~liters~~ gallons.
(6) For non-biomass solids, report in units of ~~metric~~ short tons.
(7) For ~~biomass-derived~~ biomass solid fuels, report in units of bone dry short tons or bone dry metric tons.

(c) Average carbon content of each fuel, if used to compute CO_2 emissions.

(d) Average ~~high~~ higher heating value of each fuel, ~~as~~ if used to compute CO_2 emissions.

(e) Annual steam generation in pounds or kilograms, for units that burn biomass fuels or municipal solid waste.

[Please note that most of the calculation methodologies in this section currently accommodate inputs in English units, only, and not SI units. The section will be revised to allow inputs in SI

units, as well as to provide applicable Canadian emission factors from "National Inventory Report 1990-2007: Greenhouse Gas Sources and Sinks in Canada – The Canadian Government's Submission to the UN Framework Convention on Climate Change, April 2009." (http://www.ec.gc.ca/pdb/ghg/inventory_e.cfm)]

§ WCI.23 Calculation of CO_2 Emissions

For each fuel, calculate CO_2 mass emissions using one of the four calculation methodologies specified in this section, subject to the restrictions in §WCI.23(e).

(a) Calculation Methodology 1. Calculate the annual CO_2 mass emissions by substituting a fuel-specific default CO_2 emission factor, a default ~~high~~ higher heating value, and the annual fuel consumption into the Equation 20-1:

$$CO_2 = Fuel \times HHV \times EF \times 0.001$$ **Equation 20-1**

Where:

CO_2	=	Annual CO_2 mass emissions for the specific fuel type (metric tons).
Fuel	=	Mass or volume of fuel combusted per year (express mass in short tons for solid fuel, volume in standard cubic feet for gaseous fuel, and volume in gallons for liquid fuel).
HHV	=	Default ~~high heat~~ higher heating value of the fuel, from column 3 of Table 20-1 (mmBtu per mass or mmBtu per volume, as applicable).
EF	=	Fuel-specific default CO_2 emission factor, from column 5 of Table 20-1 (kg CO_2/mmBtu).
0.001	=	Conversion factor from kilograms to metric tons.

(b) Calculation Methodology 2. Calculate the annual CO_2 mass emissions using a default fuel-specific CO_2 emission factor, ~~and either Equation 20-2 or 20-3, as appropriate~~ a higher heating value provided by the supplier or measured by the operator, using Equation 20-2, except for emissions from the combustion of biomass fuels and municipal solid waste, for which the operator may instead elect to use the method shown in Equation 20-3.

(1) ~~Equation 20-2 of this section can be used~~ For any type of fuel for which an emission factor is provided in Tables 20-1 or 20-2, except biomass fuels and municipal solid waste when the operator elects to use the method in WCI.23(b)(2), use Equation 20-2:

$$CO_2 = \sum_{p=1}^{n} Fuel_P \times HHV_P \times EF \times 0.001$$ **Equation 20-2**

Where:

CO_2	=	Annual CO_2 mass emissions for a specific fuel type (metric tons).
n	=	Number of required heat content measurements for the year as specified in WCI.25.
$Fuel_p$	=	Mass or volume of the fuel combusted during the measurement period "p" (express mass in short tons for solid fuel, volume in standard cubic feet for gaseous fuel, and volume in gallons for liquid fuel).

HHV_p	=	~~High heat~~ Higher heating value of the fuel for the measurement period (mmBtu per mass or volume).
EF	=	Fuel-specific default CO_2 emission factor, from column 5 of Table 20-1 or from Table 20-2 (kg CO_2/mmBtu).
0.001	=	Conversion factor from kilograms to metric tons.

(2) ~~Equation 20-3 of this section can be used~~ For biomass solid fuels and municipal solid waste ~~only~~, use either Equation 20-2 above or Equation 20-3:

$$CO_2 = Steam \times B \times EF \times 0.001$$ **Equation 20-3**

Where:

CO_2	=	Annual CO_2 mass emissions from ~~MSW~~ biomass solid fuel or municipal solid waste combustion (metric tons).
Steam	=	Total mass of steam generated by ~~MSW~~ biomass solid fuel or municipal solid waste combustion during the reporting year (lb steam).
B	=	Ratio of the boiler's ~~maximum~~ design rated heat input capacity to its design rated steam output capacity (mmBtu/lb steam).
EF	=	Default ~~carbon content for MSW~~ emission factor for biomass solid fuel or municipal solid waste, from column 5 of Table ~~WCI.20-1~~ 20-1 (kg CO_2/mmBtu).
0.001	=	Conversion factor from kilograms to metric tons.

(c) Calculation Methodology 3. Calculate the annual CO_2 mass emissions by ~~substituting measurements of fuel carbon content, molecular weight (gaseous fuels, only), and the quantity of fuel combusted into the following equations. For solid fuels, the amount of fuel combusted is obtained from company records kept as provided in this rule. For liquid and gaseous fuels, the volume of fuel combusted is measured directly, using fuel flow meters (including gas billing meters). For fuel oil, tank drop measurements may also be used~~ using measurements of fuel carbon content or molar fraction (for gaseous fuels only), conducted by the operator or provided by the fuel supplier, and the quantity of fuel combusted, using Equation 20-4. For emissions from the combustion of biomass fuels and municipal solid waste, the operator may instead elect to use the method shown in Equation 20-5.

(1) For a solid fuel, use Equation 20-4 of this section:

$$CO_2 = \sum_{i=1}^{n} Fuel_i \times CC_i \times 3.664 \times \underline{0.907}$$ **Equation 20-4**

Where:

CO_2	=	Annual CO_2 mass emissions from the combustion of the specific solid fuel (metric tons).
n	=	Number of ~~monthly~~ carbon content determinations for the year.
$Fuel_i$	=	Mass of the solid fuel combusted in ~~month "n" (metric tons)~~ measurement period "i" (short tons).
CC_i	=	Carbon content of the solid fuel, from the fuel analysis results for ~~month "n"~~ measurement period "i" (percent by weight, expressed as a decimal fraction, e.g., 95% = 0.95).

3.664 = Ratio of molecular weights, CO_2 to carbon.
0.907 = Conversion factor from short tons to metric tons.

(2) For biomass fuels or municipal solid waste, use either Equation 20-4 above or Equation 20-5:

$$CO_2 = Steam \times B \times EF \times 0.001$$ **Equation 20-5**

Where:

CO_2 = Annual CO_2 mass emissions from biomass solid fuel or municipal solid waste combustion (metric tons).

Steam = Total mass of steam generated by biomass solid fuel or municipal solid waste combustion during the reporting year (lb steam).

B = Ratio of the boiler's design rated heat input capacity to its design rated steam output capacity (mmBtu/lb steam).

EF = Default emission factor for biomass solid fuel or municipal solid waste, from column 5 of Table 20-1, (kg CO_2/mmBtu), adjusted no less often than every third year as provided in WCI.25(a)(5)(B).

0.001 = Conversion factor from kilograms to metric tons.

(3) For a liquid fuel, use Equation ~~20-5~~ 20-6 of this section:

$$CO_2 = \sum_{i=1}^{n} 3.664 \times Fuel_i \times CC_i \times 0.001$$ **Equation 20-6**

Where:

CO_2 = Annual CO_2 mass emissions from the combustion of the specific liquid fuel (metric tons).

n = Number of required carbon content determinations for the year, as specified in WCI.25.

$Fuel_i$ = Volume of the liquid fuel combusted in ~~month "n"~~ measurement period "i" (gallons).

CC_i = Carbon content of the liquid fuel, from the fuel analysis results for ~~month "n"~~ measurement period "i" (kg C per gallon of fuel).

3.664 = Ratio of molecular weights, CO_2 to carbon.

0.001 = Conversion factor from kg to metric tons.

(4) For a gaseous fuel, use Equation ~~20-6~~ 20-7 of this section:

$$CO_2 = \sum_{i=1}^{n} 3.664 \times Fuel_i \times CC_i \times \frac{MW}{MVC} \times 0.001$$ **Equation 20-7**

Where:

CO_2 = Annual CO_2 mass emissions from combustion of the specific gaseous fuel (metric tons).

n = Number of required carbon content and molecular weight determinations for the year, as specified in WCI.25.

$Fuel_i$ = Volume of the gaseous fuel combusted in period "i" (a day or month, as applicable)(scf).

CC_i = Average carbon content of the gaseous fuel, from the fuel analysis results for the period "i" (day or month, as applicable) (kg C per kg of fuel).

MW = Molecular weight of the gaseous fuel, from fuel analysis (kg/kg-mole).

MVC = Molar volume conversion factor (849.5 scf per kg-mole ~~at standard conditions~~ for STP of 20°C and 1 atmosphere or 836 scf per kg-mole for STP of 60°F, and 1 atmosphere).

3.664 = Ratio of molecular weights, CO_2 to carbon.

0.001 = Conversion factor from kg to metric tons.

(d) Calculation Methodology 4. Calculate the annual CO_2 mass emissions from all fuels combusted in a unit, by using data from continuous emission monitoring systems (CEMS) as specified in (d)(1) through (d)(7).

(1) ~~The operator of~~ For a facility that combusts fossil fuels or biomass fuels and operates CEMS in response to federal, state, provincial, or local regulation, ~~may~~ use CO_2 or O_2 concentrations and flue gas flow measurements to determine hourly CO_2 mass emissions using methodologies provided in 40 CFR Part 75, Appendix F or equivalent requirements as applicable in Canada.

(A) The operator shall report CO_2 emissions for the ~~report~~ reporting year in metric tons based on the sum of hourly CO_2 mass emissions over the year, converted to metric tons.

(B) If the operator of a facility that combusts biomass fuels uses O_2 concentrations to calculate CO_2 concentrations, annual source testing must demonstrate that calculated CO_2 concentrations when compared to measured CO_2 concentrations meet the Relative Accuracy Test Audit (RATA) requirements in 40 CFR Part 60, Appendix B, Performance Specification 3.

(2) ~~The operators of a facility that combusts municipal solid waste or other waste-derived fuels~~ For a facility that combusts waste-derived fuels (as defined in the General Provisions and listed in Table 20-2, including municipal solid waste), and operates a CEMS in response to federal, state, provincial, or local regulations ~~must~~ use CO_2 concentrations and flue gas flow measurements to determine hourly CO_2 mass emissions using methodologies provided in 40 CFR Part 75, Appendix F or equivalent requirements as applicable in Canada.

(A) Annual CO_2 emissions shall be reported in metric tons based on the sum of hourly CO_2 mass emissions over the year.

(B) Emissions calculations shall not be based on O_2 concentrations.

(3) The operator of a facility that combusts ~~MSW or other~~ waste-derived fuels and calculates CO_2 emissions using the methodology provided in WCI.23(d)(2) shall determine the portion of emissions associated with the combustion of biomass-derived fuels using the method provided in WCI.23(f).

(4) An operator who uses CEMS data to report CO_2 emissions from a facility that co-fires fossil fuels with biomass fuels or waste-derived fuels that are partly biomass fuels shall determine the portion of total CO_2 emissions separately assigned to the fossil fuel and the ~~biomass-derived fuel~~ biomass fuels using the method provided in WCI.23(f), if applicable. The operator who co-fires pure biomass fuels with fossil fuels may elect to calculate CO_2 emissions for the fossil fuels using methods designated in ~~WCI.23(b)(3) by fuel type and then subtract~~ WCI.23(a) or WCI.23(b)(1), as applicable, by fuel type and then calculate biomass fuel emissions by subtracting the fossil fuel related emissions from the total CO_2 emissions determined using the CEMS based methodology.

(5) For any units for which CO_2 emissions are reported using CEMS data, the operator is relieved of the requirement to separately report process emissions from combustion emissions for that unit or to report emissions separately for different fossil fuels for that unit when only fossil fuels are co-fired. In this circumstance, operators shall still report fuel use by fuel type as otherwise required.

(6) If a facility is subject to requirements in 40 CFR Part 60 or 40 CFR Part 75 and the operator chooses to add devices to an existing ~~continuous monitoring system~~ CEMS for the purpose of measuring CO_2 concentrations or flue gas flow, the operator shall select and operate the added devices pursuant to the requirements in 40 CFR Part 60 or Part 75 that apply to the facility. If the facility is subject to both 40 CFR Part 60 and 40 CFR Part 75, the operator shall select and operate the added devices pursuant to the requirements in 40 CFR Part 75.

(7) If a facility does not have a ~~continuous emissions monitoring system~~ CEMS and the operator chooses to add one in order to measure CO_2 concentrations, the operator shall select and operate the CEMS pursuant to the requirements in 40 CFR Part 75 or equivalent requirements as applicable in Canada.

(A) The operator shall use CO_2 concentrations and flue gas flow measurements to determine hourly CO_2 mass emissions using methodologies provided in 40 CFR Part 75, Appendix F or equivalent requirements as applicable in Canada.

(B) The operator shall report CO_2 emissions for the report year in metric tons based on the sum of hourly CO_2 mass emissions over the year, converted to metric tons.

(C) Operators who add CEMS under this article are subject to specifications in WCI.23(d)(1)-(5), if applicable.

(e) Use of the Four CO_2 Calculation Methodologies. Use of the four CO_2 emissions calculation methodologies described in paragraphs (a) through (d) of this section is subject to the following requirements and restrictions:

(1) Calculation Methodology 1 may not be used by a facility that is subject to the verification requirements of WCI.8, except for stationary combustion units that combust natural gas with a ~~high~~ higher heating value between 975 and 1,150 Btu per cubic foot. Otherwise, Calculation Methodology 1 may be used for any type of fuel for which a default CO_2 emission factor and a default ~~high heat~~ higher heating value for the fuel is specified in Table 20-1.

(2) Calculation Methodology 2 may not be used by a facility that is subject to the verification requirements of WCI.8, except for stationary combustion units that combust natural gas with a ~~high~~ higher heating value between 975 and 1,150 Btu per cubic foot. Otherwise,

Calculation Methodology 2 may be used for any type of fuel combusted for which a default CO_2 emission factor for the fuel is specified in Table 20-1 or 20-2.

(3) Calculation Methodology 3 may be used for a unit of any size combusting any type of fuel, except when the use of Calculation Methodology 4 is required.

(4) Calculation Methodology 4 may be used for a unit of any size combusting any type of fuel, and must be used for ~~either of the following conditions:~~ a combustion unit with a CEMS that is required by any federal, state, provincial, or local regulation <u>and that includes both a stack gas volumetric flow rate monitor and a CO_2 concentration monitor</u>.

~~(ii) A municipal solid waste combustion unit that is subject to the verification requirements of WCI.8.~~

(f) ~~Biogenic CO_2 emissions. The operator that combusts fuels or fuel mixtures that contain biomass~~ <u>Mixtures of biomass fuel and fossil fuel. The owner or operator that combusts fuels or fuel mixtures for which the biomass fuel fraction is unknown or cannot be documented (for example, municipal solid waste or tire-derived fuels)</u> shall determine the ~~biomass-derived~~ <u>biomass fuel</u> portion of CO_2 emissions using ASTM D6866-06a, as specified in this paragraph. This procedure is not required for fuels that contain less than 5 percent biomass <u>fuel</u> by weight or for waste-derived fuels that are less than 30 percent ~~biomass by weight on an annual basis~~ <u>by weight of total fuels combusted in the year for which emissions are being reported, except where the operator wishes to report a biomass fuel fraction of CO_2 emissions</u>.

(1) The operator shall conduct ASTM D6866-06a analysis <u>on a representative fuel or exhaust gas sample</u> at least every three months, and shall collect ~~each gas sample for analysis during normal operating conditions~~ <u>exhaust gas samples</u> over at least 24 consecutive hours <u>following the standard practice specified by ASTM D7459-08</u>.

(2) The operator shall divide total CO_2 emissions between ~~biomass-derived emissions and non-biomass-derived emissions using the average proportionalities of the samples analyzed~~ <u>biomass fuel emissions and non-biomass fuel emissions using the average proportions of the samples analyzed for the year for which emissions are being reported</u>.

(3) If there is a common fuel source to multiple units at the facility, the operator may elect to conduct ASTM D6866-06a testing for one of the units.

§ WCI.24 Calculation of CH_4 and N_2O Emissions

Calculate the annual CH_4 and N_2O mass emissions from stationary fuel combustion sources using the procedures in paragraph (a), (b), or (c), as appropriate.

(a) If the heat content of the fuel is <u>not</u> measured <u>for CO_2 estimation</u>, calculate CH_4 and N_2O emissions ~~the following Equation 20-7~~ <u>using Equation 20-8</u>:

$$\text{deleted equation}: CH_4 \text{ or } N_2O = \sum_{1}^{n} Fuel_P \times HHV_P \times EF \times 0.001$$

$$\text{inserted equation}: CH_4 \text{ or } N_2O = Fuel \times HHV_D \times EF \times 0.001$$

Equation 20-8

Where:

CH_4 or N_2O = Combustion emissions from specific fuel type, metric tons CH_4 or N_2O per year.

~~n = Period/frequency of heat content measurements over the year (e.g. monthly n = 12).~~

~~$Fuel_p$~~ Fuel = Mass or volume of fuel combusted for the measurement period, p, specified by fuel type, units of mass or volume per unit time.

~~HHV_p~~ HHV_D = ~~High heat~~ Default higher heating value ~~measured for the measurement period~~ specified by fuel type provided in Table 20-1, MMBtu per unit of mass or volume.

EF = Default CH_4 or N_2O emission factor provided in Table 20-3, kg CH_4 or N_2O per MMBtu.

0.001 = Factor to convert kg to metric tons.

(b) If the heat content of the fuel is ~~not~~ measured for CO_2 estimation, calculate CH_4 and N_2O emissions using ~~the following~~ Equation 20-9:

$$deleted\ equation: CH_4\ or\ N_2O = \sum_1^n Fuel \times HHV_D \times EF \times 0.001$$

Equation 20-9

$$inserted\ equation: CH_4\ or\ N_2O = \sum_{p=1}^n Fuel_p \times HHV_p \times EF \times 0.001$$

Where:

CH_4 or N_2O = CH_4 or N_2O emissions from a specific fuel type, metric tons CH_4 or N_2O per year.

~~Fuel~~ $Fuel_p$ = Mass or volume of fuel combusted specified by fuel type, unit of mass (short tons) or volume (scf, barrel) per year.

~~HHV_D~~ HHV_p = ~~Default high heat value~~ Higher heating value measured for the measurement period, p, specified by fuel type ~~provided in Table 20-3~~, MMBtu per unit ~~of~~ mass or volume.

EF = Default emission factor provided in Table 20-3, kg CH_4 or N_2O per MMBtu.

0.001 = Factor to convert kg to metric tons.

(c) For biomass and municipal solid waste combustion, the operator may elect to use Equation ~~20-9~~ 20-10 of this section to estimate CH_4 and N_2O emissions:

$$CH_4\ or\ N_2O = Steam \times B \times EF \times 0.001$$

Equation 20-10

Where:

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a municipal solid waste (metric tons).

Steam = Total mass of steam generated by ~~MSW~~ municipal solid waste combustion during the reporting year (lb steam).

B = Ratio of the boiler's maximum rated heat input capacity to its design rated steam output (mmBtu/lb steam).

EF = Fuel-specific emission factor for CH_4 or N_2O, from Table WCI.20-3 of this subpart (kg CH_4 or N_2O per mmBtu).

0.001 = Conversion factor from kilograms to metric tons.

(d) The operator may elect to calculate CH_4 ~~and~~ or N_2O emissions using source-specific emission factors derived from source tests conducted at least annually under the supervision of (*jurisdiction*). Upon approval of a source test plan, the source test procedures in that plan shall be repeated in each future year to update the source specific emission factors annually.

(e) Use of the Four CO_2 Calculation Methodologies. Use of the four CH_4 and N_2O emissions calculation methodologies described in paragraphs (a) through (d) of this section is subject to the following requirements and restrictions:

(1) WCI.24(a) may not be used by a facility that is subject to the verification requirements of WCI.8, except for stationary combustion units that combust natural gas with a higher heating value between 975 and 1,150 Btu per cubic foot. Otherwise, WCI.24(a) may be used for any type of fuel for which a default CH_4 or N_2O emission factor and a default higher heat value for the fuel is specified in Table 20-3.
(2) WCI.24(b) may be used for a unit of any size combusting any type of fuel.
(3) WCI.24(c) may only be used for biomass or municipal solid waste combustion.
(4) WCI.24(d) may be used for a unit of any size combusting any type of fuel.

§ WCI.25 Sampling, Analysis, and Measurement Requirements

(a) Fuel Sampling Requirements. Fuel sampling must be conducted or fuel sampling results must be received from the fuel supplier at the frequency specified in ~~paragraph~~ paragraphs (a)(1) through (a)(4) of this section.

(1) ~~At receipt of~~ Once for each new fuel shipment or delivery or on a monthly basis for middle distillates (diesel, gasoline, fuel oil, kerosene), residual oil, liquid waste-derived fuels, and LPG (ethane, propane, isobutene, n-butane, unspecified LPG);
(2) Monthly for natural gas, associated gas, and mixtures of low Btu gas.
(3) Monthly for gases derived from biomass including landfill gas and biogas from wastewater treatment or agricultural processes.
(4) Monthly for solid fuels, as specified below:

(A) The monthly solid fuel sample shall be a composite sample of weekly samples.
(B) The solid fuel shall be sampled at a location after all fuel treatment operations but before fuel mixing and the samples shall be representative of the fuel chemical and physical characteristics immediately prior to combustion.
(C) Each weekly sub-sample shall be collected at a time (day and hour) of the week when the fuel consumption rate is representative and unbiased.
(D) Four weekly samples (or a sample collected during each week of operation during the month) of equal mass shall be combined to form the monthly composite sample.
(E) The monthly composite sample shall be homogenized and well mixed prior to withdrawal of a sample for analysis.
(F) One in twelve composite samples shall be randomly selected for additional analysis of its ~~discreet~~ discrete constituent samples. This information will be used to monitor the homogeneity of the composite.

(5) For biomass fuels and waste-derived fuels, the following may apply in lieu of WCI.25(a)(4):

(A) If CO_2 emissions are calculated using WCI.23(c)(1), the source-specific carbon content is determined annually. Upon approval of a source test plan by [*jurisdiction*], the source test procedures in that plan shall be repeated in subsequent years to update the source specific emission factors annually.

(B) If CO_2 emissions are calculated using WCI.23(c)(2) (biomass fuels and municipal solid waste only), the operator shall adjust the emission factor, in kg CO2/MMBtu not less frequently than every third year, through a stack test measurement of CO2 and use of the applicable ASME Performance Test Code to determine heat input from all heat outputs, including the steam, flue gases, ash and losses.

(b) Fuel Consumption Monitoring Requirements.

~~(1) Facilities that are subject to the verification requirements of WCI.8 must determine annual fuel consumption by direct measurement.~~

(1) Facilities ~~that are not subject the verification requirements of WCI.8~~ may determine fuel consumption on the basis of direct measurement or recorded fuel purchase or sales invoices measuring any stock change (measured in million Btu, gallons, million standard cubic feet, short tons or bone dry short, tons) using the following equation:

Fuel Consumption in the Report Year = Total Fuel Purchases – Total Fuel Sales + Amount Stored at Beginning of Year – Amount Stored at Year End

(2) Fuel consumption measured in Btu values shall be converted to the required metrics of mass or volume using heat content values that are either provided by the supplier, measured by the facility, or provided in Table 20-1.

(3) All oil and gas flow meters (except for gas billing meters) shall be calibrated prior to the first year for which GHG emissions are reported under this rule, using an applicable flow meter test method listed in section WCI.6 or the calibration procedures specified by the flow meter manufacturer. Fuel flow meters shall be recalibrated either annually or at the minimum frequency specified by the manufacturer.

(4) For fuel oil, tank drop measurements may also be used.

(c) Fuel Heat Content Monitoring Requirements. ~~High heat values shall be determined using one of the following methods~~ Higher heating values shall be based on the results of fuel sampling and analysis received from the fuel supplier or determined by the operator, in either case using an applicable analytical method listed in section WCI.6.

(1) For gases, use ASTM D1826-94 (Reapproved 2003), ASTM D3588-98 (Reapproved 2003), ASTM D4891-89 (Reapproved 2006), GPA Standard 2261-00 “Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography.” The operator may alternatively elect to use on-line instrumentation that determines heating value accurate to within ± 5.0 percent. Where existing on-line instrumentation provides only low heating value, the operator shall convert the value to ~~high~~ higher heating value as ~~specified in section 95125(c)(1)(C)~~ follows:

$$inserted\ \ equation : HHV = LHV \times CF \qquad \textbf{Equation 20-11}$$

Where:

HHV = fuel or fuel mixture higher heating value (Btu/scf).
LHV = fuel or fuel mixture lower heating value (Btu/scf).
CF = conversion factor.

For natural gas, a CF of 1.11 shall be used. For refinery fuel gas and mixtures of refinery fuel gas, a weekly average fuel system-specific CF shall be derived as follows:

(A) by concurrent LHV instrumentation measurements and HHV determined by on-line instrumentation or laboratory analysis as part of the daily carbon content determination; or,

(B) by the HHV/LHV ratio obtained from the laboratory analysis of the daily samples.

(2) For middle distillates and oil, or liquid waste-derived fuels, use ASTM D240-02 (Reapproved 2007), ~~ASTM D240-87 (Reapproved 1991), ASTM D4809-00 (Reapproved 2005)~~ ASTM D4809-06 (Reapproved 2005).

(3) For solid biomass-derived fuels use ASTM D5865-07a.

(4) For waste-derived fuels use ASTM D5865-07a or ASTM D5468-02 (Reapproved 2007). Operators who combust waste-derived fuels that are ~~partly but~~ not pure biomass fuels shall determine the ~~biomass-derived~~ biomass fuel portion of CO_2 emissions using the method specified in section WCI.23(f), if applicable

(d) Fuel Carbon Content Monitoring Requirements. Fuel carbon ~~contents should be monitored in the following manner~~ content and either molecular weight or molar fraction for gaseous fuels shall be based on the results of fuel sampling and analysis received from the fuel supplier or determined by the operator, in either case using an applicable analytical method listed in section WCI.6.

(1) For coal and coke, solid ~~biomass-derived~~ biomass fuels, and waste-derived fuels; use ~~ASTM 5373-02 (Reapproved 2007)~~ ASTM 5373-08.

(2) For liquid fuels, use the following ASTM methods: For petroleum-based liquid fuels and liquid waste-derived fuels, use ASTM D5291-02 (Reapproved 2007) "Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants", ultimate analysis of oil or computations based on ASTM D3238-95 (Reapproved 2005) and either ASTM D2502-04 or ASTM D2503-92 (Reapproved ~~2002~~ 2007).

(3) For gaseous fuels, use ASTM D1945-03 (Reapproved 2006) or ASTM D1946-90 (Reapproved 2006). The operator may alternatively elect to use on-line instrumentation that determines fuel carbon content accurate to ± 5 percent.

(e) Fuel Analytical Data Capture. When the applicable emissions estimation methodologies in sections WCI.20 through WCI.XXX require periodic collection of fuel analytical data for an emissions source, the operator shall demonstrate every reasonable effort to obtain a fuel analytical data capture rate of 100 percent for each report year.

(1) If the operator is unable to obtain fuel analytical data such that more than 20 percent of emissions from a source cannot be directly accounted for, the emissions from that source shall be considered unverifiable for the report year.

(2) If the fuel analytical data capture rate is at least 80 percent but less than 100 percent for any emissions source identified in sections WCI.20 through WCI.XXX, the operator shall use the mean of the fuel analytical data results captured to substitute for the missing values for the period of missing data.

(f) Procedure for Interim Fuel Analytical Data Collection.

(1) In the event of an unforeseen breakdown of fuel analytical data monitoring equipment required for the emissions estimation methodologies in sections WCI.20 through WCI.XXX, [jurisdiction] may authorize an operator to use an interim data collection procedure if [jurisdiction] determines that the operator has satisfactorily demonstrated that:

(A) The breakdown may result in a loss of more than 20 percent of the source's fuel data for the reporting year, such that emissions for the affected source could not be verified under the provisions of section WCI.8;

(B) The fuel analytical data monitoring equipment cannot be promptly repaired or replaced without shutting down a process unit significantly affecting facility operations, or that the monitoring equipment must be replaced and replacement equipment is not immediately available;

(C) The interim procedure will not remain in effect longer than is reasonably necessary for repair or replacement of the malfunctioning data monitoring equipment; and

(D) The request was submitted within 30 calendar days of the breakdown of the fuel analytical data monitoring equipment.

(2) An operator seeking approval of an interim data collection procedure must, within 30 days of the monitoring equipment breakdown, submit a written request to [jurisdiction] that includes all of the following:

(A) The proposed start date and end date of the interim procedure;

(B) A detailed description of what data are affected by the breakdown;

(C) A discussion of the accuracy of data collected during the interim procedure compared with the data collected under the operator's usual equipment-based method;

(D) A demonstration that no feasible alternative procedure exists that would provide more accurate emissions data; and

(E) A demonstration that the proposed interim procedure meets the criteria specified in section WCI.2(i)(1).

(3) [The jurisdiction] may limit the duration of the interim data collection procedure or include other conditions of approval to ensure the criteria in section WCI.2(i)(1) are met.

(4) Data collected pursuant to an approved interim data collection procedure shall be considered captured data for purposes of compliance with the capture rate requirements in section WCI.2(g). When approving an interim data collection procedure, [jurisdiction] shall determine whether the accuracy of data collected under the procedure is reasonably equivalent to data collected from properly functioning monitoring equipment, and if it is not, the relative accuracy to assign for purposes of assessing possible material misstatement under section WCI.8(q).

Table 20-1. Default Carbon Content, Heat Content, and Carbon Dioxide Emission Factors from Stationary Combustion by Fuel Type				
Fuel Type	**Carbon Content**	**~~High~~ Higher Heat Value**	**CO_2 Emission Factor**	**CO_2 Emission Factor**
Coal and Coke	**kg C / MMBtu**	**MMBtu / Short Ton**	**kg CO_2 / Short Ton**	**kg CO_2 / MMBtu**
Anthracite	28.26	25.09	2,597.94	103.54
Bituminous	25.49	24.93	2,328.35	93.40
Sub-bituminous	26.48	17.25	1,673.64	97.02
Lignite	26.30	14.21	1,369.32	96.36
Unspecified (Residential/Commercial)	26.00	22.24	2,118.67	95.26
Unspecified (Industrial Coking)	25.56	26.28	2,461.17	93.65
Unspecified (Other Industrial)	25.63	22.18	2,082.89	93.91
Unspecified (Electric Power)	25.76	19.97	1,884.86	94.38
Coke	27.85	24.80	2,530.65	102.04
Natural Gas (By Heat Content)	**kg C / MMBtu**	**Btu / Standard cubic foot**	**kg CO_2 / Standard cubic ~~ft.~~ foot**	**kg CO_2 / MMBtu**
975 to 1,000 Btu / Standard cubic foot	14.73	n/a	n/a	53.97
1000 to 1,025 Btu / Std cubic foot	14.43	n/a	n/a	52.87
1025 to 1,050 Btu / Std cubic foot	14.47	n/a	n/a	53.02
1050 to 1,075 Btu / Std cubic foot	14.58	n/a	n/a	53.42
1075 to 1,100 Btu / Std cubic foot	14.65	n/a	n/a	53.68
Greater than 1,100 Btu / Std cubic foot	14.92	n/a	n/a	54.67
Unspecified (Weighted U.S. Average)	14.47	1,027	0.0544	53.02

Table 20-1. Default Carbon Content, Heat Content, and Carbon Dioxide Emission Factors from Stationary Combustion by Fuel Type (continued)				
Petroleum Products	**kg C / MMBtu**	**MMBtu / Barrel**	**kg CO_2 / gallon**	**kg CO_2 / MMBtu**
Asphalt & Road Oil	20.62	6.636	11.94	75.55
Aviation Gasoline	18.87	5.048	8.31	69.14
Distillate Fuel Oil (#1, 2 & 4)	19.95	5.825	10.14	73.10
Jet Fuel	19.33	5.670	9.56	70.83
Kerosene	19.72	5.670	9.75	72.25
LPG (energy use)	17.19	3.861	5.79	62.98
Propane	17.20	3.824	5.74	63.02
Ethane	16.25	2.916	4.13	59.54
Isobutane	17.75	4.162	6.44	65.04
n-Butane	17.72	4.328	6.69	64.93
Lubricants	20.24	6.065	10.71	74.16
Motor Gasoline	19.33	5.218	8.80	70.83
Residual Fuel Oil (#5 & 6)	21.49	6.287	11.79	78.74
Crude Oil	20.33	5.800	10.29	74.49
Naphtha (<401 deg. F)	18.14	5.248	8.30	66.46
Natural Gasoline	18.24	4.620	7.35	66.83
Other Oil (>401 deg. F)	19.95	5.825	10.14	73.10
Pentanes Plus	18.24	4.620	7.35	66.83
Petrochemical Feedstocks	19.37	5.428	9.17	70.97
Petroleum Coke	27.85	6.024	14.64	102.04
Still Gas	17.51	6.000	9.17	64.16
Special Naphtha	19.86	5.248	9.09	72.77
Unfinished Oils	20.33	5.825	10.33	74.49
Waxes	19.81	5.537	9.57	72.58
Other Solid Fuels	**kg C / MMBtu**	**MMBtu / Short Ton**	**kg CO_2 / Short Ton**	**kg CO_2 / MMBtu**
Biomass Derived Fuels (Solid). Wood and Wood Waste (12% moisture content) or other solid biomass-~~derived~~ fuels	25.60	15.38	1,442.62	93.80
Municipal Solid Waste (MSW)	24.74	8.7	788.7	90.65
Biomass-derived Fuels (Gas)	**kg C / MMBtu**	**Btu / Standard cubic foot**	**kg CO_2 / Standard cubic ft.**	**kg CO_2 / MMBtu**
Biogas (includes landfill gas and manure biogas)[*]	28.4	Varies	Varies	104.06

Note: Heat content factors are based on higher heating values (HHV).

The emission factors for biogas include both the CO_2 from combustion and the pass-through CO_2, which are assumed to be in equal proportions.

Sources:

U.S. EPA, *Inventory of Greenhouse Gas Emissions and Sinks: 1990-2007 (2009)*, Annex 2.1, Tables A-28, A-31, A-32, A-35, and A-36, except:

- Heat Content factors for Unspecified Coal (by sector), Coke, Naptha (<401 F°), and Other Oil (>401 F°), from U.S. Energy Information Administration, *Annual Energy Review 2005 (2006)*, Tables A-1, A-4, and A-5;
- Heat Content factors for Coal (by type) and LPG, and all factors for Wood and Wood Waste, Landfill Gas, and Wastewater Treatment Biogas, from U.S. EPA Climate Leaders, *Stationary Combustion Guidance (2004)*, Tables B-1 and B-2; and

Municipal Solid Waste (MSW) factors, from Energy Information Administration, http://www.eia/doe/gov/oiaf/1605/coefficients.html and California Air Resources Board, *MSW California Air Resources Board, 2008.*

Table 20-2. Default Carbon Dioxide Emission Factors from Stationary Combustion for Waste Derived Fuels	
Fuel Type	**kg CO_2 / MMBtu**
Waste Oil	78
Tires	90
Plastics	79
Solvents	78
Impregnated Saw Dust	79
Other Fossil Based Wastes	84
Dried Sewage Sludge	116
Mixed Industrial Waste	88
Municipal Solid Waste	~~91~~ See Table 20-1
Note: Emission factors are based on higher heating values (HHV). Values were converted from LHV to HHV assuming that LHV are 5 percent lower than HHV for solid and liquid fuels.	
Source: WBCSD/WRI, *The Cement CO_2 Protocol: CO_2 Accounting and Reporting Standard for the Cement Industry Calculation Tool (2004).*	

~~**Table 20-3. Default CH_4 and N_2O Emission Factors from Stationary Combustion by Fuel Type**~~		
~~**Fuel Type**~~	~~**CH_4 Emission Factor (kg CH_4/ MMBtu)**~~	~~**N_2O Emission Factor (kg N_2O / MMBtu)**~~
~~Asphalt~~	~~0.003~~	~~0.006~~
~~Aviation Gasoline~~	~~0.003~~	~~0.006~~
~~Coal~~	~~0.01~~	~~1.5~~
~~Crude Oil~~	~~0.003~~	~~0.006~~
~~Digester Gas~~	~~0.0009~~	~~0.1~~
~~Distillate~~	~~0.003~~	~~0.006~~
~~Gasoline~~	~~0.003~~	~~0.006~~
~~Jet Fuel~~	~~0.003~~	~~0.006~~
~~Kerosene~~	~~0.003~~	~~0.006~~
~~Landfill Gas~~	~~0.0009~~	~~0.1~~
~~LPG~~	~~0.001~~	~~0.1~~
~~Lubricants~~	~~0.003~~	~~0.006~~
~~MSW~~	~~0.03~~	~~0.004~~
~~Naphtha~~	~~0.003~~	~~0.006~~
~~Natural Gas~~	~~0.0009~~	~~0.1~~
~~Natural Gas Liquids~~	~~0.003~~	~~0.006~~
~~Other Biomass~~	~~0.03~~	~~0.004~~
~~Petroleum Coke~~	~~0.003~~	~~0.006~~
~~Propane~~	~~0.001~~	~~0.1~~
~~Refinery Gas~~	~~0.0009~~	~~0.1~~
~~Residual Fuel Oil~~	~~0.003~~	~~0.006~~
~~Tires~~	~~0.003~~	~~0.006~~

~~Table 20-3. Default CH_4 and N_2O Emission Factors from Stationary Combustion by Fuel Type~~		
~~Fuel Type~~	~~CH_4 Emission Factor (kg CH_4/ MMBtu)~~	~~N_2O Emission Factor (kg N_2O / MMBtu)~~
~~Waste Oil~~	~~0.03~~	~~0.004~~
~~Waxes~~	~~0.003~~	~~0.006~~
~~Wood (Dry)~~	~~0.03~~	~~0.004~~
~~Note: Heat content factors are based on higher heating values (HHV).~~		

Table 20-3. Default CH_4 and N_2O Emission Factors from Stationary Combustion by Fuel Type		
Fuel Type	CH_4 Emission Factor (kg CH_4/ MMBtu)	N_2O Emission Factor (kg N_2O / MMBtu)
Asphalt	0.003	0.0006
Aviation Gasoline	0.003	0.0006
Coal	0.01	0.0015
Crude Oil	0.003	0.0006
Digester Gas	0.0009	0.0001
Distillate	0.003	0.0006
Gasoline	0.003	0.0006
Jet Fuel	0.003	0.0006
Kerosene	0.003	0.0006
Kraft Black Liquor	0.0026	0.0021
Landfill Gas	0.0009	0.0001
LPG	0.001	0.0001
Lubricants	0.003	0.0006
Municipal Solid Waste	0.03	0.004
Naphtha	0.003	0.0006
Natural Gas	0.0009	0.0001
Natural Gas Liquids	0.003	0.0006
Other Biomass Fuels	0.03	0.004
Petroleum Coke	0.003	0.0006
Propane	0.001	0.0001
Refinery Gas	0.0009	0.0001
Residual Fuel Oil	0.003	0.0006
Tires	0.003	0.0006
Waste Oil	0.03	0.004
Waxes	0.003	0.0006
Wood (Dry)	0.03	0.004

Note: Heat content factors are based on higher heating values (HHV).
Source: Intergovernmental Panel on Climate Change, *2006 IPCC Guidelines for National Greenhouse Gas Inventories (2006)*, Volume 2, Tables 2.2, 2.3, and 2.4, except:

- Kraft Black Liquor emission factors, from International Council of Forest and Paper Associations, *Calculation Tools for Estimating Greenhouse Gas Emissions from Pulp and Paper Mills (2005)*, Appendix F, Table 8.

Attachment 3: General Stationary Combustion

INTEGRATED VERSION

§ WCI.20 GENERAL STATIONARY COMBUSTION

§ WCI.21 Source Category Definition

General stationary fuel combustion sources are devices that combust solid, liquid, or gaseous fuel for the purpose of generating steam (or providing useful heat or energy) for industrial, commercial, or institutional use; or reducing the volume of waste by removing combustible matter. General stationary combustion sources are boilers, combustion turbines, engines, incinerators, and process heaters, and any other stationary combustion device that is not specifically addressed under the provisions for another source category in this rule.

Note: The source category definition may need to be revised after the remaining ER sections are completed.

§ WCI.22 Greenhouse Gas Reporting Requirements

The emissions data report shall include the following information at the facility level:

(a) Annual greenhouse gas emissions in metric tons, reported as follows:

(1) Total CO_2 emissions for fossil and biomass fuels, reported by fuel type.
(2) Total CH_4 emissions, reported by fuel type.
(3) Total N_2O emissions, reported by fuel type.

(b) Annual fuel consumption:

(1) For gases, report in units of standard cubic feet.
(2) For liquids, report in units of gallons.
(3) For non-biomass solids, report in units of short tons.
(4) For biomass solid fuels, report in units of bone dry short tons or bone dry metric tons.

(c) Average carbon content of each fuel, if used to compute CO_2 emissions.

(d) Average higher heating value of each fuel, if used to compute CO_2 emissions.

(e) Annual steam generation in pounds or kilograms, for units that burn biomass fuels or municipal solid waste.

Please note that most of the calculation methodologies in this section currently accommodate inputs in English units, only, and not SI units. The section will be revised to allow inputs in SI units, as well as to provide applicable Canadian emission factors from "National Inventory Report 1990-2007: Greenhouse Gas Sources and Sinks in Canada – The Canadian

Government's Submission to the UN Framework Convention on Climate Change, April 2009." (http://www.ec.gc.ca/pdb/ghg/inventory_e.cfm)]

§ WCI.23 Calculation of CO_2 Emissions

For each fuel, calculate CO_2 mass emissions using one of the four calculation methodologies specified in this section, subject to the restrictions in §WCI.23(e).

(a) Calculation Methodology 1. Calculate the annual CO_2 mass emissions by substituting a fuel-specific default CO_2 emission factor, a default higher heating value, and the annual fuel consumption into the Equation 20-1:

$$CO_2 = Fuel \times HHV \times EF \times 0.001$$ **Equation 20-1**

Where:

CO_2	=	Annual CO_2 mass emissions for the specific fuel type (metric tons).
Fuel	=	Mass or volume of fuel combusted per year (express mass in short tons for solid fuel, volume in standard cubic feet for gaseous fuel, and volume in gallons for liquid fuel).
HHV	=	Default higher heating value of the fuel, from column 3 of Table 20-1 (mmBtu per mass or mmBtu per volume, as applicable).
EF	=	Fuel-specific default CO_2 emission factor, from column 5 of Table 20-1 (kg CO_2/mmBtu).
0.001	=	Conversion factor from kilograms to metric tons.

(b) Calculation Methodology 2. Calculate the annual CO_2 mass emissions using a default fuel-specific CO_2 emission factor, a higher heating value provided by the supplier or measured by the operator, using Equation 20-2, except for emissions from the combustion of biomass fuels and municipal solid waste, for which the operator may instead elect to use the method shown in Equation 20-3.

(1) For any type of fuel for which an emission factor is provided in Tables 20-1 or 20-2, except biomass fuels and municipal solid waste when the operator elects to use the method in WCI.23(b)(2), use Equation 20-2:

$$CO_2 = \sum_{p=1}^{n} Fuel_p \times HHV_p \times EF \times 0.001$$ **Equation 20-2**

Where:

CO_2	=	Annual CO_2 mass emissions for a specific fuel type (metric tons).
n	=	Number of required heat content measurements for the year as specified in WCI.25.
$Fuel_p$	=	Mass or volume of the fuel combusted during the measurement period "p" (express mass in short tons for solid fuel, volume in standard cubic feet for gaseous fuel, and volume in gallons for liquid fuel).
HHV_p	=	Higher heating value of the fuel for the measurement period (mmBtu per mass or volume).

EF = Fuel-specific default CO_2 emission factor, from column 5 of Table 20-1 or from Table 20-2 (kg CO_2/mmBtu).
0.001 = Conversion factor from kilograms to metric tons.

(2) For biomass solid fuels and municipal solid waste, use either Equation 20-2 above or Equation 20-3:

$$CO_2 = Steam \times B \times EF \times 0.001$$ **Equation 20-3**

Where:
CO_2 = Annual CO_2 mass emissions from biomass solid fuel or municipal solid waste combustion (metric tons).
Steam = Total mass of steam generated by biomass solid fuel or municipal solid waste combustion during the reporting year (lb steam).
B = Ratio of the boiler's design rated heat input capacity to its design rated steam output capacity (mmBtu/lb steam).
EF = Default emission factor for biomass solid fuel or municipal solid waste, from column 5 of Table 20-1 (kg CO_2/mmBtu).
0.001 = Conversion factor from kilograms to metric tons.

(c) Calculation Methodology 3. Calculate the annual CO_2 mass emissions by using measurements of fuel carbon content or molar fraction (for gaseous fuels only), conducted by the operator or provided by the fuel supplier, and the quantity of fuel combusted, using Equation 20-4. For emissions from the combustion of biomass fuels and municipal solid waste, the operator may instead elect to use the method shown in Equation 20-5.

(1) For a solid fuel, use Equation 20-4 of this section:

$$CO_2 = \sum_{i=1}^{n} Fuel_i \times CC_i \times 3.664 \times 0.907$$ **Equation 20-4**

Where:
CO_2 = Annual CO_2 mass emissions from the combustion of the specific solid fuel (metric tons).
n = Number of carbon content determinations for the year.
$Fuel_i$ = Mass of the solid fuel combusted in measurement period "i" (short tons).
CC_i = Carbon content of the solid fuel, from the fuel analysis results for measurement period "i" (percent by weight, expressed as a decimal fraction, e.g., 95% = 0.95).
3.664 = Ratio of molecular weights, CO_2 to carbon.
0.907 = Conversion factor from short tons to metric tons.

(2) For biomass fuels or municipal solid waste, use either Equation 20-4 above or Equation 20-5:

$$CO_2 = Steam \times B \times EF \times 0.001$$ **Equation 20-5**

Where:

CO_2	=	Annual CO_2 mass emissions from biomass solid fuel or municipal solid waste combustion (metric tons).
Steam	=	Total mass of steam generated by biomass solid fuel or municipal solid waste combustion during the reporting year (lb steam).
B	=	Ratio of the boiler's design rated heat input capacity to its design rated steam output capacity (mmBtu/lb steam).
EF	=	Default emission factor for biomass solid fuel or municipal solid waste, from column 5 of Table 20-1, (kg CO_2/mmBtu), adjusted no less often than every third year as provided in WCI.25(a)(5)(B).
0.001	=	Conversion factor from kilograms to metric tons.

(3) For a liquid fuel, use Equation 20-6 of this section:

$$CO_2 = \sum_{i=1}^{n} 3.664 \times Fuel_i \times CC_i \times 0.001$$ **Equation 20-6**

Where:

CO_2	=	Annual CO_2 mass emissions from the combustion of the specific liquid fuel (metric tons).
n	=	Number of required carbon content determinations for the year, as specified in WCI.25.
$Fuel_i$	=	Volume of the liquid fuel combusted in measurement period "i" (gallons).
CC_i	=	Carbon content of the liquid fuel, from the fuel analysis results for measurement period "i" (kg C per gallon of fuel).
3.664	=	Ratio of molecular weights, CO_2 to carbon.
0.001	=	Conversion factor from kg to metric tons.

(4) For a gaseous fuel, use Equation 20-7 of this section:

$$CO_2 = \sum_{i=1}^{n} 3.664 \times Fuel_i \times CC_i \times \frac{MW}{MVC} \times 0.001$$ **Equation 20-7**

Where:

CO_2	=	Annual CO_2 mass emissions from combustion of the specific gaseous fuel (metric tons).
n	=	Number of required carbon content and molecular weight determinations for the year, as specified in WCI.25.
$Fuel_i$	=	Volume of the gaseous fuel combusted in period "i" (a day or month, as applicable) (scf).
CC_i	=	Average carbon content of the gaseous fuel, from the fuel analysis results for the period "i" (day or month, as applicable) (kg C per kg of fuel).
MW	=	Molecular weight of the gaseous fuel, from fuel analysis (kg/kg-mole).
MVC	=	Molar volume conversion factor (849.5 scf per kg-mole for STP of 20°C and 1 atmosphere or 836 scf per kg-mole for STP of 60°F, and 1 atmosphere).
3.664	=	Ratio of molecular weights, CO_2 to carbon.
0.001	=	Conversion factor from kg to metric tons.

(d) Calculation Methodology 4. Calculate the annual CO_2 mass emissions from all fuels combusted in a unit, by using data from continuous emission monitoring systems (CEMS) as specified in (d)(1) through (d)(7).

(1) For a facility that combusts fossil fuels or biomass fuels and operates CEMS in response to federal, state, provincial, or local regulation, use CO_2 or O_2 concentrations and flue gas flow measurements to determine hourly CO_2 mass emissions using methodologies provided in 40 CFR Part 75, Appendix F or equivalent requirements as applicable in Canada.

(A) The operator shall report CO_2 emissions for the reporting year in metric tons based on the sum of hourly CO_2 mass emissions over the year, converted to metric tons.

(B) If the operator of a facility that combusts biomass fuels uses O_2 concentrations to calculate CO_2 concentrations, annual source testing must demonstrate that calculated CO_2 concentrations when compared to measured CO_2 concentrations meet the Relative Accuracy Test Audit (RATA) requirements in 40 CFR Part 60, Appendix B, Performance Specification 3.

(2) For a facility that combusts waste-derived fuels (as defined in the General Provisions and listed in Table 20-2, including municipal solid waste), and operates a CEMS in response to federal, state, provincial, or local regulations use CO_2 concentrations and flue gas flow measurements to determine hourly CO_2 mass emissions using methodologies provided in 40 CFR Part 75, Appendix F or equivalent requirements as applicable in Canada.

(A) Annual CO_2 emissions shall be reported in metric tons based on the sum of hourly CO_2 mass emissions over the year.

(B) Emissions calculations shall not be based on O_2 concentrations.

(3) The operator of a facility that combusts waste-derived fuels and calculates CO_2 emissions using the methodology provided in WCI.23(d)(2) shall determine the portion of emissions associated with the combustion of biomass-derived fuels using the method provided in WCI.23(f).

(4) An operator who uses CEMS data to report CO_2 emissions from a facility that co-fires fossil fuels with biomass fuels or waste-derived fuels that are partly biomass fuels shall determine the portion of total CO_2 emissions separately assigned to the fossil fuel and the biomass fuels using the method provided in WCI.23(f), if applicable. The operator who co-fires pure biomass fuels with fossil fuels may elect to calculate CO_2 emissions for the fossil fuels using methods designated in WCI.23(a) or WCI.23(b)(1), as applicable, by fuel type and then calculate biomass fuel emissions by subtracting the fossil fuel related emissions from the total CO_2 emissions determined using the CEMS based methodology.

(5) For any units for which CO2 emissions are reported using CEMS data, the operator is relieved of the requirement to separately report process emissions from combustion emissions for that unit or to report emissions separately for different fossil fuels for that unit when only fossil fuels are co-fired. In this circumstance, operators shall still report fuel use by fuel type as otherwise required.

(6) If a facility is subject to requirements in 40 CFR Part 60 or 40 CFR Part 75 and the operator chooses to add devices to an existing CEMS for the purpose of measuring CO2 concentrations or flue gas flow, the operator shall select and operate the added devices pursuant to the requirements in 40 CFR Part 60 or Part 75 that apply to the facility. If the

facility is subject to both 40 CFR Part 60 and 40 CFR Part 75, the operator shall select and operate the added devices pursuant to the requirements in 40 CFR Part 75.

(7) If a facility does not have a CEMS and the operator chooses to add one in order to measure CO_2 concentrations, the operator shall select and operate the CEMS pursuant to the requirements in 40 CFR Part 75 or equivalent requirements as applicable in Canada.

(A) The operator shall use CO_2 concentrations and flue gas flow measurements to determine hourly CO_2 mass emissions using methodologies provided in 40 CFR Part 75, Appendix F or equivalent requirements as applicable in Canada.

(B) The operator shall report CO_2 emissions for the report year in metric tons based on the sum of hourly CO_2 mass emissions over the year, converted to metric tons.

(C) Operators who add CEMS under this article are subject to specifications in WCI.23(d)(1)-(5), if applicable.

(e) Use of the Four CO_2 Calculation Methodologies. Use of the four CO_2 emissions calculation methodologies described in paragraphs (a) through (d) of this section is subject to the following requirements and restrictions:

(1) Calculation Methodology 1 may not be used by a facility that is subject to the verification requirements of WCI.8, except for stationary combustion units that combust natural gas with a higher heating value between 975 and 1,150 Btu per cubic foot. Otherwise, Calculation Methodology 1 may be used for any type of fuel for which a default CO2 emission factor and a default higher heating value for the fuel is specified in Table 20-1.

(2) Calculation Methodology 2 may not be used by a facility that is subject to the verification requirements of WCI.8, except for stationary combustion units that combust natural gas with a higher heating value between 975 and 1,150 Btu per cubic foot. Otherwise, Calculation Methodology 2 may be used for any type of fuel combusted for which a default CO2 emission factor for the fuel is specified in Table 20-1 or 20-2.

(3) Calculation Methodology 3 may be used for a unit of any size combusting any type of fuel, except when the use of Calculation Methodology 4 is required.

(4) Calculation Methodology 4 may be used for a unit of any size combusting any type of fuel, and must be used for: a combustion unit with a CEMS that is required by any federal, state, provincial, or local regulation and that includes both a stack gas volumetric flow rate monitor and a CO_2 concentration monitor.

(f) Mixtures of biomass fuel and fossil fuel. The owner or operator that combusts fuels or fuel mixtures for which the biomass fuel fraction is unknown or cannot be documented (for example, municipal solid waste or tire-derived fuels) shall determine the biomass fuel portion of CO_2 emissions using ASTM D6866-06a, as specified in this paragraph. This procedure is not required for fuels that contain less than 5 percent biomass fuel by weight or for waste-derived fuels that are less than 30 percent by weight of total fuels combusted in the year for which emissions are being reported, except where the operator wishes to report a biomass fuel fraction of CO_2 emissions.

(1) The operator shall conduct ASTM D6866-06a analysis on a representative fuel or exhaust gas sample at least every three months, and shall collect exhaust gas samples over at least 24 consecutive hours following the standard practice specified by ASTM D7459-08.

(2) The operator shall divide total CO_2 emissions between biomass fuel emissions and non-biomass fuel emissions using the average proportions of the samples analyzed for the year for which emissions are being reported.
(3) If there is a common fuel source to multiple units at the facility, the operator may elect to conduct ASTM D6866-06a testing for one of the units.

§ WCI.24 Calculation of CH_4 and N_2O Emissions

Calculate the annual CH_4 and N_2O mass emissions from stationary fuel combustion sources using the procedures in paragraph (a), (b), or (c), as appropriate.

(a) If the heat content of the fuel is not measured for CO_2 estimation, calculate CH_4 and N_2O emissions using Equation 20-8:

$$CH_4 \text{ or } N_2O = Fuel \times HHV_D \times EF \times 0.001$$ **Equation 20-8**

Where:

CH_4 or N_2O	=	Combustion emissions from specific fuel type, metric tons CH_4 or N_2O per year.
Fuel	=	Mass or volume of fuel combusted for the measurement period, p, specified by fuel type, units of mass or volume per unit time.
HHV_D	=	Default higher heating value specified by fuel type provided in Table 20-1, MMBtu per unit of mass or volume.
EF	=	Default CH_4 or N_2O emission factor provided in Table 20-3, kg CH_4 or N_2O per MMBtu.
0.001	=	Factor to convert kg to metric tons.

(b) If the heat content of the fuel is measured for CO_2 estimation, calculate CH_4 and N_2O emissions using Equation 20-9:

$$CH_4 \text{ or } N_2O = \sum_{p=1}^{n} Fuel_p \times HHV_p \times EF \times 0.001$$ **Equation 20-9**

Where:

CH_4 or N_2O	=	CH_4 or N_2O emissions from a specific fuel type, metric tons CH_4 or N_2O per year.
$Fuel_p$	=	Mass or volume of fuel combusted specified by fuel type, unit of mass (short tons) or volume (scf, barrel) per year.
HHV_p	=	Higher heating value measured for the measurement period, p, specified by fuel type, MMBtu per unit mass or volume.
EF	=	Default emission factor provided in Table 20-3, kg CH_4 or N_2O per MMBtu.
0.001	=	Factor to convert kg to metric tons.

(c) For biomass and municipal solid waste combustion, the operator may elect to use Equation 20-10 of this section to estimate CH_4 and N_2O emissions:

$$CH_4 \text{ or } N_2O = Steam \times B \times EF \times 0.001$$ **Equation 20-10**

Where:

CH_4 or N_2O	=	Annual CH_4 or N_2O emissions from the combustion of a municipal solid waste (metric tons).
Steam	=	Total mass of steam generated by municipal solid waste combustion during the reporting year (lb steam).
B	=	Ratio of the boiler's maximum rated heat input capacity to its design rated steam output (mmBtu/lb steam).
EF	=	Fuel-specific emission factor for CH_4 or N_2O, from Table WCI.20-3 of this subpart (kg CH_4 or N_2O per mmBtu).
0.001	=	Conversion factor from kilograms to metric tons.

(d) The operator may elect to calculate CH_4 or N_2O emissions using source-specific emission factors derived from source tests conducted at least annually under the supervision of (*jurisdiction*). Upon approval of a source test plan, the source test procedures in that plan shall be repeated in each future year to update the source specific emission factors annually.

(e) Use of the Four CO_2 Calculation Methodologies. Use of the four CH_4 and N_2O emissions calculation methodologies described in paragraphs (a) through (d) of this section is subject to the following requirements and restrictions:

(1) WCI.24(a) may not be used by a facility that is subject to the verification requirements of WCI.8, except for stationary combustion units that combust natural gas with a higher heating value between 975 and 1,150 Btu per cubic foot. Otherwise, WCI.24(a) may be used for any type of fuel for which a default CH_4 or N_2O emission factor and a default higher heat value for the fuel is specified in Table 20-3.
(2) WCI.24(b) may be used for a unit of any size combusting any type of fuel.
(3) WCI.24(c) may only be used for biomass or municipal solid waste combustion.
(4) WCI.24(d) may be used for a unit of any size combusting any type of fuel.

§ WCI.25 Sampling, Analysis, and Measurement Requirements

(a) Fuel Sampling Requirements. Fuel sampling must be conducted or fuel sampling results must be received from the fuel supplier at the frequency specified in paragraphs (a)(1) through (a)(4) of this section.

(1) Once for each new fuel shipment or delivery or on a monthly basis for middle distillates (diesel, gasoline, fuel oil, kerosene), residual oil, liquid waste-derived fuels, and LPG (ethane, propane, isobutene, n-butane, unspecified LPG).
(2) Monthly for natural gas, associated gas, and mixtures of low Btu gas.
(3) Monthly for gases derived from biomass including landfill gas and biogas from wastewater treatment or agricultural processes.
(4) Monthly for solid fuels, as specified below:

(A) The monthly solid fuel sample shall be a composite sample of weekly samples.
(B) The solid fuel shall be sampled at a location after all fuel treatment operations but before fuel mixing and the samples shall be representative of the fuel chemical and physical characteristics immediately prior to combustion.

(C) Each weekly sub-sample shall be collected at a time (day and hour) of the week when the fuel consumption rate is representative and unbiased.
(D) Four weekly samples (or a sample collected during each week of operation during the month) of equal mass shall be combined to form the monthly composite sample.
(E) The monthly composite sample shall be homogenized and well mixed prior to withdrawal of a sample for analysis.
(F) One in twelve composite samples shall be randomly selected for additional analysis of its discrete constituent samples. This information will be used to monitor the homogeneity of the composite.

(5) For biomass fuels and waste-derived fuels, the following may apply in lieu of WCI.25(a)(4):

(A) If CO_2 emissions are calculated using WCI.23(c)(1), the source-specific carbon content is determined annually. Upon approval of a source test plan by [*jurisdiction*], the source test procedures in that plan shall be repeated in subsequent years to update the source specific emission factors annually.
(B) If CO_2 emissions are calculated using WCI.23(c)(2) (biomass fuels and municipal solid waste only), the operator shall adjust the emission factor, in kg CO2/MMBtu not less frequently than every third year, through a stack test measurement of CO2 and use of the applicable ASME Performance Test Code to determine heat input from all heat outputs, including the steam, flue gases, ash and losses.

(b) Fuel Consumption Monitoring Requirements.

(1) Facilities may determine fuel consumption on the basis of direct measurement or recorded fuel purchase or sales invoices measuring any stock change (measured in million Btu, gallons, million standard cubic feet, short tons or bone dry short, tons) using the following equation:

Fuel Consumption in the Report Year = Total Fuel Purchases – Total Fuel Sales + Amount Stored at Beginning of Year – Amount Stored at Year End

(2) Fuel consumption measured in Btu values shall be converted to the required metrics of mass or volume using heat content values that are either provided by the supplier, measured by the facility, or provided in Table 20-1.
(3) All oil and gas flow meters (except for gas billing meters) shall be calibrated prior to the first year for which GHG emissions are reported under this rule, using an applicable flow meter test method listed in section WCI.6 or the calibration procedures specified by the flow meter manufacturer. Fuel flow meters shall be recalibrated either annually or at the minimum frequency specified by the manufacturer.
(4) For fuel oil, tank drop measurements may also be used.

(c) Fuel Heat Content Monitoring Requirements. Higher heating values shall be based on the results of fuel sampling and analysis received from the fuel supplier or determined by the operator, in either case using an applicable analytical method listed in section WCI.6.

(1) For gases, use ASTM D1826-94 (Reapproved 2003), ASTM D3588-98 (Reapproved 2003), ASTM D4891-89 (Reapproved 2006), GPA Standard 2261-00 “Analysis for

Natural Gas and Similar Gaseous Mixtures by Gas Chromatography." The operator may alternatively elect to use on-line instrumentation that determines heating value accurate to within ± 5.0 percent. Where existing on-line instrumentation provides only low heating value, the operator shall convert the value to higher heating value as follows:

$$HHV = LHV \times CF$$

Equation 20-11

Where:

HHV = fuel or fuel mixture higher heating value (Btu/scf).
LHV = fuel or fuel mixture lower heating value (Btu/scf).
CF = conversion factor.

For natural gas, a CF of 1.11 shall be used. For refinery fuel gas and mixtures of refinery fuel gas, a weekly average fuel system-specific CF shall be derived as follows:

(A) by concurrent LHV instrumentation measurements and HHV determined by on-line instrumentation or laboratory analysis as part of the daily carbon content determination; or,
(B) by the HHV/LHV ratio obtained from the laboratory analysis of the daily samples.

(2) For middle distillates and oil, or liquid waste-derived fuels, use ASTM D240-02 (Reapproved 2007), ASTM D4809-06 (Reapproved 2005).
(3) For solid biomass-derived fuels, use ASTM D5865-07a.
(4) For waste-derived fuels, use ASTM D5865-07a or ASTM D5468-02 (Reapproved 2007). Operators who combust waste-derived fuels that are not pure biomass fuels shall determine the biomass fuel portion of CO_2 emissions using the method specified in section WCI.23(f), if applicable

(d) Fuel Carbon Content Monitoring Requirements. Fuel carbon content and either molecular weight or molar fraction for gaseous fuels shall be based on the results of fuel sampling and analysis received from the fuel supplier or determined by the operator, in either case using an applicable analytical method listed in section WCI.6.

(1) For coal and coke, solid biomass fuels, and waste-derived fuels; use ASTM 5373-08.
(2) For liquid fuels, use the following ASTM methods: For petroleum-based liquid fuels and liquid waste-derived fuels, use ASTM D5291-02 (Reapproved 2007) "Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants", ultimate analysis of oil or computations based on ASTM D3238-95 (Reapproved 2005) and either ASTM D2502-04 or ASTM D2503-92 (Reapproved 2007).
(3) For gaseous fuels, use ASTM D1945-03 (Reapproved 2006) or ASTM D1946-90 (Reapproved 2006). The operator may alternatively elect to use on-line instrumentation that determines fuel carbon content accurate to ± 5 percent.

(e) Fuel Analytical Data Capture. When the applicable emissions estimation methodologies in sections WCI.20 through WCI.XXX require periodic collection of fuel analytical data for an emissions source, the operator shall demonstrate every reasonable effort to obtain a fuel analytical data capture rate of 100 percent for each report year.

(1) If the operator is unable to obtain fuel analytical data such that more than 20 percent of emissions from a source cannot be directly accounted for, the emissions from that source shall be considered unverifiable for the report year.
(2) If the fuel analytical data capture rate is at least 80 percent but less than 100 percent for any emissions source identified in sections WCI.20 through WCI.XXX, the operator shall use the mean of the fuel analytical data results captured to substitute for the missing values for the period of missing data.

(f) Procedure for Interim Fuel Analytical Data Collection.

(1) In the event of an unforeseen breakdown of fuel analytical data monitoring equipment required for the emissions estimation methodologies in sections WCI.20 through WCI.XXX, [jurisdiction] may authorize an operator to use an interim data collection procedure if [jurisdiction] determines that the operator has satisfactorily demonstrated that:
(A) The breakdown may result in a loss of more than 20 percent of the source's fuel data for the reporting year, such that emissions for the affected source could not be verified under the provisions of section WCI.8;
(B) The fuel analytical data monitoring equipment cannot be promptly repaired or replaced without shutting down a process unit significantly affecting facility operations, or that the monitoring equipment must be replaced and replacement equipment is not immediately available;
(C) The interim procedure will not remain in effect longer than is reasonably necessary for repair or replacement of the malfunctioning data monitoring equipment; and
(D) The request was submitted within 30 calendar days of the breakdown of the fuel analytical data monitoring equipment.
(2) An operator seeking approval of an interim data collection procedure must, within 30 days of the monitoring equipment breakdown, submit a written request to [jurisdiction] that includes all of the following:
(A) The proposed start date and end date of the interim procedure;
(B) A detailed description of what data are affected by the breakdown;
(C) A discussion of the accuracy of data collected during the interim procedure compared with the data collected under the operator's usual equipment-based method;
(D) A demonstration that no feasible alternative procedure exists that would provide more accurate emissions data; and
(E) A demonstration that the proposed interim procedure meets the criteria specified in section WCI.2(i)(1).
(3) *[The jurisdiction]* may limit the duration of the interim data collection procedure or include other conditions of approval to ensure the criteria in section WCI.2(i)(1) are met.
(4) Data collected pursuant to an approved interim data collection procedure shall be considered captured data for purposes of compliance with the capture rate requirements in section WCI.2(g). When approving an interim data collection procedure, [jurisdiction] shall determine whether the accuracy of data collected under the procedure is reasonably equivalent to data collected from properly functioning monitoring equipment, and if it is not, the relative accuracy to assign for purposes of assessing possible material misstatement under section WCI.8(q).

Table 20-1. Default Carbon Content, Heat Content, and Carbon Dioxide Emission Factors from Stationary Combustion by Fuel Type				
Fuel Type	**Carbon Content**	**Higher Heat Value**	**CO_2 Emission Factor**	**CO_2 Emission Factor**
Coal and Coke	**kg C / MMBtu**	**MMBtu / Short Ton**	**kg CO_2 / Short Ton**	**kg CO_2 / MMBtu**
Anthracite	28.26	25.09	2,597.94	103.54
Bituminous	25.49	24.93	2,328.35	93.40
Sub-bituminous	26.48	17.25	1,673.64	97.02
Lignite	26.30	14.21	1,369.32	96.36
Unspecified (Residential/Commercial)	26.00	22.24	2,118.67	95.26
Unspecified (Industrial Coking)	25.56	26.28	2,461.17	93.65
Unspecified (Other Industrial)	25.63	22.18	2,082.89	93.91
Unspecified (Electric Power)	25.76	19.97	1,884.86	94.38
Coke	27.85	24.80	2,530.65	102.04
Natural Gas (By Heat Content)	**kg C / MMBtu**	**Btu / Standard cubic foot**	**kg CO_2 / Standard cubic foot**	**kg CO_2 / MMBtu**
975 to 1,000 Btu / Standard cubic foot	14.73	n/a	n/a	53.97
1000 to 1,025 Btu / Std cubic foot	14.43	n/a	n/a	52.87
1025 to 1,050 Btu / Std cubic foot	14.47	n/a	n/a	53.02
1050 to 1,075 Btu / Std cubic foot	14.58	n/a	n/a	53.42
1075 to 1,100 Btu / Std cubic foot	14.65	n/a	n/a	53.68
Greater than 1,100 Btu / Std cubic foot	14.92	n/a	n/a	54.67
Unspecified (Weighted U.S. Average)	14.47	1,027	0.0544	53.02

Table 20-1. Default Carbon Content, Heat Content, and Carbon Dioxide Emission Factors from Stationary Combustion by Fuel Type (continued)

Petroleum Products	kg C / MMBtu	MMBtu / Barrel	kg CO_2 / gallon	kg CO_2 / MMBtu
Asphalt & Road Oil	20.62	6.636	11.94	75.55
Aviation Gasoline	18.87	5.048	8.31	69.14
Distillate Fuel Oil (#1, 2 & 4)	19.95	5.825	10.14	73.10
Jet Fuel	19.33	5.670	9.56	70.83
Kerosene	19.72	5.670	9.75	72.25
LPG (energy use)	17.19	3.861	5.79	62.98
Propane	17.20	3.824	5.74	63.02
Ethane	16.25	2.916	4.13	59.54
Isobutane	17.75	4.162	6.44	65.04
n-Butane	17.72	4.328	6.69	64.93
Lubricants	20.24	6.065	10.71	74.16
Motor Gasoline	19.33	5.218	8.80	70.83
Residual Fuel Oil (#5 & 6)	21.49	6.287	11.79	78.74
Crude Oil	20.33	5.800	10.29	74.49
Naphtha (<401 deg. F)	18.14	5.248	8.30	66.46
Natural Gasoline	18.24	4.620	7.35	66.83
Other Oil (>401 deg. F)	19.95	5.825	10.14	73.10
Pentanes Plus	18.24	4.620	7.35	66.83
Petrochemical Feedstocks	19.37	5.428	9.17	70.97
Petroleum Coke	27.85	6.024	14.64	102.04
Still Gas	17.51	6.000	9.17	64.16
Special Naphtha	19.86	5.248	9.09	72.77
Unfinished Oils	20.33	5.825	10.33	74.49
Waxes	19.81	5.537	9.57	72.58
Other Solid Fuels	**kg C / MMBtu**	**MMBtu / Short Ton**	**kg CO_2 / Short Ton**	**kg CO_2 / MMBtu**
Biomass Derived Fuels (Solid). Wood and Wood Waste (12% moisture content) or other solid biomass fuels	25.60	15.38	1,442.62	93.80
Municipal Solid Waste (MSW)	24.74	8.7	788.7	90.65
Biomass-derived Fuels (Gas)	**kg C / MMBtu**	**Btu / Standard cubic foot**	**kg CO_2 / Standard cubic ft.**	**kg CO_2 / MMBtu**
Biogas (includes landfill gas and manure biogas)*	28.4	Varies	Varies	104.06

Note: Heat content factors are based on higher heating values (HHV).

* The emission factors for biogas include both the CO_2 from combustion and the pass-through CO_2, which are assumed to be in equal proportions.

Sources:

U.S. EPA, *Inventory of Greenhouse Gas Emissions and Sinks: 1990-2007 (2009)*, Annex 2.1, Tables A-28, A-31, A-32, A-35, and A-36, except:

- Heat Content factors for Unspecified Coal (by sector), Coke, Naptha (<401 F°), and Other Oil (>401 F°), from U.S. Energy Information Administration, *Annual Energy Review 2005 (2006)*, Tables A-1, A-4, and A-5;
- Heat Content factors for Coal (by type) and LPG, and all factors for Wood and Wood Waste, Landfill Gas, and Wastewater Treatment Biogas, from U.S. EPA Climate Leaders, *Stationary Combustion Guidance (2004)*, Tables B-1 and B-2; and
- Municipal Solid Waste (MSW) factors, from Energy Information Administration, http://www.eia/doe/gov/oiaf/1605/coefficients.html and California Air Resources Board, *MSW California Air Resources Board, 2008*.

Table 20-2. Default Carbon Dioxide Emission Factors from Stationary Combustion for Waste Derived Fuels	
Fuel Type	**kg CO_2 / MMBtu**
Waste Oil	78
Tires	90
Plastics	79
Solvents	78
Impregnated Saw Dust	79
Other Fossil Based Wastes	84
Dried Sewage Sludge	116
Mixed Industrial Waste	88
Municipal Solid Waste	See Table 20-1

Note: Emission factors are based on higher heating values (HHV). Values were converted from LHV to HHV assuming that LHV are 5 percent lower than HHV for solid and liquid fuels.

Source: WBCSD/WRI, *The Cement CO_2 Protocol: CO_2 Accounting and Reporting Standard for the Cement Industry Calculation Tool (2004).*

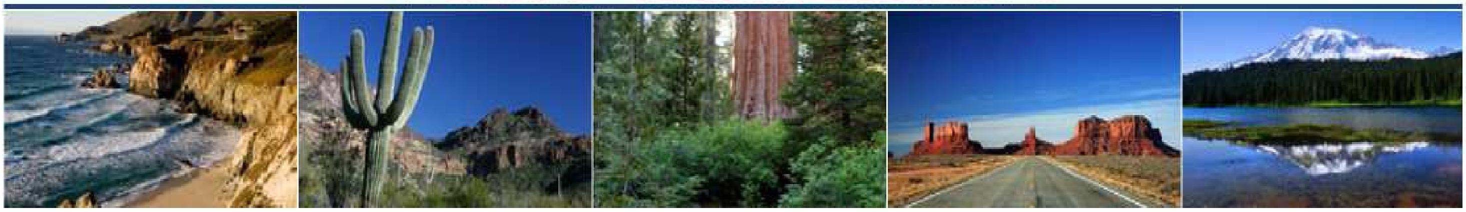
Table 20-3. Default CH_4 and N_2O Emission Factors from Stationary Combustion by Fuel Type		
Fuel Type	**CH_4 Emission Factor (kg CH_4/ MMBtu)**	**N_2O Emission Factor (kg N_2O / MMBtu)**
Asphalt	0.003	0.0006
Aviation Gasoline	0.003	0.0006
Coal	0.01	0.0015
Crude Oil	0.003	0.0006
Digester Gas	0.0009	0.0001
Distillate	0.003	0.0006
Gasoline	0.003	0.0006
Jet Fuel	0.003	0.0006
Kerosene	0.003	0.0006
Kraft Black Liquor	0.0026	0.0021
Landfill Gas	0.0009	0.0001
LPG	0.001	0.0001
Lubricants	0.003	0.0006
Municipal Solid Waste	0.03	0.004
Naphtha	0.003	0.0006
Natural Gas	0.0009	0.0001
Natural Gas Liquids	0.003	0.0006
Other Biomass Fuels	0.03	0.004
Petroleum Coke	0.003	0.0006
Propane	0.001	0.0001
Refinery Gas	0.0009	0.0001
Residual Fuel Oil	0.003	0.0006
Tires	0.003	0.0006
Waste Oil	0.03	0.004
Waxes	0.003	0.0006
Wood (Dry)	0.03	0.004

Note: Heat content factors are based on higher heating values (HHV).

Source: Intergovernmental Panel on Climate Change, *2006 IPCC Guidelines for National Greenhouse Gas Inventories (2006),* Volume 2, Tables 2.2, 2.3, and 2.4, except:

- Kraft Black Liquor emission factors, from International Council of Forest and Paper Associations, *Calculation Tools for Estimating Greenhouse Gas Emissions from Pulp and Paper Mills (2005),* Appendix F, Table 8.

Western Climate Initiative



Suggested Essential Requirements for Reporting of Imported Electricity

§ WCI.60 IMPORTED ELECTRICITY

§ WCI.61 Definitions

"Balancing authority" means a responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports interconnection frequency in real time.

"Balancing authority area" means the collection of generation, transmission, and loads within the metered boundaries of a balancing authority. A balancing authority maintains load-resource balance within this area.

"Busbar" means a power conduit of an electricity generating facility that serves as the starting point for the electricity transmission system.

"Electricity generating facility" means a facility that generates electricity and includes one or more electricity generating units at the same location.

"Electricity importer" means [common boundary FJD] an owner of electricity generated outside the WCI region as it is delivered to the first point of delivery in the WCI Region for electricity having a final point of delivery in the WCI Region or; [individual boundary FJD] an owner of electricity generated outside the WCI region as it is delivered to the first point of delivery in the WCI Partner jurisdiction of the final point of delivery [Both definitions included until the Partners make a final decision on the boundary issue.]

"Electricity transaction" means the purchase, sale, import, export or exchange of electric power.

"Entity" means a person, firm, association, organization, partnership, business trust, corporation, limited liability company, company, or government agency.

"Exchange agreement" means a commitment between electricity market participants to swap energy for energy. Exchange transactions do not involve transfers of payment or receipts of money for the full market value of the energy being exchanged, but may include payment for net differences due to market price differences between the two parts of the transaction or to settle minor imbalances.

"Final point of delivery" means the last point of delivery for a given electricity transaction.

"First Jurisdictional Deliverer" means the owner or operator of an electricity generating facility in a WCI Partner jurisdiction or an electricity importer that is jurisdictional to the regulatory authority of a WCI Partner jurisdiction or the immediate downstream purchaser or recipient of electricity from a non-jurisdictional electricity importer.

“Gross generation” means the total electrical output of the generating unit, expressed in megawatt hours (MWh) per year.

“Imported power” means electric power generated in a non-WCI location, delivered into the WCI Region and having a final point of delivery in the WCI Region.

“Megawatt hour” or “MWh” means the electrical energy unit of measure equal to one million watts of power supplied to, or taken from, an electric circuit steadily for one hour.

“Multi-jurisdictional retail provider” means a retail provider that provides electricity to consumers in a WCI Partner jurisdiction and in one or more other non-WCI states and provinces in a contiguous service territory.

“Nameplate generating capacity” means the maximum rated output of a generator under specific conditions designated by the manufacturer, expressed in megawatts (MW) or kilowatts (kW).

“Net power generated” means the gross generation minus station service or unit service power requirements, expressed in megawatt hours (MWh) per year. In the case of cogeneration, this value is intended to include internal consumption of electricity for the purposes of a production process, as well as power put on the grid.

“NERC E-tag” means North American Electric Reliability Corporation (NERC) energy tag representing transactions on the North American bulk electricity market scheduled to flow between or across balancing authority areas.

“Point of delivery” means a point on an electricity transmission or distribution system where a power supplier delivers electricity to the receiver of that energy. This point can be an interconnection with another system or a substation where the transmission provider’s transmission and distribution systems are connected to another system, or a distribution substation where electricity is imported into the WCI region over a multi-jurisdictional retail provider’s distribution system.

“Power contract” means an arrangement for the purchase of electricity. Power contracts may be, but are not limited to, power purchase agreements and tariff provisions.

“Purchasing/selling entity” means an entity that purchases or sells energy or capacity and reserve transmission services between or among balancing authority areas.

“Renewable energy” means energy from sources that constantly renew themselves or that are regarded as practically inexhaustible. Renewable energy includes, but is not limited to, energy derived from solar, wind, geothermal, hydroelectric, wood, biomass, tidal power, sea currents, and ocean thermal gradients.

“Renewable energy certificate” means a certificate of proof issued by an approved generation information system or third-party verifier that one MWh of electricity was generated by a renewable energy source

“Retail provider” means an entity that provides electricity to retail end users in the WCI Region

“Specified source” means a specific electricity generating unit or electricity generating facility which can be matched to a reported electricity transaction due to full or partial ownership by the first jurisdictional deliverer or due to its identification in a power contract with the first jurisdictional deliverer.

"Stationary source" means any building, structure, facility, or installation that emits or may emit greenhouse gases.

"Unspecified source" means electricity generation that cannot be matched to a specific electricity generating facility or electricity generating unit. Unspecified sources of power may include power purchased from entities that own fleets of generating facilities such as independent power producers, retail providers, and federal power agencies and power purchased from electricity marketers, brokers, and markets.

"Western Climate Initiative" or "WCI" means a collaborative effort of the U.S. states and Canadian provinces that comprise the WCI Region to reduce greenhouse gas emissions in their respective jurisdictions.

"WCI Region" means the Canadian provinces of British Columbia, Manitoba, Ontario, and Quebec plus the U.S. states of Arizona, California, Montana, New Mexico, Oregon, Utah, and Washington, excluding lands that are not subject to state or provincial jurisdiction.

§ WCI.62 Greenhouse Gas Emissions Data Report: First Jurisdictional Deliverers of Imported Power

(a) General Requirements. First jurisdictional deliverers shall meet the following general requirements in preparing their greenhouse gas emissions data report for each report year. When reporting emissions and electricity transactions, first jurisdictional deliverers shall:

(1) Specify the amount of emissions;

(2) Specify the amount of electricity in MWh;

(3) Aggregate imported power by point of delivery;

(4) Report the amount of electricity as measured at the first point of delivery in the WCI Region;

(5) For electricity from unspecified sources, disaggregate imported power for each point of delivery by purchasing/seller entity from which the power was purchased, if applicable;

(6) For electricity from specified sources, specify the facility name, the facility ID, and the electricity generating unit ID for the unit generating the power, if applicable;

(7) Report the number of renewable energy certificates from sources not in the WCI region that are retired, or whose greenhouse gas source specification fields are retired, associated with unspecified imported power or specified imported power having an emission rate equal to or less than the default rate for the region where the specified generating facility is located

(8) Specify electricity imported under exchange agreements as you would other import transactions;

(9) Report quantities of imported electricity wheeled through the WCI Region to a final point of delivery outside the WCI Region as measured at the first point of delivery inside the WCI Region;

(10) Retain for purposes of verification NERC E-tags, power contracts, settlements data, and all other information needed to confirm the transactions.

(b) Report Content. First Jurisdictional Deliverers shall include the following information in the greenhouse gas emissions data report for each report year.

(1) Specified Imported Power Transactions. Electricity from specified sources for which the First Jurisdictional Deliverer is the electricity importer or that the First Jurisdictional Deliverer purchased or received immediately downstream from a non-jurisdictional electricity importer.

(A) Power imported into the WCI Region from a specified hydroelectric generating facility with nameplate capacity of greater than 30 MW that was operational prior to January 1, 2008 or from a specified nuclear facility that was operational prior to January 1, 2008 shall be listed as one of the following:

(i) Power purchased with a contract in effect prior to January 1, 2008 that remains in effect or has been renegotiated for the same facility for the same share or quantity of net generation within one year of contract expiration;

(ii) Power purchased not meeting (2)(A)1.a and that is not associated with an increase in the facility's generating capacity;

(iii) Power purchased not meeting (2)(A)1.a that is associated with an increase in the facility's generating capacity due to increased efficiencies or other capacity increasing actions;

(iv) Power purchased from hydroelectric generating facilities during a "spill or sell" situation where power not purchased is lost;

(v) Power purchased that does not meet (2)(A)1.a due to federal power redistribution polices for federally owned resources and not related to price bidding.

(2) Unspecified Imported Power Transactions. Electricity from unspecified sources for which the First Jurisdictional Deliverer is the electricity importer or that the First Jurisdictional Deliverer purchased or received immediately downstream from a non-jurisdictional electricity importer with final point of delivery in the WCI Region.

(3) Electricity Wheeled Through the WCI Region. Power imported into the WCI Region for which the First Jurisdictional Deliverer is the electricity importer or that the First Jurisdictional Deliverer purchased or received immediately downstream from a non-jurisdictional electricity importer with a final point of delivery outside of the WCI Region, measured at the first point of delivery in the WCI Region.

§ WCI.63 Greenhouse Gas Emissions Data Report: Additional Requirements for Retail Providers Only

Retail providers that serve consumers in the WCI Region shall include the following information in the greenhouse gas emissions data report for each report year, in addition to the information identified in the sections above.

(c) If the retail provider holds a contract that entitles the retail provider to a specified percentage of the generation in the report year from an electricity generating facility not located in the WCI Region, the retail provider shall include power purchased or sold from that facility as being from a partially owned facility.

(d) For electricity generating facilities not located in the WCI Region that are fully or partially owned by the retail provider that have CO2 emissions greater than 500 kg of CO2 per MWh based on the most recent greenhouse gas emissions data report that received a positive verification opinion or on CO2 emissions reported to U.S.EPA under 40 CFR Part 75 or reported to Environment Canada under Section 71 of the Canadian Environmental Protection Act, the retail provider shall include:

   (1) Facility name, state/province designated facility ID, state/province designated generating unit ID as applicable, percent ownership share at the facility level, ownership share at the generating unit level as applicable, and both net and gross power generated in the report year;

   (2) Quantity of power from the electricity generating facility or electricity generating unit measured at the busbar and imported into the WCI Region with a final point of delivery in the WCI Region;

   (3) Quantity of power sold by the retail provider or on behalf of the retail provider from the electricity generating facility or electricity generating unit measured at the busbar and with a final point of delivery outside the WCI Region. These quantities shall be disaggregated by purchasing counterparty.

§ WCI.64 Greenhouse Gas Emissions Data Report: Additional Requirements for Multi-Jurisdiction Retail Providers Only.

Multi-jurisdictional retail providers that import power into the WCI Region at the distribution level shall include the following information in the greenhouse gas emissions data report for each report year, in addition to the information identified in the sections above. Multi-jurisdictional retail providers meeting this condition shall provide:

(a) A report of the emissions associated with serving the load of the service territory that includes consumers in the WCI Region following the Climate Registry's Electric Power Sector Protocol or the applicable state or provincial reporting protocol for retail providers;

(b) The total retail load served by the multi-jurisdictional retail provider in the service territory that includes consumers in the WCI Region;

(c) The retail load of customers served in the WCI Region portion of the service territory; and

(d) A report on adjustments to the service territory's average emission rate that cause the average emission rate to differ among the various state or provincial portions of the service territory due to mandatory factors such as different Renewable Portfolio Standard requirements in the WCI state or province and the non-WCI state(s) or province(s).

Attachment 4: Iron and Steel Manufacturing

§ WCI.150 IRON AND STEEL MANUFACTURING

§ WCI.151 Source Category Definition

Iron and steel manufacturing comprises four categories: primary facilities that produce both iron and steel, secondary steelmaking facilities, iron production facilities, and offsite production of metallurgical coke. These processes may occur together in an "integrated" facility or they may occur in separate offsite facilities.

§ WCI.152 Greenhouse Gas Reporting Requirements

In addition to the information required by WCI.3, the annual emissions data report shall contain the following information:

(a) Total emissions of CO_2 and CH_4 in metric tons at the facility level.

(b) CO_2 and CH_4 emissions from coke production (metric tons) and the following information:

(1) Quantity of coking coal consumed in coke production (metric tons)
(2) Quantity of other process materials (e.g., natural gas, fuel oil, etc.) consumed in coke production (metric tons)
(3) Quantity of blast furnace gas consumed in coke production (metric tons)
(4) Quantity of coke produced (metric tons)
(5) Quantity of coke oven gas transferred offsite (metric tons)
(6) Quantity of other coke oven by-products (e.g., coal tar, light oil, coke breeze, etc.) transferred offsite (metric tons)
(7) Carbon content of material inputs and outputs listed in (b)(1) through (b)(6) (metric tons of C per metric ton of material [equivalent to wt% C/100])

(c) CO_2 and CH_4 emissions from iron and steel production (metric tons) and the following information:

(1) Quantity of coke consumed in iron and steel production (excluding sinter production) (metric tons)
(2) Quantity of on-site coke oven by-products (e.g., coal tar, light oil, coke breeze, etc.) consumed in blast furnace (metric tons)
(3) Quantity of coal directly injected into blast furnace (metric tons)
(4) Quantity of limestone directly injected into blast furnace (metric tons)
(5) Quantity of dolomite directly injected into blast furnace (metric tons)
(6) Quantity of carbon electrodes consumed in EAFs (metric tons)
(7) Quantity of other carbonaceous or process material (e.g., sinter, waste plastic, etc.) consumed in iron and steel production (metric tons)
(8) Quantity of coke oven gas consume in blast furnace (metric tons)
(9) Quantity of steel produced (metric tons)
(10) Quantity of iron production not converted to steel (metric tons)

(11) Quantity of blast furnace gas transferred offsite (metric tons)
(12) Carbon content of material inputs and outputs listed in (c)(1) through (c)(11) (metric tons of C per metric ton of material [equivalent to wt% C/100])

(d) Process CO_2 and CH_4 emissions from sinter production (metric tons) and the following information:

(1) Quantity of coke breeze (purchased and produced on-site) used for sinter production (metric tons)
(2) Quantity of coke oven gas consumed in blast furnace in sinter production (metric tons)
(3) Quantity of blast furnace gas consumed in sinter production (metric tons)
(4) Quantity of other process materials (e.g., natural gas, fuel oil, etc.) consumed in sinter production (metric tons)
(5) Quantity of sinter off gas transferred offsite (metric tons)
(6) Carbon content of material inputs and outputs listed in (d)(1) through (d)(5) (metric tons of C per metric ton of material [equivalent to wt% C/100])

(e) Process CO_2 and CH_4 emissions from direct reduced iron production (metric tons) and the following information:

(1) Energy from natural gas used in direct reduced iron production (gigajoules [GJ])
(2) Energy from coke breeze used in direct reduced iron production (GJ)
(3) Energy from metallurgical coke used in direct reduced iron production (GJ)
(4) Carbon of material inputs listed in (e)(1) through (e)(3) (metric tons of C per GJ)

(f) CO_2, N_2O, and CH_4 emissions from stationary combustion units as specified in WCI.20.

§ WCI.153 Calculation of CO_2 Emissions

(a) Process CO_2 emissions. Determine process CO_2 emissions as specified under either paragraph (1) or (2) of this section.

(1) Continuous emissions monitoring systems (CEMS) as specified in WCI.23(d).
(2) Calculation methodologies specified in paragraph (b) of this section.

[CEMS and mass balance approach are based on IPCC Tier 3 methods.)

(b) Process CO_2 Emissions Calculation Methodology. Calculate total CO_2 process emissions using the following mass balance approach:

(1) Calculate the coke production CO_2 (either within integrated facilities or at offsite facilities) emissions using Equation 150-1 (if applicable):

$$E_{coke} = \left[(CC \times C_{CC}) + \sum_a (PM_a \times C_a) + (BG \times C_{BG}) - (CO \times C_{CO}) - (COG \times C_{COG}) - \sum_b (COB_b \times C_b) \right] \times 3.664$$

Equation 150-1

Where:

E_{coke}	=	Emissions of CO_2 from coke production (metric tons);
CC	=	Quantity of coking coal (metric tons);
PM_a	=	Quantity of other process material *a* (not included as separate terms), such as natural gas or fuel oil (metric tons);
BG	=	Quantity of blast furnace gas consumed in coke ovens (metric tons);
CO	=	Quantity of coke produced (metric tons)
COG	=	Quantity of coke oven gas transferred offsite (metric tons);
COB_b	=	Quantity of coke oven by-product *b* transferred offsite (metric tons);
C_x	=	Carbon content of material input or output *x* (metric tons C/metric tons of *x*);
3.664	=	Conversion factor from metric tons of C to metric tons of CO_2.

(2) Calculate the iron and steel production CO_2 emissions using Equation 150-2:

$$E_{iron,steel} = \Big[(CO \times C_{CO}) + \sum_a (COB_a \times C_a) + (CI \times C_{CI}) + (L \times C_L) + (D \times C_D) + (CE \times C_{CE}) + \sum_b (O_b \times C_b) + (COG \times C_{COG}) - (S \times C_S) - (IP \times C_{IP}) - (BG \times C_{BG}) \Big] \times 3.664$$

Equation 150-2

Where:

$E_{iron,steel}$	=	Emissions of CO_2 from iron and steel production (metric tons);
CO	=	Quantity of coke consumed (excluding sinter production) (metric tons);
COB_a	=	Quantity of coke oven by-product *a* consumed in blast furnace (metric tons);
CI	=	Quantity of coal directly injected into blast furnace (metric tons);
L	=	Quantity of limestone consumed (metric tons);
D	=	Quantity of dolomite consumed (metric tons);
CE	=	Quantity of carbon electrodes consumed in EAFs (metric tons);
O_b	=	Quantity of other carbonaceous and process material *b*, such as sinter or waste plastic (metric tons);
COG	=	Quantity of coke oven gas consumed in blast furnace (metric tons);
S	=	Quantity of steel produced (metric tons);
IP	=	Quantity of iron production not converted to steel (metric tons);
BG	=	Quantity of blast furnace gas transferred offsite (metric tons);
C_x	=	Carbon content of material input or output *x* (metric tons C/metric tons of *x*);
3.664	=	Conversion factor from metric tons of C to metric tons of CO_2.

(3) Calculate the sinter production CO_2 emissions using Equation 150-3 (if applicable):

$$E_{sinter} = \Big[(CBR \times C_{CBR}) + (COG \times C_{COG}) + (BG \times C_{BG}) + \sum_a (PM_a \times C_a) - (SOG \times C_{SOG}) \Big] \times 3.664$$

Equation 150-3

Where:

E_{sinter} = Emissions of CO_2 from sinter production (metric tons);
CBR = Quantity of purchased and onsite produced coke breeze used for sinter production (metric tons);
COG = Quantity of coke oven gas consumed in blast furnace for sinter production (metric tons);
BG = Quantity of blast furnace gas consumed for sinter production (metric tons);
PM_a = Quantity of other process material *a* consumed for sinter production (not included as separate terms), such as natural gas or fuel oil (metric tons);
SOG = Quantity of sinter off gas transferred offsite (metric tons);
C_x = Carbon content of material input or output *x* (metric tons C/metric tons of *x*);
3.664 = Conversion factor from metric tons of C to metric tons of CO_2.

(4) Calculate the direct reduced iron production CO_2 emissions using Equation 150-4 (if applicable):

$$E_{DRI} = \left[\left(DRI_{NG} \times C_{NG}\right) + \left(DRI_{BZ} \times C_{BZ}\right) + \left(DRI_{CK} \times C_{CK}\right)\right] \times 3.664$$ **Equation 150-4**

Where:

E_{DRI} = Emissions of CO_2 from direct reduced iron production (metric tons);
DRI_{NG} = Energy from natural gas used in direct reduced iron production (GJ);
DRI_{BZ} = Energy from coke breeze used in direct reduced iron production (GJ);
DRI_{CK} = Energy from metallurgical coke used in direct reduced iron production (GJ);
C_{NG} = Carbon content of natural gas (metric ton C/GJ);
C_{BZ} = Carbon content of coke breeze (metric ton C/GJ);
C_{CK} = Carbon content of metallurgical coke (metric ton C/GJ);
3.664 = Conversion factor from metric tons of C to metric tons of CO_2.

(5) Calculate the total CO_2 emissions using Equation 150-5:

$$E_{CO2} = E_{coke} + E_{iron,steel} + E_{sinter} + E_{DRI}$$ **Equation 150-5**

Where:

E_{CO2} = Total CO_2 emissions (metric tons);
E_{coke} = Emissions from coke production (metric tons);
$E_{iron,steel}$ = Emissions from iron and steel production (metric tons);
E_{sinter} = Emissions from sinter production (metric tons);
E_{DRI} = Emissions from direct reduced iron production (metric tons).

§ WCI.154 Calculation of CH_4 Emissions

(a) Process CH_4 emissions. Determine process CH_4 emissions as specified under either paragraph (1) or paragraph (2) of this section.

(1) Continuous emissions monitoring systems (CEMS) as specified in WCI.23(d).
(2) Site-specific emission factors.

§ WCI.155 Sampling, Analysis, and Measurement Requirements

Measurements of carbon contents of the material balance input, output, and by-product materials shall be conducted as described below.

Note: The sampling, analysis, and measurement procedures will be standardized for each calculation input to reduce variation between facilities within the iron and steel industry. Material sampling frequency and technique is distinct from material analysis conducted in a laboratory. The WCI is seeking stakeholder feedback on this topic and is specifically interested in proposals from stakeholders with expertise in this industry related to sampling, analysis and measurement procedures already in use at these facilities for the material quantities and/or concentrations listed below. Those proposing procedures should include sampling frequency and technique, indicate the uncertainty associated with the procedures, and describe the application of the procedure at a facility.

(b) Fuel Carbon Content Requirements. Fuel carbon contents should be monitored in the following manner (from § WCI.25):

(1) For coal and coke, solid biomass-derived fuels, and waste-derived fuels; use ASTM 5373-02 (Reapproved 2007).
(2) For liquid fuels, use the following ASTM methods: For petroleum-based liquid fuels and liquid waste-derived fuels, use ASTM D5291-02 (Reapproved 2007) "Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants", ultimate analysis of oil or computations based on ASTM D3238-95 (Reapproved 2005) and either ASTM D2502-04 or ASTM D2503-92 (Reapproved 2002).
(3) For gaseous fuels, use ASTM D1945-03 or ASTM D1946-90 (Reapproved 2006).

(c) By-Product Carbon Content Requirements. Carbon contents of by-products (e.g., blast furnace gas, coke oven gas, coal tar, light oil, coke breeze, sinter off gas, etc.) from all iron and steel production processes should be monitored in the following manner:

(1) [Methodology to be determined.]

(d) Flux Carbon Content Requirements. Carbon contents of fluxes (i.e., limestone and dolomite) from all iron and steel production processes should be monitored in the following manner:

(1) For limestone and dolomite, use ASTM C25-06.

(e) Electrode Carbon Content Requirements. Carbon contents of carbon electrodes used in electric arc furnaces (EAFs) should be monitored in the following manner:

(1) Vendor specifications of carbon content in EAF carbon electrodes.

(f) Finished Product Carbon Content Requirements. Carbon contents of finished products (i.e., steel, iron not converted to steel, and direct reduced iron) from all iron and steel production processes should be monitored in the following manner:

(1) For iron and steel, use ASTM E1019-08 or ASTM E351-93.

(g) Quantity Measurement Requirements. The quantities of process inputs, outputs, and by-products must be determined using the following methods:

(1) For solid process inputs, outputs, and by-products, quantities must be determined by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.
(2) For liquid process inputs, outputs, and by-products, quantities must be determined by direct volume measurement using the same plant instruments used for accounting purposes.
(3) For gaseous process inputs, outputs, and by-products, quantities must be determined by direct volume measurement using the same plant instruments used for accounting purposes.

Attachment 9: Petrochemical Manufacturing

§ WCI.300 PETROCHEMICAL MANUFACTURING

§ WCI.301 Source Category Definition

The petrochemical manufacturing source category consists of any facility that manufacturers petrochemicals, including acrylonitrile, propylene, ethylene, ethylene dichloride, ethylene oxide, or methanol, from feedstocks derived from petroleum, or petroleum and natural gas liquids.

§ WCI.302 Greenhouse Gas Reporting Requirements

In addition to the information required by WCI.3, the annual emissions report must contain the following information:

(a) CO_2, N_2O, and CH_4 emissions from combustion of fuels in the stationary combustion unit in metric tons, as specified in WCI.20.

(b) CO_2, N_2O, and CH_4 emissions from flares and other oxidizers in metric tons, as specified in WCI.303(a).

(c) CO_2, N_2O, and CH_4 emissions from process vents in metric tons, as specified in WCI.303(b).

(d) CH_4 emissions tons from equipment leaks in metric, as specified in WCI.303(c).

(e) Annual consumption of feedstock by type for all feedstocks that result in GHG emissions in million standard cubic feet for gases, gallons for liquids, short tons for non-biomass solids, and bone dry short tons for biomass-derived solid fuels.

§ WCI.303 Calculation of GHG Emissions

(a) **Flares and Other Oxidizers.** You must calculate GHG emissions from flares and oxidation control devices as follows:

(1) Calculate CO_2, CH_4 and N_2O emissions resulting from the combustion of flare pilot and purge gas using the appropriate method(s) specified in WCI.20.

(2) Calculate CO_2 emissions for each gas destroyed in a flare or other oxidation control device using Equation 300-1.

Equation 300-1

$$CO_2 = \sum_{i=1}^{n} GV_i \times CC_i \times MW_i / MVC \times 3.664 \times 0.001$$

Where:

CO_2	=	CO_2 emissions (metric tons/year).
GV_i	=	Volume of gas *i* destroyed annually (scf/year).
CC_i	=	Average annual carbon content of gas *i* (kg C/kg fuel).
MW_i	=	Average annual molecular weight of gas *i*.

MVC	=	Molar volume conversion factor (849.5 scf/kg- mole for STP of 20°C and 1 atmosphere or 836 scf/kg-mole, for STP of 60°F, and 1 atmosphere).
3.664	=	Ratio of molecular weights, CO_2 to carbon.
0.001	=	Conversion factor, kg to metric tons.
n	=	Number of gases destroyed.

(b) **Process Vents.** Except for process emissions calculated pursuant to WCI.303(a) or (c), you must calculate process emissions of CO_2, CH_4, and N_2O from process vents using Equation 300-2.

$$E_x = \sum_{i=1}^{n} VR_i \times F_{xi} \times (MW_x / MVC) \times VT_i \times 0.001$$ **Equation 300-2**

Where:

E_x	=	Emissions of x (metric tons/yr), where x = CO_2, N_2O, or CH_4.
VR_i	=	Vent rate for venting event i (scf/unit time).
F_{xi}	=	Molar fraction of x in vent gas stream during event i.
MW_x	=	Molecular weight of x (kg/kg-mole).
MVC	=	Molar volume conversion (849.5 scf/kg-mole for STP of 20°C and 1 atmosphere or 836 scf/kg-mole for STP of 60°F, and 1 atmosphere).
VT_i	=	Time duration of venting event i (same units of time used for VR_i).
n	=	Number of venting events.
0.001	=	Conversion factor, kg to metric tons.

(c) **Equipment Leaks.** You must calculate CH_4 emissions for each valve, pump seal, connector, flange, open-ended line, and other components in natural gas, fuel gas, and off-gas systems as follows:

(1) Identify and screen each valve, pump seal, connector, flange, open-ended line, and other components in natural gas, fuel gas, and off-gas systems using the monitoring method in WCI.304. Components identified as "other" components include instruments, loading arms, pressure relief valves, vents, compressors, dump lever arms, diaphragms, drains, hatches, meters, and polished rods stuffing boxes.

(2) Use the results of the component screening and the following equations to calculate VOC emissions:

(A) For components where the measured screening value is equal to zero when corrected for background, calculate VOC emissions using Equation 300-3 and the appropriate default emission factors from Table 300-1:

$$E_{VOC-0} = \sum_{i=1}^{6} CC_i \times ZF_{i0} \times t$$ **Equation 300-3**

Where:

E_{VOC-0} = Emissions from components with a screening value equal to zero, when corrected for background (kg/screening period).

i = Component type (valve, pump seal, other, connector, flange, open-ended line).

CC_i = Number of i components where the screening value is 0.

ZF_{i0} = Default zero factor for component i from Table 300-1 (kg/hr).

t = Time since last screening (hours/screening period).

(B) For components where the measured screening value, corrected for background, is between 0 and 10,000 ppmv, calculate VOC emissions using Equation 300-4 and the appropriate default factors from Table 300-1:

$$E_{VOCL-C} = \sum_{i=1}^{6} \sum_{n=1}^{n} \left(\sigma_i \times SV_n^{\ \beta i} \right) \times t$$ **Equation 300-4**

Where:

E_{VOCL-C} = Emissions from components with screening values, corrected for background, between 0 and 10,000 (kg/screening period).

i = Component type (valve, pump seal, others, connector, flange, open ended-line).

n = Number of *i* components.

σ_i = Correlation equation coefficient for component type *i* from Table 300-1.

SV_n = Screening value for component *n.*

βi = Correlation equation exponent for component type *i* from Table 300-1.

t = Time component has been leaking (default value is time from last screening) (hours/screening period).

(C) For components where the screening value, corrected for background, is greater than or equal to 10,000 ppmv, calculate VOC emissions using Equation 300-5 and the appropriate default factors from Table 300-1:

$$E_{VOCP} = \sum_{i=1}^{6} CC_i \times PF_{iP} \times t$$ **Equation 300-5**

Where:

E_{VOCP} = Emissions from components with screening values, corrected for background, greater than or equal to 10,000 ppmv (kg/screening period).

i = Component type (1=valve, 2=pump seal, 3=others, 4=connector, 5=flange, 6=open-ended line).

CC_i = Number of *i* components with screening values greater than 9,999 ppmv.

PF_{iP} = VOC emission factor for component type *i* pegged over 9,999 ppmv from Table 300-1 (kg/hr).

t = Time component has been leaking (default value is time since last screening) (hours/screening period).

(3) Calculate CH_4 emissions using Equation 300-6 and either a default factor of 0.6 for CF_{VOC} or a site-specific conversion factor calculated from the composition and methane content of the gas.

$$CH_4 = \sum_{1}^{n} (E_{VOC-0} + E_{VOC-LC} + E_{VOCP})_n \times CF_{VOC} \times 0.001 \qquad \textbf{Equation 300-6}$$

Where:

CH_4	=	CH_4 emissions (metric tons/year).
n	=	Number of screenings/year.
E_{VOC-0}	=	Emissions from components with a screening value equal to zero, when corrected for background (kg/screening period).
E_{VOC-LC}	=	Emissions from components with screening values, corrected for background, between 0 and 10,000 (kg/screening period).
E_{VOCP}	=	Emissions from components with screening values, corrected for background, greater than or equal to 10,000 ppmv (kg/screening period).
CF_{VOC}	=	VOC to CH_4 conversion factor (default $CF_{VOC} = 0.6$).
0.001	=	Conversion factor (kg to metric tons).

WCI.304 Monitoring Requirements

(a) Flares and Other Oxidizers. You must measure:

(1) The volume of each gas destroyed annually determined to an accuracy of ± 5 percent.
(2) The carbon content and molecular weight of each gas quarterly using the methods specified in WCI.25 and calculate the annual average values for carbon content and molecular weight for each gas destroyed.

(b) Process **Vents.** You must measure the following parameters for each process vent, using methods that comply with the measurement accuracy provisions in WCI.2(g):

(1) The gas flow rate for each venting event.
(2) The molar fraction of CO2, N2O, and CH4 in the vent gas stream during each venting event.
(3) The duration of each venting event.

(c) **Equipment Leaks.** You must screen each valve, pump seal, connector, flange, and open-ended line used in natural gas, fuel gas, and off-gas systems using the methods specified in CAPCOA (1999) Method 3: Correlation Equation Method and an instrument capable of detecting methane. Screenings must be performed at the frequency interval required by [*insert jurisdiction*]. The instrumentation used for screening must be capable of detecting methane.

(d) **Feedstock Consumption.** You must measure the feedstock consumption using methods that comply with the measurement accuracy provisions in WCI.2(g).

Table 300-1. Fugitive Emissions from Gas Service Components			
Component Type / Service Type	**Default Zero Factor (kg/hr)**	**Correlation Equation (kg/hr)**	**Pegged Factor (kg/hr)**
	(SV = 0) Zf_{i0}	**(SV > 0 and < 10,000)** σ_i **and** β_i	**(SV ≥ 10,000)** PF_{iP-10}
Valves	7.8×10^{-6}	$2.27 \times 10^{-6}(SV)^{0.747}$	0.064
Pump seals	1.9×10^{-5}	$5.07 \times 10^{-5}(SV)^{0.622}$	0.089
Others[a]	4.0×10^{-6}	$8.69 \times 10^{-6}(SV)^{0.642}$	0.082
Connectors	7.5×10^{-6}	$1.53 \times 10^{-6}(SV)^{0.736}$	0.030
Flanges	3.1×10^{-7}	$4.53 \times 10^{-6}(SV)^{0.706}$	0.095
Open-ended lines	2.0×10^{-6}	$1.90 \times 10^{-6}(SV)^{0.724}$	0.033

[a] The "other" component type should be applied to any component type other than connectors, flanges, open-ended lines, pump seals, or valves. The "other" component type includes: instruments, loading arms, pressure relief valves, vents, compressors, dump lever arms, diaphragms, drains, hatches, meters, and polished rods stuffing boxes.

Attachment 7: Pulp and Paper

§ WCI.210 PULP AND PAPER MANUFACTURING

§ WCI.211 Source Category Definition

The pulp and paper manufacturing source category consists of facilities that produce pulp either at stand-alone pulp facilities or integrated pulp and paper mills.

§ WCI.212 Greenhouse Gas Reporting Requirements

In addition to the information required by WCI.3, the annual emissions report must contain the following information:

(a) Annual CO_2 process emissions from all recovery furnaces and kilns in metric tons, as specified in WCI.213.

(b) CO_2, N_2O, and CH_4 emissions from stationary combustion units in metric tons, as specified in WCI.23.

(c) Annual consumption of carbonate in metric tons.

(d) Annual black liquor production in metric tons.

(e) Under consideration: Annual N_2O, and CH_4 emissions from onsite wastewater treatment plants in metric tons, as specified in WCI.200(g).

§ WCI.213 Calculation of GHG Emissions

(a) You must calculate CO_2 process emissions from recovery furnaces and kilns using Equation 210-1:

$$CO_2 = \sum_{i=1}^{12} [(BL_i \times CC_i) + (\sum_{j=1}^{n} RM_j \times EF_j)_i] \qquad \textbf{Equation 210-1}$$

Where:

CO_2 = CO_2 process emissions from recovery furnaces and kilns (metric tons/year).
BL_i = Black liquor produced in month i (metric tons/month).
CC_i = Carbon content of the black liquor (percent by weight expressed as a decimal fraction).
RM_j = Amount of carbonate j consumed in month i (metric tons/month).
EF_j = Carbon content of carbonate material j for month i (percent by weight, expressed as a decimal fraction).
3.664 = Ratio of molecular weights, CO_2 to carbon.

WCI.214 Monitoring Requirements

Note: The sampling, analysis, and measurement procedures will be standardized for each calculation input to reduce variation between facilities within the pulp and paper industry. Material sampling frequency and technique is distinct from material analysis conducted in a laboratory. The WCI is seeking stakeholder feedback on this topic and is specifically interested in proposals from stakeholders with expertise in this industry related to sampling, analysis and measurement procedures already in use at these facilities for the material quantities and/or concentrations listed below. Those proposing procedures should include sampling frequency and technique, indicate the uncertainty associated with the procedures, and describe the application of the procedure at a facility.

(a) Measure the quantity of black liquor produced each month using methods that comply with the measurement accuracy provisions in WCI.2(g)

(b) Collect monthly samples of black liquor and analyze each sample for carbon content using ASTM [*To be determined*].

(c) For the amount of carbonate material consumed, you must either use records provided by the material supplier or monitor carbonate material consumption using methods that comply with the measurement accuracy provisions in WCI.2(g).

(d) For the carbon content of each carbonate material consumed, you must either use carbon content data provided by the supplier or collect monthly samples of each carbonate material consumed and analyze each sample for carbonate content using ASTM [*To be determined*].

Attachment 8: Soda Ash Production

§ WCI.230 SODA ASH PRODUCTION

§ WCI.231 Source Category Definition

The soda ash production source category consists of facilities that produce soda ash by calcining sodium carbonate bearing ore or brine.

§ WCI.232 Greenhouse Gas Reporting Requirements

In addition to the information required by WCI.3, the annual emissions report must contain the following information:

(a) Annual CO_2 process emissions from all soda ash calcining kilns combined, as specified in WCI.233 (metric tons).

(b) CO_2, N_2O, and CH_4 emissions from combustion of fuels in the calcining kilns, as specified in WCI.20 (metric tons).

(c) Annual consumption of trona ore or sodium carbonate-rich brine (metric tons).

(d) Annual soda ash production (metric tons).

(e) Annual mass of waste material output from calcining kilns (metric tons).

(f) For plants recycling the CO_2 generated from calcination for use in the carbonation towers, report annual CO_2 recycled within the process (metric tons).

§ WCI.233 Calculation of GHG Emissions

(a) You must calculate CO_2 emissions using the methods in either paragraphs (a)(1) or (a)(2) of this section.

(1) **Continuous Emission Monitoring Systems.** The owner or operator may measure CO_2 emissions using CEMS, as specified WCI.23(d).

(2) **Feedstock Material Balance.** The owner or operator may estimate CO_2 process emissions using Equation 230-1 and the measured carbon content and feedstock input of the trona ore or carbonate-rich brine.

$$CO_2 = \sum_{j=1}^{12} (3.664)[(Ci_j \times Ti_j) - (Cs_j \times Ts_j) - (Cw_j \times Tw_j)]$$

Equation 230-1

Where:

CO_2 = CO_2 process emissions from soda ash production (metric tons/year).
Ci_j = Carbon content of feedstock (trona ore or carbonate-rich brine) input (percent by weight, expressed as a decimal fraction).
Ti_j = Weight of feedstock (trona ore or carbonate-rich brine) input (metric tons/month).
Cs_j = Carbon content of soda ash output (percent by weight, expressed as a decimal fraction).
Ts_j = Weight of soda ash output (metric tons/month).
Cw_j = Carbon content of waste material output from the kiln (i.e. kiln dust collected in control devices and not combined with the soda ash product) (percent by weight, expressed as a decimal fraction).
Tw_j = Weight of waste material output from the kiln (i.e. kiln dust collected in control devices and not combined with the soda ash product) (metric tons/month).
3.664 = Ratio of molecular weights, CO_2 to carbon.

(b) If you operate a soda ash production facility in which CO_2 generated in calcining kilns is recycled to carbonate towers for brine pre-treatment, you must calculate recycled CO_2 using Equation 230-2.

$$CO_2 = \sum_{j=1}^{12} (3.664)[(Cb_j \times Tb_j) - (Ci_j \times Ti_j)] \qquad \textbf{Equation 230-2}$$

Where:

CO_2 = Recycled CO_2 from the ore calcining kiln (metric tons/year).
Ci_j = Carbon content of ore input (percent by weight, expressed as a decimal fraction).
Ti_j = Weight of ore input (metric tons/month).
Cb_j = Carbon content of sodium carbonate-rich brine input (percent by weight, expressed as a decimal fraction).
Tb_j = Weight of sodium carbonate-rich brine input (metric tons/month).
3.664 = Ratio of molecular weights, CO_2 to carbon.

WCI.234 Monitoring Requirements

Owners and operators using the mass balance method must comply with the following monitoring requirements:

(a) Measure the quantity of ore, soda ash, waste material, and carbonate-rich brine (as applicable) by direct measurement using the same instruments used for accounting purposes.

(b) Collect monthly samples of ore, soda ash, waste material, and carbonate-rich brine (as applicable) and analyze each sample for carbon content. For the carbon content of the brine ore and carbonate-rich brine, use a total organic carbon analyzer according to the ultraviolet light/chemical (sodium persulfate) oxidation method in ASTM D4839-03. Use method ASTM E359-00(2005) for the carbon content of trona ore, soda ash, and waste material.

Western Climate Initiative

Attachment 1: General Provisions

(UNDERLINE/STRIKEOUT VERSION SHOWING CHANGES FROM JANUARY 6, 2009 RELEASE, FOLLOWED BY INTEGRATED VERSION)

GENERAL PROVISIONS

§ WCI.0 PURPOSE

§ WCI.1 APPLICABILITY

§ WCI.2 GENERAL GREENHOUSE GAS REPORTING REQUIREMENTS AND SCHEDULE

§ WCI.3 CONTENTS OF THE GREENHOUSE GAS EMISSIONS REPORT

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§ WCI.0 PURPOSE

This rule requires mandatory reporting and verification of greenhouse gas (GHG) emissions data by certain facilities that directly emit GHG, by importers of electricity, and by suppliers of fossil fuels. The GHGs that must be reported under this rule are carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFC), perfluorocarbons (PFC), and sulfur hexafluoride (SF_6).

§ WCI.1 APPLICABILITY

(a) The GHG emissions reporting requirements, and related monitoring, recordkeeping, and verification requirements of this rule apply to the owners and operators *[Each jurisdiction will select the specific terminology for the regulated persons in accordance with their customary rule-writing practices]* of any facility that meets the requirements of paragraph (a)(1) of this section; and any fuel suppliers and electricity importers that meet the requirements of paragraph (a)(2), (a)(3), or (a)(4) of this section:

(1) Any facility that emits 10,000 metric tons CO_2e or more per year in combined emissions from one or more of the source categories listed in this paragraph in any calendar year starting in 2010.

[Please note that the quantification and monitoring methods for many of these source categories are currently being assessed. Only source categories for which adequate quantification methods exist will be included in the final WCI Essential Requirements for mandatory reporting.]

Adipic acid manufacturing
Aluminum manufacturing
Ammonia manufacturing [*still being assessed*]
Carbon dioxide transfer recipients [*still being assessed*]
Cement manufacturing
Coal mine fugitive emissions (active and abandoned)
Coal storage
Cogeneration [*still being assessed*]
Electricity generation
Electronics Manufacturing [*still being assessed*]
Ferroalloy production [*still being assessed*]
General stationary fuel combustion
Glass Production and other uses of carbonates [*still being assessed*]
HCFC-22 production [*still being assessed*]
Hydrogen production
Industrial wastewater *[still being assessed for some industries]*
Iron and steel manufacturing
Lead production
Lime manufacturing
Magnesium production *[still being assessed]*
Natural gas transmission and distribution systems *[still being assessed]*
Nitric acid manufacturing *[still being assessed]*
Nonroad equipment at facilities *[still being assessed]*

Oil and gas production & gas processing *[still being assessed]*
Petrochemical production
Petroleum refineries
Phosphoric acid production *[still being assessed]*
Pulp and paper manufacturing
Refinery fuel gas
SF_6 from electrical equipment *[still being assessed]*
Soda ash manufacturing
Zinc production

(2) All importers of electricity. Importers of electricity include both retail providers and marketers that import electricity into the WCI region. *[This is preliminary language, pending definition of electricity importers by another WCI Committee.]*

(3) Any supplier that within the WCI region distributes transportation fuels in quantities that when combusted would emit 10,000 metric tons CO_2e per year or more in any calendar year starting in 2010. *[This is preliminary language, pending future determination of point of regulation for transportation fuels.]*

(4) Any supplier that distributes within the WCI region residential, commercial, and industrial fuels in quantities that when combusted would emit 10,000 metric tons CO_2e per year or more in any calendar year starting in 2010. *[This is preliminary language, pending future determination of points of regulation for these fuels.]*

(b) To calculate GHG emissions for comparison to the 10,000 metric ton CO_2e per year emission threshold in paragraph (a)(1) of this section, the owner or operator shall calculate annual CO_2e emissions, as described in paragraphs (b)(1) through (b)(4) of this section.

(1) Estimate the annual emissions of CO_2, CH_4, N_2O, HFC, PFC, and SF_6 in metric tons for each unit, process, activity, or operation for which emission calculation methodologies are provided in sections WCI.20 through WCI.XX. The GHG emissions shall be calculated using methodologies specified in each applicable section.

(2) For stationary combustion units, carbon dioxide emissions from the combustion of biomass fuels shall be included in the calculations, with the following exceptions:

(A) Until such time as [jurisdiction] has made a determination regarding the carbon neutrality of any biomass fuels, a maximum of 15,000 metric tons of carbon dioxide emissions from the combustion of pure solid biomass fuel may be excluded from calculation of GHG emissions for comparison to the 10,000 metric ton CO_2e per year emission threshold in paragraph (a)(1) of this section, provided that total GHG emissions including emissions from solid biomass fuel are less than 25,000 metric tons CO_2e.

(B) After such time as [jurisdiction] has made a determination regarding the carbon neutrality of any biomass fuels, the carbon dioxide emissions from the combustion of those fuels may be excluded from calculation of GHG emissions for determining whether the 10,000 metric tons CO_2e per year emission threshold in paragraph (a)(1) of this section has been met.

[A WCI Partner jurisdiction may, in its discretion, choose to require carbon dioxide emissions from the combustion of biomass fuel to be included in the determination of stationary combustion units that are required to report and may require that those emissions be reported separately from emissions from fossil fuels.]

[WCI is also considering a deduction of biomass fuel combustion emissions that have occurred within a jurisdiction that has deemed them to be carbon neutral from the determination of whether the verification threshold has been met and from the scope of the verification.]

(3) Sum the total facility emissions for each GHG and calculate the metric tons of CO_2e using equation 1-1 below.

$$CO_2e = \sum_{i=1}^{n} GHG_i \times \mathrm{GWP}_i \qquad \textbf{Equation 1-1}$$

Where:

CO_2e = Carbon dioxide equivalent, metric tons/year.

GHG_i = Mass emissions of each greenhouse gas emitted, metric tons/year.

GWP_i = Global warming potential for each greenhouse gas from Table WCI.10-1 of this regulation.

n = The number of greenhouse gases emitted.

(4) For purpose of determining if an emission threshold has been exceeded, any CO_2 that is captured for on-site use, on-site storage, or transfer off-site must be included in the emissions total.

(c) To calculate GHG emissions for comparison to the 10,000 metric ton CO_2e per year emission threshold for suppliers of transportation fuels in paragraphs (a)(3) of this section, the owner or operator shall follow the procedures of paragraphs (c)(1) through (c)(2) below:

(1) Calculate the total mass in metric tons per year of CO_2, CH_4, and N_2O that would result from the complete combustion or oxidation of all transportation fuels that are distributed within the WCI region. The mass of each GHG shall be calculated using any of the applicable methodologies specified in section WCI.XX [Transportation Fuels Combustion] of this rule.

(2) Sum the emissions of each GHG and calculate total metric tons of CO_2e using Equation 1-1 of this rule.

(d) To calculate GHG emissions for comparison to the 10,000 metric ton CO_2e per year emission threshold for suppliers of residential, commercial, and industrial fuels in paragraph (a)(4) of this section, the owner or operator shall follow the procedures of paragraphs (d)(1) and (d)(2) below:

(1) Calculate the total mass in metric tons per year of CO_2, CH_4, and N_2O that would result from the complete combustion or oxidation of all residential, commercial, and industrial fuels that are distributed within the WCI region. The calculation shall exclude any fuels that are supplied to facilities that are required to report GHG emissions under section WCI.1(a)(1). *[These accounting issues will be dealt with in 2009.]* The mass of each GHG shall be calculated using any of the applicable methodologies specified in section WCI.XX [Residential, Commercial and Industrial Fuels Combustion] of this rule.

(2) Sum the emissions of each GHG and calculate total metric tons of CO_2e using Equation 1-1 of this rule.

(e) If the operations of a facility or fuel supplier that is subject to this rule change such that emissions fall below 10,000 metric tons CO_2e per year, then the following reporting requirements shall apply:

(1) If, prior to such emission reduction, the emissions report was subject to the verification requirements of this rule; then the owner or operator shall continue to submit ~~verified~~ emission reports until reported emissions are below 10,000 metric tons CO_2e per year for a minimum of 3 consecutive years. If reported emission are less than 10,000 metric tons CO_2 per year during 3 consecutive years, then the owner or operator shall be exempted from further reporting until CO_2e emissions again exceed 10,000 metric tons in any future calendar year.

(2) If, prior to such emission reduction, the emissions report was not subject to the verification requirements of this rule; then the owner or operator shall submit to the *[jurisdiction]* a signed statement certifying that emissions are less than 10,000 metric tons CO_2e during the prior year. After certifying that emissions are below 10,000 metric tons CO_2e per year for 3 consecutive years, the owner or operator shall be exempted from further reporting until CO_2e emissions again exceed 10,000 metric tons in any future calendar year.

(3) Notwithstanding the requirements of paragraphs (e)(1) and (2) of this section, a facility or fuel supplier that is ~~subject to an emissions limitation~~ <u>a covered entity</u> under the WCI cap-and-trade program must continue to submit ~~verified~~ annual <u>emissions</u> reports.

(f) Upon request by the [*jurisdiction*], owner or operator of any facility or fuel supply operation must submit a demonstration that emissions have not exceeded one or more of the applicability criteria specified in this section in any year since 2010. Such demonstration shall be provided to the [*jurisdiction*] within 20 working days of receipt of a written request. *[WCI is considering whether this and other deadlines for responses provide sufficient time, and whether such deadlines should be standardized across requirements.]*

§ WCI.2 GENERAL GREENHOUSE GAS REPORTING REQUIREMENTS AND SCHEDULE

[Specific requirements of this section may change based on the future final design of the marketing trading program.]

(a) General. Owners or operators that are subject to this rule must submit an annual GHG emissions report. Owners and operators must collect data; calculate GHG emissions; and follow the procedures for quality assurance, missing data, recordkeeping, and reporting as specified in these General Provisions and in each relevant section WCI.20 through WCI.XX of this rule.

(1) A facility, fuel supplier, or electricity importer that commenced operation before January 1, 2010, must report emissions beginning in 2011 for GHGs emitted in calendar year 2010.

(2) A new facility, fuel supplier, or electricity importer that commences operation on or after January 1, 2010, must report emissions for the first calendar year in which the facility operates, beginning with the first operating month and ending on December 31 of that year. Each subsequent annual report must cover emissions for the calendar year, beginning on January 1 and ending on December 31.

(b) Reporting and Verification Schedule.

(1) Annual GHG emissions reports must be submitted to [*the jurisdiction*] by April 1 of each year for emissions in the previous calendar year.

(2) Reporters subject to the verification requirements of WCI.8, must complete their verification process, including submittal of a verification statement to [*the jurisdiction*], according to the following schedule:

(A) For reporting years 2010 through 2011, September 1 of the year following the reporting year.

(B) For reporting years 2012 and later, *[date to be determined]*.

(c) Submission of GHG Emissions Report. The annual GHG emissions report must be submitted to [*the jurisdiction*] in a format [*to be specified by each jurisdiction*].

(d) Simplified Emission Calculation Methods for De Minimis Sources. The owner or operator may elect to designate as de minimis one or more sources or pollutants that collectively emit no more than 3 percent of the facility's total CO_2e emissions, but not to exceed 20,000 metric tons CO_2e. The owner or operator may estimate emissions for these de minimis sources using alternative methods to those required to be used by this rule. If verification of the emissions report is required by this rule, then the selection of any alternative GHG calculation method is subject to the concurrence of the verification team that the use of such methods provides reasonable assurance that the emissions so designated do not exceed the applicable de minimis limits. The operator shall separately identify and include in the emissions data report the emissions from designated de minimis sources.

(e) To ensure accuracy of reported data and the ability to conduct audits and/or verifications of each emissions data report, the owner or operator shall establish and maintain data acquisition and handling activities that provide for the transparency and verifiability of emissions calculations and supporting information consistent with section WCI.4 . *[As a means of assuring a smooth verification process and a positive verification opinion WCI jurisdictions may also require or advise in guidance materials that facilities have a full GHG inventory management plan.]* ~~GHG Inventory Management Plan. The owner or operator shall prepare and follow a written GHG inventory management plan that ensures that the emissions calculations and other information that is required to be reported under this rule are transparent, accurate, and independently verifiable. The owner or operator shall establish, document, implement, and maintain data acquisition and handling activities for the calculation and reporting of GHG emissions. Such activities shall include measuring, monitoring, analyzing, recording, processing and calculating the parameters specified by this rule. The owner or operator shall implement systems of internal audit, quality assurance, and quality control for the reporting program and the data reported.~~

(f) GHG Emissions Report Revisions.

(1) The owner or operator shall maintain documentation to support any revisions made to a previously submitted annual GHG emissions report. Documentation for all revisions shall be retained by the operator for 7 years.

(2) If, after the verification deadline, a report subject to verification is found to contain an error, or accumulation of errors, greater than 5 percent of the total CO_2e emissions reported, the owner or operator shall revise and resubmit an annual GHG emissions report

within 60 days of the finding. To the extent possible, the revised report must correct all identified errors. A revised report will be accepted only if verified according to WCI.8 and approved by [*the jurisdiction*]. <u>[The jurisdiction] will send notification of approval or disapproval and an explanation of the reasons for any disapproval within 60 days of receipt of the revised report.</u>

(3) If, after the report submittal deadline, a report not subject to verification is found to contain an error, or accumulation of errors, greater than 5 percent of the total CO_2e emissions reported, the owner or operator shall revise and resubmit an annual GHG emissions report within 30 days of the finding. To the extent possible, the revised report must correct all identified errors. A revised report will be accepted only if approved by [*the jurisdiction*]. <u>[The jurisdiction] will send notification of approval or disapproval and an explanation of the reasons for any disapproval within 60 days of receipt of the revised report.</u>

(4) An owner or operator that voluntarily chooses to correct errors of 5 percent or less in total CO_2e emissions reported may do so according to the following requirements:

(A) For reports subject to verification, a revised report will be accepted only if verified according to WCI.8 and approved by [*the jurisdiction*].

(B) For reports not subject to verification, a revised report will be accepted if approved by [*the jurisdiction*].

~~(g) Fuel Use Measurement Accuracy. The operator shall use procedures to quantify fuel use (mass or volume flow) that provide data with an accuracy within ±5 percent. All fuel use measurement devices shall be maintained and calibrated in a manner and at a frequency required to maintain this level of accuracy. The operator shall make available to the verification team documentation to support this level of accuracy. The operator who measures solid fuels shall validate fuel consumption estimates with belt or conveyor scale calibrations conducted at least quarterly, and retain record of such calibrations.~~

(g) Where this rule specifies a choice between use of a fuel-based or mass balance-based calculation or use of a continuous emissions monitoring system (CEMS) to calculate CO_2 emissions, the operator shall make this choice and continue to use the method chosen for all future emissions data reports, unless the use of the alternative calculation method is approved in advance by *[the jurisdiction]*.

§ WCI.3 CONTENTS OF THE GREENHOUSE GAS EMISSIONS REPORT

Each annual GHG emissions report shall contain the following information:

(a) Facility name, identification number, physical address, mailing address, and NAICS code.

(b) Reporting year.

(c) Date of report submittal.

(d) Total facility emissions aggregated from all applicable source categories in subparts WCI.20 through WCI.XX expressed in metric tons of CO_2e calculated using Equation 1-1 of section WCI.1, excluding emissions from CO_2 that is captured and CO_2 emissions from the combustion of biomass and biomass-derived fuels, which are reported separately.

(e) Total facility emissions of CO_2 from the combustion of biomass and biomass-derived fuels.

(f) Total annual mass of CO_2 captured for on-site use, on-site storage, or transfer off site, in metric tons.

(g) For applicable fuel supplier categories in subparts WCI.XX [Transportation Fuels Combustion] and WCI.XX [Residential, Commercial and Industrial Fuels Combustion], total CO_2e emissions aggregated from all specified fuels.

(h) Emissions from each applicable source category or fuel supplier category in subparts WCI.20 through WCI.XX, expressed in metric tons per year of CO_2, CH_4, N_2O, HFC, PFC, and SF_6. CO_2 emissions from the combustion of biomass and biomass-derived fuels shall be reported separately.

(i) For electricity importers, the information required by WCI.XX [Electricity Imports].

(j) Emissions and other data for individual units, processes, activities, and operations as specified for each source category in sections WCI.20 through WCI.XX of this rule.

(k) <u>Emission factors developed or measured by the operator using approved source testing as provided under sections WCI.20 through WCI.XXX. Emission factors shall be provided in units of emissions per amount of fuel consumed, where fuel is reported in the units specified in this regulation.</u>

(l) Mass emissions from each designated de minimis source or pollutant, reported in metric tons per year of each GHG for which an alternative emission calculation method is used.

(m) Name and contact information including e-mail address and telephone number of the person primarily responsible for preparing and submitting the emissions report.

(n) <u>[only applicable in United States jurisdictions]</u> A signed and dated statement provided by the owner or operator, or their designated representative, certifying that the report has been prepared in accordance with this rule and that, subject to verification, the statements and information contained in the emissions data report are true, accurate, and complete to the best of their knowledge.

(o) <u>[only applicable in Canadian jurisdictions] A statement signed and dated by the operator's representative, certifying that:</u>

   (1) <u>the operator's representative has examined the emissions report and ensured that it is complete and accurate, and</u>

   (2) <u>the emissions report has been prepared in accordance with this rule and that the statements and information contained in the emissions report are true and fair to the best of the knowledge of the operator's representative.</u>

§ WCI.4 DOCUMENT RETENTION AND RECORD KEEPING REQUIREMENTS

(a) The operator shall establish and maintain procedures for document retention and record keeping. The operator shall retain all documents regarding the design, development and maintenance of the GHG inventory in paper, electronic or other usable format for a period of not less than 7 years following submission of each emissions data report. The retained documents, including GHG emissions data, shall be sufficient to allow for the verification of each emissions data report.

(b) Upon request by *[jurisdiction]*, the operator shall provide within 10 working days all documents and data used to develop an emissions data report.

(c) In addition to information submitted as part of the emissions data report, each operator shall retain, at a minimum, the following information, if applicable, for at least 7 years after the submission of the report:

(1) A list of all GHG sources (i.e., units, operations, processes, and activities) included in the emission estimates.
(2) All ~~data~~ records and documents used to calculate emissions for each source, categorized by process and fuel or material type.
(3) Documentation of the process for collecting emissions data.
(4) Any GHG emissions calculations and methods used;
(5) All emission factors used for emission estimates, including documentation for any factors not provided in the rule.
(6) All input data used for emission estimates.
(7) Documentation of biomass fractions for specific fuels.
(8) All other data submitted to the [*jurisdiction*] under this rule, including the GHG emissions report.
(9) All computations made to gap-fill missing data.
(10) Names and documentation of key facility personnel involved in emissions calculating and reporting;
(11) Any other information that is required for the verification of the GHG emissions report.
(12) A log to be prepared for each reporting year, beginning January 1, documenting all procedural changes made in GHG accounting methods and changes to instrumentation for GHG emissions estimation.
(13) The GHG inventory data audit trail, data control policies and procedures, and supporting documentation. ~~A copy of the GHG Inventory Management Plan~~.

(d) For measurement based methodologies, the following information, if applicable,also must be retained for at least 7 years after the submission of the emissions data report:

(1) List of all emission points monitored.
(2) Collected monitoring data.
(3) Quality assurance and quality control information collected ~~under the GHG Inventory Management Plan required by section WCI.2~~ for the WCI.2(e) data audit trail and data controls section of this rule.
(4) A detailed technical description of the continuous measurement system, including documentation of any findings and approvals by federal, State or local agencies.
(5) Raw and aggregated data from the continuous measurement system.
(6) A log book of all system down-times, calibrations, servicing, and maintenance of the continuous measurement system.
(7) Documentation of any changes in the continuous measurement system over time.

§ WCI.5 COMPLIANCE AND ENFORCEMENT

(a) Submission of false or misleading information to the *[jurisdiction]* or a verification body shall constitute a single, separate violation of the requirements of this article for each day after the information has been received by the Executive Officer or verification body.

[Partners must be able to enforce this provision in the absence of evidence of intent, e.g., strict or absolute liability, depending on the jurisdiction.] ~~Knowing submission of false information to the *[jurisdiction*] or a verification body, shall constitute a single, separate violation of the requirements of this article for each day after the information has been received by the [*jurisdiction*].~~

(b) Each violation of this rule shall constitute a single, separate violation for each day the violation continues ~~beyond the specified reporting date. A violation includes failure to submit any report, failure to collect data needed to calculate GHG emissions, failure to monitor and test as required, failure to calculate GHG emissions following the methodologies specified in this rule, failure to retain required records, failure to provide all information required in the report, and failure to submit a report on time. For the purposes of this rule, "report" means any GHG emissions data report, verification statement, or other document required to be submitted by this rule~~.

§ WCI.6 INCORPORATION BY REFERENCE

The following documents are incorporated by reference into this rule. These materials are incorporated as they exist on the date this article is adopted.

(a) ~~American Society for Testing and Materials (ASTM) D1826-94 (Reapproved 2003), ASTM D3588-98 (Reapproved 2003), ASTM D4891-89 (Reapproved 2006), ASTM D240-02 (Reapproved 2007), ASTM D4809-00 (Reapproved 2005), ASTM 5373-02 (Reapproved 2007), ASTM D5291-02 (Reapproved 2007), ASTM D3238-95 (Reapproved 2005), ASTM D2502-04, ASTM D2503-92 (Reapproved 2002), ASTM D1945-03, ASTM D1946-90 (Reapproved 2006), ASTM D6866-06a, ASTM D388-05, ASTM D5468-02 (Reapproved 2007), ASTM D240-87 (Reapproved 1991), ASTM D5865-07a, ASTM Specification D396-07, ASTM Specification D975-07b~~.

(a) The following materials are available for purchase from the following addresses: American Society for Testing and Material (ASTM), 100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428-B2959; and the University Microfilms International, 300 North Zeeb Road, Ann Arbor, Michigan 48106:

(1) ASTM D240-02, (Reapproved 2007), Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter.
(2) ASTM D388-05, Standard Classification of Coals by Rank.
(3) ASTM D396-08, Standard Specification for Fuel Oils.
(4) ASTM D975-08, Standard Specification for Diesel Fuel Oils.
(5) ASTM D1250-07, Standard Guide for Use of the Petroleum Measurement Tables.
(6) ASTM D1826-94 (Reapproved 2003), Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter.
(7) ASTM Specification D1835-05 (2005).
(8) ASTM D1945-03 (Reapproved 2006), Standard Test Method for Analysis of Natural Gas by Gas Chromatography.
(9) ASTM D1946-90 (Reapproved 2006), Standard Practice for Analysis of Reformed Gas by Gas Chromatography.
(10) ASTM D2013-07, Standard Practice of Preparing Coal Samples for Analysis.
(11) ASTM D2234/D2234M-07, Standard Practice for Collection of a Gross Sample of Coal.

(12) ASTM D2502-04 (Reapproved 2002), Standard Test Method for Estimation of Molecular Weight (Relative Molecular Mass) of Petroleum Oils from Viscosity Measurements.
(13) ASTM D2503-92 (Reapproved 2007), Standard Test Method for Relative Molecular Mass (Relative Molecular Weight) of Hydrocarbons by Thermoelectric Measurement of Vapor Pressure.
(14) ASTM D2880-03, Standard Specification for Gas Turbine Fuel Oils.
(15) ASTM D3176-89 (Reapproved 2002), Standard Practice for Ultimate Analysis of Coal and Coke.
(16) ASTM D3238-95 (Reapproved 2005), Standard Test Method for Calculation of Carbon Distribution and Structural Group Analysis of Petroleum Oils by the n-d-M Method.
(17) ASTM D3588-98 (Reapproved 2003), Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels.
(18) ASTM Specification D3699-07, Standard Specification for Kerosene.
(19) ASTM D4057-06, Standard Practice for Manual Sampling of Petroleum and Petroleum Products.
(20) ASTM D4809-06, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method).
(21) ASTM Specification D4814-08a, Standard Specification for Automotive Spark-Ignition Engine Fuel.
(22) ASTM D4891-89 (Reapproved 2006), Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion.
(23) ASTM D5291-02 (Reapproved 2007), Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants.
(24) ASTM D5373-08, Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal and Coke.
(25) ASTM D5865-07a, Standard Test Method for Gross Calorific Value of Coal and Coke.
(26) ASTM D6316-04, Standard Test Method for the Determination of Total, Combustible and Carbonate Carbon in Solid Residues from Coal and Coke.
(27) ASTM D6866-06a, Standard Test Methods for Determining the Biobased Content of Natural Range Materials Using Radiocarbon and Isotope Ratio Mass Spectrometry Analysis.
(28) ASTM E1019-03, Standard Test Methods for Determination of Carbon, Sulfur, Nitrogen, and Oxygen in Steel and in Iron, Nickel, and Cobalt Alloys.
(29) ASTM E1915-07a, Standard Test Methods for Analysis of Metal Bearing Ores and Related Materials by Combustion Infrared-Absorption Spectrometry.
(30) ASTM CS-104 (1985), Carbon Steel of Medium Carbon Content.
(31) ASTM D 7459-08, Standard Practice for Collection of Integrated Samples for the Speciation of Biomass (Biogenic) and Fossil-Derived Carbon Dioxide Emitted from Stationary Emissions Sources.
(32) ASTM D6060-96(2001) Standard Practice for Sampling of Process Vents With a Portable Gas Chromatograph.
(33) ASTM D 2502-88(2004)e1 Standard Test Method for Ethylene, Other Hydrocarbons, and Carbon Dioxide in High-Purity Ethylene by Gas Chromatography.
(34) ASTM C25-06 Standard Test Method for Chemical Analysis of Limestone, quicklime, and Hydrated Lime.
(35) UOP539-97 Refinery Gas Analysis by Gas Chromatography.

(36) ASTM D5468-02 (Reapproved 2007).

(b) The following materials are available for purchase from the American Society of Mechanical Engineers (ASME), 22 Law Drive, P.O.Box 2900, Fairfield, NJ 07007-2900:

(1) ASME MFC-3M-2004, Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi.
(2) ASME MFC-4M-1986 (Reaffirmed 1997), Measurement of Gas Flow by Turbine Meters.
(3) ASME-MFC-5M-1985, (Reaffirmed 1994), Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters.
(4) ASME MFC-6M-1998, Measurement of Fluid Flow in Pipes Using Vortex Flowmeters.
(5) ASME MFC-7M-1987 (Reaffirmed 1992), Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles.
(6) ASME MFC-9M-1988 (Reaffirmed 2001), Measurement of Liquid Flow in Closed Conduits by Weighing Method.

(c) The following materials are available for purchase from the American National Standards Institute (ANSI), 25 West 43rd Street, Fourth Floor, New York, New York 10036:

(1) ISO 8316: 1987 Measurement of Liquid Flow in Closed Conduits- Method by Collection of the Liquid in a Volumetric Tank.
(2) ISO/TR 15349-1:1998, Unalloyed steel-Determination of low carbon content. Part 1: Infrared absorption method after combustion in an electric resistance furnace (by peak separation).
(3) ISO/TR 15349-3: 1998, Unalloyed steel-Determination of low carbon content. Part 3: Infrared absorption method after combustion in an electric resistance furnace (with preheating).

(d) The following materials are available for purchase from the following address: Gas Processors Association (GPA), 6526 East 60th Street, Tulsa, Oklahoma 74143:

(1) GPA Standard 2172-96, Calculation of Gross Heating Value, Relative Density and Compressibility Factor for Natural Gas Mixtures from Compositional Analysis.
(2) GPA Standard 2261-00, Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography.

(e) The following American Gas Association materials are available for purchase from the following address: ILI Infodisk, 610 Winters Avenue, Paramus, New Jersey 07652:

(1) American Gas Association Report No. 3: Orifice Metering of Natural Gas, Part 1: General Equations and Uncertainty Guidelines (1990), Part 2: Specification and Installation Requirements (1990).
(2) American Gas Association Transmission Measurement Committee Report No. 7: Measurement of Gas by Turbine Meters (2006).

(f) The following materials are available for purchase from the following address: American Petroleum Institute, Publications Department, 1220 L Street, NW., Washington, DC 20005-4070:

(1) American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 3- Tank Gauging:

(A) Section 1A, Standard Practice for the Manual Gauging of Petroleum and Petroleum Products, Second Edition, August 2005.

(B) Section 1B-Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Tanks by Automatic Tank Gauging, Second Edition June 2001 (Reaffirmed, October 2006).

(C) Section 3-Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Pressurized Storage Tanks by Automatic Tank Gauging, First Edition June 1996 (Reaffirmed, October 2006).

(2) Shop Testing of Automatic Liquid Level Gages, Bulletin 2509 B, December 1961 (Reaffirmed August 1987, October 1992).

(3) American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 4- Proving Systems:

(A) Section 2-Displacement Provers, Third Edition, September 2003.

(B) Section 5-Master-Meter Provers, Second Edition, May 2000 (Reaffirmed, August 2005).

(4) American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 22- Testing Protocol, Section 2-Differential Pressure Flow Measurement Devices, First Edition, August 2005.

(g) The following material is available for purchase from the following address: American Society of Heating, Refrigerating and Air-Conditioning Engineers, Inc., 1791 Tullie Circle, NE., Atlanta, Georgia 30329: ASHRAE 41.8-1989: Standard Methods of Measurement of Flow of Liquids in Pipes Using Orifice Flowmeters.

(h) California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities, California Air Pollution Control Officers Association (CAPCOA) and California Air Resources Board (ARB), February 1999.

(i) Control of Emissions from Refinery Flares, Rule 118, South Coast Air Quality Management District, Amended November 4, 2005.

(j) U.S. EPA TANKS Version 4.09D, US Environmental Protection Agency, October 2005.

(k) Gas Processors Association (GPA) Standard 2261-00, Revised 2000.

§ WCI.7 DESIGNATED REPRESENTATIVE (ONLY APPLICABLE TO WCI JURISDICTIONS IN THE UNITED STATES)

(a) General. Each fuel supplier, electricity importer, and owner or operator of a facility that is subject to this rule, shall select a designated representative that is responsible for certifying and submitting GHG emissions reports under this reporting rule.

(b) Authorization of a Designated Representative. The designated representative of the facility shall be selected by a certificate of representation agreement that is signed by the designated representative and owners or operators of the facility. The designated representative must be an individual having responsibility for the overall operation of the facility or activity such as the position of the plant manager, operator of a well or a well field, superintendent, position of equivalent responsibility, or an individual or position having overall responsibility for environmental matters for the company.

(c) Responsibility of the Designated Representative.

(1) The designated representative of the facility shall represent and by any representations, actions, inactions, or submissions, legally bind each owner and operator in all matters pertaining to this rule.
(2) Each GHG emission report submitted under this rule must be signed by the designated representative and must contain the following certification statement: "I have been authorized to make this submission on behalf of the owners and operators of the facility (or supply operation, as appropriate). I certify under penalty of law that I have personally examined the information submitted in this document. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(d) Changing a Designated Representative. The designated representative may be changed at any time upon submission of a superseding certificate of representation. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous designated representative before time of the superseding certificate of representation shall be binding on the new designated representative and the owners and operators.

(e) Changes in Owners and Operators. In the event of any change in ownership of the facility, any new owner or operator shall be deemed to be bound by the representations, actions, inactions, and submissions of the designated representative of the facility until such time as the designated representative is changed.

(f) Certificate of Representation. A certificate of representation must be submitted to *[the jurisdiction]* and kept on location by the facility, fuel supplier, or electricity importer. The certificate shall include the following information:

(1) Identification of the facility, fuel supplier, or electricity importer for which the certificate of representation is submitted.
(2) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the designated representative.
(3) A list of the owners and operators.
(4) Certification statements that the actions of the designated representative with respect to this rule are binding on the owners and operators, and that the designated representative has the necessary authority to carry out duties and responsibilities on behalf of the owners and operators.
(5) The signature of the designated representative and owner(s) and operator(s), and the dates signed.

§WCI.8 REQUIREMENTS FOR VERIFICATION OF GREENHOUSE GAS EMISSIONS DATA REPORTS AND REQUIREMENTS APPLICABLE TO EMISSIONS DATA VERIFIERS

[Replaced -- See Attachment 2 of this document.]

§ WCI.9 DEFINITIONS

[This is a partial list of definitions. Additional definitions are under development based on the Canadian regulations come from "Section 71 of the Canadian Environmental Protection Act (CEPA) 1999"and the CARB definitions come from "Title 17, Subchapter 10, Article 2, Section 95102 of the California Code of Regulations.]

"Adverse verification statement" means a verification statement rendered by a verification body stating that the verification body cannot ~~say with~~ provide reasonable assurance that the submitted emissions data report is free of material misstatement, or that it cannot provide a ~~qualifying~~ positive statement that the emissions data report conforms to the requirements of this article.

"Biomass fuels" or "biomass-derived fuels" means fuels derived entirely from biomass.

"Carbon dioxide equivalent" or "CO_2 equivalent" or "CO_2e" means a measure for comparing carbon dioxide with other GHGs, based on the quantity of those gases multiplied by the appropriate global warming potential (GWP) factor and commonly expressed as metric tons of carbon dioxide equivalent.

"Conflict of interest" means a situation in which, because of financial or other activities or relationships with other persons or organizations, a person or body is unable or potentially unable to render an impartial verification opinion of a potential client's greenhouse gas emissions, or the person or body's objectivity in performing verification services is or might be otherwise compromised.

"Continuous emissions monitoring system" or "CEMS" means the total equipment required to obtain a continuous measurement of a gas concentration or emission rate from combustion or industrial processes.

"Data check" means any independent calculation or checking of data conducted by a verifier to recreate the emissions for a discreet source included in an emissions data report.

"Electricity generating unit" or "EGU" means any combination of physically connected generator(s), reactor(s), boiler(s), combustion turbine(s), or other prime mover(s) operated together to produce electric power.

"Exporter" means…*[To be defined later for transportation and RCI fuels accounting]*

"Facility" means any property, plant, building, structure, stationary source, stationary equipment or grouping of stationary equipment or stationary sources located on one or more contiguous or adjacent properties, in actual physical contact or separated solely by a public roadway or other public right-of-way, under common operational control, and having the same first two digits of the Standard Industrial Classification (SIC) or same first three digits of the North American Industry Classification System (NAICS) code. *[WCI is currently working to develop a definition that will harmonize common usages of the term in the U.S. and Canada. Some special facilities, such as oil and gas production fields will have separate definitions.]*

“Fuel analytical data” means any data collected about the mass, volume, flow rate, heat content, or carbon content of a fuel.

“Full verification” means all verification services as provided in section ~~WCI.8(c)~~ WCI.8(b).

“Global warming potential” or “GWP factor” means the radiative forcing impact of one mass-based unit of a given greenhouse gas relative to an equivalent unit of carbon dioxide over a given period of time.

“Greenhouse gas”, “greenhouse gases” or “GHG” means carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), and perfluorocarbons (PFCs).

“Hydrofluorocarbons” or “HFCs” means a class of GHGs primarily used as refrigerants, consisting of hydrogen, fluorine, and carbon.

“Importer” means…*[To be defined later by the Electricity Committee.]*

"Impregnated saw dust" means...
[WCI is developing a definition of impregnated saw dust, which generally refers to saw dust from wood treated or impregnated with resins, glues, or other substances derived from fossil fuels.]

“Independent Peer Reviewer” means a Lead Verifier within a Verification Body who has not participated in conducting verification services for the current reporting year who provides an independent review of verification services rendered as required in section WCI.8(f).

“Lead verifier” means a person that has met all of the requirements in section WCI.8 *[TBD]*~~, and who may act as the lead verifier of a verification team providing verification services or as a lead verifier providing an independent review of verification services rendered.~~

“Less Intensive Verification” means the verification services provided in interim years between full verifications; less intensive verification only requires risk assessment and data checks on an owner or operator's emissions data report based on the most current sampling plan developed as part of the most current full verification services. This level of verification may only be used if the verifier can provide findings with a reasonable level of assurance.

“Material misstatement” means ~~one or more inaccuracies identified in the course of verification that result in the total reported emissions being outside the 95 percent accuracy required to receive a positive verification statement.~~
(a) The individual or aggregate effect (overstatements and understatements offset each other) of one or more errors, omissions or misstatements identified in the course of verification that result in the total reported emissions being outside the 95 percent accuracy required to receive a positive verification statement. Material misstatement does not include any evaluation of acceptable measurement uncertainty of the monitoring equipment or quantification methodologies, or

(b) The individual or aggregate effect of one or more errors, omissions or misstatements identified in the course of verification which make it probable that the judgment of a reasonable person judging the total reported emissions would have been changed or influenced by the error, omission or misrepresentation.

"Measurement-based" means any of the various emission quantification methodologies that involve the determination of emissions by means of direct measurement of the flue gas flow, as well as the concentration of the relevant GHG(s) in the flue gas.

“Measurement uncertainty” means the scientific uncertainty associated with measuring of GHG emissions due to limitations of monitoring equipment or quantification methodologies. The WCI allows a measurement uncertainty of ±5 % for all measuring equipment which provides information underlying emissions reporting.

"Nonroad equipment" means...
[WCI is developing a definition for nonroad equipment.]

“Owner or operator” means any person who owns, leases, operates, controls, or supervises a facility or fuel supply operation; or who imports electricity into the WCI region.

"Operator's representative" means:

(a) if the operator of the facility is an individual, the operator,

(b) if the operator of the facility is a corporation, either

   (1) any officer of the corporation, whether or not the officer is also a director of the corporation, who performs a policy making function in respect of the corporation and who has the capacity to influence the direction of the corporation, or
   (2) the individual with primary responsibility for the operations and management of the facility

(c) if the operator of the facility is not an individual or a corporation, the individual with primary responsibility for the operations and management of the facility.

“Perfluorocarbons” or “PFCs” means a class of greenhouse gases consisting on the molecular level of carbon and fluorine.

"Process emissions" means...
[WCI is developing a definition of process emissions, which generally refers to non-combustion emissions.]

“Positive verification statement” means a verification statement rendered by a verification body stating that the verification body can say with reasonable assurance that the submitted emissions data report is free of material misstatement and ~~includes a qualifying statement~~ that the emissions data report conforms to the requirements of this article.

"Pure" means consisting of at least 97 percent by mass of a specified substance. For facilities burning biomass fuels, this means the fraction of biomass carbon accounts for at least 97 percent of the total amount of carbon in the fuel burned at the facility.

"Reasonable assurance" means a high degree of confidence that submitted data and statements are valid and that the reported emissions are free from material misstatement (i.e. that the emissions report presents fairly, in all material respects, the annual emissions for the facility, fuel supplier, or electricity importer).

"Senior officer" means:

(a) the chair of the board of directors, a vice-chair of the board of directors, the president, a vice-president, the secretary, the treasurer or the general manager of a corporation or any other individual who performs functions for a corporation similar to those normally performed by an individual occupying any such office, and

(b) each of the five highest paid employees of a corporation, including any individual referred to in clause (a).

"Solid biomass fuel" means plants or parts of plants, in their natural state or mechanically modified, but not chemically altered from the natural state.

"Stationary combustion unit" means any boiler, heater, furnace, kiln, turbine, internal combustion engine, incinerator or other non-mobile source device that combusts any solid, liquid, or gaseous fuel for purposes of producing useful heat or energy for industrial, commercial, or institutional use; or for purposes of reducing the volume of waste by removing combustible material.

"Supplier" means . . . *[To be defined later for transportation and RCI fuels accounting.]*.

"Verification" means ~~the process used to ensure that an operator's emissions data report is free of material misstatement and complies with WCI's reporting procedures and methods for calculating and reporting GHG emissions~~ a systematic, independent and documented process for the evaluation of an operator's emissions data report against the WCI's reporting procedures and methods for calculating and reporting GHG emissions.

"Verification body" means a firm accredited by the [Accreditation Body TBD] and recognized by the jurisdiction or its designee, that is able to render a verification statement and provide verification services for operators subject to reporting under this article.

"Verification cycle" means ~~one year of full verification and the next consecutive two years of less intensive verification for operators subject to annual verification. For operators subject to triennial verification, a verification cycle means one year of full verification, and if elected, the next consecutive two years of less intensive verification. A verification cycle cannot exceed three calendar years~~ three years of verification activities. Each verification cycle must include at least one year of full verification, and may include two years of less intensive verification, if eligible.

"Verification statement" means the final ~~opinion rendered by a verification body attesting whether an operator's emissions data report is free of material misstatement and a qualifying statement whether the emissions data report conforms to the requirements of this article~~ written declaration rendered by a verification body attesting whether an operator's emissions data report is free of material misstatement and whether the emissions data report conforms to the requirements of this article.

"Verification services" means services provided during verification as specified in section WCI.8, including but not limited to reviewing an owner's or operator's emissions data report, verifying its accuracy according to the standards specified in this section, assessing the owner's or operator's compliance with this section, and submitting a verification statement to the *[jurisdiction or its agent]*.

"Verification team" means all of those working for a verification body, including all subcontractors, to provide verification services for an operator. ~~The lead verifier for the verification team shall be a lead verifier in the verification body.~~

"Verifier" means an individual ~~accredited by the jurisdiction or its designee~~ employed or contracted by an accredited verification body who has been deemed competent by the verification body to carry out verification services as specified in section WCI.8.

"Waste-derived fuel" means a fuel typically derived from waste and generally used as a substitute for conventional fossil fuels. Waste-derived fuels can include fossil fuels such as waste oil, plastics, or solvents; biomass such as dried sewage or impregnated saw dust; or fractions of both fossil fuels and biomass such as municipal solid waste or tires.

§ WCI.10 Global Warming Potentials

Owners and operators must use the global warming potential (GWP) values given in Table WCI.10-1 when converting emissions of greenhouse gases to metric tons of carbon dioxide equivalent (CO_2e), using Equation 1-1.

Table WCI.10-1. Global Warming Potential Factors for Greenhouse Gases			
Common Name	**Formula**	**Chemical Name**	**GWP**
Carbon dioxide	CO_2		1
Methane	CH_4		21
Nitrous oxide	N_2O		310
Sulfur hexafluoride	SF_6		23,900
Hydrofluorocarbons (HFCs)			
HFC-23	CHF_3	trifluoromethane	11,700
HFC-32	CH_2F_2	difluoromethane	650
HFC-41	CH_3F	fluoromethane	150
HFC-43-10mee	$C_5H_2F_{10}$	1,1,1,2,3,4,4,5,5,5- decafluoropentane	1,300
HFC-125	C_2HF_5	pentafluoroethane	2,800
HFC-134	$C_2H_2F_4$	1,1,2,2-tetrafluoroethane	1,000
HFC-134a	$C_2H_2F_4$	1,1,1,2-tetrafluoroethane	1,300
HFC-143	$C_2H_3F_3$	1,1,2-trifluoroethane	300
HFC-143a	$C_2H_3F_3$	1,1,1-trifluoroethane	3,800
HFC-152	$C_2H_4F_2$	1,2-difluoroethane	43
HFC-152a	$C_2H_4F_2$	1,1-difluoroethane	140
HFC-161	C_2H_5F	fluoroethane	12
HFC-227ea	C_3HF_7	1,1,1,2,3,3,3- heptafluoropropane	2,900
HFC-236cb	$C_3H_2F_6$	1,1,1,2,2,3-hexafluoropropane	1,300
HFC-236ea	$C_3H_2F_6$	1,1,1,2,3,3-hexafluoropropane	1,200
HFC-236fa	$C_3H_2F_6$	1,1,1,3,3,3-hexafluoropropane	6,300
HFC-245ca	$C_3H_3F_5$	1,1,2,2,3-pentafluoropropane	560
HFC-245fa	$C_3H_3F_5$	1,1,1,3,3-pentafluoropropane	950
HFC-365mfc	$C_4H_5F_5$	1,1,1,3,3-pentafluorobutane	890
Perfluorocarbons (PFCs)			
Perfluoromethane	CF_4	tetrafluoromethane	6,500
Perfluoroethane	C_2F_6	hexafluoroethane	9,200
Perfluoropropane	C_3F_8	octafluoropropane	7,000
Perfluorobutane	C_4F_{10}	decafluorobutane	7,000
Perfluorocyclobutane	$c\text{-}C_4F_8$	octafluorocyclobutane	8,700
Perfluoropentane	C_5F_{12}	dodecafluoropentane	7,500
Perfluorohexane	C_6F_{14}	tetradecafluorohexane	7,400

Attachment 1: General Provisions

INTEGRATED VERSION

GENERAL PROVISIONS

§ WCI.0 PURPOSE

§ WCI.1 APPLICABILITY

§ WCI.2 GENERAL GREENHOUSE GAS REPORTING REQUIREMENTS AND SCHEDULE

§ WCI.3 CONTENTS OF THE GREENHOUSE GAS EMISSIONS REPORT

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§ WCI.10 GLOBAL WARMING POTENTIALS

EMISSIONS QUANTIFICATION, AND SAMPLING, ANALYSIS AND MEASUREMENT

§ WCI.20 THROUGH § WCI.XX

§ WCI.0 PURPOSE

This rule requires mandatory reporting and verification of greenhouse gas (GHG) emissions data by certain facilities that directly emit GHG, by importers of electricity, and by suppliers of fossil fuels. The GHGs that must be reported under this rule are carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFC), perfluorocarbons (PFC), and sulfur hexafluoride (SF_6).

§ WCI.1 APPLICABILITY

(a) The GHG emissions reporting requirements, and related monitoring, recordkeeping, and verification requirements of this rule apply to the owners and operators *[Each jurisdiction will select the specific terminology for the regulated persons in accordance with their customary rule-writing practices]* of any facility that meets the requirements of paragraph (a)(1) of this section; and any fuel suppliers and electricity importers that meet the requirements of paragraph (a)(2), (a)(3), or (a)(4) of this section:

(1) Any facility that emits 10,000 metric tons CO_2e or more per year in combined emissions from one or more of the source categories listed in this paragraph in any calendar year starting in 2010.

[Please note that the quantification and monitoring methods for many of these source categories are currently being assessed. Only source categories for which adequate quantification methods exist will be included in the final WCI Essential Requirements for mandatory reporting.]

Adipic acid manufacturing
Aluminum manufacturing
Ammonia manufacturing [*still being assessed*]
Carbon dioxide transfer recipients [*still being assessed*]
Cement manufacturing
Coal mine fugitive emissions (active and abandoned)
Coal storage
Cogeneration [*still being assessed*]
Electricity generation
Electronics Manufacturing [*still being assessed*]
Ferroalloy production [*still being assessed*]
General stationary fuel combustion
Glass Production and other uses of carbonates [*still being assessed*]
HCFC-22 production [*still being assessed*]
Hydrogen production
Industrial wastewater *[still being assessed for some industries]*
Iron and steel manufacturing
Lead production
Lime manufacturing
Magnesium production *[still being assessed]*
Natural gas transmission and distribution systems *[still being assessed]*
Nitric acid manufacturing *[still being assessed]*
Nonroad equipment at facilities *[still being assessed]*

Oil and gas production & gas processing *[still being assessed]*
Petrochemical production
Petroleum refineries
Phosphoric acid production *[still being assessed]*
Pulp and paper manufacturing
Refinery fuel gas
SF_6 from electrical equipment *[still being assessed]*
Soda ash manufacturing
Zinc production

(2) All importers of electricity. Importers of electricity include both retail providers and marketers that import electricity into the WCI region. *[This is preliminary language, pending definition of electricity importers by another WCI Committee.]*

(3) Any supplier that within the WCI region distributes transportation fuels in quantities that when combusted would emit 10,000 metric tons CO_2e per year or more in any calendar year starting in 2010. *[This is preliminary language, pending future determination of point of regulation for transportation fuels.]*

(4) Any supplier that distributes within the WCI region residential, commercial, and industrial fuels in quantities that when combusted would emit 10,000 metric tons CO_2e per year or more in any calendar year starting in 2010. *[This is preliminary language, pending future determination of points of regulation for these fuels.]*

(b) To calculate GHG emissions for comparison to the 10,000 metric ton CO_2e per year emission threshold in paragraph (a)(1) of this section, the owner or operator shall calculate annual CO_2e emissions, as described in paragraphs (b)(1) through (b)(4) of this section.

(1) Estimate the annual emissions of CO_2, CH_4, N_2O, HFC, PFC, and SF_6 in metric tons for each unit, process, activity, or operation for which emission calculation methodologies are provided in sections WCI.20 through WCI.XX. The GHG emissions shall be calculated using methodologies specified in each applicable section.

(2) For stationary combustion units, carbon dioxide emissions from the combustion of biomass fuels shall be included in the calculations, with the following exceptions:

(A) Until such time as [jurisdiction] has made a determination regarding the carbon neutrality of any biomass fuels, a maximum of 15,000 metric tons of carbon dioxide emissions from the combustion of pure solid biomass fuel may be excluded from calculation of GHG emissions for comparison to the 10,000 metric ton CO_2e per year emission threshold in paragraph (a)(1) of this section, provided that total GHG emissions including emissions from solid biomass fuel are less than 25,000 metric tons CO_2e.

(B) After such time as [jurisdiction] has made a determination regarding the carbon neutrality of any biomass fuels, the carbon dioxide emissions from the combustion of those fuels may be excluded from calculation of GHG emissions for determining whether the 10,000 metric tons CO_2e per year emission threshold in paragraph (a)(1) of this section has been met.

[A WCI Partner jurisdiction may, in its discretion, choose to require carbon dioxide emissions from the combustion of biomass fuel to be included in the determination of stationary combustion units that are required to report and may require that those emissions be reported separately from emissions from fossil fuels.]

[WCI is also considering a deduction of biomass fuel combustion emissions that have occurred within a jurisdiction that has deemed them to be carbon neutral from the determination of whether the verification threshold has been met and from the scope of the verification.]

(3) Sum the total facility emissions for each GHG and calculate the metric tons of CO_2e using equation 1-1 below.

$$CO_2e = \sum_{i=1}^{n} GHG_i \times GWP_i \qquad \textbf{Equation 1-1}$$

Where:

CO_2e = Carbon dioxide equivalent, metric tons/year.
GHG_i = Mass emissions of each greenhouse gas emitted, metric tons/year.
GWP_i = Global warming potential for each greenhouse gas from Table WCI.10-1 of this regulation.
n = The number of greenhouse gases emitted.

(4) For purpose of determining if an emission threshold has been exceeded, any CO_2 that is captured for on-site use, on-site storage, or transfer off-site must be included in the emissions total.

(c) To calculate GHG emissions for comparison to the 10,000 metric ton CO_2e per year emission threshold for suppliers of transportation fuels in paragraphs (a)(3) of this section, the owner or operator shall follow the procedures of paragraphs (c)(1) through (c)(2) below:

(1) Calculate the total mass in metric tons per year of CO_2, CH_4, and N_2O that would result from the complete combustion or oxidation of all transportation fuels that are distributed within the WCI region. The mass of each GHG shall be calculated using any of the applicable methodologies specified in section WCI.XX [Transportation Fuels Combustion] of this rule.

(2) Sum the emissions of each GHG and calculate total metric tons of CO_2e using Equation 1-1 of this rule.

(d) To calculate GHG emissions for comparison to the 10,000 metric ton CO_2e per year emission threshold for suppliers of residential, commercial, and industrial fuels in paragraph (a)(4) of this section, the owner or operator shall follow the procedures of paragraphs (d)(1) and (d)(2) below:

(1) Calculate the total mass in metric tons per year of CO_2, CH_4, and N_2O that would result from the complete combustion or oxidation of all residential, commercial, and industrial fuels that are distributed within the WCI region. The calculation shall exclude any fuels that are supplied to facilities that are required to report GHG emissions under section WCI.1(a)(1). *[These accounting issues will be dealt with in 2009.]* The mass of each GHG shall be calculated using any of the applicable methodologies specified in section WCI.XX [Residential, Commercial and Industrial Fuels Combustion] of this rule.

(2) Sum the emissions of each GHG and calculate total metric tons of CO_2e using Equation 1-1 of this rule.

(e) If the operations of a facility or fuel supplier that is subject to this rule change such that emissions fall below 10,000 metric tons CO_2e per year, then the following reporting requirements shall apply:

(1) If, prior to such emission reduction, the emissions report was subject to the verification requirements of this rule; then the owner or operator shall continue to submit emission reports until reported emissions are below 10,000 metric tons CO_2e per year for a minimum of 3 consecutive years. If reported emission are less than 10,000 metric tons CO_2 per year during 3 consecutive years, then the owner or operator shall be exempted from further reporting until CO_2e emissions again exceed 10,000 metric tons in any future calendar year.

(2) If, prior to such emission reduction, the emissions report was not subject to the verification requirements of this rule; then the owner or operator shall submit to the *[jurisdiction]* a signed statement certifying that emissions are less than 10,000 metric tons CO_2e during the prior year. After certifying that emissions are below 10,000 metric tons CO_2e per year for 3 consecutive years, the owner or operator shall be exempted from further reporting until CO_2e emissions again exceed 10,000 metric tons in any future calendar year.

(3) Notwithstanding the requirements of paragraphs (e)(1) and (2) of this section, a facility or fuel supplier that is a covered entity under the WCI cap-and-trade program must continue to submit annual emissions reports.

(f) Upon request by the [*jurisdiction*], owner or operator of any facility or fuel supply operation must submit a demonstration that emissions have not exceeded one or more of the applicability criteria specified in this section in any year since 2010. Such demonstration shall be provided to the [*jurisdiction*] within 20 working days of receipt of a written request. *[WCI is considering whether this and other deadlines for responses provide sufficient time, and whether such deadlines should be standardized across requirements.]*

§ WCI.2 GENERAL GREENHOUSE GAS REPORTING REQUIREMENTS AND SCHEDULE

[Specific requirements of this section may change based on the future final design of the marketing trading program.]

(a) General. Owners or operators that are subject to this rule must submit an annual GHG emissions report. Owners and operators must collect data; calculate GHG emissions; and follow the procedures for quality assurance, missing data, recordkeeping, and reporting as specified in these General Provisions and in each relevant section WCI.20 through WCI.XX of this rule.

(1) A facility, fuel supplier, or electricity importer that commenced operation before January 1, 2010, must report emissions beginning in 2011 for GHGs emitted in calendar year 2010.

(2) A new facility, fuel supplier, or electricity importer that commences operation on or after January 1, 2010, must report emissions for the first calendar year in which the facility operates, beginning with the first operating month and ending on December 31 of that year. Each subsequent annual report must cover emissions for the calendar year, beginning on January 1 and ending on December 31.

(b) Reporting and Verification Schedule.

(1) Annual GHG emissions reports must be submitted to [*the jurisdiction*] by April 1 of each year for emissions in the previous calendar year.
(2) Reporters subject to the verification requirements of WCI.8, must complete their verification process, including submittal of a verification statement to [*the jurisdiction*], according to the following schedule:
(A) For reporting years 2010 through 2011, September 1 of the year following the reporting year.
(B) For reporting years 2012 and later, *[date to be determined]*.

(c) Submission of GHG Emissions Report. The annual GHG emissions report must be submitted to [*the jurisdiction*] in a format [*to be specified by each jurisdiction*].

(d) Simplified Emission Calculation Methods for De Minimis Sources. The owner or operator may elect to designate as de minimis one or more sources or pollutants that collectively emit no more than 3 percent of the facility's total CO_2e emissions, but not to exceed 20,000 metric tons CO_2e. The owner or operator may estimate emissions for these de minimis sources using alternative methods to those required to be used by this rule. If verification of the emissions report is required by this rule, then the selection of any alternative GHG calculation method is subject to the concurrence of the verification team that the use of such methods provides reasonable assurance that the emissions so designated do not exceed the applicable de minimis limits. The operator shall separately identify and include in the emissions data report the emissions from designated de minimis sources.

(e) To ensure accuracy of reported data and the ability to conduct audits and/or verifications of each emissions data report, the owner or operator shall establish and maintain data acquisition and handling activities that provide for the transparency and verifiability of emissions calculations and supporting information consistent with section WCI.4 .
[As a means of assuring a smooth verification process and a positive verification opinion WCI jurisdictions may also require or advise in guidance materials that facilities have a full GHG inventory management plan.]

(f) GHG Emissions Report Revisions.

(1) The owner or operator shall maintain documentation to support any revisions made to a previously submitted annual GHG emissions report. Documentation for all revisions shall be retained by the operator for 7 years.
(2) If, after the verification deadline, a report subject to verification is found to contain an error, or accumulation of errors, greater than 5 percent of the total CO_2e emissions reported, the owner or operator shall revise and resubmit an annual GHG emissions report within 60 days of the finding. To the extent possible, the revised report must correct all identified errors. A revised report will be accepted only if verified according to WCI.8 and approved by [*the jurisdiction*]. [The jurisdiction] will send notification of approval or disapproval and an explanation of the reasons for any disapproval within 60 days of receipt of the revised report.
(3) If, after the report submittal deadline, a report not subject to verification is found to contain an error, or accumulation of errors, greater than 5 percent of the total CO_2e emissions reported, the owner or operator shall revise and resubmit an annual GHG emissions report within 30 days of the finding. To the extent possible, the revised report

must correct all identified errors. A revised report will be accepted only if approved by [*the jurisdiction*]. [The jurisdiction] will send notification of approval or disapproval and an explanation of the reasons for any disapproval within 60 days of receipt of the revised report.

(4) An owner or operator that voluntarily chooses to correct errors of 5 percent or less in total CO_2e emissions reported may do so according to the following requirements:

(A) For reports subject to verification, a revised report will be accepted only if verified according to WCI.8 and approved by [*the jurisdiction*].

(B) For reports not subject to verification, a revised report will be accepted if approved by [*the jurisdiction*].

(g) Where this rule specifies a choice between use of a fuel-based or mass balance-based calculation or use of a continuous emissions monitoring system (CEMS) to calculate CO_2 emissions, the operator shall make this choice and continue to use the method chosen for all future emissions data reports, unless the use of the alternative calculation method is approved in advance by *[the jurisdiction]*.

§ WCI.3 CONTENTS OF THE GREENHOUSE GAS EMISSIONS REPORT

Each annual GHG emissions report shall contain the following information:

(a) Facility name, identification number, physical address, mailing address, and NAICS code.

(b) Reporting year.

(c) Date of report submittal.

(d) Total facility emissions aggregated from all applicable source categories in subparts WCI.20 through WCI.XX expressed in metric tons of CO_2e calculated using Equation 1-1 of section WCI.1, excluding emissions from CO_2 that is captured and CO_2 emissions from the combustion of biomass and biomass-derived fuels, which are reported separately.

(e) Total facility emissions of CO_2 from the combustion of biomass and biomass-derived fuels.

(f) Total annual mass of CO_2 captured for on-site use, on-site storage, or transfer off site, in metric tons.

(g) For applicable fuel supplier categories in subparts WCI.XX [Transportation Fuels Combustion] and WCI.XX [Residential, Commercial and Industrial Fuels Combustion], total CO_2e emissions aggregated from all specified fuels.

(h) Emissions from each applicable source category or fuel supplier category in subparts WCI.20 through WCI.XX, expressed in metric tons per year of CO_2, CH_4, N_2O, HFC, PFC, and SF_6. CO_2 emissions from the combustion of biomass and biomass-derived fuels shall be reported separately.

(i) For electricity importers, the information required by WCI.XX [Electricity Imports].

(j) Emissions and other data for individual units, processes, activities, and operations as specified for each source category in sections WCI.20 through WCI.XX of this rule.

(k) Emission factors developed or measured by the operator using approved source testing as provided under sections WCI.20 through WCI.XXX. Emission factors shall be provided in units of emissions per amount of fuel consumed, where fuel is reported in the units specified in this regulation.

(l) Mass emissions from each designated de minimis source or pollutant, reported in metric tons per year of each GHG for which an alternative emission calculation method is used.

(m) Name and contact information including e-mail address and telephone number of the person primarily responsible for preparing and submitting the emissions report.

(n) [only applicable in United States jurisdictions] A signed and dated statement provided by the owner or operator, or their designated representative, certifying that the report has been prepared in accordance with this rule and that, subject to verification, the statements and information contained in the emissions data report are true, accurate, and complete to the best of their knowledge.

(o) [only applicable in Canadian jurisdictions] A statement signed and dated by the operator's representative, certifying that:

(1) the operator's representative has examined the emissions report and ensured that it is complete and accurate, and
(2) the emissions report has been prepared in accordance with this rule and that the statements and information contained in the emissions report are true and fair to the best of the knowledge of the operator's representative.

§ WCI.4 DOCUMENT RETENTION AND RECORD KEEPING REQUIREMENTS

(a) The operator shall establish and maintain procedures for document retention and record keeping. The operator shall retain all documents regarding the design, development and maintenance of the GHG inventory in paper, electronic or other usable format for a period of not less than 7 years following submission of each emissions data report. The retained documents, including GHG emissions data, shall be sufficient to allow for the verification of each emissions data report.

(b) Upon request by *[jurisdiction]*, the operator shall provide within 10 working days all documents and data used to develop an emissions data report.

(c) In addition to information submitted as part of the emissions data report, each operator shall retain, at a minimum, the following information, if applicable, for at least 7 years after the submission of the report:

(1) A list of all GHG sources (i.e., units, operations, processes, and activities) included in the emission estimates.
(2) All records and documents used to calculate emissions for each source, categorized by process and fuel or material type.
(3) Documentation of the process for collecting emissions data.
(4) Any GHG emissions calculations and methods used;
(5) All emission factors used for emission estimates, including documentation for any factors not provided in the rule.
(6) All input data used for emission estimates.
(7) Documentation of biomass fractions for specific fuels.
(8) All other data submitted to the [*jurisdiction*] under this rule, including the GHG emissions report.

(9) All computations made to gap-fill missing data.
(10) Names and documentation of key facility personnel involved in emissions calculating and reporting;
(11) Any other information that is required for the verification of the GHG emissions report.
(12) A log to be prepared for each reporting year, beginning January 1, documenting all procedural changes made in GHG accounting methods and changes to instrumentation for GHG emissions estimation.
(13) The GHG inventory data audit trail, data control policies and procedures, and supporting documentation.

(d) For measurement based methodologies, the following information, if applicable,also must be retained for at least 7 years after the submission of the emissions data report:

(1) List of all emission points monitored.
(2) Collected monitoring data.
(3) Quality assurance and quality control information collected for the WCI.2(e) data audit trail and data controls section of this rule.
(4) A detailed technical description of the continuous measurement system, including documentation of any findings and approvals by federal, State or local agencies.
(5) Raw and aggregated data from the continuous measurement system.
(6) A log book of all system down-times, calibrations, servicing, and maintenance of the continuous measurement system.
(7) Documentation of any changes in the continuous measurement system over time.

§ WCI.5 COMPLIANCE AND ENFORCEMENT

(a) Submission of false or misleading information to the *[jurisdiction]* or a verification body shall constitute a single, separate violation of the requirements of this article for each day after the information has been received by the Executive Officer or verification body. [Partners must be able to enforce this provision in the absence of evidence of intent, e.g., strict or absolute liability, depending on the jurisdiction.]

(b) Each violation of this rule shall constitute a single, separate violation for each day the violation continues.

§ WCI.6 INCORPORATION BY REFERENCE

The following documents are incorporated by reference into this rule. These materials are incorporated as they exist on the date this article is adopted.

(a) The following materials are available for purchase from the following addresses: American Society for Testing and Material (ASTM), 100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428-B2959; and the University Microfilms International, 300 North Zeeb Road, Ann Arbor, Michigan 48106:

(1) ASTM D240-02, (Reapproved 2007), Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter.
(2) ASTM D388-05, Standard Classification of Coals by Rank.
(3) ASTM D396-08, Standard Specification for Fuel Oils.

(4) ASTM D975-08, Standard Specification for Diesel Fuel Oils.
(5) ASTM D1250-07, Standard Guide for Use of the Petroleum Measurement Tables.
(6) ASTM D1826-94 (Reapproved 2003), Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter.
(7) ASTM Specification D1835-05 (2005).
(8) ASTM D1945-03 (Reapproved 2006), Standard Test Method for Analysis of Natural Gas by Gas Chromatography.
(9) ASTM D1946-90 (Reapproved 2006), Standard Practice for Analysis of Reformed Gas by Gas Chromatography.
(10) ASTM D2013-07, Standard Practice of Preparing Coal Samples for Analysis.
(11) ASTM D2234/D2234M-07, Standard Practice for Collection of a Gross Sample of Coal.
(12) ASTM D2502-04 (Reapproved 2002), Standard Test Method for Estimation of Molecular Weight (Relative Molecular Mass) of Petroleum Oils from Viscosity Measurements.
(13) ASTM D2503-92 (Reapproved 2007), Standard Test Method for Relative Molecular Mass (Relative Molecular Weight) of Hydrocarbons by Thermoelectric Measurement of Vapor Pressure.
(14) ASTM D2880-03, Standard Specification for Gas Turbine Fuel Oils.
(15) ASTM D3176-89 (Reapproved 2002), Standard Practice for Ultimate Analysis of Coal and Coke.
(16) ASTM D3238-95 (Reapproved 2005), Standard Test Method for Calculation of Carbon Distribution and Structural Group Analysis of Petroleum Oils by the n-d-M Method.
(17) ASTM D3588-98 (Reapproved 2003), Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels.
(18) ASTM Specification D3699-07, Standard Specification for Kerosene.
(19) ASTM D4057-06, Standard Practice for Manual Sampling of Petroleum and Petroleum Products.
(20) ASTM D4809-06, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method).
(21) ASTM Specification D4814-08a, Standard Specification for Automotive Spark-Ignition Engine Fuel.
(22) ASTM D4891-89 (Reapproved 2006), Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion.
(23) ASTM D5291-02 (Reapproved 2007), Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants.
(24) ASTM D5373-08, Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal and Coke.
(25) ASTM D5865-07a, Standard Test Method for Gross Calorific Value of Coal and Coke.
(26) ASTM D6316-04, Standard Test Method for the Determination of Total, Combustible and Carbonate Carbon in Solid Residues from Coal and Coke.
(27) ASTM D6866-06a, Standard Test Methods for Determining the Biobased Content of Natural Range Materials Using Radiocarbon and Isotope Ratio Mass Spectrometry Analysis.
(28) ASTM E1019-03, Standard Test Methods for Determination of Carbon, Sulfur, Nitrogen, and Oxygen in Steel and in Iron, Nickel, and Cobalt Alloys.
(29) ASTM E1915-07a, Standard Test Methods for Analysis of Metal Bearing Ores and Related Materials by Combustion Infrared-Absorption Spectrometry.

(30) ASTM CS-104 (1985), Carbon Steel of Medium Carbon Content.
(31) ASTM D 7459-08, Standard Practice for Collection of Integrated Samples for the Speciation of Biomass (Biogenic) and Fossil-Derived Carbon Dioxide Emitted from Stationary Emissions Sources.
(32) ASTM D6060-96(2001) Standard Practice for Sampling of Process Vents With a Portable Gas Chromatograph.
(33) ASTM D 2502-88(2004)e1 Standard Test Method for Ethylene, Other Hydrocarbons, and Carbon Dioxide in High-Purity Ethylene by Gas Chromatography.
(34) ASTM C25-06 Standard Test Method for Chemical Analysis of Limestone, quicklime, and Hydrated Lime.
(35) UOP539-97 Refinery Gas Analysis by Gas Chromatography.
(36) ASTM D5468-02 (Reapproved 2007).

(b) The following materials are available for purchase from the American Society of Mechanical Engineers (ASME), 22 Law Drive, P.O.Box 2900, Fairfield, NJ 07007-2900:

(1) ASME MFC-3M-2004, Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi.
(2) ASME MFC-4M-1986 (Reaffirmed 1997), Measurement of Gas Flow by Turbine Meters.
(3) ASME-MFC-5M-1985, (Reaffirmed 1994), Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters.
(4) ASME MFC-6M-1998, Measurement of Fluid Flow in Pipes Using Vortex Flowmeters.
(5) ASME MFC-7M-1987 (Reaffirmed 1992), Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles.
(6) ASME MFC-9M-1988 (Reaffirmed 2001), Measurement of Liquid Flow in Closed Conduits by Weighing Method.

(c) The following materials are available for purchase from the American National Standards Institute (ANSI), 25 West 43rd Street, Fourth Floor, New York, New York 10036:

(1) ISO 8316: 1987 Measurement of Liquid Flow in Closed Conduits- Method by Collection of the Liquid in a Volumetric Tank.
(2) ISO/TR 15349-1:1998, Unalloyed steel-Determination of low carbon content. Part 1: Infrared absorption method after combustion in an electric resistance furnace (by peak separation).
(3) ISO/TR 15349-3: 1998, Unalloyed steel-Determination of low carbon content. Part 3: Infrared absorption method after combustion in an electric resistance furnace (with preheating).

(d) The following materials are available for purchase from the following address: Gas Processors Association (GPA), 6526 East 60th Street, Tulsa, Oklahoma 74143:

(1) GPA Standard 2172-96, Calculation of Gross Heating Value, Relative Density and Compressibility Factor for Natural Gas Mixtures from Compositional Analysis.
(2) GPA Standard 2261-00, Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography.

(e) The following American Gas Association materials are available for purchase from the following address: ILI Infodisk, 610 Winters Avenue, Paramus, New Jersey 07652:

(1) American Gas Association Report No. 3: Orifice Metering of Natural Gas, Part 1: General Equations and Uncertainty Guidelines (1990), Part 2: Specification and Installation Requirements (1990).

(2) American Gas Association Transmission Measurement Committee Report No. 7: Measurement of Gas by Turbine Meters (2006).

(f) The following materials are available for purchase from the following address: American Petroleum Institute, Publications Department, 1220 L Street, NW., Washington, DC 20005-4070:

(1) American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 3- Tank Gauging:

(A) Section 1A, Standard Practice for the Manual Gauging of Petroleum and Petroleum Products, Second Edition, August 2005.

(B) Section 1B-Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Tanks by Automatic Tank Gauging, Second Edition June 2001 (Reaffirmed, October 2006).

(C) Section 3-Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Pressurized Storage Tanks by Automatic Tank Gauging, First Edition June 1996 (Reaffirmed, October 2006).

(2) Shop Testing of Automatic Liquid Level Gages, Bulletin 2509 B, December 1961 (Reaffirmed August 1987, October 1992).

(3) American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 4- Proving Systems:

(A) Section 2-Displacement Provers, Third Edition, September 2003.

(B) Section 5-Master-Meter Provers, Second Edition, May 2000 (Reaffirmed, August 2005).

(4) American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 22- Testing Protocol, Section 2-Differential Pressure Flow Measurement Devices, First Edition, August 2005.

(g) The following material is available for purchase from the following address: American Society of Heating, Refrigerating and Air-Conditioning Engineers, Inc., 1791 Tullie Circle, NE., Atlanta, Georgia 30329: ASHRAE 41.8-1989: Standard Methods of Measurement of Flow of Liquids in Pipes Using Orifice Flowmeters.

(h) California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities, California Air Pollution Control Officers Association (CAPCOA) and California Air Resources Board (ARB), February 1999.

(i) Control of Emissions from Refinery Flares, Rule 118, South Coast Air Quality Management District, Amended November 4, 2005.

(j) U.S. EPA TANKS Version 4.09D, US Environmental Protection Agency, October 2005.

(k) Gas Processors Association (GPA) Standard 2261-00, Revised 2000.

§ WCI.7 DESIGNATED REPRESENTATIVE (ONLY APPLICABLE TO WCI JURISDICTIONS IN THE UNITED STATES)

(a) General. Each fuel supplier, electricity importer, and owner or operator of a facility that is subject to this rule, shall select a designated representative that is responsible for certifying and submitting GHG emissions reports under this reporting rule.

(b) Authorization of a Designated Representative. The designated representative of the facility shall be selected by a certificate of representation agreement that is signed by the designated representative and owners or operators of the facility. The designated representative must be an individual having responsibility for the overall operation of the facility or activity such as the position of the plant manager, operator of a well or a well field, superintendent, position of equivalent responsibility, or an individual or position having overall responsibility for environmental matters for the company.

(c) Responsibility of the Designated Representative.

(1) The designated representative of the facility shall represent and by any representations, actions, inactions, or submissions, legally bind each owner and operator in all matters pertaining to this rule.
(2) Each GHG emission report submitted under this rule must be signed by the designated representative and must contain the following certification statement: "I have been authorized to make this submission on behalf of the owners and operators of the facility (or supply operation, as appropriate). I certify under penalty of law that I have personally examined the information submitted in this document. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(d) Changing a Designated Representative. The designated representative may be changed at any time upon submission of a superseding certificate of representation. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous designated representative before time of the superseding certificate of representation shall be binding on the new designated representative and the owners and operators.

(e) Changes in Owners and Operators. In the event of any change in ownership of the facility, any new owner or operator shall be deemed to be bound by the representations, actions, inactions, and submissions of the designated representative of the facility until such time as the designated representative is changed.

(f) Certificate of Representation. A certificate of representation must be submitted to *[the jurisdiction]* and kept on location by the facility, fuel supplier, or electricity importer. The certificate shall include the following information:

(1) Identification of the facility, fuel supplier, or electricity importer for which the certificate of representation is submitted.
(2) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the designated representative.
(3) A list of the owners and operators.

(4) Certification statements that the actions of the designated representative with respect to this rule are binding on the owners and operators, and that the designated representative has the necessary authority to carry out duties and responsibilities on behalf of the owners and operators.
(5) The signature of the designated representative and owner(s) and operator(s), and the dates signed.

§WCI.8 REQUIREMENTS FOR VERIFICATION OF GREENHOUSE GAS EMISSIONS DATA REPORTS AND REQUIREMENTS APPLICABLE TO EMISSIONS DATA VERIFIERS

[Replaced -- See Attachment 2 of this document.]

§ WCI.9 DEFINITIONS

[This is a partial list of definitions. Additional definitions are under development based on the Canadian regulations come from "Section 71 of the Canadian Environmental Protection Act (CEPA) 1999"and the CARB definitions come from "Title 17, Subchapter 10, Article 2, Section 95102 of the California Code of Regulations.]

"Adverse verification statement" means a verification statement rendered by a verification body stating that the verification body cannot provide reasonable assurance that the submitted emissions data report is free of material misstatement, or that it cannot provide a positive statement that the emissions data report conforms to the requirements of this article.

"Biomass fuels" or "biomass-derived fuels" means fuels derived entirely from biomass.

"Carbon dioxide equivalent" or "CO_2 equivalent" or "CO_2e" means a measure for comparing carbon dioxide with other GHGs, based on the quantity of those gases multiplied by the appropriate global warming potential (GWP) factor and commonly expressed as metric tons of carbon dioxide equivalent.

"Conflict of interest" means a situation in which, because of financial or other activities or relationships with other persons or organizations, a person or body is unable or potentially unable to render an impartial verification opinion of a potential client's greenhouse gas emissions, or the person or body's objectivity in performing verification services is or might be otherwise compromised.

"Continuous emissions monitoring system" or "CEMS" means the total equipment required to obtain a continuous measurement of a gas concentration or emission rate from combustion or industrial processes.

"Data check" means any independent calculation or checking of data conducted by a verifier to recreate the emissions for a discreet source included in an emissions data report.

"Electricity generating unit" or "EGU" means any combination of physically connected generator(s), reactor(s), boiler(s), combustion turbine(s), or other prime mover(s) operated together to produce electric power.

“Exporter” means…*[To be defined later for transportation and RCI fuels accounting]*

“Facility” means any property, plant, building, structure, stationary source, stationary equipment or grouping of stationary equipment or stationary sources located on one or more contiguous or adjacent properties, in actual physical contact or separated solely by a public roadway or other public right-of-way, under common operational control, and having the same first two digits of the Standard Industrial Classification (SIC) or same first three digits of the North American Industry Classification System (NAICS) code. *[WCI is currently working to develop a definition that will harmonize common usages of the term in the U.S. and Canada. Some special facilities, such as oil and gas production fields will have separate definitions.]*

“Fuel analytical data” means any data collected about the mass, volume, flow rate, heat content, or carbon content of a fuel.

“Full verification” means all verification services as provided in section WCI.8(b).

“Global warming potential” or “GWP factor” means the radiative forcing impact of one mass-based unit of a given greenhouse gas relative to an equivalent unit of carbon dioxide over a given period of time.

“Greenhouse gas”, “greenhouse gases” or “GHG” means carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), and perfluorocarbons (PFCs).

“Hydrofluorocarbons” or “HFCs” means a class of GHGs primarily used as refrigerants, consisting of hydrogen, fluorine, and carbon.

“Importer” means…*[To be defined later by the Electricity Committee.]*

"Impregnated saw dust" means...
[WCI is developing a definition of impregnated saw dust, which generally refers to saw dust from wood treated or impregnated with resins, glues, or other substances derived from fossil fuels.]

“Independent Peer Reviewer” means a Lead Verifier within a Verification Body who has not participated in conducting verification services for the current reporting year who provides an independent review of verification services rendered as required in section WCI.8(f).

“Lead verifier” means a person that has met all of the requirements in section WCI.8 *[TBD]*.

“Less Intensive Verification” means the verification services provided in interim years between full verifications; less intensive verification only requires risk assessment and data checks on an owner or operator's emissions data report based on the most current sampling plan developed as part of the most current full verification services. This level of verification may only be used if the verifier can provide findings with a reasonable level of assurance.

“Material misstatement” means
(a) The individual or aggregate effect (overstatements and understatements offset each other) of

one or more errors, omissions or misstatements identified in the course of verification that result in the total reported emissions being outside the 95 percent accuracy required to receive a positive verification statement. Material misstatement does not include any evaluation of acceptable measurement uncertainty of the monitoring equipment or quantification methodologies, or

(b) The individual or aggregate effect of one or more errors, omissions or misstatements identified in the course of verification which make it probable that the judgment of a reasonable person judging the total reported emissions would have been changed or influenced by the error, omission or misrepresentation.

"Measurement-based" means any of the various emission quantification methodologies that involve the determination of emissions by means of direct measurement of the flue gas flow, as well as the concentration of the relevant GHG(s) in the flue gas.

“Measurement uncertainty” means the scientific uncertainty associated with measuring of GHG emissions due to limitations of monitoring equipment or quantification methodologies. The WCI allows a measurement uncertainty of ±5 % for all measuring equipment which provides information underlying emissions reporting.

"Nonroad equipment" means...
[WCI is developing a definition for nonroad equipment.]

“Owner or operator” means any person who owns, leases, operates, controls, or supervises a facility or fuel supply operation; or who imports electricity into the WCI region.

"Operator's representative" means:

(a) if the operator of the facility is an individual, the operator,

(b) if the operator of the facility is a corporation, either

  (1) any officer of the corporation, whether or not the officer is also a director of the corporation, who performs a policy making function in respect of the corporation and who has the capacity to influence the direction of the corporation, or
  (2) the individual with primary responsibility for the operations and management of the facility

(c) if the operator of the facility is not an individual or a corporation, the individual with primary responsibility for the operations and management of the facility.

“Perfluorocarbons” or “PFCs” means a class of greenhouse gases consisting on the molecular level of carbon and fluorine.

"Process emissions" means...
[WCI is developing a definition of process emissions, which generally refers to non-combustion emissions.]

“Positive verification statement” means a verification statement rendered by a verification body stating that the verification body can say with reasonable assurance that the submitted emissions data report is free of material misstatement and that the emissions data report conforms to the requirements of this article.

“Pure” means consisting of at least 97 percent by mass of a specified substance. For facilities burning biomass fuels, this means the fraction of biomass carbon accounts for at least 97 percent of the total amount of carbon in the fuel burned at the facility.

“Reasonable assurance” means a high degree of confidence that submitted data and statements are valid and that the reported emissions are free from material misstatement (i.e. that the emissions report presents fairly, in all material respects, the annual emissions for the facility, fuel supplier, or electricity importer).

"Senior officer" means:

(a) the chair of the board of directors, a vice-chair of the board of directors, the president, a vice-president, the secretary, the treasurer or the general manager of a corporation or any other individual who performs functions for a corporation similar to those normally performed by an individual occupying any such office, and

(b) each of the five highest paid employees of a corporation, including any individual referred to in clause (a).

"Solid biomass fuel" means plants or parts of plants, in their natural state or mechanically modified, but not chemically altered from the natural state.

“Stationary combustion unit” means any boiler, heater, furnace, kiln, turbine, internal combustion engine, incinerator or other non-mobile source device that combusts any solid, liquid, or gaseous fuel for purposes of producing useful heat or energy for industrial, commercial, or institutional use; or for purposes of reducing the volume of waste by removing combustible material.

“Supplier” means . . . *[To be defined later for transportation and RCI fuels accounting.]*.

“Verification” means a systematic, independent and documented process for the evaluation of an operator’s emissions data report against the WCI’s reporting procedures and methods for calculating and reporting GHG emissions.

“Verification body” means a firm accredited by the [Accreditation Body TBD] and recognized by the jurisdiction or its designee, that is able to render a verification statement and provide verification services for operators subject to reporting under this article.

“Verification cycle” means three years of verification activities. Each verification cycle must include at least one year of full verification, and may include two years of less intensive verification, if eligible.

“Verification statement” means the final written declaration rendered by a verification body attesting whether an operator’s emissions data report is free of material misstatement and whether the emissions data report conforms to the requirements of this article.

“Verification services” means services provided during verification as specified in section WCI.8, including but not limited to reviewing an owner’s or operator’s emissions data report, verifying its accuracy according to the standards specified in this section, assessing the owner’s or operator’s compliance with this section, and submitting a verification statement to the *[jurisdiction or its agent]*.

“Verification team” means all of those working for a verification body, including all subcontractors, to provide verification services for an operator.

“Verifier” means an individual employed or contracted by an accredited verification body who has been deemed competent by the verification body to carry out verification services as specified in section WCI.8.

“Waste-derived fuel” means a fuel typically derived from waste and generally used as a substitute for conventional fossil fuels. Waste-derived fuels can include fossil fuels such as waste oil, plastics, or solvents; biomass such as dried sewage or impregnated saw dust; or fractions of both fossil fuels and biomass such as municipal solid waste or tires.

§ WCI.10 Global Warming Potentials

Owners and operators must use the global warming potential (GWP) values given in Table WCI.10-1 when converting emissions of greenhouse gases to metric tons of carbon dioxide equivalent (CO_2e), using Equation 1-1.

Table WCI.10-1. Global Warming Potential Factors for Greenhouse Gases			
Common Name	**Formula**	**Chemical Name**	**GWP**
Carbon dioxide	CO_2		1
Methane	CH_4		21
Nitrous oxide	N_2O		310
Sulfur hexafluoride	SF_6		23,900
Hydrofluorocarbons (HFCs)			
HFC-23	CHF_3	trifluoromethane	11,700
HFC-32	CH_2F_2	difluoromethane	650
HFC-41	CH_3F	fluoromethane	150
HFC-43-10mee	$C_5H_2F_{10}$	1,1,1,2,3,4,4,5,5,5- decafluoropentane	1,300
HFC-125	C_2HF_5	pentafluoroethane	2,800
HFC-134	$C_2H_2F_4$	1,1,2,2-tetrafluoroethane	1,000
HFC-134a	$C_2H_2F_4$	1,1,1,2-tetrafluoroethane	1,300
HFC-143	$C_2H_3F_3$	1,1,2-trifluoroethane	300
HFC-143a	$C_2H_3F_3$	1,1,1-trifluoroethane	3,800
HFC-152	$C_2H_4F_2$	1,2-difluoroethane	43
HFC-152a	$C_2H_4F_2$	1,1-difluoroethane	140
HFC-161	C_2H_5F	fluoroethane	12
HFC-227ea	C_3HF_7	1,1,1,2,3,3,3- heptafluoropropane	2,900
HFC-236cb	$C_3H_2F_6$	1,1,1,2,2,3-hexafluoropropane	1,300
HFC-236ea	$C_3H_2F_6$	1,1,1,2,3,3-hexafluoropropane	1,200
HFC-236fa	$C_3H_2F_6$	1,1,1,3,3,3-hexafluoropropane	6,300
HFC-245ca	$C_3H_3F_5$	1,1,2,2,3-pentafluoropropane	560
HFC-245fa	$C_3H_3F_5$	1,1,1,3,3-pentafluoropropane	950
HFC-365mfc	$C_4H_5F_5$	1,1,1,3,3-pentafluorobutane	890
Perfluorocarbons (PFCs)			
Perfluoromethane	CF_4	tetrafluoromethane	6,500
Perfluoroethane	C_2F_6	hexafluoroethane	9,200
Perfluoropropane	C_3F_8	octafluoropropane	7,000
Perfluorobutane	C_4F_{10}	decafluorobutane	7,000
Perfluorocyclobutane	$c\text{-}C_4F_8$	octafluorocyclobutane	8,700
Perfluoropentane	C_5F_{12}	dodecafluoropentane	7,500
Perfluorohexane	C_6F_{14}	tetradecafluorohexane	7,400

Attachment 2: General Provisions – Verification Only

§WCI.8 REQUIREMENTS FOR VERIFICATION OF GREENHOUSE GAS EMISSIONS DATA REPORTS AND REQUIREMENTS APPLICABLE TO EMISSIONS DATA VERIFIERS

Note: The verification requirements laid out in this section strive for consistency with ISO 14064-3[1] *requirements and set forth a high standard for verification that will ultimately support a WCI cap and trade program. Due to differences in rulemaking procedures between jurisdictions, Supplement 1 provides supplemental text that jurisdictions must incorporate into either the jurisdiction's prescriptive rule language, replacing more general procedural language in Section WCI.8, or into enforceable guidance documents. There are notes in WCI.8 that direct readers to appropriate text in Verification Supplement 1 when applicable. It is imperative that all jurisdictions have the same level of rigor and implementation for verification to support a WCI regional program. Reporters and verifiers with operations throughout the WCI region will benefit from a consistent approach and such an approach would facilitate administration of the verification requirements by a central body or designee.*

Note: For definitions of terms used in this section, see WCI.9 in Attachment 1.

(a) Applicability.

(1) Owners or operators [Each jurisdiction will select the specific terminology for the regulated persons in accordance with their customary rule-writing practices] are required to obtain annual verification when the reported annual emissions of the operation subject to this rule are equal to or greater than 25,000 metric tons of CO_2e in any calendar year starting in 2010.

(2) When the operation of a facility, fuel supplier, or electricity importer subject to the requirements of this section is changed such that the operator has reported less than 25,000 metric tons of CO_2e emissions for a calendar year, the operator shall obtain verification of annual emissions reports for the lesser of three subsequent calendar years or for those years remaining in the current compliance period. If CO_2e emissions of a facility, fuel supplier, or electricity importer subject to the requirements of this section again exceed 25,000 metric tons in any calendar year the provisions of WCI.8(a)(1) apply.

(3) Notwithstanding WCI.8(a)(1) and (2), any facility, fuel supplier or electricity importer included as a covered entity under the WCI cap-and-trade program shall obtain verification of reported annual emissions.

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[1] ISO (2006) ISO 14064-3: Greenhouse Gases-Part 3: Specification with guidance for the validation and verification of greenhouse gas assertions, March, 2006, International Organization for Standardization, Switzerland.

[WCI is considering a deduction of pure biomass fuel combustion emissions that have occurred within a jurisdiction that has deemed them to be carbon neutral from the determination of whether the verification threshold has been met and from the scope of the verification when one is required.]

(b) Requirements for Annual Verification of Emissions Data Reports.

(1) Facility owners or operators, fuel suppliers, and electricity importers required to obtain annual verification shall be subject to full verification requirements in the first year that verification is required for an emissions data report. Upon completion of a positive verification statement under full verification requirements, the facility owner or operator, fuel supplier, or electricity importer may be eligible for two years of less intensive verification services as described in section WCI.9. This cycle may be repeated in subsequent three-year cycles; however, full verification requirements shall apply at least once every three years.

(2) Facility owners or operators, fuel suppliers, and electricity importers required to obtain annual verification will be required to obtain full verification services if any of the following apply:

(A) Change in the verification body from the previous year; or

(B) A verification body issued an adverse verification statement for that facility's previous year's emissions data report;

(c) Accreditation Requirements for Verification Bodies.

(1) The accreditation requirements specified in this subsection shall apply to all verification bodies, that wish to provide verification services under this rule.

(2) A verification body is qualified to conduct verification services for the WCI if it has demonstrated knowledge of the WCI reporting requirements and if it is:

(A) Accredited by the California Air Resources Board under Title 17, California Code of Regulation, section 95132, or

(B) Accredited to ISO 14065 through a program developed under ISO 17011 by an accreditation body that is a member of the International Accreditation Forum.

[Note the details of the WCI's specific accreditation process for verification bodies (which has yet to be developed) will be consistent with ISO 14065 through an accreditation program that will developed under ISO 17011 and will include demonstrated knowledge of the WCI reporting requirements. The WCI will explore additional accreditation requirements and/or other criteria for individual lead verifiers, general verifiers, and/or sector specialists.]

(C) The WCI will only grandfather in existing verification bodies that meet the requirements of WCI.8(c)(2)(A)-(B) if they are accredited by December 31, 2012 to provide verification services for programs other than the WCI.

(d) Requirements for Verification Services. Verification services shall be subject to the following requirements. The following verification services must be provided for each emissions data report.

(1) As part of the verification services, the verification team shall review documents submitted, assess risks of a material misstatement, develop a verification plan (that includes a sampling plan), evaluate the emissions data report against the verification requirements, and assess the materiality of errors, omissions and misstatements identified.
(2) The verification team shall request any information and documents needed for verification services. Such information shall include, but is not limited to original records and supporting data for the emissions data report.

(e) Level of Assurance. Verification bodies shall conduct verification processes and design verification procedures to provide a reasonable level of assurance for each separate emissions data report every year of the verification cycle.

(f) A verification team must include the following:

(1) a Lead Verifier;
(2) an Independent Peer Reviewer;
(3) at least one sector specialist with demonstrated knowledge and specific skills, if required per WCI [TBD];

[Note, the WCI will identify industrial sectors where a subject matter expert must be part of the verification team as part of development of its accreditation requirements.]

(g) Subcontracting. The following requirements shall apply to any verification body that elects to subcontract verification services.

(1) The primary verification body must assume full legal responsibility for verification services performed by subcontracted verifiers or verification bodies.
(2) A verification body or verifier acting as a subcontractor to the primary verification body will not further subcontract that same work to another firm or individual.
(3) Any verification body or verifier acting as a subcontractor is bound to all Conflict of Interest requirements in Section WCI.8(h).
(4) Must be identified by the primary verification body as part of the verification team.

(h) Conflict of Interest Requirements for Verification Bodies. The conflict of interest provisions of this section shall apply to the verification body, entities related to the verification body, and the verification team accredited according to the requirements of the WCI to perform verification services for the WCI program. Member for purposes of this section means any employee or subcontractor of the verification body or entities related to the verification body. Member also includes any individual with a majority equity share in the verification body or entities related to the verification body.

(1) Prior to commencing verification services for an owner or operator, a verification body must first be authorized in writing by [*(e.g. WCI regional administrative body or other organization to be determined) or jurisdiction in which the entity reports* (TBD)] to provide verification services. To obtain authorization the verification body shall submit to [TBD] a self-evaluation of the potential for any conflict of interest that the verification body, entities related to the verification body, and members of the verification team, including subcontractors, may have with the owner or operator or their related entities for which it will perform verification services. This self-evaluation must include evaluation of any threats to the verification body's independence including: [*note: a standardized Conflict of Interest Assessment form will be developed for the WCI*]

(A) Threats created by the reporting operation offering inducements to the verification body, subcontractors or verification team members for a positive opinion,

(B) Threats created by members of the verification body, verification team members, subcontractors, or family of subcontractors or team members having a financial interest in the reporting operation or its operator,

(C) Threats created by members of the verification body reviewing work of the verification body, subcontractors, members of the verification team, or related companies, including but not limited to any situation where the body, subcontractors, team members or companies have provided services related to greenhouse gases:

(D) Threats created by members of the verification body, verification team members, or subcontractors having a close relationship with the reporting operation, such that they might become too sympathetic to the interests of the reporting operation, or

(E) Threats created by members of the verification body, verification team members, or subcontractors being deterred from acting objectively or exercising professional skepticism by threats, actual or perceived, from the reporting operation.

(2) The verification body shall deem the potential for conflict of interest to be low if

(A) No threats as listed in WCI.8(h)(1) exist, and

(B) Any non-verification services provided by all members of the verification body the verification team to the owner or operator within the last three years are valued at less than [percent TBD] of the verification body's revenue.

(3) The verification body shall deem the potential for conflict of interest to be high if threats as listed in WCI.8(h)(1) exist, unless it is a potential for individual conflict of interest as provided in section WCI.8((h)(5) and may be mitigated per section WCI.8(h)(3)(B).

(4) The verification body shall deem the potential for a conflict of interest to be medium if

(A) the potential for a conflict of interest is not deemed to be either high or low as specified in sections WCI.8(h)(1)-(2).

(5) If a verification body deems the potential for conflict of interest to be medium and wishes to provide verification services for the owner or operator, then

(A) the verification body shall submit, in addition to the Conflict of Interest Assessment form, a plan to avoid, neutralize, or mitigate the potential conflict of interest situation.

(B) the verification body may submit a plan to neutralize a high individual conflict of interest assessed under WCI.8(h)(1)(B).

(C) the [TBD] shall evaluate the conflict of interest mitigation plan and determine whether verification services may proceed, as provided in section WCI.8(h)(4).

(6) Conflict of Interest Determinations. The *[TBD]* shall review the self-evaluation submitted by the verification body and determine whether the verification body is authorized to perform verification services for the owner or operator

(A) The *[TBD]* shall notify the verification body in writing when the conflict of interest evaluation information submitted under section WCI.8(h)(1) is deemed complete. Within *[Number of days TBD]* of deeming the evaluation information complete, *[TBD]* shall determine whether the verification body is authorized to proceed with verification and shall so notify the verification body.

(B) If *[TBD]* determines the verification body or any member of the verification team has any threats specified in section WCI.8(h)(1), *[TBD]* shall find a high potential conflict of interest and verification services may not proceed.

(C) If *[TBD]* determines that there is a low potential conflict of interest, verification services may proceed.

(D) If *[TBD]* determines that the verification body and verification team have a medium potential for a conflict of interest, *[TBD]* shall evaluate the conflict of interest mitigation plan and may request additional information from the applicant to complete the determination. In determining whether verification services may proceed, *[TBD]* may consider factors including, but not limited to, the nature of previous work performed, the current and past relationships between the verification body and its subcontractors with the owner or operator, and the cost of the verification services to be performed. If *[TBD]* determines that these factors when considered in combination with the mitigation plan demonstrate a low level of potential conflict of interest, then *[TBD]* will authorize the verification body to provide verification services.

(7) Monitoring Conflict of Interest Situations.

(A) After commencement of verification services, the verification body shall monitor and immediately make full disclosure in writing to *[TBD]* regarding any potential for a conflict of interest situation that arises. This disclosure shall include a description of actions that the verification body has taken or proposes to take to avoid, neutralize, or mitigate the potential for a conflict of interest.

(B) The verification body shall monitor arrangements or relationships that may be present for a period of one year after the completion of verification services. During that period, within 30 calendar days of any change in arrangements or relationships with the owner or operator for which the verification body has provided verification services, the verification body shall notify *[TBD]* of the change and provide a description of the nature of the change.

(C) The verification body shall report to *[WCI Regional Body or jurisdiction TBD]* any changes in its organizational structure, including mergers, acquisitions, or divestitures, for one year after completion of verification services within 30 days and submit an evaluation of how the change(s) impacts the potential for conflict of interest.

(D) *[TBD]* may invalidate a verification finding if a medium or high potential conflict of interest has arisen for the verification body or any member of the verification team. In such a case, the owner or operator shall be provided 180 calendar days to have their emissions report verified by a different verification body.

(E) If the verification body or its subcontractor(s) are found to have violated the conflict of interest requirements of this section, *[Accreditation Body TBD]* may rescind its accreditation for any appropriate period of time as provided in section WCI.8(aa) Additionally, (WCI Regional Body *[TBD]* may separately rescind its recognition of an accredited Verification Body. *[TBD – accreditation requirements]*.

(i) Notice of Verification Services. Prior to commencing verification services for a facility owner or operator, fuel supplier, and electricity importer, the verification body shall submit a notice of verification services to the *[TBD]*. Verification activities shall not proceed for 15 business days or until the verification body receives written approval to proceed from the

[TBD], whichever is earlier. If the *[TBD]* does not respond to the verification body within 15 business days, the verification body may begin to conduct verification activities.

(The NOVS form will be standardized across WCI and developed later, Supplement will include some minimum information to be contained in NOVS)

(j) Verification Plan.

(1) Accounting for requirements set by WCI.8, the verification plan shall document:
(A) the scope of the verification;
(B) the level of assurance;
(C) the verification standard;
(D) the verification criteria;
(E) the objectives of the verification;
(F) the timing of the verification, including site visits;
(G) the nature of the communications required;
(H) the resources required to conduct the verification, including the role of verification team members, and
(I) the nature, timing and extent of the verification procedures, including the sampling plan

(2) The verification body shall retain the verification plan in paper, electronic, or other format for a period of not less than seven years following the submission of each verification statement.

(k) Site visits. In years for which full verification services are required under WCI.8(b), at least one member of the verification team shall at a minimum make one onsite site visit to each facility or fuel supply location [Note that exact location of fuel supplier site visits remains TBD] for which an emissions data report is submitted. If the verification team requires a sector specialist as required (TBD through accreditation), that specialist must participate in the onsite visit(s). The verification team member(s) shall also conduct an onsite visit of the headquarters or other location of central data management, if different from the facility or fuel supply location, when the owner or operator is an electricity importer.

(l) Owners or operators shall make available to the verification team all information and documentation used to calculate and report emissions, electricity transactions, and other information required under this rule, as applicable.

(m) As applicable for electricity importers, the verification team shall review electricity transaction records, including receipts of power attributed to the Northwest or Southwest region as verifiable via North American Electric Reliability Corporation (NERC) E-Tags, settlements data, or other information as confirmation of the region of origin. [Note that this procedure is subject to change pending WCI Electricity Committee review.]

(n) Data Checks. To determine the reliability of the submitted emissions data report, the verification team shall use data checks as described in WCI.9, Definitions.

(o) Emissions Data Report Modifications. If as a result of review by the verification team and prior to completion of a verification statement the operator chooses to make improvements or corrections to the submitted emissions data report, a revised emissions data report must be submitted to [the jurisdiction] as specified by section WCI.2(f). The operator shall maintain documentation to support any revisions made to the initial emissions data report. Documentation for all emissions data report submittals shall be retained by the operator for seven years pursuant to section WCI.4.

(p) Materiality and Conformance Assessment Criteria. The verifier shall determine if the annual emissions report is prepared in such a way that it conforms to the verification criteria. To verify that the emissions data report is free of material misstatement, the verification team shall make its own determination of emissions checked based on the sampling plan and shall determine whether there is reasonable assurance if the individual or aggregate effect of any errors, omissions or misrepresentation could have resulted in an underestimation or overestimation of emissions by more than five percent of the facility's, fuel supplier's, or electricity importer's total reported CO2e emissions. To assess conformance with this rule the verification team shall review the methods and factors used to develop the emissions data report for adherence to the requirement of this rule. The verification team shall keep a log of any issues identified in the course of verification activities that may affect determinations of material misstatement and nonconformance, and how those issues were resolved.

(q) Completion of verification services shall include:

(1) Verification Statement. Upon completion of the verification services specified in sections WCI.8(d)(j)-(s), the verification body shall complete a verification statement for each emissions data report, and provide that statement to the owner or operator and [the jurisdiction or other body] according to the schedule specified in section WCI.2(b). Before that statement is completed, the verification body shall have the verification services and findings of the verification team independently reviewed and approved by an Independent Peer Reviewer.

(2) The verification body shall provide either a positive or adverse verification statement to the reporter and to the [the jurisdiction or other central body (alternatively, this could be the reporter's responsibility to submit the statement to the jurisdiction)] based on its findings during the verification process.

(3) The lead verifier in the verification team shall attest on the verification statement that the verification team has carried out all verification services as required by this rule, and the Independent Peer Reviewer shall attest to his or her independent review on behalf of the verification body and his or her concurrence with the verification findings. If the Independent Peer Reviewer does not determine that that the verification team has carried out all verification services as required by the rule or if the Independent Peer Reviewer rejects the verification team's findings, then the verification body cannot issue a positive verification statement.

(4) The verification body shall provide to the owner or operator a detailed verification report. The verification report shall at minimum include the detailed comparison of the data checks with the submitted emissions data report, errors, omissions and misstatements identified during the course of the verification, any corrections made to the original annual emissions report as a result of the verification, and observations about the data management systems that are connected to the errors, omissions and misstatements identified, as well as any qualifying comments on findings during verification services. The detailed verification report shall be made available to [*the jurisdiction*] upon request.

(r) Prior to the verification body providing an adverse verification statement to [*the* jurisdiction], the owner or operator shall be provided at least 14 working days to modify the emissions data report to correct any material misstatement or nonconformance found by the verification team. The modified report and verification statement must be submitted to [*the jurisdiction*] before the applicable verification deadline, unless the operator makes a request to [*the jurisidiction]* as follows:

(s) If the owner or operator and the verification body cannot reach agreement on modifications to the emissions data report that result in a positive verification statement, the operator may petition *[TBD]* to make a final decision as to the verifiability of the submitted emissions data report.

(1) If *[TBD]* determines that the emissions data report does not meet the standards and requirements specified in this rule, the owner or operator shall have the opportunity to submit within 60 calendar days of the date of this decision [Note that this time frame may need to be changed pending details of cap-and-trade system design and needs.] any emissions data report revisions that address *[TBD's]* determination, for re-verification of the emissions data report. In re-verifying a revised emissions data report, the verification body and verification team shall be subject to the requirements in section WCI.8(q)-(s).

(2) Upon provision of the verification statement to *[the jurisdiction]*, the emissions data report shall be considered final and no changes shall be made except as provided in section WCI.2(f). All verification requirements of this rule shall be considered complete upon provision of the verification statement.

(t) In addition to initiating WCI's dispute resolution process, the operator and verification body must inform the applicable accreditation body of the dispute.

(u) The *[TBD]* may make void the positive verification statement submitted by the verification body if:

(1) The [TBD] finds a high level of conflict of interest existed between a verification body and an owner or operator; or,

(2) An emissions data report that received a positive verification statement fails an audit by *[TBD]*.

(v) Upon request by *[TBD]*, the owner or operator shall provide the data used to generate an emissions data report, including all data available to a verifier in the conduct of verification services. *[TBD]* may also review the full verification report given by the verification body to the owner or operator. The full verification report shall be provided to the *[TBD]* upon request.

(w) Upon written notification by the *[TBD]*, the verification body shall make itself available for a verification services audit.

(x) Duration of verification services by one verification body. Facility owners or operators, fuel suppliers, or electricity importers subject to annual verification shall not use the same verification body for a period of more than six consecutive years. If a facility owner or operator, fuel supplier, or electricity importer is required or elects to contract with another verification body, they may contract verification services from the previous verification body only after not using the previous verification body for at least three years. If a verification body or verification team member has been providing verification services for a [operator/owner] in a greenhouse gas reporting or reductions program other than WCI within the previous three years, those years of services will count towards the six consecutive year limit in the WCI.

(y) Suspension of Verification Bodies. A jurisdiction may review, and for good cause, work to revoke or modify the accreditation status of a WCI-recognized verification body. If a WCI-recognized verification body is suspended in any other mandatory or voluntary GHG reporting or trading program, that verification body will not be allowed to provide any verification services under the WCI until that suspension ends. If a WCI-recognized verification body has their verification body accreditation revoked under any other mandatory or voluntary GHG reporting or trading program, that verification body will no longer be allowed to provide verification services under WCI until they are reaccredited.

NEW OR REVISED DEFINITIONS OF TERMS USED IN WCI.8 ARE SHOWN IN ATTACHMENT 1, GENERAL PROVISIONS, SECTION WCI.9.

Verification Supplement 1

Note: the additional content in this Supplement must either be included in regulatory text in the appropriate subsections of WCI.8 or enforceable guidance documents by jurisdictions. The language in this section provides further explanation of items required in WCI.8 or alternative, more prescriptive language of those requirements.

Preliminary Activities and Verification Plan

The verification team shall discuss with the owner or operator the scope and objective of the verification services and obtain information from the owner or operator necessary to develop a verification plan. Such information shall include but is not limited to:

- Information to allow the verification team to develop a general understanding of facility or entity boundaries, operations, emissions sources, electricity transactions, as applicable;
- Information about the data management system used to track GHG emissions, electricity transactions, and other required measurement data as applicable;
- Information regarding the training or qualifications of personnel involved in developing the GHG emissions data report;
- Description of the specific methodologies used to quantify and report GHG emissions, electricity transactions, and other required data as applicable;
- Records of measured data related to emissions and operations for the prior and current period;
- Inventory of sources and their associated emissions for the reporting period, and
- Any prior verification reports, if applicable.

In developing the verification plan, the verifier shall:

- Gain an understanding of the organization and the process that emit greenhouse gases;
- Conduct a risk assessment to evaluate inherent, control and detection risk;
- Conduct preliminary analytical testing to identify anomalies in the data;
- Conduct a sensitivity analysis to assess the relative contribution of each source in the inventory to the reported annual emissions, and
- Consider any other relevant developments at the facility, in the regulations, or legal environment.

Sampling Plan

As part of the verification procedures, the verification team shall develop a sampling plan that, when combined with the other verification procedures, provides sufficient and appropriate evidence to allow the verifier to arrive at a conclusion. The sampling plan shall be designed to achieve the specified verification objective. The sample plan shall consider:

- Statistical versus non-statistical approaches

- Design of the sample, including the population characteristics
- Stratification (categorization of population into subgroups)
- Emission weighted selection
- Sample size
- Sample selection

As relevant information becomes available during the course of verification activities, the verification team must modify the sampling plan as necessary to address potential issues emerge of material misstatement or nonconformance with the requirements of this rule.

Data Checks

The verification team conducts data checks throughout the verification process and shall focus first on the largest and most uncertain estimates of emissions and electricity transactions.

- In establishing the verification plan, the verification team shall use professional judgment to determine the number of data checks required for the team to conclude with reasonable assurance whether the reported emissions and transactions are free of material misstatement and the emissions data report otherwise conforms to the requirements of this rule.
- The verification team shall choose emissions sources, and electricity transactions data as applicable, for data checks based on their relative sizes and risks of material misstatement as indicated in the verification plan;
- The verification team, through the conformance assessment, shall ensure that the appropriate methodologies and emission factors have been applied for the emissions sources and electricity transactions for sampled data covered under sections WCI.20 through WCI.XX;

Site Visits

During the site visit, the verification team member(s) shall conduct the following:

- Observe whether all sources at the site are represented in the emissions report as specified in sections WCI.20 to WCI.XX as applicable to the owner or operator.
- Assess whether the source inventory is identified, categorized, and reported appropriately. Collect evidence as to explanations for data anomalies identified in the verification plan.
- Understand the data trail used by the owner or operator to measure, quantify, and report greenhouse gas emissions and, when applicable, electricity transactions.
- Understand and evaluate the associated data controls used by the owner to ensure the completeness and accuracy of the data

Materiality Assessment

In assessing whether misstatements are material, the verification team shall determine whether the total reported emissions are at least 95 percent accurate using the following equation:

Percent accuracy = 100 – (sum of (errors, omissions, misreporting) * 100 / (total reported emissions))

To assess conformance with this rule the verification team shall review the methods and factors used to develop the emissions data report for adherence to the requirement of this rule. The verification team shall keep a record of any errors, omissions or misstatements identified in the course of verification activities that may affect determinations of material misstatement and nonconformance, and how those issues were resolved.

Conflict of Interest (*could replace more general procedural language in Section WCI.8*)

(1) Conflict of Interest Submittal Requirements for Accredited Verification Bodies.

(A) Before the start of any work related to providing verification services to an owner or operator, a verification body must first be authorized in writing by *[TBD]* to provide verification services. To obtain authorization the verification body shall submit to *[TBD]* a self-evaluation of the potential for any conflict of interest that the verification body, entities related to the verification body, and members of the verification team including, subcontractors may have with the owner or operator or their related entities for which it will perform verification services. For the purposes of this section, the term member refers to staff on the verification team, in the verification body and any subcontractors. The submittal shall include the following:

i. Identification of whether the potential for conflict of interest is high, low, or medium based on factors specified in this section;

ii. An organizational chart of the business structure of the verification body, including its related entities and brief description of the primary work done by the verification body and related entities;

iii. Identification of whether any member of the verification body, entities related to the verification body, or the verification team including subcontractors has previously provided verification services for the owner or operator or its related entities and, if so, the years in which such verification services were provided;

iv. Identification of whether any member of the verification body, entities related to the verification body, or the verification team or including subcontractors has engaged in any non-verification services of any nature with the owner or operator or related entities either within or outside the WCI region during the previous three years. The verification body must also disclose any services listed under section (high COI list) it has provided to the owner or operator, regardless of when these services occurred. If non-verification services have previously been provided, the following information shall also be submitted:

- Identification of the nature and location of the work performed for the owner or operator and whether the work is similar to the type of work to be performed during verification, such as emissions inventory auditing, energy efficiency, renewable energy, or other work with implications for the operator's greenhouse gas emissions or the accounting of greenhouse gas emissions or electricity transactions;

- The nature of past, present or future relationships the verification body, entities related to the verification body, and members of the verification team including subcontractors have with the owner or operator or related entity including:
  - Instances when any member has performed or intends to perform work for the owner or operator;
  - Identification of whether work is currently being performed for the owner or operator and, if so, the nature of the work;
  - Whether any member has any contracts or other arrangements to perform work for the owner or operator or a related entity;
  - Identify how much work was performed in each of the last three years, as a percentage of the verification body's total gross income for each of the last three years;
  - Identify how much work related to greenhouse gases or electricity transactions was has performed for the owner or operator or related entities in each of the last three years, as a percentage of the verification body's income for each of the last three years;
  - Identify how much work was performed by each subcontractor for the operator in each of the last three years, as a percentage of each subcontractor's total gross income for each of the last three years.
- Explanation of how the amount and nature of work previously performed is such that any member of the verification team's credibility and lack of bias should not be under question.

v. A list of names of the verification team members that will perform verification services for the owner or operator and a description of any instances of personal or family relationships with management or employees of the owner or operator that potentially represent a conflict of interest; and,

vi. Identification of any other circumstances or relevant information known to the verification body or owner or operator that could result in a conflict of interest, or any situation where the appearance of impartiality could undermine confidence in the verification body's ability to assess the reported emissions.

(2) The potential for a conflict of interest shall be deemed to be high where:

(A) The verification body and owner or operator share any management staff or board of directors membership, or any of the management staff of the owner or operator have been employed by the verification body, or vice versa, within the previous three years; or

(B) Within the previous three years, any member of the verification body, any entity related to the verification body, and the verification team has provided to the owner or operator any of the following non-verification services:

i. Designing, developing, implementing, or maintaining an inventory or information or data management system for facility greenhouse gases, or, where applicable, electricity transactions;

ii. Developing greenhouse gas emission factors or other greenhouse gas-related engineering analysis;
iii. Designing energy efficiency, renewable power, or other projects which explicitly identify greenhouse gas reductions as a benefit;
iv. Preparing or producing greenhouse gas-related manuals, handbooks, or procedures specifically for the reporting facility;
v. Appraisal services of carbon or greenhouse gas liabilities or assets;
vi. Brokering in, advising on, or assisting in any way in carbon or greenhouse gas-related markets;
vii. Managing any health, environment or safety functions which explicitly identify greenhouse gas reductions as a benefit;
viii. Bookkeeping or other services related to the accounting records or financial statements, unless those services limited to financial auditing;
ix. Any service related to information systems, unless those systems will not be part of the verification process and excluding third-party auditor or registration services;
x. Appraisal and valuation services, both tangible and intangible related to GHG emissions or reductions inventories;
xi. Fairness opinions and contribution-in-kind reports in which the verification body has provided its opinion on the adequacy of consideration in a transaction, unless the resulting services shall not be part of the verification process;
xii. Any actuarially oriented advisory service involving the determination of amounts recorded in financial statements and related accounts;
xiii. Any internal audit service as provided under section (GHG plan) that has been outsourced by the operator that relates to the owner's or operator's internal accounting controls, financial systems or financial statements, unless no consulting or advice was provided as part of the audit;
xiv. Acting as a broker-dealer (registered or unregistered), promoter or underwriter on behalf of the owner or operator;
xv. Any legal services related to GHG emissions;
xvi. Expert services to the owner or operator or his or her legal representative for the purpose of advocating his or her's interests in litigation or in a regulatory or administrative proceeding or investigation involving GHG emissions, unless providing factual testimony.

(C) The potential for a conflict of interest shall also be deemed to be high where any staff member of the verification body, entity related to the verification body, or the verification team has provided verification services for the owner or operator for six consecutive years or within three years of the termination of a previous GHG verification contract with the owner or operator. If a verification body or verification team member has been providing verification services for a [operator/owner] in a greenhouse gas reporting or reductions program other than WCI within the past three years, those years of services will count towards the six consecutive year limit in the WCI.

(D) The potential for a conflict of interest shall be deemed high where the Independent Peer Reviewer for the verification team has provided verification or non-verification services for the operator during the current reporting year.

(3) The potential for a conflict of interest shall be deemed to be low where:

(A) No potential for a conflict of interest is found under section WCI.8(h) *(may need to be updated, depending upon final version of WCI.8)* and any non-verification services provided by all members of the verification body and the verification team to the owner or operator within the last three years are valued at less than *[Percent TBD*] of the verification body's revenue.

****

WCI.8 OPTIONAL GUIDANCE

Note: This text is supporting material and not intended as part of the essential requirements.

Collection of Evidence

The verification body shall obtain sufficient and appropriate evidence to be able to draw reasonable conclusions on which to base the verification statement. The verification body obtains evidence by performing verification procedures. Verification procedures are classified as:

- **Computation (or Recalculation)** is the checking of mathematical accuracy of documents or records
- **Observation** of a process or procedure
- **Confirmation** is obtaining representations from a third party
- **Enquiry** is seeking information from a knowledgeable person
- **Inspection** of Records or Documents/Assets
- **Re-performance** is the verifiers independent execution of procedures or controls
- **Analysis** is the evaluation of information made by studying the plausible relationships among different types of data

Some or all of these techniques can be used to obtain sufficient and appropriate evidence. Site visits are used to obtain evidence that is readily available at that location.

May 8, 2009 Final Draft Essential Requirements of Mandatory Reporting for the Western Climate Initiative comments

List of Commenters

American Forest & Paper Association

ArcelorMittal Montreal Inc.

Arizona Public Service Company

BC Forest Industry Climate Change Working Group

Beta Analytic Inc.

Canadian Chemical Producers' Association

Canadian Petroleum Products Institute

Canadian Steel Producers Association

Cement Association of Canada

Chelan County PUD

Covanta Energy

CSA America

Ecotek

Forest Products Association of Canada

National LIme Association

Northwest Pulp and Paper Association

Ontario Forest Industries Association

Pacific Gas and Electric Company

PNGC Power

Public Power Council

Puget Sound Energy

Rio Tinto

Sacramento Municipal Utility District

Shell Canada Energy

Shell Oil Company and Shell Canada LTD

Spectra Energy

Utah Business Climate Change Coalition

Washington Forest Protection Association

Washington Public Utility Districts Association

Waste Management Inc.

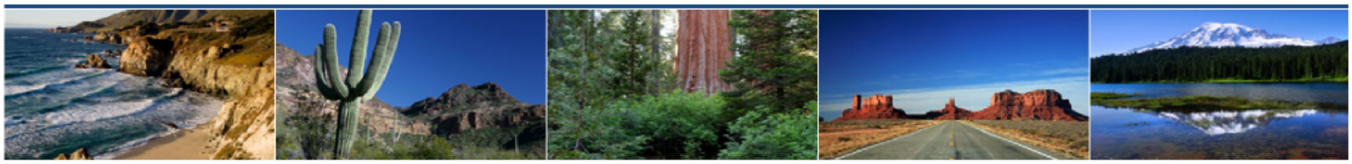
WEST Associates

Western Climate Advocates Network (WeCAN)

Western States Petroleum Association

Weyerhaeuser

Western Climate Initiative



May 7, 2009

To All Interested Parties:

Today, the Western Climate Initiative (WCI) is releasing their document "Response to Stakeholder Comments, and Final Draft Essential Requirements of Mandatory Reporting for the Western Climate Initiative." Attached to this document are the Final Draft Essential Requirements of Mandatory Reporting which include revisions to some previously released requirements, as well as new requirements for certain source categories not previously released.

New and revised sections included in this document are as follows:

General Provisions (WCI.1-10). Note that verification requirements (WCI.8) have been substantially rewritten and are provided as a separate attachment	Revised
General Stationary Combustion (WCI.20)	Revised
Iron and Steel Manufacturing (WCI.150)	Revised
Adipic Acid Manufacturing (WCI.XX0)	New
Primary Aluminum Production (WCI.70)	New (as rule format, previously in narrative)
Pulp and Paper Manufacturing (WCI.210)	New (as rule format, previously in narrative)
Soda Ash Production (WCI.230)	New
Petrochemical Manufacturing (WCI.300)	New

Sections previously released on January 6, 2009, which remain unchanged and are not included here, are as follows:

Refinery Fuel Gas Combustion (WCI.30)	Petroleum Refineries (WCI.200)
Electricity Generation (WCI.40)	Lime Production (WCI.170)
Cement Production (WCI.90)	Zinc Production (narrative)
Coal Storage (WCI.100)	Lead Production (narrative)
Hydrogen Production (WCI.130)	Coal Mine Fugitive Emissions (narrative)

You are invited to participate in a stakeholder conference call to discuss the new and revised requirements contained in this final draft and the previously released requirements on May 19, 2009, at 1:00 – 2:30 PM Pacific Time. The call-in numbers are 1-800-868-1837 (inside U.S. and Canada) and 1-404-920-6440 (outside U.S. and Canada), participant code 659537#.

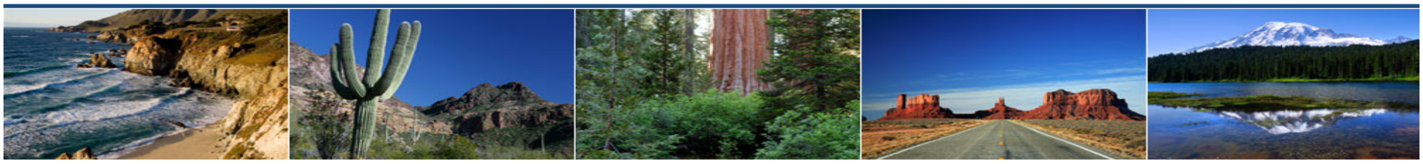
Also released on this date, as a separate document, are draft Essential Requirements for reporting for Electricity Imports. The stakeholder conference call to discuss these requirements will also be on May 19, 2009, at 11:30 AM – 12:30 PM Pacific Time, using the call-in numbers provided above.

We ask that written comments be submitted by June 4, 2009 through the WCI Website: www.westernclimateinitiative.org

Sincerely,

Jim Norton, Chair
WCI Reporting Committee
State of New Mexico

Western Climate Initiative



Response to Stakeholder Comments and Final Draft Essential Requirements of Mandatory Reporting for the Western Climate Initiative

May 7, 2009

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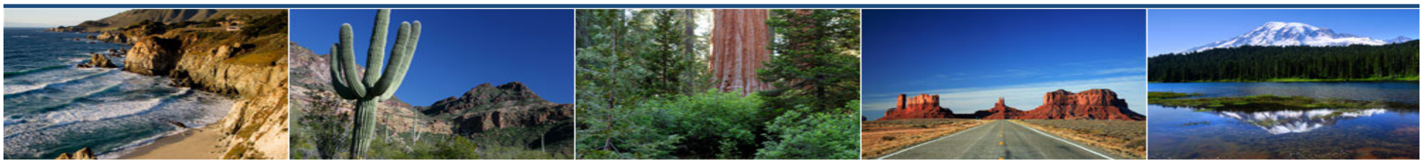
Western Climate Initiative



Response to Stakeholder Comments and Final Draft Essential Requirements of Mandatory Reporting for the Western Climate Initiative

May 7, 2009

1.0 INTRODUCTION

This document revises and expands upon the document issued in January 2009 ("Background Document and Progress Report for Essential Requirements of Mandatory Reporting for the Western Climate Initiative, Third Draft") that addressed continuing work conducted by the WCI Partner jurisdictions and the Reporting Committee. Its purposes are to: 1) respond to stakeholder comments received on the January 2009 document; 2) present proposed revisions of Essential Requirements sections previously released and identify sections that are still under review or development; 3) present proposed new Essential Requirements sections, including rule-format language for some source category requirements that were previously presented in a narrative discussion format; and 4) seek public comment on revised and new reporting Essential Requirements.

Comments on this document should be submitted in writing by June 4, 2009, through the WCI Website: www.westernclimateinitiative.org

On March 10, 2009, the U.S. EPA released the prepublication text of their proposed mandatory reporting rule (MRR) for reporting greenhouse gases (GHGs). The WCI is reviewing this proposed rule and is planning to submit comments to the U.S. EPA. WCI will also be looking at this proposed rule as a potential source for emissions quantification and/or sampling, analysis and measurement methods, just as it has reviewed other rules and protocols (e.g., California Air Resources Board [CARB], Environment Canada, Intergovernmental Panel on Climate Change [IPCC], European Union Emissions Trading Scheme [EU ETS], The Climate

Registry [TCR], World Resources Institute/World Business Council for Sustainable Development [WRI/WBCSD] Corporate Standard, industry protocols) for the same purpose.

In reviewing quantification methods in the proposed U.S. EPA rule, WCI will keep in mind that the U.S. EPA rule was designed to inform a variety of potential future policies, whereas methods for use in the WCI reporting requirements must be sufficiently accurate to support a cap-and-trade program. WCI has not had sufficient time after the release of the proposed U.S. EPA rule to incorporate a consideration of that proposed rule into the current document, but the U.S. EPA proposed rule will be considered as WCI develops the Final Essential Requirements, to be released in June 2009. WCI invites comments on which elements of U.S. EPA proposed rule might be useful for the WCI reporting requirements to support the cap-and-trade system. We urge stakeholders to provide these comments to WCI early in the comment period so that they can be considered as the WCI develops comments on the EPA rule (due June 9).

2.0 SUMMARY OF STAKEHOLDER COMMENTS AND WCI RESPONSES

This section contains a summary of the stakeholder comments received on the third draft of the reporting Essential Requirements, along with the WCI responses.[1] These are organized depending on the comments' topic or source category. The section begins by addressing comments received for which WCI will not, at this time, make changes to the reporting Essential Requirements (ERs); these include comments addressing design components of the cap-and-trade program or issues to be addressed in the future (e.g., source categories, such as fuel suppliers, for which WCI has not yet proposed reporting requirements), and comments simply not requiring a response. The next topic of comments and responses pertains to the part of the ERs known as "General Provisions." The last set of comments and responses covers the source category-specific ERs.

2.1 Comments on WCI Design Elements and Future Issues

This section summarizes comments and responses related to design elements, and future issues to be addressed under reporting and other subject areas within WCI.

[1] Where this document refers to "WCI", it represents a perspective that the WCI Partner jurisdictions have reached through consensus building.

2.1.1 Design Element Comments

Many stakeholders commented on WCI program design elements that were presented for comment in documents released earlier, prior to the January 6, 2009 "Background Document and Progress Report for Essential Requirements of Mandatory Reporting for the Western Climate Initiative, Third Draft" (Third Draft Essential Requirements). Many of these early design recommendations were presented in the "Design Recommendations for the WCI Regional Cap-and-Trade Program" released September 23, 2008, and others were first presented in early public releases related to mandatory reporting.

Verification

Many commenters questioned the need for third party verification of emissions reports (Design Recommendation 10.3 in the September 23, 2008 document). A general discussion of the value and necessity of third party verification is included elsewhere within this document as part of the responses to comments on WCI.8 relating to verification.

Thresholds

Many commenters expressed the view that thresholds for reporting and/or verification were too low. These thresholds were recommended in the September 23, 2008 document: 25,000 metric tons CO_2e per year for the cap-and-trade program (Recommendation 3.1) and 10,000 metric tons CO_2e per year for mandatory emissions reporting (Recommendation 10.2). The choice of the cap-and-trade program threshold was made after analysis of estimated facility-level emissions and was designed to ensure capture of 85-90% of WCI Partner jurisdiction emissions. Raising this threshold to 50,000 or 100,000 metric tons CO_2e as recommended by some commenters would create the potential for serious inequity among facilities in some industries, and would incentivize "leakage" of emissions to smaller facilities within an industry. The reporting threshold was set at a lower level to allow monitoring of uncapped sources for "leakage', to allow WCI Partner jurisdictions to check for avoidance of the cap by facilities underestimating their emissions, and to allow more accurate jurisdictional emissions inventories. WCI expects that many of the facilities with emissions in the 10,000 to 25,000 metric tons CO_2e emissions range will have only simple combustion sources and that emissions quantification for these facilities will be fairly simple.

Biomass in Thresholds

Many commenters, especially those in forest products industries, questioned the inclusion of biomass combustion emissions of CO_2 in determining whether a facility exceeded the thresholds for reporting or for the cap and verification. Commenters noted that these emissions are excluded from accounting or reporting under other GHG protocols such as EU ETS, WRI/WBCSD, IPCC, and Environment Canada, under the assumption that such emissions are carbon neutral. Commenters also noted that national and some jurisdictional programs encourage the substitution of biomass and biofuels for fossil fuels.

WCI Design Recommendation 1.3 calls for reporting of biomass combustion CO_2 emissions, but specifies that such emissions that are determined by the WCI Partner jurisdiction to be carbon neutral are not included in the cap-and-trade program (i.e., subject to the cap). Design Recommendation 1.4 says that CO_2 emissions from combustion of biofuels (pure, or as a fraction of blended fuels such as B20 or E85) are to be reported, but are not included in the cap-and-trade program. Design Recommendation 1.5 says that "Prior to program start, the WCI Partner jurisdictions will assess whether and how to include upstream emissions from biofuel and fossil fuel production, taking into consideration the potential for emissions leakage, the potential role of other policies (such as a low carbon fuel standard), consistent treatment among fuels, and other factors (such as practicality of implementation)." These earlier recommendations were based in part on the recognition that biomass or biofuel combustion CO_2 emissions may not be carbon neutral under all circumstances. For example, forest biomass harvesting that is not sustainable and results in a net long-term decrease in forest carbon stocks is not carbon neutral, and the use of fossil fuel combustion in the process of biofuel production is not carbon neutral if the production takes place outside the program boundaries and fossil fuel emissions are therefore not accounted for.

Inclusion of those biomass and biofuel combustion CO_2 emissions not yet deemed carbon neutral in the reporting threshold will ensure that these emissions are accounted for pending future decisions on carbon neutrality, low carbon fuel standard, and other related policies. WCI supports more reliance on biomass fuels as substitutions for fossil fuels when net GHG reductions can be achieved. WCI believes it is important to track the growth in biomass fuels usage at facilities subject to mandatory reporting, both to monitor the success of reduction strategies and to ensure rigorous and consistent emissions accounting as required in the ER.

At the same time, WCI recognizes the burdens that may be imposed on small facilities burning mostly pure biomass, such as those in the forest products industry. A provision allowing exclusion of up to 15,000 metric tons of CO_2 from the combustion of pure solid biomass has therefore been added to WCI.1(b). Furthermore, this exclusion will apply to all carbon-neutral biomass, after a WCI Partner jurisdiction has made a determination regarding the carbon neutrality of any biomass fuels. WCI is also considering an exclusion of carbon dioxide from biomass combustion emissions for purposes of determining verification applicability and from the scope of verification when one is required.

Consistency and Overlap of Reporting Requirements

Several commenters expressed concern that the reporting requirements of WCI Partner jurisdictions should be consistent, to avoid creating a patchwork of requirements across the region. This concern arises from the Design Recommendation 10.6, which states that "Nothing in the WCI program design limits the discretion of any WCI Partner jurisdiction to require reporting earlier, at lower thresholds, or for entities and facilities not covered by the cap-and-trade program." This recommendation was made in recognition that individual jurisdictions may have policies and programs in addition to the cap-and-trade program that require reporting beyond the coverage of the WCI Essential Requirements. WCI expects that any extension of reporting beyond the Essential Requirements would not be arbitrary, but would be based on the necessity of such additional reporting to support other programs and policies of the WCI Partner jurisdiction. The role envisioned for other policies is described in Design Recommendations 1.6, 5.1 and 5.2.

Some commenters also urged that WCI emissions reporting be consistent with existing or future national reporting requirements. WCI notes that the current U.S. national reporting of GHGs is limited to a small number of very large sources in the Acid Rain Program (see above for WCI comments on the recently released U.S. EPA rule proposal for GHG Reporting). WCI also notes that Environment Canada describes their current reporting program as preliminary and limited in scope: "Focusing on a limited number of emitters and basic reporting requirements, this system will serve to lay the foundation for a fully developed system".[2] The Environment Canada reporting program allows reporters to choose among multiple quantification

[2] Facility Greenhouse Gas Emissions Reporting Program, Overview of the Reported 2007 Greenhouse Gas Emissions, www.ec.gc.ca/pdb/ghg/onlineData/downloadDB_e.cfm, accessed March 9, 2009.

methodologies. Neither the U.S. nor Canadian national programs were designed to support an economy-wide cap-and-trade program such as that being developed by WCI. WCI reporting must not only cover a more comprehensive range of sources, but must also be more prescriptive in regard to emissions quantification methods to ensure equity and the integrity of the market program. WCI Partner jurisdictions do of course recognize the value of consistency with federal programs, and intend to promote and influence federal GHG emissions reduction programs that are consistent with the WCI cap-and-trade design principles and ensure that those programs translate into absolute GHG reductions.

Many commenters also urged that WCI reporting requirements be consistent with various existing GHG protocols such as WRI/WBCSD, IPCC, TCR, and/or protocols developed by industry associations. In developing these Essential Requirements, WCI has drawn upon these protocols as a source of information and methodologies. However, these protocols are not sufficiently prescriptive as to methodologies to support a market system. As noted in the WRI/WBCSD Corporate Standard GHG Protocol:

"GHG trading programs are likely to impose additional layers of accounting specificity relating to which approach is used for setting organizational boundaries; which GHG and sources are addressed; how base years are established; the type of calculation methodology used; the choice of emissions factors; and the monitoring and verification approaches employed."[3]

Starting Year for Reporting

Some commenters expressed concern that setting 2010 as the initial year for which emissions would be reported would not allow sufficient time for reporters to prepare to collect the necessary data. Design Recommendation 10.1 set this as the initial emissions year to be reported so that data would be available in 2011 to inform cap setting and allowance distribution prior to the first year (2012) of the first compliance period. While WCI recognizes that this is an aggressive schedule, requirements are unlikely to change substantially during the period when jurisdictions are in their rulemaking process to incorporate the Essential Requirements, so there is less uncertainty regarding the final form of the requirements than there might otherwise be. WCI Partner jurisdictions need not wait until jurisdictional rules are finally and officially promulgated before beginning planning for the necessary measurement and monitoring.

[3] "The Greenhouse Gas Protocol, A Corporate Accounting and Reporting Standard, Revised Edition", 2004, WRI/WBCSD, p. 14.

Electricity Use and Other Scope 2 Indirect Emissions

Some commenters recommended that facility reporting include the emissions associated with purchased electricity, heat and steam. WCI has recommended that emissions associated with electricity be covered at level of the generator or the importer of electricity for consumption within the WCI Partner jurisdiction (Design Recommendation 1.2.1). The present document does not include reporting for electricity importers, but these requirements will be addressed in future releases.

2.1.2 Future-Issue Comments

Many comments were received regarding source categories or issues that will be addressed in the future. Source categories that will be addressed in the future include oil and gas production and gas processing, electricity importers, and suppliers of residential, commercial, industrial and transportation fuels. References to these source categories in this and earlier versions of the Essential Requirements should be considered as placeholders pending a full consideration of the source categories later in the process.

Comments were also received regarding various aspects of market design and functioning. These included questions on how caps and allowances will be applied to facilities substituting on-site electricity generation from combined heat and power for purchased electricity, how allowances will be available to new sources, the kinds of projects available for offset credits, and the treatment of waste-to-energy and lifecycle emissions under the cap. These and other market-related issues are being or will be addressed by other WCI Committees.

WCI's Work Plan for 2009-10, which is available on the WCI web site (www.westernclimateinitiative.org), may be consulted for the scheduled time frames when these source categories and issues will be addressed. Comments already received on these issues will be retained and consulted as appropriate when these issues are addressed later.

2.2 General Provisions Comments

2.2.1 Applicability

This section addresses comments received on topics concerning discontinuation of reporting when facility emissions drop below the 10,000 metric ton CO_2e per year threshold, definitions used in the reporting Essential Requirements, CO_2 capture and transfer, and other miscellaneous topics related to facility/source applicability.

Discontinuation of Reporting

Several commenters objected to the provisions in paragraph WCI.1(e) relating to discontinuation of reporting. Many of these commenters said that it was unreasonable to require reporting for an additional three years after emissions drop below the reporting threshold of 10,000 metric tons CO_2e per year, and suggested that the previous year's emission level should be used to determine whether reporting was required the following year.

WCI clarifies that, for a facility not previously required to verify emissions, complete reporting of emissions is not required when emissions drop below the reporting threshold. All that is required is a certified statement that emissions were below 10,000 metric tons CO_2e for the year that emissions first drop below this level. After three consecutive years of such certified statements, the requirement ends, until and unless emissions again equal or exceed the threshold level. Without this requirement, the WCI Partner jurisdiction would be unable to distinguish between sources failing to report and sources not reporting because they fell below the threshold.

For facilities that exceeded the verification threshold in any previous year and then drop below the 10,000 metric ton threshold, full emissions reports must be submitted until three consecutive years of such reports have been submitted. The continuation of full reporting in this case is to ensure that all emissions within the compliance period are covered.

These provisions were proposed in lieu of the much simpler and easier to administer "once-in-always-in" approach. In addition, when a facility's operation has changed such that the operator has reported less than 25,000 metric tons of CO_2e emissions for a calendar year, the WCI has added a provision that will allow for verification, but not reporting, to be discontinued after the lesser of three subsequent calendar years or those years remaining in the current compliance period. Some commenters expressed support for such a provision.

Some commenters said that a provision was needed to address plant shutdown. WCI notes that temporary plant closures or shutdowns followed by restarting may vary in duration from less than a year to multiple years. WCI believes the three year sun-setting provisions are sufficient to address temporary closures or shutdowns, and note that verification costs would be trivial for any year that the facility would completely shut down.

Definitions

Several comments were received regarding the definition of "facility." WCI is currently working to develop a definition that will harmonize common usages of the term in the U.S. and Canada.

One commenter requested a definition of "operator" be added. WCI notes that "owner or operator" is defined, and each WCI Partner jurisdiction will select the specific terminology for regulated persons that is in accordance with its rule language conventions.

One commenter requested that WCI add a definition for "source category". WCI believes that the term is defined by its initial use in WCI.1(a)(1), and that a definition would be circular in that it would refer to the list in this paragraph.

One commenter questioned the use of the defined term "material misstatement" because it could imply that the misstatement was intentional, and suggested that this be replaced by "material error" or "material inaccuracy". WCI notes that the word "misstatement" does not imply intent. The word "material" also does not imply intent, but refers to the quantitative significance of the misstatement, as indicated in the present definition. Also, WCI points out that the question of intent need not be determined for civil liability under the standards of strict liability (U.S.) or absolute liability (Canada).

One commenter asked that definitions of "biomass" and "process emissions" be added. WCI continues to work on developing a comprehensive definition of biomass, and will take note of the more detailed comments regarding biomass as it does so. WCI is working to develop a definition of "process emissions" that will harmonize slightly different existing definitions in other rules and voluntary GHG protocols.

One commenter requested that a definition of "impregnated saw dust" be added. WCI is working to develop a definition, which will generally refer to saw dust from wood treated or impregnated with resins or glues derived from fossil hydrocarbons.

CO_2 Capture and Transfer

Several commenters objected to the inclusion of captured or transferred CO_2 in the emissions totals used to determine whether an emissions threshold (for reporting or verification) has been exceeded [WCI.1(b)(4)], on the basis that this CO_2 is not emitted. WCI believes that inclusion of captured CO_2 in the thresholds is necessary to ensure that jurisdictional audit or third party verification can be performed to verify that the reported capture amount was valid. The Reporting Committee does not expect that captured and transferred or stored CO_2 would be subject to the cap.

Miscellaneous Applicability Issues

One commenter asked that WCI clarify whether sources that WCI later determines are not covered by the cap will then no longer be required to report emissions. WCI cannot say at this time, because it depends on the specifics of the source category, and WCI Partner jurisdictions would individually have the option to require continued reporting to provide data needed for a jurisdictional policy or program.

One commenter understands that WCI will sum reported emissions to obtain a regional total, and asks that WCI specify that jurisdictional totals be calculated. WCI can clarify that this is an intermediate step that is necessary for cap setting and allowance distribution. It is not specified in the Essential Requirements, which are requirements for reporters and verifiers, not WCI Partner jurisdictions.

One commenter recommends that the reporting program allow companies with multiple facilities to compile and submit one aggregated report with facility level emissions to TCR. WCI can clarify that emissions will be reported facility by facility and that reports will be submitted to each WCI Partner jurisdiction. However, WCI will work to ensure the greatest consistency possible between the reporting tools of different jurisdictions. Work to develop the regional emissions database and the jurisdictional reporting tools will begin later in 2009, and stakeholders will be given the opportunity to comment on their design.

One commenter recommends that, for industry sectors with emissions that are well characterized, emissions reporting should be limited to only those sources that are significant. WCI notes that the de minimis provisions of WCI.2(d) allow for use of simplified methods for estimating emissions from small sources that collectively account for less than 3% of the facility emissions total, not to exceed 20,000 metric tons CO_2e. This de minimis provision is intended to address concerns regarding the burden of estimating emissions from sources that contribute little to the facility total emissions.

One commenter asks whether companies are required to report GHG emissions from the electricity used at their facility. WCI can clarify that these emissions are not required to be reported, in contrast to some voluntary GHG protocols. Emissions associated with electricity will be covered by the cap, but the covered entities will be generators and electricity importers. Requirements for electricity importers are under development, and draft recommendations will be released later in 2009.

2.2.2 Administrative Requirements

The comments related to administrative requirements covered the nine topics summarized below: content of report, confidentiality, compliance and enforcement, designated representative, document retention, GHG inventory management plan, report revisions, reporting (general), and report deadlines.

Content of Report

Many commenters expressed concern that the information required in emissions reports for individual units, processes, sources, fuel types, activities and operations is excessive and unnecessary. This concern was expressed in comments regarding both the general requirements in WCI.3 and regarding source category specific requirements. For some commenters, the concern about the level of detail in reports was in part a concern about confidential business information (CBI). Also, several commenters felt that third party verification would provide sufficient confidence in reported data, therefore, detailed reporting (e.g., at the unit, process level) is overkill, and potentially redundant.

The reporting of data for "individual units, processes, activities and operations" in WCI.3(j) depends upon the requirements of the source-category specific quantification method. Where such data is needed for a WCI Partner jurisdiction to properly assess and perform quality assurance on a facility's emissions report, the data is required, but may not be made public if it qualifies as CBI under laws and regulations of that jurisdiction. In other cases, such as for general stationary combustion, reporting is only designed to be for specific fuels, not at the unit or process level. Unit-level reporting and providing detailed data as part of the emissions report helps to facilitate verification and agency audits; verification should not take the place of detailed reporting. It is noted that the proposed U.S. EPA mandatory GHG reporting rule has more detailed specifications than does the current WCI reporting requirements.

One commenter states that reporting by "non-capped facilities" should be simplified both in determining if they meet thresholds, and in actual reporting requirements, as using simplified methods for these purposes does not compromise the effectiveness of the cap-and-trade program. WCI notes that most emissions from non-capped sources will be from general stationary combustion, and these facilities without the need to verify can use fairly simple calculations (either equation 20-1 or equation 20-2 in WCI.20) to determine emission levels. Reporting for these types of sources is intended to be for total emissions (by fuel and GHG) at the facility level.

One commenter states that the WCI methods require unreasonable effort to quantify sources that are smaller than the inaccuracies in more significant sources (in addition to requiring an unnecessary level of reporting detail.) WCI understands that uncertainties for some larger emission sources at a facility may be greater than total emissions from smaller sources; however, it is necessary to receive a complete emission profile for reporters. Which sources are smaller and which are larger may vary substantially between facilities; therefore, emission sources that fall within the de minimis specification of 3% of total emissions (see WCI.2(d)) may be estimated using alternative GHG estimation methods that will reduce the reporting burden.

Confidentiality

Many commenters raised concerns about maintaining the confidentiality of data included in GHG emissions reports to be submitted under the WCI program. Some commenters maintained that the separate reporting and public disclosure of emissions from different units or processes would be tantamount to the divulgence of confidential business information (CBI) because it would allow competitors to reverse engineer the commenter's process. Other commenters were concerned about the possible public disclosure of CBI used to calculate emissions, such as "physical fuel information."

The commenters offered two different solutions to this problem. Some advocated restrictions on the disclosure of data to the public. Others believed it necessary to withhold information from the WCI Partner jurisdictions themselves in order to protect CBI. One commenter, for example, stated that for combustion emissions the WCI should require the submission of only emissions rates, not the fuel-use data employed to calculate those rates. Many of the commenters advocating this approach maintained that the third party verification requirement would provide sufficient assurance of the reliability of emissions reports and therefore obviated the need to submit the underlying data to WCI Partner jurisdictions.

Some of the comments argued that reports to the WCI Partner jurisdictions or the data available to the public should be limited to aggregate emissions.

One commenter asserted that the treatment of data submitted by Canadian entities should be governed by Canadian, not U.S. law. In contrast, many other comments complained about the failure of the Essential Requirements to address confidentiality and asked WCI to include a common approach to public disclosure.

WCI's response is that, in general, confidentiality will be governed by laws and regulations of the WCI Partner jurisdiction where the data are reported. WCI is a regional organization for cooperation, and does not have the power to direct jurisdictions on how to apply their existing laws regarding disclosure and non-disclosure. WCI policy calls for public disclosure of facility-level aggregate emissions data in order to ensure market transparency. Jurisdictional laws and regulations govern whether disaggregated emissions data and ancillary data may be considered confidential. In at least some WCI Partner jurisdictions, the reporting and public disclosure of disaggregated emissions data has been required for decades with no reported adverse effect on the industries subject to those requirements. Section 114(c) of the Clean Air Act, for example, provides that U.S. EPA may not consider any emission data to be confidential.

The laws of the WCI Partner jurisdiction typically specify the procedures by which data submitted to an environmental agency may be judged to be confidential and withheld from the public, and these procedures vary widely from jurisdiction to jurisdiction.

Confidential data submitted to jurisdictions and then transferred to the regional database within TCR will not be subject to public records laws, because TCR is a private organization, acting in essence as a contractor to the jurisdiction. The data will be available only through each WCI Partner jurisdiction.

Comments advocating restrictions on the data submitted to WCI are addressed elsewhere in the response document.

Compliance and Enforcement

<u>List of Violations.</u> Several comments objected to the provision in WCI.5(b) that "[e]ach violation of this rule shall constitute a single, separate violation for each day beyond the specified reporting date" and the subsequent list of types. A number of comments urged WCI to follow California's example and argued that WCI.5(b) was more stringent than section 95107 of the California GHG reporting rule. Two commenters maintained that the potential penalty exposure under the WCI approach could be "many times higher" than under section 95107. According to these comments, under section 95107, the failure to include all information required allegedly would be "considered only one daily violation, irrespective of the quantity of information omitted" under section 95107 but could be considered multiple violations under WCI.5(b). One comment argued that "WCI should not extend compliance and enforcement actions beyond the submittal of the GHG emissions report and verification according to the deadlines established."

WCI disagrees with the approach advocated by these comments and in fact has revised WCI.5(b) to ensure that it is not given an unduly narrow interpretation. The list of violations has been removed because it may be mistakenly interpreted as an exclusive list. Failure to comply with any requirement of the rule is potentially a violation. The revised language for WCI.5 is substantively similar to the effect of California law taken as a whole, including section 95107.

<u>Leaving Compliance and Enforcement Issues to the Individual Jurisdictions.</u> A number of commenters urged WCI to leave the scope of enforcement authority and potential penalties to each WCI Partner jurisdiction. WCI believes this essential requirement is necessary, in addition to existing jurisdictional rules and mechanisms for enforcement and compliance and notes that many WCI Partner jurisdictions already have statutory enforcement authority similar to that contemplated by the ERs for violations of their existing rules.

<u>The Relationship of Enforcement to Third-Party Verification.</u> A number of comments argued that provisions for enforcement were unwarranted in light of the expansive, third-party verification program already required of reporting facilities. WCI believes that jurisdictional enforcement is a key component to the integrity of the WCI cap-and-trade program. Third party verification, though a powerful means of ensuring the accuracy of reported data, is not an enforcement activity. The third party verification process identifies non-compliance issues; it

does not prescribe or take enforcement action. Also, under the WCI program not all facilities will be required to have third party verification. WCI Partner jurisdictions need to have enforcement tools besides market remedies to insure program compliance.

Choice of Methodologies. The comments were that it is unreasonable not to allow choice of alternative data or methodologies for GHG calculation for certain specific sources. Such calculation and methodology should be justified with documentation by the reporter and verified by the verifier. WCI believes that allowing unlimited choice of data or methodologies would not ensure the consistency in reported emissions required for a market program, and could allow methodology choices to be made to over- or underestimate emissions for market advantage.

Standard for Liability. The comment was that WCI should limit the compliance and enforcement actions related to GHG reporting to submittal of the emissions reports and any willful falsification of these documents. WCI disagrees. Strict liability (U.S.) or absolute liability (Canada) is the normal standard for the imposition of civil liability in environmental regulatory programs. WCI.5(a) has been revised to make it clear that a strict or absolute liability standard is imposed, depending on whether the jurisdiction is U.S. or Canadian.

Fines. The comment was that fines for violations do not need to be consistent across states and should be subject to implementation by the individual states and provinces as appropriate. However, WCI.5 does not specify that fines for violations be consistent across WCI Partner jurisdictions.

Missing Data and Data Capture. Commenters stated that there are two vital provisions missing in the WCI reporting requirements that are linked with the compliance and enforcement requirements in WCI.5:

1. There needs to be provisions to address equipment breakdowns or other types of malfunctions when data cannot be physically; and
2. There needs to be provisions for defining data capture requirements.

In response to this comment, new sections, based on the referenced sections of the California mandatory GHG reporting rule, have been added to the ERs.

Deferral of Enforcement. The commenter stated that that reporting facilities should be given sufficient time to rectify any concerns with respect to reported emissions prior to having penalties imposed on them. WCI Partner jurisdictions will likely provide compliance assistance to reporters to answer questions about measurement and reporting. However, adding this suggested provision would release reporters from the responsibility to ensure that the reported emissions are correct when submitted.

Designated Representative

Certification Requirement. A number of commenters objected to the requirement in WCI.7(b) to prepare and submit to the WCI Partner jurisdiction a certificate or representation agreement selecting the designated representative. Some argued that the requirements was "not consistent to other instruments which the designated representative must certify" under Canadian programs. Others maintained that requirements for designated representatives should be set by the individual WCI Partner jurisdictions.

WCI recognizes that the concept of a "designated representative" is an unprecedented concept in the Canadian context. Therefore, WCI.7 will only be applicable in the U.S. WCI Partner jurisdictions. For the certification statement language in WCI.3, there are now two alternatives for the U.S. and Canadian jurisdictions respectively [WCI.3(n) and WCI.3(o)], with the U.S. language referencing the Designated Representative of WCI.7 and the Canadian language requiring certification by the "operator's representative." The "operator's representative" provision is meant to have the same effect as the designated representative provision, but follows precedent that has been set in other Canadian and provincial statutes and regulations whereby the representative is based on either the corporate structure or the management of the operation.

Liability for Acts of Previous Designated Representative. Several commenters objected that WCI.7(e) could be interpreted to impose personal liability on a subsequent representative for the representations, actions, inactions, and submissions of the prior representatives.

To clarify the meaning of this section: Owners and operators will be liable for compliance with the monitoring and reporting requirements. Until the U.S. WCI Partner jurisdiction receives the new certificate, the facility is bound by the actions of the existing Designated Representative. The binding language does not create personal liability for the proposed new Designated Representative; it only prevents the new Designated Representative from repudiating the actions of the existing Designated Representative. That is, the representations of the previous Designated Representative are not invalidated simply because there is a new Designated Representative.

Consistency with Title V. A number of commenters urged WCI to model the designated representative requirements on the "responsible official" provisions of rules adopted under Title V of the Clean Air Act. A number of these comments noted that there was no requirement to certify in Title V. One comment noted that there was such a requirement in the U.S. Acid Rain program, but argued that "the circumstances are different in that it applies exclusively to large power plants" and that "these plants often have divided ownership with different utilities owning percentages of different turbines at the same plant."

WCI points out that the Title V provisions are not designed to support an emissions trading program. WCI.7 requirements are modeled instead on provisions of the U.S. EPA Acid Rain program which, as an emissions trading program, is a closer analogy to the WCI program. The intent is to ensure that upper level management attention is paid to ensuring that all the necessary systems are in place to ensure accuracy of the reported data, which is convertible to a financial obligation or benefit, and that there is a single person responsible for certifying the reported data.

Consistency with Part 75. Commenters stated that the proposed ERs are much more stringent than the existing Part 75 certification requirements for designated representatives, and add undue burdens to business operations by controlling how businesses delegate authority and manage operational responsibilities.

WCI disagrees. WCI.7 is modeled on and closely follows the designated representative provisions of the Acid Rain rules (which appear in 40 C.F.R. Part 72, rather than Part 75).

Qualifying Officers. Commenters stated that the ERs should allow any corporate officer to be a designated representative. In addition, corporate staff other than the environmental director should be eligible to be a designated representative (e.g., the director of sustainable development).

WCI points out that the intent of WCI.7 is to ensure that upper level management attention is paid to ensuring that all the necessary systems are in place to ensure accuracy of the reported data, which is convertible to a financial obligation or benefit. The language does not require that the individual have the title of "environmental director", and it is possible that other persons, such as the person holding the title of "director of sustainable development" might qualify to be the designated representative, depending on their duties and responsibilities.

Definitions. The comment requested to include definitions of the terms “certificate of representation” and “Designated Representative” in the General Provisions section. WCI believes these terms are fully described in WCI.7, and that any definition would simply refer to that section and would thus be circular rather than adding meaning.

Document Retention

7-Year Retention Period. Several comments objected to the proposed requirement to retain records relating to GHG monitoring for 7 years. Many of these comments urged consistency with the five-year record retention requirement found in U.S. EPA's Title V permit program, many state air quality permit programs and The Climate Registry's General Verification Protocol. Some argued that the additional two-years of retention time would impose significant burdens, such as “costly and unnecessary re-programming of CEMS hardware and software systems” and the additional cost “to maintain the space for hard records and electronic storage for electronic records.” One commenter questioned “the need for 7-year data retention for CEMS CO_2 data that has been reported annually to EPA's Clean Air Markets Division (“CAMD”) and which data submittals must pass EPA's data submittal standards and filtering requirements each year upon submittal.” Two comments agreed with the 7-year retention requirement.

WCI believes that 7 years is a reasonable retention period in the context of this program. The key compliance transaction is surrender of allowances in Year 4 (if the first year of a compliance period is designated Year 1). The 7-year retention requirement ensures that all the emissions records which are supporting data for this compliance transaction are retained for an additional 3 years after the transaction. WCI notes that 7-year retention periods are not unusual in guidelines for retention of supporting documents for tax and financial purposes.

Logging Requirements. Two comments maintained that the requirement for a single log that tracks both procedural and instrument changes is counter productive. They noted that typically, this information is individually managed in either document control portions of procedures or in instrumentation calibration logs.

WCI believes that auditing of multiple logs without a master list would be extremely difficult. A master log could reference other logs for details.

Another comment requested that WCI should delete the provision to maintain a log of procedural revisions in GHG accounting or recommend that this is a voluntary recommended measure, not subject to an enforcement action. It has been our experience that the verifiers will request such information, but to have a company face an enforcement action for missing a single log entry is an example of the unintended consequences of such provisions.

Under the WCI reporting program, WCI Partner jurisdictions retain the authority to audit any emissions reports, as a check on the validity of the verification report and for reports which are not required to be verified. If records of changes in instrumentation or calculation methods are lacking, it will be extremely challenging to determine the accuracy of the emissions report. WCI Partner jurisdictions may use discretion in taking enforcement action for inconsequential violations.

<u>Key Personnel.</u> The commenter states that the requirement in Section WCI.4(c)(10) to retain the names and "documentation of key personnel involved in emissions calculating" is vague. In particular, the reference to "documentation" is vague and should be limited to relevant emissions related documentation, or should be stricken entirely, given that subsection (c) lists the documents to be retained.

WCI believes that it is clear from the context of this language that the documentation referred to is that relating to emissions calculation and reporting.

<u>Certificates of Representation.</u> The commenter stated that the information listed in WCI.4(c)(10) should include all Certificates of Representation. However, certificates of Representation are submitted as part of the emissions data report, and therefore do not need to be listed separately here (see WCI.4(c) introductory phrase).

<u>Applicability.</u> The commenter stated that information retention requirements should be qualified to clearly reflect that they are applicable only if appropriate. For example the retention requirement language in subsections (c) and (d) could be revised as follows: "the following information, 'if applicable' . . ." This qualification is particularly important for the record keeping requirements specified under WCI.4(c)(7), WCI.4(c)(9), WCI.4(d)1, WCI.4(d).

WCI agrees. This phrase has been added to the referenced sections.

One commenter believes that the requirement in WCI.4(c)(3) to keep documentation of the process for collection of emissions data is excessive. There is little purpose served by the source having to maintain a document identifying that it collected its fuel usage data (assuming that is what is meant by emissions data) from its fuel meter or purchase records. This will be self-evident from the records themselves. WCI.4(c)(7) requires "documentation of biomass fractions for specific fuels." It is unclear what is meant by this. If the requirement is for sources to differentiate between and record white wood, bark, shavings and sawdust consumption, the commenter fails to see the benefit and questions the typical source's capability to report this data. This requirement also seems to contradict the intent of WCI.23(b)(2), which indicates that a biomass source need not monitor fuel usage if it instead monitors steam production.

WCI believes that documentation of the process for collection of emissions data need not be complex for reports using simple methods and with few emitting units. Documentation of biomass fractions would not be applicable for pure biomass. The introductory phrase will be revised to indicate that only those items on the list that are applicable must be retained.

GHG Inventory Management Plan

Numerous commenters objected to the proposed requirement in WCI.2(e) that the owner or operator prepare and implement a GHG Inventory Management Plan. The commenters contended that the requirement would be costly and time-consuming, would constitute an unnecessary intrusion into the internal management of regulated facilities and would provide no additional benefits beyond those that would otherwise be achieved by the ERs. Many comments stated that it would be more appropriate to recommend the adoption of a GHG Inventory Management Plan in guidance. A few comments stated that a GHG Inventory Management Plan should not be imposed if third party verification is required.

WCI has carefully considered the requirements for a GHG Inventory Management Plan and has decided that a requirement for the owner or operator to establish and maintain data acquisition and handling activities that provide for the transparency and verifiability of emissions calculations will instead best serve the function of ensuring that verifiers and auditors can review and confirm a facility's GHG emission calculations and documentation in the most efficient manner (thereby reducing total costs). This requirement will also help to ensure that GHG emissions reports parallel the accuracy and transparency found in corporate financial reports and records, and will help to ensure compatibility with international carbon markets, such as the EU-ETS. A formal GHG inventory management plan is, however, a recommended best practice for facilities and will likely be outlined in guidance documents.

Report Revisions

Revision Submittal Deadlines. A commenter stated that WCI.2(f) contains revision submittal deadlines of 30 to 60 days, on top of requiring pre-approval of those revisions by the jurisdictional authority. These deadlines may be beyond the control of reporters given the jurisdictional authority approval step. Reporters cannot be held responsible for deadlines they cannot control.

WCI points out that jurisdictional review and approval does not begin until after resubmissions of revised reports. Therefore the 30- and 60-day periods do not include this step. Jurisdictional "acceptance" means that the WCI Partner jurisdiction agrees that the data originally reported may be replaced by the revised data. WCI thinks the language is clear on this point.

One commenter suggested that report corrections should be allowed up until the final date of annual compliance certification under the cap-and-trade program. However, WCI believes that for proper market functioning, it is important that publicly available emissions reports be corrected in a timely manner, not just immediately prior to the allowance surrender date.

Another commenter requested that WCI should consider modifying subsection WCI.2(f)(3) to allow 60 days for filing corrected reports not subject to verification. Additionally, both subsection (f)(2) and (f)(3) should include language to clarify that the time period for reporting corrections applies to the time frame in which the report must be filed within the applicable WCI Partner jurisdiction.

WCI points out that the longer timeframe for submitting revisions to reports subject to verification is to allow extra time for the verification of the revised data. This additional time is not needed for unverified reports. WCI believes the language in (f)(2) and (f)(3) is clear that the 30 and 60 day timeframes refer to the maximum time between finding the error and submission of the revised data to the WCI Partner jurisdiction.

Deadline for Jurisdiction Approval of Revised Reports. One commenter urged adoption of a deadline for the WCI Partner jurisdiction to take action on a revised report and suggested that the proposed ERs be reworded such that the revised reports are deemed accepted and approved within 30 days of filing unless the jurisdiction has notified the reporter that the revisions have not been accepted and approved.

WCI understands the need for Partner jurisdictions to approve or disapprove revised reports submitted under WCI.2(f) in a timely manner and therefore has added a deadline for the jurisdiction to take action. At the same time, because of the paramount need for data accuracy, it would not be appropriate to provide for approval by default, as suggested in the comment. Rather, reporters will have to avail themselves of whatever existing remedies the law of the WCI Partner jurisdiction provides to compel an administrative agency to comply with a regulatory deadline. In addition, WCI believes, given the likely complexity of many report revisions, that 60, rather than 30, days would be the appropriate time frame for the agency response.

Revisions in Initial Cycle. One commenter recommended that, in the initial years of reporting, errors be corrected as part of the next reporting cycle, not within the 30 or 60 days as proposed. WCI points out that for proper market functioning, it is important that publicly available emissions reports be corrected in a timely manner.

Reporting (General)

Minimizing Complexity and Cost. WCI recognizes that many reporters see these draft Essential Requirements of mandatory reporting as unfamiliar, complex and difficult to follow. The WCI Partner jurisdictions will work to provide outreach, training and compliance assistance to reporters.

Several stakeholders expressed concern with the administrative and real cost burdens that they may incur to comply with the reporting requirements as drafted. They requested that effort be made ensure the reporting needs do not go beyond what is required for a properly functioning cap-and-trade system. One commenter specifically requested an assessment of the total cost of compliance with the proposed reporting and monitoring requirements compared against alternatives to find a balance between data accuracy and the level of effort/cost of compliance.

The costs of inaccurate emissions data are impossible to quantify, because the impacts are on the integrity and functioning of the allowance trading system, which will be a substantial market. WCI has been working to incorporate specific improvements suggested by stakeholders and has attempted to minimize the complexity and burden to the extent possible without jeopardizing the integrity of the data and the market system. WCI believes that revisions and clarifications made in this version may reduce burdens.

Submission Process. A commenter requested clarification as to whether those with reporting requirements would only be required to report their emissions once to either the WCI or The Climate Registry (TCR). Another stakeholder recommended that the development of reporting through the TCR be harmonized with other existing mandatory reports in WCI Partner jurisdictions, to limit the reporting burden on regulated entities.

Emissions reports will be submitted to the WCI Partner jurisdiction, as specified by WCI.2(b)(1). Some jurisdictions may choose to develop an independent reporting tool and database, and then transfer the data to the WCI regional database to be developed by TCR. Other jurisdictions may choose to adopt and customize a reporting tool hosted by TCR but under the control of the jurisdiction. A WCI Partner jurisdiction would ideally be able to harmonize reporting requirements to a certain extent to streamline the requirements on reporters within its jurisdiction.

Drawing on Existing Protocols. Three commenters from the forest industry expressed concern about the extent and complexity of monitoring, calculation and reporting required in the draft Essential Requirements of Mandatory Reporting. They recommended that WCI follow existing internationally accepted protocols that streamline accounting and reporting requirements.

Where possible, the WCI has attempted to reduce the level of reporting burden for the forest industry through revisions and clarifications. A certain level of consistency and accuracy is required to operate a market-based program. Existing protocols that the WCI looked at that did not provide for those requirements were not recommended.

Distinguishing Reporting Applicability from Other Aspects of Cap-and-Trade Applicability. One commenter requested the draft Essential Requirements of Mandatory Reporting recognize of the benefit of waste-to-energy by excluding it from the requirements.

WCI points out that the requirements set out in the draft Essential Requirements of mandatory reporting are for reporting only. Many of the emissions sources that are required to report may have environmental benefits, but those benefits should be recognized and encouraged through policies other than a waiver of reporting requirements. For waste-to-energy specifically, WCI recognizes that there are multiple issues to be considered in evaluating the overall environmental impacts

Refinery Requirements. One commenter from the oil and gas industry requested that the WCI only require the use of best available data to report 2010 calendar year emissions, expressing concern about the time to prepare for any new programs or measurement equipment, and associated training, required to meet the reporting requirements during the first year.

The reporting requirements for refineries build off of existing measurement and reporting requirements. WCI believes it should be possible for refineries to begin preparing for the implementation of the reporting rules before promulgation of final rules. WCI will address requirements for other segments of the oil and gas industry later this year.

Cogeneration Requirements. One commenter expressed disagreement with the forest product industry cogeneration facilities being included under WCI.50 with the dedicated electric generation units. Regarding pulp and paper manufacturing, the commenter has concerns about the mass balance approach proposed and pointed to the tools for recovery boiler reporting the industry developed with the help of WRI.

Requirements for recovery boilers have been revised, utilizing information provided by industry commenters.

Weigh Feeder Terminology. One commenter suggested that, in regard to validating fuel consumption estimates, the more general terminology of weigh feeder, which includes weigh belts, conveyor scales, and other devices, be used.

WCI agrees with this interpretation, which may be provided in guidance documents if not incorporated into the language in WCI.2.

Stakeholder Input. A stakeholder association felt that it had not been given the opportunity to provide comprehensive input into the WCI proposals and requested that industry have an opportunity to provide meaningful input on the proposals.

WCI recognizes the importance of stakeholder engagement in design of the cap-and-trade system and is interested in learning from others' experience. Stakeholders are being requested to provide input on the final draft Essential Requirements and additional opportunities for input will be available at the jurisdictional level.

Report Deadlines

April 1 Deadline for Submission of Reports. Several comments requested a deadline for the submission of emission reports later than the April 1 date specified in WCI.2(b)(1). Many of these comments contended that it would not be feasible to compile the necessary data, prepare the reports and conduct internal QA/QC by April 1. Others noted that data needed to develop GHG emissions reports would in some instances not be available until some time after the end of the calendar year.

Some comments advocated an alternative deadline of June 1, because it would provide "a reasonable balance as among the various existing or proposed mandatory GHG reporting deadlines for WCI Partner jurisdictions" or "to maintain consistency with other reporting requirements in other Canadian jurisdictions." Others advocated a deadline of July 1, in order to give reporters additional time after the existing Canadian deadlines to work on their GHG inventories or to be consistent with the U.S. toxic release inventory deadline.

The WCI reporting deadline of April 1 is driven by the need for verification to be completed before July 1, to meet Design Element 12.2, which requires allowances for the first compliance period to be surrendered by July 1 of following year.

20 Days to Respond to Requests for Verification of Applicability. A number of commenters contended that the 20-day timeframe specified in WCI.1(f) for responding to a request to demonstrate that emissions have not exceeded one or more of the applicability criteria was too short.

WCI believes that a 20-day time frame is appropriate for operators to demonstrate they have not exceeded one or more of the applicability thresholds. In a market system timely compliance reviews will be paramount to the proper function of the market. For reporting operators this documentation and data was the foundation of the submitted emissions report and should have been previously assembled and retained. Operators outside the reporting requirement should have relatively simple data and should have documentation from the preliminary estimate to determine if they were subject to the reporting requirements. In addition, these comments failed to note that the ERs specify 20 *working* days.

10 Days to Respond to Requests for Supporting Data. Several commenters also questioned the reasonableness of the 10-day timeframe specified in WCI.4(f) for responding to a WCI Partner jurisdiction's request for the data records supporting an emissions report.

WCI believes this deadline is reasonable because it applies to the submission of records that the facility should already be keeping. In addition, these comments failed to note that the ERs specify 10 *working* days.

Strict Compliance. A commenter stated that given that the WCI Partner jurisdictions will not have reporting regulations in place until late 2009 at the earliest, it is unreasonable that reporting in strict compliance with the reporting regulations be required in 2011 for the 2010 emission year. Emitters will require time to develop GHG management plans, modify processes and purchase and install sample ports, sampling devices and measuring devices as required by the reporting regulations. Reporting in strict compliance with the reporting regulations should only commence for the emission year that is two years following the year reporting regulations are adopted. This will allow emitters the necessary time to put appropriate equipment and emission measurement systems in place prior to having to meet specific sampling and measurement requirements. Reporting with less stringent requirements beginning in 2011 for the 2010 emission year is reasonable.

WCI points out that problems in the European Union Emissions Trading Scheme (EU ETS) show the importance of using good data to determine allowances and caps. 2010 emissions data will be used, along with other information, in setting allowances and caps for the first compliance period. Using data that is incomplete or not strictly comparable to compliance period data could compromise market functioning.

2.2.3 Verification Requirements

A substantial volume of stakeholders provided input on WCI.8, the Essential Requirements for verification. Many stakeholders expressed strong opposition to the requirement for facility owners or operators to obtain third party verification of their emissions reports. Certain stakeholders expressed opposition to specific components of the verification requirements such as the level of assurance or the timing of verification statement submissions. Some stakeholders were in favor of regulatory agency review of reported emissions in place of verification, relying on a system similar to that used for other types of contaminant reporting. Other stakeholders expressed a desire for clarification of certain elements of the verification process. A number of stakeholders also expressed support for verification, accreditation requirements and a three-year verification cycle. Just fewer than 40 stakeholders provided feedback on the topic of verification.

The WCI appreciates the input from stakeholders on the topic of verification and has considered each comment received, making an effort to understand the reasons behind the concerns expressed. The WCI has made significant modifications to WCI.8 in response to the comments received but still firmly believes that third party verification is necessary for the cap-and-trade program. The discussion below describes the reasons the WCI believes third party verification is necessary and responds to the comments received on verification. The discussion also indicates how WCI.8 has been modified, and provides rationale for decisions WCI has made regarding the content of the verification requirements.

Rationale for Third Party Verification

In deciding to require third party verification of reported emissions, the WCI considered a number of factors, including:

- Experience of verification and verification requirements of other programs, such as those from Alberta, California and the European Union;
- Costs of verification;
- Alternatives to verification, and
- The unique nature of reporting for cap-and-trade.

By examining the experience of other GHG programs, WCI has found that third party verification is a cornerstone of national and international GHG reporting protocols. Internationally, third-party verification has been employed by several GHG programs, including the United Nations Framework Convention on Climate Change (UNFCCC) Clean Development Mechanism (CDM), European Union's Emissions Trading System (EU ETS), the United Kingdom's GHG Emissions Trading System, and Alberta's Specified Gas Emitters Program. Within WCI Partner jurisdictions, California's mandatory GHG reporting rule (AB 32) requires third party verification of reported data to ensure high quality and accurate reporting. The Climate Registry also requires third-party verification for its voluntary reporting program.

In general, GHG emissions are calculated from fuel and other data and not directly measured, as is often the case with criteria air contaminants for "traditional" environmental reporting. Some of the methods for calculating GHG emissions can be complex and potentially subject to reporting errors. Experience with both voluntary and mandatory GHG reporting programs shows that errors are quite common in the development of GHG inventories. Third-party verification provides an independent evaluation of the GHG calculation process and helps to ensure all specified methods are complied with in calculating GHG emissions. Having an independent third party evaluate the completeness of emission reports and compliance with reporting requirements substantially enhances the value and credibility of submitted emissions reports.

WCI is proposing to require a verification process that is based on financial auditing practices, consistent with international best practice for GHG programs, and already in use in existing voluntary and mandatory programs. In order for WCI Partner jurisdictions to provide this quality and level of assurance of reported GHG data, additional staff resources and funding would be needed.

Accreditation of verifiers provides a systematic consistent approach which may not be available using a "qualified professions" approach, as recommended by some commenters. The resources available to support rigorous agency review would vary by department, division, jurisdiction, etc. Thus, variability in how agency reviews are conducted, especially across jurisdictional borders, would be expected. The use of verifiers that are trained and accredited under a common framework will provide consistency that agency review lacks. The use of accredited, independent third-party verifiers is the most cost effective mechanism to remain consistent with international best practices and assure high quality data.

Accurate emissions data are especially important if the reported emissions are used to determine compliance with a cap-and-trade program because the reported emissions will be reconciled with allowances to determine program compliance. Entities will account for allowances as “assets” and emissions as “liabilities” on their financial statements. In a future cap-and-trade market, it is particularly important to remove any appearance of conflict of interest that would arise with facility operators verifying their own emissions reports, especially when those data take on monetary value.

The advent of GHG information carrying financial value has spurred conversations between financial auditors and GHG verification bodies to work to consolidate GHG assessments so that financial institutions can rely upon verification bodies' findings rather than duplicating the GHG assessments. This reconciliation effort, which is underway, speaks to the importance of high quality GHG data for financial applications such as regulatory compliance and market transactions. Most financial institutions believe it is critical to have confidence in reported emissions within a cap-and-trade program for the financial implications if for nothing else.

However, the WCI recognizes that it is important to evaluate and balance the degree of assurance required for the program to operate effectively in comparison with the costs associated with achieving that level of assurance. The WCI looked at a cost evaluation of verification in an existing voluntary program, the California Climate Action Registry (CCAR). The verification costs were determined to be relatively minor for the types and sizes of the facilities subject to the regulation. The costs were determined to be pennies on the metric ton. In comparison, the current costs for purchasing a metric ton of CO_2 in either a voluntary or compliance market range anywhere from US$ 3 to US$ 40.

The CCAR program has found that third party verification adds value to the process of accurately accounting for GHG emissions. On average, due to the complicated nature of GHG emissions, entities usually have to make corrections to their initial emission reports before they are able to successfully submit them to GHG programs for review and acceptance. As a result of errors identified during verification, entities have generally found that the verification process plays a key role in helping to strengthen their internal GHG data and management processes. CCAR has over four years of experience using third-party verification for its voluntary GHG reporting program. Over that period of time, over 200 entities have successfully completed the verification process. One common occurrence throughout the process is that entities gain significant benefit, in terms of data accuracy, from third-party verification. Almost all initial entity reports are changed as a result of verification.

In reviewing the CCAR verification process, only two emission reports out of 600 did not ultimately receive an acceptable verification finding in their first year of reporting. In both cases the entities did not have the appropriate data available to support their reported emissions. Also, in both instances, the entities were small organizations where mobile sources represented a significant portion of the inventory, and the emissions data from the mobile sources was not adequately tracked to be confirmed and reported.

In looking at other GHG programs, the WCI also determined that the cost of verification activities can vary significantly based on a number of key factors associated with a facility's emissions. Note that a facility can control two of the three factors:

1. Organization of Data: Since verification bodies must survey and review a facility's emissions inventory in order to develop a sampling plan and conduct verification activities, the organization of a facility's data is a critical determinant of cost. Well organized data will generally be centrally collected and stored, automated to the extent possible, and representative of the organization it describes. If data is not centralized, disorganized, or incomplete, the cost of verification will rise significantly.
2. Quality of Data Collected: If GHG data is well documented such that it is transparent, and can be easily assessed (and re-calculated) by a Verification Body, it will help to reduce the costs of verification.
3. Complexity of Emissions: If the nature of the reported GHG emissions is complex, verification activities to confirm compliance of complicated emissions and complex organizational structures will generally require more technical analysis, which will likely cost more than the assessment of simple GHG emissions.

Generally, the cost to verify emissions for the first year is higher than subsequent years, as a facility often is not sure how to best organize and collect their GHG data until they have experienced the verification process first hand. As data collection and quality improves, and as a verification body becomes familiar with a facility's operations, the cost of verification usually decreases. Also, facility training in GHG data organization, monitoring, and emissions quantification methods can result in better quality reports that are more easily verified.

Two stakeholders were particularly interested in how the WCI had considered the verification program in Alberta and whether the WCI could adopt the CCAR or TCR verification protocols.

The CCAR and TCR protocols and verification requirements support a voluntary facility-based reporting program. Since WCI is proposing a mandatory facility level reporting program to support a regional market cap-and-trade program, individual site visits are required, consistent with other mandatory facility GHG reporting programs. Also, the WCI reporting requirements will be in the form of regulatory language and not protocols. The exact calculation methods will involve the reporting of stationary combustion, process, and fugitive emissions where WCI will provide all methods to calculate and report those emissions. Some of those methods may overlap with the TCR protocol, but WCI will not be relying on the TCR protocols. WCI is committed to consistency in implementation of its regional program across all of the WCI Partner jurisdictions. As discussed in the "Background Document and Progress Report for Essential Requirements of Mandatory Reporting for the Western Climate Initiative, Third Draft", released for stakeholder input on January 6, 2009, the WCI may delegate certain functions to a regional body or designee such as TCR. However, WCI Partner jurisdictions are ultimately responsible for the enforcement of their programs, a responsibility and that cannot be delegated to a third party such as TCR.

WCI learned from its observations of the implementation of verification in Alberta that there is value in: (1) ensuring that verification requirements are set out clearly and supporting guidance is as comprehensive as possible at the program start to achieve consistency in implementation, since third party verification is being recommended as a means to obtain reliable, high-quality data across the region; (2) setting common standards and conflict-of-interest requirements for verifiers in order to communicate expectations clearly and establish a rigorous process for gathering important market information; (3) ensuring there is a sufficient pool of verifiers at the program start for the program to operate efficiently and to avoid excessive transaction costs. Areas in which the WCI draft recommendation differs from the Alberta Specified Gas (GHG) program include: (i) WCI's use of the accredited verification body approach compared to Alberta's use of the qualified professional approach; (ii) reasonable compared to limited level of assurance; and (iii) Alberta's requirement for verification to include production information needed for the intensity approach.

Entities participating in CCAR have shared the following thoughts regarding verification, and have found that third-party verification:

- Provides entities a new perspective on existing problems.
- Has encouraged entities to look at data differently, and more comprehensively. It has led to company teams interacting with one another in ways they have not previously (EHS, Facilities, and Accounting working together, for instance).

- Has resulted in cost savings. (For example, entities discovered that they were paying for things that are no longer in their inventory).
- Helps to identify operational inefficiencies by comparing emissions across a facility's operations.
- Requires that entities look at processes they may not have previously examined.
- Helps entities to better understand their GHG emissions and have confidence in their reporting. Some entities were surprised that their largest emission sources were not what they expected.

Stakeholder Comments and WCI Responses on Specific Components of the Proposed Verification Requirements

Responsibility for errors. One commenter stated that the verifier and regulatory agency should be responsible for errors made during verification. This topic will be addressed with other compliance provisions when the WCI further develops the verification and accreditation programs.

Materiality. Several commenters provided feedback on the discussion of materiality in WCI.8. The WCI recognizes the concerns expressed and has made changes to WCI.8 to provide better clarity. Stakeholders should refer to the revised description and definition of materiality in WCI.8.

Support of phase-in of verification requirements. Two commenters voiced support for a phase-in of verification requirements, including a transition period for facilities installing CEMs equipment, extended or staggered deadlines, requiring verification for combustion sources only and reduced COI checks. The timing of verification requirements was determined to provide high quality assurance of data during a pre-market period. This will be essential to generate accurate information as allocations and caps are being set. Verification will provide that quality assurance.

Supply of verifiers. Numerous stakeholders were also concerned about an adequate pool of accredited verification bodies available to offer services when reporting requirements commence. The WCI understands that an adequate supply of verification bodies will be necessary to create competition in the verification services market and keep verification costs at a reasonable level. Commenters voiced this concern in the context of the COI requirements, the timing of verification requirements and the competencies and accreditation requirements for verification bodies. One commenter also urged that accreditation requirements be finalized as soon as possible to provide verifiers adequate time to prepare for and obtain accreditation.

WCI will have verification bodies available through recognition of existing ANSI and CARB (and future SCC) accredited verification bodies that demonstrate familiarity with the WCI program. Many existing verification bodies are multinational companies with offices all over the world. WCI is committed to provide a sufficient number of verifiers through a continuous accreditation process. The supply of verification bodies will be a key consideration as the accreditation system is developed and implemented in 2009. Continued stakeholder input will be valuable during the further development of verification and accreditation systems during 2009.

More intensive verification years in the beginning of the program are expected, however, WCI also expects the balance of work to even out over time. Verification cycles will increasingly vary over time due to a variety of factors including changes in verification body utilized, phase-in of new facilities, the desire to obtain a positive verification opinion following an adverse opinion, and changes in facility operations.

<u>Conflict of Interest.</u> Numerous stakeholders also provided comments specifically addressing the COI requirements described in WCI.8. As noted above, stakeholders expressed concern that the COI requirements would limit the competitiveness of the verification market and restrict their ability to hire a verification body of their selection. The WCI does not intend to express distrust of facilities subject to GHG reporting. The COI requirements are in response to observations of other GHG programs and are based on requirements in existing EPA programs, Kyoto requirements, US federal legislation of Sarbanes and Oxley and the Canadian Institute of Chartered Accountants' independence guidance. The requirements are designed to protect the WCI market system from a minority of reporters and verifiers who may attempt to gain from situations involving high threats to independence.

One commenter objected to the triggering of full verification requirements when a reporter elects to engage a new verification body. For each annual verification, a verification body must provide reasonable assurance that a reporter's inventory is accurate and complies with the WCI ERs. In order for a verification body to be able to provide reasonable assurance, they must conduct a full verification in the first year of the verification cycle and form a verification opinion based on the findings of their own verification team's assessment. The reporter could choose to follow the primary contact to the new Verification Body; however, a full verification would be required. If due to the departure of the primary contact, the original verification body does not retain the necessary technical expertise (or sector accreditation) to continue to provide verification services to the reporter, then the reporter must retain a different, qualified verification body. If the original verification body retains the necessary technical expertise (or sector accreditation), then the quality of the verification should not be compromised.

When a reporter's primary contact at a Verification Body changes places of employment, this individual may retain some background knowledge about the reporter's inventory. However, in most cases, when an individual changes places of employment, they are not allowed to access, copy, or remove the verification records from their former employer.

In response to comments regarding subsection WCI.8 (e)(2)(B)vii, the WCI agrees with this comment and is including appropriate wording in WCI.8.

Commenters also objected to the six-year limit on a reporter's continuous reliance on a single verifier, particularly in light of the specialized technical expertise required for verification of certain facilities. In response to these concerns, the limit provides a mechanism for a new set of eyes to review the data for a reporter and protect against complacency on the part of the existing verifier. The six-year limit also limits the financial relationship from progressing to a level where a potential for high conflict of interest could occur.

One commenter recommended allowing a verification body to defend its verification statement and COI situation before a positive verification statement is disallowed. The WCI intends that within the verification program a mechanism will exist for a reporter to defend their verification statement and conflict of interest determination. It may be up to each WCI Partner jurisdiction on how to deal with this issue or it may be handled through a regional body. This process will have to be developed in 2009 to account for timely responses in a market program and as enforcement actions and penalty decisions are finalized.

One commenter expressed support for a principles-based rather than prescriptive approach to COI. The WCI has added consideration of the principles of independence to WCI.8 to support the framework for COI.

Stakeholders should also note that some revisions to the COI section of WCI.8 have been made in response to other technical details raised by stakeholders. While it may be standard practice for some Canadian provinces to take a standards-based approach, some U.S. jurisdictions may be held to a more prescriptive approach in their individual rule-making process. The Essential Requirements document provides consistent language for both types of approaches.

CEMS. Three commenters advocated that quality assurance steps which already exist in Canada and the US for reported emissions from CEMS equipment be relied on in place of verification under WCI. In Canada, "Protocols and Performance Specifications for Continuous Monitoring of Gaseous Emissions from Thermal Power Generation" (1/PG/7) guides the selection, installation, and operation of CEMS. In the US, 40 CFR 75 establishes requirements for the monitoring, recordkeeping, and reporting of contaminants and other data under the Acid Rain Program. While the term "verification" is used to describe the quality assurance measures required for CEMS equipment in the context of US and Canadian federal requirements, "verification" as described in WCI.8 is a broader, internationally accepted, and more comprehensive assurance step for greenhouse gas emissions reporting. The current federal quality assurance requirements for CEMS equipment will support verification for WCI emissions reports, but cannot be relied on as a substitute for verification under WCI.8. Also, not all facilities have CEMS, some may optionally add CEMS. Not all sources at a facility can be covered by a CEMS system, such as some process and fugitive emissions. Third party verification will ensure that all sources of emissions subject to reporting at a facility are correctly identified and reported, and provide for checks on CEMS systems that are not part of any existing regulatory program.

Consistency across jurisdictions. Three commenters urged the WCI to ensure consistency in verification protocols and implementation across WCI Partner jurisdictions to support a sufficient pool of competent verifiers and future compatibility with other programs.

As described in the rationale for verification, WCI is committed to consistency in implementation of its regional program across all of the WCI Partner jurisdictions. This includes the verification process and accreditation requirements to facilitate the availability of accredited verifiers throughout the entire region.

Applicability. Several stakeholders commented on the applicability of verification in terms of sources that should or should not contribute to the threshold for verification. While this topic is still under review by the WCI, commenters should refer to changes made to the applicability discussion in WCI.8.

Role of technical experts and accreditation. A few commenters provided input on the specialized technical expertise required for verification teams as well as on the accreditation requirements for verification bodies under WCI.8. The accreditation program and competency requirements will be further developed in 2009, as described in a note under the January 6 version of WCI.8(c)(2)(E), which states: "[Note that other source-category specialist skills may be required. These requirements are being discussed by the WCI, as are any additional accreditation requirements for individual lead verifiers, general verifiers, or sector specialists.]" It is intended that if the verification team requires a source category specific person, that person must be part of the site visit team.

Confidentiality. Stakeholders also expressed concern about the capacity for confidentiality to be maintained during verification, in the context of agency oversight of verification, the role of "TBD" and information that would be made public. To complement the protection of confidential information under the laws of individual WCI Partner jurisdictions, provisions for confidentiality in the context of WCI verification will be further developed in 2009 as the role of a potential regional body is determined. Stakeholders should note that the accreditation process under SCC and ANSI is rigorous and requirements of professional conduct as verification bodies will involve stringent confidentiality procedures.

Regarding agency oversight of verification, WCI Partner jurisdictions may defer enforcement action until verification is complete. Third party verification is a rigorous systematic review requiring highly trained and accredited personnel. As such it is an important element in the compliance structure and a verifier's issue log could be used as one of the elements used in an enforcement case. Issues in the log may include areas of concern that do not constitute a violation, but, in general, any credible evidence may be used for enforcement.

Regarding information that will be available to the public, it is essential that facility (or other reporting entity) emissions totals be shared across jurisdictions and made public to facilitate allowance market functioning. Other reported data used to calculate emissions may be subject to confidentiality requests, which could prevent such data from being shared with other jurisdictions and the public.

Three-year verification cycle. Some commenters expressed a desire for clarification of the requirements for full and less intense verification, and how this relates to the ability of a verification body to provide a reasonable level of assurance. Several stakeholders expressed support for the three-year verification cycle, with full verification occurring in the first year and less intense verification occurring in the second and third years. In response to these comments, the descriptions and definitions of full and less intense verification in WCI.8 have been revised.

Timing of verification requirements. One stakeholder expressed concern about meeting the April 1st deadline due to unavailability of some supporting internal data until second quarter of each calendar year. The stakeholder recommends adopting the current Canadian federal GHG reporting submission deadline of June 1st. WCI acknowledges that one submission deadline is desirable; however, the April 1st submission deadline is required to facilitate timely allowance retirement and distribution. Existing emission trading systems in Ontario and Alberta already have a reporting/retirement timeline of March 31st.

Verification Integrity. One stakeholder advised that a panel may be useful to oversee the development of requirements for reporting and third party verification and to maintain a pool of accredited verifiers that meet the WCI conflict of interest requirements. The WCI is considering the role of such a panel and the potential for a regional administrative body to help coordinate the WCI Partner jurisdictions in addressing emerging issues that require their attention.

Verification Statement. The WCI will provide stakeholders with an opportunity to provide comment on any standardized verification statement template that it develops and will look to verification experts for feedback.

Notice of Verification Services. One stakeholder expressed concern that verifiers must first receive approval in response to their notice of verification services before commencing those activities. In fact, verification services may commence upon receipt of a positive response to the notice, or fifteen days following submission of the notice, whichever comes first. The notification of verification services allows for a jurisdiction to make arrangements to audit a particular verification service, should the WCI Partner jurisdiction choose to do so. Auditing is an important component of overseeing a verifier accreditation program. The notification of verification services also allows for a jurisdiction to check that the verification team has the appropriate skill set to provide verification services for a facility of a particular source category.

Conformance Check. The conformance check is used to determine whether the reporting rule requirements have been met and is therefore within the scope of the role of the verification body.

Consistency in Professional Determinations. One commenter's suggestion that there should be room for differences in professional opinion without resulting in an adverse verification finding cannot be the case for a market-based system. The WCI aims to provide a consistent, clear standard for reporting that will help ensure that a "ton is a ton" across the WCI.

Reverification. One commenter expressed concern about a hypothetical circumstance in which an emissions report cannot be reverified due to an historic non-conformance to the reporting rule. If an emissions report cannot pass verification, whether the first time or second time, an adverse verification statement will be issued, thus completing the reporting and verification requirements for that year.

Verification Plan and Sampling Plan. The requirements of a verification plan and sampling plan and related references have been revised in the final draft to provide further clarity. The verification plan is shared with the owner or operator. However, the sampling plan, which identifies what areas are subject to data checks, is retained by the verification body and may not be shared with the owner or operator. The use of a log of issues has also been clarified.

2.2.4 General Quantification and GHG Measurements

There were over 100 stakeholder comments relating to the general quantification and measurement requirements of emissions from facilities (not including comments relating to quantification or measurement requirements specific source categories, such as petroleum refineries, cement plants, etc., which are addressed in Section 2.3 of this document). This section addresses only general requirements applicable to all types of facilities.

Comments and responses are separated into five categories based on subject matter: de minimis thresholds, quantification methods, measurement accuracy, fuel use measurement accuracy, and miscellaneous comments.

Many stakeholders expressed strong opposition to the de minimis requirement of 3% for emissions reporting and its lack of harmonization to the 5% materiality threshold for verification. Many stakeholders expressed strong opposition to the periodic fuel sampling requirements to determine higher heating value and carbon content, particularly when such data may already be provided by the fuel supplier. In addition, many stakeholders felt that the 5% fuel measurement accuracy for fuels is unattainable and cannot be met.

The WCI appreciates the input from stakeholders on the topic of quantification and measurement and has considered each comment received, making an effort to understand the reasons behind the concerns expressed. Changes to the reporting ERs based on stakeholder feedback are still under discussion by the WCI and have not been made at this time.

The following sections summarize comments and feedback in each of the five categories specified above.

De Minimis Thresholds

A summary of stakeholder comments pertaining to de minimis thresholds is as follows:

- The 3% de minimis threshold has not been justified, is unnecessarily onerous and would place significant cost and resource burdens on facilities
- The alternative 20,000 metric tons CO_2e threshold is not justified and should be removed
- The 3% de minimis threshold and the 5% materiality threshold for verification should be harmonized
- There should be a list of negligible emission sources (e.g. portable propane-fired space heaters) which need not be tracked under the WCI
- Clarification is needed between a de minimis 'source' and a 'source category'

WCI responses to these comments are as follows:

- WCI is examining whether the de minimis threshold (currently 3%) and materiality threshold for verification (currently 5%) need to be harmonized.
- The 3% and 20,000 metric tons CO_2e thresholds are based on the CARB regulation; justification for these values and their applicability to other WCI Partner jurisdictions is being examined
- The WCI will consider providing a list of smaller emission sources for which emissions need not be tracked

- The WCI will require a sufficient number of significant digits to ensure accurate reporting of emissions

Quantification Methods

A summary of stakeholder comments pertaining to quantification methods is as follows:

- Quantification methods, such as stack sampling, are overly burdensome and are key departures from established methods.
- Facilities should have flexibility in the use of quantification methods not prescribed by WCI, provided these methods can be shown to fall within an established level of accuracy.
- WCI proposed requirements do not appear to follow established methodologies or protocols for GHG emissions quantification. Sources for quantification methods should be indicated in an Appendix to each source category.
- The WCI needs to establish a system to account for updated emission factors and calculation methodologies, and the extent to which emission reports are back-dated to reflect these updates.
- The term 'adequate quantification method' is not defined.

WCI responses to these comments are as follows:

- In order to maintain the integrity of the WCI cap-and-trade program, it is necessary to use more accurate inventory methods than for voluntary reporting. WCI believe the proposed protocols provide the necessary level of accuracy, but it is reviewing the accuracy of less burdensome methods.
- In order to maintain the integrity of the WCI cap-and-trade program it is necessary for all covered sources to calculate and report emissions using the same methodology. Therefore, a facility cannot use its own quantification methods to calculate emissions.
- The WCI reporting methods are based on established protocols used by voluntary and mandatory reporting systems around the world. WCI consulted Canadian sources including Section 71 of the Canadian Environmental Protection Act, as well as U.S sources and international sources like the IPCC and TCR when developing our methods. The final methodologies are those that WCI believes are rigorous enough to support the WCI cap-and-trade program.
- The WCI will develop a system that accounts for updated emission factors. The extent of back-calculating of previous emissions is currently being examined.
- The WCI will consider the addition of an Appendix to each Reporting section in the Essential Requirements which lists data sources. A list of data sources has been added to the tables in the General Stationary Combustion rule.
- 'Adequate quantification methods' are methods that estimate emissions within an established threshold of accuracy.

Measurement Accuracy

A summary of stakeholder comments pertaining to measurement accuracy are as follows:

- Internationally or nationally recognized default emission factors should be sufficient for emissions quantification.
- WCI should allow for more frequent periodic sampling if desired by the facility.
- WCI should accommodate upstream fuel sampling if this provides a more accurate measurement of heat value or carbon content.

WCI responses to these comments are as follows:

- In order to maintain the integrity of the WCI cap-and-trade program it is necessary to use more accurate inventory methods than for voluntary reporting. WCI believe the proposed protocols provide the necessary level of accuracy.
- WCI will consider increased frequency of periodic sampling if desired by the facility. However, WCI must also consider the need for all facilities to report using the same methodology.
- WCI will consider cases where upstream sampling may provide a more accurate measurement of heat value or carbon content.

Fuel Measurement Accuracy

A summary of stakeholder comments pertaining to fuel measurement accuracy are as follows:

- Fuel use measurement devices for natural gas are typically owned by the utility company. It is impractical, illegal and even impossible for a facility to maintain and calibrate these measurement devices.
- Established periodic calibration requirements are burdensome in several cases, due to the need to shut down operation of kilns, smelters, etc. in order to calibrate measurement devices. Less frequent calibration requirements would be preferable.
- In some cases, measurements are required for fuel or other feedstock though these measurements are not used to calculate emissions. Measurement in these cases should not be required.
- Provisions should be made in cases where measurement equipment malfunctions; otherwise, failure to report under the Essential Requirements will be a violation.

WCI responses to these comments are as follows:

- The WCI is developing draft language on metered natural gas billing data along with utility supplied higher heating value and content of natural gas being an allowable quantification method so long that the metering and carbon dioxide testing methods meet appropriate standards.

- The WCI is considering whether fuel use need be reported if not used to calculate emissions.
- The WCI is considering provisions in the case of equipment malfunctions or other problems preventing physical measurements

Miscellaneous

A summary of stakeholder comments pertaining to other miscellaneous comments are as follows:

- Emissions should be reported to at least two significant digits.
- Switching from one calculation methodology for fuel combustion emissions to CEMS should not require advance approval from WCI.
- List of source categories include those with inadequate or non-existent quantification methods. Such categories should be removed from consideration in the WCI.
- WCI protocols should be as consistent as possible with other widely accepted protocols.
- WCI should use appropriate and consistent units of measure both whether in imperial or metric units and allow for conversions between units at appropriate places.
- Clarification is needed in WCI.8 regarding the term ‘actual.’

WCI responses to these comments are as follows:

- WCI will ensure a sufficient number of significant digits are included in emission totals to ensure accuracy.
- Although an administrative step, advance approval is viewed as necessary to ensure that facilities do not use equipment change as a way to modify total reported emissions in their favor.
- The WCI does not include source categories that lack adequate quantification methods. Therefore, if the source category is included, WCI believes adequate quantification methods do exist.
- WCI has attempted to make reporting requirements as consistent as possible with other international protocols, and differs when it is felt these protocols do not provide adequate quantification of emissions to be used in a cap-and-trade system.
- WCI will ensure the use of and conversion between units is consistent and does not burden the facility.
- The use of the term ‘actual’ in WCI.8 will be reviewed and modified if appropriate.

2.3 Source Category-Specific Comments

The following comments and responses pertain to specific source categories mainly for which quantification and reporting requirements were proposed in the third draft of the ERs.

2.3.1 Adipic Acid

One comment was submitted regarding the methodology for estimating N_2O emissions from adipic acid manufacturing. The commenter put forth a method which has been accepted by Environment Canada. This method is basically the IPCC Tier 2 methodology (i.e., emission factor of 0.3 tons N_2O/ton adipic acid) and has an estimated uncertainty of ±10%.

WCI is proposing, for the first time in this document, reporting requirements and a GHG methodology for adipic acid. Based on a meeting held between commenter (INVISTA) and a WCI Partner jurisdiction (Ontario Ministry of Environment and Energy), the proposed WCI method for adipic acid will allow either (1) the IPCC Tier 3 methodology (i.e., direct measurement), which has an estimated uncertainty of ±5%, or (2) the option of doing stack testing, or use of a jurisdiction approved CEMs, to calculate the uncontrolled emission factor to within 5% accuracy.

2.3.2 Aluminum

WCI's proposed method is based on the Environment Canada document "Aluminum Production – Guidance Manual for Estimating Greenhouse Gas Emissions," March 2004. This method is same as the IPCC Tier 3 methodology, which is also the same methodology as contained in the International Aluminum Institute (IAI) protocol. WCI prefers the IPCC Tier 3 methodology for its better accuracy as compared to the IPCC Tier 2 methodology (i.e., technology based emission factors).

Several commenters said that any GHG method for aluminum should reference the IAI protocol. Although not specifically cited, the proposed WCI method is the same as the method contained in the IAI protocol (as stated above). Also, several commenters requested that the IPCC Tier 3 method be used; this is what is recommended by WCI.

Several commenters requested specific methods for estimating PFC emissions from pot startups, and on how to handle historical data/coefficient changes. WCI investigated this issue, and it could not identify any existing methods for quantification of PFCs from pot startups; therefore, WCI will not include these in the reporting requirements at this time.

Several commenters requested more specific guidance on sampling frequency and data requirements to establish Tier 3 coefficients. WCI has included specific sampling frequencies, however, more work is needed (with input from industry) in order to identify the most appropriate sampling requirements for all parameters.

One commenter requested CEMS to be added to the calculation methods. The aluminum method now directs the facility to WCI.20 (General Stationary Combustion) for requirements pertaining to use of CEMS on combustion equipment.

One commenter requested that some issues be resolved though an Aluminum Work Group or Task Force that would include industry experts. The WCI is taking this under advisement.

Finally, a comment requesting more specific guidance on the SF6 estimation method resulted in changes to these to be more detailed and specific in the revised aluminum reporting requirements. A new file is included with these ERs in rule format.

2.3.3 Cement

The majority of stakeholder input on WCI.90 (Cement Manufacturing) was from the respective U.S. and Canadian associations, with some comments provided by individual companies. The WCI appreciates the input from stakeholders on these ERs and has considered each comment received, making every effort to understand the reasons behind the concerns expressed.

Where the WCI agrees with the comments and rationale, the appropriate sections of WCI.90 have been revised. However, where comments or suggested changes to the protocols have not been incorporated, the WCI provides rationale behind these decisions below.

The reporting ERs pertaining to cement manufacturing are based on California's mandatory GHG reporting rule, which in turn was primarily derived from the California Climate Action Registry and the Cement Sustainability Initiative's (CSI) Cement CO_2 Protocol, a recognized worldwide methodology for calculating CO_2 emissions from cement manufacturing. The association comments appeared to agree with the WCI's choice of the CSI protocol as the basis for WCI.90.

Below is summary of stakeholder input along with the WCI responses. Comments that have an overreaching theme applicable to the entire protocol are addressed first, followed by section specific issues.

'Standalone' Reporting Protocol

Several comments received by stakeholders suggested that the cement sector should not be required to report coal storage CO_2 emissions or other non-process emissions, until it is included in their CSI protocol from which the WCI protocol was derived.

Paramount to an effective cap-and-trade program is the assurance that all substantial emissions sources are accounted for using established quantification methods where available. Coal storage is one such emission source, and a common activity at cement manufacturing facilities. Therefore, the WCI requires that cement facilities, along with any other sector use the WCI.100 protocol to estimate coal storage emissions as opposed to incorporating this quantification method repeatedly into the sectors to which it would apply.

WCI's rationale also applies to estimating CO_2 emissions from general stationary combustion, since this occurs across many sectors. Prescribed methodologies for calculation of combustion emissions are detailed in the WCI.20 and can easily be applied by any and all sectors.

CH_4 and N_2O Emissions from Calcination

Comments received indicated that there are negligible CH_4 and N_2O emissions associated with the calcination process and therefore they should not be required to report these.

The WCI only requires reporting of N_2O and CH_4 for fuel combustion in kilns and other combustion units. The protocol will be revised to clearly reflect this.

Uniform Cement GHG Performance Standard

One stakeholder requested that WCI consider establishing target / allowance requirements on the basis of a uniform cement GHG performance standard.

Allowance requirements will be established in a separate WCI Essential Elements document. For inventory purposes the WCI must have an account of total emissions. However, WCI also requires reporting of annual production so that the WCI records will have information related to intensity.

WCI.92 Greenhouse Gas Reporting Requirements

One comment received indicated that the WCI.92(b)(2) requirement to report a plant specific CKD calcination rate as well as direct measurement of the CKD discard rate would be difficult as this data is not collected and there is no direct measurement of CKD discard rates.

It is the WCI's understanding that the CSI protocol on which this protocol is based requires the same parameters/information and recommends using plant-specific data, with one exception. The CSI protocol allows a default value of 2% for CKD if it is not available. This default value was derived from the IPCC Tier 1 method. The WCI has chosen the Tier 3 method from IPCC for better accuracy.

WCI.93 Calculation of GHG Emissions from Kilns

Several stakeholders commented that the requirement for monthly calculations of key factors (e.g. clinker emission factor, CKD emission factor, and organic content of raw material) is not administratively efficient and that although supporting data collection is conducted on a monthly basis, calculating these key factors should only be undertaken annually.

The WCI feels that because kiln conditions, production rates and feed material may change at any time during the year, once a year sampling would only capture immediate conditions which may not represent the whole year. Monthly sampling and emission calculation marries a monthly chemical analysis with a production for the same month.

WCI.94 Sampling, Analysis, and Measurement Requirements

Stakeholders were asked to provide feedback on this topic and provide proposals from those with expertise in the industry related sampling, analysis and measurement procedures already in use at facilities for the material and quantities and/or concentrations in protocol.

Stakeholders stressed that several of the required parameters would be difficult to collect. A specific example is the requirement to determine the uncalcined MgO, which would require X-Ray diffraction, not a recognized analytical procedure and currently considered experimental.

It is the WCI's understanding that X-ray diffraction is a well established analytical method which has been used for many years in material analysis. It is not as common in the cement industry as other methods, but its acceptance has been growing rapidly and is now in use by numerous cement plants. Other analytical methods with equivalent accuracy can be allowed if the WCI desires.

Objections were also raised by stakeholders to the proposed direct weight measurement of clinker using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh conveyors. Stakeholders informed WCI that very few cement plants use direct measurement of clinker from the kilns and that most, if not all, cement plants rely on a physical inventory measurement instead. Requiring other measure to be installed would be financially burdensome.

With regard to this issue, it is the WCI's understanding that the vast majority of the protocols require direct measurement of clinker, which must be conducted prior to milling and blending. Thus, product output via truck scales or some similar measure of cement or blended product and not clinker, will not provide the parameters required for the accepted protocols. However, WCI can allow a measurement device other than just the two mentioned above, if it is of equivalent accuracy and is measuring clinker production.

The WCI will take all comments regarding this section under advisement as it further evaluates options for sampling, analysis and measurement essential requirements for reporting.

2.3.4 Coal Mines

The basis for WCI's recommended quantification method for coal mines is IPCC Tier 3 methodology. The applicability is limited to underground coal mine fugitive CH_4 emissions, and will exclude the following sources due to lack of quantification methods, highly inaccurate quantification methods, and/or difficulty in measuring GHG emissions from the particular sources:

- Post-mining operations (subsequent handling, processing, and transportation of coal);
- Low temperature oxidation (oxidation of coal when exposed to oxygen in air);
- Uncontrolled combustion (active fire caused by trapped heat and increased temperature from low temperature oxidation); and
- Abandoned mines.

All of the commenters referred to the methodology paper discussion on surfacing mining category and suggested that the Tier 2 method discussed in the methodology paper should not be used due to its high uncertainty. In fact, WCI does not intend to include surface coal mining for this reason, and furthermore narrows the reporting Requirements as follows: "Annual CH_4 emissions will be reported for each specific underground mine using the Tier 3 methodology."

2.3.5 Electric Generating Units

WCI received only one comment directly related to the electric generating units (EGUs), while nearly 80 comments made by EGU industry commenters were related to other areas (e.g., verification, general reporting requirements, general stationary combustion). The commenter stated that WCI should allow the use of alternative monitoring methods (i.e. predictive emissions monitoring systems). WCI is currently discussing the option of allowing alternative EGU monitoring methods.

2.3.6 General Stationary Combustion

WCI received approximately 80 individual comments related to general stationary combustion (GSC) emissions quantification methodologies. These comments were divided into five summary topics: equations and tables, fuel sampling, fuel use measurement, monitoring and source testing, and edits to specific ER language. The common theme with the comments is that WCI reporting requirements for GSC are too inflexible. Commenters said that the GSC methodology needs to include more alternatives in estimation, monitoring and source testing, and fuel sampling procedures.

WCI appreciates stakeholders reviewing and making comment on the GSC methodologies and related documents. The following section includes a summary of all comments and WCI's response. WCI has made numerous revisions to the ERs in response to the comments in order to increase the flexibility WCI.20.

Equations and Tables

The first recurring topic of comments related to GSC addressed the equations and tables in WCI.20.

<u>Cite References.</u> WCI received several comments requesting that references be cited for where and how equations in the GSC method were developed. In addition, commenters asked that WCI identify where the default values (i.e. carbon content, high heating values, and emissions factors, etc.) for Tables 20-1 through 20-3 were derived.

WCI has added the references for the various emission factors and default values to the end of the tables.

<u>Emission Factor Errors.</u> WCI received a few comments that indicated the N_2O emission factor for natural gas is off by a factor of 100 and needs to be confirmed.

After reviewing Table 20-3 in response to these comments, WCI determined that several of the emission factors for N_2O were incorrect because of a failure to convert from grams to kilograms. These values have been corrected in the Final Draft.

Exclusion of Certain Fuel Types. Some commenters felt that WCI was excluding certain fuels from Table 20-1 through 20-3 which already have established greenhouse gas emission factors (i.e. IPCC or WRI). WCI will investigate whether additional factors are now available and augment the tables as appropriate in the future.

Use of Alternative Quantification Methodologies, Emission Factors, Default Values, or Units of Measure. There were several comments requesting that WCI allow the use of alternative quantification methods, emission factors, default values, and units of measure. Specifically:

- WCI needs to allow the use of alternative CH_4 and N_2O emission factors and calculation methods where the alternative factors are more conservative and therefore would result in higher emissions.

  WCI did not make this change, because the objective of the reporting rules will be to produce the most accurate emissions estimates possible, not the most conservative.

- WCI should refrain from using different units of measure for the same fuel type across multiple equations such as using cubic meters in one equation but using cubic feet in another equation.

  WCI agrees with this comment and has attempted to make the units of measurement in the ERs consistent.

- WCI should allow the use of mole fractions of gas components to calculate a site-specific CO_2 emission factor.

  WCI agrees and has modified the ERs to make it clear that this is allowed.

- WCI should allow the use of LHV in place of HHV (i.e. cement manufacturing industry).

  For purposes of common currency WCI has kept all values to HHV. It is possible for the reporter to convert LHV to HHV.

- Commenter requested that WCI provide alternative units of measure for gaseous fuels.

  WCI believes that the ERs and reporting will be less confusing if consistent units of measurement are employed. The ERs will be revised in the future, however, to include metric alternatives to English units.

- In WCI.23(b)(2): The boiler "design" rated heat input capacity should be used in B not the "maximum" rated heat capacity.

  WCI agrees and has made this change.

- WCI needs to clarify the meaning of "12% moisture" for wood fuels.

The source for this figure is U.S. EPA Inventory of Emissions and Sinks, 1990-2007 (2009). WCI does not require a correction for moisture content.

- WCI should allow the use of alternative established emission estimation tools and quantification methods from other greenhouse gas protocols sources such as WRI, WBC/SD, IPCC, EPA, Environment Canada, etc.

  WCI has reviewed all of these sources of emission estimation techniques and has chosen the methods that it believes to be the most reliable and reasonable for reporters.

- Canadian emission factors and quantification methodologies should be considered.

  WCI will include additional emission factors for Canadian fuels in the future.

Use of CH_4 and N_2O Calculation Methodologies

WCI.24 describes four calculation methodologies that can be used to calculate CH_4 and N_2O emissions from fuel combustion (WCI.24(a) through (d)). The January 6 version of the draft General Stationary Combustion protocol did not specify the conditions under which operators would be required to use each calculation methodology. These requirements are now described in WCI.24(e) and align with the requirements for CO_2 combustion outlined in WCI.23(e).

Fuel Sampling

The second recurring topic of comments related to GSC addressed fuel sampling methods and accuracy. New sections have been added on fuel analytical data capture [WCI.2(g)] and procedures for interim fuel analytical data collection in case of breakdown [WCI.2(i)] have been added.

Numerous commenters recommended that reporters should be allowed to use fuel vendor information rather than being required to sample and test fuels at the facility. They argued that the requirement to sample and test for all reporters subject to verification would be unduly burdensome and costly and pointed to examples of other programs where on-site fuel sampling and testing was not required.

After considering these comments, WCI has determined that the use of vendor-supplied data on carbon content and heating value should be allowed and has amended the ERs accordingly. The ERs have been modified to allow for this, provided fuel suppliers use the fuel analysis methods specified for operators.

Other related issues that were raised, included the following:

- Weekly and monthly fuel sampling frequencies are too extreme. WCI should consider relaxed sampling requirements for fuel types that consists of <10% of the total heat input.

  WCI made changes so that fuel sampling requirements now allow the use of analysis results provided by the fuel supplier. Sampling frequencies were carefully considered and reflect fuel-specific variation in carbon content.

- Suggest using sampling and analytical equipment such as gas chromatographs and online instrumentation instead of ASTM methods.

  WCI has made changes so that the ERs now allow for this where recognized sampling, analysis and measurement requirements exist.

- WCI should allow the use of ASTM methods in addition to those listed in the ERs.

  WCI has expanded the list of ASTM methods allowed to include all those referenced in the EPA's proposed MRR. Additional methods, including recognized Canadian standard methods, will be added in the future.

- Measurement accuracy for HHVs to within 5% is not reasonable.

  WCI has replaced this with specified calibration requirements, in addition to measurement accuracy requirements in the applicable ASTM methods

- WCI.24 should allow testing of one gas (say CH_4) and use of the default for the other gas (i.e., N_2O).

  This change was made**.**

- WCI language should be modified to allow reporting entities to extend the ASTM methods to adequately capture Olefins compounds to avoid underreporting.

  WCI agrees and has made this change.

Fuel Use Measurement

Several comments objected to the direct fuel-use measurement requirement. They argued that most "regulated facilities have internal control procedures to determine which method is the most consistent and accurate for its operations given its fuels and fuel systems and multiple data analysis and reporting requirements" and that "adding another layer of monitoring and recordkeeping is redundant with no added value."

WCI agrees and has modified the ERs to allow the use of recorded fuel purchase or sales invoices for all reporters.

Monitoring and Source Testing

The fourth recurring topic of comments related to GSC addressed the requirements pertaining to monitoring and source testing (i.e., sampling, analysis, and measurements) requirements in WCI.20. Several comments noted that regulatory monitoring and reporting requirements for CEMS may not include the necessary measurements required by the ERs (e.g. CO_2 concentration measurements or stack gas flow measurements). They argued that requiring installation of these additional CEMS components where they are lacking would be extremely onerous and expensive without improving overall accuracy.

WCI agrees, and has amended the language of the ERs to require the use of CEMS only where existing regulatory requirements already require stack gas flow and CO_2 concentration measurements.

Other comments in this area:

- WCI.24 allows for development of CH_4 and N_2O site-specific emission factors through annual source testing in place of default emission factors. The commenter felt that since CH_4 and N_2O emissions are influenced by choice of combustion equipment it would be more reasonable and cost-efficient to remove the annual testing requirement and to only require additional source testing upon changes to the combustion equipment.

  WCI notes that emissions are also influenced by fuel choice, and fuels may change annually or even seasonally; no change is recommended at this time.

- In WCI.23(d)(2)(B): There is no technical or scientific basis for this exclusion if the conditions of WCI.23(d)(1)(B) are met.

  WCI notes that waste has a greater variability than biomass and contains fossil as well as biomass sources of carbon. It is conceivable that waste might meet the relative accuracy test audit requirements of WCI.23(d)(1)(B) when the test is conducted, and not meet the relative accuracy requirements during the remainder of the year. Thus, using O_2 as a surrogate for CO_2 is disallowed for waste fuels in WCI.23(d)(2)(B).

Miscellaneous Edits to WCI.20

The fourth recurring topic of comments related to GSC addressed miscellaneous edits to the language of the reporting requirements in WCI.20. These are summarized and responded to below.

A commenter noted that WCI.23(b)(2) appears to be missing critical language that needs to be corrected. The equation variables define municipal solid waste combustors but not biomass for calculating emissions based on steam generation. WCI agrees and has made this change.

A commenter noted that WCI.23(d)(4) references WCI.123(b)(3) but there is no (3) under WCI.123(b). WCI has changed this reference to "WCI.23(a) or (b)(1), as applicable."

A commenter stated that there is confusion over the organization of the four GSC calculation methods and how to determine who uses which of four GSC methods. It was suggested that WCI create a simplified flow chart or process diagram that would help facilities determine which of the four GSC methods they would need to use. Also, maybe WCI needs to reorganize this section so it is clearer, even if it makes it less compact. WCI has attempted to improve the organization of the GSC methods.

A commenter stated that the word “immediately” should be deleted from WCI.25(a)(4) because it may be construed to mean that taking fuel samples from the feeder or belt leading to (in contrast to after) the coal mill would not meet the standard. Because fuel is dried in the grinding mill, some VOCs may volatilize there. If coal is sampled after the mill (i.e., “immediately” before combustion), carbon in the gas that had volatilized in the mill would not be captured in the sample. The sample would understate, and thus not be “representative” of the total carbon content of the fuel. Weekly samples should be expressed as the minimum sampling frequency in order to allow for more frequent sampling. WCI has added clarifying language to address this issue.

2.3.7 Iron and Steel

The basis for WCI’s recommended quantification method for iron and steel manufacturing is IPCC Tier 3 methodology. One commenter expressed concern that the level of uncertainty with the proposed method was ±10%, however, WCI believes the commenter misunderstood the method proposed, which is estimated to have a ±5% uncertainty (according to IPCC). Also, another commenter requested that Environment Canada guidance document for estimating emissions from iron and steel production be applied to WCI. WCI feels that there is no guarantee that this guidance would be applicable under the Canadian framework. WCI reviewed the Section 17 requirements, and these allow a full range of options of quantification for GHG emissions estimation (e.g., CEMS, to default emission factors, to engineering estimates); these are not prescriptive enough and many are not accurate enough for reporting GHGs under WCI’s cap-and-trade program.

One commenter stated that methods for estimating GHG emissions from melting scrap in EAFs and monitoring carbon content of electrodes used in EAFs were missing. WCI is not aware of a reliable method to sample carbon content of scrap metal, which seems to only be viable after the material is molten when some of the carbon is lost. WCI did add a provision for using vendor data for determining carbon content of electrodes; see WCI.155(e).

Several commenters requested information on the source of the methods proposed for estimating CO_2, and requested an alternative method other than CEMS for estimating CH_4 emissions. A reference was added to WCI.153(b) indicating the basis is the IPCC Tier 3 methodology, and an option for use of facility-specific emission factors was added to WCI.154(2).

One commenter requested that the carbon content of the inputs and outputs be determined on a percentage of carbon by weight (in addition to tons of carbon per unit of material). This option was added to the relevant WCI.152 subsections.

One commenter, the owner/operator of an iron and steel facility in Quebec, stated that the WCI emission quantification methods do not address all technologies. The commenter goes on to suggest that reporters be allowed to participate in the development of methodologies. WCI is attempting to contact this commenter to discuss future development of methods for specialized technologies and processes.

2.3.8 Lime

The majority of stakeholder input on WCI.170 (Lime Manufacturing) was from the respective U.S. and Canadian associations, with some comments provided by individual companies. The WCI appreciates the input from stakeholders on the protocol and has considered each comment received, making every effort to understand the reasons behind the concerns expressed.

Where the WCI agrees with the comments and rationale, the appropriate sections of WCI.170 will be revised. However, where comments or suggested changes to the protocols have not been incorporated, the WCI provides the rationale behind these decisions below.

The lime manufacturing protocol is based on the National Lime Association's "CO_2 Emissions Calculation Protocol for the Lime Industry English Units Version", February 5, 2008

Revision (http://www.climatevision.gov/sectors/lime/pdfs/lime_protocol.pdf) ("NLA Protocol"), which is a recognized protocol accepted and applied by association members in the US and Canada.

Below is summary of stakeholder input along with the WCI responses. Comments that have an overreaching theme applicable to the entire protocol are addressed first, followed by section specific issues.

Emission Reporting by Type of Lime

A recurring comment was that the lime industry produces several types of lime (and associated LKD) which have different process emission factors, and by extension different process emissions. It was therefore recommended by stakeholders that the WCI protocol require CO_2 process emissions and emission factors be determined by lime type and type of LKD produced. Suggestions were made to revise all sections of the protocol to reflect this (information required in section WCI.172; Equation 170-1).

The WCI gave serious consideration to adding a requirement to calculate process CO_2 emissions for each type of lime and TKD produced both for the reasons offered by the comments and because this approach would achieve consistency with EPA's proposed MRR. *See* EPA, *Proposed Mandatory GHG Reporting Rule Text (full version)* § 98.193(b)(1), at 316 (http://www.epa.gov/climatechange/emissions/downloads/MRR-Rule.pdf).

The WCI has concluded, however, that this approach presents practical difficulties. There are infinite blends of calcium and dolomitic lime and infinite degrees of calcination (i.e. soft burnt and hard burnt and in-between). A facility may choose to produce more than one of these products at any time.

This fact is reflected in the industry's own inconsistency in classifying lime products. While the comments maintain that there are two types of lime and LKD—high-calcium and dolomite—the NLA Protocol identifies four—"soft burned high calcium, hard burned high calcium, soft burned dolomitic and dead burned dolomitic." The NLA's answers to Frequently Asked Questions (http://www.lime.org/faqs.html) provide yet a third list:

- *High calcium quicklime*--derived from limestone containing 0 to 5 percent magnesium carbonate.

- *Magnesian quicklime*--derived from limestone containing 5 to 35 percent magnesium carbonate.
- *Dolomitic quicklime*--derived from limestone containing 35 to 46 percent magnesium carbonate

Although, as noted, the MRR requires separate emission factors for different lime types, it does not even identify, let alone define, lime or LKD types, but simply requires different emission factors for each type at each kiln. This opens the door to inconsistent approaches among lime manufacturing plants.

On the other hand, by requiring CO_2 calculations for each kiln and by month, the changes in either degree of calcination or type of lime are automatically accounted for in the protocol. The WCI therefore does not intend to add a reporting-by-type requirement to the ERs. It should be noted that this approach is consistent with the spreadsheet accompanying the NLA Protocol. Although the protocol discusses the calculation of different emission factors for different lime types, the spreadsheet accommodates the entry of only one set of percentages of CaO and MgO produced for each kiln.

Emission reporting by kiln

Stakeholders comments, including comments submitted by the NLA, indicated strong opposition to reporting by kiln, since different facilities have different material handling configurations which may prevent them from determining quantities of lime or LKD produced at a specific kiln (i.e. one or more kilns may feed into one single storage area).

Reporting by kiln is consistent with the NLA Protocol. On page 2, the protocol states:

> *"[Process] emissions result from the production of quicklime* at each kiln *at the plant, as well as from calcined byproducts/wastes. Emission calculations are based on tonnage of each type of quicklime and calcined byproducts/wastes produced at* the kiln.
>
> *The NLA spreadsheet includes separate worksheets for quicklime and for calcined byproduct/wastes and further instructs tha*t *the relevant kiln is clearly identified so that kiln-by-kiln intensities and efficiencies can be calculated."*

In the spreadsheet, the worksheet for calculating quicklime emissions includes cells for inputting the CaO and MgO content and capacity for each kiln. Based on these inputs, the spreadsheet calculates a separate emission factor and CO_2 emission estimate for each kiln. There is a link to additional worksheets for plants with more than five kilns.

EPA's proposed MRR, which is based on the NLA protocol, also requires reporting by kiln. *See* EPA, *Proposed Mandatory GHG Reporting Rule Text (full version)* § 98.193(b)(1), at 316 (http://www.epa.gov/climatechange/emissions/downloads/MRR-Rule.pdf); EPA, *Technical Support Document for the Lime Manufacturing Sector: Proposed Rule for Mandatory Reporting of Greenhouse Gases* 9, 13 (January 22, 2009) (Technical Support Document for the Lime Manufacturing Sector).

Maintaining CO_2 calculation by individual kiln in WCI.170 will assure consistency between the WCI and U.S federal reporting programs. The WCI is therefore retaining the requirement to report process emissions for each lime kiln at a lime manufacturing plant.

Uncalcined CaO

One commenter requested that WCI replace all occurrences of "uncalcined CaO" with "weight fraction of CaO in uncalcined carbonate." The WCI acknowledges that there are multiple terms used by industry and it will include multiple terms in the protocol to clearly convey the meaning of each parameter.

Uncalcined MgO

Stakeholder comments consistently indicated that all magnesium oxide in raw feed material is calcined during the process, since the reaction occurs at much lower temperatures than calcium oxide, therefore the need to report uncalcined MgO is not necessary or relevant. The WCI agrees with this suggestion and will incorporate into the revised protocol the option of allowing the reporting facility to assume all Mg has been calcined to MgO.

Lime Kiln Dust Discarded

Stakeholder comments consistently indicated that any reference to lime kiln dust (LKD) should refer to it as "produced " and not "discarded" since LKD is not a waste product but generally sold for agricultural use and other applications. WCI agrees with this recommendation and the protocol will be revised. Clarifying language will be added to assure that only LKD not recycled to the kiln is counted in determining process CO_2 emissions.

WCI.173 - Calculation of GHG Emissions from Kilns

It was noted that in WCI.173(c) the word “Pure” appears as a definition only and does not appear in the text. This was an omission and the requirements have been modified to include the word "pure" in the paragraph.

WCI.174 - Sampling, Analysis and Measurement Requirements

Stakeholders were asked to provide feedback on this topic and provide proposals from those with expertise in the industry related sampling, analysis and measurement procedures already in use at facilities for the material and quantities and/or concentrations in protocol.

Many of the comments received indicated that measurement for accounting and inventory purposes at lime facilities generally centered on lime and lime kiln dust (LKD) produced and sold. Accordingly, measuring raw material consumed is not a common practice at lime facilities and requiring facilities to do so under WCI.174(d) would result in expensive process modifications.

Comments were also received on sampling and analysis procedures and essentially stakeholders do not concur with WCI’s approach of prescribing sampling, analysis and measurement methods. The WCI will take all these comments under advisement and will need to further evaluate these areas of the protocol before responding.

2.3.9 Pulp and Paper Manufacturing, Biomass

Many comments were received on the quantification methods for the pulp and paper industry. Also, comments from the pulp and paper industry addressed biomass emissions quantification.

Fuel Distribution

Several stakeholders expressed concern about the potential inclusion of biomass-based fuels in reporting by fuel distributors and the risk of double-counting emissions, given that wood products facilities supply biomass fuels to other consumers. This issue will be taken up later (late 2009, or 2010) when WCI addresses suppliers of residential, commercial and industrial fuels.

Inclusion of Biomass-Derived Emissions for Reporting

Numerous stakeholders were opposed to the inclusion in the reporting requirements of biomass-derived emissions. Stakeholders argued that only carbon dioxide from fossil sources, and fossil- and biomass-derived methane and nitrous oxide from stationary combustion devices be included in the reporting requirements and thresholds for determining reporting obligations. Commenters were also concerned about requirements for fuel testing for facility- or fuel-specific CO_2 emission factors. Stakeholders pointed to the carbon-neutrality of CO_2 from biomass and the requirements of other programs and protocols. The comments received also expressed concern about burdening small facilities.

IPCC guidance indicates that forestry practices resulting in net decrease in carbon stocks are not carbon-neutral. WCI Partners have recommended that biomass and biofuel carbon dioxide emissions should be reported (September 23, 2008 Design Recommendations 1.3 and 1.4). Carbon dioxide emissions from biomass/biofuel combustion may in the future be determined by some WCI Partner jurisdictions not to be carbon-neutral, and therefore subject to the cap (Design Recommendation 1.5). Jurisdictions promoting the substitution of carbon-neutral biomass for fossil fuels can use the biomass carbon dioxide emissions data to monitor progress.

As noted in section 2.1.1 above, WCI has added a provision to WCI.1(b) affecting applicability determinations, allowing the exclusion of up to 15,000 metric tons of CO_2 from the combustion of pure solid biomass, prior to determination of a fuel's carbon neutrality by a WCI Partner jurisdiction. This exclusion will apply to all carbon-neutral biomass once the jurisdiction has defined that term and made that determination by fuel type. Jurisdictions retain discretion to require consideration of biomass fuel emissions in determining applicability. WCI is also considering the exclusion of biomass combustion emissions for purposes of determining verification applicability and from the scope of verification when one is required.

One commenter suggested that facilities that do not have sufficient data to determine quantities of biomass fuel combusted should be allowed to back-calculate fuel combustion quantities based on boiler steam generation quantities, and boiler steam generation efficiencies. These back-calculated biomass fuel consumption quantities could then be used in conjunction with default emission factors to estimate biomass CO_2 emissions. WCI agrees. The last draft of WCI.23 allowed the use of this method for facilities that are not required to verify. The new draft has added a provision that allows the use of the same method at facilities required to verify, provided that the emission factor is updated every three years on the basis of source-specific testing.

Several commenters objected to the requirement in WCI.23(f) for stack testing and radiocarbon dating for facilities to quantify the biomass derived portion of CO_2 emissions, as applied to facilities combusting wood and other forest products. Other commenters argued that these methods should not be required at a facility that can employ a mass balance approach. WCI agrees and therefore has amended WCI.23(f) to require the use of testing and radiocarbon dating only for facilities that cannot determine and document the biomass fraction of the fuel combusted.

Black Liquor Boiler and Lime Kiln Emissions

Stakeholders recommended including spent pulping liquor as a biomass-derived fuel and also noted the potential to combine reporting of biogenic carbon dioxide from the recovery boiler and lime kiln.

The WCI has revised its consideration of black liquor boiler and lime kiln emissions reporting, based on the technical advice and resources referenced in the comments received. Stakeholders should refer to the new requirements regarding emissions from the black liquor boiler in Attachment 7 to this document.

Also, in response to comments, WCI will add black liquor CH_4 and N_2O emission factors to the GSC emission factor table (Table 20-3) in the future.

Wastewater treatment

Stakeholders also commented on emissions from waste and wastewater treatment. As the revised methodology in Attachment 7 notes, this topic is still under consideration.

Offsets

A number of stakeholders provided feedback on the topic of offsets in relation to the forest industry and forest carbon measurement. This topic is beyond the scope of the ER. These comments will be taken into consideration by the WCI Offset Committee.

Definitions

A number of comments discussed definitions related to biomass such as "waste derived fuel". The WCI is considering the comments received and will determine at a later date appropriate definitions for inclusion in the ER, as part of the broader discussion on biomass-derived fuels. WCI requests further clarification on the nature of this concern.

A commenter requested a definition for “impregnated sawdust”, and others recommended that this material be excluded from the definition of "waste-derived fuel". WCI will develop a definition for "impregnated saw dust" in the future. This definition will refer to sawdust from wood impregnated or treated with resins or glues derived from fossil hydrocarbons, and would not include wood from raw trees and untreated lumber. "Impregnated saw dust" has been included in the definition of "waste-derived fuel" because this is a category of fuel that contains fossil hydrocarbons and thus has special emissions quantification methods. The definition of "waste-derived fuel" in these Essential Requirements is for the purposes of these requirements only and may be different from definitions of "waste" in various other existing regulations.

2.3.10 Refineries and Refinery Fuel Gas

WCI received wide-ranging stakeholder comments concerning WCI proposals for the determination of GHG emissions from Petroleum Refineries (WCI.200), and Refinery Fuel Gas Combustion (WCI.30). The major comment topic areas are listed and discussed below.

Use of CEMS to Determine Combustion and Process Emissions. The reporting committee agrees that facilities should have the option to use appropriate CEMS for the determination of refinery combustion and process emissions. However, CEMS must be installed, calibrated and maintained in a consistent manner. The reporting committee is currently examining U.S. and Canadian CEMS regulations.

Addition of standard conversion factors consistent with industry standard temperature and pressure condition. Molar volume conversion factors will be provided that are appropriate to the standard temperature and pressure conditions typically used at Canadian and U.S. industry facilities

Appropriateness of WCI Fugitive Emission Calculation Methodologies. The WCI Reporting Committee recognizes that there are many different regional and national regulations and requirements currently in-place dealing with the measurement and control of equipment fugitive emissions (e.g. Leak Detection and Repair Programs – LDAR). Provisions in the recently released draft U.S. EPA Reporting are being examined to determine if the approach proposed by the U.S. EPA would provide consistent and accurate data.

De Minimis Sources and Accuracy Requirements. Reporters currently are allowed to use best available methods for the determination of emissions reported as de minimis. In this case fuel accuracy requirements would not apply.

Determination of Variables Required for the Determination of Process Emissions Related to Fluid Catalytic Cracking Units and Catalyst Regeneration. All U.S. petroleum refineries are currently required to measure all of the variables specified in WCI.203. WCI is in the process of determining if these measurement criteria are also applicable to Canadian refiners.

Frequency of Determination of Refinery Fuel Gas Composition. Refinery fuel gas is a major source of combustion in US and Canadian petroleum refineries. Furthermore refinery fuel gas composition can vary widely within a refinery and from refinery to refinery. For these reasons stringent and consistent methods are required to quantify this emission source. WCI has endeavored to provide regulatory flexibility which will provide reporters with several quantification procedures. The reporting committee acknowledges the fact that in some refineries, refinery fuel gas may have been monitored (flow rate and composition) only for process control purposes in the past. This process control data may not meet the minimum requirements for the accurate and consistent determination of this important GHG source and thus upgrading or installation of equipment flow and composition instrumentation will be necessary.

Accuracy of the Specified SRU "Molecular Fraction Value." The regulation allows reporters to use site specific molecular fraction data determined using methods approved by the jurisdictional authorities if they feel that the default value is not appropriate.

Definition and Clarification of Terminology. Additional definitions will be added where required.

Appropriateness of Fugitive Emission Methodologies (i.e., Equipment and Storage Tank Emissions). The WCI is currently examining the draft U.S. EPA Greenhouse Gas regulation to determine if the methods contained in this regulation can be used by WCI. Similar to WCI the

EPA regulation does require the use of the TANKS model to determine emissions from storage tanks.

Methods for the Determination of Flaring Emissions. The current U.S. EPA draft rule allows the use of flow meters, HHV and carbon content or engineering approaches to determine flare emissions. WCI is currently examining the applicability of these requirements for Canadian refineries and will adopt US EPA methods if warranted.

Difficulties Complying with Fuel Use and HHV Accuracy Requirements. The WCI recognizes that installation of flow meters and HHV analyzers will be required. The necessity of accurate and consistent data makes this necessary.

2.3.11 Landfills and Wastewater Treatment

WCI methods for industrial landfills and wastewater treatment are defined for the refinery category, and are under investigation for the pulp and paper category. The only comments received on industrial landfills and wastewater treatment pertained to these sources located at pulp and paper facilities. All comments cited a NCASI special report which studied the methane emissions from pulp and paper mill landfills and wastewater treatment and found these to be "essentially zero" according to the commenters. WCI is continuing to investigate the applicability of these sources at pulp and paper mills.

3.0 NEW AND REVISED ESSENTIAL REQUIREMENTS

Based on on-going work conducted by WCI's Reporting Committee since the third draft of the reporting Essential Requirements (January 6, 2009), and in response to comments received by stakeholders on that third draft, WCI has revised some reporting Essential Requirements previously contained in the third draft, and developed new requirements for source categories not previously included in the Essential Requirements. The revised and new requirements are contained in the following attachments to this document:

- Revised section file names (Attachments 1 through 4):
  - WCI_FinalDraft_GPs_050709_att01.doc
  - WCI_FinalDraft_GPs_Verification_050709_att02.doc
  - WCI_FinalDraft_20_Combustion__0507099_att03.doc
  - WCI_FinalDraft_150_Iron_Steel_050709_att04.doc

- New section files names (first time in rule format; Attachments 4 through 8):
  - WCI_FinalDraft_XX0_Adipic Acid_050709_att05.doc
  - WCI_FinalDraft_70_Primary Aluminum_050709_att06.doc (previously reviewed by stakeholders in narrative format)
  - WCI_FinalDraft_210_Pulp_Paper_050709_att07.doc
  - WCI_FinalDraft_230_Soda Ash_050709_att08.doc
  - WCI_FinalDraft_300_Petrochemical_050709_att09.doc

Western Climate Initiative

Cap Setting and Allowance Distribution Stakeholder Workshop

Committee Overview

May 28, 2009

Seattle, Washington

www.westernclimateinitiative.org

Committee Mission

- The Cap Setting and Allowance Distribution Committee (CSAD) has been formed to recommend methodologies for establishing:
  - The regional WCI GHG emissions cap
  - Each WCI Partner jurisdiction's allowance budgets
  - Allowance distribution guidelines
- The work of CSAD will help to ensure:
  - The data being used to inform these decisions are as accurate as possible
  - The approach taken addresses competitiveness issues
  - The methodologies are applied consistently to achieve each WCI Partner jurisdiction's specific goal as well as the WCI regional goal

CSAD Tasks

- Task 1: Data Review and Collection
- Task 2: Cap and Budget Setting
- Task 3: Competitiveness Analysis
- Task 4: 2012 One-Time Budget Adjustments
- Task 5: Offsets Compliance Limit
- Task 6: Early Reduction Allowances (ERAs)

CSAD Committee Output

- A common consistent emission projection methodology to enable 2012 and 2015 estimates for use in setting caps and budgets
- A methodology for establishing the:
  - Aggregate regional cap for 2012 to 2020,
  - Each WCI Partner jurisdiction's budget for 2012 to 2020, and
  - Process to review the budgets and regional cap to 2020 and make adjustments at the end of each compliance period.
- Competitive Analysis
  - Process to review and perform analyses on competitiveness issues from sectors or sources, and
  - A common allowances distribution system, where appropriate, to address competitiveness, for consideration by Partner jurisdictions

CSAD Committee Output

- A methodology for the distribution of the one-time, one percent contribution from jurisdictions of the 2012 budget
- A methodology for implementing the offset limit of no more than 49% of the total emission reductions from 2012-2020, including:
  - Options and recommendations on implementing the limit
- The elements of an Early Reduction Allowances (ERAs) approach, including:
  - Criteria for eligibility
  - Entities eligible
  - Process for issuing ERAs

Stakeholder Interaction

- Workshops:
- Conference calls and webinars
- Joint educational opportunities
- Written comment:
  - White papers
  - Draft recommendations
- Individual jurisdictions' stakeholder processes

Remainder of Today's Workshop

1. Offset Limit – White Paper
   - Offset limit used in other systems
   - Criteria for evaluating limits
   - Options for limits
2. ERAs – White Paper
   - Review of other systems
   - General design issues
3. Competitiveness Analysis
   - Principles for analysis of competitiveness issues

Western Climate Initiative

Cap Setting and Allowance Distribution
Stakeholder Workshop

CSAD Task 5: Offset Limits

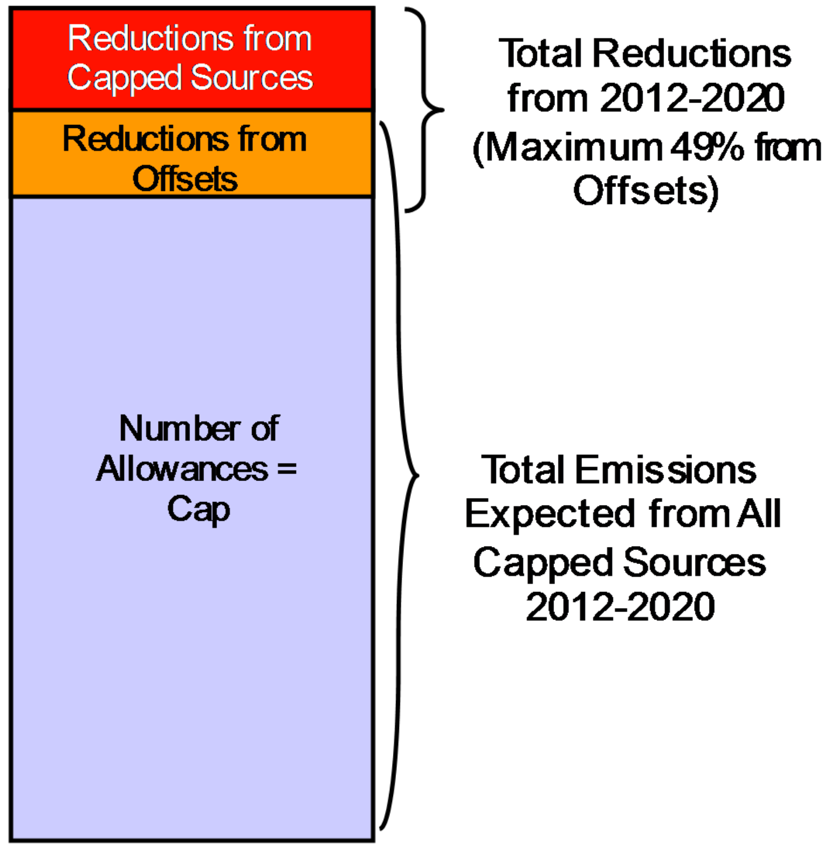
May 28, 2009
Seattle, Washington

Background

- The WCI Design Recommendations (September, 2008)
  - Specify that a majority of emission reductions required under the program occur at covered entities and facilities
  - Consequently, WCI Partner jurisdictions set a limit on the use of offset credits issued by WCI Partner jurisdictions, as well as the use of offset credits and allowances from other GHG emission trading systems that are recognized by the WCI Partner jurisdictions to more than 49 percent of the total emission reductions from 2012 to 2020

  - Note that "offset limit" is inclusive of the use of allowances issued by other GHG emission trading systems

Illustration of the WCI Offset Limit



Objectives for CSAD Task 5

- Review options for implementing an offset limit
    - *Consider offset limit approaches used in other emissions trading systems*

- Develop and recommend a methodology for implementing the offset limit

Work Plan & Timing for CSAD Task 5

- Design Development/Consultation
  - May 20 - Release of White Paper
    - Review of other programs
    - Key issues for discussions
  - May 28 - Workshop
  - June 19 - Deadline for comments
- Summer – Draft Recommendations
- Fall – Final Recommendations

Offset Limit White Paper

- Three key questions
  1. What mechanism should be used to impose the limit?
  2. How should the offset limit be applied across jurisdictions?
  3. How should the limit be applied across compliance periods?

Principles to Consider in Evaluating Options

- Fairness
- Economic efficiency
- Cost containment
- Effectiveness and enforceability
- Administrative cost and simplicity

Other Offset Limit Approaches Reviewed

- Regional Greenhouse Gas Initiative (RGGI)
- European Union Emission Trading Scheme
- Limits proposed in US National Cap-and-Trade Legislation
  - Waxman-Markey Discussion Bill
  - Dingell-Boucher Discussion Bill
  - Boxer Substitute of Lieberman-Warner (S. 3036)
  - Lieberman-Warner Climate Security Act (S. 2191)

What Mechanism Should Be Used to Impose the Limit?

- Should the offset limit be applied on
  - **offset use** (e.g., the amount of offsets covered entities can surrender for compliance purposes) or
  - **offset supply** (e.g., the overall amount of offsets issued in a given period of time)?
- If the limit is based on use, what is the preferred mechanism?
- If the limit is based on supply, what is the preferred mechanism?
- Should access to offsets be linked with the distribution of allowances, and if so in what manner?

Options Under Consideration

- Percentage use limit
  - Based on compliance obligations (RGGI, EU ETS, Dingell-Boucher, Waxman-Markey, L-W)
  - Based on distributed allowances (some EU ETS member states; could be a “tonnage” limit instead)
- Offset surrender certificate
- Supply (issuance) limit (Boxer amendment)
- Other options?

How Should the Offset Limit Be Applied Across Jurisdictions?

- Should the limit be applied on a **common** or **differentiated** basis?
  - If the limit is differentiated by Partner jurisdiction, what factor(s) should be the basis of differentiation? (e.g., differences in emission reduction targets, marginal abatement costs, or other factors across jurisdictions)

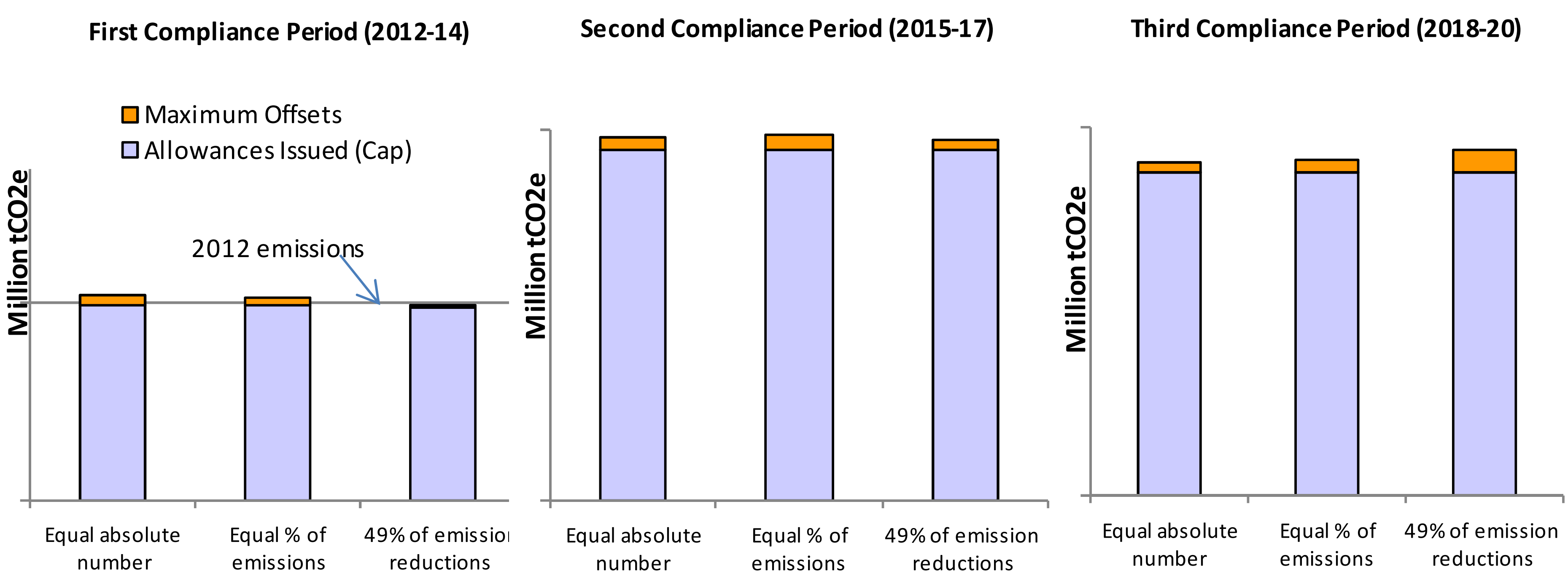
Comparison of Common and Differentiated Use Limits

Option:	Common % Use	Differentiated % Use
Example	X% of compliance obligations in all jurisdictions	49% of emission reductions in each jurisdiction translated to percentages of compliance obligation
Fairness	Entities that emit more GHGs could use more offset credits for compliance.	Emitters from jurisdictions that have a deeper reduction goal for 2020 relative to a base year would be allowed a higher percentage of offsets.
Efficiency	To the extent that offset use falls short of the overall limit as a result of the mechanism used to implement the offset limit, opportunities for efficiency gains may be unrealized.	
Cost Containment	The relative cost containment impact of each option remains to be evaluated.	
Effectiveness and Enforceability	WCI region-wide limit met. Individual partner limits may not be met.	WCI region-wide limit could be exceeded if individual Partners' limits are specified as a percent of compliance obligations.
Administrative Simplicity	Administratively simple to implement.	Slightly more complex to implement

How Should the Limit Be Applied Across Compliance Periods?

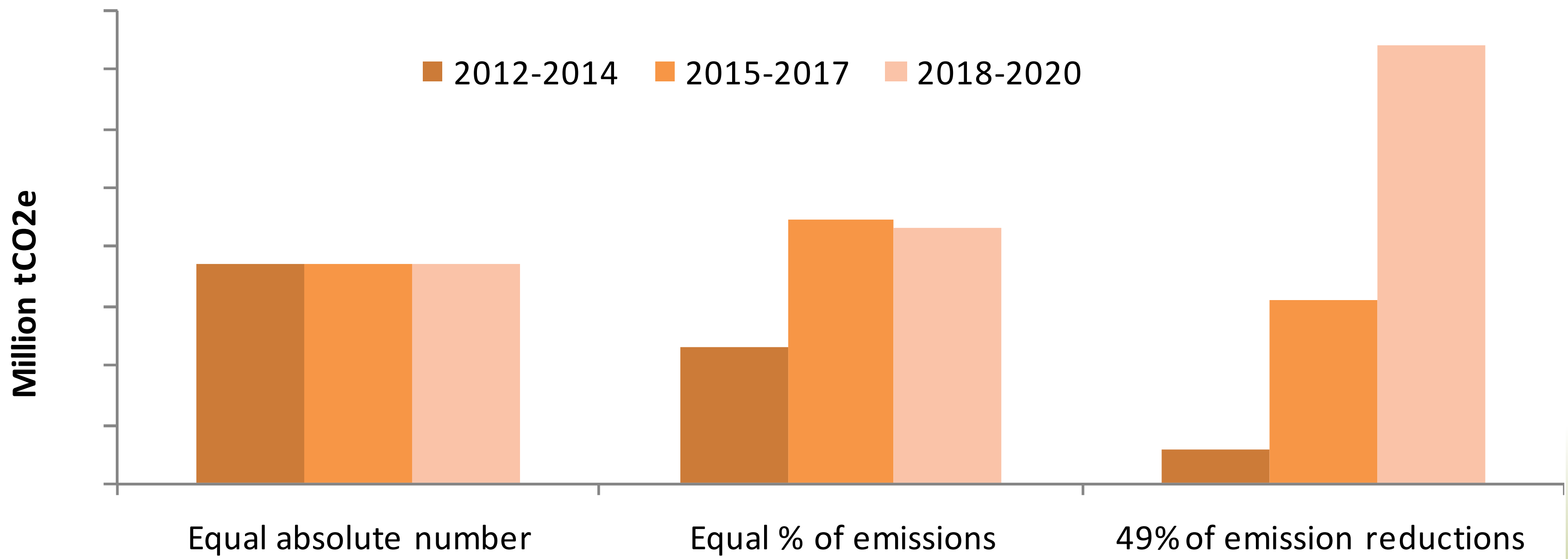
- Equal absolute number of offsets in each compliance period (Waxman-Markey)
- Equal percent of use across compliance periods (RGGI, L-W)
- 49% of Emission Reductions in each period
- No restrictions across compliance periods
- Other Ramp Up (Dingell-Boucher bill) or Ramp Down
- Carry-over (Boxer, EU Phase III)

Offset Limit Options Across Periods: Illustration



- Other options not depicted: No restrictions across time periods (supply limit); other ramp up/ramp down; carry over

Closer View of Relative Offset Amounts



Next Steps

- June 19 - Deadline for comments on white paper
  - Review and consider comments
  - Develop draft recommendations
- Summer 2009
  - Draft recommendations for consultation
- Fall 2009
  - Final recommendations

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Cap Setting and Allowance Distribution Stakeholder Workshop

CSAD Task 6: Early Reduction Allowances

May 28, 2009
Seattle, Washington

Background

- WCI Design Recommendation (8.11.1 to 8.11.3):
  - Each jurisdiction may issue Early Reduction Allowances (ERAs) for certain emission reductions at covered entities and facilities that are achieved after Jan. 1, 2008 and before January 1, 2012.
  - By the end of 2009, establish criteria to determine which early reductions will be eligible for ERAs.
  - Each jurisdiction that issues ERAs will do so in 2012. Any ERAs will be issued in addition to each Partner's 2012 allowance budget.
- CSAD Task 6 to develop the elements of the program including:
  - Criteria for awarding ERAs
  - Process for issuing ERAs.

ERA Work Plan

- Design Development/Consultation
  - May 15 - Release of White Paper
    - Review of other programs
    - Key issues for discussions
  - May 28 – Workshop
  - June 19 Deadline for comments
  - Summer – Draft Design Recommendation
  - Late Fall – final Design Recommendation

ERA Jurisdiction Scan

- Key Programs reviewed
  - RGGI
  - US NOx SIP Call
  - US Proposals:
    - Waxman-Markey
    - Lieberman-Warner
    - Dingell-Boucher
  - EU-ETS
  - Canada: Turning the Corner

Key Observations from Scan

- Stakeholder input into the development of an ERA approach is critical.
- Criteria for determining the nature of verified and credible emission reductions is central to the legitimacy of the ERA.
- Most initiatives placed an upper limit or time restriction on the amount of ERA available.
- Need for clear eligibility guidelines and a sufficient timeframe for regulated sector to respond to ERA opportunities.
- Administration of the program, including determining allocation of ERA can be very rigorous and resource-intensive.
- Allowance allocation design can remove any disadvantage from taking early action, and reduce or eliminate the need to consider ERA.

ERA Approaches

- Which approach should we pursue for ERAs?
  - Programmatic – with application and evaluation against applicable criteria (e.g., like an offset)
  - Baseline approach – based on streamlined evaluation of baseline emissions/reductions and selected criteria

- What ERA approach best fulfills WCI's goal to encourage emissions reductions prior to the cap and trade program start in 2012?
  - Is there a hybrid approach that could be developed reflecting the best of both options?
  - Should there be general guidance rather than project protocols?
  - How should the baseline be established for ERAs?

Other Issues for Consultation

- Eligibility criteria
  - How should we define additionality?
  - Should government funded projects be eligible?
  - What is the balance between administration cost and quality of the ERAs?
  - Reductions at facilities are eligible for ERAs
    - Should reductions be considered across a corporation?
    - How should the electricity generation sector be considered in light of changing mix in generation and conservation programs?

Other Issues for Consultation

- Should there be a limit on ERAs and if so, what should it be based on?
  - Will limits discourage early actions?
  - Do limits introduce competitive issues?
  - Will limits help with addressing gaming?
  - Can you limit ERAs through other means such as stringent criteria or rigorous quantification requirements?

Other Issues for Consultation

- How should we treat the transportation, residential and commercial fuel sector
  - What criteria should we use?
  - How to quantify reductions?

- ERAs are issued by jurisdiction, are there functions that should be done by a regional body?

Immediate Next Steps

- June 19 - Deadline for comments on white paper
  - Review and consider comments
  - Develop draft recommendations

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CSAD Task 3 Competitiveness Update

May 28. 2009

www.westernclimateinitiative.org

Background to CSAD Task 3

- February 19, 2009 CSAD Work Plan: the allocation and cap setting approach will address competitiveness concerns.
- Task 3 Competitive Issues task group created to:
  - Seek, receive, review and perform analyses on competitiveness issues, from sectors or sources that have been identified and/or that self-identify as having competitiveness issues related to cap-and-trade.
  - Assess how WCI Partner jurisdictions should address competitiveness
    - Among the identified industries, and
    - Within each identified industry. If a common allowance distribution method is recommended, CSAD will recommend a distribution method for consideration by WCI Partner jurisdictions.

Objectives for CSAD Task 3

- Characterize risk of carbon and economic leakage related to cost impacts attributable to WCI
- Develop recommendations to Partners for mitigating carbon and economic leakage related to cost impacts attributable to WCI

Work Plan and Timing

2009-10 Work Plan sets out 5 Tasks under CSAD 3:

Subtasks	Deliverables	Dates
3.1	**Competitiveness evaluation and Statement of Principle** • Identify competitiveness issues and existing methodologies; and, • Develop principles to guide the WCI competitiveness evaluation process	2009 Q2
3.2	**Solicit Information from industry** • Emitters from covered sectors provide information related to their competitiveness risks • Finalize WCI process to assess competitiveness exposure and initiate analyses	2009 Q3-4 (2009 Q2)
3.3	**Create Workgroups to review industry information** • Creation of sector specific workgroups, as needed, to review industry information and engage with stakeholders	2009 Q3-4 (2009 Q2)
3.4	**Competitiveness analysis** • Finalize competitiveness exposure analyses, including review of independent analyses	2010 Q1
3.5	**Options to address competitiveness** • Task 3 workgroup will provide recommendations to the Partners for addressing forecasted competitiveness impacts to covered sectors	2010 Q2

First Steps: Ensure a Consistent Approach with other Major Carbon Initiatives

WCI comparison to other programs:

	Waxman-Markey	RGGI	EU	Australia	WCI
Characterize Economic and Carbon Leakage Risks to Covered Sectors	✓	✓	✓	✓	✓
Assess Covered Sectors Risk Levels	✓	✓	✓	✓	✓
Recommended Strategies to Address Leakage	✓	✓	✓	✓	✓

Approaches of other Major Carbon Initiatives

Two main objectives in other programs:

1. **Avoid carbon leakage stemming from cost impacts**
2. **Smooth the transition when competitiveness risks exist**

Examples from other programs:

- **EU Phase III:**
    - Identify sectors with “significant risk of carbon leakage”
    - For significant risks, 100% free allowances “to the extent that they use the most efficient technology”. Phase in auction for others.
- **Australia**. Address transitional challenges faced by emissions-intensive, trade-exposed industries with free allocations

Approaches of other Major Carbon Initiatives

- **Waxman-Markey.** "carbon leakage …substantial increase in GHG by manufacturing entities located in countries without commensurate GHG regulation, provided that such increase is caused ... from the implementation of title VII of the Clean Air Act".
  - Compensate the owners and operators of entities in eligible domestic industrial sectors and subsectors for carbon emission costs incurred.
  - Eliminate or reduce distribution of rebates when such distribution is no longer necessary to prevent carbon leakage
- **RGGI**. "A cost increase due to a carbon cap could drive geographic changes in the operation of the electric power system…a scenario where RGGI sunsets once a national program is implemented, would obviate any potential for emissions leakage"

Subtask 1: Competitiveness Evaluation and Statement of Principle

- Review information from WCI jurisdictions, and what other analyses, proposals, and programs say about:
  1. How to define, measuring and determine competitiveness impacts. (e.g., using carbon costs relative to sales and value added; defining trade exposure; etc.)
  2. How to mitigate potential impacts. (e.g., allowance distribution method; thresholds; tariffs)
- Statement of Principle – Core concepts to guide the WCI competitiveness evaluation process (released to Stakeholders)
- Use stakeholder feedback in designing Subtask 2 (the process by which the WCI will solicit industry input to help identify and characterize competitiveness issues).

Questions for Stakeholders

1. What principles should govern how the WCI Partner jurisdictions evaluate and address potential competitiveness impacts of the WCI regional cap-and-trade program ?

2. What aspects of the WCI cap-and-trade program have the potential to cause intra-WCI competitiveness impacts (i.e., among businesses within the WCI Partner jurisdictions that compete with each other)? How significant are the potential intra-WCI competitiveness impacts compared to potential impacts arising from competition with businesses located outside the WCI Partner jurisdictions ?

Questions for Stakeholders

3. How can the WCI Partner jurisdictions best anticipate potential U.S. and Canadian federal efforts to address competitiveness impacts associated with climate policies, such as cap-and-trade? To what extent should the WCI Partner jurisdictions strive to harmonize with current federal proposals to address these impacts? With those currently employed in the European Union? What competitiveness issues should the WCI Partner jurisdictions emphasize in communications with the two federal governments ?

4. What opportunities and/or challenges, in terms of competitiveness of the covered sectors, might the WCI cap-and-trade program present as the region emerges from the current economic downturn? What other factors might interact with the cap-and-trade program to enhance or hinder the competitiveness of covered sectors within a jurisdiction?

Questions for Stakeholders

5. For those sectors for which internalizing the cost of carbon through a cap-and-trade program presents competitiveness risks, which options should the WCI Partner jurisdictions consider to address those potential impacts ?

Questions for Stakeholders

1. Principles to govern WCI evaluation
2. Intra-WCI vs. External competition
3. Federal Interaction
4. Economic Downturn & Other Factors (Positive & Negative)
5. Options for addressing competitiveness risks

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The WCI CSAD Committee thanks you for your participation!

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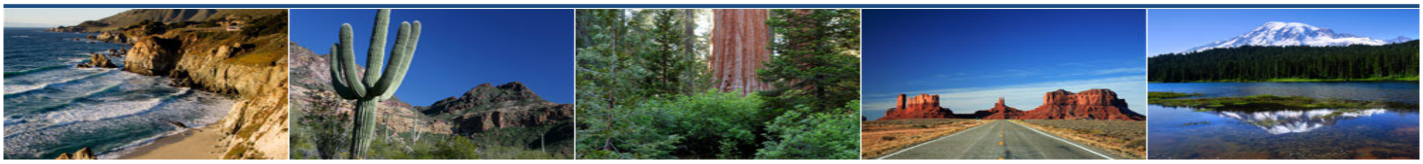

Early Reduction Allowances White Paper

May 14, 2009

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Appendix 1:

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1 Purpose and Objective of Early Reductions

As part of the *Design Recommendations for the WCI Regional Cap-and-Trade Program*, the WCI Partners may issue Early Reduction Allowances (ERAs). ERAs are used to recognize emissions reductions at facilities covered by the cap occurring between January 1, 2008 and January 1, 2012. This approach is intended to provide an additional incentive for covered entities and facilities to invest in projects that reduce emissions before the beginning of the WCI cap-and-trade program, rather than waiting to implement emissions reduction projects until the program is underway.

The WCI Partners have a number of options they can use to recognize early actions. In the case of auctioned allowances, early reduction activity would lead to lower costs for the covered entity or facility undertaking the early action. If allowances were issued based on industry-specific benchmarks, the basic allocation approach would reward facilities that have reduced their emissions below the identified benchmark. If allowances are distributed based on historical emission levels (sometimes called grandfathering) partners could consider distributing allowances based on historic emission levels, which means entities that have taken early action have more allowances compared to their emissions. .

According to the Sept. 23, 2008 WCI Design Recommendation Background report (Section 1.10.4), ERAs could be issued by each Partner jurisdiction in 2012 to facilities and entities covered by the cap that have made eligible emissions reductions. Any facility covered by the cap in either 2012 or 2015 will be eligible to receive ERAs. Once issued, ERAs can be traded or used for compliance purposes, equivalent to any other WCI emissions allowance.

The WCI plans to issue ERAs in addition to each Partner's allowance budget. This is based on the assumption that any emissions reductions qualifying for ERAs will lead to a lower emissions cap in 2012. Without a means to encourage emission reductions in advance of the program, there may be a perverse incentive for facilities to wait until the cap-and-trade program begins before investing in emission reducing technology or even increase their emissions to get more allowances if allowance distribution is based on best estimates of 2012 emissions.

If properly designed, ERAs will encourage real reductions prior to the start of the cap-and-trade system in 2012. However, if significant amounts of ERAs are rewarded for reductions not fully reflected in the level at which the cap is set, some jurisdictions have expressed concerns that ERAs could diminish the intended level of allowance scarcity. In order to prevent such an over allocation and to ensure the quality of the reductions, ERAs will have to be issued based on clearly established criteria to ensure that reductions are voluntary, additional, real, verifiable, permanent and enforceable.

There are different approaches on how to issue ERAs in 2012. In a programmatic approach, there would be an application process and determination of ERAs to be issued, similar to offset projects. An alternative is the baseline approach, where the ERAs are calculated based on verified emission reductions between 2008 and 2012 submitted by the entity using the same reporting infrastructure of the WCI.

The Cap Setting and Allowance Distribution (CSAD) Committee received the mandate to develop the methodology for implementing the WCI ERA approach. As part of this work the CSAD Committee seeks input on answering the following questions. More detailed questions are posed throughout the document on each topic.

1. What ERA approach best fulfills WCI's goal to encourage emissions reductions prior to the cap and trade program start in 2012?
2. In the programmatic approach to ERAs:
    a. What criteria should WCI Partners use to evaluate ERA projects?
    b. Will it be necessary to establish an application process for ERAs prior to the final regulation in 2010/11 in order to issue ERAs in 2012?
    c. Should the WCI develop general guidance documents to ensure consistency in the implementation of the program (rather than develop project specific protocols)?
3. Under an ERA baseline approach, what documentation should be required to establish the baseline?
4. ERAs are administered by the jurisdictions. Are there functions that would benefit from being coordinated through the regional administrative body? If so, which ones?
5. Should there be a limit on the number of ERAs issued? If so, what should the limits be based on?

This white paper seeks stakeholder input on these, and other, issues related to the ERA program. First, we briefly outline similar approaches from other cap-and-trade systems currently in operation or under development in jurisdictions around the world. Then we present a number of issues for discussion in establishing a successful ERA approach. Finally, we provide information on how stakeholders can provide input to the CSAD Committee as it drafts recommendations for Early Reduction Allowances.

2 Jurisdictional Scan of Approaches to Early Reduction Recognition Under Other Trading Systems

The WCI Cap Setting and Allowance Distribution Task Group 6 "Emission Reductions Allowances" reviewed several existing and proposed emission trading systems to inform the WCI ERA design process. The review considered the Regional Greenhouse Gas Initiative, the European Union Emissions Trading System, the NOx SIP Call, the Canadian Regulatory Framework on Air Emissions, the proposed Australian Carbon Pollution Reduction Scheme, and four proposed U.S. federal acts – the Dingell-Boucher Discussion Draft, the Bingaman-Specter Low Carbon Economy Act, the Lieberman-Warner Climate Security Act, and the Waxman-Markey Discussion Draft. The recommendations of the U.S Climate Action Partnership were also considered. The table below provides an overview of the key elements found in other approaches to recognizing early action. Detailed information on the approaches reviewed is provided in Appendix 1.

The review of the approaches surveyed above highlights some key lessons that should be considered by the WCI partners as they develop the design details of any Early Reduction Allowance program:

- An appropriate allowance allocation design can remove any disadvantage from taking early action, and hence reduce or eliminate the need to consider ERAs.
- The majority of the initiatives placed an upper limit or time restriction on the amount of ERAs available to capped entities and facilities.
- The criteria for determining the exact nature of verified and credible emission reductions is central to the legitimacy of the ERAs.
- Capped entities and facilities will require clear eligibility guidelines and a sufficient timeframe to respond to ERA opportunities.
- Stakeholder input into the development of an ERA approach is critical.
- Administration of the program, including determining the allocation of ERAs can be very rigorous and resource-intensive.

Table A. Summary of Programs Reviewed

Trading System/Bill Name	Sectors/ Sources covered	Explicit early action approach?	Years Eligible for Consideration	ERAs in addition to the "Cap"?	Limit on ERAs Issued?	Additionality and other key criteria	Method to quantify early reductions
RGGI	Electricity	Yes	2006-2008	Yes. Awarded directly to the CO2 budget source, are not included in the auction, and are in addition to the cap.	No	No requirement to show financial additionality or that action taken exceeded existing regulation	Two different formula developed for quantification
EU ETS	Large GHG emitters including electricity and industrial sectors CO2 emissions only	Yes, but up to individual Member States. Some member states believe early reduction rewards are already in the program design.	Determined by member state but based on EU Directives	No. Limited to reductions of covered emissions beyond reductions made pursuant to legislation, or to actions undertaken in the absence of any such legislation. Implies fewer allowances available to installations not taking early action.		Varies by jurisdiction. For example, Germany uses a number of criteria including minimum percentage reduction before rewarding early reduction allowances.	Varies by jurisdiction
US EPA NOx SIP Call	Large electricity generating sources/large combustion point sources of NOx	Yes	2003 and 2004 ozone season	Can be issued if reduction surplus to regulatory requirement	Cannot be greater than the compliance Supplement Pool (CSP).	Reductions beyond a benchmark (NOx intensity) or an absolute reduction.	Follow SIP protocols and approved by EPA

Trading System/Bill Name	Sectors/ Sources covered	Explicit early action approach?	Years Eligible for Consideration	ERAs in addition to the "Cap"?	Limit on ERAs Issued?	Additionality and other key criteria	Method to quantify early reductions
Canadian Regulatory Framework	Electricity generation from combustion oil; oil and gas; smelting and refining; iron and steel; mining; cement; lime; chemicals Kyoto GHGs	Yes	1992 to 2006		Yes	Incremental to regulatory requirements, beyond standard improvements and beyond actions resulting from government incentive programs.	Defined in "Guidance Manual for Applicants for Early Reduction Credits".
Canadian Baseline Protection Initiative	Designed to reduce impacts of regulation on entities that took early action	Yes	1990 to 2000				
Australian Carbon Pollution Reduction Scheme		No					
Dingell-Boucher Discussion Draft	Limited detail available	Yes					
Bingaman-Specter Low Carbon Economy Act	Limited Detail available	Yes					

Trading System/Bill Name	Sectors/ Sources covered	Explicit early action approach?	Years Eligible for Consideration	ERAs in addition to the “Cap”?	Limit on ERAs Issued?	Additionality and other key criteria	Method to quantify early reductions
Lieberman-Warner Climate Security Act	Limited detail available	Yes					
US-CAP		Yes	No earlier than 1995 (given as an example) until enactment date of mandatory program		“adequate set aside of allowances under the cap”	“Financial additionality not an appropriate criterion”	Not defined
Waxman-Markey Discussion Draft	Limited detail available	Bill does not address allowance distribution issues at this time					

3 Issues for discussion

A framework for ERAs requires certain essential elements including defining additionality; identification of project types and entities that could apply for ERAs; and clarity on acceptable methods for quantifying reductions, administration of ERA distribution and linkages to the broader WCI program. In designing the ERA approach, there has to be consideration given to how an ERA program will interact with the setting of caps/budgets at the beginning of the cap and trade program and their potential effects on the emission trading market.

3.1 Additionality

The WCI ERA approach, as described in the Design Recommendations, is intended to incent voluntary reductions within the covered sectors of the cap-and-trade system. Aside from being voluntary, the Design Recommendations also indicate that the emission reductions must also be additional, real, verifiable, permanent and enforceable.

Additionality is one of the key criteria in designing an ERA approach. Some commonly applied criteria would likely be part of the WCI definition including: surplus to regulatory requirements; reductions not due to decreases in production or shut downs and reductions that are not supplanted by transferring activities or production to other facilities.[1] Other additionality criteria such as beyond business as usual; financial additionality[2]; and projects that are not the result of government funded projects, will be reviewed and evaluated in developing the WCI recommendations.

Defining additionality within the context of an ERA approach requires sensitivity to many of the same issues that arise when applying additionality tests to offsets. Any effort to determine additionality in an ERA approach will need to balance administrative efficiency and cost with overall effectiveness and stringency. WCI Partners and stakeholders have a range of issues to address, from essential definitions to broader implementation-related concerns including:

- How is additionality defined in an ERA programmatic approach? Is it as simple as, 'without the ERA, the project would not proceed' or 'without the ERA, the project would be delayed until after the cap is in place'? Alternately, should it be based on a more general criterion such as a minimum absolute reduction?

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[1] Supplantation can occur within the same corporation, or within or outside of the WCI region. Supplantation may be allowed if a demonstration is made of a net reduction in GHG emissions as a result of the curtailment or shut down.

[2] A project-specific assessment that considers the total cost of a reduction project, the financial rationale for undertaking or rejecting the project and assesses whether the value of potential ERAs would make the project financially viable, making the case to proceed.

- Should government funded projects be eligible for ERAs?
- Once a basic definition is settled upon, what "additionality tests" (financial, project-by-project BAU, benchmarking, barrier, etc.) are best suited for assessing additionality in a WCI ERA approach?
- What is the right balance of stringency and transparency in additionality testing?
- What is the balance between high administrative costs to ensure high quality ERAs and minimization of costs to encourage early reductions?

3.2 Entities that are eligible for ERAs

The design recommendation indicates each WCI Partner may issue ERAs for reductions at covered entities and facilities within its jurisdiction for reductions between January 1, 2008 and January 1, 2012. Covered sources would include electricity generation (including electricity imported into a Partner jurisdiction), industrial and commercial facilities which emit at least 25,000 tonnes of CO2e annually. In addition, covered entities would include the providers of transportation, residential, commercial and industrial fuel regulated at a point upstream of combustion. The covered sources may be controlled or owned by a range of entities including publicly traded companies/corporations, private owners, government owned utilities, government corporations, government agencies, state/provincial government, regional or municipal governments.

Reduction at individual facilities will be eligible for ERA provided they meet the applicable criteria. However, in many cases corporations may operate a number of facilities within the WCI jurisdictions.

- Should reductions be considered across the entire corporation provided there is a demonstration of net GHG reductions (e.g., for cases where inefficient production is closed at one site and moved to sites with less GHG-intensive operations?

For the electricity generation sector, a jurisdiction can have a mix of different types of generation. As the mix is changed towards lower carbon or zero carbon generation:

- How should the electricity sector be handled in light of mandated or non-mandated changes and/or energy efficiency programs intended to advance this transition?

3.3 Potential limits on total ERA issued

Our review of ERA approaches clearly indicates that there is no single, standard approach to placing limits on early action credits in cap-and-trade systems. So WCI partners will only be able to look to these other approaches for limited guidance in determining the potential limits on total ERAs issued.

While a well designed ERA program should not lead to over-allocation over the long term, there could be effects on the market in the early compliance periods. The availability of a large volume of ERAs at the start of the first compliance period could be a key cost containment mechanism; however, excessive amounts of ERAs could affect the market and lead to an unintended reduction in the price of allowances. In order to determine the limit level that may be applied (or if there should be a limit at all) to the system, Partners and stakeholders should consider the following:

- What are the options and impacts of different limits levels?
  - Do limits introduce competitive advantages or disadvantages into the system, and who are the affected parties?
  - Will limits reduce concerns of system gaming?
  - Will limits disincent early action in covered sectors?
- Could a limit on ERAs be achieved through other means such as a stringent program design – either through stringent criteria for specific eligible actions or a rigorous quantification methods?

3.4 Relationship of ERA and 2012 allowance budget

Section 1.7.2 of the WCI Background Report on the Design Recommendations notes that voluntary reductions recognized under ERAs be reflected in the estimates of the 2012 allowance budget. Section 1.10.4 of the Background Report suggests that an ERA approach "will not result in an over-allocation of allowances because the Early Reduction Allowances will apply to reductions of emissions that would have otherwise been included in each Partner's 2012 allowance budget." The report cites both the Northeast NOx Budget Cap-and-Trade Program and the U.S. Environmental Protection Agency (EPA) NOx SIP-Call Program as supporting the workability of this recommendation. If the mechanism developed to reconcile 2012 allowance budgets for each Partner is to be based on either of the two programs noted above, then Partners and stakeholders will have to consider:

- Does the broad scope of the WCI cap-and-trade system make it too complicated to develop an ERA mechanism similar to those used in the USEPA NOx programs, which primarily covered the electricity sector?
- How should the emission reductions achieved by ERAs be coordinated with the setting of caps/budgets for 2012/15 and issuances of allowances by each jurisdiction?

3.5 Coordination of Implementation of ERA

The ERA process will likely be included as part of the essential elements to be adopted by jurisdictions in their emissions trading regulations. The regulation would provide authority for the jurisdiction to issue ERAs and the conditions that must be met before they are issued. Individual jurisdictions are most familiar with their industries, which provide for easier interactions with potential applicants.

Each WCI Partner jurisdiction can issue ERAs in 2012. In a programmatic approach, there is a need for an ERA application process as early as possible and likely before the finalization of the final regulations in 2010/11. This would allow the jurisdiction to obtain the information to make the determination of ERAs to be issued in 2012. An alternative is the baseline approach, where the reductions and ERAs are calculated based on verified emission reductions between 2008 and 2012 submitted by the entity using the same reporting infrastructure of the WCI.

A large number of entities, industries and types of projects may apply for ERA, which may make it impractical to develop protocols/methods for all the types of projects that are eligible (unlike offsets). However, under a more programmatic approach, some general guidance would still be required to ensure consistency in the application, evaluation and final determinations of allowances to be issued. In particular the transportation, residential and commercial fuel sectors would need clear guidance on the types of activities that would be eligible and how the reductions should be quantified.

WCI is seeking stakeholders' views on:

- The use of a programmatic approach with an application process or a baseline approach for ERAs prior to the final regulation.
- The use of general guidance documents to ensure consistency in the implementation of the approach (rather than project specific protocols).
- Should ERA distribution be administered by the jurisdictions or through a central administrative body?
- What criteria should be used to determine the types of activities that are eligible for ERAs in the transportation, residential and commercial fuel sectors? How should the reductions be quantified?

4 Next steps

WCI has released this White Paper to provide background on the approach to the Early Reduction Allowances. The Paper reviewed existing approaches and identified some key questions to provide common foundation for the design of the ERA approach.

WCI is seeking stakeholder input on the White Paper. We ask that written comments be submitted through the WCI website by June 19, 2009 (www.westernclimateinitiative.org).

You are also invited to participate in a stakeholder meeting (and/or webinar) to discuss the White Paper on May 28, 2009 at Seattle, Washington http://www.westernclimateinitiative.org/WCI_Meetings_Events.cfm.

The input provided by stakeholders will be considered by WCI and inform the development of draft recommendations on ERAs for further stakeholder input in early Fall 2009.

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Appendix 1: Additional Details on Existing or Proposed Early Reduction Recognition Programs

Regional Greenhouse Gas Initiative

The Regional Greenhouse Gas Initiative (RGGI) covers carbon dioxide emissions from the electricity sector in ten North-Eastern and Mid-Atlantic states. The RGGI Model Rule allows participating states to award ERAs entities that make voluntary emission reductions prior to the beginning of the first compliance period. Early reductions made during 2006-2008 are eligible for early reduction allowances.[3] Entities must include all CO_2 units for which they were responsible under the 2002-2004 baseline in order to verify their reductions, as well as accounting for new units added since the baseline period. Reductions resulting from operation shutdowns are not eligible for ERAs. In order to receive ERAs entities must demonstrate that the reductions occurred relative to the baseline period (2002-2004). ERAs are distributed in addition to each state's allowance budget and there is no limit on the number of ERAs that can be issued.

The Model Rule does not require entities seeking early action reductions to demonstrate that their reductions are financially additional or exceed new regulatory requirements. Two formulas are used to determine the amount of ERAs an entity can receive. The first formula is for entities that experienced an increase in total heat output from their baseline levels. These entities calculate the total tonnage of CO2 emissions during the ERA period and subtract the amount from the baseline period CO2 emissions. Entities that experience a decline in total heat input between the baseline period and the early action period use a more complex formula that must demonstrate a decrease in carbon intensity (lbs. CO2 per MWh) in order to receive allowances.

Applications from entities seeking ERAs are submitted to the state's designated regulatory agency, which evaluates applications to determine if the ERA criteria are met. The deadline for submission of applications established in the Model Rule is May 1, 2009 and regulating agencies must distribute all early reduction allowances by December 31.

[3] As of May 2008, Vermont did not include early reduction allowances in its implementation rule.

European Union Emissions Trading System

The European Union Emissions Trading System (EU ETS) is the cornerstone of the EU's strategy to help Member States and EU achieve compliance with their commitment under Kyoto Protocol, and to promote reductions of GHG emissions in a cost-effective and economically efficient manner. The EU ETS is a GHG cap- and-trade Scheme covering large emitters, including the electricity and industrial sectors. The EU ETS was established officially by Directive 2003/87/EC of the European Parliament and of the Council of 13 October 2003, which sets the rules to put in place and implement the Scheme. EU ETS started out on January 1, 2005, with the first compliance period (2005-2007). The second compliance period is currently under way (2008-2012). The directive establishing the EU ETS refers to all six Kyoto GHGs but regulation only applies to emissions of CO2.

For the first two compliance periods, each Member State developed a National Allocation Plan (NAP) stating the total quantity of allowances that it intends to allocate for that period and how it proposes to allocate them among the installations which are subject to the Scheme. When summed the allowance numbers specified in these NAPs are equal to the total 'cap' for the program. The NAP process was based on objective and transparent criteria, including those listed in Annex III of Directive 2003/87/EC.

One of these criteria, Criterion 7, pertains to early action, and says:
The plan may accommodate early action and shall contain information on the manner in which early action is taken into account. Benchmarks derived from reference documents concerning the best available technologies may be employed by Member States in developing their National Allocation Plans, and these benchmarks can incorporate an element of accommodating early action.

Therefore, this was an optional criterion: Member States did not have to recognize or accommodate early action.

In order to assist Member States in the implementation of the criteria listed in Annex III, European Commission issued on 27 January 2004, a communication (COM (2003) 830 final) giving guidance, among others, on the Criterion 7 (Early Action), which can be summarised as followed:

- The accommodation of early action was considered desirable from a fairness point of view.
- Early action was limited to reductions of covered emissions beyond reductions made pursuant to Community or national legislation, or to actions undertaken in the absence of any such legislation.

- The application of this criterion necessarily implied fewer allowances available for installations that did not undertake early action (to prevent over-allocation all early action was rewarded from within the total quantity of allowances to be allocated).
- Three methods were possible for Member States to accommodate early action (the Commission can also assess others) :
    - choosing an early base period
    - making a two-round allocation at installation level
    - using benchmarks

The European Commission issued another important communication in 2005 giving guidance to Member States on developing NAP for the second compliance period (COM (2005) 703 final). However, this communication doesn't give further information on early action.

Therefore, at the European level, there is no specific early action program allocating ERAs. However, Member States may recognize or accommodate early reductions in their NAP within their cap.

The National Action Plans of three of the six largest emitter Member States in EU ETS (France, United Kingdom and Germany) are reviewed below.

<u>France</u>: accommodates early action using the "early base period" method:

- In NAP I (2005-2007), early action is accommodated in two ways:
    - In allowances distribution from the cap to Sectors budget, using the average 1998-2001 period for the base specific emissions;
    - In allowances distribution from Sectors budget to Installations, using a base year or period that can go back to 1996.
- In NAP II (2008-2012), early action is accommodated in one way:
    - In allowances distribution from Sectors budget to Installations, using a base year or period that can go back to 1996.
    - It is clearly mentioned that taking into account early action doesn't change the total quantity of allowances to be allocated (the cap).

<u>United Kingdom</u>: does not consider that it is appropriate to reward early action specifically in the Phase II NAP (2008-2012).

This is because it considers that it is very difficult to identify instances of early action other than those undertaken either:

- In compliance with relevant legislation or other policies, which the Commission guidance makes clear is not covered by the definition of early action; or

- For economic reasons, for which there would appear to be little justification for additional award.

However, the use of average emissions data from 2000-2003 to distribute allowances to individual installations takes some account of major decreases in emissions during later years by incorporating data for early years, and therefore rewards an operator who took early action during the baseline period. It also avoids the penalty for early action that would result from basing allocations on a single recent year (e.g. 2003) or on individual forecasts of emissions.

Germany: accommodates and recognizes early action using a mixed method in NAP I (2005-2007).

First of all, Germany carries out the allocation to installations in its NAP I based on grandfathering (allocation based on an installation's historical emissions in a reference period) and benchmarking (allocation based on the average specific emissions of a product category).

The allocation to an individual installation is calculated using:

- CO_2 emissions from the installation in the reference period 2000-2002; and
- The compliance factor.

The compliance factor is always equal to or less than 1; a factor less than one implies a reduction burden. As for early action recognition, two ways are used. The first is by using an early reference period (2000-2002) to calculate the allocation. The second way is an early action mechanism (special allocation rules), which enables qualified installations to be entitled to apply a compliance factor of 1 (no reduction burden). A compliance factor of 1 could be applied to existing installations which were modernised and to newly built installations if (re-)commissioning occurred between 1 January 1994 and 31 December 2002.

Existing installations qualify as early action installations if they can demonstrate a predefined reduction in specific CO_2 emissions, provided that these reductions were not achieved simply by decommissioning the plant and/or a decline in productive output. These specific emissions reductions have to range from 8 to 14% depending on the year commissioned. Moreover, measures to reduce specific emissions will not be ranked as early action measures if they were substantially funded by public means or if they would have been required in any case due to legal stipulations.

If an installation was newly commissioned between 1 January 1994 and 31 December 2002, it is assumed to have achieved at least the defined reduction in specific emissions. There is, therefore, no need to supply evidence.

Applications for a compliance factor of 1 could be made for a period of 12 years after the completion of the modernisation.

The greater the number of early action installations that would be entitled to apply a compliance factor of 1, the higher the reduction burden would be for the other emitters. That is what happened on 21 April 2004 when the German government adopted an Act to amend NAP I before coming into force, modifying the general compliance factor for 0.9755 (emissions to be reduced by 2.45%), in order to recognize more early actions. The initial general compliance factor was 0.9765 (emissions to be reduced by 2.35%).

United States Environmental Protection Agency NOx SIP call

The United States EPA NOx SIP call is a NOx Budget Trading program (NBP) implemented in 2003 for Midwest and North-Eastern States in order to reduce NOx emissions enabling the States to attain national ambient air quality standards for ozone. The Budget Trading Program covered large electricity generating units (EGUs> 25 MW) and other large combustion point sources (non-EGUs >250 mmBTU/hour). NOx Budgets were established for each State, along with a Compliance Supplement Pool (CSP) to support efforts to encourage early reductions.

States could issue early reduction credits if the reduction was surplus to regulatory requirements in the SIP or the Clean Air Act (CAA), as well as verifiable and quantifiable. States could also develop an early action program to provide for additional early reduction credits; but, the total amount of early action credits must not be greater than the CSP.

USEPA established a NOx Budget Trading program which could be adopted by individual States (23 in total, including D.C.) in their State Implementation Plan (SIP). The NBP includes a budget for each State in the period starting in 2003 and a compliance supplement pool (CSP). The CSP can be used by States to encourage early action, or to reduce the reliability risk of the electricity supply and provide flexibility for facilities that cannot meet the requirements in the early years. The CSP can also be used to integrate the earlier Ozone Transport Commissions (OTC) NOx trading program (started in 1999) into NBP – by carrying all of the banked OTC NOx allowances into the NBP.

In order to issue CSP for early action, the State must meet the following provisions:

- Complete the issuance prior to May 1, 2003 (in the first compliance period);
- Emission reduction must not be required by SIP or CAA (e.g., surplus to regulatory requirements);

- Emission reductions must be verified as having occurred in the ozone season;
- An optional method is to require emissions reductions that are no less than 20% below the year 2000 emission rate, and the amount of allowances will be equal to the difference between a benchmark and the actual emission rate;
- Emission reductions must be quantified according to the SIP and approved by EPA; and
- The CSP credits may be traded with other sources in the trading program.

Allowances issued under the CSP could only be used to demonstrate compliance in the 2003 and 2004 ozone season, meaning they must have been used in the first two compliance periods and could not be banked for future use. A total of 200,000 tons of CSP allowances were set out by USEPA in the rule, 170,192 CSP allowances were issued/retired according to Clean Air Markets. The total NOx Budget for EGU and non-EGU sources is 1,102,443 tons. The CSP is approximately 18% of the EGU/Non-EGU budget.

Under the USEPA model program, each NOx Budget source is required to have a federally enforceable permit; such permits include a NOx budget permit. The permit may be a Title V or a non-Title V permit provided it include provisions for addressing permit application, permit duration, permit issuance, etc. The permitting authority allocates NOx allowances to each Budget unit and also submits to the Administrator (US EPA) the NOx allowance allocation. The Administrator establishes appropriate account(s) for each NOx Budget Unit, and records the allocations of the allowances into the account.

A review of selected State regulation shows Pennsylvania (PA) does not mention allocations through the permitting process, whereas New York (NY) does issue allowances through the permitting process. PA and NY both issued early reduction allowances that are actually transfers of banked allowances from the OTC trading program. PA also allocated CSP based on reductions below a NOx benchmark and emissions that are 20% below the 2000 emissions.

Canadian Regulatory Framework on Air Emissions

The Canadian Regulatory Framework on Air Emissions or *Turning the Corner* was released in April 2007. It provides a regulatory framework for short-term industrial emission greenhouse gas (GHG) reduction targets, and sets medium- and long-term national targets. Targets are based on a 2006 baseline. The Framework sets out emission-intensity reduction targets for industrial sectors that will come into force in 2010. The targets shift from intensity-based to absolute in 2020. The Regulatory Framework covers facilities in the following sectors: electricity generation produced by combustion; oil and gas; forest products; smelting and refining; iron and steel; some mining; and cement, lime and chemicals.

The framework includes a one-time allocation of Credits for Early Action. There is a maximum allocation of 15 MT and only 5 MT can be used each year (for 3 years). If total tonnage of eligible emission reductions were to exceed 15Mt, the credits would be distributed to individual firms in proportion to their contribution to the total emission reduction achieved. The eligibility criteria for the Credit for Early Action Program includes actions that are incremental to regulatory requirements, beyond standard improvements and beyond actions that result from the receipt of a direct federal or provincial/territorial climate change incentive.

The Credit for Early Action Program is intended to address the disadvantage that a firm could incur for having undertaken an incremental action to reduce GHGs before the regulatory regime was set out. It is a one-time allocation of credits to those firms covered by the proposed regulations that took verified action to reduce their GHG emissions between 1992 and 2006.

The *Credit for Early Action Program – Final Program Guide* provides the direction for submitting an application for early action recognition. The program requires that evidence of emission reductions be audited.

Six eligibility criteria must be met in order to qualify for Credit for Early Action:

1. The action reduced emissions in the facility of one or more GHGs: carbon dioxide (CO2), methane (CH4), nitrous oxide (N20), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs) and sulphur hexafluoride (SF6).
2. The action occurred in a "facility" as defined in the Final Program Guide.
3. The action occurred in a facility where the emissions from or capacity of the facility in 2006 exceeded a minimum threshold specified in the Final Program Guide.
4. The initial GHG reductions from the action occurred in 1992 or later, and the reductions continued at least until December 31, 2006.
5. The GHG reductions from the action are unique (the firm has not received a GHG credit through a mandatory program or in a voluntary system).
6. The action was incremental, that is, beyond usual business conditions, when the GHG reductions first occurred. There are two options to demonstrate an action is incremental. An applicant can show intensity reductions and cumulative improvements are more than 1% per year, or they may submit information to show the action is surplus to beyond standard improvements (e.g., not a result of capital turnover, financial barriers that prevent others from such actions, etc.)

Actions that are ineligible for Credits for Early Action are also defined. These include: reductions that were a result of reductions in production or shut-downs; actions implemented outside a facility's boundary; emissions that were reduced by moving production off-site (displacement instead of reduction); GHGs being captured / recovered and sequestered, moved off-site or sold to another facility; reductions resulting from an energy efficiency improvement that reduced the emissions of another facility (e.g. an action reduced the electricity, steam or heat consumption of the facility but these inputs were purchased from a grid or another facility); the action reduced emissions from a fixed process; or the action reduced fugitive emissions.

The program has a three phase implementation process:

- Phase I: "Initial information submission phase." Completion and submission of a Notice of Interest" and a "Phase I Submission" template.
- Phase II: "Final submission phase." Applicants provide the information needed for the final allocation decisions. Details for the Phase II application process have not yet been released, but it is expected to have requirements for acceptable evidence of reductions, acceptable approaches to establishing a baseline, acceptable quantification approaches, qualifications for third-party verifiers and information for verifiers regarding their roles and responsibilities in the verification process. Phase I must be completed successfully in order to participate in Phase II.
- Phase III: "Allocation of Early Action Credits." The government will allocate entitlement to early action credits.

The industrial air emissions regulations proposed in the Regulatory Framework will set out the conditions under which regulated entities will be able to use Early Action Credits to comply with their compliance obligations.

Early action credits will have the following characteristics:

- Unique: Each will have a unique serial number and will be tracked from issuance to retirement or cancellation. Each will represent one whole tonne of carbon dioxide equivalent
- Earned: Allocation and issuance will only occur when GHG reductions can be demonstrated in accordance with the Program requirements
- Uses for regulatory compliance: Proposed industrial GHG regulations will set out conditions for use of Early Action Credits to comply with their obligations.
- Tradable: Credits can be traded among facilities as well as other market participants
- Bankable: It is anticipated that the proposed regulations will not impose any restrictions on the banking of credits for future use.

The Final Program Guide also introduces a number of technical issues regarding the quantification of GHG reductions. These will be addressed in more detail in the forthcoming "Guidance Manual for Applicants for Early Action Credits." The Manual will provide technical guidance to applicants, and will include requirements for acceptable third-party verifiers and guidance for undertaking verifications.

It should also be noted that the intensity target for emissions from adipic acid production will be set to recognize voluntary early action by industry. This is separate from the Credit for Early Action Program.

Canadian National Implementation Strategy on Climate Change – Baseline Protection Initiative

In January 2000, federal, provincial and territorial Ministers of Energy and the Environment announced a Baseline Protection Initiative under the National Implementation Strategy on Climate Change. Beginning March 2001, Canadian emitters were able to register eligible greenhouse gas emission reductions through the Voluntary Challenge Registry and, in Quebec, through ÉcoGESte.

The Baseline Protection Initiative (BPI) was intended to remove a significant disincentive for early action by emitters. Without baseline protection, a compliance requirement based on emissions in a future year would significantly disadvantage early actors. For example, a requirement to reduce emissions by 10% would mean that emitters that had voluntarily reduced their emissions before the regulation would have to make further reductions at additional cost. Emitters that did not take early action would be required to reduce their emissions only once. With baseline protection early reducers would be deemed to have the same emissions as if they had not voluntarily reduced their emissions before the regulation was introduced. Their early emission reductions can then be applied towards the reduction requirements contained in the new regulation, ensuring fair treatment of all emitters.

To be eligible for baseline protection, the BPI required that emission reduction actions must have been implemented since January 1, 1990. They must have resulted in real, net reductions, i.e., emission reductions or avoided emissions that are directly attributable to specific, identifiable actions.

The Baseline Protection Initiative was discontinued prior to the introduction of the Canadian Regulatory Framework on Air Emissions.

Australian Carbon Pollution Reduction Scheme

The Australian Carbon Pollution Reduction Scheme is the federal Australian cap-and-trade system for greenhouse gases expected to commence July 1, 2010. The current design of the scheme does not provide any explicit reward or credit for early action.

As part of the cap-and-trade program design process the Australian government considered a program to reward early action in the discussion paper entitled *Abatement Incentives Prior to the Commencement of the Australian Emissions Trading Scheme*.

The Australian government eventually chose not to set up an early action program to explicitly reward early action at capped facilities for the following reasons:

- Given the proposed allocation strategy (a gradual progression to high levels of auction) businesses are likely to seek to reduce emissions in preparation for the commencement of trading. Thus, the cap and trade scheme will implicitly reward early action by reducing the number of permits that a business will be required to surrender.
- Given the substantial work involved in establishing early action arrangements, there was a risk that resources could be diverted from core scheme design and implementation tasks. Early action arrangements would increase administrative complexity and raise implementation risks for business and the Government at a time when preparing for the Carbon Pollution Reduction Scheme is a critical challenge.

Key Proposed U.S. Cap-and-Trade Bills

This paper also briefly examines three proposed U.S. federal acts – the Dingell-Boucher Discussion Draft, the Bingaman-Specter Low Carbon Economy Act and the Lieberman-Warner Climate Security Act – as well as the USCAP Blueprint and the Waxman-Markey American Clean Energy and Security Act to determine the extent to which ERAs are included in their design, as these acts may provide some clues to what could be included in the legislation that will eventually be voted on by Congress.

The **Dingell-Boucher Discussion Draft** recognizes early action credits using 3% of allowances in 2012-2013 and 2% of allowances in 2014-2026. The proposed system would pre-empt state and regional systems. Holders of allowances from state or regional systems would be compensated based on the costs of purchasing and holding allowances rather than by a pre-determined conversion factor. If demand for early action credits was higher than available supply, state and regional allowance holders would be compensated first.

The **Bingaman-Specter Low Carbon Economy Act** would allocate 1% of total allowances to entities and facilities undertaking early actions. According to the bill text, entities applying for ERAs must provide information that verifies that an actual reduction in GHG emissions has been achieved “relative to the historic emission levels of the entity; and taking into consideration any increase in any other GHG emissions of the entity; and if the reduction exceeds the net reduction of direct greenhouse gas emission of the entity, the entity reported a reduction that was adjusted so as to not exceed the net reduction”.

The **Lieberman-Warner Climate Security Act** stipulates that no later than two years after the date of enactment the Administrator of the EPA will recognize early actions regulated entities have taken since January 1994 resulting in “verified and credible reductions of greenhouse gas emissions” by allocating five percent of the emissions allowances established for 2012, four percent for 2013, three percent for 2014, 2 percent for 2015 and 1 percent for 2016. Four methods for registering “verified and credible” reductions are identified in the act, but all reductions must be registered before the act comes into effect. The four methods are:

- The Climate Leaders Program or other voluntary GHG reduction program of the EPA or the DoE
- The Voluntary Reporting of GHGs Program of the EIA
- State or regional GHG emission reduction programs that incorporate systems for tracking and verifying GHG emission reductions
- Voluntary entity programs resulting in entity-wide GHG reductions.

The **United States Climate Action Partnership: Blueprint for Legislative Action** was released in January 2009 by a group of businesses and leading environmental organizations. The Blueprint provides a broad range of principles and recommendations to inform the development of US federal climate legislation. It suggests that credit for early action is, when allowances are freely allocated, an important cost containment tool for addressing competitive imbalances for early actors. The Blueprint recommends that credit for early action be rewarded from within a specifically created set-aside (from within the cap), that the EPA establish by rule the criteria and procedures for awarding early action, that reductions must be real and verifiable and additional, but that financial additionality is not an acceptable criterion for recognition, the administrative burden and complexity of an early action program should be minimal and where possible the program should recognize the actions undertaken in voluntary programs like the EPA Climate Leaders as long the programs meet the criteria the early action program establishes.

The **Waxman-Markey American Clean Energy and Security Act of 2009** was released in discussion draft form on March 11, 2009. While the bill addresses many cap and trade design elements in great detail it does not provide any guidance on the allocation of allowances. This issue and other related issues (possibly including early reduction allowances) will be addressed through discussions among Energy and Commerce Committee members during the upcoming bill mark up periods.

May 19, 2009 Early Reduction Allowances White Paper

List of Commenters

Alcoa, Inc.

BC Forestry Climate Change Working Group

Canadian Steel Producers Association

Cement Association of Canada

Independent Energy Producers Association

Northwest Pulp and Paper Association

Ontario Forest Industries Association

Pacific Gas and Electric Company

Quebec Business Council on the environment

RÉSEAU environnement

WEST Associates

Western Climate Advocates Network

Western Climate Initiative

Offset Limit White Paper

May 19, 2009

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1 Background and Purpose

As part of the design for the WCI Regional Cap-and-Trade Program, the WCI Partner jurisdictions recommended that a rigorous offset system be developed and implemented. The purpose of the offset system is to reduce compliance costs while encouraging emission reductions, innovation, and technology development for sources and sinks not covered by the cap-and-trade program.

Offsets are GHG emission reductions, GHG emissions avoided, or GHG removals from the atmosphere, measured in metric tons of CO2e. Offsets are achieved through activities that are often referred to as "offset projects." Offset credits (also measured in metric tons of CO2e) are issued for offsets that are achieved by offset projects that meet certain criteria. Offset credits can be traded and can be used for compliance purposes or as part of voluntary actions. When used within a cap-and-trade program, offset credits used for compliance purposes come from emission sources or sinks not covered by the cap.

The Design Recommendations for the WCI Regional Cap-and-Trade Program specify that a majority of emission reductions required under the program occur at covered entities and facilities. Consequently, for compliance purposes, the WCI Partner jurisdictions set a limit on the use of offset credits issued by WCI Partner jurisdictions, as well as the use of offset credits and allowances from other GHG emission trading systems that are recognized by the WCI Partner jurisdictions, to no more than 49 percent of the total emission reductions from 2012 to 2020.[1] This limit and rationale are established in the WCI's Design Recommendations (September 23, 2008). This paper addresses how this limit could be implemented, rather than discussing the limit itself.

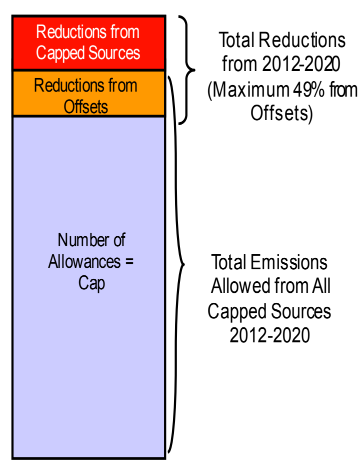

Figure 1. Illustration of the WCI Offset Limit

The offset limit is conceptually illustrated in Figure 1. The bar is comprised of three pieces. The bottom part of the bar is the total number of emission allowances issued from 2012 to 2020, a direct reflection of the emissions cap. The top two pieces combined are the total emission reductions required of the

[1] It is important to note that while we refer to the "offset limit" throughout this paper, it should be understood to encompass not only offsets issued by WCI Partner jurisdictions, but also offsets and allowances issued by other GHG emission trading systems approved for use in the system by the WCI Partner jurisdictions.

covered entities and facilities for the period 2012 to 2020. The total emission reductions are divided into two parts: the top part is the total emission reduction achieved at the covered entities and facilities; the second part is the total emission reduction that was achieved through offsets or allowances form other GHG emission trading systems. As specified in the program design recommendations, this second part, the offsets and allowances from other systems, can be no more than 49 percent of the total emission reductions.

As part of its work on the offset limit, the WCI Cap Setting and Allowance Distribution (CSAD) Committee seeks to answer the following questions:

1. What mechanism should be used to impose the limit?
2. How should the offset limit be applied across jurisdictions?
3. How should the limit be applied across compliance periods?

The purpose of this white paper is to seek stakeholders' input on these questions and on the principles that should be used to guide the decision-making process.

2 Offset Limits in Other Trading Schemes

The CSAD Committee has undertaken a review of how other existing or proposed cap-and-trade programs limit offsets. This review will help the committee to identify options for implementing the offset limit and the implications of these options. In our review, we considered the following programs and federal proposals:

- Regional Greenhouse Gas Initiative
- European Union Emissions Trading Scheme
- Waxman-Markey Discussion Draft
- Dingell-Boucher Discussion Draft
- Boxer substitute of Lieberman-Warner (S. 3036)
- Lieberman-Warner Climate Security Act (S.2191)
- US Climate Action Partnership Proposal

Table 1 summarizes how offset limits were designed or proposed in these programs and proposals. As illustrated in Table 1, there is wide variation in how the limits would be applied and how the availability of offsets changes over time. More detailed descriptions of these offset programs and proposals can be found in the Annex to this paper.

Table 1. Summary of Offset Limit Provisions of Cap-and-Trade Systems and Proposals

<table>
<tr><th>Cap-and-trade program or proposed legislation</th><th>Overall limit description and mechanism of application</th><th>Difference in limit across jurisdictions</th><th>Change in limit over time</th></tr>
<tr><td colspan="4">US Regional</td></tr>
<tr><td>Regional GHG Initiative (RGGI)</td><td>3.3% of a covered entity's emissions (in order to contain allowance price, overall offset limit increases as the allowance price exceeds threshold levels)</td><td>No difference</td><td>No change in % over time (unless price triggers increase limit). Absolute amount of allowable offsets decreases as the number of allowances available decreases.</td></tr>
<tr><td colspan="4">European Union</td></tr>
<tr><td>EU Emissions Trading System (EU ETS)</td><td>No more than 50% of emission reductions, EU-wide, typically implemented by member states as a percentage of covered entities' emissions (e.g., as a percentage of allowances distributed).</td><td>Phase II (2008-2012): Varies across member states from 0% to 20% of allowances distributed</td><td>Phase II (2008-2012): Based on National Allocation Plans (NAPs)
Phase III (2013-2020): NAPs replaced by EU-wide caps and allocation rules.</td></tr>
<tr><td colspan="4">US National Legislation and Proposals</td></tr>
<tr><td>Waxman-Markey Discussion Bill</td><td>~2 billion metric tons per year. Implemented as a fraction of covered entity's emissions (compliance obligation) that increases from ≈30% in 2012 to ≈60% by 2050 as cap declines.</td><td rowspan="5">Not applicable (single jurisdiction)</td><td>Offsets allowed increases as a fraction of allowances issued over time.</td></tr>
<tr><td>Dingell-Boucher Discussion Bill</td><td>5-35% of a covered entity's emissions</td><td>Increasing percentage over time from 5% starting in 2013 to 35% by 2025.</td></tr>
<tr><td>Boxer Substitute of Lieberman-Warner (S. 3036)</td><td>Up to 15% of total emissions allowances issued per year</td><td>No change in % over time. Absolute amount of allowable offsets decreases with cap. Includes a roll-over for unissued allowances for use in subsequent years.</td></tr>
<tr><td>Lieberman-Warner Climate Security Act (S. 2191)</td><td>Up to 15% of a covered entity's emissions</td><td>No change in % over time. Absolute amount of allowable offsets decreases with cap.</td></tr>
<tr><td>US Climate Action Partnership Proposal (US CAP)[2]</td><td>2 billion metric tons per year. A Carbon Market Board would have authority to increase limit to 3 billion metric tons.</td><td>No major change in absolute amount of offsets allowed.</td></tr>
</table>

[2] USCAP Blueprint for Legislative Action: Consensus Recommendations for U.S. Climate Protection Legislation, January, 2009. USCAP is "an expanding alliance of major businesses and leading climate and environmental groups that have come together to call on the federal government to enact legislation requiring significant reductions of greenhouse gas emissions." http://www.us-cap.org/about/index.asp

3 Principles in Evaluating Offset Limit Options

The CSAD committee is considering the following principles in defining the design and operation of an offset limit:

- **Fairness**: An offset limit should be implemented in a manner that provides fair access to offset markets by offset project developers and covered entities, as well as other market participants. An offset limit should be designed to apply fairly to covered entities and not create competitiveness concerns.
- **Economic efficiency**: An offset limit should be implemented so that the market operates efficiently and that greenhouse gas emission reductions can be achieved at the least cost. An offset limit should not unduly inhibit the realization of the least-cost offsets.
- **Cost Containment**: The offset limit should be implemented in a manner that helps to contain compliance costs and maintains offset fungibility across the WCI. Recognizing that offset supply is essential for achieving cost containment, the offset limit should not unduly restrict the ability of offset project proponents to finance and develop prospective projects, the ability of jurisdictions to issue, or market participants to acquire, offsets in a timely manner.
- **Effectiveness and enforceability**: The offset limit should be implemented to ensure that the limit is enforceable and is effective at achieving the WCI goal that offsets are supplemental to emission reductions at covered sources, and thus that no more than 49% of total emissions reductions 2012-2020 are achieved by the use of offsets (and allowances and offsets from other emission trading systems).
- **Administrative simplicity and cost**: Implementation of the limit should provide as clear a path forward as possible for all parties, including administrative bodies, offset project developers, and covered entities. Administrative costs and transaction costs should be minimized for all parties, consistent with the need to ensure effective limit compliance.

4 Options for Implementing the Limit across Jurisdictions

While the WCI design document specifies a limit on the amount of offsets credits that may be used for compliance purposes in the WCI regional cap-and-trade program, it does not indicate how such a limit might be implemented among the WCI Partner jurisdictions. The question of jurisdictional limits is unique to multi-jurisdictional emission trading programs, such as RGGI, the EU ETS and WCI.

There are two approaches Partners could employ to limit the total amount of offsets used. They could either limit the *use* of offsets (e.g., the number of offset credits a covered entity can use for compliance) or they could limit the *supply* of offsets (e.g., the total number of offset credits available to use for compliance). Within these two categories many detailed mechanisms are conceivable. This paper will consider four detailed mechanisms: three that we categorize as usage limits ('percentage limits' based on actual emissions, 'percentage limits' based on freely distributed allowances, and 'offset surrender certificates') and one as a supply limit ('first-come, first-issued'). For each of these approaches there are also two broad options for addressing offset limits across jurisdictions: a *common* or a *differentiated* offset limit and multiple ways in which the limits could change over time.

Limiting the *use* of offsets

The offset limit could be set as a *percentage use limit* at the individual entity with a compliance obligation. The limit could be applied on a *common* basis across all jurisdictions, whereby the same entity-based percentage limit would apply across jurisdictions to any WCI-covered entity. Under this option, a common entity-based offset use limit specified as a percent of total compliance obligations (or as a percent of distributed allowances) would be applied across the WCI. This is the approach taken by RGGI. The common percentage use limit would be calculated by dividing the total offsets allowed by total number of allowances to be issued (or distributed) within a given time period (see next section).

Alternatively, the WCI could adopt jurisdictionally *differentiated* percentage use limits, whereby the limit in each jurisdiction would differ based on one or more factors, such as the emission reductions below 2012 (or 2005) levels represented by a partner's emission goal. An example of the latter would be to apply the WCI-wide limit—no more than 49% of emission reductions between 2012-2020 from offsets—at the individual partner level. In such a case, jurisdictions with deeper targets relative to a base year level would allow proportionately more offset use per entity.

With a differentiated percentage-use approach, there is a risk that the total regional limit could be exceeded if the limit is specified as a percent of the total compliance obligation (i.e., emissions). This risk occurs because allowances can be traded among jurisdictions, thus actual emissions that will occur in a given jurisdiction—and the corresponding amount of offsets allowed—cannot be known in advance.[3]

An alternative would be to specify the offset limit in tons individually for covered entities, computed as a percent of the number of allowances that are distributed directly to covered entities within a given Partner jurisdiction. This way, the risk of exceedance would be avoided, since the number of free allowances and corresponding number of allowable offsets would be specified in advance.[4] This approach would provide access to offset use only to covered entities that receive allowances directly (and in some proportion to allowances received).

The EU has, thus far, largely taken a differentiated percentage use approach to offset use limits.[5] As noted in the Annex, in Phase II of the EU ETS each member state was allowed to propose an offset limit as part of its National Allocation Plan. These plans are then subject to EU review and approval. As a result, the fraction of compliance obligations that emitters can fulfill using offsets varies from country to country.

The choice between common and differentiated percentage approaches to jurisdictional limits has implications in terms of how offset opportunities and risks are distributed across partners. This comparison is summarized in Table 2.

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[3] The following provides an example of how exceedance might occur. Assume, for instance, that the total number of offsets to be allowed is 5 tons for a two-jurisdiction region (with total emissions of 100 tons). Jurisdiction K is allowed 4 tons of offsets (with emissions of 50 tons), and jurisdiction L is allowed 1 ton (with emissions of 50 tons):

- The region-wide offset use rate would be 5/100 = 5%.
- The offset use rate for jurisdiction K would be 4/50 =8%, and for jurisdiction L it would be 1/50= 2%. Let's say jurisdiction K has a much deeper reduction target, and thus a higher offset use rate.

If no allowances are traded between jurisdictions K and L, the overall offset limit will be respected [0.08*50 + 0.02*50 = 5 tons]. If emitters from jurisdiction K buys allowance from emitters from jurisdiction L, say 14 tons (jurisdiction K now holds allowances for 60 tons and jurisdiction L 35 tons), then the overall offset limit will be exceeded [0.08*60 + 0.02*35 = 4.8 + 0.8 = 5.6 tons]. The opposite is also true if jurisdiction L buys allowances from jurisdiction K.

[4] Using the example described in footnote 3, if we apply the limit to the number of allowances that were initially distributed in each jurisdiction, then emitters from jurisdiction K would be allowed 4 tons (.08*50) of offset credits and jurisdiction L 1 ton of offset credits (.02*50) regardless of allowance transactions between the two jurisdictions, thus ensuring the overall limit is not exceeded.

[5] The EU percentage use limit is specified as the percent of allowance received for free by any given regulated emitter rather than as a percentage of compliance obligations.

Table 2. Comparison of Jurisdictional Percentage Use Offset Limit Options and Implications

Option:	Common % Use	Differentiated % Use
Example	X% of compliance obligations in all jurisdictions	49% of emission reductions in each jurisdiction translated to different percentages of compliance obligation in each jurisdiction
Fairness	Covered entities can use the same percentage of offset across the WCI region. Entities that emit more GHGs could use more offset credits for compliance.	Emitters from jurisdictions that have a deeper reduction goal for 2020 relative to a base year would be allowed a higher percentage of offsets. Within a given jurisdiction, entities that emit more GHGs could use more offset credits for compliance. If the limit is based on allowance distribution (rather than only % of compliance obligation), then entities receiving more free allowances would have greater access to offsets.
Efficiency	To the extent that offset use falls short of the overall limit as a result of the mechanism used to implement the offset limit, opportunities for efficiency gains may be unrealized. The relative efficiency impact of each option remains to be evaluated.	
Cost Containment	The relative cost containment impact of each option remains to be evaluated.	
Effectiveness and Enforceability	WCI region-wide limit met. Individual partner limits may not be met.	WCI region-wide limit could be exceeded if individual Partners' limits are specified as a percent of compliance obligations.
Administrative Simplicity	Administratively simple to implement.	Slightly more complex to implement than the common % use approach.

As an alternative to the percentage use limit, the WCI Partner jurisdictions could choose to employ a usage limit which we will refer to as the *offset surrender certificates* mechanism. In this approach, the WCI Partner jurisdictions would issue and distribute (auction, sell or give for free) a number of certificates equal to the offset limit in tons. Covered entities would have to surrender one certificate for each offset credit they desire to use for compliance.

Under this mechanism, individual entities need not be limited by a percentage limit on their use of offsets. This approach could simplify the implementation of limits differentiated at the jurisdictional level and ensure that any regional limit on offsets would be maintained. This mechanism would also increase the likelihood that the full allowed amount of offsets (49% of emission reductions) would be used; under a percentage use limit, all entities not in need of offsets would need to engage in allowance-to-offset arbitrage in order to make the full amount of offsets available.[6]

[6] Assuming that offset credits are available for less than allowance prices, under a percent use approach an arbitrage opportunity could arise. If an individual entity does not need to use the maximum amount of offsets allowed (perhaps due to a generous free allocation of allowances), this entity would have the opportunity to acquire offsets (not needed for its own compliance purposes) up to the percentage limit and free up allowances to trade to others.. However, there is no guarantee that this action would be taken by all market participants. If this

In contrast to limits on supply (see below), the offset surrender certificate approach would not inhibit the creation of offset projects or issuance of credits. However, the surrender certificate approach creates an additional market of compliance instruments which would be accompanied by increases in complexity, transaction costs, and associated concerns related to topics such as market manipulation.

Limiting the *supply* of offsets

Another option is to limit the supply of offset credits. Under a common supply limit, the same pool of offset credits would be available to any covered entity in the WCI region. Under a differentiated supply limit, each Partner would have its own pool of offset credits and those offset credits could either be restricted to their covered entities or could be available for any covered entities throughout the WCI Partner jurisdictions.

Conceptually, a supply limit approach would simplify the implementation of jurisdictional differentiated limits. However, limiting the issuance of offset credits especially through a *first-come, first-issued*, mechanism could create significant uncertainty for offset project developers. There is also no guarantee that the lowest cost projects would be the first to enter the market. Furthermore, a supply limit may hamper a regulated entity's ability to ensure that an offset supplier can deliver in a specific year (due to first come, first serve basis).

Similar to the surrender certificate approach described above, individual entities need not have a percentage limit on the number of offsets used for compliance and a supply limit would ensure that no amount of offsets available under the limit would be left on the table due to the lack of allowance-to-offset arbitrage by individual entities. Unlike all of the use approaches described above, a supply limit would allow individual entities to treat offset credits and allowances as perfect substitutes.

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opportunity was not acted on by all entities, some offsets could be"left on the table" from a system-wide viewpoint.

5 Application of the Offset Limit over Time

The offset limit could be set at a common level across all three compliance periods or it could be designed to vary over time. Some stakeholders have argued for more offsets in early years in case rapid reductions prove difficult to implement; it has also been suggested that offsets may be more valuable in early years as emerging low-GHG technologies mature and their costs decline. Other stakeholders have argued for greater offsets in later years to provide cost containment as emission caps are tightened and allowance prices might be expected to rise. Another rationale for greater offset availability in later years is that offsets could be more abundant and reliable as offset markets and rules mature over time.

Regardless of the specific offset use limit mechanism chosen (see Section 4), there are several options for addressing variation in time, including, but not limited to, the following:

- **Equal absolute number of offsets in each compliance period:** This is the approach embodied in the US CAP proposal and conceptually in the Waxman-Markey bill formula described in Table 1.
- **Equal percent of use across compliance periods.** This approach is used by RGGI and was proposed in the Lieberman-Warner Bill (S.2191). While the fraction of emissions that could be covered by offsets would remain constant, the absolute amount of offsets that could be used would decline if the number of available allowances declines over time.[7]
- **49% of Emission Reductions in each period.** This option would impose a different absolute or percent offset limit for each compliance period in order to ensure that no more than 49% of emission reductions are in the form of offsets in every period. Since the amount of needed emission reductions from 2012 levels increases over time as the cap declines, so would the amount of offsets available.[8]
- **No restrictions across compliance periods:** This approach would provide the most flexibility by imposing no restrictions across compliance periods. The total amount of offset credits that can be used under the limit could be available for use in any compliance period. Entities with compliance obligations would decide when they want

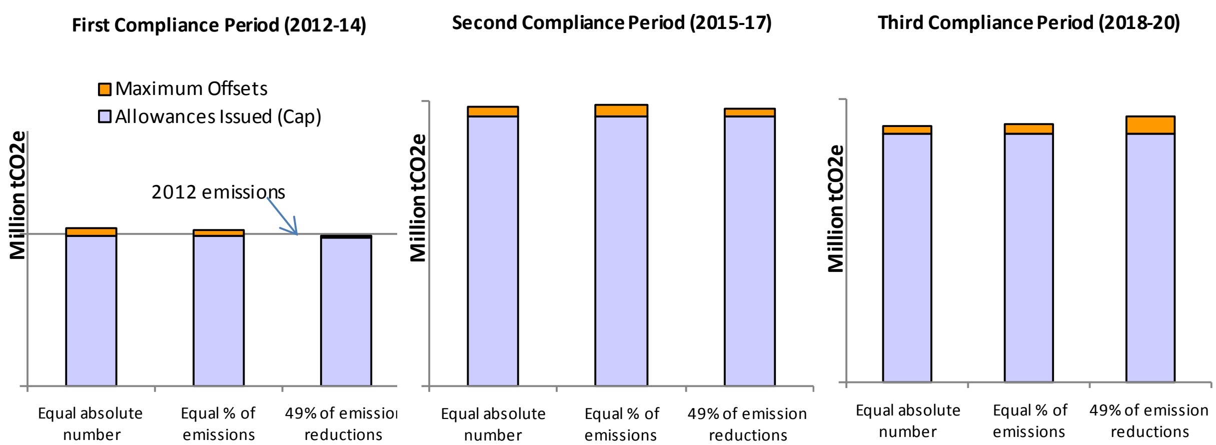
[7] In the case of the WCI, the introduction of transportation, residential, and commercial fuels leads to an increase in the emissions cap in 2015, and the absolute amount of allowable offsets would increase significantly from the first (2012-2014) to the second (2015-2017) compliance period.
[8] The increase in the 2015-2017 will be even greater due to the introduction of transportation, residential, and commercial fuels in 2015.

to use offset credits, so that the distribution of offset credit use over time would be determined by the market as a whole.[9]

- **Other Ramp Up or Ramp Down:** There are other options for specifying increases or decreases in the amount of allowable offsets over time. For example, the Dingell-Boucher draft discussion bill provided a schedule for increasing the percentage of offsets that could be used over time (see Table 1).
- **Carry-over:** Any unused or unissued offsets (under the limit) could carry over to next compliance period and be added to that period's offset limit. This approach, included in the Boxer amendment (S.3036) and in EU Phase III proposal, could be implemented in conjunction with any options above.

Figure 2 provides a visual comparison of the differences in offsets over time among the first three temporal options listed above, relative to the overall emissions budgets for the three compliance periods and assuming no carry-over. Figure 3 zooms in on the allowable offsets for each option, for each compliance period. (The charts shown are illustrative only, since precise cap levels have yet to be established.) As shown, the equal absolute number and equal percentage limit options allow greater offset availability in early periods. As illustrated in Figure 2, these options would allow emissions to exceed 2012 levels in the first compliance period.

Figure 2. Illustration of offset limit options across compliance periods



(The higher bars in the 2nd and 3rd compliance periods reflect the expansion of program scope in 2015. All figures shown are illustrative)

[9] This option could be implemented using a supply limit, a certificate surrender mechanism, or by an offset use limit expressed in tons rather than % use (e.g. if offset use were linked with allowance distribution). It would be incompatible with a straight percentage use limit.

Figure 3. Illustration of offset limit options across compliance periods (zoom-in on offset amounts)

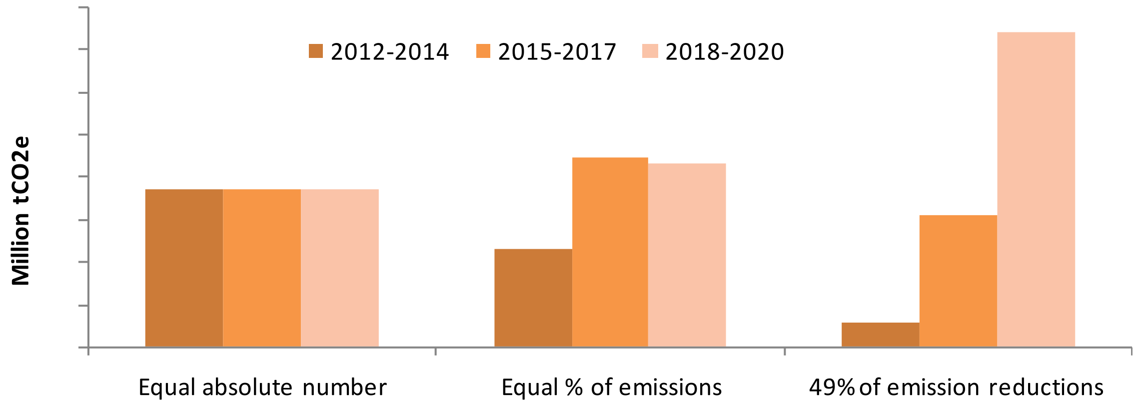


Table 3 compares each of the three options depicted above in terms of the principles listed in Section 3. In terms of fairness, the differences are a matter of perspective: the first two approaches would make more offsets available to covered sources that enter the program in 2012, whereas the third approach shown (49% of emissions reductions in each period) would distribute offset availability in accordance with the extent of emission reductions needed (more in last period when deeper reductions are required). With respect to cost containment, as described in the table, the optimal approach will depend on future allowance prices. In terms of effectiveness, each of the first two options (equal absolute number and equal % of emissions) would allow more than 49% of emission reductions to come from offsets during the first two compliance periods. While this outcome could be avoided by setting the limit at 49% of emission reductions in each period (the third option), depending on how the limit is implemented (see previous section) this option could enable total emission reductions met by offsets to exceed 49% under the percentage use limit in some circumstances.

While all options shown in the table should be similar in terms of enforceability and administrative simplicity and cost, the carry-over approach noted above might require added administrative effort in the case of the percentage use mechanism and create some added uncertainty for the offset market. Data on the total amount of offsets used during a prior compliance period would be needed before setting the offset limit for the current period, and this information might not be fully available for several months into the period. Either a supply limit or the surrender certificate mechanism could address concerns about carry-over of excess offset capacity between compliance periods in a more straightforward way.

Table 3. Comparison of options for limiting offsets across compliance periods

Option→ ↓ Principle	Equal absolute number of offsets in each period	Equal % of emissions in each period	49% of emission reductions in each period
Fairness	Would make more offsets available to entities covered in the first compliance period (relative to other options)	Would make more offsets available to entities covered in first compliance period, but less so than the "equal absolute" option	Would make offsets available to covered entities in accordance with the extent of emission reductions required in a given period.
Economic Efficiency	Any proscription of offset use by compliance period has the potential to lead to unrealized efficiency gains.		
Cost Containment	Might provide greater cost containment if internal emission reductions turn out to be more costly in the early period (s).		Might provide greater cost containment if internal emission reductions turn out to be more costly in the final period.
Effectiveness and Enforceability	Would meet WCI 49% limit across all periods, but could exceed it in first and second compliance periods if sufficient offsets are available and are extensively used.		Could exceed overall 49% limit (across 2012-2020) under the percentage use limit, if allowances are banked in early periods and used in later periods when the percentage of allowed offsets is higher. Exceedance could be avoided through a supply limit or surrender certificate approach or linking offset use to allowance distribution (see Section 4).
Administrative Simplicity and Cost	No significant difference among options		

If a supply limit or surrender certificate use limit is chosen instead of a percentage use limit (see Section 4), then the options for spreading offset availability across compliance periods could be set by how certificates are distributed or offsets issued in each period. As noted above, these options could more easily allow for the full targeted amount of offsets to be available across all three periods.

6 Stakeholder Involvement and Next Steps

The WCI Partner jurisdictions invite stakeholders to provide written comments on the different options presented in this white paper or any other alternative options.

We would appreciate comments structured around the primary questions the CSAD Committee seeks to answer on this topic:

1. What mechanism should be used to impose the limit?
    a. Should the offset limit be applied on offset use (e.g., the amount of offsets covered entities can surrender for compliance purposes) or on offset supply (e.g., the overall amount of offsets issued in a given period of time)?
    b. If the limit is based on use, what is the preferred mechanism for limiting use? If the limit is based on supply, what is the preferred mechanism for limiting supply?
    c. Should access to offsets be linked with the distribution of allowances, and if so in what manner?
2. How should the offset limit be applied across jurisdictions?
    a. Should the limit be applied on a common or differentiated basis?
    b. If the limit is differentiated by Partner jurisdiction, what factor(s) should be the basis of differentiation? (e.g., differences in emission reduction targets, marginal abatement costs, or other factors across jurisdictions)
3. How should the limit be applied across compliance periods?
4. Please describe any competiveness impacts, such as differences in the cost of compliance, you believe the Committee should consider in evaluating options to apply the offset limit.

We invite stakeholders to discuss with us and provide their comments in person during a stakeholder event in Seattle on May 28th, 2009. Registration is free. Stakeholders can register online on the Western Climate Initiative website (www.westernclimateinitiative.org).

Written comments can be submitted via the Western Climate Initiative website until June 19, 2009.

Annex 1: Detailed Description of Offset Limits in Other Trading Schemes

Regional Greenhouse Gas Initiative (RGGI)[10]

Limits: The Regional Greenhouse Gas Initiative (RGGI) allows entities to use carbon offsets to cover a portion of their compliance obligation. Entities can use offsets to cover up to 3.3% of their total compliance obligation. This limit increases to 5% if the carbon price is over $7 per ton, and further increases to 10% if the allowance price exceeds $10 per ton.

Project Eligibility: The RGGI Model Rule identifies five project types that are eligible for offsets:

- Landfill methane capture
- Sulfur hexafluoride (SF6) capture
- Forest sequestration
- Energy efficiency for natural gas, propane and heating oil
- Animal methane management

New project categories will be adopted if they are approved by each of the RGGI states.

In order to receive offset credit, emission reductions from these project types must be:

- Real and quantifiable
- Additional beyond business as usual assumptions
- Verifiable
- Permanent
- Enforceable

Offset Limit Methodology: In order to strike a balance between achieving real emission reductions in covered sectors and providing entities with a flexible compliance option, RGGI states decided that offset use should be limited to 50% of the total emission reduction amount. According to the Staff Working Group (SWG) analysis, the 50% goal was not viewed as a hard target, but rather as a guiding principle in determining a quantitative offset limit. The SWG recommended an entity level offset limit, rather than a state-wide or system-wide limit. The SWG modeled the impact of different offset limit amounts to determine an entity level limit that would approximate the 50% goal. The final SWG analysis recommended limiting offsets to

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[10] Sources for this section include: Regional Greenhouse Gas Initiative Model Rule (12/31/08 final with corrections. (www.rggi.org); Analysis Supporting Offsets Limit Recommendation (5.1.06). (www.rggi.org); Offsets Summary: the Regional Greenhouse Gas Initiative. Environment Northeast (http://www.env-ne.org/public/resources/pdf/ENE_RGGI_offset-design.pdf)

3.3% of an entities' total compliance obligation. This recommendation was adopted in the RGGI Model Rule.

The price trigger provision recognizes this modeling uncertainty by making the offset limit a function of the factors that drive price increases. Allowance price increases are partially a factor of the trajectory and the starting cap—allowing the offset limit to increase when the price increases serves as a means of correcting for inaccuracies in setting of these factors. This allows the offset limit to more closely align with the overall RGGI goal of controlling compliance costs.

European Union Emission Trading Scheme

Summary of Limits: The European Union Emissions Trading Scheme (EU ETS) imposes limits on the amount of offset credits that may be used for compliance in both Phase II and III. These limits are percentage use limits applied at the facility level.

The actual limit is different in each phase, for each Member State, and may differ by type of installation. The Phase III limits are likely to be more stringent than the Phase II limits and may be harmonized across the EU; actual limits for Phase III are contingent on the results of international climate change negotiations.

Project Eligibility and Geographic Limitations:
Phase II: The permissible offset credits in Phase II are certified emission reductions (CERs) from the clean development mechanism (CDM) and emission reduction units (ERUs) from joint implementation (JI) projects.[11]

Phase III: Limits on the use of CERs and ERUs in Phase III are contingent on the evolution of these programs as a result of international negotiations. The EU may also begin to explore other types of domestic offsets.[12]

Offset Limit Methodology:
Phase II: In international climate negotiations it was decided that internal (domestic) abatement of emissions should take precedent over external participation in flexible

[11] For a list of approved CDM methodologies see:
http://cdm.unfccc.int/methodologies/PAmethodologies/approved.html

[12] See point 22 of the following document:
http://europa.eu/rapid/pressReleasesAction.do?reference=MEMO/08/796&format=HTML&aged=0&language=EN&guiLanguage=en

mechanisms such as the CDM and JI.[13] In the context of the Kyoto Protocol this concept is referred to as "supplementarity."

The requirement to take significant action domestically was included in the international agreements partially at the behest of European nations. Therefore, the concept of prioritizing domestic action (from capped sources located in the EU) was included in the design of the EU ETS.

Each member state in the EU ETS has a different limit on the use of offsets credits from the international flexible mechanisms (CDM and JI credits) in the second phase of the EU ETS.[14] These limits are usually specified as a percentage of the total amount of allowances freely allocated to an installation.[15]

There is currently no EU-wide agreement on the definition of supplementarity. It is roughly interpreted that at least 50% of reductions (also referred to as the "level of effort") should be met by direct reductions at covered facilities. However, in actual implementation it appears that the levels set for use of offsets in Phase II may allow for more than 50% of reductions to be met through offsets.[16]

Wide discretion was given to the Member States as limits on the use of CDM/JI credits were set in Phase II. The European Commission considered that, as a rule of thumb, installations should be allowed to use JI and CDM credits to supplement their allowance allocation by up to 10%.[17] However, each member state set the actual binding limit in its national allocation plan, which was then subject to approval by the Commission. Some approved limits were 20% and above.[18] In aggregate these limits would allow operators in the EU ETS to import approximately 1.4 billion metric tons of credits from 2008-2012.[19]

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[13] See the Kyoto Protocol. Available from: http://unfccc.int/resource/docs/convkp/kpeng.pdf

[14] Phase II of the EU ETS runs from 2008-2012.

[15] For example, the United Kingdom limits on project credits in Phase II is 9.3% of allocation for large electricity producers and 8% of allocation for all other installations. See page 16 of the DEFRA's *An Operator's Guide to the EU Emissions Trading System* available from: http://www.defra.gov.uk/environment/climatechange/trading/eu/pdf/events-guide.pdf

[16] Some environmental groups estimate that between 88-100% of the emission reductions required under the combined cap for the EU ETS could theoretically take place outside of the EU through the use of offset credits. See for example, WWF, *Emission Impossible: access to JI/CDM credits in phase II of the EU Emissions Trading Scheme* June 2007. Available from: http://assets.panda.org/downloads/emission_impossible___final_.pdf

[17] European Commission. *Questions and Answers on Emissions Trading and National Allocation Plans from 2008 to 2012*. Page 4. Available from: http://ec.europa.eu/environment/climat/pdf/m06_452_en.pdf

[18] According to the WWF analysis, Irelands limit is 21.9%, Spain and Germany's limit is 20%. See each country's Phase II NAP for more details.

[19] The Carbon Trust (2008) *Cutting Carbon in Europe: The 2020 plans and the future of the EU ETS* Available from: http://www.carbontrust.co.uk/publications/publicationdetail.htm?productid=CTC734

Phase III: The EU has recognized that the level of offsets allowed in Phase II is likely to prevent achievement of the supplementarity goal and has proposed changes to prevent this in Phase III of the EU ETS. Beyond the supplementarity considerations, motivations for this increase in stringency are strategic in nature. The EU is attempting to use the EU ETS's influence on the demand for CERs as a tool in the international negations. The goal is to motivate large-emitting non-annex 1 countries (e.g., China) to increase action on climate change, including considering firm caps on emissions.

The rules for Phase III have recently been established as part of a comprehensive Climate and Energy Package.[20, 21] This package specifies that the level and type of offset credits allowed in Phase III is contingent on a successful implementation of an international agreement on climate change that will cover this period (post-2012). In the absence of an international agreement, the offset limit will be much tighter than in Phase II.

Limits proposed in US National Cap-and-Trade Legislation

Lieberman-Warner Climate Security Act (US Senate Bill 2191, 110th Congress)[22]

Senators Lieberman and Warner introduced the Climate Security Act, which was referred to the Environment and Public Works Committee, on October 18, 2007. Hearings were held to discuss the bill at the subcommittee and committee level in the fall of 2007.

Summary of limits: The Lieberman-Warner Climate Security Act stipulates that the owner or operator of a covered entity may meet up to 15% of their total compliance obligation using offset allowances. This percentage use limit is applied to each year or each compliance period. The limit does not change from year to year and there is no roll-over option for unused allowances to be used in future years or compliance periods.

Offset limit methodology: Covered entities may submit offset allowances that satisfy up to 15% of their total allowance submission requirement each year. These offsets must be generated in accordance with the bill—specifically the eligibility criteria and provisions in

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[20] See: http://www.euractiv.com/en/climate-change/mixed-reactions-parliament-approves-eu-climate-deal/article-178163

[21] The revisions to the EU ETS in perpetration for Phase III were made as part of the climate and energy package proposed by the European Commission (EC), as accepted by the European Parliament on Dec. 17, 2008. See: http://www.europarl.europa.eu/sides/getDoc.do?pubRef=-//EP//TEXT+TA+P6-TA-2008-0610+0+DOC+XML+V0//EN&language=EN#BKMD-12

[22] S.2191 bill http://thomas.loc.gov/cgi-bin/query/z?c110:S.2191

Subtitle D (the offsets section). This option may be provided as a means to contain cost while also creating an administratively simple offsets program.

Boxer Substitute of the Lieberman-Warner Climate Security Act (US Senate Bill 3036, 110th Congress)[23]

The Boxer Substitute of Lieberman-Warner's Climate Security Act (S. 3036) was reported to the US Senate on May 20, 2008. The Boxer Substitute made considerable changes to the Climate Security Act in general and specifically the offsets provisions in the original bill. The Boxer Substitute was debated on the US Senate in the summer of 2008 and did not pass on the floor. The Boxer version shifted to an aggregate supply limit on total offsets allowed in the market, rather than a use based limit.

Summary of limits: The Boxer Substitute sets a supply limit on offsets allowed in the proposed cap-and-trade system. The supply limit would allow EPA to control the issuance of offset credits and cap the total supply to the cap-and-trade market. Language in the bill places an aggregate limit on how many offsets are available for purchase from three categories: domestic, international, and forestry offsets. The total supply limit for each of these categories is 30%: 15% domestic, 5% international, and 10% international forest offsets. The bill proposes the following:

- EPA limits the creation of ***domestic offsets*** to 15% of the total quantity of emission allowances issued in each year. The limit applies to the total number of offsets, not to an individual entity's compliance obligation.
    - Any unissued portion of the offsets for one year may be added to the 15% limit for the following year.
    - Offsets will be issued (at an appropriate discount rate determined by EPA) for each offset issued under RGGI.
- EPA limits the use of ***international offsets*** to 5% of the total quantity of emission allowances.
    - Any unused portion of international offsets may be added to the 5% limit for the following year.
    - International offsets from a project at a facility that competes directly with a US facility will not be allowed.
- EPA limits the use of ***international forest offsets*** to 10% of the total quantity of emission allowances for each year.

[23] S.3030 bill http://thomas.loc.gov/cgi-bin/query/z?c110:S.3036; ; Summary of S. 2191: Lieberman-Warner Climate Security Act of 2008 Manager's Substitute Amendment by the World Resources Institute. URL: http://www.wri.org/publication/summary_lieberman_warner_climate_security_act_2008_substitute_managers_amendment

- Forest offsets can be generated from reductions in deforestation and forest degradation as compared to caps or reference scenarios used by foreign countries.
- After enactment of the bill, EPA will periodically review the performance of the forestry offset program.
- Ten years after enactment, the EPA may discount offset credits from countries that have not reduced total emissions from forests.

Project eligibility: Section 2403 lists projects eligible to generate offset allowances, including:

- Afforestation and reforestation
- Altered tillage practices
- Capture of fugitive emissions
- Capture or combustion of methane at non-agricultural facilities
- Conversion of cropland to rangeland or grassland
- Cover cropping
- Forest management
- Manure management
- Reduced carbon emissions from organic soils
- Reduction of fertilizer use
- Rice-paddy flood management

Offset limit methodology: The Boxer Substitute creates flexibility for covered entities to use offset credits from a variety of projects and locations. The issuance limit was designed to increase the supply of offsets and thus, reduce costs for those sources that have a compliance obligation. By allowing more project types, international offsets, and a roll over clause—the bill seeks to create a large supply of offsets and contain costs.

Dingell-Boucher Draft Discussion Bill (House Draft Bill)[24]

The draft Dingell-Boucher bill was released to the public for discussion purposes by the US House Committee on Energy and Commerce in October 2008. The bill has not been officially introduced in the US House of Representatives.

Summary of limits: Regulated entities may use verified domestic or international offsets for a portion of surrendered allowances rising from 5% starting in 2013 up to 35% by 2024. The percentage of allowable domestic and international offsets increases in each compliance period.

[24] energycommerce.house.gov/images/stories/Documents/PDF/selected_legislation/clim08_001_xml.pdf

Project eligibility: The draft bill permits regulated entities to purchase EPA-approved offset credits for domestic and international emission reduction projects. The proposal requires EPA to recognize domestic offset credits for

- Afforestation or reforestation on acreage not forested after January 1, 2008
- Landfill methane
- Manure management
- Methane collection at coal mines

Other project types will be reviewed for future consideration in the offsets program:

- Controlled wastewater treatment
- Conversion of cropland to rangeland or grassland
- Forest management resulting in an additional increase in forest stand volume
- Methane reduction from reclamation of abandoned surface mines
- Practices that increase agricultural soil carbon sequestration
- Recycling and waste minimization
- Reduced deforestation
- Reduction of nitrogen fertilizer or increase in nitrogen use efficiency

Offset limit methodology: Offsets play a greater role in each compliance period. Covered entities will submit offset allowances that represent up to 5%-35% of their total submission requirement during each compliance period:

- Up to 5% (domestic or international) in 2013-2017
- Up to 15% (domestic or international) in 2018-2020
- Up to 30% in 2021-2024 (15% domestic/15% international)
- Up to 35% in 2025-2050 (20% domestic/15% international)

Waxman-Markey Draft Discussion Bill (House Draft Bill)

Summary of limits: The Waxman-Markey discussion bill establishes an entity-based limit that is calculated on an annual basis, such that the total offsets available will be approximately 2 billion tons annually. The use limit is split evenly between domestic and international offsets each. Lastly, for every tonne of an entity's compliance obligation, an entity is required to turn in 1.25 offsets. Therefore, the effective limit is 2.5 billion tons.

Project eligibility: Additionality is determined by the following criteria: 1) not required by law or regulation, 2) not commenced prior to January 1, 2009, and 3) based on activity baselines based on a standardized baseline that reflect "a conservative estimate of business as usual" performance or practice.

Other key project eligibility criteria include:

- Accounting for leakage
- Activity baselines
- Addressing reversals
- Approval via crediting periods
- Auditing
- Verification and verification accreditation

Offset project types will be reviewed and approved within two years with consultation from the offset integrity advisory board. This board will prioritize offset project types for consideration.

Offset limit methodology: Offsets could play a greater role over time in the proposed program—increasing from a 30% use limit to approximately 65% in the later years. The formula to calculate the use limit requires EPA to divide the number 2 billion by 2 billion plus the emission allowances available in the previous year and multiply by 100 (for a percentage limit). For 2013 this results in limit that is 30% of an entity's compliance obligation. In addition, the program will recognize offsets for reduced deforestation that meet specific eligibility criteria. According to Congressional committee staff, international deforestation credits may result in about 6% or more of the total offset credits available.

May 19, 2009 Offset Limit White Paper

List of Commenters

Alcoa, Inc.

BC Forestry Climate Change Working Group

Camco International

Carbon Offset Providers Coalition

Cement Association of Canada

Independent Energy Producers Association

International Rivers

Mazzetti Nash Lipsey Burch

Morgan Stanley Capital Group, Inc.

National Alliance of Forest Owners, California Forestry Association, Oregon Forest Industries Council, Washington Forest Protection Association

Ontario Forest Industries Association

Pacific Gas and Electric Company

Quebec Business Council on the environment

RÉSEAU environnement

Southern California Edison Company

The Climate Trust

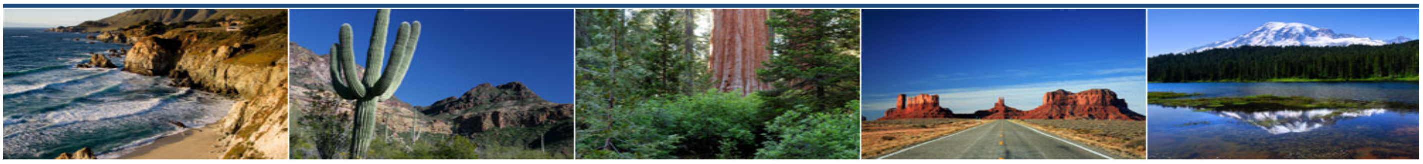
WEST Associates

Western Power Trading Forum

Weyerhaeuser

Zini, Gian

Western Climate Initiative



Stakeholder Discussion Questions on Competitiveness

May 19, 2009

The following questions are intended to motivate a discussion of how the WCI can evaluate and address competitiveness impacts of the WCI cap-and-trade program. These questions will be discussed at the May 28 stakeholder workshop in Seattle. Stakeholders may also submit written comments via the WCI website through June 19, 2009. For further background, please see the CSAD Committee portion of the WCI Work Plan, which is posted on the WCI website.

1. What principles should govern how the WCI Partner jurisdictions evaluate and address potential competitiveness impacts of the WCI regional cap-and-trade program?

2. What aspects of the WCI cap-and-trade program have the potential to cause intra-WCI competitiveness impacts (i.e., among businesses within the WCI Partner jurisdictions that compete with each other)? How significant are the potential intra-WCI competitiveness impacts compared to potential impacts arising from competition with businesses located outside the WCI Partner jurisdictions?

3. How can the WCI Partner jurisdictions best anticipate potential U.S. and Canadian federal efforts to address competitiveness impacts associated with climate policies, such as cap-and-trade? To what extent should the WCI Partner jurisdictions strive to harmonize with current federal proposals to address these impacts? With those currently employed in the European Union? What competitiveness issues should the WCI Partner jurisdictions emphasize in communications with the two federal governments?

4. What opportunities and/or challenges, in terms of competitiveness of the covered sectors, might the WCI cap-and-trade program present as the region emerges from the current economic downturn? What other factors might interact with the cap-and-trade program to enhance or hinder the competitiveness of covered sectors within a jurisdiction?

5. For those sectors for which internalizing the cost of carbon through a cap-and-trade program presents competitiveness risks, which options should the WCI Partner jurisdictions consider to address those potential impacts?

May 19, 2009 Stakeholder Questions on Competitiveness

List of Commenters

Alcoa, Inc.

BC Forestry Climate Change Working Group

Canadian Lime Institute

Canadian Steel Producers Association

Cement Association of Canada

Ontario Federation of Labour

Quebec Business Council on the environment

Short, Shelly, Washington State House of Representatives

Southern California Edison Company

Western Climate Advocates Network

Western Power Trading Forum

Western Climate Initiative

National Clean Car Standards

WCI Partners Meeting
Seattle, WA
May 27, 2009

www.westernclimateinitiative.org

Introduction

- An agreement was successfully struck between the Obama administration, the auto makers and the California Air Resources Board.
- The agreement was announced by President Obama on May 19, 2009.

Three Part Agreement

- The agreement has three parts:
  - Federal notice of intent for joint rulemaking by the U.S. Environmental Protection Agency (EPA) and National Highway Traffic Safety Administration (NHTSA).
  - A commitment letter from the California Air Resources Board.
  - Commitment letters from each auto manufacturer and their industry groups.

Overview of the Agreement

- The national 50 states GHG standards will be developed by EPA and NHTSA and will start in model-year 2012, and go to 2016.
- In 2016, the national standard will be the same as the California (Pavley) standard.
- It is expected that California's waiver for model-years 2009 to 2016 will be approved by EPA by the end of June.

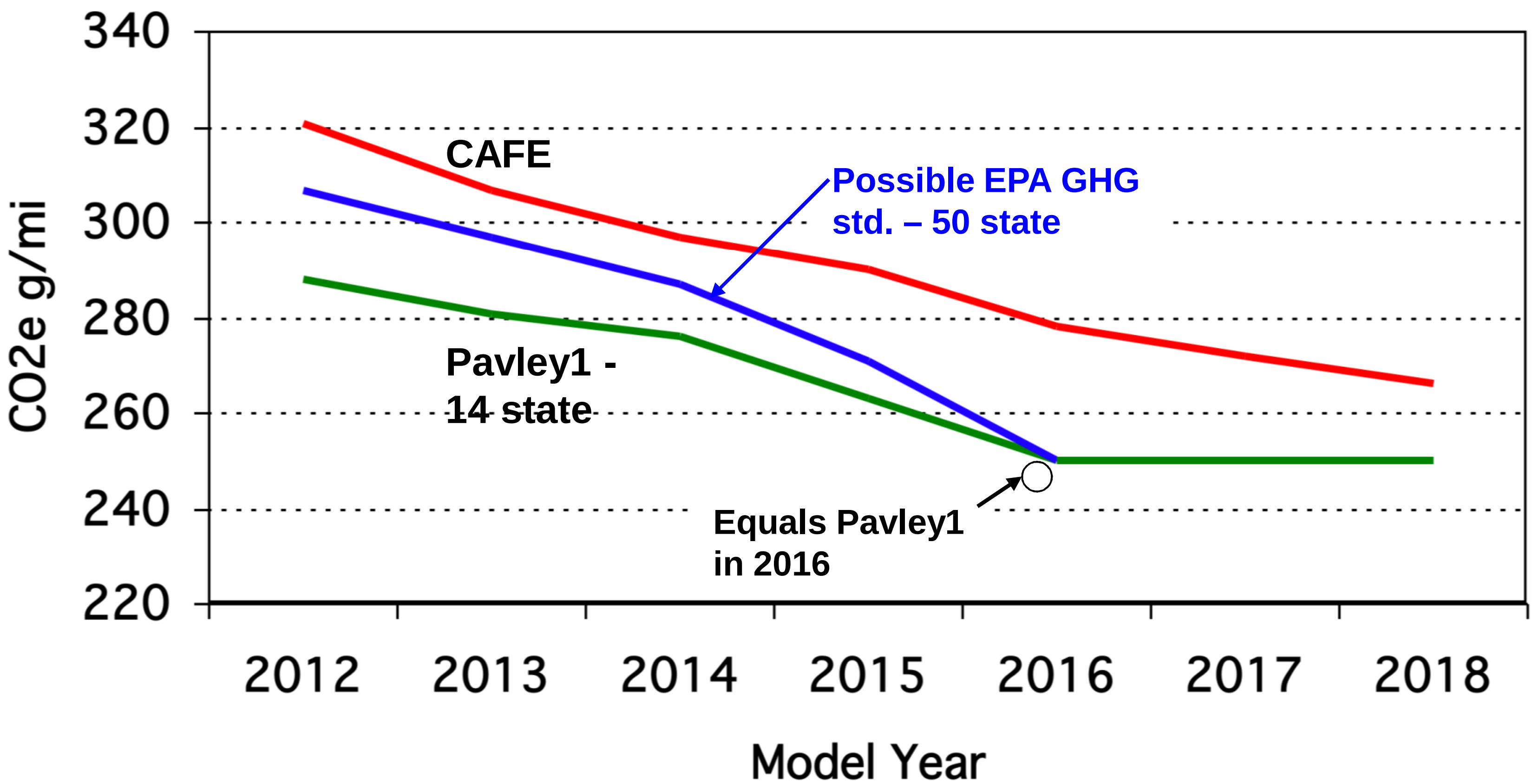
Overview of the Agreement (con't)

- California does not give up any authority under the Clean Air Act.
- California will amend its rule to allow compliance with the national standard between 2012 and 2016 to be recognized as complying with the California (Pavley) standard.
- The auto industry will drop its lawsuits challenging the California (Pavley) standards.

GHG Reductions Impact

- Once the waiver is granted, California will enforce the standards for model-years 2009 to 2011.
- For model-years 2012 to 2016, the national GHG standards developed jointly by EPA and NHTSA will be in effect.
- In 2016 the California (Pavley) standard and the national standard will be the same (250 g/pm).

Pavley 1 – CAFÉ - National GHG Comparison of Stringency



Pavley II

- ARB staff is developing standards for the 2017 model-year and beyond
- Staff expects to bring the new standards to the Board in the summer of 2010.

Federal Climate Change Policy Update

WCI Meeting
Seattle, Washington
May 27, 2009

Judi Greenwald
Vice President, Innovative Solutions
Pew Center on Global Climate Change
www.pewclimate.org

The Political Landscape

Obama is Determined to Lead at Home and Abroad; Reframes Cost Debate

My presidency will mark a *new chapter in America's leadership on climate change* that will strengthen our security and create millions of new jobs in the process. That will start with a *federal cap and trade system*. We will establish strong annual targets that set us on a course to reduce emissions to their 1990 levels by 2020 and reduce them an additional 80% by 2050.

Further, *we will invest $15 billion each year to catalyze private sector efforts* to build a clean energy future…This investment will not only help us *reduce our dependence on foreign oil*, making the United States more secure. And it will not only help us bring about a clean energy future, saving our planet. It will also help us *transform our industries* and steer our country out of this economic crisis by generating five million new green jobs that pay well and can't be outsourced.

And once I take office, you can be sure that *the United States will once again* engage vigorously in these [international] negotiations, and help *lead the world* toward a new era of global cooperation on climate change.

… Statement to Bi-Partisan Governors Summit, November 2008

Obama: climate/energy top priority

- Appointed a White House lead on energy/climate
- Appointed special envoy for international climate negotiations
- Forged agreement between U.S. EPA, U.S. DOT, State of California, and automakers on vehicle standards for GHG emissions and fuel economy
- Supported billions in stimulus package for renewable and low-carbon energy infrastructure and R&D
- Strong proponent of cap and trade

Some of Obama's Climate Team

Carol Browner Assistant to the President for Energy and Climate Change	**Nancy Sutley** Chair, White House Council on Environmental Quality	**John Holdren** Director, White House Office of Science and Technology Policy
Hillary Clinton Secretary of State		**Todd Stern** Special Envoy on Climate Change
Steven Chu Secretary of Energy	**Lisa Jackson** EPA Administrator	**Jane Lubchenco** NOAA Administrator

U.S. EPA

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- EPA proposed rule requiring GHG reporting, to be final for 2010 reporting
- Supreme Court in *Mass vs EPA*: Determined GHGs could be regulated under existing CAA; ordered EPA to determine if they should be
- EPA has recognized that GHG emissions can endanger public health and welfare
- EPA has a number of options for moving forward
- Key questions:
  - How fast will EPA act?
  - Which parts of the Clean Air Act will it use?
- EPA has clear authority to do GHG standards; may be able to do cap and trade, but would be constrained
- Threat of EPA action may drive legislation

U.S. Congress

SENATE

59-40 D Senate majority

(1 still undecided)

Majority Leader Reid

EPW Chairman Boxer

Need 60 votes for a bill

Need 67 votes for treaty

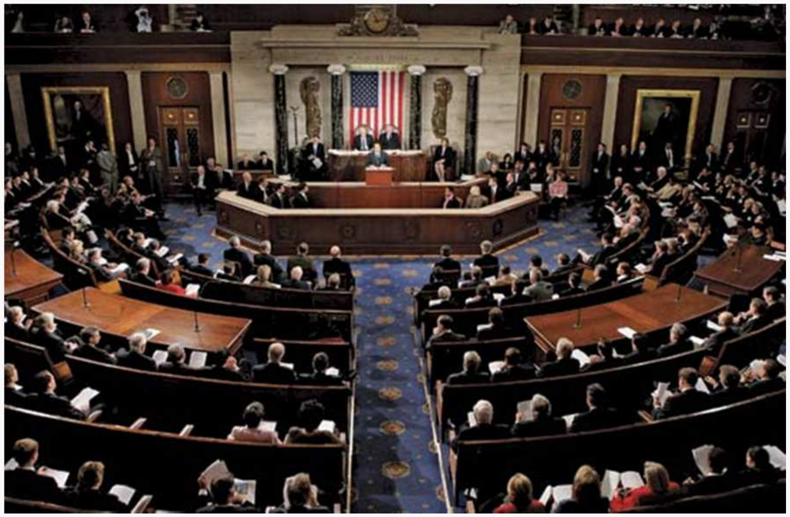
HOUSE OF REPRESENTATIVES

256-178 D House majority

Speaker Pelosi

E&C Chairman Waxman

Need 218 votes for a bill



Legislative Process

- House Energy and Commerce Committee reported bill (May 22)
- Other House Committees have referrals (Agriculture, Natural Resources, Science, Ways and Means)
- Full House vote (possibly Summer 2009)
- Senate committee action (possibly in 2009)
- Full Senate vote (2009 or 2010)
- House-Senate Conference (2009 or 2010)
- President's signature (2009 or 2010)

House Committee on Energy and Commerce

- Chairman Waxman (D-CA)
- Subcommittee Chairman Markey (D-MA)
- 59 members
- After roughly 37 hours and 94 amendments, the panel approved the bill, 33-25.
- Bono Mack only Republican to vote Yes

House Committee on Energy and Commerce

YES VOTES:

Waxman (D-CA), Dingell (D-MI), Markey (D-MA), Boucher (D-VA), Pallone (D-NJ), Gordon (D-TN), Rush (D-IL), Eshoo (D-CA), Stupak (D-MI), Engel (D-NY), Green (D-TX), DeGette (D-CO), Capps (D-CA), Doyle (D-PA), Harman (D-CA), Schakowsky (D-IL), Gonzalez (D-TX), Inslee (D-WA), Baldwin (D-WI), Weiner (D-NY), Butterfield (D-NC), Hill (D-IN), Matsui (D-CA), Christensen (D-VI), Castor (D-FL), Sarbanes (D-MD), Murphy (D-CT), Space (D-OH), McNerney (D-CA), Sutton (D-OH), Braley (D-IA), Welch (D-VT), Bono Mack (R-CA)

NO VOTES:

Barton (R-TX), Upton (R-MI), Hall (R-TX), Stearns (R-FL), [Deal (R-GA)], Whitfield (R-KY), Shimkus (R-IL), Shadegg (R-AZ), Blunt (R-MO), Buyer (R-IN), Radanovich (R-CA), Pitts (R-PA) Walden (R-OR), Terry (R-NE), Rogers (R-MI), Myrick (R-NC), Sullivan (R-OK), Murphy (R-PA), Burgess (R-TX), Blackburn (R-TN), Gingrey (R-GA), Scalise (R-LA), Ross (D-AR), Matheson (D-UT), Melancon (D-LA), Barrow (D-GA)

Waxman-Markey Bill Highlights

- Coverage: 85% of U.S. emissions through cap-and-trade
- Cap: 17% below 2005 levels by 2020; 83% below by 2050
- Threshold: Cover entities >25K tons CO_2e; EPA may lower to 10K after 2020
- Offsets: 2 billion tons domestic & int'l
- Cost containment: Strategic reserve of 2.5 billion allowances available if allowances prices rise above trigger price
- Clean Air Act limitation: GHGs not regulated as criteria pollutants or hazardous air pollutants under CAA
- State role: GHG cap-and-trade programs on hold for 5 years; other state programs unaffected
- Allowance distribution: Used for consumer protection, industry and worker transition assistance, technology innovation, and adaptation (initially 85% free allocation/15% auction; shift to auction over time)
- Many USCAP Recommendations in Waxman-Markey Bill

USCAP Partnership

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USCAP
United States Climate Action Partnership

"We are committed to a pathway that will slow, stop and reverse the growth of U.S. emissions while expanding the U.S. economy."

CHRYSLER
ALCAN
ALCOA
Boston Scientific
bp
CATERPILLAR®
Environmental Defense — finding the ways that work
ConocoPhillips
DOW®
Duke Energy®
DUPONT®
Exelon.
FPL GROUP.
Ford
GM
Johnson & Johnson
JOHN DEERE
MARSH
NRG
GE
NRDC — The Earth's Best Defense
The Nature Conservancy. Protecting nature. Preserving life.
PEPSICO
PEW CENTER ON Global CLIMATE CHANGE
PG&E Corporation.
PNM Resources
Shell
RIO TINTO
SIEMENS
WORLD RESOURCES INSTITUTE
XEROX.

Waxman- Markey Complementary Policies

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- Efficiency and Renewable Portfolio Standard (20% by 2020)
- Coal measures (CCS deployment strategy and funding, performance standards for new plants, etc.)
- Energy efficiency measures: building efficiency codes, energy efficiency resource standard, etc.
- Transportation: PHEV planning and incentives, states and MPOs to develop GHG reduction plans
- GHG performance standards
- Transmission planning, smart grid advancement, green jobs and worker transition, etc.

Allowance Allocation to States

- Renewables and energy efficiency: starts at 9.5%; 4.5% after 2021)
- Home heating oil and propane users: starts at 1.875%, declining to 0.3% in 2029.
- Other purposes if eligibility requirements met:
  - Building efficiency codes: 0.5% initially
  - Adaptation: Starts at 0.9% for domestic adaptation; 0.385% for natural resources adaptation; increases over time.
- Holders of allowances issued by California, RGGI or WCI before 12/31/11 may exchange these for federal allowances.
- Other funds for states: Funds raised through the federal ERES are given directly to states for use in renewable energy and energy efficiency programs.
- States can set up State Energy & Environment Development (SEED) Funds to combine federal clean energy/climate assistance

Additional Detail

Coverage

- Covers 7 GHGs: Carbon dioxide (CO_2), Methane (CH_4), Nitrous oxide (N_2O), Sulfur hexaflouride (SF_6), hydrofluorocarbons (HFCs) emitted as a byproduct, perfluorocarbons (PFC), nitrogen trifluoride (NF_3), and any other anthropogenic gas EPA finds has GWP equal to or greater than CO_2.
- Coverage is phased
  - 2012: Electricity and transportation
  - 2014: Industrial processes and combustors
  - 2016: Residential/commercial/small industrial natural gas consumption at LDC
- Separate cap and trade program for HFCs

Cost Containment

- Full trading and banking of allowances; unlimited next-year borrowing; limited borrowing for 2-5 years in the future w/8% interest.
- Domestic & international offsets are permitted; 2 billion tpy system-wide
  - Up to 1bn dom/1bn int'l; if < 1bn dom; EPA can increase int'l up to 1.5 billion
  - Domestic can be used 1:1 for compliance; international can be used 1:1 until 2018 and then discounted 20%
  - Firm-level limits set by formula; % compliance w/ offsets increases over time.
  - President may recommend Congress alter total # of offsets up or down.
  - EPA will list w/in 1 yr accepted project types based on recommendations from Offset Integrity Advisory Board
  - Methane emissions (other than from agriculture) may be covered by performance standards and thus ineligible as offsets unless below standard. EPA must assess impact on offset supply.
- International emission allowances from countries with absolute caps, subject to approval from the EPA, are permitted without limit.

Cost Containment (cont'd)

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- Strategic allowance reserve created from future year allowances:
  - 1% each year from 2012-2019; 2% from 2020-2029 ; 3% from 2030-2050.
- EPA conducts quarterly strategic reserve auctions (SRAs) open only to covered entities.
- Minimum SRA price:
  - 2012: $28/ton; 2013-2014: the previous year's auction price increased by inflation plus 5%; after 2014: 60% above 36-month rolling average.
- Maximum number of SRA allowances:
  - 2012-2016, no more than a quantity equal to 5% of annual allowances issued for a given year ; 2017 onwards: 10%
- No entity may purchase from SRA more than 20% of its obligation.
- Forest carbon tons sold on consignment by private entities if SRA tons exhausted and 80% of allowed system offsets to be utilized that year.
- SRA proceeds used to purchase international forest carbon tons to replenish the reserve at a 20% discount

Competitiveness

- Output-based allowance distribution approach is primary mechanism to deal with competitiveness, w/ International Reserve Allowance program—requiring allowances for imported goods' embodied GHG emissions – as a backstop.
- Distributes emission allowances to energy-intensive, trade-exposed industries. Sets criteria which would make sectors and subsectors presumptively eligible, and allows the EPA to designate more.
- Allowances compensate for direct and indirect carbon costs; firms do not have to be covered to qualify.
- Distribution would begin phasing out by 10% each year starting in 2026 (pending Presidential review).
- In 2022, President is required to make a finding that could trigger International Reserve Allowance program for particular sector or subsectors (this program would begin no earlier than 2025).

Complementary Measures for Coal

- Federal agencies to develop national strategy for CCS deployment
- EPA Administrator ordered to develop regulations for geologic sequestration sites
- Boucher CCS trust fund for early stage deployment
- Performance standard for new coal power plants and financial incentives for CCS deployment
  - Similar but not identical to USCAP *BLA*
  - New facilities permitted in 2020 must reduce annual CO_2 emissions by 65% compared to operation without CCS. Plants permitted between 2009 and 2019 subject to 50% reduction
  - Plants permitted 2009-2019 must comply by the earlier of January 1, 2025 or 4 years after deployment of at least 4 GW of CCS in the U.S.
  - Authorizes rebate for early large scale deployment (and specifies rebate values for first 6 GW of CCS capacity)
  - After initial 6 GW of CCS, bonus allowances to be awarded via reverse auction or via first-come, first-served program, if the Administrator deems the latter to be more effective.

Adaptation

- Establishes National Climate Change Adaptation Program within USGCRP.
- Requires President to develop and implement Natural Resources Climate Change Adaptation Strategy.
- Requires states and federal agencies to develop natural resource adaptation plans.
- Establishes Natural Resources Climate Change Adaptation Fund in the Treasury. States could apply for these funds if they have prepared a natural resources adaptation plan.
- Provides 2% of allowance value increasing over time for domestic adaptation (much of that goes to states)
- Provides 1% of allowance value increasing over time for international adaptation.

Renewable Energy and Efficiency

- Combined Efficiency and Renewable Electricity Standard
  - Standard starts at 6% of sales in 2012 and rises to 20% in 2020
  - Up to one quarter of the requirement can be automatically met with electricity savings. Upon petition by a state's governor, FERC can allow a state's utilities to use electricity savings to meet up to two fifths of the standard
  - New nuclear and CCS generation do not increase requirements for efficiency and renewables
- Promotes energy efficiency in new and retrofitted buildings
  - Establishes national building energy efficiency codes
  - Establishes a building retrofits program
  - Establishes a program to upgrade inefficient manufactured homes
  - Establishes a model building energy performance labeling program
- New efficiency standards for lighting and other appliances, including financial incentives to retailers who sell high volumes of "Best-in-Class" appliances.

Some other provisions

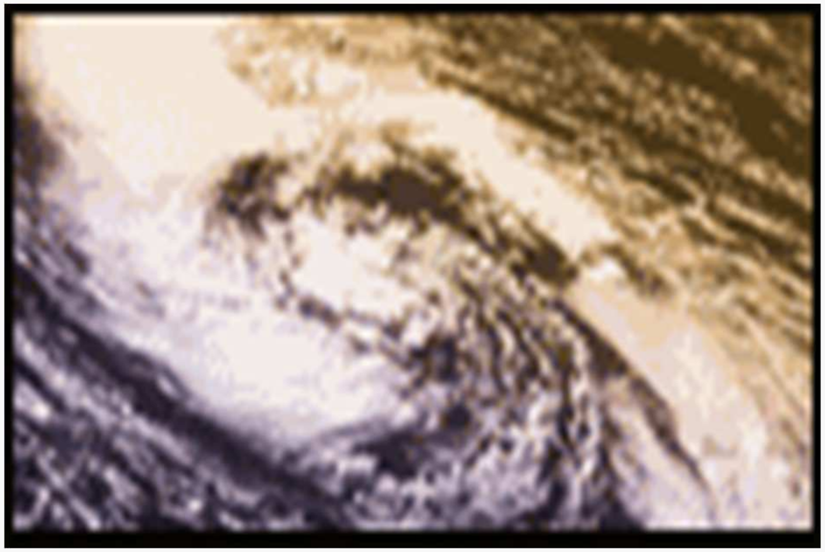
Targets beyond cap and trade: same as cap and trade except 20% below 2005 levels in 2020

Allowance distribution:

- Consumers: To LDCs for electric and gas, to states for heating oil and propane; federal rebates for low and moderate income families
- Supplemental reductions: 10% (720 mtCO_2e) below 2005 levels by 2020 (cumulatively 6 btCO_2e by 2025) thru sale of 5% of allowances to fund REDD.
- Competitiveness, workers, EERE investment, adaptation, international programs
- Provides 1% of allowance value increasing over time for International Clean Technology Fund in Treasury

For More Information

www.pewclimate.org



USCAP

Why would businesses want urgent enactment of climate legislation?

- Cost of regulatory uncertainty
- Supreme Court has effectively ordered EPA to regulate GHGs
- State action: 24 states developing GHG cap (1/2 population)
- GHG regulation in place in Europe
- Want US to influence post-2012 international climate negotiations
- Convinced by climate science, concerned by increasing risk from climate impacts

Coverage in 2012

- All electricity sources
- Producers and importers of liquid fuels whose combustion will emit more than 25,000 tons of CO_2e
- Producers and importers of fluorinated gases (except HFCs)
- Geological sequestration sites
- Electricity sources not required to submit allowances for emissions resulting from the use of petroleum-based or coal-based liquid fuel; biomass; petroleum coke; or HFCs, PFCs, SF_6, NF_3, or any other fluorinated gas that is a GHG.

Coverage in 2014 (Industry)

PEW CENTER ON Global CLIMATE CHANGE

- Producers and manufacturers of: adipic acid; primary aluminum; ammonia; cement, excluding grinding-only operations; HCFCs; lime; nitric acid; petroleum refining; phosphoric acid; silicon carbide; soda ash; titanium dioxide; coal-based liquid or gaseous fuel production
- Manufacturers of acrylonitrile, carbon black, ethylene, ethylene dichloride, ethylene oxide, or methanol; or manufacturers of a petrochemical product not manufactured as of the date of enactment, if EPA determined that manufacturing that product results in annual process emissions of 25,000 or more tons of CO_2e in 2008 or after.
- Producers and manufacturers of ethanol, ferroalloy, glass, hydrogen, iron and steel, lead, kraft pulp and paper, zinc, and food processors that have emitted 25,000 or more tons of CO_2e in 2008 or any subsequent year.
- Any fossil fuel-fired combustion device or grouping of such devices that is all or part of an industrial source not specified above; and has emitted 25,000 or more tons of CO_2e in 2008 or any subsequent year.

Coverage – More detail (cont'd)

- In 2016: Emissions from the combustion of natural gas for residential, commercial and small industrial use would also be covered at local distribution companies (LDCs) which deliver 460,000,000 cubic feet or more of natural gas annually.

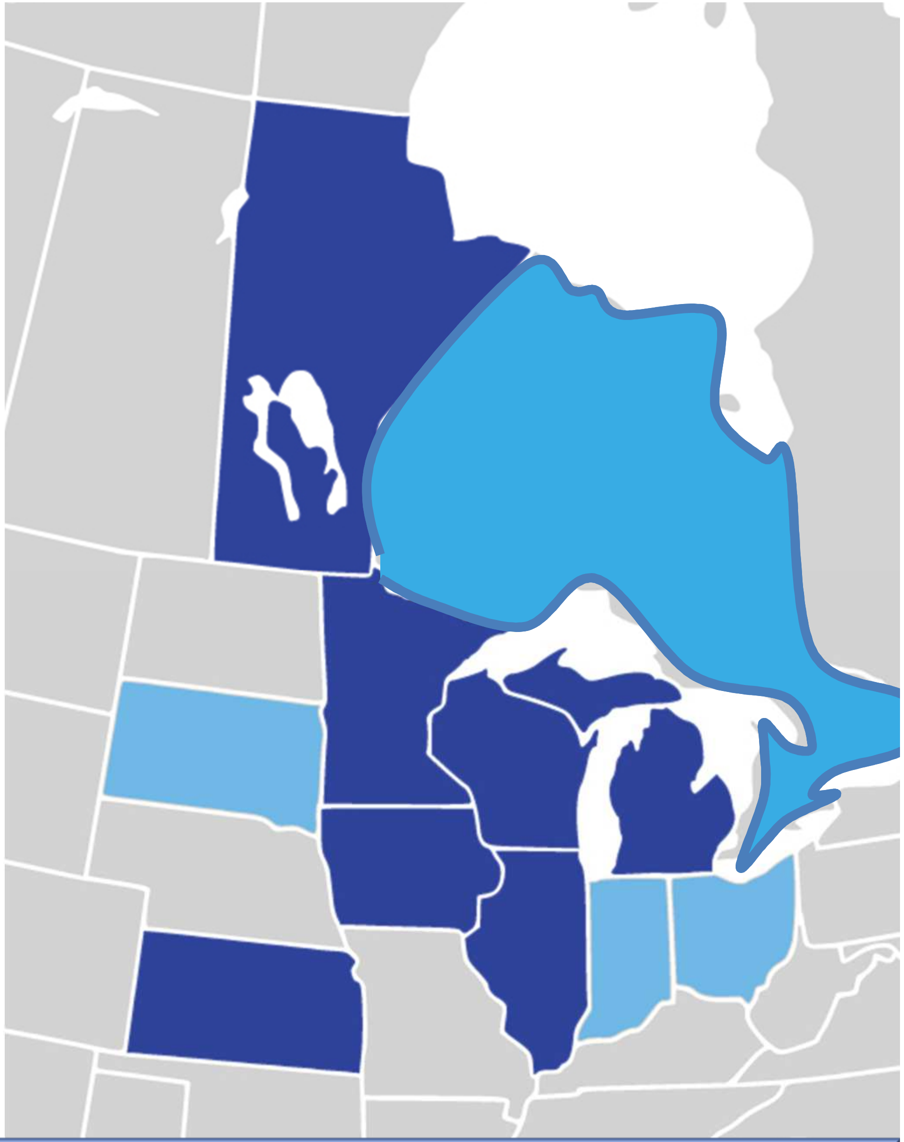
- In 2012. HFCs covered by separate cap-and-trade program and a tax. The draft would set an emissions baseline derived from the average annual importation and production of HFCs from 2004-2006, and a target range of reducing HFC emissions to 85% below the baseline by 2032.

- EPA to promulgate regs to reduce domestic black carbon emissions

USCAP Recommendations

- Targets
  - 100-105% of today's levels within five years
  - 90-100% of today's levels within 10 years
  - 70-90% of today's levels within 15 years
  - Goal of 60-80% reduction by 2050 (~450-550 ppm)
- Economy-wide cap-and-trade system is essential to create market price signal for GHGs
- Additional policies/measures where price signal alone is not sufficient
  - Transportation
  - Power generation
  - Energy efficiency
- Technology research, development, demonstration, and deployment
- Need for renewed U.S. leadership in international efforts

Midwestern Greenhouse Gas Reduction Accord



Draft Final Recommendations
May 2009

Process Overview

- November 2007: Governors' and Premier's Summit in Milwaukee, Wisconsin
- Accord Advisory Group created by Governors
  - Includes Executive Committee comprised of Governors'/Premiers' Reps
  - Stakeholders
- Draft Recommendations November 2008
- Draft Final Recommendations May 2009
- Governors' and Premier's Summit October 2009

Process Note

- Not a consensus effort
- The final draft recommendations have general support of the Advisory Group, but not unanimous support.
- No votes taken, but an effort was made to strike a balance between different interests on each issue
- Recommendations have unanimous support of the participating states and province.

Program Feature	Midwestern Accord Approach
Reductions and Timetables	• Program starts in 2012; • 18 to 20% below 2005 levels by 2020; • 80% below 2005 levels by 2050.
Scope	• Electricity combustion, including imports; • Industrial combustion and process emissions; • Transportation fuels (phased in 2nd period for MB); • Residential, commercial and industrial (RCI) fuels not otherwise covered at emissions source (phased in 2nd period for MB) • Biomass emissions are exempt
Point of Regulation	• Electricity and industrial sources at point of emissions; • Transportation fuels at the point where the fuels enter the participating jurisdiction; • RCI fuels where the fuels enter the participating jurisdiction.
Threshold for coverage	• 25,000 metric tons of annual emissions • 3-year rolling average; once-in, always in. • Electric generators with nameplate capacity under 25 megawatts exempt

Program Feature	Midwestern Accord Approach
Distributing Allowances	• Up to States and Province, but Advisory Group recommends: • Approximately 33% auction; 67% sold for a fee: • All transportation and merchant power generator allowances will be auctioned; • 5% of other sectors' allowances will be auctioned with proceeds to a Technology Fund, with rest <u>sold</u> for modest fee. • Transition to 100% beginning in 4th compliance period.
Offsets	• Offsets may be used to cover up to 20% of each entity's compliance obligation. • Offsets from region, plus states & provinces with MOU
Reporting	• Commence in 2011 • Threshold: 20,000 metric tons annual emissions
Share of Reductions from Capped Sectors	• Capped sectors will provide their proportional share of reductions

Program Feature	Midwestern Accord Approach

Cost Containment	• Compliance period 3 years
	• Banking allowed
	• Borrowing allowed two years into next compliance period
	• Establish regional Market Advisory and Cost Containment Committee (MACCC):
	  • 2% allowance reserve pool, to be released as follows:
	    • MACCC to establish a price “collar” with a low price and high price;
	    • If allowance price substantially exceeds the high price, then allowances will be released from the 2% allowance reserve pool.
	  • MACCC will also monitor the market for signs of gaming or manipulation

Next Steps

- Influence the federal cap and trade discussion, while moving forward with development of a regional program as backstop

- Complete REMI modeling of jobs and macroeconomic impacts prior to issuing final design recommendations, with modeling results later in the summer.

- Model Rule development has commenced (on schedule for completion in September 2009)

- Governors and Premier Summit in October 2009

Questions?

Western Climate Initiative News

June 2, 2009

This status report is issued once a month from WCI Partner jurisdictions to all interested stakeholders via the WCI listserv and website.

In This Issue

Upcoming Events

May 27 WCI Partners Meeting Highlights

CSAD Releases White Papers, Hosts Workshop

Complementary Policies Committee Underway

Comments on U.S. EPA's Proposed Endangerment Finding

Upcoming Events

June 8: Presentation to the WCI Markets Committee

Michael Sheehan of the New York State Dept. of Environmental Conservation will have a discussion with the Markets Committee Compliance, Verification and Enforcement (CV&E) Task Group regarding NY state CV&E in the RGGI system on Monday, June 8 from 8:30 - 10:00 a.m. (Pacific). Details are posted on the WCI website.

June 18: Stakeholder Update Call

The next stakeholder update call will be Thursday, June 18 from 12:30 - 2:00 p.m. (Pacific). To join the call, dial 1.800.868.1837 (toll free) or 1.404.920.6440 (direct dial), and enter participant code 659537#. These bi-monthly calls provide an opportunity for stakeholder updates and discussions between Partner meetings, which also occur bi-monthly.

June 22: Presentation to the WCI Markets Committee

Rob Gemmill of the

May 27 WCI Partners Meeting Highlights

The WCI Partners meeting on May 27 included three presentations to the WCI Partners, as well as updates from the WCI Committees. The presentations on Waxman-Markey, the Midwest Greenhouse Gas Accord, and the new National Clean Car Standards are available on the WCI website. Highlights of the Committee updates include:

- The **Markets Committee** is currently reviewing comments received on the principles and discussion questions it released in April, as well as developing a series of white papers.
- The **Reporting Committee** encourages submission of public comments on its final draft essential requirements by June 4. The Committee will be reviewing these comments as it finalizes the requirements, to be released at the end of June. The Committee is also finalizing comments on the U.S. EPA's proposed mandatory greenhouse gas reporting rule and is working with The Climate Registry to develop a reporting database that will serve as a repository for the WCI Partners' regional emissions data.
- The **Offsets Committee**, having completed a series of public webinars on approaches to developing offset protocols and the structure and capacity of existing organizations, is drafting options for Partners to consider as they determine how to proceed, including examining options to fast-track approval of existing protocols. The Committee will also be releasing a white paper for stakeholder input that defines an offset and discusses potential WCI eligibility criteria.
- The **Electricity Committee** has been working with the Reporting Committee in finalizing the essential elements for reporting for the electricity sector. These elements are posted for stakeholder comment on the WCI website. The

Environment Agency for England and Wales will be giving a presentation to the Markets Committee Verification and Enforcement Task Group regarding monitoring, verification and enforcement in the EU ETS on Monday, June 22 from 8:30 - 9:30 a.m. (Pacific). Details are posted on the WCI website.

Release of Offsets White Paper

The Offsets Committee will be releasing a white paper in June regarding offset definition and eligibility criteria. An announcement will be made via the WCI listserv when it is available and posted on the WCI website.

July 21: WCI Partners Meeting

The next WCI Partners meeting will be in Portland, Oregon on Tuesday, July 21. Details regarding the agenda and public participation will be distributed when available.

Committee will provide an update to stakeholders this summer on its work to incorporate electricity imports in WCI's cap-and-trade program design.

- The **Economic Modeling Team** is completing its third phase of ENERGY 2020 modeling (expected to be available in July) and is preparing to use these results to analyze the macroeconomic impacts of the WCI's cap-and-trade program.

Cap Setting & Allowance Distribution (CSAD) Releases White Papers, Hosts Workshop

On May 21, the CSAD Committee released white papers on offset limits and early reduction allowances, as well as discussion questions regarding competitiveness. This material was the subject of a May 28 workshop in Seattle. The material and workshop presentations are available on the WCI website. There is also a link on the website for submitting comments. Comments should be submitted by June 19.

Complementary Policies Committee Underway

The WCI Partners approved a work plan for the Complementary Policies Committee. The work plan was summarized at the May 27 WCI Partners meeting and will be publicly available soon. The Committee will focus on policies where coordination and harmonization would be useful among the WCI Partner jurisdictions and recommend to the Partners those policies that will aid in achieving regional emissions reduction goals across all sectors of the economy.

Oral Comments on U.S. EPA's Proposed Endangerment Finding

On Thursday, May 21, U.S. Co-Chair Janice Adair (Washington Department of Ecology) provided testimony on behalf of the WCI to the U.S. EPA regarding its proposed greenhouse gas endangerment finding hearing, which was held in Seattle. For a copy of the testimony, click here.

To subscribe or unsubscribe from the WCI listserv, click here.

The EU Emissions Trading Scheme: MRVCE

Rob Gemmill
Technical Advisor
WCI Markets Task 2 (22nd June 2009)

Outline

- Background/Scene Setting
- Main components
- Most important MRVCE requirements
- UK implementation/good practice
- Latest EU ETS developments
- Compliance and Enforcement Issues
- Initiatives promoting greater consistency

The Environment Agency for England &Wales (Proposed Strategy 2010-2015)

We are a regulator, assessor, advisor, promoter

Our aim

- *A better place for people and wildlife, now and in the future*

To achieve this we will:

- *Act to reduce climate change and its consequences*
- *Protect and improve air, land and water quality*
- *Put people and communities at the heart of what we do*
- *Work with businesses and the public sector to use resources wisely*
- *Be the best we can*

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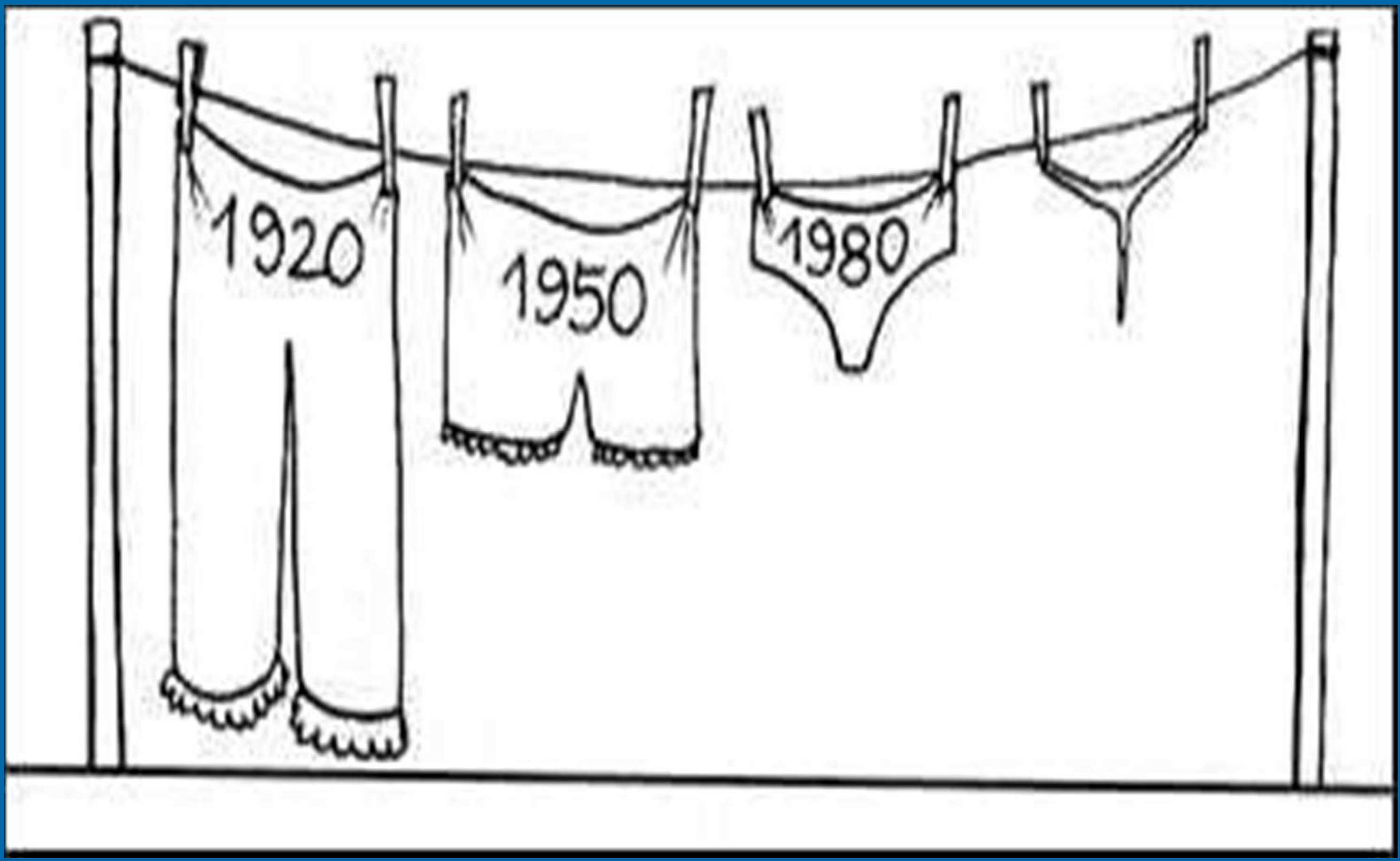
Evidence of climate change



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International Policy Action

- United Nations Framework Convention on Climate Change signed at the Earth Summit, Rio de Janeiro, 1992
- Kyoto Protocol, 1997 - Some developed countries agreed targets to reduce overall emissions of carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulphur hexafluoride by 5.2 % below 1990 levels by 2008 -2012
- EU ETS part of EC commitment to meet a Kyoto Commitment to reduce all Greenhouse Gases by 8% based on 1990 levels by 2008 - 2012 (UK: 12.5%)
- COP 15, Copenhagen (December 2009)

Environment Agency

EU ETS Directive

- Directive 2003/87/EC of 13 October 2003 *establishing a scheme for GHG emission allowance trading within the Community and amending Council Directive 96/61/EC*
- Article 1: *This Directive establishes a scheme for greenhouse gas emission allowance trading within the Community* ***in order to promote reductions of greenhouse gas emissions in a cost-effective and economically effective manner***
- Cap and trade - emissions cut wherever cheapest
- Predicted to deliver EU Kyoto target at a cost of €2.9-3.7 billion annually (<0.1% EU GDP - compared €6.8 billion/year compliance costs without the scheme)

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Main Components (of cap and trade)

- Cap overall emissions (UK Phase 2: 1,230MtCO_2; 246/year)
  - Prescribed activities (Annex I)
  - National allocation plan (Article 9)
- Distribute allowances to installation operators (Articles 10 & 11)
  - one allowance = one tonne of CO_2 equivalent
- Impose obligations
  - Permits/Monitoring Plans (Articles 4, 5, 6)
  - Monitoring and reporting of emissions (Article 14 & Annex IV)
  - Verification of emissions (Article 15 & Annex V)
  - Surrender of allowances (Article 12)
- Trading mechanism/Registry
  - Buying and selling as appropriate (Articles 12 & 19)

The "MRG" (Commission Decision 2007/589/EC)

Guidelines for M&R of emissions from activities listed in Annex I of EU ETS Directive

- Annex I: Definitions; Principles; Monitoring (calculation and measurement options); Uncertainty requirements; Reporting; Retention (of information); Control and Verification; Reference emission factors; Biomass; Activity-specific data/factors; Reporting format; Reporting categories; Small emitters
- Annexes II-XI: Sector specific guidelines
- Annex XII: Guidelines for CEMS

- Annex XIII (N_2O), Annexes XIV & XV (Aviation), Annexes XVI-XVIII (CCS)

Environment Agency

Main MRG Monitoring Requirements

- Determination of emissions by calculation; or measurement (CEMS) if it reliably results in a more accurate determination of annual emissions
- By approved monitoring plans (Annex I, Section 4.3)
- Calculation based on:

  CO_2 emissions = activity data * emission factor * oxidation/conversion factor
- Tier-based approach (Annex I, Section 5.2)
  - Highest tier default (for larger emitters), minimum set by Annex I, Table 1
  - Activity data tiers set according to uncertainty thresholds
  - Other inputs based on IPCC factors, country-specific factors, and installation-specific determinations (frequency of determination & ISO 17025 issues)
- Fall-back approach (Annex I, Section 5.3) – last resort (overall uncertainty threshold requirement)
- Control requirements (Annex I, Section 10)

Control Requirements (QA/QC)

- Operator required to maintain written procedures covering:
  - Data flow (acquisition and handling), including methods of calculation
  - Assessment of risks to misstatement (errors, misrepresentations or omissions) in the annual emissions report, or non-conformity with the approved monitoring plan, permit or MRG
  - Management of competences for assigned responsibilities
  - QA of measuring equipment and IT
  - Internal review of reported data (validation – vertical/horizontal checks)
  - Outsourcing
  - Corrections and corrective action
  - Records
  - Any other control activities required to mitigate identified risks (under the control system risk assessment)

Environment Agency

EU ETS Verification (Third Party)

- To confirm reliability, credibility and accuracy of monitoring systems and reported data (further contribution to EU ETS integrity)
- Contracted between operator and verifier in the UK (permit requirement to submit a verified annual emission report)
- Scope of work:
  - Strategic analysis, risk assessment, verification, internal and external verification reports (MRG Annex I, Section 10.4)
  - Annual emissions report verified as satisfactory *if the total emissions are not materially misstated, and if, in the opinion of the verifier there are no material non-conformities* (based on reasonable assurance, i.e. a high level of certainty)
  - Misstatements, non-conformities and recommended improvements reported
- In the UK, “Verifier” means *a verification body or person accredited (and, if required, endorsed by UKAS) to carry out the verification requirements of Article 15 of the Directive. In this context, “accredited” means accredited by a member of the ‘European Co-operation for Accreditation’ having regard to the latter’s greenhouse gas verification guidance* [reference to EA-6/03]

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EA-6/03

- EU ETS applicable (European Accreditation Regulation applicable)
- Based on requirements of international standards (ISO14065; or EN45011 and EA-6/01; ISO17020 and IAF/ILAC A4)
- Provides for mutual recognition of Member State verifiers
- Key elements:
  - ‘Reasonable assurance’ approach
  - Based on verifier’s assessment of verification risk
  - Thorough and auditable documentation
  - Prescription of the entire EU ETS verification process
  - Identification of verifier competence requirements
  - Identification of technical competence requirements
  - Normative requirements for ‘impartiality and independence’
  - Additional informative guidance on ‘materiality, uncertainty, and examples of verification opinion’, ‘verification plan details’, ‘verification effort and repeat verifications within the same installation’, ‘factors for allocating time and determining the data sampling plan’, the ‘scope of accreditation’, ‘content of the verifier’s internal verification documentation’, ‘content of the verification report’, ‘misstatements and non-conformities’, ‘site visits’

Summary of UK Implementation

- Directive (2003/87/EEC): October 2003
- UK GHG Emissions Trading Scheme Regulations entered into force 31st December 2003
- Commission Decision establishing guidelines for M&R of GHG Emissions 29th January 2004
- 1,100 permits including approved M&R plans issued by 31st December 2004
- Re-issue of Consolidated Regulations 2005
- Start of Phase 1 on 1st January 2005 - just CO_2
- Revised Commission Decision for M&R of 18th July 2007
- Permits re-issued for Phase 2 (2008-2012) by 31st December 2007
  - ca. 900 permitted installations
  - still just CO_2

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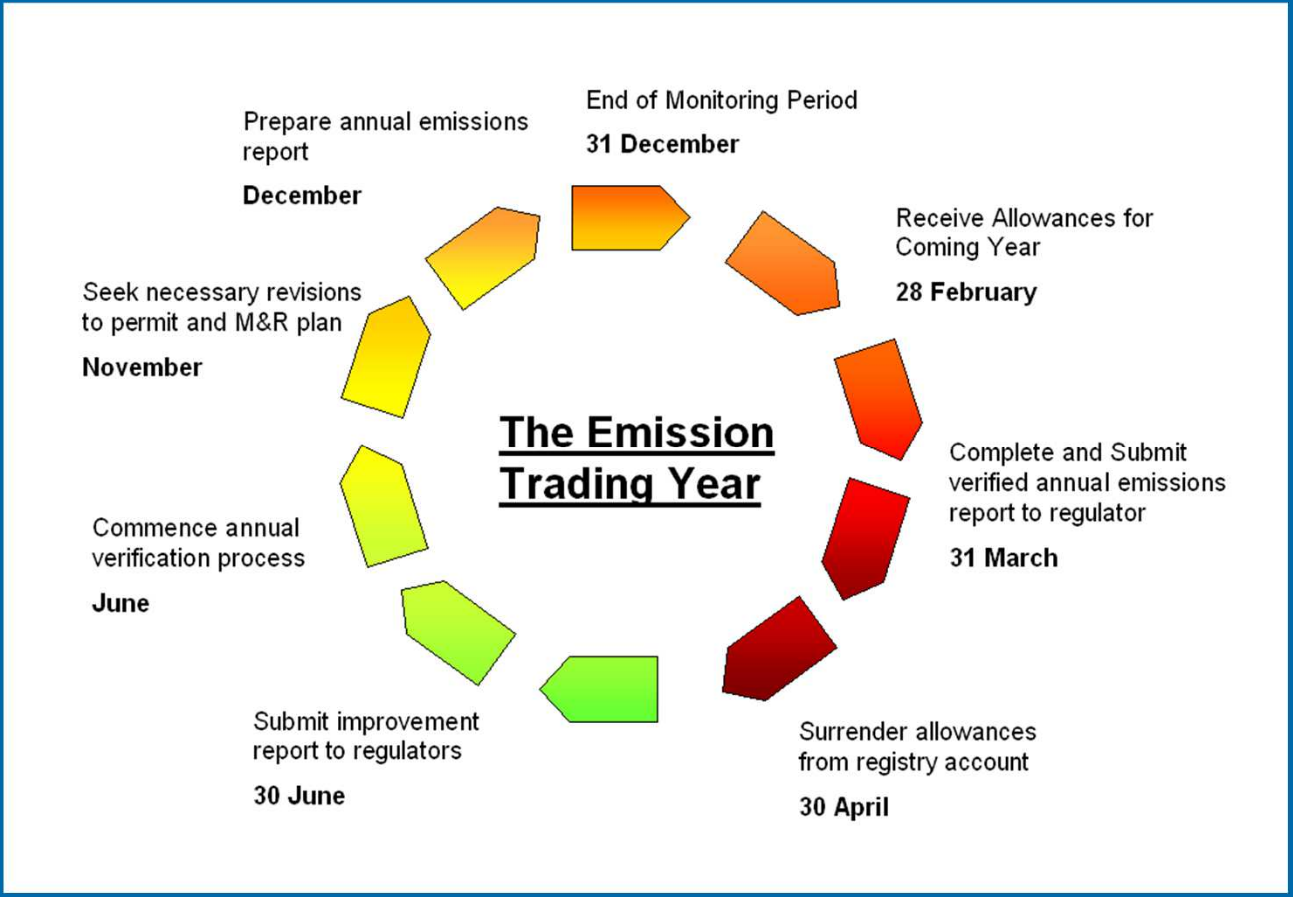
Key Roles

- DECC (DEFRA, BERR), DfT - Development of Regulations, policy, and the national allocation plans
- Regulators (Environment Agency, SEPA, EANI, DECC Offshore) - Permitting, Enforcement, Inspection
- Environment Agency operates the UK Registry
- Operators - Permits to operate, M&R, and surrendering sufficient allowances
- Verifiers (accredited by UKAS or a fellow member of the European co-operation for Accreditation according to EA-6/03)
- Traders/Brokers - EU ETS Registry

Our Annual EU ETS Compliance Cycle



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UK Good Practice

- Dedicated “National Once Task and Finish Groups” established
- Strong coordination/communications between Government, Regulators, Verifiers and Industry:
  - Emissions Trading Group (also MRV and Regulators Groups)
  - Consultations/workshops
- Electronic Application and Permitting System
- Helpdesks and websites for queries and products/guidance. Standard Forms
- Avoiding duplication: costs kept down

Web Addresses

www.environment-agency.gov.uk/emissionstrading

www.defra.gov.uk/environment/climatechange/trading/eu/operators/mon-rep-ver.htm

http://ec.europa.eu/environment/climat/emission/

http://ec.europa.eu/environment/climat/aviation_en.htm

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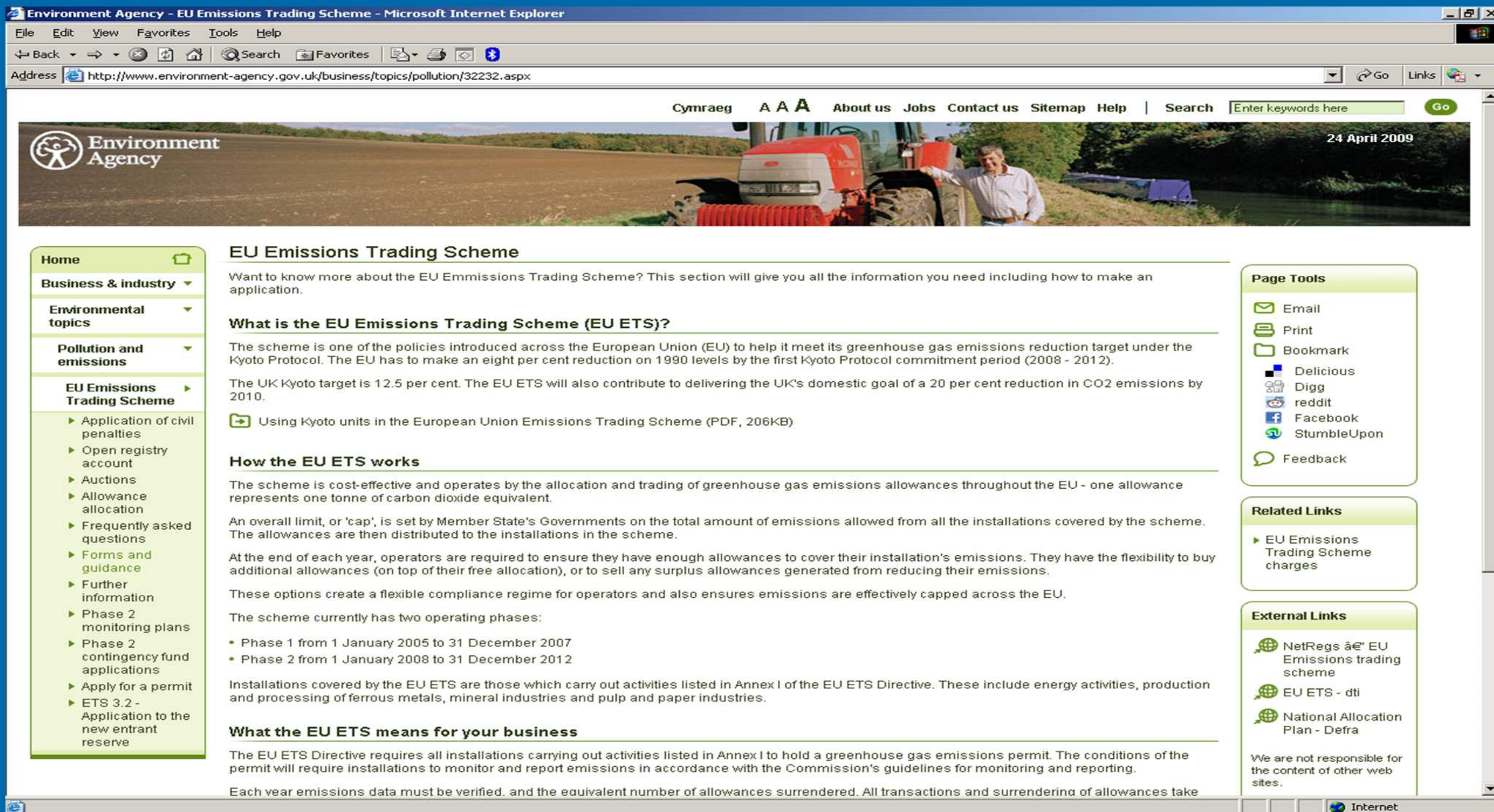
Environment Agency Web-site



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24 April 2009

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  - Application of civil penalties
  - Open registry account
  - Auctions
  - Allowance allocation
  - Frequently asked questions
  - Forms and guidance
  - Further information
  - Phase 2 monitoring plans
  - Phase 2 contingency fund applications
  - Apply for a permit
  - ETS 3.2 - Application to the new entrant reserve

EU Emissions Trading Scheme

Want to know more about the EU Emmissions Trading Scheme? This section will give you all the information you need including how to make an application.

What is the EU Emissions Trading Scheme (EU ETS)?

The scheme is one of the policies introduced across the European Union (EU) to help it meet its greenhouse gas emissions reduction target under the Kyoto Protocol. The EU has to make an eight per cent reduction on 1990 levels by the first Kyoto Protocol commitment period (2008 - 2012).

The UK Kyoto target is 12.5 per cent. The EU ETS will also contribute to delivering the UK's domestic goal of a 20 per cent reduction in CO2 emissions by 2010.

Using Kyoto units in the European Union Emissions Trading Scheme (PDF, 206KB)

How the EU ETS works

The scheme is cost-effective and operates by the allocation and trading of greenhouse gas emissions allowances throughout the EU - one allowance represents one tonne of carbon dioxide equivalent.

An overall limit, or 'cap', is set by Member State's Governments on the total amount of emissions allowed from all the installations covered by the scheme. The allowances are then distributed to the installations in the scheme.

At the end of each year, operators are required to ensure they have enough allowances to cover their installation's emissions. They have the flexibility to buy additional allowances (on top of their free allocation), or to sell any surplus allowances generated from reducing their emissions.

These options create a flexible compliance regime for operators and also ensures emissions are effectively capped across the EU.

The scheme currently has two operating phases:

- Phase 1 from 1 January 2005 to 31 December 2007
- Phase 2 from 1 January 2008 to 31 December 2012

Installations covered by the EU ETS are those which carry out activities listed in Annex I of the EU ETS Directive. These include energy activities, production and processing of ferrous metals, mineral industries and pulp and paper industries.

What the EU ETS means for your business

The EU ETS Directive requires all installations carrying out activities listed in Annex I to hold a greenhouse gas emissions permit. The conditions of the permit will require installations to monitor and report emissions in accordance with the Commission's guidelines for monitoring and reporting.

Each year emissions data must be verified, and the equivalent number of allowances surrendered. All transactions and surrendering of allowances take

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Related Links

- EU Emissions Trading Scheme charges

External Links

- NetRegs â€" EU Emissions trading scheme
- EU ETS - dti
- National Allocation Plan - Defra

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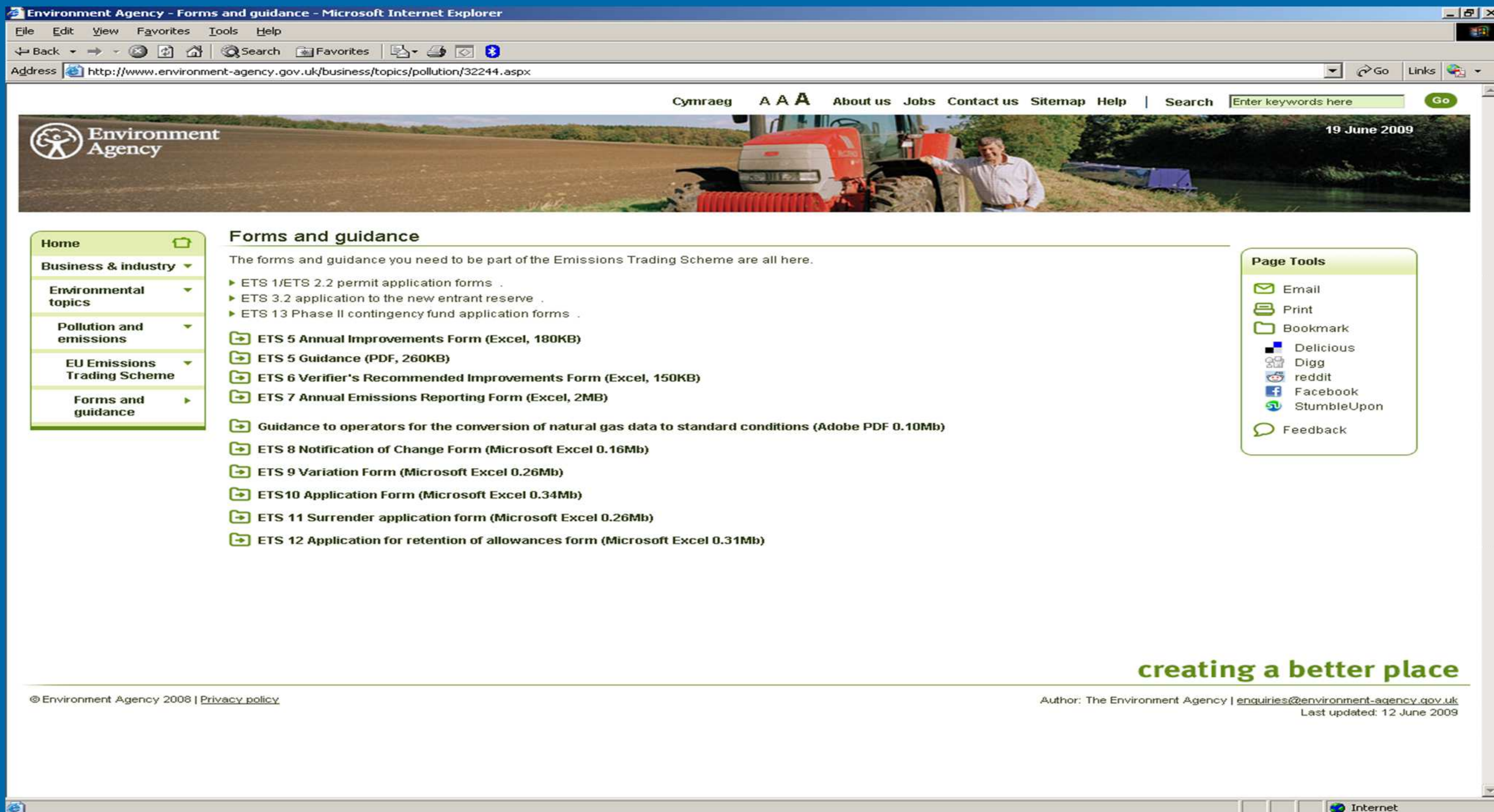

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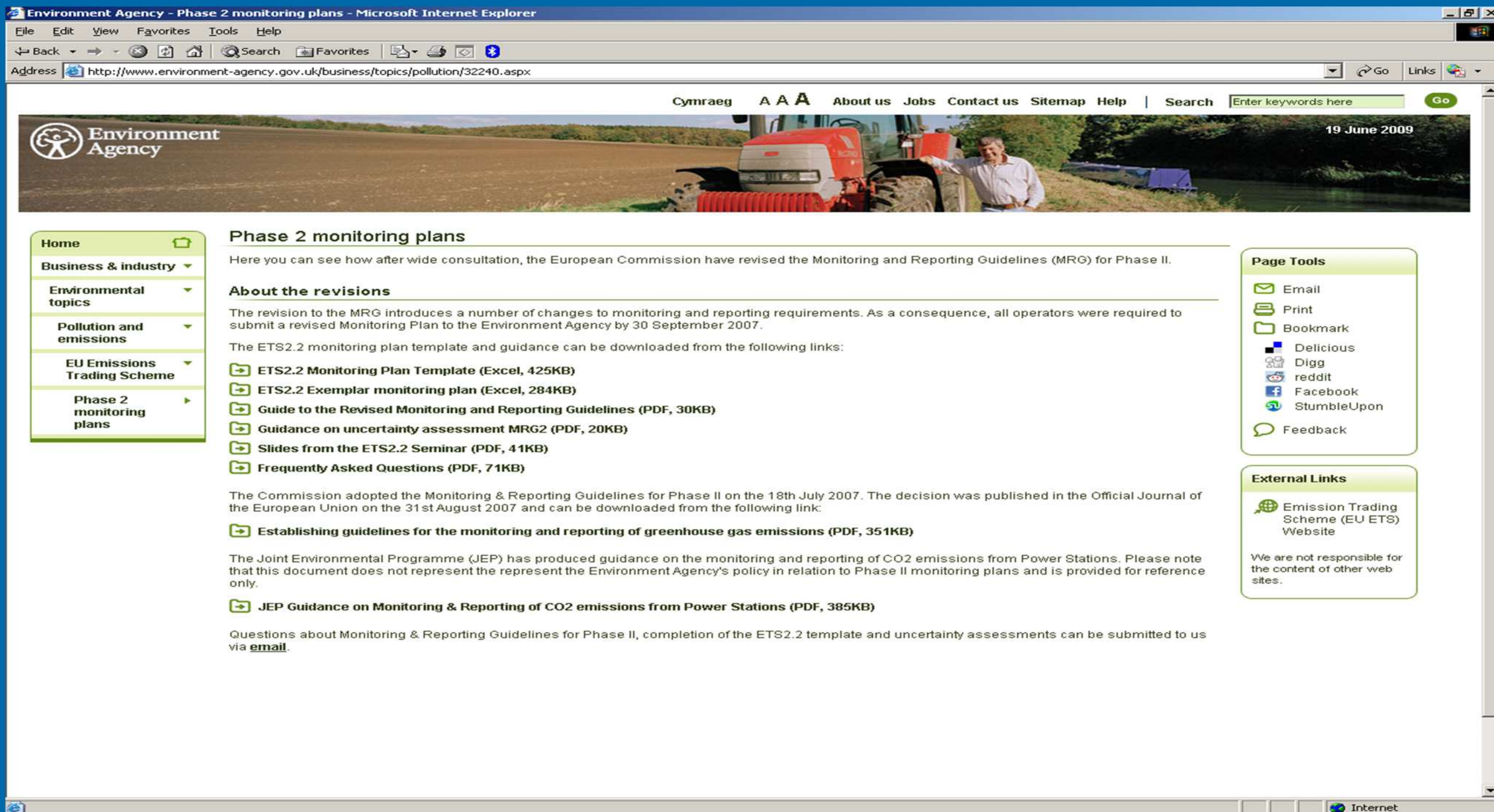

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Environment Agency 19 June 2009

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EU Emissions Trading Scheme
Phase 2 monitoring plans

Phase 2 monitoring plans

Here you can see how after wide consultation, the European Commission have revised the Monitoring and Reporting Guidelines (MRG) for Phase II.

About the revisions

The revision to the MRG introduces a number of changes to monitoring and reporting requirements. As a consequence, all operators were required to submit a revised Monitoring Plan to the Environment Agency by 30 September 2007.

The ETS2.2 monitoring plan template and guidance can be downloaded from the following links:

- **ETS2.2 Monitoring Plan Template (Excel, 425KB)**
- **ETS2.2 Exemplar monitoring plan (Excel, 284KB)**
- **Guide to the Revised Monitoring and Reporting Guidelines (PDF, 30KB)**
- **Guidance on uncertainty assessment MRG2 (PDF, 20KB)**
- **Slides from the ETS2.2 Seminar (PDF, 41KB)**
- **Frequently Asked Questions (PDF, 71KB)**

The Commission adopted the Monitoring & Reporting Guidelines for Phase II on the 18th July 2007. The decision was published in the Official Journal of the European Union on the 31st August 2007 and can be downloaded from the following link:

- **Establishing guidelines for the monitoring and reporting of greenhouse gas emissions (PDF, 351KB)**

The Joint Environmental Programme (JEP) has produced guidance on the monitoring and reporting of CO2 emissions from Power Stations. Please note that this document does not represent the represent the Environment Agency's policy in relation to Phase II monitoring plans and is provided for reference only.

- **JEP Guidance on Monitoring & Reporting of CO2 emissions from Power Stations (PDF, 385KB)**

Questions about Monitoring & Reporting Guidelines for Phase II, completion of the ETS2.2 template and uncertainty assessments can be submitted to us via email.

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Emission Trading Scheme (EU ETS) Website

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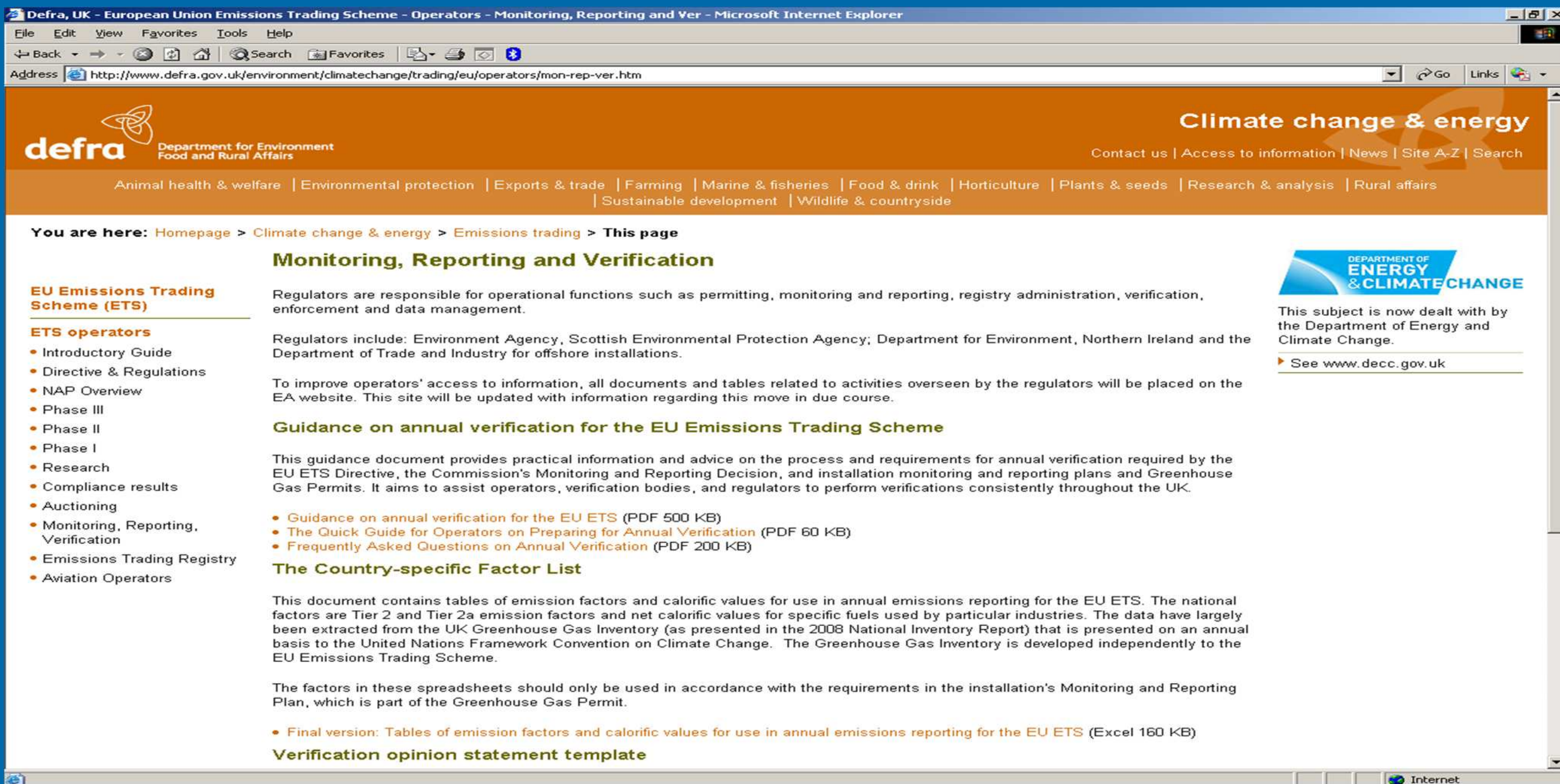
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Address http://www.defra.gov.uk/environment/climatechange/trading/eu/operators/mon-rep-ver.htm

defra Department for Environment Food and Rural Affairs

Climate change & energy

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You are here: Homepage > Climate change & energy > Emissions trading > **This page**

EU Emissions Trading Scheme (ETS)

ETS operators

- Introductory Guide
- Directive & Regulations
- NAP Overview
- Phase III
- Phase II
- Phase I
- Research
- Compliance results
- Auctioning
- Monitoring, Reporting, Verification
- Emissions Trading Registry
- Aviation Operators

Monitoring, Reporting and Verification

Regulators are responsible for operational functions such as permitting, monitoring and reporting, registry administration, verification, enforcement and data management.

Regulators include: Environment Agency, Scottish Environmental Protection Agency; Department for Environment, Northern Ireland and the Department of Trade and Industry for offshore installations.

To improve operators' access to information, all documents and tables related to activities overseen by the regulators will be placed on the EA website. This site will be updated with information regarding this move in due course.

Guidance on annual verification for the EU Emissions Trading Scheme

This guidance document provides practical information and advice on the process and requirements for annual verification required by the EU ETS Directive, the Commission's Monitoring and Reporting Decision, and installation monitoring and reporting plans and Greenhouse Gas Permits. It aims to assist operators, verification bodies, and regulators to perform verifications consistently throughout the UK.

- Guidance on annual verification for the EU ETS (PDF 500 KB)
- The Quick Guide for Operators on Preparing for Annual Verification (PDF 60 KB)
- Frequently Asked Questions on Annual Verification (PDF 200 KB)

The Country-specific Factor List

This document contains tables of emission factors and calorific values for use in annual emissions reporting for the EU ETS. The national factors are Tier 2 and Tier 2a emission factors and net calorific values for specific fuels used by particular industries. The data have largely been extracted from the UK Greenhouse Gas Inventory (as presented in the 2008 National Inventory Report) that is presented on an annual basis to the United Nations Framework Convention on Climate Change. The Greenhouse Gas Inventory is developed independently to the EU Emissions Trading Scheme.

The factors in these spreadsheets should only be used in accordance with the requirements in the installation's Monitoring and Reporting Plan, which is part of the Greenhouse Gas Permit.

- Final version: Tables of emission factors and calorific values for use in annual emissions reporting for the EU ETS (Excel 160 KB)

Verification opinion statement template

DEPARTMENT OF ENERGY & CLIMATE CHANGE

This subject is now dealt with by the Department of Energy and Climate Change.

- See www.decc.gov.uk

Internet

Environment Agency

Latest EU ETS Development: N_2O

- Nitrous oxide emissions from nitric acid plant
- By opt-in during EU ETS Phase 2 (2008 - 2012)
  - Applications currently approved from the Netherlands and Austria
- MRG amended (Commission Decision of 17 December 2008; OJ, L24/18, 28th January 2009)
  - Annex XIII: Activity-specific guidelines for determination of nitrous oxide (N_2O) from nitric acid, adipic acid, caprolactum, glyoxal, and glyoxylic acid production
- Mandatory inclusion from 1st January 2013 (the start of EU ETS Phase 3)

Environment Agency

Latest EU ETS Development: Aviation

- Directive 2008/101/EC amending Directive 2003/87/EC to include aviation
- Annex I activity from 2012, but:
  - Baseline t-km (payload x distance) requirement 2010 (to apply for free allowances)
  - Aircraft operators to report verified annual emissions for 2010 onwards (fuel consumption x emission factor)
- UK expecting ca. 1,500 monitoring plan submissions by 31st August for approval by 31st December 2009 (Europe ca. 6,800)
- Special geographical and scale of operator challenges
- Commission may adopt detailed provisions for verification (amended Article 15)
- MRG amended and common templates planned

Latest EU ETS Development: CCS

- MRG amendments to cover carbon capture and storage
  - Appropriate changes to the general guidelines of Annex I and to Annex XII (Guidelines for determination of emissions or amount of transfer of GHG by CEMS)
  - Annex XVI Capture
  - Annex XVII Transport
  - Annex XVIII Geological storage (MRV only in the event of leakage)
    - Uncertainty supplement approach
- Approved by the EC Climate Change Committee 16th March 2009

Revision of the EU ETS Directive

- For Phase 3 (from 1st January 2013)
- Extensions to proposed listed activities and gases
- Further revision awaiting outcome of COP15
- DECC planning 10 main work-streams, including on benchmarking, carbon leakage, auction design, and MRV
- Main issues MRV:
  - Article 14: Commission adoption of an M&R Regulation
  - Article 15: Commission adoption of a Regulation for verification of emission reports, and for accreditation and supervision of verifiers

  (Both by 31st December 2011)

Environment Agency

Compliance and Enforcement Issues 1

In general, require:

- A level playing field:
  - "A tonne is a tonne"; a common currency; for
  - Credibility
  - Linking
- Complete coverage of central requirements in domestic/regional legislation and permits/monitoring plans
- Common understanding and efficiencies: Template forms and reports; succinct guidance; electronic systems including helpdesks
- Reasonable flexibility
  - Different routes to the same outcome
  - Sound control system and quality assurance provisions

Compliance and Enforcement Issues 2

Regulatory Concerns:

- Approval of permits/monitoring plans
- Duty to enforce compliance with M&R conditions
- Enforcement Notices (to rectify contravention of M&R conditions)
- Checking of annual emission reports/verifier reports
- Power to determine reportable emissions
- Inspections - sufficient/proportionate; risk based
- Provisions for ‘entry’; and variation, surrender, revocation of permits/plans
- Improvement mechanism/account of verifier recommendations

Compliance and Enforcement Issues 3

- Meaningful sanctions/penalties (compared to the cost of carbon)
- Efficient system for imposing sanctions and penalties, and encouraging resumed compliance
- Civil penalties (better regulation)
- Costs
  - Need for robust data and affordable implementation/enforcement
  - Some problems with disproportionate costs for ‘small’ operators; proportionate approaches
  - Risk based approaches

Environment Agency

EC Forums and Technical Working Groups

- Further European Commission initiative **to improve the efficiency and consistency** of EU ETS implementation
- WG 3 Emissions Trading Group (CCC)
- Compliance Conference/Compliance Forum
- Verification Forum
- M&R Technical Working Group
- Verification, Accreditation and Accreditation Control Project Group
- Auctioning Technical Working Group
- Benchmarking Technical Working Group
- Aviation Technical Working Group – standard templates
- Etc.

EU ETS Compliance Forum

Objectives to:

- Strengthen, harmonise and raise the profile of the EU ETS Compliance Chain
- Improve communications between CAs to share experiences and best practice
- Raise the importance of consistent implementation to ensure common outcomes and integrity of the scheme
- Identify issues to be resolved/capacity build
- Bring together relevant stakeholders

EU ETS Compliance Forum: Tasks

- Aviation Implementation: 1. FAQ; 2. Exemplars and Guidance; 3. Approval of MPs, Enforcement and Sanctions
- E-reporting and use of IT in emissions trading
- Capacity building, compliance training, and inspections
- Communications (web-site, newsletter, digital forum)
- Interface with verification and accreditation
- Carbon capture and storage
- Auctioning
- Preparing for Phase 3 (the revised Directive)

- Compliance Conference: 3rd & 4th September 2009

IMPEL

- European Network for Implementation and Enforcement of Environmental Law

- Three EU ETS Projects to date:
  - I. Identifying Good Regulatory Practice In The EU Emissions Trading Scheme
  - II. Options and Proposals for Consistency in the Implementation of the EU Emissions Trading Scheme
    - Small installations;
    - Verification;
    - Compliance and enforcement; and
    - Monitoring and reporting.
  - III. Proposals for future development of the EU Emissions Trading Scheme – Phase II & beyond (Annex 5: technical guidance notes)

- See: http://ec.europa.eu/environment/impel/eu_ets.htm

Environment Agency

Concluding Comments

- An ETS puts emphasis on what rather than how
- It establishes maximum allowable emission level (compressed cap)
- It enforces the cap with increased emphasis on robust MRVCE and allowance surrender obligations
- It avoids dictating how each source is to comply (no elvs), and provides an incentive to go beyond allocations
- It puts a price on the emission
- Harmonised implementation important for equity and confidence - need a common currency
- Global linking should be the goal (common outputs likely to be more important than completely common structures)

Questions and Answers

Environment Agency

The EU Emissions Trading Scheme: MRVCE

Rob Gemmill
rob.gemmill@environment-agency.gov.uk
Technical Advisor
WCI Markets Task 2 (22nd June 2009)

Western Climate Initiative News

June 26, 2009

This status report is issued on the last Friday of each month from WCI Partner jurisdictions to all interested stakeholders via the WCI listserv and website.

In This Issue

Upcoming Events

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WCI Submits Comments on U.S. EPA Proposed Endangerment Finding

Quebec Passes Cap-and-Trade Legislation

Ontario Proposed Cap-and-Trade Legislation

Documents Planned for Release in July

Upcoming Events

July 6: Presentation to the WCI Markets Committeee

Jackie Huggins, Manager of Verification Services at The Climate Registry will discuss compliance, verification, and enforcement issues on Monday, July 6 from 8:30 - 10:00 a.m. Pacific Time. Details are posted on the WCI website.

July 21: WCI Partners Meeting

Stakeholders are invited to attend the next WCI Partners meeting either in-person or via teleconference, starting at 1:00 p.m. on Tuesday, July 21. The meeting will be held at The Nines Hotel in Portland, Oregon. To join the teleconference, dial 1-800-868-1837 toll free in the U.S. and Canada (1-404-920-6440 for outside the U.S. and Canada), and enter participant code 659537#. Follow this link to access the webinar portion of the meeting. Additional details will be posted to the WCI website as they become available.

WCI and Other Regional Initiatives Share Lessons and Discuss Roles

On Tuesday, June 23, 2009, representatives of the three U.S. and Canadian initiatives pursuing regional greenhouse gas reduction programs, including regional cap-and-trade programs, held their first joint meeting in Washington, DC.

Together, the Regional Greenhouse Gas Initiative, the Midwest Greenhouse Gas Reduction Accord, and the Western Climate Initiative involve 23 U.S. states and 4 Canadian provinces as members. Additional U.S. states, Mexican states, and Canadian provinces participate as official observers to these initiatives.

U.S. states participating in the three regional initiatives encompass about half of the U.S. population and GDP and ⅓ of all U.S. GHG emissions. Canadian provinces participating in the three regional initiatives account for more than ¾ of the Canadian population and GDP and nearly ½ of Canadian GHG emissions.

The purpose of the meeting was to:

- Share information on the status and future plans of each regional initiative.
- Identify and discuss issues on which inter-regional collaboration and information sharing may be beneficial to the ongoing program development activities of each regional group.

- Discuss the current status of US federal legislation, focusing on issues that have the most relevance to states and the regional initiatives.
- Explore the role of states and the regional initiatives under emerging federal programs (legislative and regulatory).

State and Provincial representatives participating in the meeting emphasized the importance of federal action and the critical role of states and provinces in the development and implementation of national programs. They also identified several areas of commonality and committed to continue to work together.

Complementary Policies Work Plan Available

The WCI Partners have approved the work plan for the WCI Complementary Policies Committee, which is available on the WCI website. This document will guide the deliberations of the Committee, which has been formed to evaluate and recommend to the WCI Partner jurisdictions complementary policies that will aid in achieving regional emissions reduction goals across all sectors of the economy, if these policies are adopted by some or all of the WCI Partner jurisdictions. The Complementary Policies Committee work plan was announced and summarized at the WCI public meeting on May 27. While the WCI Partners are not seeking formal comment on this document, the WCI Partners value feedback and will consider any comments that are submitted.

WCI Submits Comments To The U.S. EPA On Its Proposed Rule For Mandatory Reporting Of Greenhouse Gases

The WCI comments were submitted on June 9, 2009, and can be viewed on the WCI website.

WCI Submits Comments To The U.S. EPA On Its Proposed Endangerment Finding

The WCI comments were submitted on June 23, 2009, and can be viewed on the WCI website.

Quebec Passes Cap-and-Trade Legislation

On June 18, 2009, legislationwas adopted in Quebec which authorizes the government to implement a cap-and-trade system for greenhouse gases in North America, per its commitment to the WCI.

Ontario Proposes Cap-and-Trade Legislation

On May 27, 2009, the Ontario government introduced enabling legislation that if passed, would allow the implementation of a cap-and-trade system through future regulations that can link to the WCI and other emerging North American systems. To complement the proposed legislation, the Ontario government is seeking stakeholder comments on a discussion paper to inform the development of potential future regulations. The paper and proposed legislation are available at Ontario's Environmental Registry under number 010-6740.

Documents Planned for Release in July

The following documents are planned for release in July. Announcements will be sent through the WCI listserv as they become available, including information on how to submit comments.

- Final Essential Requirements for Mandatory GHG Reporting
- Offsets System Essential Elements White Paper
- Regional Emissions Database Reporting Options White Paper
- Implementation Update on the First Jurisdictional Deliverer Approach to Regulating Electricity Imports
- Draft Statement of Principles for Addressing Competitiveness Issues
- Phase III Economic Modeling Results and Revised Assumptions Book

The Climate Registry's Accreditation Program

The Climate Registry

Presented to WCI Markets Task 2 Compliance Verification and Enforcement (CVE) Group

July 6, 2009

Overview

- The Climate Registry's Accreditation Process
- The Climate Registry's Role and Responsibilities
- The Accreditation Body's Role and Responsibilities
- Dispute Resolution
- Enforcement
- Considerations/Next Steps for the WCI

The Process of Accreditation

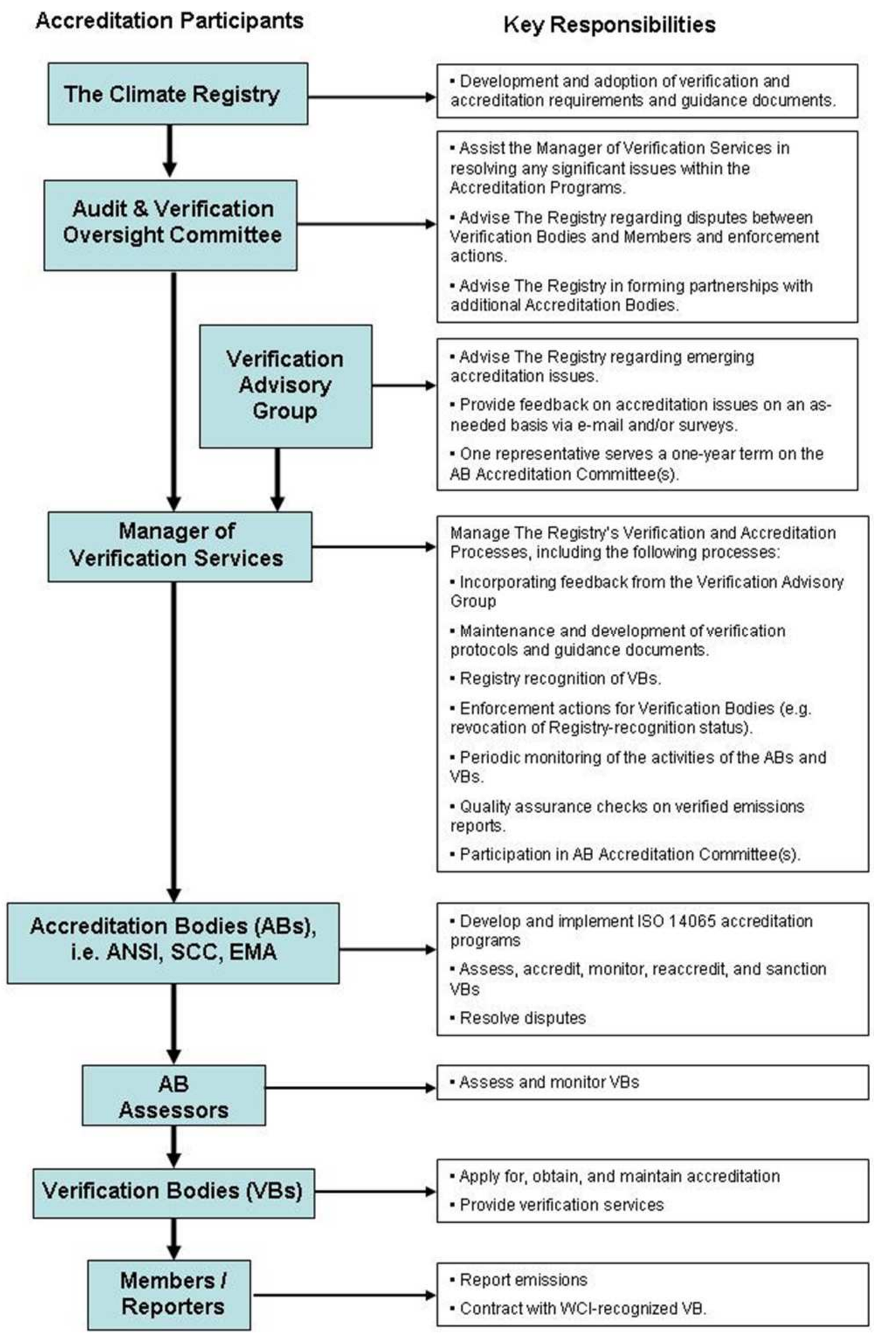
- Consistent with approach to accreditation for other schemes
  - Management systems or product certification
- Consistent with international approaches
  - ISO 14065
  - International Accreditation Forum (IAF) Mandatory Document for the Application of ISO 14065
- 3 stages :
  - Initial accreditation
  - Surveillance for maintenance of accreditation
  - Re-accreditation at the end of the cycle

ISO 14065 Requirements - Summary

- Verification Process Management System
- Impartiality
- Competency
- Personnel deployment & management
- Communications
- Records maintenance
- Verification processes must demonstrate:
  - VB applies ISO14064-3 & Registry's GVP requirements

Organizational Structure

The Climate Registry's Accreditation Organization Chart



Guidance on Accreditation (GoA)

for Verification Bodies

Provides overview of processes and requirements that Verification Bodies seeking recognition by The Climate Registry must meet:

http://www.theclimateregistry.org/downloads/GoA.pdf

The Climate Registry

Structure of the GoA

- Background
  - Relationships and responsibilities
- The Accreditation Processes
- Accreditation Requirements
  - ISO 14065
  - Registry-specific additional requirements
- Frequently Asked Questions
- Appendices: Including Accreditation Body-Specific Processes

Witness Assessments

- Three options for Verification Bodies to complete witness assessments:
  - TCR Members
  - CCAR Members
  - An entity that has produced an emissions inventory of at least 6 months of data consistent with the requirements of TCR's GRP.

Key Registry-Specific Criteria

- Knowledge of The Climate Registry's program requirements
- Consent to observation of verification by Verification Oversight Panel
- Compliance with COI process as described in GVP
- Liability insurance of at least $1,000,000
- Personnel competence expectations
- Requirement for 2 Lead Verifiers
- Provisions for use of subcontractors
- Reporting of engagement activity
- Record retention (5 years)

The Climate Registry

ANSI's Responsibilities

- Review VB applications
- Assess the professional credibility of the VBs
- Ensure that VBs possess the requisite knowledge, competence and impartiality
- Issue certificates of accreditation to VBs
- Monitor VBs
- Implement investigations and/or sanctions against accredited VBs, when necessary
- Manage the Accreditation Committee (through which the Registry will participate in key accreditation decisions)
- Prepare an annual report for the Registry
- Re-accredit

The Climate Registry

Registry's Oversight Role

- Develop Verification Program criteria
- Develop Registry-specific accreditation criteria
- Assist Accreditation Bodies (ABs) with accreditation decisions
- Monitoring/oversight of ABs and Verification Bodies (VBs)
- Contribute to appeals/dispute/conflict investigation and resolution process
- Participate in sanctioning
- Assess and improve program
- Audit and Verification Oversight Committee is responsible for high level oversight of accreditation and verification programs

Dispute Resolution

- Order of appeals:
  - Verification Body's internal dispute resolution process (in consultation with The Registry as necessary to resolve questions)
  - Request resolution from Accreditation Body
    - Either party may appeal
    - AB decisions is binding on Reporter and VB
    - VB is not required to agree or issue new statement

The Climate Registry

ISO 14065 Requirements for Appeals, and Complaints

- Documented process
- Publicly available upon request
- Persons engaged in resolution are different from those who carried out the validation or verification and prepared statements on the GHG assertion
- Provide complainant/appellant with reports and formal notice of the outcome
- Ensure that decisions on appeals do not result in any discriminatory actions against the complainant/ appellant.

The Climate Registry

ANSI Enforcement

ANSI may suspend, reduce or withdraw its accreditation of a Verification Body if any of the following occur:

a) Filing of any voluntary or involuntary petition of bankruptcy;

b) Making of any arrangement with creditors or holding of "composition of creditors" action in regard to financial difficulties or bankruptcy proceedings;

c) Appointment of a receiver for the business;

d) Voluntary or involuntary liquidation of the business or the organization;

e) Discontinuance of the accredited V/V Body program;

ANSI Enforcement

a) Failure by the V/V Body to take appropriate and timely corrective action on deficiencies in its program that have been requested by ANSI;

b) Persistent failure by a V/V Body to conform with the accreditation criteria, ANSI procedures or other program requirements, including sector- or GHG program-specific requirements

c) Inability or unwillingness of the V/V Body to ensure conformity of its clients with applicable verification/validation requirements

d) Improper use of the certificate of accreditation or ANSI accreditation mark

e) Failure to meet the requirements of accreditation or to abide by the rules for accreditation;

f) Failure to meet financial obligations to ANSI

g) Falsification of any nature

The Climate Registry

The Climate Registry Enforcement

The Climate Registry can:

- Issue warnings,
- Suspend or revoke Registry recognition, and/or
- Annul verification statements

In response to issues such as:

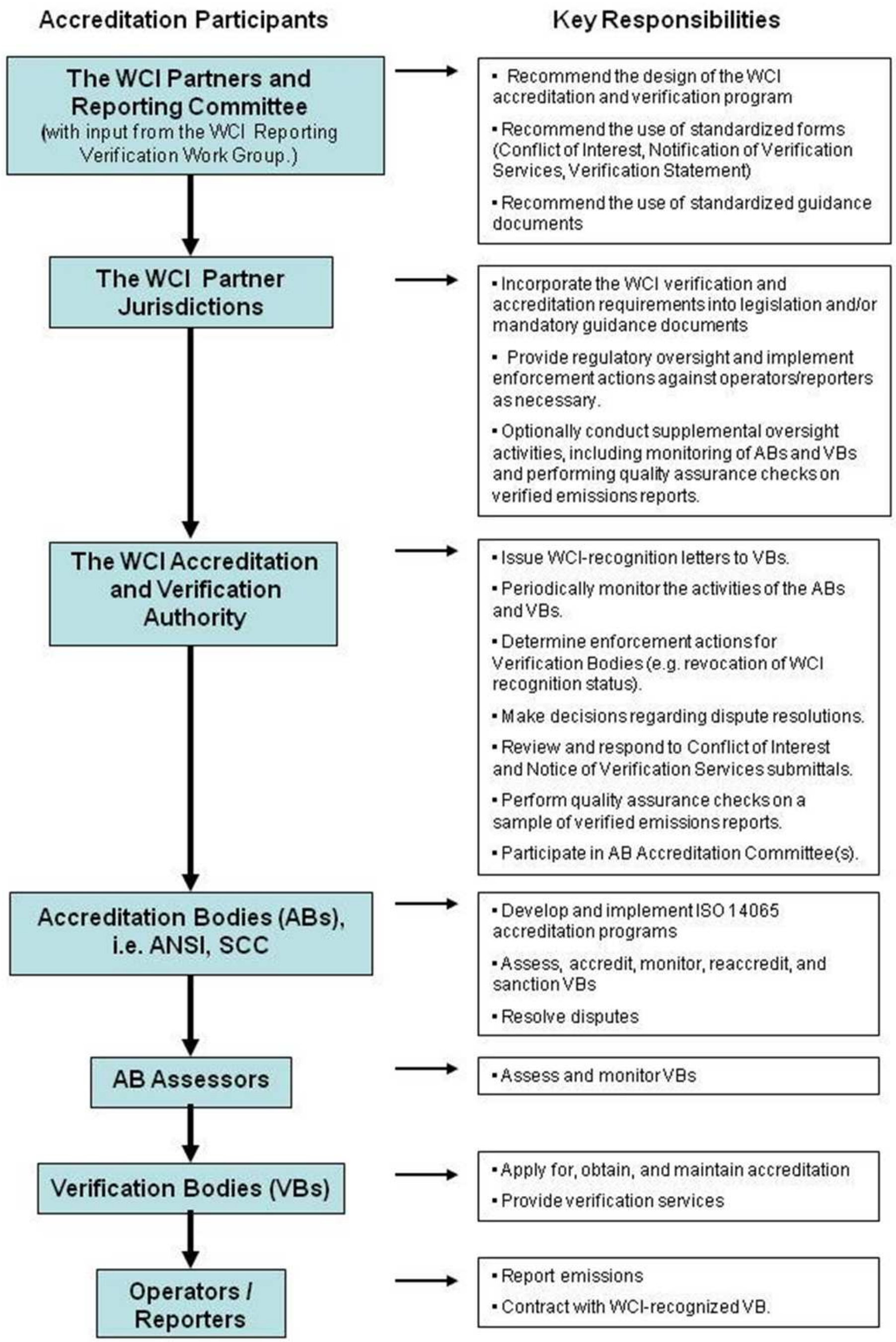
- Nonconformance with accreditation criteria
- ANSI and/or other GHG program enforcement action
- Submittal of incorrect/false COI assessments
- Significant concerns identified through oversight/surveillance activities

WCI Accreditation Program Goals

- Standardized, consistent accreditation process for the WCI region to ensure that qualified VBs conduct verification services according to WCI's requirements.
- Administrative simplicity for reporters and VBs.
- Efficient, cost-effective centralized program to reduce redundancy in resources allocated by jurisdictions.
- Flexible program to ensure jurisdictions can conduct additional oversight activities.
- Coordinated enforcement action (e.g. revocation of a VB's WCI-recognition status).

The Climate Registry

A Model for WCI Accreditation



Accreditation Considerations

- Partnership with ANSI and SCC
- WCI must define accreditation requirements for Verification Bodies
  - Demonstration of knowledge of the WCI program requirements
  - Appropriate level of professional indemnity insurance for VBs
  - WCI rules for VB use of subcontractors
  - Records retention requirements for VBs
  - Dispute resolution process (and how relates to AB process)
  - Etc.

Management Considerations

- WCI program management consideration
  - How much oversight does WCI want to have over the accreditation process and verification process?
  - How involved does WCI want to be with respect to COI?
  - How involved does WCI want to be with respect to monitoring VBs (surveillance audits, etc.)
- TCR is interested in providing services to promote a common, centralized, and streamlined accreditation administrative process.

Summary

The following documents are great resources to learn more about our program:

- Our website: www.theclimateregistry.org
- General Reporting Protocol (GRP)
  - http://www.theclimateregistry.org/downloads/GVP.pdf
- Updates and Clarifications to the GRP
  - Member Resources > Reporting Protocols > General Reporting Protocol
- General Verification Protocol (GVP)
  - http://www.theclimateregistry.org/downloads/GVP.pdf
- Updates and Clarifications to the GVP
  - Member Resources > Verification > GVP
- Guidance on Accreditation (GoA)
  - http://www.theclimateregistry.org/downloads/GoA.pdf

Questions?

Jackie Huggins

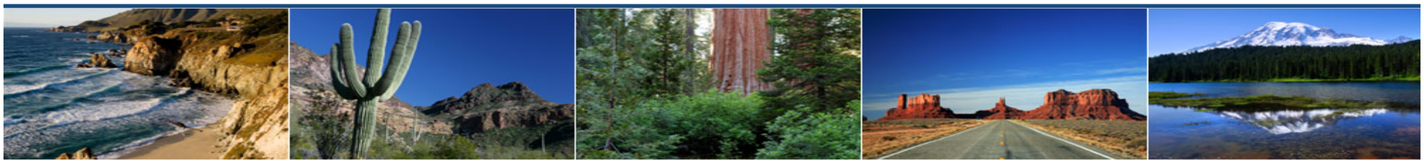
Manager, Verification Services

201-238-2572

jackie@theclimateregistry.org

The Climate Registry

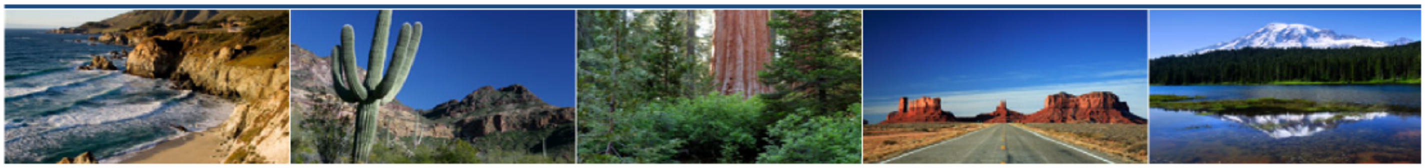
Western Climate Initiative



Final Essential Requirements of Mandatory Reporting

July 15, 2009

Western Climate Initiative



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EMISSIONS QUANTIFICATION, AND SAMPLING, ANALYSIS AND MEASUREMENT

§ WCI.20 through § WCI.xx

[These Essential Requirements for Reporting include placeholder references to requirements for reporting GHG emissions from the combustion of residential, commercial and industrial fuels and electricity imports that have not yet been completed by the WCI and will not go into effect for the 2010 reporting year. WCI Partner Jurisdictions may omit these references until they amend their rules to include reporting requirements for these sectors.]

§ WCI.0 PURPOSE

This rule requires mandatory reporting and verification of greenhouse gas (GHG) emissions data by certain facilities that directly emit GHG, by importers of electricity, and by suppliers of fossil fuels. The GHGs that must be reported under this rule are carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFC), perfluorocarbons (PFC), and sulfur hexafluoride (SF_6).

§ WCI.1 APPLICABILITY

(a) The GHG emissions reporting requirements, and related monitoring, recordkeeping, and verification requirements of this rule apply to the owners and operators *[Each jurisdiction will select the specific terminology for the regulated persons in accordance with its customary rule-writing practices]* of any facility that meets the requirements of paragraph (a)(1) of this section; and any fuel suppliers and electricity importers that meet the requirements of paragraph (a)(2), (a)(3), or (a)(4) of this section:

(1) Any facility that emits 10,000 metric tons CO_2e or more per year in combined emissions from one or more of the source categories listed in this paragraph in any calendar year starting in 2010.

[Please note that the quantification and monitoring methods for many of these source categories are currently being assessed. Only source categories for which adequate quantification methods exist will be included in the final WCI Essential Requirements for mandatory reporting.]

Adipic acid manufacturing
Aluminum manufacturing
Ammonia manufacturing [*still being assessed*]
Carbon dioxide transfer recipients [*still being assessed*]
Cement manufacturing
Coal mine fugitive emissions (active and abandoned)
Coal storage
Cogeneration
Electricity generation
Electronics Manufacturing [*still being assessed*]
Ferroalloy production [*still being assessed*]
General stationary fuel combustion
Glass Production and other uses of carbonates [*still being assessed*]
HCFC-22 production [*still being assessed*]
Hydrogen production
Industrial wastewater [still being assessed for some industries]
Iron and steel manufacturing
Lead production

Lime manufacturing
Magnesium production [still being assessed]
Natural gas transmission and distribution systems *[still being assessed]*
Nitric acid manufacturing *[still being assessed]*
Nonroad equipment at facilities *[still being assessed]*
Oil and gas production & gas processing *[still being assessed]*
Petrochemical production
Petroleum refineries
Phosphoric acid production *[still being assessed]*
Pulp and paper manufacturing
Refinery fuel gas
SF_6 from electrical equipment *[still being assessed]*
Soda ash manufacturing
Zinc production

(2) All importers of electricity. Importers of electricity include both retail providers and marketers that import electricity into the WCI region. *[This is preliminary language, pending definition of electricity importers by another WCI Committee.]*

(3) Any supplier that within the WCI region distributes transportation fuels in quantities that when combusted would emit 10,000 metric tons CO_2e per year or more in any calendar year starting in 2010. *[This is preliminary language, pending future determination of point of regulation for transportation fuels.]*

(4) Any supplier that distributes within the WCI region residential, commercial, and industrial fuels in quantities that when combusted would emit 10,000 metric tons CO_2e per year or more in any calendar year starting in 2010. *[This is preliminary language, pending future determination of points of regulation for these fuels.]*

(b) To calculate GHG emissions for comparison to the 10,000 metric ton CO_2e per year emission threshold in paragraph (a)(1) of this section, the owner or operator shall calculate annual CO_2e emissions, as described in paragraphs (b)(1) through (b)(4) of this section.

(1) Estimate the annual emissions of CO_2, CH_4, N_2O, HFC, PFC, and SF_6 in metric tons for each unit, process, activity, or operation for which emission calculation methodologies are provided in sections WCI.20 through WCI.XX. The GHG emissions shall be calculated using methodologies specified in each applicable section.

(2) For stationary combustion units, carbon dioxide emissions from the combustion of biomass fuels shall be included in the calculations, with the following exceptions:

(A) Until such time as [jurisdiction] has made a determination regarding the carbon neutrality of any biomass fuels, a maximum of 15,000 metric tons of carbon dioxide emissions from the combustion of pure solid biomass fuel may be excluded from calculation of GHG emissions for comparison to the 10,000 metric ton CO_2e per year emission threshold in paragraph (a)(1) of this section, provided that total GHG emissions including emissions from solid biomass fuel are less than 25,000 metric tons CO_2e.

(B) After such time as [jurisdiction] has made a determination regarding the carbon neutrality of any biomass fuels, the carbon dioxide emissions from the combustion of those fuels may be excluded from calculation of GHG emissions for determining whether the 10,000 metric tons CO_2e per year emission threshold in paragraph (a)(1) of this section has been met.

[A WCI Partner jurisdiction may, in its discretion, choose to require carbon dioxide emissions from the combustion of biomass fuel to be included in the determination of stationary combustion units that are required to report and may require that those emissions be reported separately from emissions from fossil fuels.]

(3) Sum the total facility emissions for each GHG and calculate the metric tons of CO_2e using equation 1-1 below.

$$CO_2e = \sum_{i=1}^{n} GHG_i \times \mathrm{GWP}_i$$ **Equation 1-1**

Where:

CO_2e = Carbon dioxide equivalent, metric tons/year.
GHG_i = Mass emissions of each greenhouse gas emitted, metric tons/year.
GWP_i = Global warming potential for each greenhouse gas from Table WCI.10-1 of this regulation.
n = The number of greenhouse gases emitted.

(4) For purpose of determining if an emission threshold has been exceeded, any CO_2 that is captured for on-site use, on-site storage, or transfer off-site must be included in the emissions total.

(c) To calculate GHG emissions for comparison to the 10,000 metric ton CO_2e per year emission threshold for suppliers of transportation fuels in paragraphs (a)(3) of this section, the owner or operator shall follow the procedures of paragraphs (c)(1) through (c)(2) below:

(1) Calculate the total mass in metric tons per year of CO_2, CH_4, and N_2O that would result from the complete combustion or oxidation of all transportation fuels that are distributed within the WCI region. The mass of each GHG shall be calculated using any of the applicable methodologies specified in section WCI.XX [Transportation Fuels Combustion] of this rule.

(2) Sum the emissions of each GHG and calculate total metric tons of CO_2e using Equation 1-1 of this rule.

(d) To calculate GHG emissions for comparison to the 10,000 metric ton CO_2e per year emission threshold for suppliers of residential, commercial, and industrial fuels in paragraph (a)(4) of this section, the owner or operator shall follow the procedures of paragraphs (d)(1) and (d)(2) below:

(1) Calculate the total mass in metric tons per year of CO_2, CH_4, and N_2O that would result from the complete combustion or oxidation of all residential, commercial, and industrial fuels that are distributed within the WCI region. The calculation shall exclude any fuels that are supplied to facilities that are required to report GHG emissions under section WCI.1(a)(1). *[These accounting issues will be dealt with later in 2009 or in 2010.]* The mass of each GHG shall be calculated using any of the applicable methodologies

specified in section WCI.XX [Residential, Commercial and Industrial Fuels Combustion] of this rule.

(2) Sum the emissions of each GHG and calculate total metric tons of CO_2e using Equation 1-1 of this rule.

(e) If the operations of a facility or fuel supplier that is subject to this rule change such that emissions fall below 10,000 metric tons CO_2e per year, then the following reporting requirements shall apply:

(1) If, prior to such emission reduction, the emissions report was subject to the verification requirements of this rule; then the owner or operator shall continue to submit emission reports until reported emissions are below 10,000 metric tons CO_2e per year for a minimum of 3 consecutive years. If reported emission are less than 10,000 metric tons CO_2 per year during 3 consecutive years, then the owner or operator shall be exempted from further reporting until CO_2e emissions again exceed 10,000 metric tons in any future calendar year.

(2) If, prior to such emission reduction, the emissions report was not subject to the verification requirements of this rule; then the owner or operator shall submit to the *[jurisdiction]* a signed statement certifying that emissions are less than 10,000 metric tons CO_2e during the prior year. After certifying that emissions are below 10,000 metric tons CO_2e per year for 3 consecutive years, the owner or operator shall be exempted from further reporting until CO_2e emissions again exceed 10,000 metric tons in any future calendar year.

(3) Notwithstanding the requirements of paragraphs (e)(1) and (2) of this section, a facility or fuel supplier that is a covered entity under the WCI cap-and-trade program must continue to submit annual emissions reports.

(f) Upon request by the [*jurisdiction*], owner or operator of any facility or fuel supply operation must submit a demonstration that emissions have not exceeded one or more of the applicability criteria specified in this section in any year since 2010. Such demonstration shall be provided to the [*jurisdiction*] within 20 working days of receipt of a written request.

§ WCI.2 GENERAL GREENHOUSE GAS REPORTING REQUIREMENTS AND SCHEDULE

[Specific requirements of this section may change based on the future final design of the market trading program.]

(a) General. Owners or operators that are subject to this rule must submit an annual GHG emissions report. Owners and operators must collect data; calculate GHG emissions; and follow the procedures for quality assurance, missing data, recordkeeping, and reporting as specified in these General Provisions and in each relevant section WCI.20 through WCI.XX of this rule.

[WCI jurisdictions have the flexibility during the first year of reporting, 2010, to allow the application of Best available data and methods (as defined in WCI.9) in circumstances in which owners and operators demonstrate that they require additional time, for example, to install equipment and institute procedures that are required for reporting.]

(1) A facility, fuel supplier, or electricity importer that commenced operation before January 1, 2010, must report emissions beginning in 2011 for GHGs emitted in calendar year 2010.

(2) A new facility, fuel supplier, or electricity importer that commences operation on or after January 1, 2010, must report emissions for the first calendar year in which the facility operates, beginning with the first operating month and ending on December 31 of that year. Each subsequent annual report must cover emissions for the calendar year, beginning on January 1 and ending on December 31.

(b) Reporting and Verification Schedule.

(1) Annual GHG emissions reports must be submitted to [*the jurisdiction*] by April 1 of each year for emissions in the previous calendar year.

(2) Reporters subject to the verification requirements of WCI.8, must complete their verification process, including submittal of a verification statement to [*the jurisdiction*], according to the following schedule:

(A) For reporting years 2010 through 2011, September 1 of the year following the reporting year.

(B) For reporting years 2012 and later, *[date to be determined]*.

(c) Submission of GHG Emissions Report. The annual GHG emissions report must be submitted to [*the jurisdiction*] in a format [*to be specified by each jurisdiction*].

(d) Simplified Emission Calculation Methods for De Minimis Sources. The owner or operator may elect to designate as de minimis one or more sources or pollutants that collectively emit no more than 3 percent of the facility's total CO_2e emissions, but not to exceed 20,000 metric tons CO_2e. The owner or operator may estimate emissions for these de minimis sources using alternative methods to those required to be used by this rule. If verification of the emissions report is required by this rule, then the selection of any alternative GHG calculation method is subject to the concurrence of the verification team that the use of such methods provides reasonable assurance that the emissions so designated do not exceed the applicable de minimis limits. The operator shall separately identify and include in the emissions data report the emissions from designated de minimis sources.

(e) To ensure accuracy of reported data and the ability to conduct audits and/or verifications of each emissions data report, the owner or operator shall establish and maintain data acquisition and handling activities that provide for the transparency and verifiability of emissions calculations and supporting information consistent with section WCI.4.

[As a means of assuring a smooth verification process and a positive verification opinion WCI jurisdictions may also require or advise in guidance materials that facilities have a full GHG inventory management plan.]

(f) GHG Emissions Report Revisions.

(1) The owner or operator shall maintain documentation to support any revisions made to a previously submitted annual GHG emissions report. Documentation for all revisions shall be retained by the operator for 7 years.

(2) If, after the verification deadline, a report subject to verification is found to contain an error, or accumulation of errors, greater than 5 percent of the total CO_2e emissions reported, the owner or operator shall revise and resubmit an annual GHG emissions report within 60 days of the finding. To the extent possible, the revised report must correct all identified errors. A revised report will be accepted only if verified according to WCI.8 and approved by [*the jurisdiction*]. [The jurisdiction] will send notification of approval or disapproval and an explanation of the reasons for any disapproval within 60 days of receipt of the revised report.

(3) If, after the report submittal deadline, a report not subject to verification is found to contain an error, or accumulation of errors, greater than 5 percent of the total CO_2e emissions reported, the owner or operator shall revise and resubmit an annual GHG emissions report within 30 days of the finding. To the extent possible, the revised report must correct all identified errors. A revised report will be accepted only if approved by [*the jurisdiction*]. [The jurisdiction] will send notification of approval or disapproval and an explanation of the reasons for any disapproval within 60 days of receipt of the revised report.

(4) An owner or operator that voluntarily chooses to correct errors of 5 percent or less in total CO_2e emissions reported may do so according to the following requirements:

(A) For reports subject to verification, a revised report will be accepted only if verified according to WCI.8 and approved by [*the jurisdiction*].

(B) For reports not subject to verification, a revised report will be accepted if approved by [*the jurisdiction*].

(g) Where this rule specifies a choice between use of a fuel-based or mass balance-based calculation or use of a continuous emissions monitoring system (CEMS) to calculate CO_2 emissions, the operator shall make this choice and continue to use the method chosen for all future emissions data reports, unless the use of the alternative calculation method is approved in advance by *[the jurisdiction]*.

§ WCI.3 CONTENTS OF THE GREENHOUSE GAS EMISSIONS REPORT

Each annual GHG emissions report shall contain the following information:

(a) Facility name, identification number, physical address, mailing address, and NAICS code.

(b) Reporting year.

(c) Date of report submittal.

(d) Total facility emissions aggregated from all applicable source categories in subparts WCI.20 through WCI.XX expressed in metric tons of CO_2e calculated using Equation 1-1 of section WCI.1, excluding emissions from CO_2 that is captured and CO_2 emissions from the combustion of biomass and biomass-derived fuels, which are reported separately.

(e) Total facility emissions of CO_2 from the combustion of biomass and biomass-derived fuels.

(f) Total annual mass of CO_2 captured for on-site use, on-site storage, or transfer off site, in metric tons.

(g) For applicable fuel supplier categories in subparts WCI.XX [Transportation Fuels Combustion] and WCI.XX [Residential, Commercial and Industrial Fuels Combustion], total CO_2e emissions aggregated from all specified fuels.

(h) Emissions from each applicable source category or fuel supplier category in subparts WCI.20 through WCI.XX, expressed in metric tons per year of CO_2, CH_4, N_2O, HFC, PFC, and SF_6. CO_2 emissions from the combustion of biomass and biomass-derived fuels shall be reported separately.

(i) For electricity importers, the information required by WCI.XX [Electricity Imports].

(j) Emissions and other data for individual units, processes, activities, and operations as specified for each source category in sections WCI.20 through WCI.XX of this rule.

(k) Emission factors developed or measured by the operator using approved source testing as provided under sections WCI.20 through WCI.XX. Emission factors shall be provided in units of emissions per amount of fuel consumed, where fuel is reported in the units specified in this regulation.

(l) Mass emissions from each designated de minimis source or pollutant, reported in metric tons per year of each GHG for which an alternative emission calculation method is used.

(m) Name and contact information including e-mail address and telephone number of the person primarily responsible for preparing and submitting the emissions report.

(n) [only applicable in United States jurisdictions] A signed and dated statement provided by the owner or operator, or their designated representative, certifying that the report has been prepared in accordance with this rule and that, subject to verification, the statements and information contained in the emissions data report are true, accurate, and complete to the best of their knowledge.

(o) [only applicable in Canadian jurisdictions] A statement signed and dated by the operator's representative, certifying that:

  (1) The operator's representative has examined the emissions report and ensured that it is complete and accurate; and

  (2) The emissions report has been prepared in accordance with this rule and that the statements and information contained in the emissions report are true and fair to the best of the knowledge of the operator's representative.

§ WCI.4 DOCUMENT RETENTION AND RECORD KEEPING REQUIREMENTS

(a) The operator shall establish and maintain procedures for document retention and record keeping. The operator shall retain all documents regarding the design, development and maintenance of the GHG inventory in paper, electronic or other usable format for a period of not less than 7 years following submission of each emissions data report. The retained documents, including GHG emissions data, shall be sufficient to allow for the verification of each emissions data report.

(b) Upon request by *[jurisdiction]*, the operator shall provide within 10 working days all documents and data used to develop an emissions data report.

(c) In addition to information submitted as part of the emissions data report, each operator shall retain, at a minimum, the following information, if applicable, for at least 7 years after the submission of the report:

(1) A list of all GHG sources (i.e., units, operations, processes, and activities) included in the emission estimates.

(2) All records and documents used to calculate emissions for each source, categorized by process and fuel or material type.

(3) Documentation of the process for collecting emissions data.

(4) Any GHG emissions calculations and methods used;

(5) All emission factors used for emission estimates, including documentation for any factors not provided in the rule.

(6) All input data used for emission estimates.

(7) Documentation of biomass fractions for specific fuels.

(8) All other data submitted to the [*jurisdiction*] under this rule, including the GHG emissions report.

(9) All computations made to gap-fill missing data.

(10) Names and documentation of key facility personnel involved in emissions calculating and reporting;

(11) Any other information that is required for the verification of the GHG emissions report.

(12) A log to be prepared for each reporting year, beginning January 1, documenting all procedural changes made in GHG accounting methods and changes to instrumentation for GHG emissions estimation.

(13) Documentation of the data acquisition and handling activities required by WCI.2(e).

(d) For measurement based methodologies, the following information, if applicable, also must be retained for at least 7 years after the submission of the emissions data report:

(1) List of all emission points monitored.

(2) Collected monitoring data.

(3) Any quality assurance and quality control information collected in accordance with the data acquisition and handling activities required by WCI.2(e).

(4) A detailed technical description of the continuous measurement system, including documentation of any findings and approvals by federal, State or local agencies.

(5) Raw and aggregated data from the continuous measurement system.

(6) A log book of all system down-times, calibrations, servicing, and maintenance of the continuous measurement system.

(7) Documentation of any changes in the continuous measurement system over time.

§ WCI.5 COMPLIANCE AND ENFORCEMENT

(a) Submission of false or misleading information to the *[jurisdiction]* or a verification body shall constitute a single, separate violation of the requirements of this article for each day after the information has been received by the Executive Officer or verification body. *[Partners must be able to enforce this provision in the absence of evidence of intent, e.g., strict or absolute liability, depending on the jurisdiction.]*

(b) Each violation of this rule shall constitute a single, separate violation for each day the violation continues.

§ WCI.6 INCORPORATION BY REFERENCE

The following documents are incorporated by reference into this rule. These materials are incorporated as they exist on the date this article is adopted.

(a) The following materials are available for purchase from the following addresses: American Society for Testing and Material (ASTM), 100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428-B2959; and the University Microfilms International, 300 North Zeeb Road, Ann Arbor, Michigan 48106:

(1) ASTM D240-02, (Reapproved 2007), Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter.

(2) ASTM D388-05, Standard Classification of Coals by Rank.

(3) ASTM D396-08, Standard Specification for Fuel Oils.

(4) ASTM D975-08, Standard Specification for Diesel Fuel Oils.

(5) ASTM D1250-07, Standard Guide for Use of the Petroleum Measurement Tables.

(6) ASTM D1826-94 (Reapproved 2003), Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter.

(7) ASTM Specification D1835-05 (2005).

(8) ASTM D1945-03 (Reapproved 2006), Standard Test Method for Analysis of Natural Gas by Gas Chromatography.

(9) ASTM D1946-90 (Reapproved 2006), Standard Practice for Analysis of Reformed Gas by Gas Chromatography.

(10) ASTM D2013-07, Standard Practice of Preparing Coal Samples for Analysis.

(11) ASTM D2234/D2234M-07, Standard Practice for Collection of a Gross Sample of Coal.

(12) ASTM D2502-04 (Reapproved 2002), Standard Test Method for Estimation of Molecular Weight (Relative Molecular Mass) of Petroleum Oils from Viscosity Measurements.

(13) ASTM D2503-92 (Reapproved 2007), Standard Test Method for Relative Molecular Mass (Relative Molecular Weight) of Hydrocarbons by Thermoelectric Measurement of Vapor Pressure.

(14) ASTM D2880-03, Standard Specification for Gas Turbine Fuel Oils.

(15) ASTM D3176-89 (Reapproved 2002), Standard Practice for Ultimate Analysis of Coal and Coke.

(16) ASTM D3238-95 (Reapproved 2005), Standard Test Method for Calculation of Carbon Distribution and Structural Group Analysis of Petroleum Oils by the n-d-M Method.

(17) ASTM D3588-98 (Reapproved 2003), Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels.

(18) ASTM Specification D3699-07, Standard Specification for Kerosene.

(19) ASTM D4057-06, Standard Practice for Manual Sampling of Petroleum and Petroleum Products.

(20) ASTM D4809-06, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method).

(21) ASTM Specification D4814-08a, Standard Specification for Automotive Spark-Ignition Engine Fuel.

(22) ASTM D4891-89 (Reapproved 2006), Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion.

(23) ASTM D5291-02 (Reapproved 2007), Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants.

(24) ASTM D5373-08, Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal and Coke.

(25) ASTM D5865-07a, Standard Test Method for Gross Calorific Value of Coal and Coke.

(26) ASTM D6316-04, Standard Test Method for the Determination of Total, Combustible and Carbonate Carbon in Solid Residues from Coal and Coke.

(27) ASTM D6866-06a, Standard Test Methods for Determining the Biobased Content of Natural Range Materials Using Radiocarbon and Isotope Ratio Mass Spectrometry Analysis.

(28) ASTM E1019-03, Standard Test Methods for Determination of Carbon, Sulfur, Nitrogen, and Oxygen in Steel and in Iron, Nickel, and Cobalt Alloys.

(29) ASTM E1915-07a, Standard Test Methods for Analysis of Metal Bearing Ores and Related Materials by Combustion Infrared-Absorption Spectrometry.

(30) ASTM D7459-08, Standard Practice for Collection of Integrated Samples for the Speciation of Biomass (Biogenic) and Fossil-Derived Carbon Dioxide Emitted from Stationary Emissions Sources.

(31) ASTM D6060-96(2001) Standard Practice for Sampling of Process Vents With a Portable Gas Chromatograph.

(32) ASTM D 2502-88(2004)e1 Standard Test Method for Ethylene, Other Hydrocarbons, and Carbon Dioxide in High-Purity Ethylene by Gas Chromatography.

(33) ASTM C25-06 Standard Test Method for Chemical Analysis of Limestone, quicklime, and Hydrated Lime.

(34) C1271-99(2006) Standard Test Method for X-ray Spectrometric Analysis of Lime and Limestone.

(35) C1301-95(2001) Standard Test Method for Major and Trace Elements in Limestone and Lime by Inductively Coupled Plasma-Atomic Emission Spectroscopy (ICP) and Atomic Absorption (AA).

(36) UOP539-97 Refinery Gas Analysis by Gas Chromatography.

(37) ASTM D5468-02 (Reapproved 2007).

(b) The following materials are available for purchase from the American Society of Mechanical Engineers (ASME), 22 Law Drive, P.O.Box 2900, Fairfield, NJ 07007-2900:

(1) ASME MFC-3M-2004, Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi.

(2) ASME MFC-4M-1986 (Reaffirmed 1997), Measurement of Gas Flow by Turbine Meters.

(3) ASME-MFC-5M-1985, (Reaffirmed 1994), Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters.

(4) ASME MFC-6M-1998, Measurement of Fluid Flow in Pipes Using Vortex Flowmeters.

(5) ASME MFC-7M-1987 (Reaffirmed 1992), Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles.

(6) ASME MFC-9M-1988 (Reaffirmed 2001), Measurement of Liquid Flow in Closed Conduits by Weighing Method.

(c) The following materials are available for purchase from the American National Standards Institute (ANSI), 25 West 43rd Street, Fourth Floor, New York, New York 10036:

(1) ISO 8316: 1987 Measurement of Liquid Flow in Closed Conduits- Method by Collection of the Liquid in a Volumetric Tank.

(2) ISO/TR 15349-1:1998, Unalloyed steel-Determination of low carbon content. Part 1: Infrared absorption method after combustion in an electric resistance furnace (by peak separation).

(3) ISO/TR 15349-3: 1998, Unalloyed steel-Determination of low carbon content. Part 3: Infrared absorption method after combustion in an electric resistance furnace (with preheating).

(d) The following materials are available for purchase from the following address: Gas Processors Association (GPA), 6526 East 60th Street, Tulsa, Oklahoma 74143:

(1) GPA Standard 2172-09, Calculation of Gross Heating Value, Relative Density and Compressibility Factor for Natural Gas Mixtures from Compositional Analysis.

(2) GPA Standard 2261-00, Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography.

(e) The following American Gas Association materials are available for purchase from the following address: ILI Infodisk, 610 Winters Avenue, Paramus, New Jersey 07652:

(1) American Gas Association Report No. 3: Orifice Metering of Natural Gas, Part 1: General Equations and Uncertainty Guidelines (1990), Part 2: Specification and Installation Requirements (1990).

(2) American Gas Association Transmission Measurement Committee Report No. 7: Measurement of Gas by Turbine Meters (2006).

(f) The following materials are available for purchase from the following address: American Petroleum Institute, Publications Department, 1220 L Street, NW., Washington, DC 20005-4070:

(1) American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 3- Tank Gauging:

(A) Section 1A, Standard Practice for the Manual Gauging of Petroleum and Petroleum Products, Second Edition, August 2005.

(B) Section 1B-Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Tanks by Automatic Tank Gauging, Second Edition June 2001 (Reaffirmed, October 2006).

(C) Section 3-Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Pressurized Storage Tanks by Automatic Tank Gauging, First Edition June 1996 (Reaffirmed, October 2006).

(2) Shop Testing of Automatic Liquid Level Gages, Bulletin 2509 B, December 1961 (Reaffirmed August 1987, October 1992).

(3) American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 4- Proving Systems:

(A) Section 2-Displacement Provers, Third Edition, September 2003.

(B) Section 5-Master-Meter Provers, Second Edition, May 2000 (Reaffirmed, August 2005).

(4) American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 22- Testing Protocol, Section 2-Differential Pressure Flow Measurement Devices, First Edition, August 2005.

(g) The following material is available for purchase from the following address: American Society of Heating, Refrigerating and Air-Conditioning Engineers, Inc., 1791 Tullie Circle, NE., Atlanta, Georgia 30329: ASHRAE 41.8-1989: Standard Methods of Measurement of Flow of Liquids in Pipes Using Orifice Flowmeters.

(h) California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities, California Air Pollution Control Officers Association (CAPCOA) and California Air Resources Board (ARB), February 1999.

(i) Control of Emissions from Refinery Flares, Rule 118, South Coast Air Quality Management District, Amended November 4, 2005.

(j) U.S. EPA TANKS Version 4.09D, US Environmental Protection Agency, October 2005.

(k) Gas Processors Association (GPA) Standard 2261-00, Revised 2000.

§ WCI.7 DESIGNATED REPRESENTATIVE (ONLY APPLICABLE TO WCI JURISDICTIONS IN THE UNITED STATES)

(a) General. Each fuel supplier, electricity importer, and owner or operator of a facility that is subject to this rule, shall select a designated representative that is responsible for certifying and submitting GHG emissions reports under this reporting rule.

(b) Authorization of a Designated Representative. The designated representative of the facility shall be selected by a certificate of representation agreement that is signed by the designated representative and owners or operators of the facility. The designated representative must be an individual having responsibility for the overall operation of the facility or activity such as the position of the plant manager, operator of a well or a well field, superintendent, position of equivalent responsibility, or an individual or position having overall responsibility for environmental matters for the company.

(c) Responsibility of the Designated Representative.

(1) The designated representative of the facility shall represent and by any representations, actions, inactions, or submissions, legally bind each owner and operator in all matters pertaining to this rule.

(2) Each GHG emission report submitted under this rule must be signed by the designated representative and must contain the following certification statement: "I have been authorized to make this submission on behalf of the owners and operators of the facility (or supply operation, as appropriate). I certify under penalty of law that I have personally examined the information submitted in this document. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(d) Changing a Designated Representative. The designated representative may be changed at any time upon submission of a superseding certificate of representation. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous designated representative before time of the superseding certificate of representation shall be binding on the new designated representative and the owners and operators.

(e) Changes in Owners and Operators. In the event of any change in ownership of the facility, any new owner or operator shall be deemed to be bound by the representations, actions, inactions, and submissions of the designated representative of the facility until such time as the designated representative is changed.

(f) Certificate of Representation. A certificate of representation must be submitted to *[the jurisdiction]* and kept on location by the facility, fuel supplier, or electricity importer. The certificate shall include the following information:

(1) Identification of the facility, fuel supplier, or electricity importer for which the certificate of representation is submitted.

(2) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the designated representative.

(3) A list of the owners and operators.

(4) Certification statements that the actions of the designated representative with respect to this rule are binding on the owners and operators, and that the designated representative has the necessary authority to carry out duties and responsibilities on behalf of the owners and operators.

(5) The signature of the designated representative and owner(s) and operator(s), and the dates signed.

§ WCI.8 REQUIREMENTS FOR VERIFICATION OF GREENHOUSE GAS EMISSIONS DATA REPORTS AND REQUIREMENTS APPLICABLE TO EMISSIONS DATA VERIFIERS

[See separate document.]

§ WCI.9 DEFINITIONS

[See separate document.]

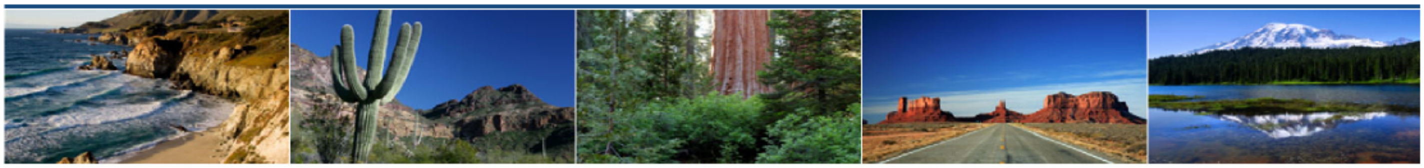
§ WCI.10 GLOBAL WARMING POTENTIALS

Owners and operators must use the global warming potential (GWP) values given in Table WCI.10-1 when converting emissions of greenhouse gases to metric tons of carbon dioxide equivalent (CO_2e), using Equation 1-1.

Table WCI.10-1. Global Warming Potential Factors for Greenhouse Gases

Common Name	Formula	Chemical Name	GWP
Carbon dioxide	CO_2		1
Methane	CH_4		21
Nitrous oxide	N_2O		310
Sulfur hexafluoride	SF_6		23,900
Hydrofluorocarbons (HFCs)			
HFC-23	CHF_3	trifluoromethane	11,700
HFC-32	CH_2F_2	difluoromethane	650
HFC-41	CH_3F	fluoromethane	150
HFC-43-10mee	$C_5H_2F_{10}$	1,1,1,2,3,4,4,5,5,5- decafluoropentane	1,300
HFC-125	C_2HF_5	pentafluoroethane	2,800
HFC-134	$C_2H_2F_4$	1,1,2,2-tetrafluoroethane	1,000
HFC-134a	$C_2H_2F_4$	1,1,1,2-tetrafluoroethane	1,300
HFC-143	$C_2H_3F_3$	1,1,2-trifluoroethane	300
HFC-143a	$C_2H_3F_3$	1,1,1-trifluoroethane	3,800
HFC-152	$C_2H_4F_2$	1,2-difluoroethane	43
HFC-152a	$C_2H_4F_2$	1,1-difluoroethane	140
HFC-161	C_2H_5F	fluoroethane	12
HFC-227ea	C_3HF_7	1,1,1,2,3,3,3- heptafluoropropane	2,900
HFC-236cb	$C_3H_2F_6$	1,1,1,2,2,3-hexafluoropropane	1,300
HFC-236ea	$C_3H_2F_6$	1,1,1,2,3,3-hexafluoropropane	1,200
HFC-236fa	$C_3H_2F_6$	1,1,1,3,3,3-hexafluoropropane	6,300
HFC-245ca	$C_3H_3F_5$	1,1,2,2,3-pentafluoropropane	560

HFC-245fa	$C_3H_3F_5$	1,1,1,3,3-pentafluoropropane	950
HFC-365mfc	$C_4H_5F_5$	1,1,1,3,3-pentafluorobutane	890
Perfluorocarbons (PFCs)			
Perfluoromethane	CF_4	tetrafluoromethane	6,500
Perfluoroethane	C_2F_6	hexafluoroethane	9,200
Perfluoropropane	C_3F_8	octafluoropropane	7,000
Perfluorobutane	C_4F_{10}	decafluorobutane	7,000
Perfluorocyclobutane	c-C_4F_8	octafluorocyclobutane	8,700
Perfluoropentane	C_5F_{12}	dodecafluoropentane	7,500
Perfluorohexane	C_6F_{14}	tetradecafluorohexane	7,400



§WCI.8 REQUIREMENTS FOR VERIFICATION OF GREENHOUSE GAS EMISSIONS DATA REPORTS AND REQUIREMENTS APPLICABLE TO EMISSIONS DATA VERIFIERS

Note: The verification requirements laid out in this section strive for consistency with ISO 14064-3[1] *requirements and set forth a high standard for verification that will ultimately support a WCI cap and trade program. Due to differences in rulemaking procedures between jurisdictions, Supplement 1 provides supplemental text that jurisdictions must incorporate into either the jurisdiction's prescriptive rule language, replacing more general procedural language in Section WCI.8, or into enforceable guidance documents. There are notes in WCI.8 that direct readers to appropriate text in Verification Supplement 1 when applicable.*

It would be ideal for all jurisdictions to enforce the same requirements and have the same implementation processes for accreditation and verification to ensure that consistent accurate data exists throughout the WCI regional program. Reporters and verifiers with operations throughout the WCI region will benefit from a consistent approach and such an approach would facilitate administration of the verification requirements by a central body or designee.

(a) Applicability and Scope.

(1) Except as provided in WCI.8(a)(2) through (4) owners or operators [Each jurisdiction will select the specific terminology for the regulated persons in accordance with their customary rule-writing practices] are required to obtain annual verification for a facility that emits 25,000 metric tons CO_2e or more per year in combined emissions from one or more of the source categories listed in WCI.1 in any calendar year starting on or after 2010.

(2) When the operation of a facility, fuel supplier, or electricity importer subject to the requirements of this section is changed such that the operator has reported less than 25,000 metric tons of CO_2e emissions for a calendar year, the operator shall obtain verification of annual emissions reports for the lesser of three subsequent calendar years or for those years remaining in the current compliance period. If CO_2e emissions of a facility, fuel supplier, or electricity importer subject to the requirements of this section again exceed 25,000 metric tons in any calendar year the provisions of WCI.8(a)(1) apply.

[1] ISO (2006) ISO 14064-3: Greenhouse Gases-Part 3: Specification with guidance for the validation and verification of greenhouse gas assertions, March, 2006, International Organization for Standardization, Switzerland.

(3) Carbon dioxide emissions from the combustion of biomass fuels shall be included in the determination regarding verification applicability, with the following exceptions:

(A) Until such time as [the jurisdiction] has made a determination regarding the carbon neutrality of any biomass fuels, a maximum of 15,000 metric tons of carbon dioxide emissions from the combustion of pure solid biomass fuel may be excluded from calculation of GHG emissions for comparison to the 25,000 metric ton CO_2e per year verification threshold in paragraph (a) of this section.

(B) After such time as [the jurisdiction] has made a determination regarding the carbon neutrality of any biomass fuels, the carbon dioxide emissions from the combustion of those fuels may be excluded from calculation of GHG emissions for determining whether the 25,000 metric tons CO_2e per year verification threshold in paragraph (a)(1) of this section has been met.

[Under Design Recommendation 1.3, carbon neutral biomass will be excluded from the cap-and-trade program. A WCI Partner jurisdiction, however, may, in its discretion, choose to require carbon dioxide emissions from the combustion of biomass fuel to be included in the determination of the verification threshold in order to obtain a complete inventory of the fuels being combusted in the jurisdiction.]

(4) Owners or operators may exclude carbon dioxide emissions from the combustion of biomass fuels that [jurisdiction] has deemed carbon neutral from the scope of verification.

[A WCI Partner jurisdiction may, in its discretion, choose to require carbon dioxide emissions from the combustion of biomass fuel to be included in the scope of verification.]

(5) Notwithstanding WCI.8(a)(2) and (3), any facility, fuel supplier or electricity importer subject to a cap-and-trade program for CO_2e emissions established by [the jurisdiction] shall obtain verification of reported annual emissions.

(b) Requirements for Annual Verification of Emissions Data Reports.

(1) Verification bodies shall conduct verification processes and design verification procedures to determine whether there is a reasonable level of assurance for each separate emissions data report every year of the verification cycle. The verification team shall find that there is a reasonable level of assurance for an emissions data report if the report

(A) contains no material misstatement; and

(B) conforms to the requirements of this article.

(2) The verification body must provide verification services in compliance with WCI.8.

(3) Facility owners or operators, fuel suppliers, and electricity importers required to obtain annual verification shall be subject to full verification requirements in the first year that verification is required for an emissions data report. Upon completion of a positive verification statement under full verification requirements, the facility owner or operator, fuel supplier, or electricity importer may be eligible for two years of less intensive verification services as described in section WCI.9. This cycle may be

repeated in subsequent three-year cycles; however, full verification requirements shall apply at least once every three years.

(4) Facility owners or operators, fuel suppliers, and electricity importers required to obtain annual verification will be required to obtain full verification services if any of the following apply:

(A) There has been a change in the verification body from the previous year; or

(B) A verification body issued an adverse verification statement for that facility's previous year's emissions data report.

(c) Accreditation Requirements for Verification Bodies.

(1) The accreditation requirements specified in this subsection shall apply to all verification bodies that wish to provide verification services under this rule.

(2) A verification body is qualified to conduct verification services for the WCI if

(A) it has demonstrated knowledge of the WCI reporting requirements; and

(B) it is accredited to ISO 14065 through a program developed under ISO 17011 by an accreditation body that is a member of the International Accreditation Forum.

[Note the details of the WCI's specific accreditation process for verification bodies (which has yet to be developed) will be consistent with ISO 14065 through an accreditation program that will developed under ISO 17011 and will include demonstrated knowledge of the WCI reporting requirements. The WCI will explore additional accreditation requirements and/or other criteria for individual lead verifiers, general verifiers, and/or sector specialists.]

(3) Prior to January 1, 2013, accreditation by the California Air Resources Board under Title 17, California Code of Regulation, section 95132, may be substituted for the accreditation required under WCI.8(c)(2)(B).

(d) Requirements for Verification Services. The following verification services must be provided for each emissions data report.

(1) As part of the verification services, the verification team shall review documents submitted, assess risks of a material misstatement, develop a verification plan (that includes a sampling plan), evaluate the emissions data report against the verification requirements, and assess the materiality of errors, omissions and misstatements identified.

(2) The verification team shall request any information and documents needed for verification services. Such information shall include, but is not limited to original records and supporting data for the emissions data report.

(e) A verification team must include the following:

(1) a Lead Verifier;

(2) an Independent Peer Reviewer;

(3) any subcontractor elected to provide verification services under WCI.8(f).

(f) Subcontracting. The following requirements shall apply to any verification body that elects to subcontract verification services.

(1) The primary verification body must assume full legal responsibility for verification services performed by subcontracted verifiers or verification bodies.

(2) A verification body or verifier acting as a subcontractor to the primary verification body will not further subcontract that same work to another firm or individual.

(3) A verification body or verifier acting as a subcontractor is subject to all Conflict of Interest requirements in Section WCI.8(g).

(4) A verification body or verifier acting as a subcontractor must be identified by the primary verification body as part of the verification team.

(g) Conflict of Interest Requirements for Verification Bodies. The conflict of interest provisions of this section shall apply to the verification body, entities related to the verification body, and the verification team accredited according to the requirements of the WCI to perform verification services for the WCI program. Member for purposes of this section means any employee or subcontractor of the verification body or entities related to the verification body. Member also includes any individual with a majority equity share in the verification body or entities related to the verification body.

(1) Prior to a jurisdiction accepting a verification statement, and prior to a jurisdiction accepting the associated emissions report for consideration for approval, the AVA must determine that the verification body has a low potential for conflict of interest as described under WCI.8(g)(6). To inform this determination by the AVA, a self-evaluation of the potential for any conflict of interest that the verification body, entities related to the verification body, and members of the verification team, including subcontractors, may have with the owner or operator or their related entities for which verification services will be or have been provided shall be submitted to the AVA. This self-evaluation must include an evaluation of any threats to the verification body's independence including: [*note: a standardized Conflict of Interest Assessment form will be developed for the WCI*]

[To facilitate timely determinations of conflict-of-interest potential, and to reduce the risk of finding medium or high conflict-of-interest potential after verification services have been initiated, it is recommended that jurisdictions require that the self evaluations be submitted and evaluated by the AVA prior to the initiation of verification services. A jurisdiction may elect to allow verification services to commence prior to the determination of the conflict-of-interest potential by the AVA.]

(A) Threats created by the reporting operation offering inducements to the verification body, subcontractors or verification team members for a positive opinion;

(B) Threats created by members of the verification body, verification team members, subcontractors, or family of subcontractors or team members having a financial interest in the reporting operation or its operator;

(C) Threats created by members of the verification body reviewing work of the verification body, subcontractors, members of the verification team, or related companies, including but not limited to any situation where the body, subcontractors, team members or companies have provided services related to greenhouse gases;

(D) Threats created by members of the verification body, verification team members, or subcontractors having a close relationship with the reporting operation, such that they might become too sympathetic to the interests of the reporting operation; and

(E) Threats created by members of the verification body, verification team members, or subcontractors being deterred from acting objectively or exercising professional skepticism by threats, actual or perceived, from the reporting operation.

(2) The verification body shall deem the potential for conflict of interest to be low if

(A) No threats as listed in WCI.8(g)(1) exist, and

(B) Any non-verification services provided by the verification body to the owner or operator within the last three years are valued at less than five percent of the verification body's annual revenue in each of those years.

(3) The verification body shall deem the potential for conflict of interest to be high if threats as listed in WCI.8(g)(1)(A) or (E) exist.

[A jurisdiction may expand the list of high threats (i.e. un-mitigatable conflicts) with the items included in paragraph 2 of the Conflict of Interest section of Supplement 1 below.]

(4) The verification body shall deem the potential for a conflict of interest to be medium if the potential for a conflict of interest is not deemed to be either low or high as specified in sections WCI.8(g)(2)-(3).

(5) If a verification body deems the potential for conflict of interest to be medium and wishes to provide verification services for the owner or operator, then the verification body shall submit, in addition to the self-evaluation, a plan to avoid, neutralize, or mitigate the potential conflict of interest situation.

(6) Conflict of Interest Determinations. The AVA shall review the self-evaluation submitted by the verification body and determine the verification body's potential conflict of interest in performing verification services for the owner or operator.

[In addition to the AVA determination, a jurisdiction may elect to conduct audits of conflict of interest submissions for compliance verification and enforcement purposes.]

(A) The AVA shall notify the verification body in writing when the conflict of interest evaluation information submitted under section WCI.8(g)(1) is deemed complete. Within 45 days after deeming the evaluation information complete, the AVA shall determine the conflict-of-interest potential and shall notify the verification body or owner or operator if the potential conflict of interest is determined to be medium or high.

(B) If the AVA determines the verification body or any member of the verification team has any threats specified in section WCI.8(g)(1), the AVA shall find a high potential conflict of interest and verification services may not proceed.

(C) If the AVA determines that there is a low potential conflict of interest prior to the verification services being provided, verification services may proceed.

(D) If the AVA determines that the verification body and verification team have a medium potential for a conflict of interest, the AVA shall evaluate the conflict of interest mitigation plan and may request additional information from the applicant to complete the determination. In determining potential conflict of interest, the AVA may consider factors including, but not limited to, the nature of previous work performed, the current and past relationships between the verification body and its subcontractors with the owner or operator, and the cost of the verification services to be performed. The AVA will determine whether these factors when considered in combination with the mitigation plan demonstrate a low level of potential conflict of interest or a high level. If the AVA determines that there is a low potential conflict of interest prior to the verification services being initiated, verification services may proceed. If a high potential is determined prior to verification services being initiated, verification services may not proceed. If a high potential is determined after verification services have been initiated, the verification statement shall not be accepted..

(7) Monitoring Conflict of Interest Situations.

(A) After commencement of verification services, the verification body shall monitor and immediately make full disclosure in writing to the AVA regarding any potential for a conflict of interest situation that arises. This disclosure shall include a description of actions that the verification body has taken or proposes to take to avoid, neutralize, or mitigate the potential for a conflict of interest.

(B) The verification body shall monitor arrangements or relationships that may be present for a period of one year after the completion of verification services. During that period, within 30 calendar days of any change in arrangements or relationships with the owner or operator for which the verification body has provided verification services that may create a medium or high threat of conflict of interest, the verification body shall notify the AVA of the change and provide a description of the nature of the change. The AVA will make a conflict of interest determination under WCI.8(g)(6).

(C) The verification body shall report to the AVA any changes in its organizational structure, including mergers, acquisitions, or divestitures that may have created a medium or high threat of conflict of interest for one year after completion of verification services within 30 days and submit an evaluation of how the change(s) impacts the potential for conflict of interest.

(D) The AVA may invalidate a verification finding if a medium or high threat of a conflict of interest has arisen for the verification body or any member of the verification team and, in the case of a medium threat, the threat has not been adequately mitigated. In such a case, the owner or operator shall be provided 180 calendar days to have their emissions report verified by a different verification body.

(E) If the verification body or its subcontractor(s) are found to have violated the conflict of interest requirements of this section, the AVA may rescind its accreditation for any appropriate period of time . Additionally, the AVA may separately revoke its recognition of an accredited Verification Body under WCI.8(w). *[The WCI intends to develop more detailed accreditation requirements in the future.]*

(h) Notice of Verification Services. Prior to commencing verification services for a facility owner or operator, fuel supplier, and electricity importer, the verification body shall submit a notice of verification services to the AVA. Verification activities shall not proceed for 15 business days or until the verification body receives written approval to proceed from the AVA, whichever is earlier. If the AVA does not respond to the verification body within 15 business days, the verification body may begin to conduct verification activities.

[The NOVS form will be standardized across WCI and developed later.]

(i) Verification Plan.

(1) Accounting for requirements set by WCI.8, the verification plan shall document:

(A) the scope of the verification;

(B) the level of assurance;

(C) the verification standard;

(D) the verification criteria;

(E) the objectives of the verification;

(F) the timing of the verification, including site visits;

(G) the nature of the communications required;

(H) the resources required to conduct the verification, including the role of verification team members; and

(I) the nature, timing and extent of the verification procedures, including the sampling plan.

(2) The verification body shall retain the verification plan in paper, electronic, or other format for a period of not less than seven years following the submission of each verification statement.

(j) Site visits. In years for which full verification services are required under WCI.8(b)(3), at least one member of the verification team shall at a minimum make one onsite site visit to each facility or fuel supply location *[Note that exact location of fuel supplier site visits remains TBD]* for which an emissions data report is submitted. The verification team member(s) shall also conduct an onsite visit of the headquarters or other location of central data management, if different from the facility or fuel supply location, when the owner or operator is an electricity importer.

(k) Owners or operators shall make available to the verification team all information and documentation used to calculate and report emissions, electricity transactions, and other information required under this rule, as applicable.

(l) As applicable for electricity importers, the verification team shall review electricity transaction records, including receipts of power attributed to the Northwest or Southwest region as verifiable via North American Electric Reliability Corporation (NERC) E-Tags, settlements data, or other information as confirmation of the region of origin. [*Note that this procedure is subject to change pending WCI Electricity Committee review.*]

(m) Data Checks. To determine the reliability of the submitted emissions data report, the verification team shall use data checks as defined in WCI.9. Verifiers will use their professional judgment in determining how many data checks are needed to provide a reasonable level of assurance.

(n) Emissions Data Report Modifications. If as a result of review by the verification team and prior to completion of a verification statement the owner or operator chooses to make improvements or corrections to the submitted emissions data report, a revised emissions data report must be submitted to [the jurisdiction] as specified by section WCI.8(q). The owner or operator shall maintain documentation to support any revisions made to the initial emissions data report. Documentation for all emissions data report submittals shall be retained by the operator for seven years pursuant to section WCI.4.

(o) Materiality and Conformance Assessment Criteria. The verifier shall determine if the annual emissions report is prepared in such a way that it satisfies WCI.8(b)(1).

(1) A verification team shall determine that an emission data report contains a material misstatement, if either of the following is true:

(A) Based on the verification team's own determination of the level of emissions subject to verification based on the sampling plan, the verification team concludes that total reported emissions are less than 95 percent accurate using the following equation:

$$PA = 100 - (SOU/TRE * 100)$$

Where:

PA	=	Percent accuracy
SOU	=	The net result of summing overstatements and understatements resulting from errors, omissions and misreporting
TRE	=	Total reported emissions

(B) The individual or aggregate effect of one or more errors, omissions or misstatements identified in the course of verification make it probable that the judgment of a reasonable person regarding the total reported emissions would have been changed or influenced by the error, omission or misrepresentation.

(2) To assess conformance with this rule the verification team shall review the methods and factors used to develop the emissions data report for adherence to the requirements of this rule.

(3) The verification team shall keep a log of any issues identified in the course of verification activities that may affect determinations of material misstatement and nonconformance, and how those issues were resolved.

(p) Completion of verification services shall include:

(1) Verification Statement. Upon completion of the verification services required by WCI.8, the verification body shall complete a verification statement for each emissions data report, and provide that statement to the owner or operator and [the jurisdiction or other body] according to the schedule specified in section WCI.2(b). Before that statement is completed, the verification body shall have the verification services and findings of the verification team independently reviewed and approved by an Independent Peer Reviewer.

(2) The verification body shall provide either a positive or adverse verification statement to the reporter and to the AVA *[alternatively, this could be the reporter's responsibility to submit the statement to the AVA]* based on its findings during the verification process.

(3) The lead verifier in the verification team shall attest on the verification statement that the verification team has carried out all verification services as required by this rule, and the Independent Peer Reviewer shall attest to his or her independent review on behalf of the verification body and his or her concurrence with the verification findings. If the Independent Peer Reviewer does not determine that the verification team has carried out all verification services as required by the rule or if the Independent Peer Reviewer rejects the verification team's findings, then the verification body cannot issue a positive verification statement.

(4) The verification body shall provide to the owner or operator a detailed verification report. The verification report shall at minimum include the detailed comparison of the data checks with the submitted emissions data report, errors, omissions and misstatements identified during the course of the verification, any corrections made to the original annual emissions report as a result of the verification, and observations about the data management systems that are connected to the errors, omissions and misstatements identified, as well as any qualifying comments on findings during verification services. The detailed verification report shall be made available to [the jurisdiction] upon request.

(q) Prior to the verification body providing an adverse verification statement pursuant to WCI.8(p)(2), the owner or operator shall be provided at least 14 working days to modify the emissions data report to correct any material misstatement or nonconformance found by the verification team. The modified report and verification statement must be submitted to [the jurisdiction] before the applicable verification deadline, unless the operator makes a request to [the jurisidiction*]* as follows:

(1) If the owner or operator and the verification body cannot reach agreement on modifications to the emissions data report that result in a positive verification statement, the operator may petition the AVA to make a final decision as to the verifiability of the submitted emissions data report.

(2) If the AVA determines that the emissions data report does not meet the standards and requirements specified in this article, the owner or operator shall have the opportunity to submit within 60 calendar days of the date of this decision *[Note that this time frame may need to be changed pending details of cap-and-trade system design and needs.]* any emissions data report revisions that address the AVA's determination, for re-

verification of the emissions data report. In re-verifying a revised emissions data report, the verification body and verification team shall be subject to the requirements in section WCI.8(q)-(s).

(3) Upon provision of the verification statement to [the jurisdiction], the emissions data report shall be considered final and no changes shall be made except as provided in section WCI.8(n) or (q). All verification requirements of this rule shall be considered complete upon provision of the verification statement.

(r) In addition to initiating WCI's dispute resolution process, the operator and verification body must inform the applicable accreditation body of the dispute.

(s) The AVA may make void the positive verification statement submitted by the verification body if:

(1) The AVA finds a high level of conflict of interest existed between a verification body and an owner or operator; or,

(2) An emissions data report that received a positive verification statement fails an audit by the AVA.

(t) Upon request by the AVA, the owner or operator shall provide the data used to generate an emissions data report, including all data available to a verification body. The AVA may also review the full verification report given by the verification body to the owner or operator. The full verification report shall be provided to the AVA upon request.

(u) Upon written notification by the AVA, the verification body shall make itself available for a verification services audit.

(v) Duration of verification services by one verification body. Facility owners or operators, fuel suppliers, or electricity importers subject to annual verification shall not use the same verification body for a period of more than six consecutive years. If a facility owner or operator, fuel supplier, or electricity importer is required or elects to contract with another verification body, they may contract verification services from the previous verification body only after not using the previous verification body for at least three years. If a verification body or verification team member has been providing verification services for an owner or operator in a greenhouse gas reporting or reductions program other than [the jurisdiction's] within the previous three years, those years of services will count towards the six consecutive year limit in this section.

(w) Revocation of Recognition. A jurisdiction may review, and for good cause, work to revoke or modify the accreditation status of a recognized verification body. If a recognized verification body is suspended in any other mandatory or voluntary GHG reporting or trading program, that verification body will not be allowed to provide any verification services until that suspension ends. If a recognized verification body has its accreditation revoked under any other mandatory or voluntary GHG reporting or trading program, that verification body will no longer be allowed to provide verification services under WCI.8 until it is reaccredited.

Verification Supplement 1

Note: the additional content in this Supplement must either be included in regulatory text in the appropriate subsections of WCI.8 or enforceable guidance documents by jurisdictions. The language in this section provides further explanation of items required in WCI.8 or alternative, more prescriptive language of those requirements.

Preliminary Activities and Verification Plan

The verification team shall discuss with the owner or operator the scope and objective of the verification services and obtain information from the owner or operator necessary to develop a verification plan. Such information shall include but is not limited to:

- Information to allow the verification team to develop a general understanding of facility or entity boundaries, operations, emissions sources, electricity transactions, as applicable;
- Information about the data management system used to track GHG emissions, electricity transactions, and other required measurement data as applicable;
- Information regarding the training or qualifications of personnel involved in developing the GHG emissions data report;
- Description of the specific methodologies used to quantify and report GHG emissions, electricity transactions, and other required data as applicable;
- Records of measured data related to emissions and operations for the prior and current period;
- Inventory of sources and their associated emissions for the reporting period, and
- Any prior verification reports, if applicable.

In developing the verification plan, the verifier shall:

- Gain an understanding of the organization and the process that emit greenhouse gases;
- Conduct a risk assessment to evaluate inherent, control and detection risk;
- Conduct preliminary analytical testing to identify anomalies in the data;
- Conduct a sensitivity analysis to assess the relative contribution of each source in the inventory to the reported annual emissions, and
- Consider any other relevant developments at the facility, in the regulations, or legal environment.

Sampling Plan

As part of the verification procedures, the verification team shall develop a sampling plan that, when combined with the other verification procedures, provides sufficient and appropriate evidence to allow the verifier to arrive at a conclusion. The sampling plan shall be designed to achieve the specified verification objective. The sample plan shall consider:

- Statistical versus non-statistical approaches
- Design of the sample, including the population characteristics
- Stratification (categorization of population into subgroups)
- Emission weighted selection
- Sample size

- Sample selection

As relevant information becomes available during the course of verification activities, the verification team must modify the sampling plan as necessary to address potential issues emerge of material misstatement or nonconformance with the requirements of this rule.

Data Checks

The verification team conducts data checks throughout the verification process and shall focus first on the largest and most uncertain estimates of emissions and electricity transactions.

- In establishing the verification plan, the verification team shall use professional judgment to determine the number of data checks required for the team to conclude with reasonable assurance whether the reported emissions and transactions are free of material misstatement and the emissions data report otherwise conforms to the requirements of this rule.
- The verification team shall choose emissions sources, and electricity transactions data as applicable, for data checks based on their relative sizes and risks of material misstatement as indicated in the verification plan;
- The verification team, through the conformance assessment, shall ensure that the appropriate methodologies and emission factors have been applied for the emissions sources and electricity transactions for sampled data covered under sections WCI.20 through WCI.XX;

Site Visits

During the site visit, the verification team member(s) shall conduct the following:

- Observe whether all sources at the site are represented in the emissions report as specified in sections WCI.20 to WCI.XX as applicable to the owner or operator.
- Assess whether the source inventory is identified, categorized, and reported appropriately. Collect evidence as to explanations for data anomalies identified in the verification plan.
- Understand the data trail used by the owner or operator to measure, quantify, and report greenhouse gas emissions and, when applicable, electricity transactions.
- Understand and evaluate the associated data controls used by the owner to ensure the completeness and accuracy of the data

Materiality Assessment

In assessing whether misstatements are material, the verification team shall determine whether the total reported emissions are at least 95 percent accurate using the following equation:

Percent accuracy = 100 **–** (sum of (errors, omissions, misreporting) * 100 / (total reported emissions))

To assess conformance with this rule the verification team shall review the methods and factors used to develop the emissions data report for adherence to the requirement of this rule. The verification team shall keep a record of any errors, omissions or misstatements identified in the course of verification activities that may affect determinations of material misstatement and nonconformance, and how those issues were resolved.

Conflict of Interest (*could replace more general procedural language in Section WCI.8*)

(1) Conflict of Interest Submittal Requirements for Accredited Verification Bodies.

(A) Before the start of any work related to providing verification services to an owner or operator, a verification body must first be authorized in writing by *the AVA* to provide verification services. To obtain authorization the verification body shall submit to *the AVA* a self-evaluation of the potential for any conflict of interest that the verification body, entities related to the verification body, and members of the verification team including, subcontractors may have with the owner or operator or their related entities for which it will perform verification services. For the purposes of this section, the term member refers to staff on the verification team, in the verification body and any subcontractors. The submittal shall include the following:

(i) Identification of whether the potential for conflict of interest is high, low, or medium based on factors specified in this section;

(ii) An organizational chart of the business structure of the verification body, including its related entities and brief description of the primary work done by the verification body and related entities;

(iii) iii. Identification of whether any member of the verification body, entities related to the verification body, or the verification team including subcontractors has previously provided verification services for the owner or operator or its related entities and, if so, the years in which such verification services were provided;

(iv) Identification of whether any member of the verification body, entities related to the verification body, or the verification team or including subcontractors has engaged in any non-verification services of any nature with the owner or operator or related entities either within or outside the WCI region during the previous three years. The verification body must also disclose any services listed under section (high COI list) it has provided to the owner or operator, regardless of when these services occurred. If non-verification services have previously been provided, the following information shall also be submitted:

(v) Identification of the nature and location of the work performed for the owner or operator and whether the work is similar to the type of work to be performed during verification, such as emissions inventory auditing, energy efficiency, renewable energy, or other work with implications for the operator's greenhouse gas emissions or the accounting of greenhouse gas emissions or electricity transactions;

(vi) The nature of past, present or future relationships the verification body, entities related to the verification body, and members of the verification team including subcontractors have with the owner or operator or related entity including:

- Instances when any member has performed or intends to perform work for the owner or operator;
- Identification of whether work is currently being performed for the owner or operator and, if so, the nature of the work;

- Whether any member has any contracts or other arrangements to perform work for the owner or operator or a related entity;
- Identify how much work was performed in each of the last three years, as a percentage of the verification body's total gross income for each of the last three years;
- Identify how much work related to greenhouse gases or electricity transactions was has performed for the owner or operator or related entities in each of the last three years, as a percentage of the verification body's income for each of the last three years;
- Identify how much work was performed by each subcontractor for the operator in each of the last three years, as a percentage of each subcontractor's total gross income for each of the last three years.

(vii) Explanation of how the amount and nature of work previously performed is such that any member of the verification team's credibility and lack of bias should not be under question.

(viii) A list of names of the verification team members that will perform verification services for the owner or operator and a description of any instances of personal or family relationships with management or employees of the owner or operator that potentially represent a conflict of interest; and,

(ix) Identification of any other circumstances or relevant information known to the verification body or owner or operator that could result in a conflict of interest, or any situation where the appearance of impartiality could undermine confidence in the verification body's ability to assess the reported emissions.

(2) The potential for a conflict of interest shall be deemed to be high where:

(A) The verification body and owner or operator share any management staff or board of directors membership, or any of the management staff of the owner or operator have been employed by the verification body, or vice versa, within the previous three years; or

(B) Within the previous three years, any member of the verification body, any entity related to the verification body, and the verification team has provided to the owner or operator any of the following non-verification services:

(i) Designing, developing, implementing, or maintaining an inventory or information or data management system for facility greenhouse gases, or, where applicable, electricity transactions;

(ii) Developing greenhouse gas emission factors or other greenhouse gas-related engineering analysis;

(iii) Designing energy efficiency, renewable power, or other projects which explicitly identify greenhouse gas reductions as a benefit;

(iv) Preparing or producing greenhouse gas-related manuals, handbooks, or procedures specifically for the reporting facility;

(v) Appraisal services of carbon or greenhouse gas liabilities or assets;

(vi) Brokering in, advising on, or assisting in any way in carbon or greenhouse gas-related markets;

(vii) Managing any health, environment or safety functions which explicitly identify greenhouse gas reductions as a benefit;

(viii) Bookkeeping or other services related to the accounting records or financial statements, unless those services limited to financial auditing;

(ix) Any service related to information systems, unless those systems will not be part of the verification process and excluding third-party auditor or registration services;

(x) Appraisal and valuation services, both tangible and intangible related to GHG emissions or reductions inventories;

(xi) Fairness opinions and contribution-in-kind reports in which the verification body has provided its opinion on the adequacy of consideration in a transaction, unless the resulting services shall not be part of the verification process;

(xii) Any actuarially oriented advisory service involving the determination of amounts recorded in financial statements and related accounts;

(xiii) Any internal audit service as provided under section (GHG plan) that has been outsourced by the operator that relates to the owner's or operator's internal accounting controls, financial systems or financial statements, unless no consulting or advice was provided as part of the audit;

(xiv) Acting as a broker-dealer (registered or unregistered), promoter or underwriter on behalf of the owner or operator;

(xv) Any legal services related to GHG emissions;

(xvi) Expert services to the owner or operator or his or her legal representative for the purpose of advocating his or her's interests in litigation or in a regulatory or administrative proceeding or investigation involving GHG emissions, unless providing factual testimony.

(C) The potential for a conflict of interest shall also be deemed to be high where any staff member of the verification body, entity related to the verification body, or the verification team has provided verification services for the owner or operator for six consecutive years or within three years of the termination of a previous GHG verification contract with the owner or operator. If a verification body or verification team member has been providing verification services for a [operator/owner] in a greenhouse gas reporting or reductions program other than WCI within the past three years, those years of services will count towards the six consecutive year limit in the WCI.

(D) The potential for a conflict of interest shall be deemed high where the Independent Peer Reviewer for the verification team has provided verification or non-verification services for the operator during the current reporting year.

(3) The potential for a conflict of interest shall be deemed to be low where no potential for a conflict of interest is found under section WCI.8(g) *[may need to be updated, depending upon final version of WCI.8)* and any non-verification services provided by all members of the verification body and the verification team to the owner or operator within the last three years are valued at less than five percent of the verification body's revenue.

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WCI.8 OPTIONAL GUIDANCE

Note: This text is supporting material and not intended as part of the essential requirements.

Collection of Evidence

The verification body shall obtain sufficient and appropriate evidence to be able to draw reasonable conclusions on which to base the verification statement. The verification body obtains evidence by performing verification procedures. Verification procedures are classified as:

- **Computation (or Recalculation)** is the checking of mathematical accuracy of documents or records
- **Observation** of a process or procedure
- **Confirmation** is obtaining representations from a third party
- **Enquiry** is seeking information from a knowledgeable person
- **Inspection** of Records or Documents/Assets
- **Re-performance** is the verifiers independent execution of procedures or controls
- **Analysis** is the evaluation of information made by studying the plausible relationships among different types of data

Some or all of these techniques can be used to obtain sufficient and appropriate evidence. Site visits are used to obtain evidence that is readily available at that location.

§ WCI.9 DEFINITIONS

“Accuracy” means the closeness of the agreement between the result of the measurement and the true value of the particular quantity (or a reference value determined empirically using internationally accepted and traceable calibration materials and standard methods), taking into account both random and systematic factors.

“Acid gas” means a gas mixture that has been separated from natural gas and consists mostly ofhydrogen sulphide or carbon dioxide and that may contain trace amounts of hydrocarbons, water, or other contaminants.

“Accreditation and Verification Authority” or “AVA” means [the jurisdiction] or any entity or entities to which [the jurisdiction] assigns any of the responsibilities for oversight and execution of the accreditation and verification program established in WCI.8.

“Adverse verification statement” means a verification statement rendered by a verification body stating that the verification body cannot conclude that there is a reasonable level of assurance for an emissions data report.

[“Article” is a placeholder for a jurisdiction-specific cross reference to whatever subdivision of its administrative code contains the WCI’s Essential Requirements for Mandatory Reporting in their entirety.]

“Asphalt” means a highly viscous liquid or semi-solid consisting mostly of bitumen and which is a residue by-product of petroleum refining

“Asphalt blowing” means the process by which air is blown through liquid asphalt to remove contaminants such as volatile compounds and to increase viscosity.

“Associated gas” means a natural gas which is found in association with crude oil, either dissolved in crude oil or as a cap of free gas above the crude oil.

“Barrel” or “bbl” means a volume equal to 42 U.S. gallons.

"Best available data and methods" means [the jurisdiction’s] methods for emissions calculations set forth in this article; or [the jurisdiction’s] approved next best alternative from the WCI source category quantification methodologies or other generally accepted methods for calculating greenhouse gas emissions organized by the same source categories and GHG species, using [jurisdiction] provided emission factors and other data.

“Compliance period” means, until such time as [the jurisdiction] adopts a cap-and-trade program covering sources subject to this article, a period of three calendar years.

“Biomass” means non-fossilized plants or parts of plants, animal waste, micro-organisms or any product made of either of these, and includes wood and wood products, agricultural residues and wastes, biologically derived organic matter found in municipal and industrial wastes, landfill gas, bio-alcohols, spent pulping liquor (black liquor), pulp fibers, sludge gas, and animal- or plant-derived oils.

“Biomass fuels” or “biomass-derived fuels” means fuels whose entire heat generating capacity is derived entirely from biomass.

“Bottoming cycle plant” means a cogeneration plant in which the energy input to the system is first applied to a useful thermal energy application or process, and at least some of the reject heat emerging from the application or process is then used for electricity production.

“Calcination” means the thermal decomposition of carbonate-based minerals, into one or more oxides and carbon dioxide

“Calcine” means to heat a substance to a high temperature but below its melting or fusion point causing oxidation or reduction.

“Calcined byproduct/waste type” refers to lime kiln dust and other partially calcined materials and co-products generated during the production of one of the three types of quicklime.

“Calcined byproduct type sold” refers to lime kiln dust and other calcined materials and coproducts, such as off-spec lime, that enters commerce.

“Calcined co-product/waste not sold” refers to any partially calcined co-product or partially calcined material produced during the calcination of limestone or other highly calcareous material that does not enter commerce as its own product or as part of another lime product. Types of calcined co-products/partially calcined material not sold include, but are not limited to, lime kiln dust, scrubber sludge, waste cores, and off-spec lime.

“Carbon dioxide equivalent” or “CO_2 equivalent” or “CO_2e” means a measure for comparing the global warming potentials of different greenhouse gases. By definition, carbon dioxide has a carbon dioxide equivalent of one, with the global warming potentials of other greenhouse gases stated relative to carbon dioxide.

“Catalytic cracking” means the process of breaking down larger, heavier, and more complex hydrocarbon molecules into simpler and lighter molecules through the use of a catalyst.

“Catalytic reforming” means the process of using controlled heat and pressure with catalysts to rearrange certain hydrocarbon molecules.

“Cement” means a building material that is produced by heating mixtures of limestone and other minerals or additives at high temperatures in a rotary kiln to form clinker, followed by cooling and grinding with blended additives to produce a finished powder.

“Cement kiln dust” or “CKD” means the fine-grained, solid, highly alkaline waste removed from cement kiln exhaust gas by air pollution control devices, consisting of partly calcined kiln feed material, dust from cement kilns and bypass systems, including bottom ash and bypass dust.

“Cement plant” means an industrial structure, installation, plant, or building primarily engaged in manufacturing Portland, natural, masonry, pozzolanic, and other hydraulic cements, and typically identified by NAICS code 327310.

“Chemical oxygen demand” or “COD” means the measure of the amount of organic compounds in water, in units of mass per unit volume of water, used to determine water quality.

“Clinker” means the mass of fused material produced in a cement kiln from which finished cement is manufactured by milling and grinding.

“Coal” means a combustible sedimentary rock composed primarily of carbon and classified as anthracite, bituminous, sub-bituminous, or lignite by the American Society for Testing and Materials Designation ASTM D388–05 “Standard Classification of Coals by Rank”.

“Cogeneration unit” means a stationary fuel combustion device which simultaneously generates electrical and thermal energy that is (i) used by the operator of the facility where the cogeneration unit is located; or (ii) transferred to another facility for use by that facility.

“Cogeneration system” means individual cogeneration components including the prime mover (heat engine), generator, heat recovery, and electrical interconnection, configured into an integrated system that provides sequential generation of multiple forms of useful energy (usually electrical and thermal), at least one form of which the facility consumes on-site or makes available to other users for an end-use other than electricity generation.

“Coke ” means a solid residue consisting mainly of carbon which is derived either from the cracking of petroleum hydrocarbons in a refinery coker unit (petroleum coke) or from the destructive distillation of low-ash, low-sulfur bituminous coal (coal coke).

“Coke burn-off” means the removal of coke from the surface of a catalyst through combustion during catalyst regeneration.

“Combustion emissions” means greenhouse gas emissions occurring during the exothermic reaction of a fuel with oxygen.

“Conflict of interest” means a situation in which, because of financial or other activities or relationships with other persons or organizations, a person or body is unable or potentially unable to render an impartial verification opinion of a potential client’s greenhouse gas emissions, or the person or body's objectivity in performing verification services is or might be otherwise compromised.

"Continuous emissions monitoring system (CEMS)" means the total equipment required to obtain a continuous measurement of a gas concentration or emission rate from combustion or industrial processes.

"Crude oil" means a combustible, liquid mixture found in natural underground reservoirs consisting of hydrocarbons and other organic compounds, or derived from tar sands, shale and coal.

"Data check" means an independent calculation or checking of data conducted by a verifier to recreate the emissions for a discreet source included in an emissions data report.

"Electricity generating unit" or "EGU" means any combination of physically connected generator(s), reactor(s), boiler(s), combustion turbine(s), or other prime mover(s) operated together to produce electricity.

"Emissions" means the release of greenhouse gases into the atmosphere from sources and processes in a facility.

"Equipment leak" means releases of fugitive greenhouse gas emissions from equipment including valves, pump seals, flanges, compressors, sampling connections, and open-ended lines and excluding storage tank emissions.

"Exporter" means *[To be defined later for transportation and RCI fuels accounting.]*

"Facility" means all buildings, plants, structures, installations, and equipment that:
(a) Emit or may emit GHG(s);
(b) Are located on one or more contiguous or adjacent properties;
(c) Are under common control of the same owner(s) or operator(s); and
(d) Form a producing unit, function as a single integrated site, or have the same first two digits of the Standard Industrial Classification or same first three digits of the North American Industry Classification System.

[For this version of the Essential Requirements, the words "nonroad engine" have been deleted from the definition of "facility." WCI, however, is considering the inclusion of a protocol for calculating nonroad engine emissions from certain facilities in a future version of the Essential Requirements. If and when that occurs, it may be appropriate to amend this definition to include nonroad engines in the list of covered activities at a stationary source.]

"Feed" means the prepared and mixed materials, which include but are not limited to materials such as limestone, clay, shale, sand, iron ore, mill scale, cement kiln dust, green coke and fly ash, that are fed into a kiln, furnace, or other equipment type but which exclude fuels that are combusted.

“Feedstock” means any raw material that is used in or upgraded by an industrial process but not combusted.

“Flexigas” means a low BTU gaseous fuel produced through the gasification of coke.

“Fluid catalytic cracking unit” or “FCCU” means a process unit in a refinery in which crude oil or a crude oil-derived feedstock is charged and fractured into smaller molecules in the presence of a catalyst, or reacts with a contact material to improve feedstock quality for additional processing, and in which the catalyst or contact material is regenerated by burning off coke and other deposits. The unit includes, but is not limited to, the riser, reactor, regenerator, air blowers, spent catalyst, and all equipment for controlling air pollutant emissions and recovering heat.

“Fluid coking” means a thermal cracking process utilizing the fluidized-solids technique to remove carbon (coke) for continuous conversion of heavy, low-grade oils into lighter products.

“Fossil fuel” means a fuel consisting of the decomposed remains of ancient plants and animals.

“Fuel” means solid, liquid or gaseous combustible material consisting of hydrocarbons and other compounds that is combusted or oxidized for the purpose of producing energy.

“Fuel analytical data” means any data collected about the mass, volume, flow rate, heat content, or carbon content of a fuel.

“Fuel gas system” means a system of compressors, piping, knock-out pots, mix drums, sulfur removal units (if necessary) and flaring units (if necessary) that collects fuel gas from one or more sources for treatment(if necessary), and transports it to a stationary combustion unit.

“Fugitive emissions” means the unintended or incidental emissions of greenhouse gases from the transmission, processing, storage, use, or transportation of fossil fuels, greenhouse gases or other substances, including but not limited to HFC emissions from refrigeration leaks, SF_6 from electric power distribution equipment, methane from mined coal, and CO_2 emitted from geyser steam and/or fluid used in geothermal generating facilities.

“Full verification” means all verification services as provided in section WCI.8(b).

“Generating unit” means any combination of physically connected generator(s), reactor(s), boiler(s), combustion turbine(s), or other prime mover(s) operated together to produce electricity.

“Global warming potential” or “GWP factor” means the radiative forcing of a greenhouse gas, calculated over a time interval of 100 years

“Greenhouse gas”, or “GHG” means any of the following: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), and perfluorocarbons (PFCs).

“High heat value” or “HHV” means the amount of heat energy released by the combustion of a unit quantity of a fuel, including the latent heat of vaporization of water embedded in the fuel

“Hydrocarbons” means chemical compounds consisting entirely of carbon and hydrogen.

“Hydrofluorocarbons” or “HFCs” means a class of GHGs consisting of hydrogen, fluorine, and carbon and primarily used as refrigerants, specifically those listed in Table WCI.10-1.

“Hydrogen plant” means a plant that produces hydrogen with steam hydrocarbon reforming, partial oxidation of hydrocarbons, or other processes.

“Importer” means *[To be defined later with input from the Electricity Subcommittee.]*

“Impregnated saw dust” means saw dust containing resins, preservatives or other substances derived from fossil fuels.

“Independent Peer Reviewer” means a Lead Verifier within a Verification Body who has not participated in conducting verification services for the current reporting year who provides an independent review of verification services rendered as required in section WCI.8(f).

“Kiln” means thermally insulated chambers, or ovens, in which controlled temperature regimes are produced, used in the production of clinker, lime and other products, and which includes any associated preheater or precalciner devices.

“Less Intensive Verification” means the verification services provided in interim years between full verifications; less intensive verification only requires risk assessment and data checks on an owner or operator's emissions data report based on the most current sampling plan developed as part of the most current full verification services. This level of verification may only be used if the verifier can provide findings with a reasonable level of assurance.

“Lime kiln dust” or “LKD” means lime dust produced in the course of production of quick lime.

“Lime type” refers to three types of quicklime derived from limestone containing varying percentages of magnesium carbonate. The three lime types are:

(a) High calcium quicklime, which is derived from limestone containing 0 to 5 percent magnesium carbonate.

(b) Magnesian quicklime, which is derived from limestone containing 5 to 35 percent magnesium carbonate

(c) Dolomitic quicklime, which is derived from limestone containing 35 to 46 percent magnesium carbonate.

“Liquefied petroleum gas” or “LPG” means a group of gaseous hydrocarbons derived from crude oil refining or natural gas fractionation, and includes propane, propylene, normal butane, butane, butylene, isobutene and isobutylene.

"Low BTU gas" means gases recovered from casing vents, vapor recovery systems, storage tanks and other components within the production process of crude oil, natural gas and petroleum products.

"Low Heat Value" or "LHV" means the heat energy released through the combustion of a unit quantity of fuel, excluding the latent heat of vaporization of water embedded in the fuel.

"Material misstatement" means an error or omission, or a collection of errors or omissions, that results in a determination that a verification statement contains a material misstatement under WCI.8(o)(1)(A) or (B).

"Measurement-based" means any of the various emission quantification methodologies that involve the determination of emissions by means of direct measurement of the flue gas flow, as well as the concentration of the relevant GHG(s) in the flue gas.

"Measurement uncertainty" means the scientific uncertainty associated with measuring of GHG emissions due to limitations of monitoring equipment or quantification methodologies.

"Municipal solid waste" or "MSW" means waste products collected from households, commercial/retail units, or institutions.

"NAICS" means the North American Industry Classification System.

"Nameplate generating capacity" means the maximum rated electrical power output of a generator under specific conditions designated by the manufacturer, expressed in megawatts (MW) or kilowatts (kW).

"Net power generated" means the gross electricity generation minus station service or unit service electricity requirements, expressed in megawatt hours (MWh) per year. In the case of cogeneration, this value is intended to include internal consumption of electricity for the purposes of a production process, as well as power put on the grid.

"Nonroad equipment" means [WCI is addressing the definition for nonroad equipment as part of its development of a nonroad equipment rule].

["Owner or operator," as noted in WCI.1(a), is a placeholder. Each jurisdiction will select the specific terminology for the regulated persons in accordance with its customary rule-writing practices.]

"Operator's representative" means:

(a) If the operator of the facility is an individual, the operator.

(b) If the operator of the facility is a corporation, either

  (1) Any officer of the corporation, whether or not the officer is also a director of the corporation, who performs a policy making function in respect of the corporation and who has the capacity to influence the direction of the corporation; or

(2) The individual with primary responsibility for the operations and management of the facility.

(c) If the operator of the facility is not an individual or a corporation, the individual with primary responsibility for the operations and management of the facility.

"Perfluorocarbons" or "PFCs" means synthetic compounds derived from hydrocarbons through the replacement of hydrogen with fluorine atoms.

"Petroleum" means crude oil.

"Petroleum refinery" or "refinery" means any facility engaged in producing gasoline, aromatics, kerosene, distillate fuel oils, residual fuel oils, lubricants, asphalt, or other products through distillation of petroleum or through redistillation, cracking, rearrangement or reforming of unfinished petroleum derivatives.

"Positive verification statement" means a verification statement rendered by a verification body stating that the verification body can say with reasonable assurance that the submitted emissions data report is free of material misstatement and that the emissions data report conforms to the requirements of this article.

"Power" means electricity, except where the context makes clear that another meaning is intended.

"Pressure swing adsorption" or "PSA" means a gas purification process which selectively concentrates target gas molecules using porous, high surface area solid adsorbents and elevated pressure.

"PSA off-gas" or "tail-gas" means the impurity stream resulting from the sequential PSA pressurization/depressurization purification process.

"Prime mover" means the type of equipment such as an engine or water wheel that drives an electric generator. "Prime movers" include, but are not limited to, reciprocating engines, combustion or gas turbines, steam turbines, microturbines, and fuel cells.

"Process" means the intentional or unintentional reactions between substances or their transformation, including, but not limited to, the chemical or electrolytic reduction of metal ores, the thermal decomposition of substances, and the formation of substances for use as product or feedstock.

"Process emissions" means the emissions from industrial processes (e.g., cement production, ammonia production) involving chemical or physical transformations other than fuel combustion. For example, the calcination of carbonates in a kiln during cement production or the oxidation of methane in an ammonia process results in the release of process CO_2 emissions to the atmosphere. Emissions from fuel combustion to provide process heat are not part of process emissions, whether the combustion is internal or external to the process equipment.

"Process vent" means an opening where a gas stream is continuously or periodically discharged during normal operation.

"Pure" means consisting of at least 97 percent by mass of a specified substance.

"Purge gas" means nitrogen, carbon dioxide, liquefied petroleum gas, or natural gas used to maintain a non-explosive mixture of gases in a flare header or provide sufficient exit velocity to prevent regressive flame travel back into the flare header.

"Quick lime" means a substance that consists of oxides of calcium and magnesium resulting from the calcination of limestone.

"Reasonable level of assurance" for an emissions data report means the report satisfies WCI.8(b)(1).

"Recycled" means a material that is reused or reclaimed.

"Refinery fuel gas" or "still gas" means gas generated at a petroleum refinery or any gas generated by a refinery process unit, and that is combusted separately or in any combination with any type of gas or used as a chemical feedstock.

"Reporting year" means the calendar year for which emissions are being reported in the emissions data report.

"Retail provider" means an entity that provides electricity to retail end users.

"Senior officer" means:

(a) The chair of the board of directors, a vice-chair of the board of directors, the president, a vice-president, the secretary, the treasurer or the general manager of a corporation or any other individual who performs functions for a corporation similar to those normally performed by an individual occupying any such office, and

(b) Each of the five highest paid employees of a corporation, including any individual referred to in clause (a).

"Screening value" or "SV" means the instrument reading (ppmv) obtained when components, including but not limited to valves, pump seals, connectors, flanges, open-ended lines and other equipment components, are evaluated for leakage as described in United States Environmental Protection Agency (U.S. EPA) Method 21 – Determination of Volatile Organic Compound Leaks.

"Sinter production" means a process that produces a fused aggregate of fine iron-bearing materials suited for use in a blast furnace. The sinter machine is composed of a continuous traveling grate that conveys a bed of ore fines and other finely divided iron-bearing material and fuel (typically coke breeze), a burner at the feed end of the grate for ignition, and a series of downdraft windboxes along the length of the strand to support downdraft combustion and heat sufficient to produce a fused sinter product.

"SI units" means the Système international d'unités (International System of Units).

"Small refiner" means any petroleum refiner who owns or operates a refinery that has a crude oil throughput capacity equal to or less than 55,000 barrels per day.

"Solid biomass fuel" means plants or parts of plants, in their natural state that have been mechanically or chemically separated, but not chemically altered from the natural state.

"Standard conditions" or "Standard Temperature and Pressure" or "STP" means either a temperature of 20 degrees Celsius (68 degrees Fahrenheit) and a pressure of 101.325 kPa (14.696 PSI) according to IUPAC standards, or a temperature of 0 degrees Celsius (32 degrees Fahrenheit) and an absolute pressure of 100 kPa, according to NIST standards.

"Standard cubic foot" or "scf" means the amount of gas that would occupy a volume of one cubic foot if free of combined water at standard conditions.

"Stationary combustion unit" means any boiler, heater, furnace, kiln, turbine, internal combustion engine, incinerator or other non-mobile source device that combusts any solid, liquid, or gaseous fuel for purposes of producing useful heat or energy for industrial, commercial, or institutional use; or for purposes of reducing the volume of waste by removing combustible material.

"Stationary fuel combustion emissions" means greenhouse gas emissions from stationary combustion units, including cogeneration units.

"Steam reforming" means the process by which methane and other hydrocarbons in natural gas are converted into hydrogen and carbon monoxide by reaction with steam over a catalyst.

"Storage tank" means any tank, other container, or reservoir used for the storage of organic liquids, excluding tanks that are permanently affixed to mobile vehicles such as railroad tank cars, tanker trucks or ocean vessels.

"Sulfur hexafluoride" or "SF_6" means a greenhouse gas composed of a single sulfur atom and six fluorine atoms, commonly used as a dielectric medium.

"Sulfur recovery unit" or "SRU" means a process unit that recovers elemental sulfur from gases that contain reduced sulfur compounds and other pollutants, usually by a vapor-phase catalytic reaction of sulfur dioxide and hydrogen sulfide.

"Supplemental firing" means an energy input to the cogeneration facility used only in the thermal process of a topping cycle plant, or in the electricity generating or manufacturing process of a bottoming cycle plant.

"Supplier" means . . . [To be defined later for transportation and RCI fuels accounting.].

"Topping cycle plant" means a cogeneration plant in which the energy input to the plant is first used to produce electricity, and at least some of the reject heat from the electricity production process is then used to provide useful thermal output.

"Total organic carbon" or "TOC" means a measure of the amount of carbon in an organic compound and is used as a measure of water quality.

"Uncertainty" means the degree to which data or a data system is deemed to be indefinite or unreliable.

"Useful thermal output" means the thermal energy made available in a cogeneration system for use in any industrial or commercial process, heating or cooling application, or delivered to other end users, i.e., total thermal energy made available for processes and applications other than electrical generation.

"Verification" means a systematic, independent and documented process for the evaluation of an operator's emissions data report against the WCI's reporting procedures and methods for calculating and reporting GHG emissions.

"Verification body" means a firm accredited by the [Accreditation Body TBD] and recognized by the jurisdiction or its designee, that is able to render a verification statement and provide verification services for operators subject to reporting under this article.

"Verification cycle" means three years of verification activities. Each verification cycle must include at least one year of full verification, and may include two years of less intensive verification, if eligible.

"Verification statement" means the final written declaration rendered by a verification body attesting whether an operator's emissions data report is free of material misstatement and whether the emissions data report conforms to the requirements of this article.

"Verification services" means services provided during verification as specified in WCI.8, including but not limited to reviewing an operator's emissions data report, verifying its accuracy according to the standards specified in this article, assessing the operator's compliance with this rule, and submitting a verification opinion to the *[jurisdiction or its agent]*.

"Verification team" means all of those working for a verification body, including all subcontractors, to provide verification services for an operator.

"Verifier" means an individual employed or contracted by an accredited verification body who has been deemed competent by the verification body to carry out verification services as specified in section WCI.8.

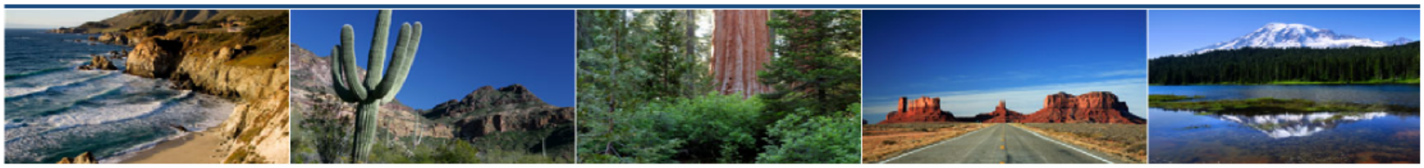
"Volatile Organic Compound" or "VOC" means an organic compound containing at least one carbon atom and which evaporates or vaporizes readily under normal conditions, participates in atmospheric photochemical reactions, and excludes carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate.

“Waste-derived fuel” means a fuel typically derived from waste(s) and generally used as a substitute for conventional fossil fuels. Waste-derived fuels can include substances derived from fossil fuels such as waste oil, plastics, or solvents. Waste-derived fuels can also include fuels containing fractions of both fossil fuels and biomass, such as municipal solid waste, tires, dried sewage or impregnated saw dust. Waste-derived fuel does not include fuels which are pure biomass.

“Wastewater” means any process water which contains oil, emulsified oil, or other organic compounds that are not recycled or otherwise used in a facility.

“Wastewater emissions” means releases of greenhouse gas emissions from wastewater and on-site wastewater treatment.

“Wastewater separator” means equipment used to separate oils and water from locations downstream of process drains.



§ WCI.20 GENERAL STATIONARY COMBUSTION

§ WCI.21 Source Category Definition

General stationary fuel combustion sources are devices that combust solid, liquid, or gaseous fuel for the purpose of generating steam (or providing useful heat or energy) for industrial, commercial, or institutional use; or reducing the volume of waste by removing combustible matter. General stationary combustion sources are boilers, combustion turbines, engines, incinerators, and process heaters, and any other stationary combustion device that is not specifically addressed under the provisions for another source category in this rule.

Note: The source category definition may need to be revised after the remaining ER sections are completed.

§ WCI.22 Greenhouse Gas Reporting Requirements

The emissions data report shall include the following information at the facility level:

(a) Annual greenhouse gas emissions in metric tons, reported as follows:

  (1) Total CO2 emissions for fossil and biomass fuels, reported by fuel type.

  (2) Total CH4 emissions, reported by fuel type.

  (3) Total N_2O emissions, reported by fuel type.

(b) Annual fuel consumption:

  (1) For gases, report in units of standard cubic feet.

  (2) For liquids, report in units of gallons.

  (3) For non-biomass solids, report in units of short tons.

  (4) For biomass solid fuels, report in units of bone dry short tons or bone dry metric tons.

(c) Average carbon content of each fuel, if used to compute CO_2 emissions.

(d) Average high heat value of each fuel, if used to compute CO_2 emissions.

(e) Annual steam generation in pounds or kilograms, for units that burn biomass fuels or municipal solid waste.

§ WCI.23 Calculation of CO_2 Emissions

For each fuel, calculate CO_2 mass emissions using one of the four calculation methodologies specified in this section, subject to the restrictions in §WCI.23(e).

(a) Calculation Methodology 1. Calculate the annual CO_2 mass emissions by substituting a fuel-specific default CO_2 emission factor, a default high heat value, and the annual fuel consumption into the Equation 20-1:

$$CO_2 = Fuel \times HHV \times EF \times CF \times 0.001$$ **Equation 20-1**

Where:

CO_2	=	Annual CO_2 mass emissions for the specific fuel type (metric tons).
Fuel	=	Mass or volume of fuel combusted per year (express mass in short tons for solid fuel, volume in standard cubic feet for gaseous fuel, and volume in gallons for liquid fuel).
HHV	=	Default high heat value of the fuel, from column 3 of Table 20-1 (mmBtu per mass or mmBtu per volume, as applicable).
EF	=	Fuel-specific default CO_2 emission factor, from column 5 of Table 20-1 (kg CO_2/mmBtu).
CF	=	Conversion factor of 0.024 (gallons to barrels) for petroleum products, only; 1.0 for all other fuels.
0.001	=	Conversion factor from kilograms to metric tons.

(b) Calculation Methodology 2. Calculate the annual CO_2 mass emissions using a default fuel-specific CO_2 emission factor, a high heat value provided by the supplier or measured by the operator, using Equation 20-2, except for emissions from the combustion of biomass fuels and municipal solid waste, for which the operator may instead elect to use the method shown in Equation 20-3.

(1) For any type of fuel for which an emission factor is provided in Tables 20-1 or 20-2, except biomass fuels and municipal solid waste when the operator elects to use the method in WCI.23(b)(2), use Equation 20-2:

$$CO_2 = \sum_{p=1}^{n} Fuel_p \times HHV_p \times EF \times 0.001$$ **Equation 20-2**

Where:

CO_2	=	Annual CO_2 mass emissions for a specific fuel type (metric tons).
n	=	Number of required heat content measurements for the year as specified in WCI.25(a).
$Fuel_p$	=	Mass or volume of the fuel combusted during the measurement period “p” (express mass in short tons for solid fuel, volume in standard cubic feet for gaseous fuel, and volume in gallons for liquid fuel).
HHV_p	=	High heat value of the fuel for the measurement period (mmBtu per mass or volume).
EF	=	Fuel-specific default CO_2 emission factor, from column 5 of Table 20-1 or from Table 20-2 (kg CO_2/mmBtu).
0.001	=	Conversion factor from kilograms to metric tons.

(2) For biomass solid fuels and municipal solid waste, use either Equation 20-2 above or Equation 20-3:

$$CO_2 = Steam \times B \times EF \times 0.001$$ **Equation 20-3**

Where:

CO_2	=	Annual CO_2 mass emissions from biomass solid fuel or municipal solid waste combustion (metric tons).
Steam	=	Total mass of steam generated by biomass solid fuel or municipal solid waste combustion during the reporting year (lb steam).
B	=	Ratio of the boiler's design rated heat input capacity to its design rated steam output capacity (mmBtu/lb steam).
EF	=	Default emission factor for biomass solid fuel or municipal solid waste, from column 5 of Table 20-1 (kg CO_2/mmBtu).
0.001	=	Conversion factor from kilograms to metric tons.

(c) Calculation Methodology 3. Calculate the annual CO_2 mass emissions by using measurements of fuel carbon content or molar fraction (for gaseous fuels only), conducted by the operator or provided by the fuel supplier, and the quantity of fuel combusted, using Equation 20-4. For emissions from the combustion of biomass fuels and municipal solid waste, the operator may instead elect to use the method shown in Equation 20-5.

(1) For a solid fuel, use Equation 20-4 of this section:

$$CO_2 = \sum_{i=1}^{n} Fuel_i \times CC_i \times 3.664 \times 0.907$$

Equation 20-4

Where:

CO_2	=	Annual CO_2 mass emissions from the combustion of the specific solid fuel (metric tons).
n	=	Number of carbon content determinations for the year as specified in WCI.25(a).
$Fuel_i$	=	Mass of the solid fuel combusted in measurement period "i" (short tons).
CC_i	=	Carbon content of the solid fuel, from the fuel analysis results for measurement period "i" (percent by weight, expressed as a decimal fraction, e.g., 95% = 0.95).
3.664	=	Ratio of molecular weights, CO_2 to carbon.
0.907	=	Conversion factor from short tons to metric tons.

(2) For biomass fuels or municipal solid waste, use either Equation 20-4 above or Equation 20-5:

$$CO_2 = Steam \times B \times EF \times 0.001$$

Equation 20-5

Where:

CO_2	=	Annual CO_2 mass emissions from biomass solid fuel or municipal solid waste combustion (metric tons).
Steam	=	Total mass of steam generated by biomass solid fuel or municipal solid waste combustion during the reporting year (lb steam).
B	=	Ratio of the boiler's design rated heat input capacity to its design rated steam output capacity (mmBtu/lb steam).

EF	=	Default emission factor for biomass solid fuel or municipal solid waste, from column 5 of Table 20-1, (kg CO_2/mmBtu), adjusted no less often than every third year as provided in WCI.25(a)(5)(B).
0.001	=	Conversion factor from kilograms to metric tons.

(3) For a liquid fuel, use Equation 20-6 of this section:

$$CO_2 = \sum_{i=1}^{n} 3.664 \times Fuel_i \times CC_i \times 0.001$$ **Equation 20-6**

Where:

CO_2	=	Annual CO_2 mass emissions from the combustion of the specific liquid fuel (metric tons).
n	=	Number of required carbon content determinations for the year, as specified in WCI.25(a).
$Fuel_i$	=	Volume of the liquid fuel combusted in measurement period "i" (gallons).
CC_i	=	Carbon content of the liquid fuel, from the fuel analysis results for measurement period "i" (kg C per gallon of fuel).
3.664	=	Ratio of molecular weights, CO_2 to carbon.
0.001	=	Conversion factor from kg to metric tons.

(4) For a gaseous fuel, use Equation 20-7 of this section:

$$CO_2 = \sum_{i=1}^{n} 3.664 \times Fuel_i \times CC_i \times \frac{MW}{MVC} \times 0.001$$ **Equation 20-7**

Where:

CO_2	=	Annual CO_2 mass emissions from combustion of the specific gaseous fuel (metric tons).
n	=	Number of required carbon content and molecular weight determinations for the year, as specified in WCI.25(a).
$Fuel_i$	=	Volume of the gaseous fuel combusted in period "i" (a day or month, as applicable) (scf).
CC_i	=	Average carbon content of the gaseous fuel, from the fuel analysis results for the period "i" (day or month, as applicable) (kg C per kg of fuel).
MW	=	Molecular weight of the gaseous fuel, from fuel analysis (kg/kg-mole).
MVC	=	Molar volume conversion factor (849.5 scf per kg-mole for STP of 20°C and 1 atmosphere or 836 scf per kg-mole for STP of 60°F, and 1 atmosphere).
3.664	=	Ratio of molecular weights, CO_2 to carbon.
0.001	=	Conversion factor from kg to metric tons.

(d) Calculation Methodology 4. Calculate the annual CO_2 mass emissions from all fuels combusted in a unit, by using data from continuous emission monitoring systems (CEMS) as specified in (d)(1) through (d)(7).

(1) For a facility that combusts fossil fuels or biomass fuels and operates CEMS in response to federal, state, provincial, or local regulation, use CO_2 or O_2 concentrations and flue gas flow measurements to determine hourly CO_2 mass emissions using methodologies provided in 40 CFR Part 75, Appendix F or equivalent requirements as applicable in Canada.

(A) The operator shall report CO_2 emissions for the reporting year in metric tons based on the sum of hourly CO_2 mass emissions over the year, converted to metric tons.

(B) If the operator of a facility that combusts biomass fuels uses O_2 concentrations to calculate CO_2 concentrations, annual source testing must demonstrate that calculated CO_2 concentrations when compared to measured CO_2 concentrations meet the Relative Accuracy Test Audit (RATA) requirements in 40 CFR Part 60, Appendix B, Performance Specification 3.

(2) For a facility that combusts waste-derived fuels (as defined in the General Provisions and listed in Table 20-2, including municipal solid waste), and operates a CEMS in response to federal, state, provincial, or local regulations use CO_2 concentrations and flue gas flow measurements to determine hourly CO_2 mass emissions using methodologies provided in 40 CFR Part 75, Appendix F or equivalent requirements as applicable in Canada.

(A) Annual CO_2 emissions shall be reported in metric tons based on the sum of hourly CO_2 mass emissions over the year.

(B) Emissions calculations shall not be based on O_2 concentrations.

(3) The operator of a facility that combusts waste-derived fuels and calculates CO_2 emissions using the methodology provided in WCI.23(d)(2) shall determine the portion of emissions associated with the combustion of biomass using the method provided in WCI.23(f).

(4) An operator who uses CEMS data to report CO_2 emissions from a facility that co-fires fossil fuels with biomass fuels or waste-derived fuels that are partly biomass shall determine the portion of total CO_2 emissions separately assigned to the fossil fuel and the biomass using the method provided in WCI.23(f), if applicable. The operator who co-fires pure biomass fuels with fossil fuels may elect to calculate CO_2 emissions for the fossil fuels using methods designated in WCI.23(a) or WCI.23(b)(1), as applicable, by fuel type and then calculate biomass fuel emissions by subtracting the fossil fuel related emissions from the total CO_2 emissions determined using the CEMS based methodology.

(5) For any units for which CO2 emissions are reported using CEMS data, the operator is relieved of the requirement to separately report process emissions from combustion emissions for that unit or to report emissions separately for different fossil fuels for that unit when only fossil fuels are co-fired. In this circumstance, operators shall still report fuel use by fuel type as otherwise required.

(6) If a facility is subject to requirements in 40 CFR Part 60 or 40 CFR Part 75 and the operator chooses to add devices to an existing CEMS for the purpose of measuring CO_2 concentrations or flue gas flow, the operator shall select and operate the added devices pursuant to the requirements in 40 CFR Part 60 or Part 75 that apply to the facility. If

the facility is subject to both 40 CFR Part 60 and 40 CFR Part 75, the operator shall select and operate the added devices pursuant to the requirements in 40 CFR Part 75.

(7) If a facility does not have a CEMS and the operator chooses to add one in order to measure CO_2 concentrations, the operator shall select and operate the CEMS pursuant to the requirements in 40 CFR Part 75 or equivalent requirements as applicable in Canada.

(A) The operator shall use CO_2 concentrations and flue gas flow measurements to determine hourly CO_2 mass emissions using methodologies provided in 40 CFR Part 75, Appendix F or equivalent requirements as applicable in Canada.

(B) The operator shall report CO_2 emissions for the report year in metric tons based on the sum of hourly CO_2 mass emissions over the year, converted to metric tons.

(C) Operators who add CEMS under this article are subject to specifications in WCI.23(d)(1)-(5), if applicable.

(e) Use of the Four CO_2 Calculation Methodologies. Use of the four CO_2 emissions calculation methodologies described in paragraphs (a) through (d) of this section is subject to the following requirements and restrictions:

(1) Calculation Methodology 1 may not be used by a facility that is subject to the verification requirements of WCI.8, except for stationary combustion units that combust natural gas with a high heat value between 975 and 1,100 Btu per cubic foot. Otherwise, Calculation Methodology 1 may be used for any type of fuel for which a default CO2 emission factor and a default high heat value for the fuel is specified in Table 20-1.

(2) Calculation Methodology 2 may not be used by a facility that is subject to the verification requirements of WCI.8, except for stationary combustion units that combust natural gas with a high heat value between 975 and 1,100 Btu per cubic foot. Otherwise, Calculation Methodology 2 may be used for any type of fuel combusted for which a default CO_2 emission factor for the fuel is specified in Table 20-1 or 20-2.

(3) Calculation Methodology 3 may be used for a unit of any size combusting any type of fuel, except when the use of Calculation Methodology 4 is required.

(4) Calculation Methodology 4 may be used for a unit of any size combusting any type of fuel, and must be used for: a combustion unit with a CEMS that is required by any federal, state, provincial, or local regulation and that includes both a stack gas volumetric flow rate monitor and a CO_2 concentration monitor.

(f) Mixtures of biomass or biomass fuel and fossil fuel.

(1) The owner or operator that combusts fuels or fuel mixtures for which the biomass fraction is known or can be documented shall use the applicable equations in WCI.23(a) through (c) to determine the fossil fuel fraction and shall determine the biomass fraction by subtracting the fossil fuel fraction from the total emissions.

(2) The owner or operator that combusts fuels or fuel mixtures for which the biomass fraction is unknown or cannot be documented (for example, municipal solid waste or tire-derived fuels) shall determine the biomass portion of CO_2 emissions using ASTM

D6866-06a, as specified in this paragraph. This procedure is not required for fuels that contain less than 5 percent biomass by weight or for waste-derived fuels that are less than 30 percent by weight of total fuels combusted in the year for which emissions are being reported, except where the operator wishes to report a biomass fuel fraction of CO_2 emissions.

(A) The operator shall conduct ASTM D6866-06a analysis on a representative fuel or exhaust gas sample at least every three months, and shall collect exhaust gas samples over at least 24 consecutive hours following the standard practice specified by ASTM D7459-08.

(B) The operator shall divide total CO_2 emissions between biomass emissions and non-biomass emissions using the average proportions of the samples analyzed for the year for which emissions are being reported.

(C) If there is a common fuel source to multiple units at the facility, the operator may elect to conduct ASTM D6866-06a testing for one of the units.

§ WCI.24 Calculation of CH_4 and N_2O Emissions

Calculate the annual CH_4 and N_2O mass emissions from stationary fuel combustion sources using the procedures in paragraph (a), (b), or (c), as appropriate.

(a) If the heat content of the fuel is not measured for CO_2 estimation, calculate CH_4 and N_2O emissions using Equation 20-8:

$$CH_4 \; or \; N_2O = Fuel \times HHV_D \times EF \times 0.001 \qquad \textbf{Equation 20-8}$$

Where:

CH_4 or N_2O	=	Combustion emissions from specific fuel type, metric tons CH_4 or N_2O per year.
Fuel	=	Mass or volume of fuel combusted specified by fuel type, unit of mass (short tons) or volume (scf, barrel) per year.
HHV_D	=	Default high heat value specified by fuel type provided in Table 20-1, MMBtu per unit of mass or volume.
EF	=	Default CH_4 or N_2O emission factor provided in Table 20-3, kg CH_4 or N_2O per MMBtu.
0.001	=	Factor to convert kg to metric tons.

(b) If the heat content of the fuel is measured for CO_2 estimation, calculate CH_4 and N_2O emissions using Equation 20-9:

$$CH_4 \; or \; N_2O = \sum_{p=1}^{n} Fuel_p \times HHV_p \times EF \times 0.001 \qquad \textbf{Equation 20-9}$$

Where:

CH_4 or N_2O	=	CH_4 or N_2O emissions from a specific fuel type, metric tons CH_4 or N_2O per year.
$Fuel_p$	=	Mass or volume of fuel combusted for the measurement period, p, specified by fuel type, unit of mass (short tons) or volume (scf, barrel) per year.

HHV_p	=	High heat value measured for the measurement period, p, specified by fuel type, MMBtu per unit mass or volume.
EF	=	Default emission factor provided in Table 20-3, kg CH_4 or N_2O per MMBtu.
0.001	=	Factor to convert kg to metric tons.

(c) For biomass and municipal solid waste combustion, the operator may elect to use Equation 20-10 of this section to estimate CH_4 and N_2O emissions:

$$CH_4 \ or \ N_2O = Steam \times B \times EF \times 0.001 \qquad \textbf{Equation 20-10}$$

Where:

CH_4 or N_2O	=	Annual CH_4 or N_2O emissions from the combustion of a municipal solid waste (metric tons).
Steam	=	Total mass of steam generated by municipal solid waste combustion during the reporting year (lb steam).
B	=	Ratio of the boiler's design rated heat input capacity to its design rated steam output (mmBtu/lb steam).
EF	=	Fuel-specific emission factor for CH_4 or N_2O, from Table WCI.20-3 of this subpart (kg CH_4 or N_2O per mmBtu).
0.001	=	Conversion factor from kilograms to metric tons.

(d) The operator may elect to calculate CH_4 or N_2O emissions using source-specific emission factors derived from source tests conducted at least annually under the supervision of (*jurisdiction*). Upon approval of a source test plan, the source test procedures in that plan shall be repeated in each future year to update the source specific emission factors annually.

(e) Use of the Four CO_2 Calculation Methodologies. Use of the four CH_4 and N_2O emissions calculation methodologies described in paragraphs (a) through (d) of this section is subject to the following requirements and restrictions:

(1) WCI.24(a) may not be used by a facility that is subject to the verification requirements of WCI.8, except for stationary combustion units that combust natural gas with a higher heating value between 975 and 1,150 Btu per cubic foot. Otherwise, WCI.24(a) may be used for any type of fuel for which a default CH_4 or N_2O emission factor and a default higher heat value for the fuel is specified in Table 20-3.

(2) WCI.24(b) may be used for a unit of any size combusting any type of fuel.

(3) WCI.24(c) may only be used for biomass or municipal solid waste combustion.

(4) WCI.24(d) may be used for a unit of any size combusting any type of fuel.

§ WCI.25 Sampling, Analysis, and Measurement Requirements

(a) Fuel Sampling Requirements. Fuel sampling must be conducted or fuel sampling results must be received from the fuel supplier at the frequency specified in paragraphs (a)(1) through (a)(4) of this section.

(1) Once for each new fuel shipment or delivery or on a monthly basis for middle distillates (diesel, gasoline, fuel oil, kerosene), residual oil, liquid waste-derived fuels, and LPG (ethane, propane, isobutene, n-butane, unspecified LPG).

(2) Monthly for natural gas, associated gas, and mixtures of low Btu gas.

(3) Monthly for gases derived from biomass including landfill gas and biogas from wastewater treatment or agricultural processes.

(4) Monthly for solid fuels, as specified below:

(A) The monthly solid fuel sample shall be a composite sample of weekly samples.

(B) The solid fuel shall be sampled at a location after all fuel treatment operations but before fuel mixing and the samples shall be representative of the fuel chemical and physical characteristics immediately prior to combustion.

(C) Each weekly sub-sample shall be collected at a time (day and hour) of the week when the fuel consumption rate is representative and unbiased.

(D) Four weekly samples (or a sample collected during each week of operation during the month) of equal mass shall be combined to form the monthly composite sample.

(E) The monthly composite sample shall be homogenized and well mixed prior to withdrawal of a sample for analysis.

(F) One in twelve composite samples shall be randomly selected for additional analysis of its discrete constituent samples. This information will be used to monitor the homogeneity of the composite.

(5) For biomass fuels and waste-derived fuels, the following may apply in lieu of WCI.25(a)(4):

(A) If CO_2 emissions are calculated using WCI.23(c)(1), the source-specific carbon content is determined annually. Upon approval of a source test plan by [*jurisdiction*], the source test procedures in that plan shall be repeated in subsequent years to update the source specific emission factors annually.

(B) If CO_2 emissions are calculated using WCI.23(c)(2) (biomass fuels and municipal solid waste only), the operator shall adjust the emission factor, in kg CO2/MMBtu not less frequently than every third year, through a stack test measurement of CO2 and use of the applicable ASME Performance Test Code to determine heat input from all heat outputs, including the steam, flue gases, ash and losses.

(b) Fuel Consumption Monitoring Requirements.

(1) Facilities may determine fuel consumption on the basis of direct measurement or recorded fuel purchase or sales invoices measuring any stock change (measured in million Btu, gallons, million standard cubic feet, short tons or bone dry short, tons) using the following equation:

Fuel Consumption in the Report Year = Total Fuel Purchases – Total Fuel Sales + Amount Stored at Beginning of Year – Amount Stored at Year End

(2) Fuel consumption measured in Btu values shall be converted to the required metrics of mass or volume using heat content values that are either provided by the supplier, measured by the facility, or provided in Table 20-1.

(3) All oil and gas flow meters (except for gas billing meters) shall be calibrated prior to the first year for which GHG emissions are reported under this rule, using an applicable flow meter test method listed in section WCI.6 or the calibration procedures specified by the flow meter manufacturer. Fuel flow meters shall be recalibrated either annually or at the minimum frequency specified by the manufacturer.

(4) For fuel oil, tank drop measurements may also be used.

(5) Equipment used to measure solid fuel consumption at a facility shall be calibrated prior to the first year for which GHG emissions are reported under this rule, using a test method listed in section WCI.6 or the calibration procedures specified by the equipment manufacturer. Equipment shall be recalibrated either annually or at the minimum frequency specified by the manufacturer.

(c) Fuel Heat Content Monitoring Requirements. High heat values shall be based on the results of fuel sampling and analysis received from the fuel supplier or determined by the operator, in either case using an applicable analytical method listed in section WCI.6.

(1) For gases, use ASTM D1826-94 (Reapproved 2003), ASTM D3588-98 (Reapproved 2003), ASTM D4891-89 (Reapproved 2006), GPA Standard 2261-00 “Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography.” The operator may alternatively elect to use on-line instrumentation that determines heating value accurate to within ± 5.0 percent. Where existing on-line instrumentation provides only low heating value, the operator shall convert the value to high heat value as follows:

$$HHV = LHV \times CF$$

Equation 20-11

Where:

HHV = fuel or fuel mixture high heat value (Btu/scf).
LHV = fuel or fuel mixture low heat value (Btu/scf).
CF = conversion factor.

For natural gas, a CF of 1.11 shall be used. For refinery fuel gas and mixtures of refinery fuel gas, a weekly average fuel system-specific CF shall be derived as follows:

(A) by concurrent LHV instrumentation measurements and HHV determined by on-line instrumentation or laboratory analysis as part of the daily carbon content determination; or,

(B) by the HHV/LHV ratio obtained from the laboratory analysis of the daily samples.

(2) For middle distillates and oil, or liquid waste-derived fuels, use ASTM D240-02 (Reapproved 2007), or ASTM D4809-06 (Reapproved 2005).

(3) For solid biomass-derived fuels, use ASTM D5865-07a.

(4) For waste-derived fuels, use ASTM D5865-07a or ASTM D5468-02 (Reapproved 2007). Operators who combust waste-derived fuels that are not pure biomass fuels shall determine the biomass fuel portion of CO_2 emissions using the method specified in section WCI.23(f), if applicable

(d) Fuel Carbon Content Monitoring Requirements. Fuel carbon content and either molecular weight or molar fraction for gaseous fuels shall be based on the results of fuel sampling and analysis received from the fuel supplier or determined by the operator, in either case using an applicable analytical method listed in section WCI.6.

(1) For coal and coke, solid biomass fuels, and waste-derived fuels; use ASTM 5373-08.

(2) For liquid fuels, use the following ASTM methods: For petroleum-based liquid fuels and liquid waste-derived fuels, use ASTM D5291-02 (Reapproved 2007) “Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants”, ultimate analysis of oil or computations based on ASTM D3238-95 (Reapproved 2005) and either ASTM D2502-04 or ASTM D2503-92 (Reapproved 2007).

(3) For gaseous fuels, use ASTM D1945-03 (Reapproved 2006) or ASTM D1946-90 (Reapproved 2006). The operator may alternatively elect to use on-line instrumentation that determines fuel carbon content accurate to ± 5 percent.

(e) Fuel Analytical Data Capture. When the applicable emissions estimation methodologies in sections WCI.20 through WCI.XXX require periodic collection of fuel analytical data for an emissions source, the operator shall demonstrate every reasonable effort to obtain a fuel analytical data capture rate of 100 percent for each report year.

(1) If the operator is unable to obtain fuel analytical data such that more than 20 percent of emissions from a source cannot be directly accounted for, the emissions from that source shall be considered unverifiable for the report year.

(2) If the fuel analytical data capture rate is at least 80 percent but less than 100 percent for any emissions source identified in sections WCI.20 through WCI.XXX, the operator shall use the mean of the fuel analytical data results captured to substitute for the missing values for the period of missing data.

(f) Procedure for Interim Fuel Analytical Data Collection.

(1) In the event of an unforeseen breakdown of fuel analytical data monitoring equipment required for the emissions estimation methodologies in sections WCI.20 through WCI.XXX, [jurisdiction] may authorize an operator to use an interim data collection procedure if [jurisdiction] determines that the operator has satisfactorily demonstrated that:

(A) The breakdown may result in a loss of more than 20 percent of the source’s fuel data for the reporting year, such that emissions for the affected source could not be verified under the provisions of section WCI.8;

(B) The fuel analytical data monitoring equipment cannot be promptly repaired or replaced without shutting down a process unit significantly affecting facility operations, or that the monitoring equipment must be replaced and replacement equipment is not immediately available;

(C) The interim procedure will not remain in effect longer than is reasonably necessary for repair or replacement of the malfunctioning data monitoring equipment; and

(D) The request was submitted within 30 calendar days of the breakdown of the fuel analytical data monitoring equipment.

(2) An operator seeking approval of an interim data collection procedure must, within 30 days of the monitoring equipment breakdown, submit a written request to [jurisdiction] that includes all of the following:

(A) The proposed start date and end date of the interim procedure;

(B) A detailed description of what data are affected by the breakdown;

(C) A discussion of the accuracy of data collected during the interim procedure compared with the data collected under the operator's usual equipment-based method;

(D) A demonstration that no feasible alternative procedure exists that would provide more accurate emissions data; and

(E) A demonstration that the proposed interim procedure meets the criteria specified in sectionWCI.25(f)(1).

(3) *[The jurisdiction]* may limit the duration of the interim data collection procedure or include other conditions of approval to ensure the criteria in section WCI.25(f)(1) are met.

(4) When approving an interim data collection procedure, [jurisdiction] shall determine whether the accuracy of data collected under the procedure is reasonably equivalent to data collected from properly functioning monitoring equipment, and if it is not, the relative accuracy to assign for purposes of assessing possible material misstatement under section WCI.8(o).

Table 20-1. Default Carbon Content, Heat Content, and Carbon Dioxide Emission Factors from Stationary Combustion by Fuel Type

Coal and Coke	kg C / MMBtu	MMBtu / Short Ton	kg CO_2 / Short Ton	kg CO_2 / MMBtu
Anthracite	28.26	25.09	2,597.94	103.54
Bituminous	25.49	24.93	2,328.35	93.40
Sub-bituminous	26.48	17.25	1,673.64	97.02
Lignite	26.30	14.21	1,369.32	96.36
Unspecified (Residential/Commercial)	26.00	22.07	2,118.67	95.26
Unspecified (Industrial Coking)	25.56	26.27	2,461.17	93.65
Unspecified (Other Industrial)	25.63	22.05	2,082.89	93.91
Unspecified (Electric Power)	25.76	19.93	1,884.86	94.38
Coke	27.85	24.80	2,530.65	102.04
Natural Gas (By Heat Content)	**kg C / MMBtu**	**MMBtu / 1,000 Standard cubic foot**	**kg CO_2 / 1,000 Standard cubic foot**	**kg CO_2 / MMBtu**
975 to 1,000 Btu / Standard cubic foot	14.73	n/a	n/a	53.97
1000 to 1,025 Btu / Std cubic foot	14.43	n/a	n/a	52.87
1025 to 1,050 Btu / Std cubic foot	14.47	n/a	n/a	53.02
1050 to 1,075 Btu / Std cubic foot	14.58	n/a	n/a	53.42
1075 to 1,100 Btu / Std cubic foot	14.65	n/a	n/a	53.68
Greater than 1,100 Btu / Std cubic foot	14.92	n/a	n/a	54.67
Unspecified (Weighted U.S. Average)	14.47	1.027	54.4	53.02

Table 20-1. Default Carbon Content, Heat Content, and Carbon Dioxide Emission Factors from Stationary Combustion by Fuel Type (continued)

Petroleum Products	kg C / MMBtu	MMBtu / Barrel	kg CO_2 / gallon	kg CO_2 / MMBtu
Asphalt & Road Oil	20.62	6.636	11.94	75.55
Aviation Gasoline	18.87	5.048	8.31	69.14
Distillate Fuel Oil (#1, 2 & 4)	19.95	5.825	10.14	73.10
Jet Fuel	19.33	5.670	9.56	70.83
Kerosene	19.72	5.670	9.75	72.25
LPG (energy use)	17.19	3.861	5.79	62.98
Propane	17.20	3.824	5.74	63.02
Ethane	16.25	2.916	4.13	59.54
Isobutane	17.75	4.162	6.44	65.04
n-Butane	17.72	4.328	6.69	64.93
Lubricants	20.24	6.065	10.71	74.16
Motor Gasoline	19.33	5.218	8.80	70.83
Residual Fuel Oil (#5 & 6)	21.49	6.287	11.79	78.74
Crude Oil	20.33	5.800	10.29	74.49
Naphtha (<401 deg. F)	18.14	5.248	8.30	66.46
Natural Gasoline	18.24	4.620	7.35	66.83
Other Oil (>401 deg. F)	19.95	5.825	10.14	73.10
Pentanes Plus	18.24	4.620	7.35	66.83
Petrochemical Feedstocks	19.37	5.428	9.17	70.97
Petroleum Coke	27.85	6.024	14.64	102.04
Still Gas	17.51	6.000	9.17	64.16
Special Naphtha	19.86	5.248	9.09	72.77
Unfinished Oils	20.33	5.825	10.33	74.49
Waxes	19.81	5.537	9.57	72.58
Other Solid Fuels	**kg C / MMBtu**	**MMBtu / Short Ton**	**kg CO_2 / Short Ton**	**kg CO_2 / MMBtu**
Biomass Derived Fuels (Solid). Wood and Wood Waste (12% moisture content) or other solid biomass fuels (EPA)	25.60	15.38	1,442.62	93.80
Biomass Derived Fuels (Solid). Wood and Wood Waste (50% moisture content) (Environment Canada	29.97	15.47	861.83	55.68
Municipal Solid Waste (MSW)	24.74	8.7	788.7	90.65
Peat	29.07	8.83	940.66	106.53
Biomass-derived Fuels (Gas)	**kg C / MMBtu**	**Btu / Standard cubic foot**	**kg CO_2 / Standard cubic foot**	**kg CO_2 / MMBtu**
Biogas (includes landfill gas and manure biogas)*	28.4	Varies	Varies	104.06

Note: Heat content factors are based on high heat values (HHV).
The emission factors for biogas include both CO_2 from combustion and the pass-through CO_2, which are assumed to be in equal proportions.
Sources:
U.S. EPA, *Inventory of Greenhouse Gas Emissions and Sinks: 1990-2007 (2009)*, Annex 2.1, Tables A-28, A-31, A-32, A-35, and A-36, except:

- Heat Content factors for Unspecified Coal (by sector), Coke, Naptha (<401 F°), and Other Oil (>401 F°), from U.S. Energy Information Administration, *Annual Energy Review 2007 (Released June 23, 2008)*, Tables A-1, A-4, and A-5;
- Heat Content factors for Coal (by type) and LPG, and all factors for Wood and Wood Waste, Landfill Gas, and Wastewater Treatment Biogas, from U.S. EPA Climate Leaders, *Stationary Combustion Guidance (May, 2008)*, Tables B-1 and B-2; and
- Municipal Solid Waste (MSW) factors, from Energy Information Administration, http://www.eia.doe.gov/oiaf/1605/coefficients.html.
- Peat Emission Factors are based on high heat values (HHV). Values were converted from LHV to HHV assuming that LHV is 5 percent lower than HHV for solid and liquid fuels.
- HHV calculated from net calorific values in Intergovernmental Panel on Climate Change, *2006 IPCC Guidelines for National Greenhouse Gas Inventories (2006)*, Volume 1, Tables 1.2.

Table 20-2. Default Carbon Dioxide Emission Factors from Stationary Combustion for Waste Derived Fuels	
Fuel Type	**kg CO_2 / MMBtu**
Waste Oil	78
Tires	90
Plastics	79
Solvents	78
Impregnated Saw Dust	79
Other Fossil Based Wastes	84
Dried Sewage Sludge	116
Mixed Industrial Waste	88
Municipal Solid Waste	See Table 20-1

Note: Emission factors are based on high heat values (HHV). Values were converted from LHV to HHV assuming that LHV are 5 percent lower than HHV for solid and liquid fuels.

Source: WBCSD/WRI, *The Cement CO_2 Protocol: CO_2 Accounting and Reporting Standard for the Cement Industry Calculation Tool (2004).*

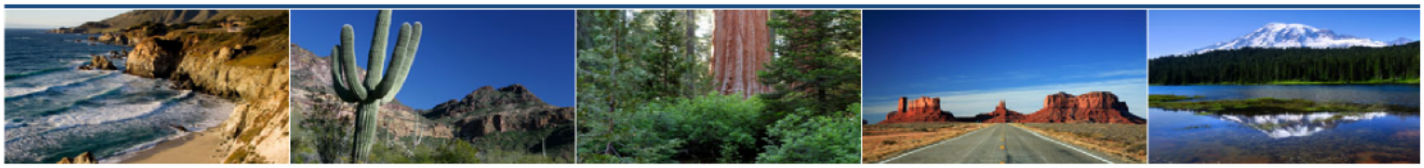
Table 20-3. Default CH_4 and N_2O Emission Factors from Stationary Combustion by Fuel Type		
Fuel Type	**CH_4 Emission Factor (kg CH_4/ MMBtu)**	**N_2O Emission Factor (kg N_2O / MMBtu)**
Asphalt	0.003	0.0006
Aviation Gasoline	0.003	0.0006
Coal	0.01	0.0015
Crude Oil	0.003	0.0006
Digester Gas	0.0009	0.0001
Distillate	0.003	0.0006
Gasoline	0.003	0.0006
Jet Fuel	0.003	0.0006
Kerosene	0.003	0.0006
Kraft Black Liquor (ICFPA)	0.0026	0.0021
Kraft Black Liquor (Environment Canada)	0.0038	0.0015
Kraft Black Liquor (EPA)	0.03	0.005
Landfill Gas	0.0009	0.0001
LPG	0.001	0.0001
Lubricants	0.003	0.0006
Municipal Solid Waste	0.03	0.004
Naphtha	0.003	0.0006
Natural Gas	0.0009	0.0001
Natural Gas Liquids	0.003	0.0006
Other Biomass Fuels	0.03	0.004
Petroleum Coke	0.003	0.0006
Propane	0.001	0.0001
Refinery Gas	0.0009	0.0001
Residual Fuel Oil	0.003	0.0006
Tires	0.003	0.0006
Waste Oil	0.03	0.004
Waxes	0.003	0.0006
Wood (Dry)	0.03	0.004

Table 20-3. Default CH_4 and N_2O Emission Factors from Stationary Combustion by Fuel Type		
Fuel Type	**CH_4 Emission Factor (kg CH_4/ MMBtu)**	**N_2O Emission Factor (kg N_2O / MMBtu)**
Wood Waste (Environment Canada)	0.0029	0.001

Note: Heat content factors are based on high heat values (HHV).
Source: Intergovernmental Panel on Climate Change, *2006 IPCC Guidelines for National Greenhouse Gas Inventories (2006)*, Volume 2, Tables 2.2, 2.3, and 2.4, except:

- Kraft Black Liquor emission factors, from International Council of Forest and Paper Associations, *Calculation Tools for Estimating Greenhouse Gas Emissions from Pulp and Paper Mills (2005),* Appendix F, Table 8.

The RC notes the significant difference in both the kraft black liquor and solid biomass (wood waste) emission factors published by the EPA and Environment Canada (as well as those submitted by industry associations). In lieu of recommending a single emission factor at this time (as there is no certainty as to which is most accurate) the RC is presenting both for information purposes. The RC will be working with experts in the two federal agencies and other organizations to ascertain the most accurate emission factor to use for both Metric and English unit versions of the Essential Requirements of Mandatory Reporting.



§ WCI.20 GENERAL STATIONARY COMBUSTION

§ WCI.21 Source Category Definition

General stationary fuel combustion sources are devices that combust solid, liquid, or gaseous fuel for the purpose of generating steam (or providing useful heat or energy) for industrial, commercial, or institutional use; or reducing the volume of waste by removing combustible matter. General stationary combustion sources are boilers, combustion turbines, engines, incinerators, and process heaters, and any other stationary combustion device that is not specifically addressed under the provisions for another source category in this rule.

Note: The source category definition may need to be revised after the remaining ER sections are completed.

§ WCI.22 Greenhouse Gas Reporting Requirements

The emissions data report shall include the following information at the facility level:

(a) Annual greenhouse gas emissions in metric tons, reported as follows:

(1) Total CO_2 emissions for fossil and biomass fuels, reported by fuel type.
(2) Total CH_4 emissions, reported by fuel type.
(3) Total N_2O emissions, reported by fuel type.

(b) Annual fuel consumption:

(1) For gases, report in units of standard cubic meters.
(2) For liquids, report in units of kiloliters.
(3) For non-biomass solids, report in units of metric tons.
(4) For biomass solid fuels, report in units of bone dry metric tons.

(c) Average carbon content of each fuel, if used to compute CO_2 emissions.

(d) Average high heat value of each fuel, if used to compute CO_2 emissions.

(e) Annual steam generation in kilograms, for units that burn biomass fuels or municipal solid waste.

§ WCI.23 Calculation of CO_2 Emissions

For each fuel, calculate CO_2 mass emissions using one of the four calculation methodologies specified in this section, subject to the restrictions in §WCI.23(e).

(a) Calculation Methodology 1. Calculate the annual CO_2 mass emissions by substituting a fuel-specific default CO_2 emission factor, a default high heat value, and the annual fuel consumption into the Equation 20-1:

$$CO_2 = Fuel \times HHV \times EF \times 0.001$$ **Equation 20-1**

Where:

CO_2	=	Annual CO_2 mass emissions for the specific fuel type (metric tons).
Fuel	=	Mass or volume of fuel combusted per year (express mass in metric tons for solid fuel, volume in standard cubic meters for gaseous fuel, and volume in kiloliters for liquid fuel).
HHV	=	Default high heat value of the fuel, from Table 20-1 (GJ per metric ton for solid fuel, GJ per kiloliter for liquid fuel, or GJ per cubic meter for gaseous fuel).
EF	=	Fuel-specific default CO_2 emission factor, from Tables 20-2, 20-3, 20-5, or 20-7, as applicable (kg CO_2/GJ).
0.001	=	Conversion factor from kilograms to metric tons.

(b) Calculation Methodology 2. Calculate the annual CO_2 mass emissions using a default fuel-specific CO_2 emission factor, a high heat value provided by the supplier or measured by the operator, using Equation 20-2, except for emissions from the combustion of biomass fuels and municipal solid waste, for which the operator may instead elect to use the method shown in Equation 20-3.

(1) For any type of fuel for which an emission factor is provided in Tables 20-2, 20-3, 20-5, or 20-7, as applicable, except biomass fuels and municipal solid waste when the operator elects to use the method in WCI.23(b)(2), use Equation 20-2:

$$CO_2 = \sum_{p=1}^{n} Fuel_p \times HHV_p \times EF \times 0.001$$ **Equation 20-2**

Where:

CO_2	=	Annual CO_2 mass emissions for a specific fuel type (metric tons).
n	=	Number of required heat content measurements for the year as specified in WCI.25.
$Fuel_p$	=	Mass or volume of the fuel combusted during the measurement period "p" (express mass in metric tons for solid fuel, volume in standard cubic meters for gaseous fuel, and volume in kiloliters for liquid fuel).
HHV_p	=	High heat value of the fuel for the measurement period (GJ per metric ton for solid fuel, GJ per kiloliter for liquid fuel, or GJ per cubic meter for gaseous fuel).
EF	=	Fuel-specific default CO_2 emission factor, from Tables 20-2, 20-3, 20-5, or 20-7, as applicable (kg CO_2/GJ).
0.001	=	Conversion factor from kilograms to metric tons.

(2) For biomass solid fuels and municipal solid waste, use either Equation 20-2 above or Equation 20-3:

$$CO_2 = Steam \times B \times EF \times 0.001$$ **Equation 20-3**

Where:

CO_2	=	Annual CO_2 mass emissions from biomass solid fuel or municipal solid waste combustion (metric tons).

Steam	=	Total mass of steam generated by biomass solid fuel or municipal solid waste combustion during the reporting year (metric tons steam).
B	=	Ratio of the boiler's design rated heat input capacity to its design rated steam output capacity (GJ/metric ton steam).
EF	=	Default emission factor for biomass solid fuel or municipal solid waste, from Table 20-2 or Table 20-7, as applicable (kg CO_2/GJ).
0.001	=	Conversion factor from kilograms to metric tons.

(c) Calculation Methodology 3. Calculate the annual CO_2 mass emissions by using measurements of fuel carbon content or molar fraction (for gaseous fuels only), conducted by the operator or provided by the fuel supplier, and the quantity of fuel combusted, using Equation 20-4. For emissions from the combustion of biomass fuels and municipal solid waste, the operator may instead elect to use the method shown in Equation 20-5.

(1) For a solid fuel, use Equation 20-4 of this section:

Equation 20-4

$$CO_2 = \sum_{i=1}^{n} Fuel_i \times CC_i \times 3.664$$

Where:

CO_2	=	Annual CO_2 mass emissions from the combustion of the specific solid fuel (metric tons).
n	=	Number of carbon content determinations for the year.
$Fuel_i$	=	Mass of the solid fuel combusted in measurement period "i" (metric tons).
CC_i	=	Carbon content of the solid fuel, from the fuel analysis results for measurement period "i" (percent by weight, expressed as a decimal fraction, e.g., 95% = 0.95).
3.664	=	Ratio of molecular weights, CO_2 to carbon.

(2) For biomass fuels or municipal solid waste, use either Equation 20-4 above or Equation 20-5:

$$CO_2 = Steam \times B \times EF \times 0.001$$

Equation 20-5

Where:

CO_2	=	Annual CO_2 mass emissions from biomass solid fuel or municipal solid waste combustion (metric tons).
Steam	=	Total mass of steam generated by biomass solid fuel or municipal solid waste combustion during the reporting year (metric tons steam).
B	=	Ratio of the boiler's design rated heat input capacity to its design rated steam output capacity (GJ/metric ton steam).
EF	=	Default emission factor for biomass solid fuel or municipal solid waste, from Table 20-2 or 20-7, as applicable (kg CO_2/GJ), adjusted no less often than every third year as provided in WCI.25(a)(5)(B).
0.001	=	Conversion factor from kilograms to metric tons.

(3) For a liquid fuel, use Equation 20-6 of this section:

$$CO_2 = \sum_{i=1}^{n} 3.664 \times Fuel_i \times CC_i$$ **Equation 20-6**

Where:

CO_2	=	Annual CO_2 mass emissions from the combustion of the specific liquid fuel (metric tons).
n	=	Number of required carbon content determinations for the year, as specified in WCI.25.
$Fuel_i$	=	Volume of the liquid fuel combusted in measurement period "i" (kiloliters).
CC_i	=	Carbon content of the liquid fuel, from the fuel analysis results for measurement period "i" (metric ton C per kiloliter of fuel).
3.664	=	Ratio of molecular weights, CO_2 to carbon.

(4) For a gaseous fuel, use Equation 20-7 of this section:

$$CO_2 = \sum_{i=1}^{n} 3.664 \times Fuel_i \times CC_i \times \frac{MW}{MVC} \times 0.001$$ **Equation 20-7**

Where:

CO_2	=	Annual CO_2 mass emissions from combustion of the specific gaseous fuel (metric tons).
n	=	Number of required carbon content and molecular weight determinations for the year, as specified in WCI.25.
$Fuel_i$	=	Volume of the gaseous fuel combusted in period "i" (a day or month, as applicable) (scm).
CC_i	=	Average carbon content of the gaseous fuel, from the fuel analysis results for the period "i" (day or month, as applicable) (kg C per kg of fuel).
MW	=	Molecular weight of the gaseous fuel, from fuel analysis (kg/kg-mole).
MVC	=	Molar volume conversion factor (24.1 scm per kg-mole for STP of 20°C and 1 atmosphere or 23.7 scm per kg-mole for STP of 60°F, and 1 atmosphere).
3.664	=	Ratio of molecular weights, CO_2 to carbon.
0.001	=	Conversion factor from kg to metric tons.

(d) Calculation Methodology 4. Calculate the annual CO_2 mass emissions from all fuels combusted in a unit, by using data from continuous emission monitoring systems (CEMS) as specified in (d)(1) through (d)(7).

(1) For a facility that combusts fossil fuels or biomass fuels and operates CEMS in response to federal, state, provincial, or local regulation, use CO_2 or O_2 concentrations and flue gas flow measurements to determine hourly CO_2 mass emissions using methodologies provided in 40 CFR Part 75, Appendix F or equivalent requirements as applicable in Canada.

(A) The operator shall report CO_2 emissions for the reporting year in metric tons based on the sum of hourly CO_2 mass emissions over the year, converted to metric tons.

(B) If the operator of a facility that combusts biomass fuels uses O_2 concentrations to calculate CO_2 concentrations, annual source testing must demonstrate that calculated

CO_2 concentrations when compared to measured CO_2 concentrations meet the Relative Accuracy Test Audit (RATA) requirements in 40 CFR Part 60, Appendix B, Performance Specification 3.

(2) For a facility that combusts waste-derived fuels (as defined in the General Provisions and including municipal solid waste), and operates a CEMS in response to federal, state, provincial, or local regulations use CO_2 concentrations and flue gas flow measurements to determine hourly CO_2 mass emissions using methodologies provided in 40 CFR Part 75, Appendix F or equivalent requirements as applicable in Canada.

(A) Annual CO_2 emissions shall be reported in metric tons based on the sum of hourly CO_2 mass emissions over the year.

(B) Emissions calculations shall not be based on O_2 concentrations.

(3) The operator of a facility that combusts waste-derived fuels and calculates CO_2 emissions using the methodology provided in WCI.23(d)(2) shall determine the portion of emissions associated with the combustion of biomass using the method provided in WCI.23(f).

(4) An operator who uses CEMS data to report CO_2 emissions from a facility that co-fires fossil fuels with biomass fuels or waste-derived fuels that are partly biomass shall determine the portion of total CO_2 emissions separately assigned to the fossil fuel and the biomass using the method provided in WCI.23(f), if applicable. The operator who co-fires pure biomass fuels with fossil fuels may elect to calculate CO_2 emissions for the fossil fuels using methods designated in WCI.23(a) or WCI.23(b)(1), as applicable, by fuel type and then calculate biomass fuel emissions by subtracting the fossil fuel related emissions from the total CO_2 emissions determined using the CEMS based methodology.

(5) For any units for which CO2 emissions are reported using CEMS data, the operator is relieved of the requirement to separately report process emissions from combustion emissions for that unit or to report emissions separately for different fossil fuels for that unit when only fossil fuels are co-fired. In this circumstance, operators shall still report fuel use by fuel type as otherwise required.

(6) If a facility is subject to requirements in 40 CFR Part 60 or 40 CFR Part 75 and the operator chooses to add devices to an existing CEMS for the purpose of measuring CO2 concentrations or flue gas flow, the operator shall select and operate the added devices pursuant to the requirements in 40 CFR Part 60 or Part 75 that apply to the facility. If the facility is subject to both 40 CFR Part 60 and 40 CFR Part 75, the operator shall select and operate the added devices pursuant to the requirements in 40 CFR Part 75.

(7) If a facility does not have a CEMS and the operator chooses to add one in order to measure CO_2 concentrations, the operator shall select and operate the CEMS pursuant to the requirements in 40 CFR Part 75 or equivalent requirements as applicable in Canada.

(A) The operator shall use CO_2 concentrations and flue gas flow measurements to determine hourly CO_2 mass emissions using methodologies provided in 40 CFR Part 75, Appendix F or equivalent requirements as applicable in Canada.

(B) The operator shall report CO_2 emissions for the report year in metric tons based on the sum of hourly CO_2 mass emissions over the year, converted to metric tons.

(C) Operators who add CEMS under this article are subject to specifications in WCI.23(d)(1)-(5), if applicable.

(e) Use of the Four CO_2 Calculation Methodologies. Use of the four CO_2 emissions calculation methodologies described in paragraphs (a) through (d) of this section is subject to the following requirements and restrictions:

(1) Calculation Methodology 1 may not be used by a facility that is subject to the verification requirements of WCI.8, except for stationary combustion units that combust natural gas with a high heat value between 36.3 and 40.98 MJ per cubic meter. Otherwise, Calculation Methodology 1 may be used for any type of fuel for which a default CO2 emission factor (Tables 20-2, 20-3, 20-5, or 20-7, as applicable) and a default high heat value for the fuel (Table 20-1) is specified.

(2) Calculation Methodology 2 may not be used by a facility that is subject to the verification requirements of WCI.8, except for stationary combustion units that combust natural gas with a high heat value between 36.3 and 40.98 MJ per cubic meter. Otherwise, Calculation Methodology 2 may be used for any type of fuel combusted for which a default CO2 emission factor for the fuel is specified in Tables 20-2, 20-3, 20-5, or 20-7, as applicable.

(3) Calculation Methodology 3 may be used for a unit of any size combusting any type of fuel, except when the use of Calculation Methodology 4 is required.

(4) Calculation Methodology 4 may be used for a unit of any size combusting any type of fuel, and must be used for: a combustion unit with a CEMS that is required by any federal, state, provincial, or local regulation and that includes both a stack gas volumetric flow rate monitor and a CO_2 concentration monitor.

(f) Mixtures of biomass or biomass fuel and fossil fuel.

(1) The owner or operator that combusts fuels or fuel mixtures for which the biomass fraction is known or can be documented shall use the applicable equations in WCI.23(a) through (c) to determine the fossil fuel fraction and shall determine the biomass fraction by subtracting the fossil fuel fraction from the total emissions.

(2) The owner or operator that combusts fuels or fuel mixtures for which the biomass fraction is unknown or cannot be documented (for example, municipal solid waste or tire-derived fuels) shall determine the biomass portion of CO_2 emissions using ASTM D6866-06a, as specified in this paragraph. This procedure is not required for fuels that contain less than 5 percent biomass by weight or for waste-derived fuels that are less than 30 percent by weight of total fuels combusted in the year for which emissions are being reported, except where the operator wishes to report a biomass fuel fraction of CO_2 emissions.

(A) The operator shall conduct ASTM D6866-06a analysis on a representative fuel or exhaust gas sample at least every three months, and shall collect exhaust gas samples over at least 24 consecutive hours following the standard practice specified by ASTM D7459-08.

(B) The operator shall divide total CO_2 emissions between biomass fuel emissions and non-biomass fuel emissions using the average proportions of the samples analyzed for the year for which emissions are being reported.

(C) If there is a common fuel source to multiple units at the facility, the operator may elect to conduct ASTM D6866-06a testing for one of the units.

§ WCI.24 Calculation of CH_4 and N_2O Emissions

Calculate the annual CH_4 and N_2O mass emissions from stationary fuel combustion sources using the procedures in paragraph (a), (b), or (c), as appropriate.

(a) If the heat content of the fuel is not measured for CO_2 estimation, calculate CH_4 and N_2O emissions using Equation 20-8 for all fuels except coal. For coal, use Equation 20-9:

$$CH_4 \text{ or } N_2O = Fuel \times HHV_D \times EF \times 0.000001 \qquad \textbf{Equation 20-8}$$

$$CH_4 \text{ or } N_2O = Fuel \times EF_c \times 0.000001 \qquad \textbf{Equation 20-9}$$

Where:

CH_4 or N_2O = Combustion emissions from specific fuel type, metric tons CH_4 or N_2O per year.

Fuel = Mass or volume of fuel combusted per year (express mass in metric tons for solid fuel, volume in standard cubic meters for gaseous fuel, and volume in kiloliters for liquid fuel).

HHV_D = Default high heat value specified by fuel type provided in Table 20-1, (GJ per metric ton for solid fuel, GJ per kiloliter for liquid fuel, or GJ per cubic meter for gaseous fuel).

EF = Default CH_4 or N_2O emission factor provided in Tables 20-2 or 20-4, as applicable, grams CH_4 or N_2O per GJ.

EF_c = Default CH_4 or N_2O emission factor for coal provided in Table 20-6 (grams CH_4 or N_2O per metric ton of coal)

0.000001 = Factor to convert grams to metric tons.

(b) If the heat content of the fuel is measured or provided by the fuel supplier for CO_2 estimation, calculate CH_4 and N_2O emissions using Equation 20-10 for all fuels except coal. For coal, use Equation 20-11:

$$CH_4 \text{ or } N_2O = \sum_{p=1}^{n} Fuel_p \times HHV_p \times EF \times 0.000001 \qquad \textbf{Equation 20-10}$$

$$CH_4 \text{ or } N_2O = \sum_{p=1}^{n} Fuel_p \times EF_c \times 0.000001 \qquad \textbf{Equation 20-11}$$

Where:

CH_4 or N_2O = CH_4 or N_2O emissions from a specific fuel type, metric tons CH_4 or N_2O per year.

$Fuel_p$ = Mass or volume of the fuel combusted during the measurement period “p” (express mass in metric tons for solid fuel, volume in standard cubic meters for gaseous fuel, and volume in kiloliters for liquid fuel)..

HHV_p	=	High heat value measured directly or provided by the fuel supplier for the measurement period, p, specified by fuel type (GJ per metric ton for solid fuel, GJ per kiloliter for liquid fuel, or GJ per cubic meter for gaseous fuel).
EF	=	Default CH_4 or N_2O emission factor provided in Tables 20-2 or 20-4, as applicable, grams CH_4 or N_2O per GJ.
EF_c	=	CH_4 or N_2O emission factor for coal, either measured directly or provided by the fuel supplier, grams CH_4 or N_2O per metric ton of coal
0.000001	=	Factor to convert grams to metric tons.

(c) For biomass and municipal solid waste combustion, the operator may elect to use Equation 20-10 of this section to estimate CH_4 and N_2O emissions:

$$CH_4 \ or \ N_2O = Steam \times B \times EF \times 0.000001$$ **Equation 20-10**

Where:

CH_4 or N_2O	=	Annual CH_4 or N_2O emissions from the combustion of a municipal solid waste (metric tons).
Steam	=	Total mass of steam generated by municipal solid waste combustion during the reporting year (metric tons steam).
B	=	Ratio of the boiler's design rated heat input capacity to its design rated steam output (GJ/metric ton steam).
EF	=	Fuel-specific emission factor for CH_4 or N_2O, from Tables 20-2, 20-4 or 20-6, as applicable (grams CH_4 or N_2O per GJ).
0.000001	=	Conversion factor from grams to metric tons.

(d) The operator may elect to calculate CH_4 or N_2O emissions using source-specific emission factors derived from source tests conducted at least annually under the supervision of (*jurisdiction*). Upon approval of a source test plan, the source test procedures in that plan shall be repeated in each future year to update the source specific emission factors annually.

(e) Use of the Four CO_2 Calculation Methodologies. Use of the four CH_4 and N_2O emissions calculation methodologies described in paragraphs (a) through (d) of this section is subject to the following requirements and restrictions:

(1) WCI.24(a) may not be used by a facility that is subject to the verification requirements of WCI.8, except for stationary combustion units that combust natural gas with a higher heating value between 975 and 1,150 Btu per cubic foot. Otherwise, WCI.24(a) may be used for any type of fuel for which a default CH_4 or N_2O emission factor (Tables 20-2, 20-4 or 20-6) and a default higher heat value (Table 20-3) is specified.
(2) WCI.24(b) may be used for a unit of any size combusting any type of fuel.
(3) WCI.24(c) may only be used for biomass or municipal solid waste combustion.
(4) WCI.24(d) may be used for a unit of any size combusting any type of fuel.

§ WCI.25 Sampling, Analysis, and Measurement Requirements

(a) Fuel Sampling Requirements. Fuel sampling must be conducted or fuel sampling results must be received from the fuel supplier at the frequency specified in paragraphs (a)(1) through (a)(4) of this section.

(1) Once for each new fuel shipment or delivery or on a monthly basis for middle distillates (diesel, gasoline, fuel oil, kerosene), residual oil, liquid waste-derived fuels, and LPG (ethane, propane, isobutene, n-butane, unspecified LPG).
(2) Monthly for natural gas, associated gas, and mixtures of low MJ gas.
(3) Monthly for gases derived from biomass including landfill gas and biogas from wastewater treatment or agricultural processes.
(4) Monthly for solid fuels, as specified below:

(A) The monthly solid fuel sample shall be a composite sample of weekly samples.
(B) The solid fuel shall be sampled at a location after all fuel treatment operations but before fuel mixing and the samples shall be representative of the fuel chemical and physical characteristics immediately prior to combustion.
(C) Each weekly sub-sample shall be collected at a time (day and hour) of the week when the fuel consumption rate is representative and unbiased.
(D) Four weekly samples (or a sample collected during each week of operation during the month) of equal mass shall be combined to form the monthly composite sample.
(E) The monthly composite sample shall be homogenized and well mixed prior to withdrawal of a sample for analysis.
(F) One in twelve composite samples shall be randomly selected for additional analysis of its discrete constituent samples. This information will be used to monitor the homogeneity of the composite.

(5) For biomass fuels and waste-derived fuels, the following may apply in lieu of WCI.25(a)(4):

(A) If CO_2 emissions are calculated using WCI.23(c)(1), the source-specific carbon content is determined annually. Upon approval of a source test plan by [*jurisdiction*], the source test procedures in that plan shall be repeated in subsequent years to update the source specific emission factors annually.
(B) If CO_2 emissions are calculated using WCI.23(c)(2) (biomass fuels and municipal solid waste only), the operator shall adjust the emission factor, in kg CO_2/MJ not less frequently than every third year, through a stack test measurement of CO_2 and use of the applicable ASME Performance Test Code to determine heat input from all heat outputs, including the steam, flue gases, ash and losses.

(b) Fuel Consumption Monitoring Requirements.

(1) Facilities may determine fuel consumption on the basis of direct measurement or recorded fuel purchase or sales invoices measuring any stock change (measured in MJ, liters, million standard cubic meters, metric tons or bone dry metric tons) using the following equation:

Fuel Consumption in the Report Year = Total Fuel Purchases – Total Fuel Sales + Amount Stored at Beginning of Year – Amount Stored at Year End

(2) Fuel consumption measured in MJ values shall be converted to the required metrics of mass or volume using heat content values that are either provided by the supplier, measured by the facility, or provided in Table 20-1.

(3) All oil and gas flow meters (except for gas billing meters) shall be calibrated prior to the first year for which GHG emissions are reported under this rule, using an applicable flow meter test method listed in section WCI.6 or the calibration procedures specified by the flow meter manufacturer. Fuel flow meters shall be recalibrated either annually or at the minimum frequency specified by the manufacturer.

(4) For fuel oil, tank drop measurements may also be used.

(c) Fuel Heat Content Monitoring Requirements. High heat values shall be based on the results of fuel sampling and analysis received from the fuel supplier or determined by the operator, in either case using an applicable analytical method listed in section WCI.6.

(1) For gases, use ASTM D1826-94 (Reapproved 2003), ASTM D3588-98 (Reapproved 2003), ASTM D4891-89 (Reapproved 2006), GPA Standard 2261-00 "Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography." The operator may alternatively elect to use on-line instrumentation that determines heating value accurate to within ± 5.0 percent. Where existing on-line instrumentation provides only low heat value, the operator shall convert the value to high heat value as follows:

$$HHV = LHV \times CF$$

Equation 20-11

Where:

HHV = fuel or fuel mixture high heat value (MJ/scm).
LHV = fuel or fuel mixture low heat value (MJ/scm).
CF = conversion factor.

For natural gas, a CF of 1.11 shall be used. For refinery fuel gas and mixtures of refinery fuel gas, a weekly average fuel system-specific CF shall be derived as follows:

(A) by concurrent LHV instrumentation measurements and HHV determined by on-line instrumentation or laboratory analysis as part of the daily carbon content determination; or,

(B) by the HHV/LHV ratio obtained from the laboratory analysis of the daily samples.

(2) For middle distillates and oil, or liquid waste-derived fuels, use ASTM D240-02 (Reapproved 2007), or ASTM D4809-06 (Reapproved 2005).

(3) For solid biomass-derived fuels, use ASTM D5865-07a.

(4) For waste-derived fuels, use ASTM D5865-07a or ASTM D5468-02 (Reapproved 2007). Operators who combust waste-derived fuels that are not pure biomass fuels shall determine the biomass fuel portion of CO_2 emissions using the method specified in section WCI.23(f), if applicable

(d) Fuel Carbon Content Monitoring Requirements. Fuel carbon content and either molecular weight or molar fraction for gaseous fuels shall be based on the results of fuel sampling and analysis received from the fuel supplier or determined by the operator, in either case using an applicable analytical method listed in section WCI.6.

(1) For coal and coke, solid biomass fuels, and waste-derived fuels; use ASTM 5373-08.
(2) For liquid fuels, use the following ASTM methods: For petroleum-based liquid fuels and liquid waste-derived fuels, use ASTM D5291-02 (Reapproved 2007) "Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants", ultimate analysis of oil or computations based on ASTM D3238-95 (Reapproved 2005) and either ASTM D2502-04 or ASTM D2503-92 (Reapproved 2007).
(3) For gaseous fuels, use ASTM D1945-03 (Reapproved 2006) or ASTM D1946-90 (Reapproved 2006). The operator may alternatively elect to use on-line instrumentation that determines fuel carbon content accurate to ± 5 percent.

(e) Fuel Analytical Data Capture. When the applicable emissions estimation methodologies in sections WCI.20 through WCI.XXX require periodic collection of fuel analytical data for an emissions source, the operator shall demonstrate every reasonable effort to obtain a fuel analytical data capture rate of 100 percent for each report year.

(1) If the operator is unable to obtain fuel analytical data such that more than 20 percent of emissions from a source cannot be directly accounted for, the emissions from that source shall be considered unverifiable for the report year.
(2) If the fuel analytical data capture rate is at least 80 percent but less than 100 percent for any emissions source identified in sections WCI.20 through WCI.XXX, the operator shall use the mean of the fuel analytical data results captured to substitute for the missing values for the period of missing data.

(f) Procedure for Interim Fuel Analytical Data Collection.

(1) In the event of an unforeseen breakdown of fuel analytical data monitoring equipment required for the emissions estimation methodologies in sections WCI.20 through WCI.XXX, [jurisdiction] may authorize an operator to use an interim data collection procedure if [jurisdiction] determines that the operator has satisfactorily demonstrated that:
    (A) The breakdown may result in a loss of more than 20 percent of the source's fuel data for the reporting year, such that emissions for the affected source could not be verified under the provisions of section WCI.8;
    (B) The fuel analytical data monitoring equipment cannot be promptly repaired or replaced without shutting down a process unit significantly affecting facility operations, or that the monitoring equipment must be replaced and replacement equipment is not immediately available;
    (C) The interim procedure will not remain in effect longer than is reasonably necessary for repair or replacement of the malfunctioning data monitoring equipment; and
    (D) The request was submitted within 30 calendar days of the breakdown of the fuel analytical data monitoring equipment.

(2) An operator seeking approval of an interim data collection procedure must, within 30 days of the monitoring equipment breakdown, submit a written request to [jurisdiction] that includes all of the following:

(A) The proposed start date and end date of the interim procedure;

(B) A detailed description of what data are affected by the breakdown;

(C) A discussion of the accuracy of data collected during the interim procedure compared with the data collected under the operator's usual equipment-based method;

(D) A demonstration that no feasible alternative procedure exists that would provide more accurate emissions data; and

(E) A demonstration that the proposed interim procedure meets the criteria specified in section WCI.25(f)(1).

(3) *[The jurisdiction]* may limit the duration of the interim data collection procedure or include other conditions of approval to ensure the criteria in section WCI.25(f)(1) are met.

(4) When approving an interim data collection procedure, *[jurisdiction]* shall determine whether the accuracy of data collected under the procedure is reasonably equivalent to data collected from properly functioning monitoring equipment, and if it is not, the relative accuracy to assign for purposes of assessing possible material misstatement under section WCI.8(o).

Table 20-1: Default Carbon Content and High Heat Value by Fuel Type

Liquid Fuels	**Carbon Content (kg C /GJ)**	**High Heat Value (GJ/kl)**
Asphalt & Road Oil	19.8	44.46
Aviation Gasoline	19.25	33.52
Diesel	19.06	38.3
Aviation Turbo Fuel	18.67	37.4
Kerosene	18.53	37.68
Propane	16.35	25.31
Ethane	15.61	17.22
Butane	16.67	28.44
Lubricants	19.66	39.16
Motor Gasoline - Off-Road	18.02	35
Light Fuel Oil	19.35	38.8
Residual Fuel Oil (#5 & 6)	20.07	42.5
Crude Oil	19.8	38.32
Naphtha	19.33	35.17
Petrochemical Feedstocks	19.33	35.17
Petroleum Coke - Refinery Use	22.71	46.35
Petroleum Coke - Upgrader Use	22.71	40.57
Solid Fuels	**Carbon Content (kg C /GJ)**	**High Heat Value (GJ/metric ton)**
Anthracite Coal	23.74	27.7
Bituminous Coal	20.97	26.33
Foreign Bituminous Coal	21.79	29.82
Sub-Bituminous Coal	25.05	19.15
Lignite	29.97	15
Coal Coke	23.69	28.83
Solid Wood Waste	28.41	18
Spent Puling Liquor	N/A	14
Gaseous Fuels	**Carbon Content (kg C /GJ)**	**High Heat Value (GJ/m3)**
Natural Gas	14.12	0.03832
Coke Oven Gas	23.03	0.01914
Still Gas - Refineries	13.34	0.03608
Still Gas - Upgraders	13.34	0.04324
Landfill Gas	14.97	0.0359
Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007; and Statistics Canada Report on Energy Supply and Demand in Canada.		

~~Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007; and Statistics Canada Report on Energy Supply and Demand in Canada~~

Table 20-2: Default Emission Factors by Fuel Type

Liquid Fuels	CO2 Emission Factor (kg /L)	CO2 Emission Factor (kg /GJ)	CH4 Emission Factor (g/L)	CH4 Emission Factor (g/GJ)	N20 Emission Factor (g/L)	N20 Emission Factor (g/GJ)
Aviation Gasoline	2.342	69.87	2.2	65.63	0.23	6.862
Diesel	2.663	69.53	0.133	3.473	0.4	10.44
Aviation Turbo Fuel	2.534	67.75	0.08	2.139	0.23	6.150
Kerosene						
- Electric Utilities	2.534	67.25	0.006	0.159	0.031	0.823
- Industrial	2.534	67.25	0.006	0.159	0.031	0.823
- Producer Consumption	2.534	67.25	0.006	0.159	0.031	0.823
- Forestry, Construction, and Commercial/Institutional	2.534	67.25	0.026	0.69	0.031	0.823
Propane						
- Residential	1.51	59.66	0.027	1.067	0.108	4.267
- All other uses	1.51	59.66	0.024	0.948	0.108	4.267
Ethane	0.976	56.68	N/A	N/A	N/A	N/A
Butane	1.73	60.83	0.024	0.844	0.108	3.797
Lubricants	1.41	36.01	N/A	N/A	N/A	N/A
Motor Gasoline - Off-Road	2.289	65.40	2.7	77.14	0.05	1.429
Light Fuel Oil						
- Electric Utilities	2.725	70.23	0.18	4.639	0.031	0.799
- Industrial	2.725	70.23	0.006	0.155	0.031	0.799
- Producer Consumption	2.643	68.12	0.006	0.155	0.031	0.799
- Forestry, Construction, and Commercial/Institutional	2.725	70.23	0.026	0.67	0.031	0.799
Residual Fuel Oil (#5 & 6)						
- Electric Utilities	3.124	73.51	0.034	0.800	0.064	1.506
- Industrial	3.124	73.51	0.12	2.824	0.064	1.506
- Producer Consumption	3.158	74.31	0.12	2.824	0.064	1.506
- Forestry, Construction, and Commercial/Institutional	3.124	73.51	0.057	1.341	0.064	1.820
Naphtha	0.625	17.77	N/A	N/A	N/A	N/A
Petrochemical Feedstocks	0.5	14.22	N/A	N/A	N/A	N/A
Petroleum Coke - Refinery Use	3.826	82.55	0.12	2.589	0.0265	0.572
Petroleum Coke - Upgrader Use	3.494	86.12	0.12	2.958	0.0231	0.569
Biomass and Other Solid Fuels	**CO2 Emission Factor (kg /kg)**	**CO2 Emission Factor (kg /GJ)**	**CH4 Emission Factor (g/kg)**	**CH4 Emission Factor (g/GJ)**	**N20 Emission Factor (g/kg)**	**N20 Emission Factor (g/GJ)**
Landfill Gas	29.89	833	0.6	16.7	0.06	1.671
Wood Waste (Env. Canada)[1]	0.95	52.8	0.05	2.778	0.02	1.111
Wood Waste (U.S. EPA)[2]	1.590	88.9	0.51	28.4	0.068	3.79
Spent Pulping Liquor	1.428	102.0	0.05	3.571	0.02	1.429

(Env.Canada)						
Spent Pulping Liquor (U.S. EPA)	1.394	99.60	0.44	31.65	0.073	5.275
Coal Coke	2.48	86.02	0.03	1.041	0.02	0.694
Tires	N/A	85	N/A	N/A	N/A	N/A
Gaseous Fuels	**CO2 Emission Factor (kg /m3)**	**CO2 Emission Factor (kg /GJ)**	**CH4 Emission Factor (g/m3)**	**CH4 Emission Factor (g/GJ)**	**N20 Emission Factor (g/m3)**	**N20 Emission Factor (g/GJ)**
Coke Oven Gas	1.6	83.60	0.037	1.933	0.035	1.829
Still Gas - Refineries	1.75	48.50	N/A	N/A	0.0222	0.615
Still Gas - Upgraders	2.14	49.49	N/A	N/A	0.0222	0.513

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007, unless otherwise stated

[1] Assumes 50% moisture content of wood waste

[2] Assumes 12% moisture content of wood waste

Table 20-3: Default Carbon Dioxide Emission Factors for Natural Gas by Province

	Marketable Gas (kg/m3)	Marketable Gas (kg/GJ)	Non-Marketable Gas (kg/m3)	Non-Marketable Gas (kg/GJ)
Quebec	1.878	49.01	Not occurring	Not occurring
Ontario	1.879	49.03	Not occurring	Not occurring
Manitoba	1.877	48.98	Not occurring	Not occurring
British Columbia	1.916	50.00	2.151	56.13

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007

Table 20-4: Default Methane and Nitrous Oxide Emission Factors for Natural Gas

	CH4 (g/m3)	CH4 (g/GJ)	N20 (g/m3)	N20 (g/GJ)
Electric Utilities	0.49	12.79	0.049	1.279
Industrial	0.037	0.966	0.033	0.861
Producer Consumption (Non-marketable)	6.5	169.6	0.06	1.566
Pipelines	1.9	49.58	0.05	1.305
Cement	0.037	0.966	0.034	0.887
Manufacturing Industries	0.037	0.966	0.033	0.861
Residential, Construction, Commercial/Institutional, Agriculture	0.037	0.966	0.035	0.913

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007

Table 20-5: Default Carbon Dioxide Emission Factors for Coal

	Emission Factor (kg/kg)	Emission Factor (kg/GJ)
Quebec		
- Canadian Bituminous	2.25	85.5
- U.S. Bituminous	2.34	88.9
- Anthracite	2.39	86.3
Ontario		
- Canadian Bituminous	2.25	85.5
- U.S. Bituminous	2.43	81.5
- Sub-bituminous	1.73	90.3
- Lignite	1.48	98.7
- Anthracite	2.39	86.3
Manitoba		
- Canadian Bituminous	2.25	85.5
- U.S. Bituminous	2.43	81.5
- Sub-bituminous	1.73	90.3
- Lignite	1.42	94.7
- Anthracite	2.39	86.3
British Columbia		
- Canadian Bituminous	2.07	78.6
- U.S. Bituminous	2.43	81.5
- Sub-bituminous	1.77	92.4

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007

Table 20-6: Default Methane and Nitrous Oxide Emission Factors for Coal

	CH4 Emission Factor (g/kg)	N2O Emission Factor (g/kg)
Electric Utilities	0.022	0.032
Industry and Heat and Steam Plants	0.03	0.02
Residential, Public Administration	4	0.02

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007

Table 20-7: Other Emission Factors

	CO2 Emission Factor (kg/GJ)	CH4 Emission Factor (g/GJ)	N2O Emission Factor (g/GJ)
Municipal Solid Waste	91.7	30	4
Peat	103	1	1.5

Source: 2006 IPCC Guidelines for National Greenhouse Gas Inventories, unless otherwise stated

The ~~RC~~WCI notes the significant difference in both the black liquor and solid biomass emission factors published by the EPA and Environment Canada (as well as those submitted by industry associations). In lieu of recommending a single emission factor at this time (as there is no certainty as to which is most accurate) the RC is presenting both for information purposes. The RC will be working with experts in the two federal agencies and other organizations to ascertain the most accurate emission factor to use for both Metric and English unit versions of the Essential Requirements of Mandatory Reporting.

§ WCI.30 REFINERY FUEL GAS COMBUSTION

WCI.31 Source Category Definition

This source category consists of any combustion device that is located at a petroleum refinery and that combusts refinery fuel gas, still gas, flexigas, or associated gas.

WCI.32 Greenhouse Gas Reporting Requirements

In addition to the information required by WCI.3, the emissions data report shall include the following information at the facility level:

(a) Annual CO_2, CH_4, and N_2O emissions from refinery fuel gas combustion in metric tons.

(b) Annual fuel consumption in units of million standard cubic feet or cubic meters.

(c) Average carbon content of each fuel, if used to compute CO_2 emissions.

(d) Average high heat value of each fuel, if used to compute CO_2 emissions.

WCI.33 Calculation of Greenhouse Gas Emissions

(a) Calculation of CO_2 Emissions. Owners and operators shall calculate daily CO_2 emissions for each fuel gas system using any of the methods specified in paragraphs (a)(1) through (a)(5) of this section. Calculate the total annual CO_2 emissions from combustion of all fuel gas by summing the CO_2 emissions from each fuel gas system.

(1) Use a CEMS that complies with the provisions in section WCI.23(d).

(2) Calculate CO_2 emissions from each refinery fuel gas system and flexigas system using measured carbon content and molecular weight of the gas and Equation 30-1.

$$CO_2 = \sum_{i=1}^{n} Fuel_i \times CC_i \times \frac{MW}{MVC} \times 3.664 \times 0.001$$ **Equation 30-1 (English Units)**

Where:

CO_2	=	Carbon dioxide emissions, metric tons/year.
$Fuel_i$	=	Daily refinery fuel or flexigas combusted (scf).
CC_i	=	Daily sample of carbon content of the fuel (kg C/kg fuel).
MW	=	Daily sample of molecular weight of fuel.
MVC	=	Molar volume conversion factor (849.5 scf/kg-mole for STP of 20°C and 1 atmosphere, or 836 scf/kg-mole for STP of 60°F and 1 atmosphere).
3.664	=	Conversion factor for carbon to carbon dioxide.
0.001	=	Conversion factor for kg to metric tons.
n	=	Number of days in a year.

$$CO_2 = \sum_{i=1}^{n} Fuel_i \times CC_i \times \frac{MW}{MVC} \times 3.664 \times 0.001$$ **Equation 30-1 (Metric Units)**

Where:

CO_2 = Carbon dioxide emissions, metric tons/year.
$Fuel_i$ = Daily refinery fuel or flexigas combusted (scm).
CC_i = Daily sample of carbon content of the fuel (kg C/kg fuel).
MW = Daily sample of molecular weight of fuel.
MVC = Molar volume conversion factor (24.06 m^3/kg-mole for STP of 20°C and 1 atmosphere, or 23.67 m^3/kg-mole for STP of 60°F and 1 atmosphere).
3.664 = Conversion factor for carbon to carbon dioxide.
0.001 = Conversion factor for kg to metric tons.
n = Number of days in a year.

(A) For refinery fuel gas, the daily carbon content shall be determined a minimum of 3 times a day (once every 8 hours) using on-line instrumentation or discrete laboratory analysis using the methods specified in WCI.34.
(B) For flexigas, the daily carbon content shall be determined once per day using the methods specified in WCI.34.

(3) Calculate CO_2 emissions from each fuel gas system and flexigas system using Equation 30-2 and a daily average high heat value that is monitored using a continuous on-line instrument.

$$CO_2 = \sum_{i=1}^{n} HHV_i \times Fuel_i \times EF_{CO2,i} \times 0.000001$$ **Equation 30-2 (English Units)**

Where:

CO_2 = CO_2 emissions resulting from the combustion of fuel gas from an individual fuel gas system (metric tons/yr).
HHV_i = Daily average high heat value of fuel gas, derived from a continuous analyzer and integrated over a 24-hour period (Btu/scf).
$Fuel_i$ = Daily fuel consumption from all fuel combustion units burning gas from the system (scf/d).
$EF_{CO2,i}$ = Daily CO_2 emission factor for an individual fuel gas system, developed using Equation 30-3 (metric tons CO_2/MMBtu).
0.000001 = Conversion factor for Btu to MMBtu.
n = Number of days per year.

Equation 30-2 (Metric Units)

$$CO_2 = \sum_{i=1}^{n} HHV_i \times Fuel_i \times EF_{CO2,i}$$

Where:

CO_2 = CO_2 emissions resulting from the combustion of fuel gas from an individual fuel gas system (metric tons/yr).
HHV_i = Daily average high heat value of fuel gas, derived from a continuous analyzer and integrated over a 24-hour period (MJ/m^3).
$Fuel_i$ = Daily fuel consumption from all fuel combustion units burning gas from the system (m^3/d).
$EF_{CO2,i}$ = Daily CO_2 emission factor for an individual fuel gas system, developed using Equation 30-3 (metric tons CO_2/MJ).
n = Number of days per year.

$$EF_{CO2,i} = CC/HHV \times MW/MVC \times 3.664 \times 1{,}000$$ **Equation 30-3 (English Units)**

Where:

$EF_{CO2,i}$ = Daily CO_2 emission factor for an individual fuel gas system (metric tons CO_2/MMBtu).
CC = Daily sample of gas carbon content for a fuel gas system, collected according to paragraph (a)(3)(A) of this section (kg carbon/kg fuel).
HHV = Daily sample of gas high heat value for a fuel gas system, collected according to paragraph (a)(3)(A) of this section (Btu/scf).
MW = Refinery fuel A molecular weight (kg/kg-mole).
MVC = Molar volume conversion (849.5 scf/ kg-mole, for STP of 20°C and 1 atmosphere, or 836 scf/kg-mole for STP of 60°F and 1 atmosphere).
3.664 = Conversion factor for carbon to carbon dioxide.
1,000 = Conversion factor for kg/Btu to metric tons/MMBtu.

$$EF_{CO2,i} = CC/HHV \times MW/MVC \times 3.664 \times 0.001$$ **Equation 30-3 (Metric Units)**

Where:

$EF_{CO2,i}$ = Daily CO_2 emission factor for an individual fuel gas system (metric tons CO_2/MJ).
CC = Daily sample of gas carbon content for a fuel gas system, collected according to paragraph (a)(3)(A) of this section (kg carbon/kg fuel).
HHV = Daily sample of gas high heat value for a fuel gas system, collected according to paragraph (a)(3)(A) of this section (MJ/m^3).
MW = Refinery fuel A molecular weight (kg/kg-mole).
MVC = Molar volume conversion (24.06 m^3/kg-mole for STP of 20°C and 1 atmosphere, or 23.67 m^3/kg-mole for STP of 60°F and 1 atmosphere).
3.664 = Conversion factor for carbon to carbon dioxide.
0.001 = Conversion factor for kg/MJ to metric tons/MJ.

(A) For Equation 30-3, the carbon content shall be determined once per day by on-line instrumentation or by laboratory analysis of a representative sample using the methods specified in WCI.34. The HHV shall be determined from either the same sample used to conduct the carbon analysis or from on-line instrumentation using the hourly average value that coincides with the same hour in which the carbon content was determined.

(B) For facilities that meet the definition of a small refiner in WCI.10, the emissions measurements and calculations for Equation 30-2 and 30-3 may be conducted weekly.

(4) For associated gas, low heat content gas, or other fossil fuels; follow the requirements for general stationary source combustion sources in WCI .23(b) or (c), as appropriate for each fuel.

(5) Where individual fuels are mixed prior to combustion, the operator may choose to calculate CO_2 emissions for each fuel prior to mixing instead of using the methods in paragraphs (a)(1), (a)(2), or (a)(3) of this section. In this case, the operator must determine the fuel flow rate and appropriate fuel specific parameters (e.g. carbon content, HHV) of each fuel stream prior to mixing, calculate CO_2 emissions for each fuel stream, and sum the emissions of the individual fuel streams to determine total CO_2 emissions from the mixture. CO_2 emissions for each fuel stream must be estimated using the following methods:

(A) For natural gas and associated gas, use the appropriate methodology specified in section WCI.23(b) or (c).

(B) For refinery fuel gas and flexigas, use the methodology in either paragraph (a)(2) or (a)(3) of this section.

(C) For low heat content gas, use the methodology in paragraph (a)(2) of this section.

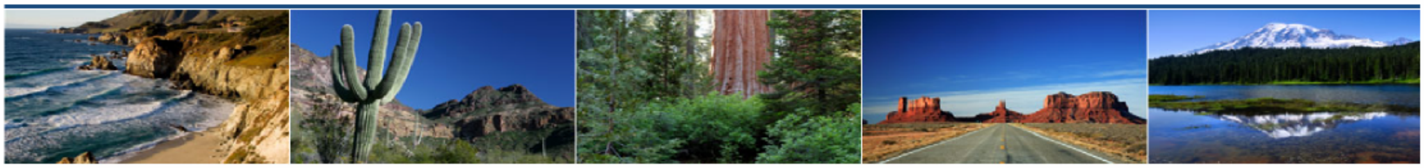
(b) Calculation of CH_4 and N_2O Emissions. Owners and operators shall use the methods specified in section WCI.24 to calculate the annual CH_4 and N_2O emissions.

WCI.34 Sampling, Analysis, and Measurement Requirements

(a) Measure the fuel consumption rate daily using methods specified in WCI.25(b).

(b) Measure the carbon content for fuel gas and flexigas using either ASTM D1945-03 (Reapproved 2006) or ASTM D1946-90 (Reapproved 2006). Where these methods do not adequately quantify all major hydrocarbons, then an owner or operator may request use of an alternative ASTM or other method to be approved by *[the jurisdiction]*.

(c) Measure high heat value using the monitoring requirements specified in WCI.25(c) for gaseous fuels.



§ WCI.40 ELECTRICITY GENERATION (ENGLISH UNITS)

§ WCI.41 Source Category Definition

An electricity generating unit is any combustion device that combusts solid, liquid, or gaseous fuel for the purpose of producing electricity either for sale or for use onsite. This source category includes cogeneration (combined heat and power) units.

§ WCI.42 Greenhouse Gas Reporting Requirements

For each electricity generating unit, the emissions data report shall include the following information:

(a) Annual greenhouse gas emissions in metric tons, reported as follows:

(1) Total CO_2 emissions for fossil fuels, reported by fuel type.

(2) Total CO_2 emissions for all biomass fuels combined.

(3) Total CH_4 emissions for fuels combined.

(4) Total N_2O emissions for all fuels combined.

(b) Annual fuel consumption:

(1) For gases, report in units of million standard cubic feet.

(2) For liquids, report in units of gallons.

(3) For non-biomass solids, report in units of short tons.

(4) For biomass-derived solid fuels, report in units of bone dry short tons.

(c) Average carbon content of each fuel, if used to compute CO_2 emissions as specified in WCI.43.

(d) Average high heating value of each fuel, if used to compute CO_2 emissions as specified WCI.43.

(e) The nameplate generating capacity in megawatts and net power generated in the reporting year in megawatt hours.

(f) For each cogeneration unit, indicate whether topping or bottoming cycle and provide useful thermal output as applicable, in mmBtu. Where steam or heat is acquired from another facility for the generation of electricity, report the provider and amount of acquired steam or heat in mmBtu. Where supplemental firing has been applied to support electricity generation or industrial output, report this purpose and fuel consumption by fuel type using the units in WCI.42(b).

(g) Process CO_2 emissions from acid gas scrubbers and acid gas reagent.

(h) Fugitive emissions of HFC from cooling units that support power generation.

(i) Fugitive CO_2 emissions from geothermal facilities.

(j) Fugitive CO_2 emissions from coal storage at coal-fired electricity generating facilities shall be reported as specified in section WCI.100.

§ WCI.43 Calculation of Greenhouse Gas Emissions

(a) Calculation of CO_2 Emissions. Operators shall use CEMS to measure CO_2 emissions if required to operate a CEMS by any other federal, state, provincial, or local regulation. Operators not required to operate a CEMS by another regulation may use either CEMS or the calculation methods specified in paragraphs (a)(1) through (a)(7). Operators using CEMS to determine CO_2 emissions shall comply with the provisions in section WCI.23(d).

(1) Natural Gas. For electric generating units combusting natural gas, use one of the following methods:

(A) If the high heat value is greater than or equal to 975 and less than or equal to 1,100 Btu/scf use either:

(i) The measured carbon content of the fuel and calculation methodology 3 in section WCI.23(c); or

(ii) The measured heat content of the fuel and the calculation methodology 2 in section WCI.23(b) provided the facility is not subject to the verification requirements of WCI.8.

(B) If the high heat value is less than 975 or greater than 1,100 Btu/scf, use the measured carbon content of the fuel and the calculation methodology 3 in section WCI.23(c).

(2) Coal or Petroleum Coke. For electric generating units combusting coal or petroleum coke, use the measured carbon content of the fuel and calculation methodology 3 in section WCI.23(c).

(3) Middle Distillates, Gasoline, Residual Oil, or Liquid Petroleum Gases. For electric generating units combusting middle distillates (such as diesel, fuel oil, or kerosene), gasoline, residual oil, or LPG (such as ethane, propane, isobutene, n-butane, or unspecified LPG), use one of the following methods:

(A) The measured carbon content of the fuel and calculation methodology 3 in section WCI.23(c); or

(B) The measured heat content of the fuel and calculation methodology 2 in section WCI.23(b) provided the facility is not subject to the verification requirements of WCI.8.

(4) Refinery Fuel Gas, Flexigas, or Associated Gas. For electric generating units combusting refinery fuel gas, flexigas, or associated gas, use the methods specified in section WCI.30.

(5) Landfill Gas, Biogas, or Biomass. For electric generating units combusting landfill gas, biogas, or biomass, use one of the following methods:

(A) The measured carbon content of the fuel and calculation methodology 3 provided in section WCI.23(c); or

(B) The measured heat content of the fuel and calculation methodology 2 in section WCI.23(b) provided the facility is not subject to the verification requirements of WCI.8.

(6) Municipal Solid Waste. Electric generating units combusting municipal solid waste, may use the measured steam generated, the default carbon content emission factor in Table 20-1, and the calculation methodology in section WCI.23(b)(2) provided the facility is not subject to the verification requirements of WCI.8. If the facility is subject to the verification requirements of WCI.8, the operator shall use CEMS to measure CO_2 emissions in accordance with WCI.23(d), or calculate emissions using steam flow and a CO_2 emission factor according to the provisions of WCI.23(c)(2).

(7) Start-up Fuels. The operators of generating facilities that primarily combust biomass-derived fuels but combust fossil fuels during start-up, shut-down, or malfunction operating periods only, shall calculate CO_2 emissions from fossil fuel combustion using one of the following methods:

(A) The default emission factors from Tables 20-1 and 20-2 and calculation methodology 1 provided in section WCI.23(a);

(B) The measured heat content of the fuel and calculation methodology 2 provided in section WCI.23(b);

(C) The measured carbon content of the fuel and calculation methodology 3 provided in section WCI.23(c); or

(D) For combustion of refinery fuel gas, the measured heat content and carbon content of the fuel, and the calculation methodology provided in section WCI.30.

(8) Co-fired Electricity Generating Units. For electricity generating units that combust more than one type of fuel, the operator shall calculate CO_2 emissions as follows.

(A) For co-fired electricity generators that burn only fossil fuels, CO_2 emissions shall be determined using one of the following methods:

(i) A continuous emission monitoring system in accordance with calculation methodology 4 in section WCI.23(d). Operators using this method need not report emissions separately for each fossil fuel.

(ii) For units not equipped with a continuous emission system, calculate the CO2 emissions separately for each fuel type using the methods specified in paragraphs (a)(1) through (a)(4) of this section.

(B) For co-fired electricity generators that burn biomass-derived fuel with a fossil fuel, CO_2 emissions shall be determined using one of the following methods:

(i) A continuous emission monitoring system in accordance with calculation methodology 4 in section WCI.23(d). Operators using this method shall determine the portion of the total CO_2 emissions attributable to the biomass-derived fuel and portion of the total CO_2 emissions attributable to the fossil fuel using the methods specified in section WCI.23(d)(4).

(ii) For units not equipped with a continuous emission system, calculate the CO_2 emissions separately for each fuel type using the methods specified in paragraphs (a)(1) through (a)(7) of this section.

(b) Calculation of CH_4 and N_2O Emissions. Operators of electricity generating units shall use the methods specified in section WCI.24 to calculate the annual CH_4 and N_2O emissions. For coal combustion, use the default CH_4 emission factor in Table 20-3.

(c) Calculation of CO_2 Emissions from Acid Gas Scrubbing. Operators of electricity generating units that use acid gas scrubbers or add an acid gas reagent to the combustion unit shall calculate the annual CO_2 emissions from these processes using Equation 40-1 if these emissions are not already captured in CO_2 emissions determined using a continuous emissions monitoring system.

$$CO_2 = S \times R \times \left(CO_{2\,MW} / Sorbent_{MW}\right)$$ **Equation 40-1**

Where:

CO_2	=	CO_2 emitted from sorbent for the report year, metric tons;
S	=	Limestone or other sorbent used in the report year, metric tons;
R	=	Ratio of moles of CO_2 released upon capture of one mole of acid gas;
$CO_{2\ MW}$	=	Molecular weight of carbon dioxide (44);
$Sorbent_{\ MW}$	=	Molecular weight of sorbent (if calcium carbonate, 100).

(d) Calculating Fugitive HFC Emissions from Cooling Units. Operators of electricity generating facilities shall calculate fugitive HFC emissions for each HFC compound used in cooling units that support power generation or are used in heat transfers to cool stack gases using either the methodology in paragraph (d)(1) or (d)(2). The Operator is not required to report GHG emissions from air or water cooling systems or condensers that do not contain HFCs.

(1) Use Equation 40-2 to calculate annual HFC emissions:

$$HFC = HFC_{inventory} + HFC_{purchases/acquisitions} - HFC_{sales/disbursements} + HFC_{\Delta capacity}$$ **Equation 40-2**

Where:

HFC	=	Annual fugitive HFC emission, metric tons;
$HFC_{inventory}$	=	The difference between the quantity of HFC in storage at the beginning of the year and the quantity in storage at the end of the year. Stored HFC includes HFC contained in cylinders (such as 115-pound storage cylinders), gas carts, and other storage containers. It does not include HFC gas held in operating equipment. The change in inventory will be negative if the quantity of HFC in storage increases over the course of the year.
$HFC_{purchases/acquisitions}$	=	The sum of all HFC acquired from other entities during the year either in storage containers or in equipment.
$HFC_{sales/disbursements}$	=	The sum of all the HFC sold or otherwise transferred offsite to other entities during the year either in storage containers or in equipment.

$HFC_{\Delta capacity}$ = The net change in the total nameplate capacity (i.e. the full and proper charge) of the cooling equipment). The net change in capacity will be negative if the total nameplate capacity at the end of the year is less than the total nameplate capacity at the beginning of the year.

(2) Use service logs to document HFC usage and emissions from each cooling unit. Service logs should document all maintenance and service performed on the unit during the report year, including the quantity of HFCs added to or removed from the unit, and include a record at the beginning and end of each report year. The operator may use service log information along with the following simplified material balance equations to quantify fugitive HFCs from unit installation, servicing, and retirement, as applicable. The operator shall include the sum of HFC emissions from the applicable equations in the greenhouse gas emissions data report.

$$HFC_{Install} = R_{new} - C_{new}$$

$$HFC_{Service} = R_{recharge} - R_{Recover}$$

$$HFC_{Retire} = C_{retire} - R_{retire}$$

Where:

$HFC_{Install}$ = HFC emitted during initial charging/installation of the unit, kilograms;
$HFC_{Service}$ = HFC emitted during use and servicing of the unit for the report year, kilograms;
HFC_{Retire} = HFC emitted during the removal from service/retirement of the unit, kilograms;
R_{new} = HFC used to fill new unit (omit if unit was pre-charged by the manufacturer), kilograms;
C_{new} = Nameplate capacity of new unit (omit if unit was pre-charged by the manufacturer), kilograms;
$R_{recharge}$ = HFC used to recharge the unit during maintenance and service, kilograms;
$R_{recover}$ = HFC recovered from the unit during maintenance and service, kilograms;
C_{retire} = Nameplate capacity of the retired unit, kilograms; and
R_{retire} = HFC recovered from the retired unit, kilograms.

(e) Fugitive CO_2 Emissions from Geothermal Facilities. Operators of geothermal electricity generating facilities shall calculate the fugitive CO_2 emissions using one of the following methods:

(1) Calculate the fugitive CO_2 emissions using Equation 40-3:

$$CO_2 = 7.53 \times Heat \times 0.001$$ **Equation 40-3**

Where:

CO_2 = CO_2 emissions, metric tons per year;
7.53 = Default fugitive CO_2 emission factor for geothermal facilities, kg per mmBtu; and
Heat = Heat taken from geothermal steam and/or fluid, mmBtu/yr.

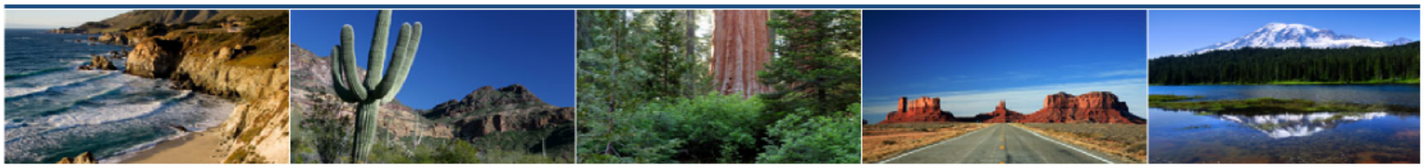
(2) Calculate CO_2 emissions using [*insert jurisdiction*] approved source specific emission factor.

§ WCI.44 Sampling, Analysis, and Measurement Requirements

(a) CO_2, CH_4 and N_2O Emissions from Fuel Combustion. Operators using CEMS to estimate CO_2 emissions from fuel combustion shall comply with the requirements in section WCI.23(d). Operators using methods other than CEMS shall comply with the applicable fuel sampling, fuel consumption monitoring, heat content monitoring, and carbon content monitoring specified in section WCI.25.

(b) CO_2 Emissions from Acid Gas Scrubbing. Operators of electricity generating units that use acid gas scrubbers or add an acid gas reagent to the combustion unit shall measure the amount of limestone or other sorbent used during the reporting year.

(c) CO_2 Emissions from Geothermal Facilities. Operators of geothermal facilities shall measure the heat recovered from geothermal steam. If using source specific emission factor instead of the default factor, the operator shall conduct an annual test of the CO_2 emission rate using a method approved by [*insert jurisdiction*]. The operator shall submit a test plan to the [*insert jurisdiction*] for approval. Once approved, the annual tests shall be conducted in accordance with the approved test plan under the supervision of the [*insert jurisdiction*].



§ WCI.40 ELECTRICITY GENERATION (METRIC UNITS)

§ WCI.41 Source Category Definition

An electricity generating unit is any combustion device that combusts solid, liquid, or gaseous fuel for the purpose of producing electricity either for sale or for use onsite. This source category includes cogeneration (combined heat and power) units.

§ WCI.42 Greenhouse Gas Reporting Requirements

For each electricity generating unit, the emissions data report shall include the following information:

(a) Annual greenhouse gas emissions in metric tons, reported as follows:

- (1) Total CO_2 emissions for fossil fuels, reported by fuel type.
- (2) Total CO_2 emissions for all biomass fuels combined.
- (3) Total CH_4 emissions for fuels combined.
- (4) Total N_2O emissions for all fuels combined.

(b) Annual fuel consumption:

- (1) For gases, report in units of standard cubic meters.
- (2) For liquids, report in units of kiloliters.
- (3) For non-biomass solids, report in units of metric tons.
- (4) For biomass-derived solid fuels, report in units of bone dry metric tons.

(c) Average carbon content of each fuel, if used to compute CO_2 emissions as specified in WCI.43.

(d) Average high heating value of each fuel, if used to compute CO_2 emissions as specified WCI.43.

(e) The nameplate generating capacity in megawatts and net power generated in the reporting year in megawatt hours.

(f) For each cogeneration unit, indicate whether topping or bottoming cycle and provide useful thermal output as applicable, in MJ. Where steam or heat is acquired from another facility for the generation of electricity, report the provider and amount of acquired steam or heat in MJ. Where supplemental firing has been applied to support electricity generation or industrial output, report this purpose and fuel consumption by fuel type using the units in WCI.42(b).

(g) Process CO_2 emissions from acid gas scrubbers and acid gas reagent.

(h) Fugitive emissions of HFC from cooling units that support power generation.

(i) Fugitive CO_2 emissions from geothermal facilities.

(j) Fugitive CO_2 emissions from coal storage at coal-fired electricity generating facilities shall be reported as specified in section WCI.100.

§ WCI.43 Calculation of Greenhouse Gas Emissions

(a) Calculation of CO_2 Emissions. Operators shall use CEMS to measure CO_2 emissions if required to operate a CEMS by any other federal, state, provincial, or local regulation. Operators not required to operate a CEMS by another regulation may use either CEMS or the calculation methods specified in paragraphs (a)(1) through (a)(7). Operators using CEMS to determine CO_2 emissions shall comply with the provisions in section WCI.23(d).

(1) Natural Gas. For electric generating units combusting natural gas, use one of the following methods:

(A) If the high heat value is greater than or equal to 36.3 and less than or equal to 40.98 MJ/scm use either:

(i) The measured carbon content of the fuel and calculation methodology 3 in section WCI.23(c); or

(ii) The measured heat content of the fuel and the calculation methodology 2 in section WCI.23(b) provided the facility is not subject to the verification requirements of WCI.8.

(B) If the high heat value is less than 36.3 or greater than 40.98 MJ/scm, use the measured carbon content of the fuel and the calculation methodology 3 in section WCI.23(c).

(2) Coal or Petroleum Coke. For electric generating units combusting coal or petroleum coke, use the measured carbon content of the fuel and calculation methodology 3 in section WCI.23(c).

(3) Middle Distillates, Gasoline, Residual Oil, or Liquid Petroleum Gases. For electric generating units combusting middle distillates (such as diesel, fuel oil, or kerosene), gasoline, residual oil, or LPG (such as ethane, propane, isobutene, n-butane, or unspecified LPG), use one of the following methods:

(A) The measured carbon content of the fuel and calculation methodology 3 in section WCI.23(c); or

(B) The measured heat content of the fuel and calculation methodology 2 in section WCI.23(b) provided the facility is not subject to the verification requirements of WCI.8.

(4) Refinery Fuel Gas, Flexigas, or Associated Gas. For electric generating units combusting refinery fuel gas, flexigas, or associated gas, use the methods specified in section WCI.30.

(5) Landfill Gas, Biogas, or Biomass. For electric generating units combusting landfill gas, biogas, or biomass, use one of the following methods:

(A) The measured carbon content of the fuel and calculation methodology 3 provided in section WCI.23(c); or

(B) The measured heat content of the fuel and calculation methodology 2 in section WCI.23(b) provided the facility is not subject to the verification requirements of WCI.8.

(6) Municipal Solid Waste. Electric generating units combusting municipal solid waste, may use the measured steam generated, the default emission factor in WCI.20 Table 20-7, and the calculation methodology in section WCI.23(b)(2) provided the facility is not subject to the verification requirements of WCI.8. If the facility is subject to the verification requirements of WCI.8, the operator shall use CEMS to measure CO_2 emissions in accordance with WCI.23(d), or calculate emissions using steam flow and a CO_2 emission factor according to the provisions of WCI.23(c)(2).

(7) Start-up Fuels. The operators of generating facilities that primarily combust biomass-derived fuels but combust fossil fuels during start-up, shut-down, or malfunction operating periods only, shall calculate CO_2 emissions from fossil fuel combustion using one of the following methods:

(A) The default emission factors from Tables 20-2, 20-3, 20-5 or 20-7, as applicable, and calculation methodology 1 provided in section WCI.23(a);

(B) The measured heat content of the fuel and calculation methodology 2 provided in section WCI.23(b);

(C) The measured carbon content of the fuel and calculation methodology 3 provided in section WCI.23(c); or

(D) For combustion of refinery fuel gas, the measured heat content and carbon content of the fuel, and the calculation methodology provided in section WCI.30.

(8) Co-fired Electricity Generating Units. For electricity generating units that combust more than one type of fuel, the operator shall calculate CO_2 emissions as follows.

(A) For co-fired electricity generators that burn only fossil fuels, CO_2 emissions shall be determined using one of the following methods:

(i) A continuous emission monitoring system in accordance with calculation methodology 4 in section WCI.23(d). Operators using this method need not report emissions separately for each fossil fuel.

(ii) For units not equipped with a continuous emission system, calculate the CO2 emissions separately for each fuel type using the methods specified in paragraphs (a)(1) through (a)(4) of this section.

(B) For co-fired electricity generators that burn biomass-derived fuel with a fossil fuel, CO_2 emissions shall be determined using one of the following methods:

(i) A continuous emission monitoring system in accordance with calculation methodology 4 in section WCI.23(d). Operators using this method shall determine the portion of the total CO_2 emissions attributable to the biomass-derived fuel and portion of the total CO_2 emissions attributable to the fossil fuel using the methods specified in section WCI.23(d)(4).

(ii) For units not equipped with a continuous emission system, calculate the CO_2 emissions separately for each fuel type using the methods specified in paragraphs (a)(1) through (a)(7) of this section.

(b) Calculation of CH_4 and N_2O Emissions. Operators of electricity generating units shall use the methods specified in section WCI.24 to calculate the annual CH_4 and N_2O emissions. For coal combustion, use the default CH_4 emission factor(s) in Table 20-6.

(c) Calculation of CO_2 Emissions from Acid Gas Scrubbing. Operators of electricity generating units that use acid gas scrubbers or add an acid gas reagent to the combustion unit shall calculate the annual CO_2 emissions from these processes using Equation 40-1 if these emissions are not already captured in CO_2 emissions determined using a continuous emissions monitoring system.

$$CO_2 = S \times R \times \left(CO_{2\,MW} / Sorbent_{MW} \right)$$ **Equation 40-1**

Where:

CO_2	=	CO_2 emitted from sorbent for the report year, metric tons;
S	=	Limestone or other sorbent used in the report year, metric tons;
R	=	Ratio of moles of CO_2 released upon capture of one mole of acid gas;
$CO_{2\ MW}$	=	Molecular weight of carbon dioxide (44);
$Sorbent_{\ MW}$	=	Molecular weight of sorbent (if calcium carbonate, 100).

(d) Calculating Fugitive HFC Emissions from Cooling Units. Operators of electricity generating facilities shall calculate fugitive HFC emissions for each HFC compound used in cooling units that support power generation or are used in heat transfers to cool stack gases using either the methodology in paragraph (d)(1) or (d)(2). The Operator is not required to report GHG emissions from air or water cooling systems or condensers that do not contain HFCs.

(1) Use Equation 40-2 to calculate annual HFC emissions:

$$HFC = HFC_{inventory} + HFC_{purchases/acquisitions} - HFC_{sales/disbursements} + HFC_{\Delta capacity}$$ **Equation 40-2**

Where:

HFC	=	Annual fugitive HFC emission, metric tons;
$HFC_{inventory}$	=	The difference between the quantity of HFC in storage at the beginning of the year and the quantity in storage at the end of the year. Stored HFC includes HFC contained in cylinders (such as 115-pound storage cylinders), gas carts, and other storage containers. It does not include HFC gas held in operating equipment. The change in inventory will be negative if the quantity of HFC in storage increases over the course of the year.
$HFC_{purchases/acquisitions}$	=	The sum of all HFC acquired from other entities during the year either in storage containers or in equipment.
$HFC_{sales/disbursements}$	=	The sum of all the HFC sold or otherwise transferred offsite to other entities during the year either in storage containers or in equipment.

$HFC_{\Delta capacity}$ = The net change in the total nameplate capacity (i.e. the full and proper charge) of the cooling equipment). The net change in capacity will be negative if the total nameplate capacity at the end of the year is less than the total nameplate capacity at the beginning of the year.

(2) Use service logs to document HFC usage and emissions from each cooling unit. Service logs should document all maintenance and service performed on the unit during the report year, including the quantity of HFCs added to or removed from the unit, and include a record at the beginning and end of each report year. The operator may use service log information along with the following simplified material balance equations to quantify fugitive HFCs from unit installation, servicing, and retirement, as applicable. The operator shall include the sum of HFC emissions from the applicable equations in the greenhouse gas emissions data report.

$$HFC_{Install} = R_{new} - C_{new}$$

$$HFC_{Service} = R_{recharge} - R_{Recover}$$

$$HFC_{Retire} = C_{retire} - R_{retire}$$

Where:

$HFC_{Install}$ = HFC emitted during initial charging/installation of the unit, kilograms;
$HFC_{Service}$ = HFC emitted during use and servicing of the unit for the report year, kilograms;
HFC_{Retire} = HFC emitted during the removal from service/retirement of the unit, kilograms;
R_{new} = HFC used to fill new unit (omit if unit was pre-charged by the manufacturer), kilograms;
C_{new} = Nameplate capacity of new unit (omit if unit was pre-charged by the manufacturer), kilograms;
$R_{recharge}$ = HFC used to recharge the unit during maintenance and service, kilograms;
$R_{recover}$ = HFC recovered from the unit during maintenance and service, kilograms;
C_{retire} = Nameplate capacity of the retired unit, kilograms; and
R_{retire} = HFC recovered from the retired unit, kilograms.

(e) Fugitive CO_2 Emissions from Geothermal Facilities. Operators of geothermal electricity generating facilities shall calculate the fugitive CO_2 emissions using one of the following methods:

(1) Calculate the fugitive CO_2 emissions using Equation 40-3:

$$CO_2 = 7.14 \times Heat \times 0.001$$ **Equation 40-3**

Where:

CO_2 = CO_2 emissions, metric tons per year;
7.14 = Default fugitive CO_2 emission factor for geothermal facilities, kg per GJ; and
Heat = Heat taken from geothermal steam and/or fluid, GJ/yr.

(2) Calculate CO_2 emissions using [*insert jurisdiction*] approved source specific emission factor.

§ WCI.44 Sampling, Analysis, and Measurement Requirements

(a) CO_2, CH_4 and N_2O Emissions from Fuel Combustion. Operators using CEMS to estimate CO_2 emissions from fuel combustion shall comply with the requirements in section WCI.23(d). Operators using methods other than CEMS shall comply with the applicable fuel sampling, fuel consumption monitoring, heat content monitoring, and carbon content monitoring specified in section WCI.25.

(b) CO_2 Emissions from Acid Gas Scrubbing. Operators of electricity generating units that use acid gas scrubbers or add an acid gas reagent to the combustion unit shall measure the amount of limestone or other sorbent used during the reporting year.

(c) CO_2 Emissions from Geothermal Facilities. Operators of geothermal facilities shall measure the heat recovered from geothermal steam. If using source specific emission factor instead of the default factor, the operator shall conduct an annual test of the CO_2 emission rate using a method approved by [*insert jurisdiction*]. The operator shall submit a test plan to the [*insert jurisdiction*] for approval. Once approved, the annual tests shall be conducted in accordance with the approved test plan under the supervision of the [*insert jurisdiction*].

§ WCI.60 IMPORTED ELECTRICITY

[*The requirements in this attachment do not include the default emissions factors necessary for reporting imported electricity from asset-controlling suppliers or imports from unspecified sources. Default factors for unspecified sources are under development by the Electricity Committee and asset-controlling suppliers will need to approach each jurisdiction for approval of a differentiated default factor*.]

§ WCI.61 Definitions

“Asset-controlling supplier” means any entity that owns or operates electricity generating facilities or serves as an exclusive marketer for certain generating facilities even though it does not own them, and is assigned a supplier-specific identification number for its fleet of generating facilities by [*the jurisdiction*].

“Balancing authority” means a responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports interconnection frequency in real time.

“Balancing authority area” means the collection of generation, transmission, and loads within the metered boundaries of a balancing authority. A balancing authority maintains load-resource balance within this area.

“Busbar” means a power conduit of an electricity generating facility that serves as the starting point for the electricity transmission system.

“Electricity generating facility” means a facility that generates electricity and includes one or more electricity generating units at the same location.

“Electricity importer” means [common boundary FJD] an owner of imported electricity [*or electricity wheeled through the WCI Region*] as it is delivered to the first point of delivery in the WCI Region or; [individual boundary FJD] an owner of imported electricity [*or electricity wheeled through the WCI Region*] as it is delivered to the first point of delivery in the WCI Partner jurisdiction of the final point of delivery. [The definition used may vary by jurisdiction.]

“Electricity transaction” means the purchase, sale, import, export or exchange of electric power.

“Electricity wheeled through the WCI Region” means electricity that is imported into the WCI Region but is simultaneously exported out of the WCI Region and has a final point of delivery in a location outside of the WCI Region.

“Entity” means a person, firm, association, organization, partnership, business trust, corporation, limited liability company, company, or government agency.

“Exchange agreement” means a commitment between electricity market participants to swap energy for energy. Exchange transactions do not involve transfers of payment or receipts of money for the full market value of the energy being exchanged, but may include payment for net differences due to market price differences between the two parts of the transaction or to settle minor imbalances.

"Final point of delivery" means the last point of delivery for a given electricity transaction.

"First Jurisdictional Deliverer" means the owner or operator of an electricity generating facility in a WCI Partner jurisdiction or an electricity importer that is jurisdictional to the regulatory authority of a WCI Partner jurisdiction or the immediate downstream purchaser or recipient of electricity from a non-jurisdictional electricity importer.

"Gross generation" means the total electrical output of the generating unit, expressed in megawatt hours (MWh) per year.

"Imported electricity" means electric power generated outside the WCI Region, delivered into the WCI Region and having a final point of delivery in the WCI Region.

"Megawatt hour" or "MWh" means the electrical energy unit of measure equal to one million watts of power supplied to, or taken from, an electric circuit steadily for one hour.

"Multi-jurisdictional retail provider" means a retail provider that provides electricity to consumers in [*the jurisdiction*] and in one or more other non-WCI jurisdictions in a contiguous service territory.

"Nameplate generating capacity" means the maximum rated output of a generator under specific conditions designated by the manufacturer, expressed in megawatts (MW) or kilowatts (kW).

"Net power generated" means the gross generation minus station service or unit service power requirements, expressed in megawatt hours (MWh) per year. In the case of cogeneration, this value is intended to include internal consumption of electricity for the purposes of a production process, as well as power put on the grid.

"NERC E-tag" means North American Electric Reliability Corporation (NERC) energy tag representing transactions on the North American bulk electricity market scheduled to flow between or across balancing authority areas.

"Point of delivery" means a point on an electricity transmission or distribution system where a power supplier delivers electricity to the receiver of that energy. This point can be an interconnection with another system or a substation where the transmission provider's transmission and distribution systems are connected to another system, or a distribution substation where electricity is imported into the WCI region over a multi-jurisdictional retail provider's distribution system.

"Power contract" means an arrangement for the purchase of electricity. Power contracts may be, but are not limited to, power purchase agreements and tariff provisions.

"Purchasing/selling entity" means an entity that purchases or sells energy or capacity and reserves transmission services between or among balancing authority areas.

"Renewable energy" means energy from sources that constantly renew themselves or that are regarded as practically inexhaustible. Renewable energy includes, but is not limited to, energy derived from solar, wind, geothermal, hydroelectric, wood, biomass, tidal power, sea currents, and ocean thermal gradients.

"Renewable energy certificate" or "renewable energy credit" means a certificate of proof issued by an approved generation information system or third-party verifier that one MWh of electricity was generated by a renewable energy source.

"Retail provider" means an entity that provides electricity to retail end users in [*the jurisdiction*].

"Specified source" means a specific electricity generating unit or electricity generating facility which can be matched to a reported electricity transaction due to full or partial ownership by the first jurisdictional deliverer or due to its identification in a power contract with the first jurisdictional deliverer.

"Unspecified source" means electricity generation that cannot be matched to a specific electricity generating facility or electricity generating unit. Unspecified sources of electricity may include electricity purchased from entities that own fleets of generating facilities such as independent power producers, retail providers, and federal power agencies and power purchased from electricity marketers, brokers, and markets.

"Western Climate Initiative" or "WCI" means a collaborative effort of the U.S. states and Canadian provinces that comprise the WCI Region to reduce greenhouse gas emissions in their respective jurisdictions.

"WCI Region" means the Canadian provinces of British Columbia, Manitoba, Ontario, and Quebec plus the U.S. states of Arizona, California, Montana, New Mexico, Oregon, Utah, and Washington, excluding lands that are not subject to state or provincial jurisdiction.

§ WCI.62 Greenhouse Gas Emissions Data Report: First Jurisdictional Deliverers of Imported Electricity

(a) General Requirements. First jurisdictional deliverers shall meet the following general requirements in preparing their greenhouse gas emissions data report for each report year. When reporting emissions and electricity transactions, first jurisdictional deliverers, excluding imported electricity that is imported at the distribution level by multi-jurisdictional retail providers, shall:

(1) Specify the amount of greenhouse gas emissions in metric tons CO_2e;

(2) Specify the amount of electricity in MWh;

(3) Aggregate imported electricity and emissions from specified sources by electricity generating facility or electricity generating unit, as applicable;

(4) For electricity from specified sources, specify the facility name, the facility ID, and, if applicable, the electricity generating unit ID for the unit generating the electricity;

(5) Report the amount of imported electricity from specified sources as measured at the busbar;

(6) For imported electricity transactions from specified sources where measurements at the busbar are not known, report the amount of imported electricity from the applicable specified sources as measured at the first point of delivery in [*the jurisdiction]* and report estimated transmission losses for each specified source;

(7) Report the amount of electricity from unspecified sources as measured at the first point of delivery in [*the jurisdiction*];

(8) For electricity from unspecified sources, disaggregate imported electricity by the balancing authority area or other geographic area as defined by [*the jurisdiction*] from which the electricity originated;

(9) Report the amount of electricity from asset-controlling suppliers as measured at the first point of delivery in [*the jurisdiction*];

(10) For electricity from asset-controlling suppliers, disaggregate imported electricity by the asset-controlling or asset-owning supplier from which the electricity was purchased;

(11) Report the number of renewable energy certificates from sources not in the WCI region that are retired, or whose greenhouse gas source specification fields are retired, as applicable, associated with imported electricity from an unspecified source or imported electricity from a specified source having an emission rate equal to or less than the default rate for the balancing authority where the specified generating facility is located;

(12) Specify electricity imported under exchange agreements as you would other import transactions;

(13) Report quantities of electricity wheeled through the WCI Region as measured at the first point of delivery inside [*the jurisdiction*];

(14) Retain for purposes of verification NERC E-tags, power contracts, settlements data, and all other information needed to confirm the transactions.

(b) Report Content. First Jurisdictional Deliverers shall include the following information in the greenhouse gas emissions data report for each report year.

(1) Specified Imported Electricity Transactions. Imported electricity and emissions from specified sources for which the First Jurisdictional Deliverer is the electricity importer or that the First Jurisdictional Deliverer purchased or received immediately downstream from a non-jurisdictional electricity importer.

(A) Electricity imported into the WCI Region from a specified hydroelectric generating facility with nameplate capacity of greater than 30 MW that was operational prior to January 1, 2008 or from a specified nuclear facility that was operational prior to January 1, 2008 shall be listed as one of the following:

(i) Electricity purchased with a contract in effect prior to January 1, 2008 that remains in effect or has been renegotiated for the same facility for the same share or quantity of net generation within one year of contract expiration;

(ii) Electricity purchased not meeting WCI.62(b)(1)(A)(i) and that is not associated with an increase in the facility's generating capacity;

(iii) Electricity purchased not meeting WCI.62(b)(1)(A)(i) that is associated with an increase in the facility's generating capacity due to increased efficiencies or other capacity increasing actions;

(iv) Electricity purchased from hydroelectric generating facilities during a "spill or sell" situation where power not purchased is lost;

(v) Electricity purchased that does not meet WCI.62(b)(1)(A)(i) due to federal power redistribution polices for federally owned resources and not related to price bidding.

(2) Unspecified Imported Electricity Transactions. Imported electricity and emissions from unspecified sources for which the First Jurisdictional Deliverer is the electricity importer or that the First Jurisdictional Deliverer purchased or received immediately downstream from a non-jurisdictional electricity importer.

(3) Imported Electricity from Asset-Controlling Suppliers. Imported electricity and emissions from asset-controlling suppliers for which the First Jurisdictional Deliverer is the electricity importer or that the First Jurisdictional Deliverer purchased or received immediately downstream from a non-jurisdictional electricity importer.

(4) Electricity Wheeled Through the WCI Region. Electricity wheeled through the WCI Region for which the First Jurisdictional Deliverer is the electricity importer or that the First Jurisdictional Deliverer purchased or received immediately downstream from a non-jurisdictional electricity importer.

§ WCI.63 Calculation of Emissions from Specified Sources

For each specified source, calculate CO_2 mass emissions using one of the two calculation methodologies specified in this section.

(a) Calculation Methodology 1: If the specified source reports emissions to [*the jurisdiction*], The Climate Registry, the U.S.EPA under 40 CFR Part 75 or to Environment Canada under Section 71 of the Canadian Environmental Protection Act calculate emissions using Equation 60-1:

$$CO_2 = CO_{2t} \times \frac{MWh_{imp}}{MWh_t}$$ **Equation 60-1**

Where:

CO_2 = Annual CO_2 mass emissions for imported electricity from the specified source (metric tons).

CO_{2t} = Total annual CO_2 mass emissions from the specified source (metric tons) reported, in order of preference, to [*the jurisdiction*], The Climate Registry, or to the U.S.EPA or Environment Canada.

MWh_{imp} = Megawatt-hours of electricity imported from the specified source, including estimated losses for transactions not measured at the busbar.

MWh_t = Total megawatt-hours of net power generated by the specified source.

(b) Calculation Methodology 2: If the specified source does not report emissions to [*the jurisdiction*], The Climate Registry, the U.S.EPA under 40 CFR Part 75 or to Environment Canada under Section 71 of the Canadian Environmental Protection Act, calculate emissions using Equation 60-2:

$$CO_2 = \sum HHV_f \times EF_f \times 0.001 \times \frac{MWh_{imp}}{MWh_t}$$ **Equation 60-2**

Where:

CO_2 = Annual CO_2 mass emissions for a specific fuel type (metric tons).
HHV_f = Higher heating value of the fuel *f* consumed for electricity production as reported in U.S. EIA Form 923, or its successor (mmBtu).
EF_f = Fuel-specific default CO_2 emission factor, from column 5 of Table 20-1 or from Table 20-2 (kg CO_2/mmBtu).
0.001 = Conversion factor from kilograms to metric tons.
MWh_{imp} = Megawatt-hours of electricity imported from the specified source.
MWh_t = Total megawatt-hours of net power generated by the specified source as reported in U.S. EIA Form 923, or its successor.

§ WCI.64 Calculation of Emissions from Asset-Controlling Suppliers and Unspecified Sources

For imported electricity from asset-controlling suppliers or unspecified sources, calculate emissions using the methodology specified in this section.

(a) Calculation Methodology: Calculate the annual CO_2 mass emissions by multiplying the reported quantities of imported electricity from each asset-controlling supplier, balancing authority area, or other geographic region defined by [*the jurisdiction*] by the appropriate default emission factor according to Equation 60-3:

$$CO_2 = MWh \times DEF$$ **Equation 60-3**

Where:
CO_2 = Annual CO_2 mass emissions for imported electricity from the specified source (metric tons).
MWh = Megawatt-hours of electricity imported from the asset-controlling supplier, balancing authority area, or other geographic region defined by [*the jurisdiction*].
DEF = The default emission factor corresponding to the asset-controlling supplier, balancing authority area, or other geographic region defined by [*the jurisdiction*].

§ WCI.65 Greenhouse Gas Emissions Data Report: Additional Requirements for Retail Providers Only

[*This section is optional. It is intended for any WCI jurisdiction that wishes to collect information about high-GHG generating facilities in other jurisdictions owned by retail providers serving its own jurisdiction.*]

Retail providers shall include the following information in the greenhouse gas emissions data report for each report year, in addition to the information identified in the sections above.

(a) If the retail provider holds a contract that entitles the retail provider to a specified percentage of the generation in the report year from an electricity generating facility not located in the WCI Region, the retail provider shall include electricity purchased or sold from that facility as being from a partially owned facility.

(b) For electricity generating facilities not located in the WCI Region that are fully or partially owned by the retail provider that have CO2 emissions greater than 500 kg of CO2 per MWh based on the most recent greenhouse gas emissions data report that received a positive verification opinion or on CO2 emissions reported to U.S.EPA under 40 CFR Part 75 or reported to Environment Canada under Section 71 of the Canadian Environmental Protection Act, the retail provider shall include:

(1) Facility name, state/province designated facility ID, state/province designated generating unit ID as applicable, percent ownership share at the facility level, ownership share at the generating unit level as applicable, and both net and gross power generated in the report year;

(2) Quantity of electricity sold by the retail provider or on behalf of the retail provider from the electricity generating facility or electricity generating unit having a final point of delivery outside the WCI Region, as measured at the busbar.

§ WCI.66 Greenhouse Gas Emissions Data Report: Additional Requirements for Multi-Jurisdictional Retail Providers Only.

[*This section applies only to jurisdictions with Multi-Jurisdictional Retail Providers, as defined.*]

Multi-jurisdictional retail providers that import electricity into the WCI Region at the distribution level shall include the following information in the greenhouse gas emissions data report for each report year in addition to the information identified in the sections above. Multi-jurisdictional retail providers meeting this condition shall provide:

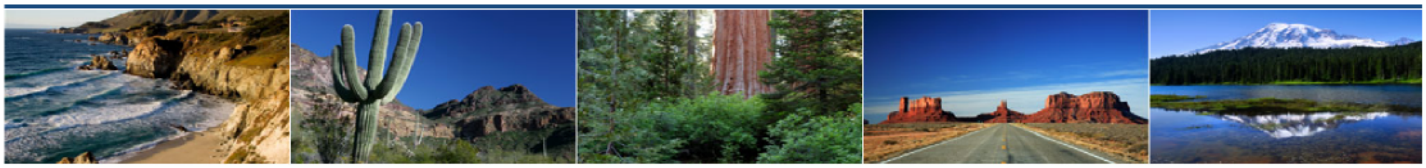
(a) A report of the greenhouse gas emissions associated with serving the load of the service territory that includes consumers in [*the jurisdiction*] following [*the jurisdiction's*] reporting protocol for retail providers or The Climate Registry's Electric Power Sector Protocol;

(b) The total retail load served by the multi-jurisdictional retail provider in the service territory that includes consumers in [*the jurisdiction*];

(c) The retail load of customers served in [*the jurisdiction's*] portion of the service territory;

(d) The greenhouse gas emissions associated with the imported electricity as the quantity of emissions reported in WCI.64(a) multiplied by the ratio of the quantity of electricity reported in WCI.64(b) to the quantity of electricity reported in WCI.64(c); and

(e) If the average emission rates differ among the various state or provincial portions of the service territory due to mandatory factors such as different Renewable Portfolio Standard requirements in [*the jurisdiction*] and the other jurisdictions, the multi-jurisdictional retail provider may report an adjusted quantity of greenhouse emissions and file a report that describes how the quantity reported in WCI.64(d) was adjusted.



§ WCI.70 PRIMARY ALUMINUM PRODUCTION

§ WCI.71 Source Category Definition

A primary aluminum production process converts alumina mineral to aluminum metal using electrolysis.

§ WCI.72 Greenhouse Gas Reporting Requirements

For each facility that includes a primary aluminum production process, the emissions data report must contain the following information:

(a) CO_2 emissions from anode consumption from prebaked and Søderberg electrolysis cells.

(b) CO_2 emissions from anode and cathode baking.

(c) CF_4 and C_2F_6 emissions for anode effects.

(d) CO_2 emissions from green coke calcination.

(e) SF_6 emissions from cover gas consumption.

(f) CO_2, N_2O, and CH_4 emissions from stationary combustion units as specified in WCI.20.

(g) Annual aluminum production.

§ WCI.73 Calculation of GHG Emissions

(a) Calculate CO_2 emissions from anode consumption using either Equation 70-1 or 70-2, as applicable.

(1) For Prebaked Anodes:

$$E_{CO_2} = \sum_{i=1}^{12}\left[NCC \times MP \times \frac{(100 - S_a - Ash_a - Imp_a)}{100} \times 3.664\right]_i$$

Equation 70-1

Where:

E_{CO2} = Annual CO_2 emissions (metric tons).

NCC = Net anode consumption per metric ton of aluminum for month i (metric ton/ metric ton aluminum).

MP = Aluminum production for month i (metric ton).

S_a = Sulfur content in baked anodes for month i (wt %).

Ash_a = Ash content in baked anodes for month i (wt %).

Imp_a = Content of fluorine and other impurities in baked anodes for month i (wt %).

3.664 = Conversion factor from carbon to CO_2.

(2) For Søderberg Anodes:

$$E_{CO_2} = \sum_{i=1}^{12} \left[\begin{array}{l} (PC \times MP) - \left(BSM \times \frac{MP}{1000} \right) - \left(\frac{BC}{100} \times PC \times MP \times \left(\frac{S_p + Ash_p + H_p}{100} \right) \right) \\ - \left(\frac{100 - BC}{100} \times PC \times MP \times \frac{S_c + Ash_c}{100} \right) \end{array} \right]_i \times 3.664$$

Equation 70-2

Where:

E_{CO2}	=	Annual CO_2 emissions (metric tons).
PC	=	Paste consumption for month i (metric tons paste/metric ton aluminum).
MP	=	Aluminum production for month i (metric tons).
BSM	=	Emissions of benzene-soluble matter (kilograms benzene-soluble matter/metric ton aluminum).
BC	=	Average binder (pitch) content in paste for month i (wt %).
S_p	=	Sulfur content in pitch for month i (wt %).
Ash_p	=	Ash content in pitch (wt %).
H_p	=	Hydrogen content in pitch (wt %).
S_c	=	Sulfur content in calcinated coke (wt %).
Ash_c	=	Ash content in calcinated coke (wt %).
3.664	=	Conversion factor from carbon to CO_2.

(b) If anode or cathode baking is performed onsite, calculate CO_2 emissions as specified in paragraphs (b)(1) or (2) as applicable. Total emissions as specified in paragraph (b)(3) if both (b)(1) and (2) are applicable.

(1) Calculate CO_2 emissions from packing coke using Equation 70-3.

$$EC_{CO_2} = \sum_{i=1}^{12} \left(PCC \times BAP \times \frac{100 - Ash_{pc} - S_{pc} - Imp}{100} \right)_i \times 3.664$$

Equation 70-3

Where:

EC_{CO2}	=	Annual CO_2 emissions (metric tons pre year).
PCC	=	Packing coke consumption per metric ton of baked anode for month i (metric tons coke/metric ton anodes).
BAP	=	Baked anode production for month i (metric tons).
Ash_{pc}	=	Ash content in packing coke for month i (wt %).
S_{pc}	=	Sulfur content in packing coke for month i (wt %).
Imp	=	Content of other impurities for month i (wt %).
3.664	=	Conversion factor from carbon to CO_2.

(2) Calculate CO_2 emissions from pitch coking using Equation 70-4.

$$EP_{CO_2} = \sum_{i=1}^{12} \left(GAW - BAP - \left(\frac{H_p}{100} \times \frac{PC}{100} \times GAW \right) - RT \right)_i \times 3.664$$ **Equation 70-4**

Where:
EP_{CO2} = CO_2 emissions (metric tons pre year).
GAW = Green anode consumption for month i (metric tons).
BAP = Baked anode production for month i (metric tons).
H_p = Hydrogen content in pitch for moth i (wt %).
PC = Pitch content in green anode for month i (wt %).
RT = Recovered tar for month i (metric tons).
3.664 = Conversion factor from carbon to CO_2.

(3) Calculate total CO_2 emissions for anode baking using Equation 70-5.

$$E_{anodebaking} = EC_{CO2} + EP_{CO2}$$ **Equation 70-5**

Where:

$E_{anodebaking}$ =Total annual CO_2 emissions from anode baking (metric tons).

EC_{CO2} = Annual CO_2 emissions from packing coke (metric tons).

EP_{CO2} = Annual CO_2 emissions from pitch coking (metric tons).

(c) Calculate CF_4 and C_2F_6 emissions from anode effects for each pot line using either the Slope Method in paragraph (c)(1) or the Pechiney Method in paragraph (c)(2).

(1) **Slope Method:** Calculate the CF_4 and C_2F_6 emissions using Equation 70-6.

$$E_{CF_4,C_2F_6} = \sum_{i=1}^{n} [slope_{CF_4,C_2F_6} \times AEF \times AED \times MP]_i$$ **Equation 70-6**

Where:
$E_{CF4, C2F6}$ = Annual emissions of CF_4 or C_2F_6 (metric tons/yr).

$slope_{CF4, C2F6}$ = Measured slope coefficient ([Metric tons of CF_4 or C_2F_6 /metric ton Aluminum]/[anode effect minutes/pot-days]).
AEF = Anode effect frequency (number of anode effects per pot per day).
AED = Anode effect duration (minutes per anode effect).
MP = Aluminum production per day (metric tons).
n = Number of operating days per year.

(2) **Pechiney Method:** Calculate the CF_4 and C_2F_6 emissions using Equation 70-7.

$$E_{CF_4,C_2F_6} = \sum_{i=1}^{n} [Over-voltage \quad coefficient_{CF_4,C_2F_6} \times \frac{AEO}{CE} \times MP]_i$$ **Equation 70-8**

Where:

$Emission_{CF4, C2F6}$	=	Emissions of CF_4 or C_2F_6 (metric tons/yr).
Over-voltage $coefficient_{CF4, C2F6}$	=	Experimentally measured ([Metric tons of CF_4 or C_2F_6 /metric ton Aluminum]/mV).
AEO	=	Anode effect over-voltage (millivolts per pot per day).
CE	=	Current efficiency of aluminum production process, expressed as a fraction.
MP	=	Aluminum production per day (metric tons).
n	=	Number of operating days per year.

(d) Calculate CO_2 emissions from onsite green coke calcination furnaces using Equation 70-9.

$$E_{CO_2} = \sum_{n=1}^{12} \left[\left[GC \times \frac{(100 - H_2O_{gc} - V_{gc} - S_{gc})}{100} - (CC + UCC + DE) \times \frac{(100 - S_{cc})}{100}\right] \times 3.664\right]_i + \left[GC \times 0.035 \times \frac{44}{16}\right]_i$$ **Equation 70-9**

Where:

E_{CO2}	=	CO_2 emissions (metric tons pre year).
GC	=	Green coke feed for month i (metric tons).
H_2O_{gc}	=	Humidity in green coke feed for month i (wt %).
V_{gc}	=	Volatiles in green coke feed for month i (wt %).
S_{gc}	=	Sulfur content in green coke feed in month i (wt %).
S_{cc}	=	Sulfur content in calcinated coke in month i (wt %).
CC	=	Calcinated coke produced in month i (metric tons).
UCC	=	Under-calcinated coke produced in month i (metric tons).
DE	=	Coke dust emissions for month i (metric tons).
3.664	=	Conversion factor from carbon to CO_2.
0.035	=	Assumed CH_4 and tar content in coke volatiles, contributing to CO_2 emissions.
44/16	=	Conversion factor from methane to CO_2.

(e) Calculate SF_6 emissions from cover gas consumption using one of the following methods:

(1) Calculate the annual SF_6 emissions using inventory records and Equation 70-10:

$$E_{SF6} = S_{Inv-Begin} - S_{Inv-End} + S_{Purchased} - S_{Shipped}$$ **Equation 70-10**

Where:

E_{SF6}	=	SF_6 emissions from cover gas (metric tons).

$S_{Purchased}$ = Quantity of SF_6 purchased (metric tons).
$S_{Shipped}$ = Quantity of SF_6 shipped offsite (metric tons).
$S_{Inv\text{-}Begin}$ = Quantity of SF_6 in storage at the beginning of the year, (metric tons).
$S_{Inv\text{-}End}$ = Quantity of SF_6 in storage at the end of the year (metric tons).

(2) Calculate the annual SF_6 emissions using Equation 70-11 and direct measurement of the SF6 input to electrolysis cells and the SF6 waste gases collected and transferred off-site:

$$E_{SF6} = \sum_{i=1}^{12} [(Q_{Input} \times C_{Input}) - (Q_{Output} \times C_{Output})]_i \qquad \textbf{Equation 70-11}$$

Where:
E_{SF6} = SF_6 emissions from cover gas (metric tons).
$Q_{in;put}$ = Quantity of SF_6 input to the electrolysis cell for month i (metric tons).
C_{Input} = Concentration of SF_6 input to the electrolysis cell for month i (metric tons).
Q_{Output} = Quantity of SF_6 gas collected during month i (if applicable) (metric tons).
C_{Output} = Concentration of SF_6 gas collected and sent off-site during month i (metric tons).

§ WCI.74 Monitoring Requirements

(a) Except as specified in paragraphs (b) through (c) of this section, all parameters must be measured monthly.

(b) Conduct performance tests once every 36 months to determine the slope or Pechiney coefficients for each pot line using the *Protocol for Measurement of Tetrafluoromethane and Hexafluoroethane Emissions from Primary Aluminum Production*, U.S. Environmental Protection Agency and International Aluminum Institute. April 2008. The test must be repeat whenever:

(1) Thirty-six months have passed since the last measurements;

(2) A change occurs in the control algorithm that affects the mix of types of anode effects or the nature of the anode effect termination routine; or

(3) Changes occur in the distribution or duration of anode effects (e.g. when the percentage of manual kills changes or if, over time, the number of anode effects decreases and results in a fewer number of longer anode effects) or, for Rio Tinto Alcan control technology, when the algorithm for bridge movements and anode effect overvoltage accounting changes.

(c) If using the direct measurement approach in WCI.73(e)(2) to calculate SF_6 emissions from cover gas consumption, you must measure the quantity of SF_6 gas input to the electrolysis cell month and the quantity and SF_6 concentration of any waste gas collected and sent off-site.

§ WCI.90 CEMENT MANUFACTURING

§ WCI.91 Source Category Definition

Cement manufacturing is comprised of all processes that are used to manufacture Portland, natural, masonry, pozzolanic, or other hydraulic cements.

§ WCI.92 Greenhouse Gas Reporting Requirements

In addition to the information required by WCI.3, the annual emissions data report shall contain the following information:

(a) Total emissions of CO_2, CH_4, and N_2O in metric tons.

(b) CO_2 process emissions from calcination (metric tons) and the following information:

- (1) Plant specific clinker emission factor (kg CO_2/metric ton clinker).
  - (A) Quantity of clinker produced (metric tons).
  - (B) Total lime (CaO) content of clinker (wt. fraction).
  - (C) Total magnesium Oxide (MgO) content of clinker (wt. fraction).
  - (D) Total carbonate (CO_2) content of clinker (wt. fraction).
- (2) Cement kiln dust (CKD) emission factor (kg CO_2/metric ton CKD discarded).
  - (A) Plant specific CKD calcination rate (unitless ratio).
  - (B) Quantity of CKD discarded (metric tons).

(c) CO_2 process emissions from organic carbon oxidation (metric tons) and the following information:

- (1) Amount of raw material consumed in the report year (metric tons).
- (2) Organic carbon content of raw material (wt. fraction).

(d) CO_2, CH_4, and N_2O emissions from fuel combustion in all kilns combined, following the calculation methods and reporting requirements specified in WCI.93(c) (metric tons).

(e) CO_2, CH_4, and N_2O emissions from all other fuel combustion units combined (kilns excluded), following the calculation methods and reporting requirements specified in WCI.20 (metric tons).

(f) If a continuous emissions monitor is used to measure CO_2 emissions from kilns, then the requirements of paragraphs (b), (c), and (d) of this section do not apply for CO_2. Cement plants that measure CO_2 emissions using CEMS shall report fuel usage by fuel type for kilns.

(g) Operators of cement plants shall also comply with the reporting requirements for any other applicable source category listed at WCI.1(a), including but not limited to the following:

- (1) Coal fuel storage as specified in WCI.100.

(2) Electricity generating as specified in WCI.40.

(3) Cogeneration systems as specified in WCI.50.

§ WCI.93 Calculation of Greenhouse Gas Emissions From Kilns

(a) Determine CO_2 emissions as specified under either paragraph (a)(1) or (a)(2) of this section.

(1) Use a continuous emissions monitoring system (CEMS) as specified in WCI.23(d).

(2) Calculate the sum of CO_2 process emissions from kilns and CO_2 fuel combustion emissions from kilns using the calculation methodologies specified in paragraph (b) and (c) of this section**.**

(b) Process CO_2 Emissions Calculation Methodology. Calculate total CO_2 process emissions as the sum of emissions from calcination, using the method specified in paragraph (b)(1) of this section; and from organic carbon oxidation, using the method specified in paragraph (b)(2) of this section (Equation 90-0).

$$CO_2 \text{ process} = CO_2 \text{ calcination} + CO_2 \text{ raw material} \qquad \textbf{Equation 90-0}$$

(1) Calcination Emissions. Calculate CO_2 process emissions from calcination using Equation 90-1 and a plant-specific clinker emission factor and a plant-specific cement kiln dust (CKD) emission factor as specified in this section.

$$CO_{2-C} = \sum_{i=1}^{12} [(Cli) \times (EF_{Cli})] + [(Q_{CKD}) \times (EF_{CKD})] \qquad \textbf{Equation 90-1}$$

Where:

$CO_{2\text{-}C}$ = CO_2 emissions from calcination, metric tones.
Cli = Monthly quantity of clinker produced, metric tons.
EF_{Cli} = Monthly clinker emission factor, metric tons CO_2/metric ton clinker computed as specified in paragraph (b)(1)(A) of this section.
Q_{CKD} = Monthly quantity CKD discarded (i.e., not recycled to the kiln), metric tons.
EF_{CKD} = Monthly CKD emission factor, computed as specified in paragraph (b)(1)(B) of this section.

(A) Clinker Emission Factor. Calculate a plant-specific clinker emission factor (EF_{Cli}) for each report year based on monthly measurements of the weight fraction of CaO, MgO and CO_2 (carbonate) content in the clinker and using Equation 90-2, which assumes all carbonate remaining in the clinker is associated with the calcium.

$$EF_{Cli} = [(CaO\ content - \frac{CO2\ Content}{Molecular\ ratio\ CO2/CaO}) \times Molecular\ ratio\ of\ CO_2/CaO] + [(MgO\ Content) \times Molecular\ ratio\ of\ CO_2/MgO] \qquad \textbf{Equation 90-2}$$

Where:

CaO Content (by weight)	=	Total CaO content of Clinker (including calcined and uncalcined) (wt. fraction).
CO_2 Content (by weight)	=	Total CO_2 content of Clinker (wt. fraction).
Molecular ratio of CO_2/CaO	=	0.785.
MgO Content (by weight)	=	Total MgO content of Clinker (including calcined and uncalcined) (wt. fraction).
Molecular ratio of CO_2/MgO	=	1.092.

(B) CKD Emission Factor. If CKD is generated and not recycled back to the kiln, then calculate a plant-specific CKD emission factor based on monthly sampling. The CKD emission factor shall be calculated using Equation 90-3 and a plant-specific CKD calcination rate as specified in Equation 90-4.

$$EF_{CKD} = \frac{\frac{EF_{Cli}}{1 + EF_{Cli}} \times d}{1 - \left(\frac{EF_{Cli}}{1 + EF_{Cli}} \times d\right)} \qquad \textbf{Equation 90-3}$$

Where:

EF_{CKD}	=	Monthly CKD emission factor, kg CO_2/metric ton CKD discarded.
EF_{Cli}	=	Clinker emission factor, determined according to Equation 90-2.
d	=	CKD calcination rate, determined according to Equation 90-4.

$$d = 1 - \frac{fCO_{2CKD} \times (1 - fCO_{2RM})}{(1 - fCO_{2CKD}) \times fCO_{2RM}} \qquad \textbf{Equation 90-4}$$

Where:

d	=	CKD calcination rate (unitless ratio).
fCO_{2CKD}	=	Weight fraction of carbonate CO_2 in the CKD.
fCO_{2RM}	=	Weight fraction of carbonate CO_2 in the raw material.

(2) Organic Carbon Oxidation Emissions. Calculate CO_2 process emissions from the total organic content in raw materials by using Equation 90-5.

$$CO_{2-RM} = TOC_{RM} \times RM \times 3.664 \qquad \textbf{Equation 90-5}$$

Where:

$CO_{2\text{-}RM}$	=	CO_2 emissions from raw material oxidation, metric tons.
TOC_{RM}	=	Total organic carbon content in raw material (wt. fraction), measured using the method in WCI.94(c) or using a default of 0.002 (0.2%).
RM	=	Amount of raw material consumed (metric tons/yr).
3.664	=	The CO_2 to carbon molar ratio.

(c) Fuel Combustion Emissions in Kilns. Calculate CO_2, CH_4, and N_2O emissions from stationary fuel combustion following the calculation methods specified in WCI.20. Cement plants that combust pure biomass-derived fuels and combust fossil fuels only during periods of start-up, shut-down, or malfunction may report CO_2 emissions from fossil fuels using the emission factor methodology in WCI.23(a). "Pure" means that the biomass-derived fuels account for 97 percent of the total amount of carbon in the fuels burned.

§ WCI.94 Sampling, Analysis, and Measurement Requirements

(a) Determine the plant-specific weight fractions of total CaO, total MgO, total carbonate CO_2 in clinker using ASTM C114-07. Determine the weight fraction of carbonate CO_2 in the CKD and the weight fraction of carbonate CO_2 in the raw material using ASTM C114-07. The monitoring must be conducted monthly from clinker and CKD samples drawn from bulk storage.

(b) If not using the default value of 0.002 for TOC_{RM} in Equation 90-5, the total organic carbon contents of raw materials must be determined annually using ASTM Method C114-07. The analysis must be conducted on sample material drawn from bulk raw material storage for each category of raw material.

(c) The quantity of clinker produced must be determined by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.

(d) The quantity of CKD discarded must be determined by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.

(e) The quantity of raw materials consumed (i.e. limestone, sand, shale, iron oxide, and alumina) must be determined by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.

§ WCI.100 COAL STORAGE

§ WCI.101 Source Category Definition

Coal storage piles are located at any facilities that combust coal. Coal storage piles release fugitive CH_4 emissions. Within natural coal deposits, CH_4 is either trapped under pressure within porous void spaces or adsorbed to the coal. Coal mining, post-mining activities, and coal-handling activities release pressurized CH_4 to the atmosphere; adsorbed CH_4 is also released until the CH_4 in the coal reaches equilibrium with the surrounding atmospheric conditions.

§ WCI.102 Greenhouse Gas Reporting Requirements

The emissions data report shall include the following information at the facility level:

(a) Annual greenhouse gas emissions in metric tons, reported as follows:

(1) Total CH_4 emissions.

(b) Annual coal purchases (tons for U.S.; metric tons for Canada).

(c) Source of coal purchases:

(1) Coal basin.

(2) State/province.

(3) Coal mine type (surface or underground).

§ WCI.103 Calculation of CH_4 Emissions

Note that this methodology for calculation of methane emissions uses emission factors for post-mining operations including all processes occurring after mining at the coal deposit and prior to combustion (e.g., preparation, handling, processing, transportation, storage, etc.) even though coal storage piles are only a subset of the overall post-mining operations. This follows the approach in the California Climate Action Registry, attributing all post-mining fugitive methane emissions to the facility combusting the coal, which is ultimately responsible for the coal having been processed and delivered to the facility.

Calculate fugitive CH_4 emissions from coal storage piles as specified under paragraph (a), (b), or (c) of this section.

(a) For coal purchased from U.S. sources, calculate fugitive CH_4 emissions using Equation 100-1 (English) and Table 100-1, or Equation 100-1 (Metric) and Table 100-2.

(b) For coal purchased from Canadian sources, calculate fugitive CH_4 emissions using Equation 100-1 (Metric) and Table 100-3.

(c) For coal purchased from non-U.S. and non-Canadian sources, owners or operators should use either WCI.103(a) or WCI.103(b), whichever is the most applicable. This chosen approach is subject to approval by [*the jurisdiction*].

$$CH_4 = \sum_i (PC_i \times EF_i) \times 0.04228 \,/\, 2{,}204.6$$ **Equation 100-1 (English Units)**

Where:

CH_4	=	Fugitive emissions from coal storage piles for each coal category *i* (metric tons CH_4 per year);
PC_i	=	Purchased coal for each coal category *i* (tons per year);
EF_i	=	Default CH_4 emission factor for each coal category *i* specified by location and mine type that coal originated from, provided in Table 100-1 (scf CH_4 per ton of coal);
0.04228	=	Methane conversion factor to convert scf to lbs;
2,204.6	=	Factor to convert lbs to metric tons.

$$CH_4 = \sum_i (PC_i \times EF_i) \times 0.6772 \,/\, 1{,}000$$ **Equation 100-1 (Metric Units)**

Where:

CH_4	=	Fugitive emissions from coal storage piles for each coal category *i*, (metric tons CH_4 per year);
PC_i	=	Purchased coal for each coal category *i* (metric tons per year);
EF_i	=	Default CH_4 emission factor for each coal category *i* specified by location and mine type that coal originated from, provided in Table 100-2 or Table 100-3 (m^3 CH_4 per metric ton of coal);
0.6772	=	Methane conversion factor to convert m^3 to kg;
1,000	=	Factor to convert kg to metric tons.

§ WCI.104 Sampling, Analysis, and Measurement Requirements

(a) Coal Purchase Monitoring Requirements.

Facilities may determine the quantity of coal purchased either using records provided by the coal supplier(s) or monitoring coal purchase quantities using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.

Table 100-1. U.S. Default Fugitive Methane Emission Factors from Post-Mining Coal Storage and Handling (CH_4 ft^3 per Short Ton)			
Coal Origin		**Coal Mine Type**	
Coal Basin	**States**	**Surface Post-Mining Factors**	**Underground Post-Mining Factors**
Northern Appalachia	Maryland, Ohio, Pennsylvania, West Virginia North	19.3	45.0
Central Appalachia (WV)	Tennessee, West Virginia South	8.1	44.5
Central Appalachia (VA)	Virginia	8.1	129.7
Central Appalachia (E KY)	East Kentucky	8.1	20.0
Warrior	Alabama, Mississippi	10.0	86.7
Illinois	Illinois, Indiana, Kentucky West	11.1	20.9
Rockies (Piceance Basin)	Arizona, California, Colorado, New Mexico, Utah	10.8	63.8
Rockies (Uinta Basin)		5.2	32.3
Rockies (San Juan Basin)		2.4	34.1
Rockies (Green River Basin)		10.8	80.3
Rockies (Raton Basin)		10.8	41.6
N. Great Plains	Montana, North Dakota, Wyoming	1.8	5.1
West Interior (Forest City, Cherokee Basins)	Arkansas, Iowa, Kansas, Louisiana, Missouri, Oklahoma, Texas	11.1	20.9
West Interior (Arkoma Basin)		24.2	107.6
West Interior (Gulf Coast Basin)		10.8	41.6
Northwest (AK)	Alaska	1.8	52.0
Northwest (WA)	Washington	1.8	18.9

Source: *Inventory of U.S. Greenhouse Gas Emissions and Sinks:1990 – 2005* April 15, 2007, U.S. Environmental Protection Agency. Annex 3, Methodological Descriptions for Additional Source or Sink Categories, Section 3.3, Table A-115, Coal Surface and Post-Mining CH_4 Emission Factors (ft^3 per Short Ton). (Only Post-Mining EFs used from Table). State assignments shown from Table 113 of Annex 3.

Table 100-2. U.S. Default Fugitive Methane Emission Factors from Post-Mining Coal Storage and Handling (CH_4 m^3 per Metric Ton)			
Coal Origin		**Coal Mine Type**	
Coal Basin	**States**	**Surface Post-Mining Factors**	**Underground Post-Mining Factors**
Northern Appalachia	Maryland, Ohio, Pennsylvania, West Virginia North	0.6025	1.4048
Central Appalachia (WV)	Tennessee, West Virginia South	0.2529	1.3892
Central Appalachia (VA)	Virginia	0.2529	4.0490
Central Appalachia (E KY)	East Kentucky	0.2529	0.6244
Warrior	Alabama, Mississippi	0.3122	2.7066
Illinois	Illinois, Indiana, Kentucky West	0.3465	0.6525
Rockies (Piceance Basin)	Arizona, California, Colorado, New Mexico, Utah	0.3372	1.9917
Rockies (Uinta Basin)		0.1623	1.0083
Rockies (San Juan Basin)		0.0749	1.0645
Rockies (Green River Basin)		0.3372	2.5068
Rockies (Raton Basin)		0.3372	1.2987

N. Great Plains	Montana, North Dakota, Wyoming	0.0562	0.1592
West Interior (Forest City, Cherokee Basins)	Arkansas, Iowa, Kansas, Louisiana, Missouri, Oklahoma, Texas	0.3465	0.6525
West Interior (Arkoma Basin)		0.7555	3.3591
West Interior (Gulf Coast Basin)		0.3372	1.2987
Northwest (AK)	Alaska	0.0562	1.6233
Northwest (WA)	Washington	0.0562	0.5900

Source: *Inventory of U.S. Greenhouse Gas Emissions and Sinks:1990 – 2005* April 15, 2007, U.S. Environmental Protection Agency. Annex 3, Methodological Descriptions for Additional Source or Sink Categories, Section 3.3, Table A-115, Coal Surface and Post-Mining CH_4 Emission Factors (ft^3 per Short Ton; converted to m^3 per metric ton). (Only Post-Mining EFs used from Table). State assignments shown from Table 113 of Annex 3.

Table 100-3. Canada Default Fugitive Methane Emission Factors from Post-Mining Coal Storage and Handling (CH_4 m^3 per Metric Ton)

Coal Origin		Coal Mine Type	
Province	**Coalfield**	**Surface Post-Mining Factors**	**Underground Post-Mining Factors**
British Columbia	Comox	0.500	n/a
	Crowness	0.169	n/a
	Elk Valley	0.900	n/a
	Peace River	0.361	n/a
	Province Average	0.521	n/a
Alberta	Battle River	0.067	n/a
	Cadomin-Luscar	0.709	n/a
	Coalspur	0.314	n/a
	Obed Mountain	0.238	n/a
	Sheerness	0.048	n/a
	Smokey River	0.125	0.067
	Wabamun	0.176	n/a
	Province Average	0.263	0.067
Saskatchewan	Estavan	0.055	n/a
	Willow Bunch	0.053	n/a
	Province Average	0.054	n/a
New Brunswick	Province Average	0.060	n/a
Nova Scotia	Province Average	n/a	2.923

Source: *Management of Methane Emissions from Coal Mines: Environmental, Engineering, Economic and Institutional Implications of Options*. Prepared by Brian G. King, Neill and Gunter (Nova Scotia) Limited, Darmouth, Nova Scotia for Environment Canada. Contract Number K2031-3-7062. March 1994. This document is cited by Environment Canada in the NIR 1990-2007 (Final Submission, April 2009), , but post-mining emission factors are not provided, so they were developed for WCI purposes by Province. Surface emission factors were derived from Table 3.1 (Coal production statistics [Column A] and post-mining emissions [Column F]). Underground emission factors were derived from Table 3.2 (Coal production statistics and post-mining emissions).

§ WCI.130 HYDROGEN PRODUCTION

§ WCI.131 Source Category Definition

A hydrogen production process produces hydrogen gas by steam hydrocarbon reforming, partial oxidation of hydrocarbons, or other transformation of hydrocarbon feedstock. The hydrogen produced may be either transferred offsite or used onsite at petrochemical, ammonia production, refineries, and other plants.

§ WCI.132 Greenhouse Gas Reporting Requirements

For each facility, the annual emissions report must contain the following information:

(a) Process CO_2 Emissions. The CO_2 process emissions from the hydrogen produced process.

(b) Feedstock Consumption (if estimating emissions using mass balance approach in WCI.133(b)). Annual feedstock consumption by feedstock type (including petroleum coke) reported in units of million standard cubic feet for gases, gallons for liquids, short tons for non-biomass solids, and bone dry short tons for biomass-derived solid fuels.

(c) Production. Annual hydrogen produced.

(d) Stationary Combustion Units. Report CO_2, N_2O, and CH_4 emissions as specified in WCI.20.

§ WCI.133 Calculation of Greenhouse Gas Emissions

The owner or operator shall calculate and report CO_2 process emissions using the methods in paragraphs (a) or (b) of this section.

(a) Continuous Emission Monitoring Systems. The owner or operator may calculate CO_2 process emissions using CEMS. The owner or operator must comply with the requirements in section WCI.20.

(b) Feedstock Material Balance. The owner or operator may calculate CO_2 process emissions using the following method. The factor S shall be used only for CO_2 and/or CH_4 emissions that are calculated and reported using applicable methods specified in this regulation. For example, carbon species in uncoverted feedstock contained in PSA off-gas and hydrogen plant product that is diverted to fuel gas systems, fed to downstream units, or diverted to flare may be included in the factor S provided the CO_2 and/or CH_4 emissions are reported using other methods in this regulation.

$$CO_2(Feedstock) = \sum_{i=1}^{n} \sum_{j=1}^{y} \left[\left(FS_j * CF_j \right) - S_j \right] * 3.664 * 0.001$$ **Equation 130-1 (English Units)**

Where:

CO_2 (Feedstock)	=	CO_2 emitted from feedstock (metric tons/year).
n	=	Days of operation per year.
FS_j	=	Feedstock b consumption rate (scf/day).
CF_j	=	Carbon content of feedstock j (kg C/scf feedstock).
y	=	Total number of feedstocks.
S_j	=	Carbon accounted for elsewhere (kg C/day).
3.664	=	ratio of molecular weights, CO_2 to carbon
0.001	=	conversion factor – kg to metric tons

$$CO_2(Feedstock) = \sum_{i=1}^{n} \sum_{j=1}^{y} \left[\left(FS_j * CF_j \right) - S_j \right] * 3.664 * 0.001$$ **Equation 130-1 (Metric Units)**

Where:

CO_2 (Feedstock)	=	CO_2 emitted from feedstock (metric tons/year).
n	=	Days of operation per year.
FS_j	=	Feedstock b consumption rate (m^3/day).
CF_j	=	Carbon content of feedstock j (kg C/m^3 feedstock).
y	=	Total number of feedstocks.
S_j	=	Carbon accounted for elsewhere (kg C/day).
3.664	=	ratio of molecular weights, CO_2 to carbon
0.001	=	conversion factor – kg to metric tons

WCI.134 Sampling, Analysis, and Measurement Requirements

(a) Owners or operators using CEMS to estimate CO_2 emissions shall comply with the monitoring requirements in section WCI.20.

(b) Owners or operators using the method in section WCI.133 (b) shall perform the following monitoring:

(1) The owner or operator shall measure the feedstock consumption rate daily.

(2) The owner or operator shall collect samples of each feedstock consumed and analyze each sample for carbon content using the methods specified in WCI.25(d). For natural gas feedstock not mixed with another feedstock prior to consumption, samples shall be collected and analyzed once per month. For all other feedstocks, samples shall be collected and analyzed daily. The samples shall be collected from a location in the

feedstock handling system that provides samples representative of the feedstock consumed in the hydrogen production process.

(3) Owners or operators shall measure the hydrogen produced daily.

(4) Owners or operators shall measure the CO_2 and CO collected daily.

§ WCI.150 IRON AND STEEL MANUFACTURING

§ WCI.151 Source Category Definition

Iron and steel manufacturing comprises four categories: primary facilities that produce both iron and steel, secondary steelmaking facilities, iron production facilities, and offsite production of metallurgical coke. These processes may occur together in an "integrated" facility or they may occur in separate offsite facilities.

§ WCI.152 Greenhouse Gas Reporting Requirements

In addition to the information required by WCI.3, the annual emissions data report shall contain the following information:

(a) Total emissions of CO_2 and CH_4 in metric tons at the facility level.

(b) CO_2 and CH_4 emissions from coke production (metric tons) and the following information:

(1) Quantity of coking coal consumed in coke production (metric tons)

(2) Quantity of other process materials (e.g., natural gas, fuel oil, etc.) consumed in coke production (metric tons)

(3) Quantity of blast furnace gas consumed in coke production (metric tons)

(4) Quantity of coke produced (metric tons)

(5) Quantity of coke oven gas transferred offsite (metric tons)

(6) Quantity of other coke oven by-products (e.g., coal tar, light oil, coke breeze, etc.) transferred offsite (metric tons)

(7) Carbon content of material inputs and outputs listed in (b)(1) through (b)(6) (metric tons of C per metric ton of material [equivalent to wt% C/100])

(c) CO_2 and CH_4 emissions from iron and steel production (metric tons) and the following information:

(1) Quantity of coke consumed in iron and steel production (excluding sinter production) (metric tons)

(2) Quantity of on-site coke oven by-products (e.g., coal tar, light oil, coke breeze, etc.) consumed in blast furnace (metric tons)

(3) Quantity of coal directly injected into blast furnace (metric tons)

(4) Quantity of limestone directly injected into blast furnace (metric tons)

(5) Quantity of dolomite directly injected into blast furnace (metric tons)

(6) Quantity of carbon electrodes consumed in EAFs (metric tons)

(7) Quantity of direct reduced iron introduced to an EAF or BOF (metric tons)

(8) Quantity of other carbonaceous or process material (e.g., sinter, waste plastic, etc.) consumed in iron and steel production (metric tons)

(9) Quantity of coke oven gas consume in blast furnace (metric tons)

(10) Quantity of steel produced (metric tons)

(11) Quantity of iron production not converted to steel (metric tons)

(12) Quantity of blast furnace gas transferred offsite (metric tons)

(13) Carbon content of material inputs and outputs listed in (c)(1) through (c)(12) (metric tons of C per metric ton of material [equivalent to wt% C/100])

(d) Process CO_2 and CH_4 emissions from sinter production (metric tons) and the following information:

(1) Quantity of coke breeze (purchased and produced on-site) used for sinter production (metric tons)

(2) Quantity of coke oven gas consumed in blast furnace in sinter production (metric tons)

(3) Quantity of blast furnace gas consumed in sinter production (metric tons)

(4) Quantity of other process materials (e.g., natural gas, fuel oil, etc.) consumed in sinter production (metric tons)

(5) Quantity of sinter off gas transferred offsite (metric tons)

(6) Carbon content of material inputs and outputs listed in (d)(1) through (d)(5) (metric tons of C per metric ton of material [equivalent to wt% C/100])

(e) Process CO_2 and CH_4 emissions from direct reduced iron production (metric tons) and the following information:

(1) Energy from natural gas used in direct reduced iron production (gigajoules [GJ])

(2) Energy from coke breeze used in direct reduced iron production (GJ)

(3) Energy from metallurgical coke used in direct reduced iron production (GJ)

(4) Quantity of direct reduced iron produced (metric tons)

(5) Carbon content of material inputs listed in (e)(1) through (e)(3) (metric tons of C per GJ)

(6) Carbon content of direct reduced iron produced per e(4) (metric tons of C per metric ton of material [equivalent to wt% C/100])

(f) CO_2, N_2O, and CH_4 emissions from stationary combustion units as specified in WCI.20.

§ WCI.153 Calculation of CO_2 Emissions

(a) Process CO_2 emissions. Determine process CO_2 emissions as specified under either paragraph (1) or (2) of this section.

(1) Continuous emissions monitoring systems (CEMS) as specified in WCI.23(d).

(2) Calculation methodologies specified in paragraph (b) of this section.

[CEMS and mass balance approach are based on IPCC Tier 3 methods.)

(b) Process CO_2 Emissions Calculation Methodology. Calculate total CO_2 process emissions using the following mass balance approach:

(b) Calculate the coke production CO_2 (either within integrated facilities or at offsite facilities) emissions using Equation 150-1 (if applicable):

$$E_{coke} = \left[(CC \times C_{CC}) + \sum_a (PM_a \times C_a) + (BG \times C_{BG}) - (CO \times C_{CO}) - (COG \times C_{COG}) - \sum_b (COB_b \times C_b) \right] \times 3.664$$

Equation 150-1

Where:

E_{coke}	=	Emissions of CO_2 from coke production (metric tons);
CC	=	Quantity of coking coal (metric tons);
PM_a	=	Quantity of other process material *a* (not included as separate terms), such as natural gas or fuel oil (metric tons);
BG	=	Quantity of blast furnace gas consumed in coke ovens (metric tons);
CO	=	Quantity of coke produced (metric tons)
COG	=	Quantity of coke oven gas transferred offsite (metric tons);
COB_b	=	Quantity of coke oven by-product *b* transferred offsite (metric tons);
C_x	=	Carbon content of material input or output *x* (metric tons C/metric tons of *x*);
3.664	=	Conversion factor from metric tons of C to metric tons of CO_2.

(c) Calculate the iron and steel production CO_2 emissions using Equation 150-2:

$$E_{iron,steel} = \left[(CO \times C_{CO}) + \sum_a (COB_a \times C_a) + (CI \times C_{CI}) + (L \times C_L) + (D \times C_D) + (CE \times C_{CE}) + (DRI \times C_{DRI}) + \sum_b (O_b \times C_b) + (COG \times C_{COG}) - (S \times C_S) - (IP \times C_{IP}) - (BG \times C_{BG}) \right] \times 3.664$$

Equation 150-2

Where:

$E_{iron,steel}$	=	Emissions of CO_2 from iron and steel production (metric tons);
CO	=	Quantity of coke consumed (excluding sinter production) (metric tons);
COB_a	=	Quantity of coke oven by-product *a* consumed in blast furnace (metric tons);
CI	=	Quantity of coal directly injected into blast furnace (metric tons);
L	=	Quantity of limestone consumed (metric tons);
D	=	Quantity of dolomite consumed (metric tons);
CE	=	Quantity of carbon electrodes consumed in EAFs (metric tons);
DRI	=	Quantity of direct reduced iron introduced to an EAF or BOF (metric tons)
O_b	=	Quantity of other carbonaceous and process material *b*, such as sinter or waste plastic (metric tons);
COG	=	Quantity of coke oven gas consumed in blast furnace (metric tons);

S = Quantity of steel produced (metric tons);
IP = Quantity of iron production not converted to steel (metric tons);
BG = Quantity of blast furnace gas transferred offsite (metric tons);
C_x = Carbon content of material input or output *x* (metric tons C/metric tons of *x*);
3.664 = Conversion factor from metric tons of C to metric tons of CO_2.

(d) Calculate the sinter production CO_2 emissions using Equation 150-3 (if applicable):

$$E_{sinter} = \left[(CBR \times C_{CBR}) + (COG \times C_{COG}) + (BG \times C_{BG}) + \sum_a (PM_a \times C_a) - (SOG \times C_{SOG}) \right] \times 3.664$$

Equation 150-3

Where:

E_{sinter} = Emissions of CO_2 from sinter production (metric tons);
CBR = Quantity of purchased and onsite produced coke breeze used for sinter production (metric tons);
COG = Quantity of coke oven gas consumed in blast furnace for sinter production (metric tons);
BG = Quantity of blast furnace gas consumed for sinter production (metric tons);
PM_a = Quantity of other process material *a* consumed for sinter production (not included as separate terms), such as natural gas or fuel oil (metric tons);
SOG = Quantity of sinter off gas transferred offsite (metric tons);
C_x = Carbon content of material input or output *x* (metric tons C/metric tons of *x*);
3.664 = Conversion factor from metric tons of C to metric tons of CO_2.

(e) Calculate the direct reduced iron production CO_2 emissions using Equation 150-4 (if applicable):

$$E_{DRI} = [(DRI_{NG} \times C_{NG}) + (DRI_{BZ} \times C_{BZ}) + (DRI_{CK} \times C_{CK}) - (DRI \times C_{DRI})] \times 3.664$$

Equation 150-4

Where:

E_{DRI} = Emissions of CO_2 from direct reduced iron production (metric tons);
DRI_{NG} = Energy from natural gas used in direct reduced iron production (GJ);
DRI_{BZ} = Energy from coke breeze used in direct reduced iron production (GJ);
DRI_{CK} = Energy from metallurgical coke used in direct reduced iron production (GJ);
DRI = Quantity of direct reduced iron produced (metric tons)
C_{NG} = Carbon content of natural gas (metric ton C/GJ);
C_{BZ} = Carbon content of coke breeze (metric ton C/GJ);
C_{CK} = Carbon content of metallurgical coke (metric ton C/GJ);
C_{DRI} = Carbon content of direct reduced iron produced (metric tons of C per metric ton of direct reduced iron)

3.664 = Conversion factor from metric tons of C to metric tons of CO_2.

(f) Calculate the total CO_2 emissions using Equation 150-5:

$$E_{CO2} = E_{coke} + E_{iron,steel} + E_{sinter} + E_{DRI}$$ **Equation 150-5**

Where:

E_{CO2} = Total CO_2 emissions (metric tons);
E_{coke} = Emissions from coke production (metric tons);
$E_{iron,steel}$ = Emissions from iron and steel production (metric tons);
E_{sinter} = Emissions from sinter production (metric tons);
E_{DRI} = Emissions from direct reduced iron production (metric tons).

§ WCI.154 Calculation of CH_4 Emissions

(a) Process CH_4 emissions. Determine process CH_4 emissions as specified under either paragraph (1) or paragraph (2) of this section.

(1) Continuous emissions monitoring systems (CEMS) as specified in WCI.23(d).

(2) Site-specific emission factors.

§ WCI.155 Sampling, Analysis, and Measurement Requirements

Measurements of carbon contents of the material balance input, output, and by-product materials shall be conducted as described below.

(a) Fuel Carbon Content Requirements. Fuel carbon contents should be monitored in the following manner (from § WCI.25):

(1) For coal and coke, solid biomass-derived fuels, and waste-derived fuels; use ASTM 5373-02 (Reapproved 2007).

(2) For liquid fuels, use the following ASTM methods: For petroleum-based liquid fuels and liquid waste-derived fuels, use ASTM D5291-02 (Reapproved 2007) “Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants”, ultimate analysis of oil or computations based on ASTM D3238-95 (Reapproved 2005) and either ASTM D2502-04 or ASTM D2503-92 (Reapproved 2007).

(3) For gaseous fuels, use ASTM D1945-03 or ASTM D1946-90 (Reapproved 2006).

(b) By-Product Carbon Content Requirements. Carbon contents of by-products (e.g., blast furnace gas, coke oven gas, coal tar, light oil, coke breeze, sinter off gas, etc.) from all iron and steel production processes should be monitored in the following manner:

[Methodology to be determined.]

(c) Flux Carbon Content Requirements. Carbon contents of fluxes (i.e., limestone and dolomite) from all iron and steel production processes should be monitored in the following manner:

(1) For limestone and dolomite, use ASTM C25-06.

(d) Electrode Carbon Content Requirements. Carbon contents of carbon electrodes used in electric arc furnaces (EAFs) should be monitored in the following manner:

(1) Vendor specifications of carbon content in EAF carbon electrodes.

(e) Finished Product Carbon Content Requirements. Carbon contents of finished products (i.e., steel, iron not converted to steel, and direct reduced iron) from all iron and steel production processes should be monitored in the following manner:

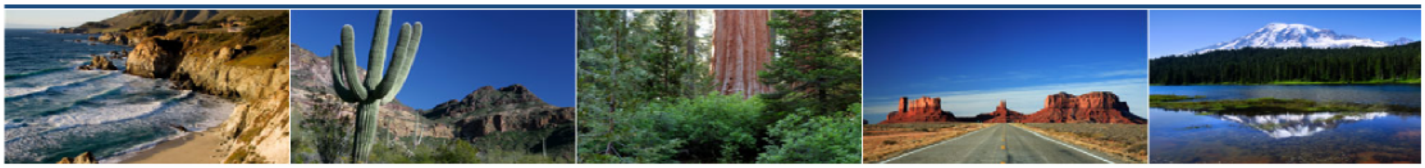
(1) For iron and steel, use ASTM E1019-08 or ASTM E351-93.

(f) Quantity Measurement Requirements. The quantities of process inputs, outputs, and by-products must be determined using the following methods:

(1) For solid process inputs, outputs, and by-products, quantities must be determined by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.

(2) For liquid process inputs, outputs, and by-products, quantities must be determined by direct volume measurement using the same plant instruments used for accounting purposes.

(3) For gaseous process inputs, outputs, and by-products, quantities must be determined by direct volume measurement using the same plant instruments used for accounting purposes.



§ WCI.170 LIME MANUFACTURING

§ WCI.171 Source Category Definition

Lime manufacturing is comprised of all processes that are used to manufacture quick lime (i.e. calcium oxide or calcium-magnesium oxide). Lime is produced via the calcination of limestone or other highly calcareous materials such as dolomite, aragonite, chalk, coral, marble, and shell.

§ WCI.172 Greenhouse Gas Reporting Requirements

In addition to the information required by WCI.3, the annual emissions data report shall contain the following information:

(a) Total emissions of CO_2, CH_4, and N_2O in metric tons.

(b) CO_2 process emissions from quick lime production (metric tons) and the following information:

(1) For lime production:

(A) The emission factor (kg CO_2/metric ton) for each lime type for each month.

(B) The quantity of lime produced (metric tons) each month.

(C) The calcium oxide (CaO) content (weight fraction) of each lime type for each month.

(D) The magnesium oxide (MgO) content (weight fraction) of each lime type for each month.

(2) For the production of calcined byproducts and wastes:

(A) The emission factor (kg CO_2/metric ton) for each calcined byproduct/waste type for each month.

(B) The quantity of each type of calcined byproduct/waste type produced each month.

(C) The calcium oxide (CaO) content (weight fraction) of each calcined byproduct/waste type for each month.

(D) The magnesium oxide (MgO) content (weight fraction) of each calcined byproduct/waste type for each month.

(c) CO_2, CH_4, and N_2O emissions from fuel combustion in all kilns combined, following the calculation methods and reporting requirements specified in WCI.173(c) (metric tons).

(d) CO_2, CH_4, and N_2O emissions from all other fuel combustion units combined (kilns excluded), following the calculation methods and reporting requirements specified in WCI.20 (metric tons).

(e) If a continuous emissions monitor is used to measure CO_2 emissions from kilns, then the requirements of paragraphs (b) and (c) of this section do not apply for CO_2.

(f) Operators of lime plants shall also comply with the reporting requirements for any other applicable source category listed at WCI.1(a), including but not limited to the following:

(1) Coal fuel storage as specified in WCI.100.

(2) Electricity generating as specified in WCI.40.

(3) Cogeneration systems as specified in WCI.42(f).

§ WCI.173 Calculation of greenhouse Gas Emissions from Kilns

(a) Determine process CO_2 emissions as specified under either paragraph (a)(1) or (a)(2) of this section.

(1) Continuous emissions monitoring systems (CEMS) as specified in WCI.23(d).

(2) Calculate the sum of CO_2 process emissions from kilns and CO_2 fuel combustion emissions from kilns using the calculation methodologies specified in paragraph (b) and (c) of this section.

(b) Process CO_2 Emissions Calculation Methodology. Calculate total CO_2 process emissions as the sum of emissions from quick lime production, using the method specified in paragraph (b)(1) of this section.

(1) CO_2 Process Emissions. Calculate CO_2 emissions from quick lime production from each kiln using Equation 170-1 and a plant-specific quick lime emission factor and a plant-specific lime kiln dust (LKD) emission factor as specified in this section.

$$CO_2 = \sum_{i}^{12} \sum_{j}^{y} \left[QL_{ij} \times EF_{QL_{ij}} \right] + \sum_{k}^{4} \sum_{l}^{z} \left[LKD_{kl} \times EF_{LKD_{kl}} \right] \qquad \textbf{Equation 170-1}$$

Where:

CO_2	=	CO_2 emissions in metric tons/yr.
QL	=	Monthly Quantity of quick lime produced, metric tons.
EF_{QL}	=	Monthly Quick lime emission factor, metric tons CO_2/metric ton quick lime computed as specified in paragraph (b)(2) of this section.
LKD	=	Quarterly Quantity of calcined byproduct/waste, including LKD, scrubber sludge and other calcined wastes, produced annually, metric tons.
EF_{LKD}	=	Quarterly calcined byproduct/waste emission factor, computed as specified in paragraph (b)(3) of this section.
i	=	Month.
j	=	Lime type.
k	=	Quarter.
l	=	Calcined byproduct/waste type.
y	=	Total number of lime types.
z	=	Total number of calcined byproduct/waste types.

(2) Monthly Quick Lime Emission Factor. Calculate a plant-specific quick lime emission factor (EF$_{QL}$) for each kiln and month based on the percent of measured CaO and MgO content in quick lime and using Equation 170-2.

$$EF_{QL} = (CaO\ \ content \times Molecular\ \ ratio\ \ of\ \ CO_2 / CaO) + (MgO\ \ content \times Molecular\ \ ratio\ \ CO_2 / MgO) \quad \textbf{Equation 170-2}$$

Where:

CaO Content (by weight)	=	Total CaO content of Quick Lime.
Molecular ratio of CO_2/CaO	=	0.785.
MgO Content (by weight)	=	Total MgO content of Quick Lime.
Molecular ratio of CO_2/MgO	=	1.092.

(3) Monthly LKD Emission Factor. If LKD is generated and not recycled back to the kiln, then calculate a plant-specific LKD emission factor for each kiln and month. The LKD emission factor shall be calculated using Equation 170-3.

$$EF_{LKD} = [(CaO\ \ content - uncalcined\ \ CaO) \times Molecular\ \ ratio\ \ of\ \ CO_2 / CaO] + [(MgO\ \ Content - uncalcined\ \ MgO) \times Molecular\ \ ratio\ \ of\ \ CO_2 / MgO] \quad \textbf{Equation 170-3}$$

Where:

EF_{LKD}	=	LKD emission factor.
CaO Content (by weight)	=	Total CaO content of LKD, including calcined and uncalcined (weight fraction).
Uncalcined CaO (by weight)	=	Uncalcined CaO content of LKD (weight fraction).
Molecular ratio of CO_2/CaO	=	0.785.
MgO Content (by weight)	=	Total MgO content of LKD, including calcined and uncalcined (weight fraction).
Uncalcined MgO	=	Uncalcined MgO content of LKD (weight fraction).
Molecular ratio of CO_2/MgO	=	1.092.

(c) Fuel Combustion Emissions in Kilns. Calculate CO_2, CH_4, and N_2O emissions from stationary fuel combustion emissions following the calculation methods specified in WCI.20. Operators of lime manufacturing plants that primarily combust biomass-derived fuels and combust fossil fuels only during periods of start-up, shut-down, or malfunction may report CO_2 emissions from fossil fuels using the emission factor methodology in WCI.23(a).

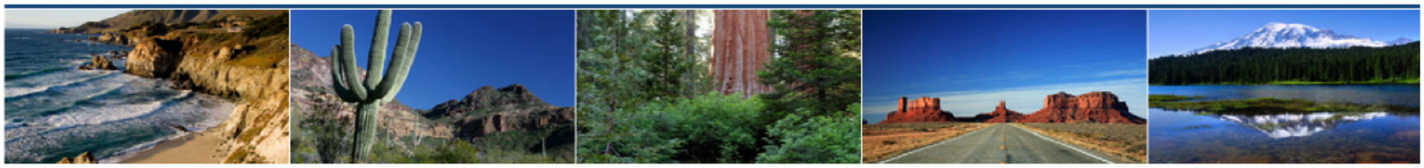
"Pure" means that the biomass-derived fuels account for 97 percent of the total amount of carbon in the fuels burned.

§ WCI.174 Sampling, Analysis, and Measurement Requirements

Determine the chemical composition (percent total CaO and percent total MgO) of each lime type and each calcined byproduct/waste type by laboratory analysis on a monthly basis for each lime type, and a quarterly basis for each calcined byproduct/waste type. This determination must be performed according to ASTM Methods C25, C1301 or C1271. Samples for analysis of the calcium oxide and magnesium oxide content of each lime type and each calcined byproduct/waste type should be collected during the same month or quarter as the production data. At least one sample must be collected monthly for each lime type produced during the month and quarterly for each calcined byproduct/waste type produced during the quarter.

(a) The quantity of lime produced and sold is to be estimated monthly using direct measurements (such as rail and truck scales) of lime sales for each lime type, and adjusted to take into account the difference in beginning- and end-of-period inventories of each lime type. The inventory period shall be annual at a minimum.

(b) The quantity of calcined byproduct/waste sold is to be estimated quarterly using direct measurements (such as rail and truck scales) of byproduct/waste sales for each byproduct/waste type, and adjusted to take into account the difference in beginning- and end-of-period inventories of each calcined byproduct/waste type. The inventory period shall be annual at a minimum. The quantity of calcined byproduct/waste not sold is to be determined no less often than quarterly for each calcined/byproduct waste type using direct measurements (such as rail and truck scales), or a calcined byproduct/waste generation rate (i.e. calcined byproduct produced as a factor of lime production).



§ WCI.200 PETROLEUM REFINERIES

§ WCI.201 Source Category Definition

A petroleum refinery consists of all processes used to produce gasoline, aromatics, kerosene, distillate fuel oils, residual fuel oils, lubricants, asphalt, or other products through distillation of petroleum or through redistillation, cracking, rearrangement or reforming of unfinished petroleum derivatives.

WCI.202 Greenhouse Gas Reporting Requirements

The annual emissions report must contain the following information reported at the facility level:

(a) Catalyst Regeneration. Report CO_2 emissions.

(b) Process Vents. Report CO_2, N_2O, and CH_4 emissions.

(c) Asphalt Production. Report CO_2 and CH_4 emissions.

(d) Sulfur Recovery. Report CO_2 emissions.

(e) Stationary Combustion Units Other than Flares and Control Devices. Report CO_2, N_2O, and CH_4 emissions as specified in WCI.23.

(f) Flares and Other Control Devices. Report CO_2, N_2O, and CH_4 emissions.

(g) Above-Ground Storage Tanks. Report CH_4 emissions.

(h) Wastewater Treatment. Report CH_4 and N_2O emissions.

(i) Oil-Water Separators. Report CH_4 emissions.

(j) Equipment Leaks. Report CH_4 emissions.

(k) Feedstock Consumption: Report feedstock consumption by type for all feedstocks which result in GHG emissions in the reporting year (including petroleum coke) in units of million standard cubic feet for gases, gallons for liquids, short tons for non-biomass solids, and bone dry short tons for biomass-derived solid fuels.

(l) Fuel Consumption: Report fuel consumption by fuel type consumed in the reporting year in units of million standard cubic feet for gases, gallons for liquids, short tons for non-biomass solids, and bone dry short tons for biomass-derived solid fuels.

WCI.203 Calculation of Greenhouse Gas Emissions

The operator shall calculate GHG emissions using the methods in paragraphs (a) through (i) of this section.

(a) Catalyst Regeneration. For units equipped with CEMS, operators shall calculate CO_2 process emissions resulting from catalyst regeneration using CEMS in accordance with WCI.20. In

the absence of CEMS data, the operator shall use the methods in paragraphs (a)(1) through (a)(3).

(1) The operator shall calculate process CO_2 emissions from the continuous regeneration of catalyst material in fluid catalytic cracking units (FCCU) and fluid cokers using Equations 200-1, 200-2, and 200-3.

$$CO_2 = \sum_{d=1}^{n} CR_d \times CF \times 3.664 \times 0.001$$ **Equation 200-1**

Where:

CO_2	=	CO_2 emissions (metric tons/yr)
n	=	number of days of operation in the report year
CR_d	=	daily average coke burn rate (kg/day)
CF	=	carbon fraction in coke burned
3.664	=	ratio of molecular weights, CO_2 to carbon
0.001	=	conversion factor – kg to metric tons

$$CR_d = \left[\sum_{i=1}^{n} [K_1 Q_r \times (\%CO_2 + \%CO) + K_2 Q_a - K_3 Q_r \times [\%CO/2 + \%CO_2 + \%O_2] + K_3 Q_{oxy} \times (\%O_{oxy})]_i \right] / n$$

Equation 200-2

Where:

CR_d	=	daily average coke burn rate (kg/day or lb/day)
K_1, K_2, K_3	=	material balance and conversion factors (K_1, K_2, and K_3 from Table 200-1
n	=	number of hours per day
Q_r	=	volumetric flow rate of exhaust gas before entering the emission control system (dscm/min or dscf/min)
Q_a	=	volumetric flow rate of air to regenerator as determined from control room instrumentation (dscm/min or dscf/min)
$\%CO_2$	=	CO_2 concentration in regenerator exhaust, percent by volume – dry basis
%CO	=	CO concentration in regenerator exhaust, percent by volume – dry basis
$\%O_2$	=	O_2 concentration in regenerator exhaust, percent by volume – dry basis
Q_{oxy}	=	volumetric flow rate of O_2 enriched air to regenerator as determined from control room instrumentation (dscm/min or dscf/min)
$\%O_{xy}$	=	O_2 concentration in O_2 enriched air stream inlet to regenerator, percent by volume – dry basis

$$Q_r = (79 \times Q_a + (100 - \%Q_{xy}) \times Q_{oxy}) / (100 - \%CO_2 - \%CO - \%O_2)$$ **Equation 200-3**

Where:

Q_r	=	volumetric flow rate of exhaust gas from regenerator before entering the emission control system (dscm/min or dscf/min)
Q_a	=	volumetric flow rate of air to regenerator, as determined from control room instrumentation (dscm/min or dscf/min)
$\%Q_{xy}$	=	oxygen concentration in oxygen enriched air stream, percent by volume – dry basis
Q_{oxy}	=	volumetric flow rate of O_2 enriched air to regenerator as determined from catalytic cracking unit control room instrumentation (dscm/min or dscf/min)
$\%CO_2$	=	carbon dioxide concentration in regenerator exhaust, percent by volume – dry basis
%CO	=	CO concentration in regenerator exhaust, percent by volume – dry basis. When no auxiliary fuel is burned and a continuous CO monitor is not required, assume %CO to be zero
$\%O_2$	=	O_2 concentration in regenerator exhaust, percent by volume – dry basis

(2) The operator shall calculate process CO_2 emissions resulting from periodic catalyst regeneration using Equation 200-4.

$$CO_2 = \sum_{i=1}^{n} CRR \times \left(CF_{spent} - CF_{regen}\right)_i \times 3.664 \times 0.001 \qquad \textbf{Equation 200-4}$$

Where:

CO_2	=	CO_2 emissions (metric tons/yr)
CRR	=	mass of catalyst regenerated (mass/regeneration cycle)
CF_{spent}	=	weight fraction carbon on spent catalyst
CF_{regen}	=	weight fraction carbon on regenerated catalyst (default = 0)
n	=	number of regeneration cycles
3.664	=	ratio of molecular weights, CO_2 to carbon
0.001	=	conversion factor – kg to metric tons

(3) The operator shall calculate process CO_2 emissions resulting from continuous catalyst regeneration in operations other than FCCUs and fluid cokers (e.g. catalytic reforming) using Equation 200-5.

$$CO_2 = CC_{irc} \times (CF_{spent} - CF_{regen}) \times H \times 3.664 \qquad \textbf{Equation 200-5}$$

Where:

CO_2	=	CO_2 emissions (metric tons/yr)
CC_{irc}	=	average catalyst regeneration rate (metric tons/hr)
CF_{spent}	=	weight carbon fraction on spent catalyst
CF_{regen}	=	weight carbon fraction on regenerated catalyst (default = 0)
H	=	hours regenerator was operational (hr/yr)
3.664	=	ratio of molecular weights, CO_2 to carbon

(b) Process Vents. Except for process emissions reported under other requirements of this regulation, the operator shall calculate process emissions of CO_2, CH_4, and N_2O from process vents using Equation 200-6.

Equation 200-6

$$E_x = \sum_{i=1}^{n} VR_i \times F_{xi} \times (MW_x / MVC) \times VT_i \times 0.001$$

Where:

E_x	=	emissions of x (metric tons/yr), where x = CO_2, N_2O, or CH_4
VR_i	=	vent rate for venting event i (scf/unit time or m^3/unit time)
F_{xi}	=	molar fraction of x in vent gas stream during event i
MW_x	=	molecular weight of x (kg/kg-mole)
MVC	=	molar volume conversion (849.5 scf/kg-mole for STP of 20°C and 1 atmosphere or 836 scf/kg-mole for STP of 60°F, and 1 atmosphere or 24.06 m^3/kg-mole for STP of 20°C and 1 atmosphere, or 23.67 m^3/kg-mole for STP of 60°F and 1 atmosphere)
VT_i	=	time duration of venting event i
n	=	number of venting events
0.001	=	conversion factor – kg to metric tons

(c) Asphalt Production. The operator shall calculate CO_2 and CH_4 process emissions from asphalt blowing activities using Equations 200-7 and 200-8.

Equation 200-7

$$CH_4 = (M_A \times EF \times MW_{CH4} / MVC) \times (1 - DE) \times 0.001$$

Where:

CH_4	=	CH_4 emissions (metric tons/yr)
M_A	=	mass of asphalt blown (10^3 bbl/yr)
EF	=	emission factor (EF = 2,555 scf $CH_4/10^3$ bbl or 72.35 m^3 $CH_4/10^3$ bbl)
MW_{CH4}	=	CH_4 molecular weight (16.04 kg/kg-mole)
MVC	=	molar volume conversion factor (849.5 scf/kg- mole, for STP of 20°C and 1 atmosphere or 24.06 m^3/kg-mole for STP of 20°C and 1 atmosphere, or 23.67 m^3/kg-mole for STP of 60°F and 1 atmosphere)
DE	=	control measure destruction efficiency (DE = 98% expressed as 0.98)
0.001	=	conversion factor – kg to metric tons

Equation 200-8

$$CO_2 = (M_A \times EF \times MW_{CH4} / MVC) \times DE \times 2.743 \times 0.001$$

Where:

CO_2	=	CO_2 emissions (metric tons/yr)
M_A	=	mass of asphalt blown (10^3 bbl/yr)
EF	=	emission factor (EF = 2,555 scf $CH_4/10^3$ bbl or 72.35 m^3 $CH_4/10^3$ bbl)
MW_{CH4}	=	CH_4 molecular weight (16.04 kg/kg-mole)

MVC	=	molar volume conversion factor (849.5 scf/kg mole, for STP of 20°C and 1 atmosphere or 24.06 m^3/kg-mole for STP of 20°C and 1 atmosphere, or 23.67 m^3/kg-mole for STP of 60°F and 1 atmosphere)
DE	=	control measure destruction efficiency (DE = 98% expressed as 0.98)
2.743	=	CH_4 to CO_2 conversion factor
0.001	=	conversion factor – kg to metric tons

(d) Sulfur Recovery. The operator shall calculate CO_2 process emissions from sulfur recovery units (SRUs) using Equation 200-9. For the molecular fraction (MF) of CO_2 in the sour gas, use either a default factor of 0.20 or a source specific molecular fraction value approved by [*insert jurisdiction*] and derived from source tests conducted at least once per calendar year under the supervision of [*insert jurisdiction*].

$$CO_2 = FR \times MW_{CO2} / MVC \times MF \times 0.001 \qquad \textbf{Equation 200-9}$$

Where:

CO_2	=	emissions of CO_2 (metric tons/yr)
FR	=	volumetric flow rate of acid gas to SRU (scf/year or m^3/year)
MW_{CO2}	=	molecular weight of CO_2 (44 kg/kg-mole)
MVC	=	molar volume conversion (849.5 scf/ kg-mole, for STP of 20°C and 1 atmosphere or 836 scf/kg-mole, for STP of 60°F, and 1 atmosphere or 24.06 m^3/kg-mole for STP of 20°C and 1 atmosphere, or 23.67 m^3/kg-mole for STP of 60°F and 1 atmosphere)
MF	=	molecular fraction (%) of CO_2 in sour gas (default MF = 20% expressed as 0.20)
0.001	=	conversion factor – kg to metric tons

(e) Flares and Other Control Devices.

(1) The operator shall calculate and report CO_2, CH_4 and N_2O emissions resulting from the combustion of flare pilot and purge gas using the appropriate method(s) specified in sections WCI.20.

(2) The operator shall calculate and report CO_2 emissions resulting from the combustion of hydrocarbons routed to flares for destruction as follows:

(A) Use Equation 200-10 if the flare is equipped with a continuous flow and high heat value monitors:

$$CO_2 = Flare_N \times HHV \times (0.001 \times EmF) \qquad \textbf{Equation 200-10}$$

Where:

CO_2	=	CO_2 emissions (metric tons/year)
$Flare_N$	=	volume of flare gas (m^3/yr)
HHV	=	High heat value for refinery fuel or flare gas (MMBtu/MMscf or J/m^3)
0.001	=	conversion factor – kg to metric tons
EmF	=	default CO_2 emission factor (60 kg CO_2/MMBtu or 5.7 kg/kJ)

(B) Use Equation 200-11 if the flare is equipped with a continuous flow and carbon content monitors:

$$CO_2 = Flare_N \times CC_N \times (MW_n / MVC) \times 3.664 \times 0.001$$ **Equation 200-11**

Where:

CO_2	=	CO_2 emissions (metric tons/year)
$Flare_N$	=	volume of flare gas (m^3/yr)
CC_N	=	carbon content of flare gas (kg of carbon/kg of fuel)
MW_N	=	molecular weight of flare gas
MVC	=	molar volume conversion factor (849.5 scf/kg- mole for STP of 20°C and 1 atmosphere or 836 scf/kg-mole for STP of 60°F, and 1 atmosphere or 24.06 m^3/kg-mole for STP of 20°C and 1 atmosphere, or 23.67 m^3/kg-mole for STP of 60°F and 1 atmosphere)
3.664	=	ratio of molecular weights, CO_2 to carbon
0.001	=	conversion factor – kg to metric tons

a. Use Equation 200-12 if the flare is not equipped with a continuous flow monitor and HHV or carbon content monitor:

$$CO_2 = RFT \times EF_{NMHC} \times CF_{NMHC} \times 3.664 \times 0.001$$ **Equation 200-12**

Where:

CO_2	=	CO_2 emissions (metric tons/year)
RFT	=	refinery feed input (m^3/yr)
EF_{NMHC}	=	non-methane hydrocarbon emission factor (EF_{NMHC} = 0.002 kg/m^3 throughput)
CF_{NMHC}	=	conversion factor – NMHC to carbon (CF_{NMHC}= 0.6)
3.664	=	ratio of molecular weights, CO_2 to carbon
0.001	=	conversion factor – kg to metric tons

(3) The operator who uses methods other than flares (e.g. incineration, combustion as a supplemental fuel in heaters or boilers) to destroy low Btu gases (e.g. coker flue gas, gases from vapor recovery systems, casing vents and product storage tanks) shall calculate CO_2 emissions using Equation 200-13. The operator shall determine CC_A and MW_A quarterly using methods specified in section WCI.20 and use the annual average values of CC_A and MW_A to calculate CO_2 emissions.

$$CO_2 = GV_A \times CC_A \times MW_A / MVC \times 3.664 \times 0.001$$ **Equation 200-13**

Where:

CO_2	=	CO_2 emissions (metric tons/year)
GV_A	=	volume of gas A destroyed annually (scf/year or m^3/year)
CC_A	=	carbon content of gas A (kg C/kg fuel)
MW_A	=	molecular weight of gas A
MVC	=	molar volume conversion factor (849.5 scf/kg- mole for STP of 20°C and 1 atmosphere or 836 scf/kg-mole for STP of 60°F, and 1 atmosphere or 24.06 m^3/kg-mole for STP of 20°C and 1 atmosphere, or 23.67 m^3/kg-mole for STP of 60°F and 1 atmosphere)
3.664	=	ratio of molecular weights, CO_2 to carbon
0.001	=	conversion factor – kg to metric tons

(f) Storage Tanks. For above-ground storage tanks containing crude oil, asphalt, naphtha, and distillate oils that are not equipped with vapor recovery technology, the operator shall calculate CH_4 emissions using the U.S. EPA TANKS Model (Version 4.09D). For crude oil, naphtha, and distillate oils, use the default chemical databases for crude oil (RVP 5), distillate fuel oil No. 2, and jet naphtha (JP4), respectively. For asphalt, use the data in Table 200-4 to create an asphalt chemical database. The annual throughput for each storage tank must be distributed equally across the twelve months of the year and the single-component liquid option selected. The total VOC emission values generated by the model shall be converted to methane emissions using:

(1) A default conversion factor of 0.6 (CH_4 = 0.6 * VOC); or
(2) Species specific conversion factors determined by storage tank headspace vapor analysis using a sampling and analysis methodology approved by [*insert jurisdiction*].

(g) Wastewater Treatment.

(1) The operator shall calculate CH_4 emissions from wastewater treatment using Equation 200-14.

$$CH_4 = [(Q \times COD_{qave}) - S] \times B \times MCF \times 0.001$$ **Equation 200-14**

Where:

CH_4	=	emission of methane (tons/yr)
Q	=	volume of wastewater treated (m^3/yr)
COD_{qave}	=	average of quarterly determinations of chemical oxygen demand of the wastewater (kg/m^3)
S	=	organic component removed as sludge (kg COD/yr)
B	=	methane generation capacity (B = 0.25 kg CH_4/kg COD)
MCF	=	methane correction factor for anaerobic decay (0-1.0) from Table 200-2
0.001	=	conversion factor – kg to metric tons

(2) The operator shall calculate N_2O emissions from wastewater treatment using Equation 200-15.

$$N_2O = Q \times N_{qave} \times EF_{N2O} \times 1.571 \times 0.001$$ **Equation 200-15**

Where:

N_2O = emissions of N_2O (metric tons/yr)
Q = volume of wastewater treated (m^3/yr)
N_{qave} = average of quarterly determinations of N in effluent (kg N/m^3)
EF_{N2O} = emission factor for N_2O from discharged wastewater (0.005 kg N_2O-N/kg N)
1.571 = conversion factor – kg N_2O-N to kg N_2O
0.001 = conversion factor – kg to metric tons

(h) Oil-Water Separators. The operator shall calculate CH_4 emissions from oil-water separators using Equation 200-16. For the CF_{NMHC} conversion factor, operators shall use either a default factor of 0.6 or species specific conversion factors determined by analysis using a sampling and analysis methodology approved by [*jurisdiction*].

$$CH_4 = EF_{sep} \times V_{water} \times CF_{NMHC} \times 0.001$$ **Equation 200-16**

Where:

CH_4 = emission of methane (tons/yr)
EF_{sep} = NMHC (non methane hydrocarbon) emission factor (kg/m^3) from Table 200-3.
V_{water} = volume of waste water treated by the separator (m^3/yr)
CF_{NMHC} = NMHC to CH_4 conversion factor
0.001 = conversion factor – kg to metric tons

(i) Equipment leaks. The operator shall calculate CH_4 emissions for all components in natural gas, refinery fuel gas, and PSA off-gas systems as follows:

(1) Components shall be identified as one of the following classification types: valve, pump seal, connector, flange, open-ended line. Operators shall use the Component Identification and Counting Methodology and screening methods found in Method 3 in CAPCOA (1999) *[or the method in CCME EPC-73E for Canadian jurisdictions]*, which are incorporated by reference in WCI.6. Operators shall conduct screenings at the frequency interval required by *[insert jurisdiction]*. Operators shall measure and record emissions using instrumentation capable of detecting methane.
(2) The VOC emissions shall be calculated using the following methods:

(C) For components where the measured screening value (SV) is indistinguishable from zero when corrected for background, operators shall calculate VOC emissions using Equation 200-17:

$$E_{VOC-0} = \sum_{i=1}^{6} CC_i \times ZF_{i0} \times t$$ **Equation 200-17**

Where:

E_{VOC-0} = zero component VOC emission (kg/screening period)
i = component type (1 = valve, 2 = pump seal, 3 = other, 4 = connector, 5 = flange, 6 = open-ended line)

CC_i = number of i components where SV = 0
ZF_{i0} = zero VOC emission factor (kg/hr) for component i from Table 200-5
t = time (hours) since last screening

(D) For leaking components, operators shall calculate VOC emissions using the following methods:

(i) For screening values between background and 9,999 ppmv, the operator shall calculate the VOC emissions using Equation 200-18.

$$E_{VOCL-C} = \sum_{i=1}^{6}\sum_{n=1}^{n}\left(\sigma_i \times SV_n^{\beta i}\right)\times t$$ **Equation 200-18**

Where:

E_{VOCL-C} = leaking components VOC emissions (kg/screening period)
i = component type (1=valve, 2=pump seal, 3=others, 4=connector, 5=flange, 6=open ended-line)
n = number of i components
σ_i = correlation equation coefficient for component type i from Table 200-5
SV_n = screening value for component n
βi = correlation equation exponent for component type i from Table 200-5
t = time (hours) component has been leaking – default value is time from last screening

(ii) For screening values greater than 9,999 ppmv, the operator shall calculate the VOC emissions using Equation 200-19.

$$E_{VOCP} = \sum_{i=1}^{6} CC_i \times PF_{iP} \times t$$ **Equation 200-19**

Where:

E_{VOCP} = VOC emissions for components pegged over SV 9,999 ppmv (kg/screening period)
i = component type (1=valve, 2=pump seal, 3=others, 4=connector, 5=flange, 6=open-ended line)
CC_i = number of i components pegged over 9,999 ppmv
PF_{iP} = VOC emission factor (kg/hr) for component type i pegged over 9,999 ppmv from Table 200-5
t = time component has been leaking (hours) – default value is time since last screening

(E) The operator shall calculate CH_4 emissions using Equation 200-20. Operators shall use system specific determinations of gas composition and methane content (refinery fuel gas, natural gas, associated gas, flexigas, low Btu gas), where available, to determine a CF_{VOC} value. The sampling and analysis methodology must be approved by *[jurisdiction]*. When representative data is not available, operators shall use the default value of 0.6 for CF_{VOC}.

$$CH_4 = \sum_{1}^{n} \left(E_{VOC-0} + E_{VOC-LC} + E_{VOCP}\right)_n \times CF_{VOC} \times 0.001 \qquad \textbf{Equation 200-20}$$

Where:

CH_4	=	methane emissions (metric tons/year)
n	=	number of screenings/year
E_{VOC-0}	=	zero component VOC emissions (kg/screening period)
E_{VOC-LC}	=	leaking component VOC emissions (kg/screening period)
E_{VOCP}	=	VOC emissions for components pegged over 9,999 ppmv (kg/screening period)
CF_{VOC}	=	VOC to CH_4 conversion factor (default CF_{VOC}=0.6)
0.001	=	conversion factor – kg to metric tons

WCI.204 Sampling, Analysis, and Measurement Requirements

(a) Catalyst Regeneration.

(1) For FCCUs and fluid coking units, the operators shall measure the following parameters:

(A) The daily oxygen concentration in the oxygen enriched air stream inlet to the regenerator.
(B) Continuous measurements of the volumetric flow rate of air and oxygen enriched air entering the regenerator.
(C) Continuous or weekly periodic measurements of the CO_2, CO and O_2 concentrations in the regenerator exhaust gas, to be determined by individual jurisdictions.
(D) Daily determinations of the carbon content of the coke burned.
(E) The number of days of operation.

(2) For periodic catalyst regeneration, the operators shall measure the following parameters.

(A) The mass of catalyst regenerated in each regeneration cycle.
(B) The weight fraction of carbon on the catalyst prior to and after catalyst regeneration.

(3) For continuous catalyst regeneration in operations other than FCCUs and fluid cokers, the operators shall measure the following parameters.

(A) The hourly catalyst regeneration rate.
(B) The weight fraction of carbon on the catalyst prior to and after catalyst regeneration.
(C) The number of hours of operation.

(b) Process vents. Operators shall measure the following parameters for each process vent.

(1) The vent flow rate for each venting event.
(2) The molar fraction of CO_2, N_2O, and CH_4 in the vent gas stream during each venting event.
(3) The duration of each venting event.

(c) Asphalt Production. Operators shall measure the mass of asphalt blown.

(d) Sulfur Recovery. The operator shall measure the volumetric flow rate of acid gas to the SRU. If using source specific molecular faction value instead of the default factor, the operator shall conduct an annual test of the CO_2 content using methods approved by [insert jurisdiction]. The operator shall submit a test plan to the *[jurisdiction]* for approval. Once approved, the annual tests shall be conducted in accordance with the approved test plan under the supervision of the [*jurisdiction*].

(e) Flares and Other Control Devices. The operator shall measure the following:

(1) If using the method specified in WCI.203(e)(2)(a), monitor the flow rate and high heat value of the flare gas using continuous monitors.
(2) If using the method specified in WCI.203(e)(2)(b), monitor the flow rate and carbon content of the flare gas using continuous monitors.
(3) If using the method specified in WCI.203(e)(3), monitor the volume of gas destroyed annually (determined to accuracy of ± 7.5%) and the carbon content.

(f) Storage Tanks. The operator shall measure the annual throughput of crude oil, naphtha, distillate oil, asphalt, and gas oil for each storage tank using flow meters.

(g) Wastewater Treatment. Operators shall measure the following parameters.

(1) The daily volume of waste water treated.
(2) The quarterly chemical oxygen demand of the wastewater.
(3) The amount of sludge removed and the organic content of the sludge.
(4) The quarterly nitrogen content of the wastewater.

(h) Oil-Water Separators. Operators shall measure the daily volume of waste water treated by the oil-water separators using methods that comply with the measurement accuracy provisions in WCI.2(d).

(i) Equipment Leaks. Operators shall measure screening values for each valve, pump seal, connector, flange, and open-ended line used in natural gas, refinery fuel gas, and PSA off-gas systems using the methods specified in CAPCOA (1999) Method 3: Correlation Equation Method *[or the method in CCME EPC-73E for Canadian jurisdictions]* and an instrument capable of detecting methane. Operators shall conduct screenings at the frequency interval required by *[jurisdiction]*.

Table 200-1. Coke burn rate material balance and conversion factors

	(kg min)/(hr dscm %)	(lb min)/(hr dscf %)
K_1	0.2982	0.0186
K_2	2.0880	0.1303
K_3	0.0994	0.0062

Table 200-2. Default MCF Values for Industrial Wastewater			
Type of Treatment and Discharge Pathway or System	**Comments**	**MCF**	**Range**
Untreated			
Sea, river and lake discharge	Rivers with high organic loading may turn anaerobic, however this is not considered here	0.1	0 - 0.2
Treated			
Aerobic treatment plant	Well maintained, some CH_4 may be emitted from settling basins	0	0 – 0.1
Aerobic treatment plant	Not well maintained, overloaded	0.3	0.2 – 0.4
Anaerobic digester for sludge	CH_4 recovery not considered here	0.8	0.8 – 1.0
Anaerobic reactor	CH_4 recovery not considered here	0.8	0.8 – 1.0
Anaerobic shallow lagoon	Depth less than 2 meters	0.2	0 – 0.3
Anaerobic deep lagoon	Depth more than 2 meters	0.8	0.8 – 1.0

For CH_4 generation capacity (B) in kg CH_4/kg COD, use default factor of 0.25 kg CH_4/kg COD.

The emission factor for N_2O from discharged wastewater (EF_{N2O}) is 0.005 kg N_2O-N/kg-N.

MCF = methane conversion factor (the fraction of waste treated anaerobically).
COD = chemical oxygen demand (kg COD/m^3).

Table 200-3. Emission Factors for Oil/Water Separators	
Separator Type	**Emission factor (EF_{sep})[a] kg NMHC/m^3 wastewater treated**
Gravity type - uncovered	1.11e-01
Gravity type - covered	3.30e-03
Gravity type – covered and connected to destruction device	0
DAF[b] of IAF[c] - uncovered	4.00e-03[d]
DAF or IAF - covered	1.20e-04[d]
DAF or Iaf – covered and connected to a destruction device	0

[a] EFs do not include ethane
[b] DAF = dissolved air flotation type
[c] IAF = induced air flotation device
[d] EFs for these types of separators apply where they are installed as secondary treatment systems

Table 200-4. Data for Preparing the Asphalt Chemical Database	
Parameter	**Database Entry**
Liquid Molecular Weight	**1000**
Vapor Molecular Weight	**105**
Liquid Density (lb/gal. at 60 ^oF)	**8.0925**
Antoine's Equation Constants (using K)	**A = 75350.06**
	B = 9.00346

Table 200-5. Gas Service Components Fugitive Emissions			
Component Type / Service Type	**Default Zero Factor (kg/hr)**	**Correlation Equation (kg/hr)**	**Pegged Factor (kg/hr)**
			10,000 ppmv
	Zf_{i0}	**σ_i and β_i**	**(SV > 9,999) PF_{iP-10}**
Valves (1)	7.8×10^{-6}	$2.27 \times 10^{-6}(SV)^{0.747}$	0.064
Pump seals (2)	1.9×10^{-5}	$5.07 \times 10^{-5}(SV)^{0.622}$	0.089
Others (3)	4.0×10^{-6}	$8.69 \times 10^{-6}(SV)^{0.642}$	0.082
Connectors (4)	7.5×10^{-6}	$1.53 \times 10^{-6}(SV)^{0.736}$	0.030
Flanges (5)	3.1×10^{-7}	$4.53 \times 10^{-6}(SV)^{0.706}$	0.095
Open-ended lines (6)	2.0×10^{-6}	$1.90 \times 10^{-6}(SV)^{0.724}$	0.033

§ WCI.210 PULP AND PAPER MANUFACTURING

§ WCI.211 Source Category Definition

The pulp and paper manufacturing source category consists of facilities that produce pulp either at stand-alone pulp facilities or integrated pulp and paper mills.

§ WCI.212 Greenhouse Gas Reporting Requirements

In addition to the information required by WCI.3, the annual emissions report must contain the following information:

(a) Annual biogenic CO_2 process emissions from all recovery furnaces and kilns in metric tons, as specified in WCI.213.

(b) Annual fossil CO_2 process emissions from all recovery furnaces and kilns in metric tons, as specified in WCI.213

(c) CO_2, N_2O, and CH_4 emissions from stationary combustion units in metric tons, as specified in WCI.23.

(d) Annual consumption of carbonate in metric tons.

(e) Annual black liquor production in metric tons.

(f) Under consideration: Annual N_2O, and CH_4 emissions from onsite wastewater treatment plants in metric tons, as specified in WCI.200(g).

§ WCI.213 Calculation of GHG Emissions

(a) Calculate biogenic CO_2 process emissions from recovery furnaces and kilns using Equation 210-1:

$$CO_{2,biogenic} = \sum_{i=1}^{12} (BL_i \times CC_i \times 3.664) \qquad \textbf{Equation 210-1}$$

Where:

$CO_{2,\ biogenic}$	=	Biogenic CO_2 process emissions from recovery furnaces and kilns (metric tons/year).
BL_i	=	Black liquor produced in month i (metric tons/month).
CC_i	=	Carbon content of the black liquor (weight fraction)..
3.664	=	Ratio of molecular weights, CO_2 to carbon.

(b) Calculate fossil CO_2 process emissions from make-up carbonates used in the recovery furnace and kiln system using Equation 210-2:

$$CO_{2,\,fossil} = \sum_{i=1}^{12} \left(\sum_{j=1}^{n} RM_j \times EF_j\right)_i \qquad \textbf{Equation 210-2}$$

Where:

$CO_{2,\,fossil}$	=	Fossil CO_2 process emissions from recovery furnace and kiln systems (metric tons/year).
RM_j	=	Amount of make-up carbonate j consumed in month i (metric tons/month).
EF_j	=	Carbonate content of carbonate material j for month i (weight fraction as CO_2).
3.664	=	Ratio of molecular weights, CO_2 to carbon.

§ WCI.214 Monitoring Requirements

(a) Measure the quantity of black liquor produced each month.

(b) Collect monthly samples of black liquor and analyze each sample for carbon content using ASTM D5373-08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal.

(c) For the amount of carbonate material consumed, either use records provided by the material supplier or monitor carbonate material consumption using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.

(d) For the carbonate content of each carbonate material consumed, either use carbonate content data provided by the supplier, the appropriate default factor from Table 1, or collect monthly samples of each carbonate material consumed and analyze each sample for carbonate content using ASTM Methods C25, C1301 or C1271.

Table 1: Formulae, Formula Weights, and Carbon Dioxide Emission Factors for Common Carbonate Species.

Carbonate	Mineral Name	Formula Weight	Emission Factor (metric tons CO_2/metric ton Carbonate)
$CaCO_3$	Calcite	100.1	0.4397
$CaMg(CO_3)_2$	Dolomite	184.4	0.4773
Na_2CO_3	Soda ash (sodium carbonate)	106.0	0.4149

§ WCI.230 SODA ASH PRODUCTION

§ WCI.231 Source Category Definition

The soda ash production source category consists of facilities that produce soda ash by calcining sodium carbonate bearing ore or brine.

§ WCI.232 Greenhouse Gas Reporting Requirements

In addition to the information required by WCI.3, the annual emissions report must contain the following information:

(a) Annual CO_2 process emissions from all soda ash calcining kilns combined, as specified in WCI.233 (metric tons).

(b) CO_2, N_2O, and CH_4 emissions from combustion of fuels in the calcining kilns, as specified in WCI.20 (metric tons).

(c) Annual consumption of trona ore or sodium carbonate-rich brine (metric tons).

(d) Annual soda ash production (metric tons).

(e) Annual mass of waste material output from calcining kilns (metric tons).

(f) For plants recycling the CO_2 generated from calcination for use in the carbonation towers, report annual CO_2 recycled within the process (metric tons).

§ WCI.233 Calculation of GHG Emissions

(a) You must calculate CO_2 emissions using the methods in either paragraphs (a)(1) or (a)(2) of this section.

(1) **Continuous Emission Monitoring Systems.** The owner or operator may measure CO_2 emissions using CEMS, as specified WCI.23(d).

(2) **Feedstock Material Balance.** The owner or operator may estimate CO_2 process emissions using Equation 230-1 and the measured carbon content and feedstock input of the trona ore or carbonate-rich brine.

$$CO_2 = \sum_{j=1}^{12} (3.664)[(Ci_j \times Ti_j) - (Cs_j \times Ts_j) - (Cw_j \times Tw_j)] \qquad \textbf{Equation 230-1}$$

Where:

CO_2 = CO_2 process emissions from soda ash production (metric tons/year).
Ci_j = Carbon content of feedstock (trona ore or carbonate-rich brine) input (percent by weight, expressed as a decimal fraction).
Ti_j = Weight of feedstock (trona ore or carbonate-rich brine) input (metric tons/month).
Cs_j = Carbon content of soda ash output (percent by weight, expressed as a decimal fraction).
Ts_j = Weight of soda ash output (metric tons/month).
Cw_j = Carbon content of waste material output from the kiln (i.e. kiln dust collected in control devices and not combined with the soda ash product) (percent by weight, expressed as a decimal fraction).
Tw_j = Weight of waste material output from the kiln (i.e. kiln dust collected in control devices and not combined with the soda ash product) (metric tons/month).
3.664 = Ratio of molecular weights, CO_2 to carbon.

(b) If you operate a soda ash production facility in which CO_2 generated in calcining kilns is recycled to carbonate towers for brine pre-treatment, you must calculate recycled CO_2 using Equation 230-2.

$$CO_2 = \sum_{j=1}^{12} (3.664)[(Ci_j \times Ti_j) - (Cb_j \times Tb_j)] \qquad \textbf{Equation 230-2}$$

Where:

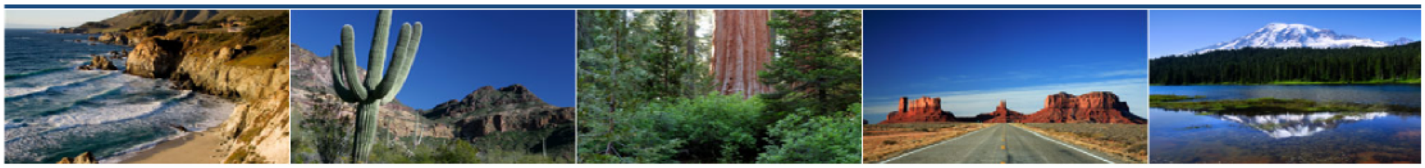
CO_2 = Recycled CO_2 from the ore calcining kiln (metric tons/year).
Ci_j = Carbon content of bicarbonate kiln input (percent by weight, expressed as a decimal fraction).
Ti_j = Weight of bicarbonate kiln input (metric tons/month).
Cb_j = Carbon content of sodium carbonate-rich brine input (percent by weight, expressed as a decimal fraction).
Tb_j = Weight of sodium carbonate-rich brine input (metric tons/month).
3.664 = Ratio of molecular weights, CO_2 to carbon.

§ WCI.234 Monitoring Requirements

Owners and operators using the mass balance method must comply with the following monitoring requirements:

(a) Measure the quantity of ore, soda ash, waste material, and carbonate-rich brine (as applicable) by direct measurement using the same instruments used for accounting purposes.

(b) Collect monthly samples of ore, soda ash, waste material, and carbonate-rich brine (as applicable) and analyze each sample for carbon content. For the carbon content of the brine ore and carbonate-rich brine, use a total organic carbon analyzer according to the ultraviolet light/chemical (sodium persulfate) oxidation method in ASTM D4839-03. Use method ASTM E359-00(2005) for the carbon content of trona ore, soda ash, and waste material.



§ WCI.300 PETROCHEMICAL MANUFACTURING

§ WCI.301 Source Category Definition

The petrochemical manufacturing source category consists of any facility that manufacturers petrochemicals, including acrylonitrile, propylene, ethylene, ethylene dichloride, ethylene oxide, or methanol, from feedstocks derived from petroleum, or petroleum and natural gas liquids.

§ WCI.302 Greenhouse Gas Reporting Requirements

In addition to the information required by WCI.3, the annual emissions report must contain the following information:

(a) CO_2, N_2O, and CH_4 emissions from combustion of fuels in the stationary combustion unit in metric tons, as specified in WCI.20.

(b) CO_2, N_2O, and CH_4 emissions from flares and other oxidizers in metric tons, as specified in WCI.303(a).

(c) CO_2, N_2O, and CH_4 emissions from process vents in metric tons, as specified in WCI.303(b).

(d) CH_4 emissions tons from equipment leaks in metric, as specified in WCI.303(c).

(e) Annual consumption of feedstock by type for all feedstocks that result in GHG emissions in million standard cubic feet for gases, gallons for liquids, short tons for non-biomass solids, and bone dry short tons for biomass-derived solid fuels.

§ WCI.303 Calculation of GHG Emissions

(a) **Flares and Other Oxidizers.** You must calculate GHG emissions from flares and oxidation control devices as follows:

(1) Calculate CO_2, CH_4 and N_2O emissions resulting from the combustion of flare pilot and purge gas using the appropriate method(s) specified in WCI.20.

(2) Calculate CO_2 emissions for each gas destroyed in a flare or other oxidation control device using Equation 300-1.

Equation 300-1

$$CO_2 = \sum_{i=1}^{n} GV_i \times CC_i \times MW_i / MVC \times 3.664 \times 0.001$$

Where:

CO_2 = CO_2 emissions (metric tons/year).
GV_i = Volume of gas *i* destroyed annually (scf/year).
CC_i = Average annual carbon content of gas *i* (kg C/kg fuel).

MW_i	=	Average annual molecular weight of gas *i*.
MVC	=	Molar volume conversion factor (849.5 scf/kg- mole for STP of 20°C and 1 atmosphere or 836 scf/kg-mole, for STP of 60°F, and 1 atmosphere).
3.664	=	Ratio of molecular weights, CO_2 to carbon.
0.001	=	Conversion factor, kg to metric tons.
n	=	Number of gases destroyed.

(b) **Process Vents.** Except for process emissions calculated pursuant to WCI.303(a) or (c), you must calculate process emissions of CO_2, CH_4, and N_2O from process vents using Equation 300-2.

$$E_x = \sum_{i=1}^{n} VR_i \times F_{xi} \times (MW_x / MVC) \times VT_i \times 0.001 \qquad \textbf{Equation 300-2}$$

Where:

E_x	=	Emissions of x (metric tons/yr), where x = CO_2, N_2O, or CH_4.
VR_i	=	Vent rate for venting event i (scf/unit time).
F_{xi}	=	Molar fraction of x in vent gas stream during event i.
MW_x	=	Molecular weight of x (kg/kg-mole).
MVC	=	Molar volume conversion (849.5 scf/kg-mole for STP of 20°C and 1 atmosphere or 836 scf/kg-mole for STP of 60°F, and 1 atmosphere).
VT_i	=	Time duration of venting event i (same units of time used for VR_i).
n	=	Number of venting events.
0.001	=	Conversion factor, kg to metric tons.

(c) **Equipment Leaks.** You must calculate CH_4 emissions for each valve, pump seal, connector, flange, open-ended line, and other components in natural gas, fuel gas, and off-gas systems as follows:

(1) Identify and screen each valve, pump seal, connector, flange, open-ended line, and other components in natural gas, fuel gas, and off-gas systems using the monitoring method in WCI.304. Components identified as "other" components include instruments, loading arms, pressure relief valves, vents, compressors, dump lever arms, diaphragms, drains, hatches, meters, and polished rods stuffing boxes.

(2) Use the results of the component screening and the following equations to calculate VOC emissions:

(A) For components where the measured screening value is equal to zero when corrected for background, calculate VOC emissions using Equation 300-3 and the appropriate default emission factors from Table 300-1:

$$E_{VOC-0} = \sum_{i=1}^{6} CC_i \times ZF_{i0} \times t \qquad \textbf{Equation 300-3}$$

Where:

E_{VOC-0}	=	Emissions from components with a screening value equal to zero, when corrected for background (kg/screening period).
i	=	Component type (valve, pump seal, other, connector, flange, open-ended line).
CC_i	=	Number of i components where the screening value is 0.
ZF_{i0}	=	Default zero factor for component i from Table 300-1 (kg/hr).
t	=	Time since last screening (hours/screening period).

(B) For components where the measured screening value, corrected for background, is between 0 and 10,000 ppmv, calculate VOC emissions using Equation 300-4 and the appropriate default factors from Table 300-1:

$$E_{VOCL-C} = \sum_{i=1}^{6}\sum_{n=1}^{n} \left(\sigma_i \times SV_n^{\beta i}\right) \times t$$ **Equation 300-4**

Where:

E_{VOCL-C}	=	Emissions from components with screening values, corrected for background, between 0 and 10,000 (kg/screening period).
i	=	Component type (valve, pump seal, others, connector, flange, open ended-line).
n	=	Number of *i* components.
σ_i	=	Correlation equation coefficient for component type *i* from Table 300-1.
SV_n	=	Screening value for component *n.*
βi	=	Correlation equation exponent for component type *i* from Table 300-1.
t	=	Time component has been leaking (default value is time from last screening) (hours/screening period).

(C) For components where the screening value, corrected for background, is greater than or equal to 10,000 ppmv, calculate VOC emissions using Equation 300-5 and the appropriate default factors from Table 300-1:

$$E_{VOCP} = \sum_{i=1}^{6} CC_i \times PF_{iP} \times t$$ **Equation 300-5**

Where:

E_{VOCP}	=	Emissions from components with screening values, corrected for background, greater than or equal to 10,000 ppmv (kg/screening period).
i	=	Component type (1=valve, 2=pump seal, 3=others, 4=connector, 5=flange, 6=open-ended line).
CC_i	=	Number of *i* components with screening values greater than 9,999 ppmv.
PF_{iP}	=	VOC emission factor for component type *i* pegged over 9,999 ppmv from Table 300-1 (kg/hr).
t	=	Time component has been leaking (default value is time since last screening) (hours/screening period).

(3) Calculate CH_4 emissions using Equation 300-6 and either a default factor of 0.6 for CF_{VOC} or a site-specific conversion factor calculated from the composition and methane content of the gas.

$$CH_4 = \sum_{1}^{n} \left(E_{VOC-0} + E_{VOC-LC} + E_{VOCP}\right)_n \times CF_{VOC} \times 0.001 \qquad \textbf{Equation 300-6}$$

Where:

CH_4	=	CH_4 emissions (metric tons/year).
n	=	Number of screenings/year.
E_{VOC-0}	=	Emissions from components with a screening value equal to zero, when corrected for background (kg/screening period).
E_{VOC-LC}	=	Emissions from components with screening values, corrected for background, between 0 and 10,000 (kg/screening period).
E_{VOCP}	=	Emissions from components with screening values, corrected for background, greater than or equal to 10,000 ppmv (kg/screening period).
CF_{VOC}	=	VOC to CH_4 conversion factor (default CF_{VOC} = 0.6).
0.001	=	Conversion factor (kg to metric tons).

§ WCI.304 Monitoring Requirements

(a) Flares and Other Oxidizers. You must measure:

(1) The volume of each gas destroyed annually determined to an accuracy of ± 5 percent.

(2) The carbon content and molecular weight of each gas quarterly using the methods specified in WCI.25 and calculate the annual average values for carbon content and molecular weight for each gas destroyed.

(b) Process **Vents.** You must measure the following parameters for each process vent:

(1) The gas flow rate for each venting event.

(2) The molar fraction of CO2, N2O, and CH4 in the vent gas stream during each venting event.

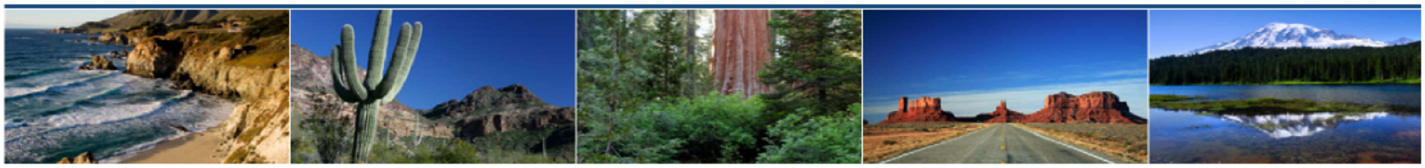
(3) The duration of each venting event.

(c) **Equipment Leaks.** You must screen each valve, pump seal, connector, flange, and open-ended line used in natural gas, fuel gas, and off-gas systems using the methods specified in CAPCOA (1999) Method 3: Correlation Equation Method and an instrument capable of detecting methane. Screenings must be performed at the frequency interval required by [*insert jurisdiction*]. The instrumentation used for screening must be capable of detecting methane.

(d) **Feedstock Consumption.** You must measure the feedstock consumption using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.

Table 300-1. Fugitive Emissions from Gas Service Components			
Component Type / Service Type	**Default Zero Factor (kg/hr)**	**Correlation Equation (kg/hr)**	**Pegged Factor (kg/hr)**
	(SV = 0) Zf_{i0}	**(SV > 0 and < 10,000)** σ_i **and** β_i	**(SV ≥ 10,000)** PF_{iP-10}
Valves	7.8×10^{-6}	$2.27 \times 10^{-6}(SV)^{0.747}$	0.064
Pump seals	1.9×10^{-5}	$5.07 \times 10^{-5}(SV)^{0.622}$	0.089
Others[a]	4.0×10^{-6}	$8.69 \times 10^{-6}(SV)^{0.642}$	0.082
Connectors	7.5×10^{-6}	$1.53 \times 10^{-6}(SV)^{0.736}$	0.030
Flanges	3.1×10^{-7}	$4.53 \times 10^{-6}(SV)^{0.706}$	0.095
Open-ended lines	2.0×10^{-6}	$1.90 \times 10^{-6}(SV)^{0.724}$	0.033

[a] The "other" component type should be applied to any component type other than connectors, flanges, open-ended lines, pump seals, or valves. The "other" component type includes: instruments, loading arms, pressure relief valves, vents, compressors, dump lever arms, diaphragms, drains, hatches, meters, and polished rods stuffing boxes.



§ WCI.XX0 ADIPIC ACID MANUFACTURING

§ WCI.XX1 Source Category Definition

Adipic acid ($HOOC(CH_2)_4COOH$) is a dicarboxylic acid used in the production of a large number of products including synthetic fibers (primarily nylon 6,6), coatings, plastics, urethane foams, and synthetic lubricants. Adipic acid is produced by oxidizing a mixture of cyclohexanone ($(CH_2)_5CO$) and cyclohexanol ($(CH_2)_5CHOH$) with nitric acid in the presence of a catalyst; nitrous oxide (N_2O) is formed as an unwanted by-product.

§ WCI.XX2 Greenhouse Gas Reporting Requirements

In addition to the information required by WCI.3, the annual emissions data report shall contain the following information:

(a) Total emissions of N_2O at the facility level (metric tons)

(b) Total quantity of adipic acid production (metric tons)

(c) Facility-specific N_2O emission factor derived from periodic emissions monitoring or irregular emissions sampling (metric tons N_2O per metric ton of adipic acid)

(d) Destruction factor for facility-specific abatement technology (e.g., catalytic destruction, thermal destruction, nitric acid recycling, adipic acid recycling, etc.)

(e) Abatement system utilization factor for facility-specific abatement technology

(f) CO_2, N_2O, and CH_4 emissions from stationary combustion units as specified in WCI.20

§ WCI.XX3 Calculation of N_2O Emissions

(a) Process N_2O emissions. Determine process N_2O emissions as specified under either paragraph (1) or (2) of this section.

(1) Continuous emissions monitoring systems (CEMS).

(2) Calculation methodologies specified in paragraph (b) of this section.

(b) Process N_2O Emissions Calculation Methodology. Calculate total N_2O process emissions using the following equation:

$$E_{N2O} = EF \times AAP \times (1 - DF \times ASUF)$$

Equation XX0-1

Where:

E_{N2O}	=	Emissions of N_2O from adipic acid production (metric tons);
EF	=	N_2O emission factor (metric tons N_2O/metric ton of adipic acid produced) derived from periodic emissions monitoring or irregular emissions sampling;
AAP	=	Adipic acid production (metric tons);
DF	=	Destruction factor (dimensionless);
ASUF	=	Abatement system utilization factor (dimensionless).

§ WCI.XX4 Sampling, Analysis, and Measurement Requirements

The following measurement methods shall be used.

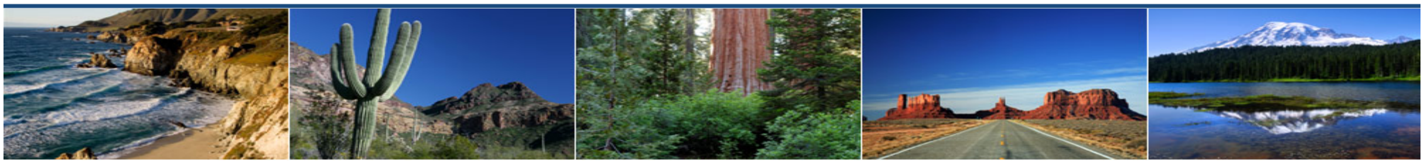
(a) Facility N_2O emissions tests. All facilities must conduct testing using:

(1) U.S. EPA Method 320 (40 CFR part 63, Appendix A) or ASTM D6348-03; or

(2) Continuous emissions monitor system (CEMS) to determine either the uncontrolled emissions to derive an emission factor (for use with the documented abator destruction efficiency), or the controlled emissions. The CEMS shall be operated in accordance with quality assurance and quality control program approved by the [jurisdiction].

(b) Adipic acid production rates. Production rates may be determined through sales records, or through direct measurement using flow meters or weigh scales.

Western Climate Initiative



Response to Stakeholder Comments on Final Draft Essential Requirements for Mandatory Reporting

July 15, 2009

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1 Introduction

The WCI is today issuing the first version of the Final Essential Requirements of Mandatory Reporting (ERMR). The ERMR will serve as the basis for Partner jurisdictions to adopt initial rules implementing the WCI's reporting program. Future versions of the ERMR will include quantification methodologies for additional sources of greenhouse gas (GHG) emissions, such as electricity importers and residential, commercial and industrial fuel suppliers, as well as refinements to existing methodologies based on the Partner jurisdictions' experience in implementing the requirements.

The Final ERMR include numerous changes made in response to stakeholder comments on both the 3rd Draft ERMR issued on January 6, 2009, and the Final Draft ERMR issued on May 7, 2009. These comments are summarized below. Where the WCI declined to make the change suggested, the reasons for that decision follow the summary of the comment.

One overarching concern addressed in a number of comments received on both prior drafts is the potential for inconsistency with U.S. and Canadian national reporting requirements. WCI notes that the Reporting Committee has begun work on the planning of the Regional Emissions Database (RED) that will serve as the repository for data submitted under the ERMR. The Committee has identified alignment with the national reporting programs in order to minimize the burden on facilities subject to both WCI and federal reporting requirements as an important principle in the RED's development.

WCI wishes to thank commenters who supported changes made in the Final Draft ERMR. These comments are not included in the following summary.

Attached to this document are marked up versions of the Final ERMR showing changes from the Final Draft ERMR. A clean reference version of the Final ERMR is also being released with this document.

2 Comments on or Inconsistent with the WCI Design Recommendations

A number of comments reiterated objections to elements of the ERMR that are prescribed by the Design Recommendations. Because the Reporting Committee has previously addressed most of these comments and is in any case charged with implementing the Design Recommendations, these comments are summarized below for the benefit of the Partners without further response:

- The reporting deadline should be June 1 or July 1, rather than April 1.

- Suppliers of residential, commercial and industrial fuels should not be included in the reporting program. (Note that these entities are not yet addressed by the ERMR, but will be in future amendments in accordance with the Design Recommendations.)
- The WCI should not allow Partner jurisdictions to require reporting earlier, at lower thresholds or for entities and facilities not covered by the cap-and-trade program. There should be uniform reporting thresholds throughout the region.
- The applicability threshold should be 100,000, rather than 10,000 metric tons per year. If lower thresholds are retained, they should be phased in over time.
- Third-party verification should not be required.

Some commenters requested that WCI extend the deadline for submitting comments on the ERMR or re-circulate certain ERMR sections for another round of comment. Doing so, however, would make it difficult or impossible for jurisdictions to adopt implementing rules in time for the 2010 reporting year and therefore would be inconsistent with the Design Recommendations.

3 Comments on the General Provisions

3.1 Applicability

A commenter requested that WCI clarify "as soon as possible, preferably before the final version of the reporting requirements" how the definition of facility would apply to natural gas and other pipelines. The Final ERMR being issued today, however, do not apply to pipelines. The Reporting Committee's Work Plan contemplates that these requirements will not be finalized until the end of this year.

WCI believes the applicability provisions for pipeline facilities should be developed at the same time as the other essential requirements for these sources.

3.2 Administrative Requirements

3.2.1 Comments Previously Addressed

A number of commenters reiterated objections to ERMR administrative requirements raised in comments on previous drafts. WCI believes these comments were adequately addressed in the previous responses, which are identified below:

Objection to requirement to retain documents for seven years as being unduly onerous	RTC Third Draft* § 2.2.2, p. 18

Objection to requirement to provide within 10 working days all documents and data used to develop an emissions data report	RTC Third Draft § 2.2.2, p. 26
Recommendation to provide public with access only to aggregate emissions data	RTC Third Draft § 2.2.2, p. 13

*WCI, "Response to Stakeholder Comments and Final Draft Essential Requirements of Mandatory Reporting for the Western Climate Initiative" (May 7, 2009) (http://www.westernclimateinitiative.org/component/remository/Reporting-Committee-Documents/Response-to-Comments-on-Draft-Essential-Requirements-(5-7-09)/) ("RTC Third Draft").

3.2.2 Error Correction Reports

One commenter recommended that in the initial years of reporting, errors be corrected as part of the next reporting cycle, not within the 30 or 60 days as provided in WCI.2(g) (formerly WCI.2(f)). The commenter contended that in "the years when facilities are first developing their inventories to meet WCI requirements, a facility could conceivably be submitting error reports every month."

WCI acknowledges that the number of reporting errors can be expected to be higher in the initial years of reporting than in later years when reporters have gained experience with the reporting system. The requirement to submit error correction reports under WCI.2(g), however, applies only when cumulative errors exceed five percent of total CO_2e emissions. WCI believes it highly unlikely that even in the initial years of reporting, a facility will discover cumulative errors of this magnitude every month.

3.2.3 Designated Representative

A commenter reiterated the concern that WCI.7(e) could be interpreted to impose personal liability on a subsequent representative for the actions of the prior representatives. In response to the same comment submitted on the Third Draft ERMR, WCI stated that WCI.7(e) "does not create personal liability for the proposed new Designated Representative; it only prevents the new Designated Representative from repudiating the actions of the existing Designated Representative."

This commenter was nevertheless concerned that the language of WCI.7(e) itself was open to misinterpretation and suggested revisions that would clarify WCI's intent:

> (d) Changing a Designated Representative. The designated representative may be changed at any time upon submission of a superseding certificate of representation. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous designated

representative before time of the superseding certificate of representation shall continue to be binding on the ~~new designated representative and the~~ owners and operators.

WCI believes that the suggested revision correctly expresses the WCI's intent and therefore has made the suggested revision in the Final ERMR.

3.2.4 Compliance and Enforcement

Two comments reiterated arguments previously raised against the compliance and enforcement provisions in WCI.5. These comments also objected to revisions to WCI.5 adopted in the Final Draft ERMR that (1) impose strict liability for the submission of false or misleading data and (2) make it clear that each violation of the ERMR constitutes a separate violation.

In general these comments objected to the potential imposition of strict liability for any deviation from the reporting requirements and argued that this approach "poses an unacceptable compliance risk." One comment noted that "based on [California's] experience, 'almost all' entity reports could be subject to a compliance action, even if the 'issues' identified by a third party verifier amount to inconsequential errors." The comments argued that WCI.5 would impose a stricter enforcement regime than either California's GHG reporting rule or EPA's proposed Mandatory Reporting Rule (MRR).

These comments argued that "based on the complexity and newness of the program, enforcement should be relaxed or deferred in the early years of the program," that "trivial or inconsequential deviations from the requirements should not be considered violations subject to enforcement" and that the submission of false or misleading information should only constitute a violation if it was done knowingly and with the intent to deceive.

Ensuring compliance with the regulatory requirements is one of the WCI's core compliance verification and enforcement principles. This will be achieved through the use of a variety of compliance tools, giving consideration to using the most appropriate tool necessary to obtain compliance, and when required, to promote general deterrence. Civil enforcement is an essential compliance tool to be applied vigorously when necessary, but reserved for those situations where alternative compliance efforts are unable to achieve the desired outcomes or it has been otherwise determined that an enforcement response is appropriate. Due to the nature of the market system, WCI Partner jurisdictions will need to obtain an acceptable emissions total in a timely manner, so the first response may require an approach that differs from traditional environmental enforcement.

As noted in the response to comments on the Third Draft ERMR, strict or absolute civil liability for violations of environmental requirements is the norm among U.S. and Canadian jurisdictions. It is also common among these jurisdictions to impose a per day penalty for each violation of environmental requirements. Indeed most, if not all, WCI jurisdictions will be able to fulfill the essential requirement in WCI.5 on the basis of existing statutory enforcement authority once their reporting rules are in place. Both California and EPA, for example, have the authority to impose substantial per day penalties for each violation of their reporting requirements. CA Health & Safety Code § 42400, et seq.; 42 U.S.C. § 7413(b).

The federal, state and provincial governments have adopted this type of enforcement regime despite the fact that many environmental requirements are complex and were at one point new to the facilities obligated to comply with them. The complexity of environmental requirements may increase the risk of inadvertent violations compared to some other legal requirements, but that same complexity makes it impossible to prescribe in advance the types of violations that warrant the imposition of penalties. In addition, because compliance is typically in the hands of a number of corporate agents, proving that a violation was knowing or committed with intent to defraud is often infeasible.

Rather than placing limits on the types of violations subject to penalties or imposing a knowledge or intent requirement, U.S. and Canadian jurisdictions have typically chosen two other means to protect regulated facilities from overzealous enforcement and excessive penalties: (1) a right to a judicial hearing on any penalties imposed and (2) identification of the factors that should be taken into account in determining the level of the penalty (in the US) or the ability of the judicial process to weigh case-specific factors when assigning penalties (in Canada.) See, e.g., 42 U.S.C. § 7413(b), (d)(4), (e). The Reporting Committee has not attempted to prescribe particular procedures or penalty factors in these Essential Requirements but instead has concluded that the existing provisions of each jurisdiction's civil enforcement laws will be adequate for the initial years of the reporting program. The Markets Committee is currently evaluating to what degree WCI should seek to establish uniformity in these and other elements of the members' compliance and enforcement programs.

3.3 Verification

One commenter recommended that WCI require certification of individual GHG verifiers to a personnel certification program that is accredited to ISO 17024.

The WCI does not believe it advisable to require personnel certification under this program at this time. The 17024 process, however, could serve as one approach, or a component of an approach, toward meeting the ISO 14065 requirement to demonstrate that a verification body's staff is qualified.

One commenter argued that a projected shortage in verifiers could make it difficult to comply with the provision requiring reporting facilities to change verifiers every six years.

WCI addressed the shortage issue in a previous comment response. [RTC Third Draft § 2.2.3, p. 32.]

3.4 General Quantification and GHG Measurements

Two commenters repeated the suggestion that the de minimis level be increased from three percent to five percent. Another commenter supported the three percent level. In response to previous comments on this issue, WCI responded that the three percent de minimis threshold was based on the California reporting rule and that WCI was examining whether the three percent de minimis threshold and the five percent materiality threshold for verification needed to be harmonized. [See RTC Third Draft § 2.2.4, p. 39.]

WCI has concluded that because the de minimis and verification materiality thresholds serve entirely different purposes, they need not be reconciled.

The de minimis threshold is designed to provide reporters relief from the obligation to apply the ERMR quantification methodologies to activities with negligible impacts on GHG emissions. The materiality threshold serves as one of the tests for whether an emissions report provides a “reasonable level of assurance” and therefore qualifies for a positive verification statement. WCI has not been able to identify, nor have any commenters identified, how establishing different thresholds for these different purposes will introduce any inconsistencies to the reporting program. The existing California program has the same thresholds and there is no indication that they have caused any difficulties for reporters.

Another commenter recommended that WCI remove the 20,000 metric ton ceiling on de minimis emissions. WCI also agreed previously to give this request further consideration.

The Design Recommendation compliance threshold has been set at 25,000 metric tons. WCI has concluded that it would be inappropriate to treat emissions close to or exceeding this level as de minimis and is therefore retaining the 20,000 metric ton cap.

Finally, a commenter suggested that WCI abandon the use of a numeric threshold altogether and instead adopt a “principled” approach that would “roughly weigh the work or cost to estimate the emissions versus the potential size of the emissions being considered.” WCI does not believe such an approach would be administratively workable or provide regulated entities the certainty they need in determining their compliance obligations.

4 Source Category-Specific Comments

The following comments and responses pertain to specific source categories for which quantification and reporting requirements were proposed in the Third or Final Draft ERMR.

4.1 Cement

4.1.1 CEMS Requirement

A commenter objected to the requirement in WCI.93(a)(1) to use CEMS to determine CO_2 emissions as specified in WCI.23(d). The commenter argued that this requirement was duplicative, burdensome and expensive because "cement manufacturers ultimately must undertake all the detailed calculations implicit in WCI.23 Methodology 3, and WCI.90."

WCI disagrees with this comment. WCI.23(d)(5) expressly provides that:

> For any units for which CO2 emissions are reported using CEMS data, the operator is relieved of the requirement to separately report process emissions from combustion emissions for that unit or to report emissions separately for different fossil fuels for that unit when only fossil fuels are co-fired. In this circumstance, operators shall still report fuel use by fuel type as otherwise required.

In addition, WCI notes that the use of a CO_2 CEMS is only required when another federal, state, provincial, or local regulation already requires both a stack gas volumetric flow rate monitor and a CO2 concentration monitor.

4.1.2 CH_4 and N_2O Emissions

A commenter stated that if WCI reporting protocols continue to require reporting of de minimis, non-CO2 emissions from cement manufacturing operations, then WCI must include a separate table of default CH_4 and N_2O emissions factors for cement (and other) kilns, and these should be consistent with current IPCC guidance (see IPCC NGGI Table 2.8).

The Final ERMR have been modified to include national, industry specific emission factors where they exist and explicitly includes factors for natural gas used in cement kilns.

4.1.3 Monthly Sampling/Calculations

A commenter maintained that the requirement in WCI.93 to perform monthly calculations of key factors (e.g. clinker emission factor, CKD emission factor, and organic content of raw material) would be administratively inefficient. The commenter stated that data collection should be conducted on a monthly basis, but that calculations of key factors should only be undertaken annually.

It was WCI's intention to require only monthly sampling, not monthly calculation of emission factors. WCI has revised the language of WCI.93 to make this intent clear.

4.1.4 Mineral Component Reporting to Inform Allocation Decisions

A commenter noted that material substitution is a key means to reducing GHG emissions associated with cement manufacturing. The commenter argued that WCI.92(b) therefore should be revised to include a requirement to report information associated with the quantity and type of mineral components consumed in the production of cements and the quantity and type of mineral components produced for use as cement substitutes.

The focus of the ERMR is to gather data on GHG emissions as well as the underlying data used to calculate GHG emissions. It is not the function of the ERMR to collect all data that could conceivably be used in making allocation decisions. The WCI will be happy to accept any data the industry may want to present to assist in making those decisions in the future.

4.2 Coal Storage

Stakeholder comments on the previous draft ERMR (January 6, 2009) are summarized below along with our responses.

One commenter said that WCI should consider assigning responsibility for coal storage emissions further upstream (i.e, to the mining sector rather than the electricity sector). WCI points out that the requirements in WCI.100 are based on the California Climate Action Registry protocol which attributes all post-mining fugitive methane emissions to the facility combusting coal, since that facility is ultimately responsible for the coal having been processed and delivered to the facility. The California Air Resources Board has also adopted this requirement. The WCI believes it is an appropriate methodology for this program.

Another commenter suggested that the category method should be dropped altogether on the basis of "no accepted methodology for [quantification]" and goes on to say that if the section is retained then emission factors for coal from outside Canada and the U.S. should be provided. WCI modified the ERMR for coal storage to include emission factors for coals originating in Canada, as well as metric-unit emission factors for U.S. coal. Since coal storage emission factors (based on post-mining emissions) are not available for non-U.S. and non-Canadian coals, a provision has been added to WCI.100 that instructs the owner or operator to use the most appropriate emission factor from the tables provided, based on approval by the relevant jurisdiction.

Finally, a commenter pointed out that the method requests information on the annual coal consumption under sampling, analysis and measurement requirements, while the rest of the method uses information on annual quantity of coal purchased. WCI has corrected the requirement to monitor annual coal purchased, and has renumbered the relevant section to WCI.104 (was previously WCI.105).

4.3 General Stationary Combustion and Electric Generating Units

WCI received approximately 22 individual comments related to electric generating units (EGUs) and general stationary combustion (GSC) emissions quantification methodologies. These comments were divided into five summary topics: fuel sampling and monitoring, cogeneration, EGU reporting, EPA MRR, and fuel monitoring. The common theme with the comments is that WCI reporting requirements for EGUs and GSCs are not flexible enough.

WCI has made some revisions to the ERMR in response to the comments in order to improve flexibility.

4.3.1 Biomass and Waste-Derived Fuels

The cement industry commented that the use of the term “biomass fuel” (also referred to as “biomass-derived fuel”), which is defined as only those fuels derived entirely from biomass, creates confusion when used in rules, such as WCI.23(f), that provide for the separate reporting of CO_2 emissions from the combustion of the biomass fraction of waste-derived fuels. The comment argued that if biomass fuels must be derived entirely from biomass, then a waste-derived fuel cannot have a biomass fuel component.

WCI agrees that the definition of biomass fuel may create confusion when used in this context and therefore has revised WCI.23(d)(3), (d)(4) and (f) to add or substitute references to the defined term biomass.

The industry also argued that procedures for separately reporting and calculating the biomass fraction of mixed fuel emissions should be incorporated into the relevant methods in WCI.23. WCI has revised WCI.23(f) to specify how to calculate the biomass fraction of mixed fuel emissions when a mass balance approach is possible.

One commenter noted that sewage “contains an important amount of fossil carbon from sources such as detergents, shampoos, etc.” and therefore should not be treated as pure biomass. WCI agrees and has revised the definition of waste-derived fuels to make it clear that fuels derived from sewage and other wastes is not considered pure biomass.

4.3.2 Fuel Sampling

WCI received a comment supporting the amended approach that allows for use of vendor provided sampling results. As it relates to solid fuels sampling, the commenter does not agree with the protocol that requires weekly collection of samples composited into a monthly sample for testing of carbon content and heating value.

After considering these comments, WCI has determined that weekly sampling with monthly testing is not onerous and will improve the accuracy of the test results compared to monthly sampling. No amendments have been made to the language of the ERMR.

4.3.3 Fuel Monitoring

WCI received a comment regarding unnecessary costs to operations. The commenter feels that the requirements to install flow meters and high heating valve analyzers add to the material costs of operation and are not necessary in order to provide regulators with reliable data.

WCI agrees, and therefore amended the language of the Final Draft ERMR to eliminate these requirements. Reporters are now entitled to rely on fuel supplier data.

WCI received another comment requesting that the WCI remove the accuracy requirement for biomass and change the accuracy for solid fuel consumption to 25% for solid fuels other than biomass.

WCI has modified the measurement accuracy requirements to reflect the EPA proposal. However, WCI believes that this requirement is not stringent enough under a market context. In a market context, we must move toward more accuracy rather than less. WCI does not support the 25% accuracy level for solid fuels because this change is unnecessary given new calibration language.

4.3.4 Cogeneration

WCI received several comments regarding the importance of the appropriate treatment of industrial cogeneration facilities in order to avoid an unintended consequence of undermining the economic viability of existing cogeneration facilities. Other comments indicated that the significant environmental benefits over conventional power generation and the carbon benefits of biomass fired generation and cogeneration are substantial. Commenters have requested that this incremental benefit be recognized in the development of carbon emissions standards for electricity generation.

WCI has modified the Final ERMR to provide for reporting of certain additional information for cogeneration plants in addition to their emissions. WCI recognizes the interest in providing incentives for efficient cogeneration and will address this issue further when allocation is discussed.

4.3.5 EGU Reporting

WCI received several comments regarding the reporting protocols for EGUs. One commenter recommended that the WCI reporting guidelines be made identical to those of the EPA, so that there is no duplication of efforts or unnecessary use of resources for reporting purposes.

WCI requires sources already using CEMS in compliance with the Acid Rain Program (ARP) to report their emissions using CEMS. This is the same as the proposed EPA MRR. WCI requires sources that do not use CEMS to comply with a federal, state or other regulation to use methods in the GSC section (WCI.20), which are similar to those required by EPA. We see no conflict between the WCI requirements and the proposed MRR for estimating emissions for EGUs that already use CEMS under the ARP. However, some differences may exist in the actual data to be reported under the two programs, due to various reasons including the fact that WCI requires third party verification for sources emitting over 25,000 metric tons CO_2e, while EPA proposes not to require third party verification.

After considering these comments, WCI has determined that no change is required as a result of this comment. No amendments have been made to the language of the ERMR.

4.3.6 Other

Another commenter has requested that WCI.43(a)(6) be changed to reflect the changes to WCI.23 with respect to allowing those facilities that meet the requirements of WCI.23 (e) to use the appropriate sections of WCI.23 (a) through (d) to report CO_2 emissions, and not just require WCI.23 (d) for those facilities not required to measure CO_2 and stack gas flow, as under WCI.23.

WCI agrees that WCI.43 should be consistent with WCI.23 and has made this modification to the language of the ERMR.

WCI received a comment requesting integration of WCI requirements with utilities' other current and future reporting obligations.

WCI agrees and will address this concern and integration with MRR during the Regional Emissions Database (RED) development.

Another commenter stated that the current EGU reporting process provides the underlying data for an effective emissions market and argues that WCI provides no evidence that the existing reporting requirements for EGUs are insufficient.

WCI disagrees, and notes that the ERMR require sources that already report using CEMS (e.g., if subject to ARP) to report their GHG emissions using CEMS. No change is required as a result of this comment.

WCI received a comment suggesting that the following standardized units be used for fuels:

Gaseous: mmscf (or standard metric),

Liquid: 1000 gallons (or standard metric),

Solid: tons (or standard metric), and

Energy: MMBTU (or standard metric).

WCI has developed 2 versions of the GSC requirements (WCI.20), one in English and one in metric units. WCI requires reporting in the units suggested here within the English version requirements. The reason for two versions is that separate versions will be adopted by Partner jurisdictions in the U.S. and Canada. In the future, the RED will also address the two versions of units. How it will treat unit conversion has yet to be determined, but the recommendation is noted and will be referred to the WCI subcommittee responsible for RED development. No change is required as a result of these comments.

WCI received a comment indicating that there is no evidence to suggest that periodic fuel sampling, conducted by the final fuel consumer, would enhance GHG emission estimates. The commenter recommends that WCI allow either national average fuel-specific emission factors, those factors published by the IPCC, or site specific factors determined through experience or provided by vendors.

The Final ERMR does not require fuel sampling by consumer. Instead, the facility is allowed to use the information provided by the fuel supplier.

WCI received a comment recommending that established and recognized emissions factors be used in place of testing carbon content and heating values of well established fuels.

WCI had made changes in the previous Draft Final ERMR document to allow use of analysis results from fuel providers in lieu of fuel sampling procedures. Sampling frequencies were carefully considered and reflect fuel specific variation in carbon content. Note that the proposed MRR requires daily, weekly, or monthly fuel sampling, as well as annual and tri-annual source testing for biomass and municipal solid waste, depending upon fuel type and verification requirements. WCI disagrees that fuels like 'wood residue' would have consistent carbon content. WCI's emission factors in tables 20-1 through 20-3 represent industry standards. No change is required as a result of these comments.

WCI received a comment stating that even though WCI.23 outlines four acceptable calculation methodologies for CO_2 mass emissions, the Draft does not cite any sources for these methodologies or basis for the selection of these equations.

The calculation methodologies and equations in WCI.23 are in standard form. These require no additional reference.

WCI received a comment recommending that the document identify the appropriate source category for flares.

Flares are defined as a combustion source device and per WCI.20 they will be quantified as such. The definition of a facility for pipeline oil and gas processing will be defined in the future.

WCI received a comment requesting that we identify the source of the referenced default HHV value and consider allowing other default values in order to be consistent with existing reporting requirements.

There is a source given in Table 20-1. WCI has determined that we should be consistent with the national emissions inventory documents because they are more up-to-date than AP-42.

WCI received a comment requesting that we revise requirements to allow for different sampling frequencies to accommodate variations in sampling equipment.

WCI has determined that frequencies should be specific to fuel after consideration of potential carbon variability, rather than dependent on currently available monitoring equipment.

WCI received a comment recommending that we establish the burden of proof of life-cycle emissions on suppliers of unconventional fuels when the fuel supplier protocols are adopted by WCI.

WCI understands the comment and will consider this further at the appropriate time.

4.4 Hydrogen

Stakeholder comments on the previous draft ERMR (January 6, 2009) are summarized below along with our responses.

One stakeholder said that the fuel carbon content monitoring requirements in WCI.25(d)(3), which are referenced in the hydrogen production ERMR, should include a 5% accuracy requirement for continuous carbon analyzers. This change was made.

Two stakeholders cited WCI.132(c) that required the measurement of daily hydrogen production, and the fact that because this measurement is not used to calculate emissions it should not be subject to WCI.2(g) accuracy requirements. This requirement has been removed.

One stakeholder stated that measurement of feedstock adds monitoring costs to the system without yielding any benefits toward quantification of GHG emissions or GHG reduction activities. WCI has limited this requirement to the method using feedstock mass balance, for which accurate feedstock measurements would be imperative.

4.5 Iron and Steel

One set of comments was received from the sole producer of direct reducing iron (DRI) in North America. This stakeholder explained the DRI process. This stakeholder noted that the WCI.150 method (i.e., Equation 150.4) implies that ALL natural gas used at DRI is transformed into CO2, which is not the case as explained above. Furthermore, use of equation 150.2, where the iron and steel production CO_2 emissions are calculated, would result in double counting of CO2 for the DRI process.

In response to comments from this stakeholder, equations 150.2 and 150.4 of WCI.150 (Iron and Steel Mfg.) have been modified to include terms specifically relating to the production and use of the DRI product. At plants where DRI is produced and converted to steel on-site, the new terms effectively cancel out. However, DRI is bought and sold as an intermediate product and has a carbon content; the revised approach ensures that emissions resulting from release of this carbon are accounted for against the steel-making process, where they actually take place.

4.6 Lime

The WCI considered the following suggested changes to the method for calculating GHG emissions from lime kilns submitted by the industry in the form of comments and proposed rule language and determined that they could be made without sacrificing the accuracy of the ERMR:

- Eliminate the requirement for bulk storage sampling. Lime plants should have the option to sample lime immediately after manufacture, which reduces the potential for lime to re-carbonate during storage (thus understating emissions).

- Eliminate the requirement to determine the oxide content of lime kiln dust (“LKD”) that is “not recycled to the kiln.” The lime manufacturing process does NOT recycle LKD to the kiln.
- Eliminate the requirement that monthly emission factors (EF) for lime and LKD reflect the oxide content of “uncalcined CaO.” “Uncalcined” material is limestone (CaCO3) that has not been converted to calcium oxide and, therefore, no CO_2 is emitted.
- Expand the weigh feeder terminology, as WCI did for the requirements to validate fuel consumption estimates, to permit the use of regulated truck/rail scales and other devices, which are more precise than weigh belts or hoppers, to measure the amount of lime and LKD produced.
- Allow reporting of emissions by lime and calcined byproduct/waste type, rather than by kiln.

The industry also asked that the ERMR require annual, rather than quarterly, calibration of measurement devices to prevent additional CO_2 emissions that result each time a kiln is shut down to calibrate measurement devices.

This requirement in the general provisions (previously WCI.2(g)), has been removed.

The industry requested that the ERMR permit annual, not monthly, computation of lime and LKD emissions to accommodate the annual estimation of LKD produced.

WCI has revised the methodology to require quarterly computation to be consistent with the proposed MRR.

Finally, the industry requested that the requirement to report process data used to calculate GHG emissions be eliminated.

The WCI declines to make this change. The ERMR consistently require industries to report the data used to calculate GHG emissions in order to allow Partner jurisdictions to properly assess and perform quality assurance on a facility's emissions report.

4.7 Pulp and Paper Manufacturing, Biomass

4.7.1 Pulp and Paper Manufacturing

Comments received regarding WCI.210, Pulp and Paper Manufacturing, related to the calculation method chosen for CO_2 emissions from recovery boilers and lime kilns, quantification of emissions from carbonate material use, recommendations based on the content of other programs, and emission factor selection. WCI appreciates the technical information provided in the comments and the support expressed by several commenters for changes made to WCI.210 in response to comments received on the draft ERMRs (January 6, 2009).

One commenter recommended the use of default carbonate content values for the calculation of emissions from the use of make-up chemicals. This recommendation has been accepted. To calculate these emissions, WCI.210 now includes the option of using supplier data, default factors provided in the method or sampling and analysis of the carbonate materials consumed.

Two commenters also argued against requiring carbon analysis of black liquor for the purpose of calculating process CO_2 emissions from recovery boilers and lime kilns. Monthly sampling and analysis for carbon content using ASTM D5373-08 is not inconsistent with the approach taken in the EPA's proposed rule. The proposed EPA method requires monthly analysis of black liquor, for higher heating value at kraft mills and for carbon content at sulfite and semi-chemical facilities. WCI determined that the use of a default black liquor carbon content value would not provide the level of accuracy required to properly assess emission levels.

Comments received also recommended the use of information, tools and calculation methods provided by other sources such as the National Council for Air and Stream Improvement, Inc. (NCASI). Two commenters encouraged WCI to contact NCASI regarding measurement and data collection. WCI considered information and quantification methods from other programs and sources when designing the ERMR, incorporating elements from these sources as appropriate for the type of emissions reporting required for a cap-and-trade program. As part of the long-term refinement of the rule, WCI will review input from new rules (such as the EPA rule) and specific bodies (in this case NCASI). We specifically invite feedback from NCASI on areas for possible improvement.

One commenter provided information about methane emissions from pulp and paper mill landfills. Landfills are currently not within the scope of the Essential Requirements, however WCI appreciates the referral to the NCASI report cited in the comment, as it may be useful for the WCI Offsets Committee.

4.7.2 Biomass

Comments were received regarding definitions related to biomass in WCI.9, the carbon neutrality of emissions from biomass and emission factors for biomass combustion.

Multiple comments recommended modification of WCI.9 definitions related to biomass to better account for certain fuels including black liquor and pulp fibers. In response to these comments, changes have been made to the definitions in WCI.9 for “biomass”, “biomass fuels” or “biomass-derived fuels”, “solid biomass fuel” and “waste-derived fuel”, including adoption of a modified version of the Environment Canada definition for biomass. However, changes to the definition of “waste-derived fuel” do not include recommendations from one commenter concerned about references to co-products and by-products as waste. The use of the term ‘waste’ by WCI does not imply the conventional meaning of waste, but indicates that a fuel could be derived from a co- or by-product of other processes.

Several commenters reiterated positions voiced in response to the draft ERMRs (January 6, 2009), relating to the carbon-neutrality of biomass. The May 7, 2009, Response to Comments document[1] provides rationale for the biomass reporting requirements, referring to the relevant Design Recommendation. Because the most recent comments received provide substantive arguments against the Design Recommendation, the Reporting Committee forwarded these comments to the Partners for their consideration.

Referring to the WCI.9 definitions, commenters also expressed concern about whether emissions from black liquor would be included in the 15,000 metric ton applicability exemption for “pure solid biomass fuel” (WCI.1(b)(2)(A)). As black liquor is not a pure solid fuel, it is not included in the applicability exemption.

Commenters also recommended that biogenic emissions be reported separately from fossil fuel-derived emissions. The ERMR do provide for separate reporting of CO_2 emissions from biomass combustion. The 15,000 metric ton exclusion is designed to exclude certain facilities from having to report at all. It does not address how biomass emissions are reported, when a facility is subject to the rule.

Adjustments have been made to the tabulated emission factors in WCI.20 in response to comments received which recommended certain alternate or additional emission factors. As noted in WCI.20, there are significant differences between both the black liquor and solid biomass emission factors published by the EPA and Environment Canada (as well as those submitted by industry associations). In lieu of recommending a single emission factor at this time (as there is no certainty as to which is most accurate) both are presented for information purposes. WCI is working with experts in the two federal agencies and other organizations to ascertain the most accurate emission factor to use for both metric and imperial representations of the rule.

[1] WCI, “Response to Stakeholder Comments and Final Draft Essential Requirements of Mandatory Reporting for the Western Climate Initiative” (May 7, 2009). Available at http://www.westernclimateinitiative.org/component/remository/Reporting-Committee-Documents/Response-to-Comments-on-Draft-Essential-Requirements-(5-7-09)/.

4.8 Refineries

Many comments on the draft ERMR (January 6, 2009) were received pertaining to refineries (WCI.200) and refinery fuel gas combustion (WCI.30). Please refer to the May 7, 2009, Response to Comments document (O104F21560.pdf) for a summary of those comments.

Based on the comments received on the January draft ERMR and on-going work by the Reporting Committee to investigate comments, clarify definitions and language, correct typographical and other errors, etc., changes made to the final requirements for refineries and refinery fuel gas are listed below. In some cases, further investigation of a comment did not result in a change to the ERMR, and in these cases the reasons to not make the change are also explained below.

- Addition of standard conversion factors consistent with industry standard temperature and pressure conditions. Molar volume conversion factors have been added to the equations 200-6 (process vents), 200-7 and 200-8 (asphalt production), 200-9 (sulfur recovery), and 200-11 and 200-13 (flares and other control devices).
- Fugitive emission calculation methods. An alternative provision for Canadian sources to use the method in CCME EPC-73E for leak detection was added, however, WCI did not change the requirement to use the component identification and counting methods found in Method 3 of CAPCOA (1999). Leak detection and repair (LDAR) programs generate screening values for a number of different components. The CAPCOA method then applies either emissions factors or correlation equations (choice based on the magnitude of the screening value). Owners or operators should all screen the gas containing components and then use the CAPCOA (or similar Canadian) calculation method, thus assuring consistent data. State program requirements will use a mixture of methods which does not generate consistent data. Furthermore, the proposed U.S. EPA default approach for estimating fugitive emissions (based on number of distillation columns, FCCUs, etc.), would not generate data with acceptable quality and comparability as needed for the cap-and-trade program.
- Continuous measurement of volumetric flow rate of exhaust gas leaving the catalyst regenerator. This requirement was removed.
- Definition and clarification of terminology. Definitions for flexigas, refinery fuel gas, and other terms have been added to WCI.9.
- Methods for determination of flaring emissions. A method has been added to allow calculation of CO_2 emissions based on the proposed U.S. EPA MRR, using flow meters, HHV, and carbon content to determine flare emissions.

Also, several comments were received from stakeholders as part of the draft final ERMR (May 7, 2009), and these are summarized below along with WCI responses.

One stakeholder requested another opportunity to review the refinery ERMR prior to finalizing. The WCI acknowledges that the refinery protocol is an important component of the

ERMR. In order to provide jurisdictions the opportunity to adopt regulations implementing the ERMR by the end of 2009 to apply to the 2010 reporting year, a final WCI version must be available by the end of June. There is therefore insufficient time to re-circulate this protocol for additional stakeholder comment. However, this does not preclude future revisions to the reporting requirements based on new data, improved methods, additional stakeholder comments, and other factors.

One commenter implied that the American Petroleum Institute (API) compendium of GHG methods should be adopted for use by the WCI. WCI points out that the ERMR relied heavily upon API Compendium-based methodologies, however, we have included different and more rigorous methods where these are deemed necessary to support a cap-and-trade program.

On commenter strongly recommended that the sampling requirements for refinery fuel gas combustion be reduced to once-per-day (from three times daily) for those facilities doing manual sampling. WCI points out that refinery fuel gas combustion is a significant source of combustion emission for petroleum refiners. Until data are available indicating that a relaxed sampling frequency is appropriate, the magnitude of this GHG sources requires a stringent methodology.

4.9 Fuel Suppliers

A number of comments addressed specific issues raised by the Design Recommendation to require reporting by residential, commercial and industrial fuel suppliers, such as the appropriate quantification methodology. WCI will defer addressing these comments until a proposal relating to this sector is developed.

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EMISSIONS QUANTIFICATION, AND SAMPLING, ANALYSIS AND MEASUREMENT

§ WCI.20 through § WCI.xx

[These Essential Requirements for Reporting include placeholder references to requirements for reporting GHG emissions from the combustion of residential, commercial and industrial fuels and electricity imports that have not yet been completed by the WCI and will not go into effect for the 2010 reporting year. WCI Partner Jurisdictions may omit these references until they amend their rules to include reporting requirements for these sectors.]

§ WCI.0 PURPOSE

This rule requires mandatory reporting and verification of greenhouse gas (GHG) emissions data by certain facilities that directly emit GHG, by importers of electricity, and by suppliers of fossil fuels. The GHGs that must be reported under this rule are carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFC), perfluorocarbons (PFC), and sulfur hexafluoride (SF_6).

§ WCI.1 APPLICABILITY

(a) The GHG emissions reporting requirements, and related monitoring, recordkeeping, and verification requirements of this rule apply to the owners and operators *[Each jurisdiction will select the specific terminology for the regulated persons in accordance with ~~their~~ its customary rule-writing practices]* of any facility that meets the requirements of paragraph (a)(1) of this section; and any fuel suppliers and electricity importers that meet the requirements of paragraph (a)(2), (a)(3), or (a)(4) of this section:

(1) Any facility that emits 10,000 metric tons CO_2e or more per year in combined emissions from one or more of the source categories listed in this paragraph in any calendar year starting in 2010.

[Please note that the quantification and monitoring methods for many of these source categories are currently being assessed. Only source categories for which adequate quantification methods exist will be included in the final WCI Essential Requirements for mandatory reporting.]

Adipic acid manufacturing
Aluminum manufacturing
Ammonia manufacturing [*still being assessed*]
Carbon dioxide transfer recipients [*still being assessed*]
Cement manufacturing
Coal mine fugitive emissions (active and abandoned)
Coal storage
Cogeneration ~~[still being assessed]~~
Electricity generation
Electronics Manufacturing [*still being assessed*]
Ferroalloy production [*still being assessed*]
General stationary fuel combustion
Glass Production and other uses of carbonates [*still being assessed*]
HCFC-22 production [*still being assessed*]
Hydrogen production
Industrial wastewater [still being assessed for some industries]
Iron and steel manufacturing
Lead production

Lime manufacturing
Magnesium production [still being assessed]
Natural gas transmission and distribution systems *[still being assessed]*
Nitric acid manufacturing *[still being assessed]*
Nonroad equipment at facilities *[still being assessed]*
Oil and gas production & gas processing *[still being assessed]*
Petrochemical production
Petroleum refineries
Phosphoric acid production *[still being assessed]*
Pulp and paper manufacturing
Refinery fuel gas
SF_6 from electrical equipment *[still being assessed]*
Soda ash manufacturing
Zinc production

(2) All importers of electricity. Importers of electricity include both retail providers and marketers that import electricity into the WCI region. *[This is preliminary language, pending definition of electricity importers by another WCI Committee.]*

(3) Any supplier that within the WCI region distributes transportation fuels in quantities that when combusted would emit 10,000 metric tons CO_2e per year or more in any calendar year starting in 2010. *[This is preliminary language, pending future determination of point of regulation for transportation fuels.]*

(4) Any supplier that distributes within the WCI region residential, commercial, and industrial fuels in quantities that when combusted would emit 10,000 metric tons CO_2e per year or more in any calendar year starting in 2010. *[This is preliminary language, pending future determination of points of regulation for these fuels.]*

(b) To calculate GHG emissions for comparison to the 10,000 metric ton CO_2e per year emission threshold in paragraph (a)(1) of this section, the owner or operator shall calculate annual CO_2e emissions, as described in paragraphs (b)(1) through (b)(4) of this section.

(1) Estimate the annual emissions of CO_2, CH_4, N_2O, HFC, PFC, and SF_6 in metric tons for each unit, process, activity, or operation for which emission calculation methodologies are provided in sections WCI.20 through WCI.XX. The GHG emissions shall be calculated using methodologies specified in each applicable section.

(2) For stationary combustion units, carbon dioxide emissions from the combustion of biomass fuels shall be included in the calculations, with the following exceptions:

(A) Until such time as [jurisdiction] has made a determination regarding the carbon neutrality of any biomass fuels, a maximum of 15,000 metric tons of carbon dioxide emissions from the combustion of pure solid biomass fuel may be excluded from calculation of GHG emissions for comparison to the 10,000 metric ton CO_2e per year emission threshold in paragraph (a)(1) of this section, provided that total GHG emissions including emissions from solid biomass fuel are less than 25,000 metric tons CO_2e.

(B) After such time as [jurisdiction] has made a determination regarding the carbon neutrality of any biomass fuels, the carbon dioxide emissions from the combustion of those fuels may be excluded from calculation of GHG emissions for determining whether the 10,000 metric tons CO_2e per year emission threshold in paragraph (a)(1) of this section has been met.

[A WCI Partner jurisdiction may, in its discretion, choose to require carbon dioxide emissions from the combustion of biomass fuel to be included in the determination of stationary combustion units that are required to report and may require that those emissions be reported separately from emissions from fossil fuels.]

~~*[WCI is also considering a deduction of biomass fuel combustion emissions that have occurred within a jurisdiction that has deemed them to be carbon neutral from the determination of whether the verification threshold has been met and from the scope of the verification.]*~~

(3) Sum the total facility emissions for each GHG and calculate the metric tons of CO_2e using equation 1-1 below.

$$CO_2e = \sum_{i=1}^{n} GHG_i \times GWP_i$$

Equation 1-1

Where:

CO_2e = Carbon dioxide equivalent, metric tons/year.
GHG_i = Mass emissions of each greenhouse gas emitted, metric tons/year.
GWP_i = Global warming potential for each greenhouse gas from Table WCI.10-1 of this regulation.
n = The number of greenhouse gases emitted.

(4) For purpose of determining if an emission threshold has been exceeded, any CO_2 that is captured for on-site use, on-site storage, or transfer off-site must be included in the emissions total.

(c) To calculate GHG emissions for comparison to the 10,000 metric ton CO_2e per year emission threshold for suppliers of transportation fuels in paragraphs (a)(3) of this section, the owner or operator shall follow the procedures of paragraphs (c)(1) through (c)(2) below:

(1) Calculate the total mass in metric tons per year of CO_2, CH_4, and N_2O that would result from the complete combustion or oxidation of all transportation fuels that are distributed within the WCI region. The mass of each GHG shall be calculated using any of the applicable methodologies specified in section WCI.XX [Transportation Fuels Combustion] of this rule.

(2) Sum the emissions of each GHG and calculate total metric tons of CO_2e using Equation 1-1 of this rule.

(d) To calculate GHG emissions for comparison to the 10,000 metric ton CO_2e per year emission threshold for suppliers of residential, commercial, and industrial fuels in paragraph (a)(4) of this section, the owner or operator shall follow the procedures of paragraphs (d)(1) and (d)(2) below:

(1) Calculate the total mass in metric tons per year of CO_2, CH_4, and N_2O that would result from the complete combustion or oxidation of all residential, commercial, and industrial fuels that are distributed within the WCI region. The calculation shall exclude any fuels that are supplied to facilities that are required to report GHG emissions under section WCI.1(a)(1). *[These accounting issues will be dealt with later in 2009 or in 2010.]* The mass of each GHG shall be calculated using any of the applicable methodologies specified in section WCI.XX [Residential, Commercial and Industrial Fuels Combustion] of this rule.

(2) Sum the emissions of each GHG and calculate total metric tons of CO_2e using Equation 1-1 of this rule.

(e) If the operations of a facility or fuel supplier that is subject to this rule change such that emissions fall below 10,000 metric tons CO_2e per year, then the following reporting requirements shall apply:

(1) If, prior to such emission reduction, the emissions report was subject to the verification requirements of this rule; then the owner or operator shall continue to submit emission reports until reported emissions are below 10,000 metric tons CO_2e per year for a minimum of 3 consecutive years. If reported emission are less than 10,000 metric tons CO_2 per year during 3 consecutive years, then the owner or operator shall be exempted from further reporting until CO_2e emissions again exceed 10,000 metric tons in any future calendar year.

(2) If, prior to such emission reduction, the emissions report was not subject to the verification requirements of this rule; then the owner or operator shall submit to the *[jurisdiction]* a signed statement certifying that emissions are less than 10,000 metric tons CO_2e during the prior year. After certifying that emissions are below 10,000 metric tons CO_2e per year for 3 consecutive years, the owner or operator shall be exempted from further reporting until CO_2e emissions again exceed 10,000 metric tons in any future calendar year.

(3) Notwithstanding the requirements of paragraphs (e)(1) and (2) of this section, a facility or fuel supplier that is a covered entity under the WCI cap-and-trade program must continue to submit annual emissions reports.

(f) Upon request by the [*jurisdiction*], owner or operator of any facility or fuel supply operation must submit a demonstration that emissions have not exceeded one or more of the applicability criteria specified in this section in any year since 2010. Such demonstration shall be provided to the [*jurisdiction*] within 20 working days of receipt of a written request.

~~*[WCI is considering whether this and other deadlines for responses provide sufficient time, and whether such deadlines should be standardized across requirements.]*~~

§ WCI.2 GENERAL GREENHOUSE GAS REPORTING REQUIREMENTS AND SCHEDULE

[Specific requirements of this section may change based on the future final design of the market~~ing~~ trading program.]

(a) General. Owners or operators that are subject to this rule must submit an annual GHG emissions report. Owners and operators must collect data; calculate GHG emissions; and follow the procedures for quality assurance, missing data, recordkeeping, and reporting as specified in these General Provisions and in each relevant section WCI.20 through WCI.XX of this rule.

[WCI jurisdictions have the flexibility during the first year of reporting, 2010, to allow the application of Best available data and methods (as defined in WCI.9) in circumstances in which owners and operators demonstrate that they require additional time, for example, to install equipment and institute procedures that are required for reporting.]

(1) A facility, fuel supplier, or electricity importer that commenced operation before January 1, 2010, must report emissions beginning in 2011 for GHGs emitted in calendar year 2010.

(2) A new facility, fuel supplier, or electricity importer that commences operation on or after January 1, 2010, must report emissions for the first calendar year in which the facility operates, beginning with the first operating month and ending on December 31 of that year. Each subsequent annual report must cover emissions for the calendar year, beginning on January 1 and ending on December 31.

(b) Reporting and Verification Schedule.

(1) Annual GHG emissions reports must be submitted to [*the jurisdiction*] by April 1 of each year for emissions in the previous calendar year.

(2) Reporters subject to the verification requirements of WCI.8, must complete their verification process, including submittal of a verification statement to [*the jurisdiction*], according to the following schedule:

(A) For reporting years 2010 through 2011, September 1 of the year following the reporting year.

(B) For reporting years 2012 and later, *[date to be determined]*.

(c) Submission of GHG Emissions Report. The annual GHG emissions report must be submitted to [*the jurisdiction*] in a format [*to be specified by each jurisdiction*].

(d) Simplified Emission Calculation Methods for De Minimis Sources. The owner or operator may elect to designate as de minimis one or more sources or pollutants that collectively emit no more than 3 percent of the facility's total CO_2e emissions, but not to exceed 20,000 metric tons CO_2e. The owner or operator may estimate emissions for these de minimis sources using alternative methods to those required to be used by this rule. If verification of the emissions report is required by this rule, then the selection of any alternative GHG calculation method is subject to the concurrence of the verification team that the use of such methods provides reasonable assurance that the emissions so designated do not exceed the applicable de minimis limits. The operator shall separately identify and include in the emissions data report the emissions from designated de minimis sources.

(e) To ensure accuracy of reported data and the ability to conduct audits and/or verifications of each emissions data report, the owner or operator shall establish and maintain data acquisition and handling activities that provide for the transparency and verifiability of emissions calculations and supporting information consistent with section WCI.4.

[As a means of assuring a smooth verification process and a positive verification opinion WCI jurisdictions may also require or advise in guidance materials that facilities have a full GHG inventory management plan.]

(f) GHG Emissions Report Revisions.

(1) The owner or operator shall maintain documentation to support any revisions made to a previously submitted annual GHG emissions report. Documentation for all revisions shall be retained by the operator for 7 years.

(2) If, after the verification deadline, a report subject to verification is found to contain an error, or accumulation of errors, greater than 5 percent of the total CO_2e emissions reported, the owner or operator shall revise and resubmit an annual GHG emissions report within 60 days of the finding. To the extent possible, the revised report must correct all identified errors. A revised report will be accepted only if verified according to WCI.8 and approved by [*the jurisdiction*]. [The jurisdiction] will send notification of approval or disapproval and an explanation of the reasons for any disapproval within 60 days of receipt of the revised report.

(3) If, after the report submittal deadline, a report not subject to verification is found to contain an error, or accumulation of errors, greater than 5 percent of the total CO_2e emissions reported, the owner or operator shall revise and resubmit an annual GHG emissions report within 30 days of the finding. To the extent possible, the revised report must correct all identified errors. A revised report will be accepted only if approved by [*the jurisdiction*]. [The jurisdiction] will send notification of approval or disapproval and an explanation of the reasons for any disapproval within 60 days of receipt of the revised report.

(4) An owner or operator that voluntarily chooses to correct errors of 5 percent or less in total CO_2e emissions reported may do so according to the following requirements:

(A) For reports subject to verification, a revised report will be accepted only if verified according to WCI.8 and approved by [*the jurisdiction*].

(B) For reports not subject to verification, a revised report will be accepted if approved by [*the jurisdiction*].

(g) Where this rule specifies a choice between use of a fuel-based or mass balance-based calculation or use of a continuous emissions monitoring system (CEMS) to calculate CO_2 emissions, the operator shall make this choice and continue to use the method chosen for all future emissions data reports, unless the use of the alternative calculation method is approved in advance by *[the jurisdiction]*.

§ WCI.3 CONTENTS OF THE GREENHOUSE GAS EMISSIONS REPORT

Each annual GHG emissions report shall contain the following information:

(a) Facility name, identification number, physical address, mailing address, and NAICS code.

(b) Reporting year.

(c) Date of report submittal.

(d) Total facility emissions aggregated from all applicable source categories in subparts WCI.20 through WCI.XX expressed in metric tons of CO_2e calculated using Equation 1-1 of section WCI.1, excluding emissions from CO_2 that is captured and CO_2 emissions from the combustion of biomass and biomass-derived fuels, which are reported separately.

(e) Total facility emissions of CO_2 from the combustion of biomass and biomass-derived fuels.

(f) Total annual mass of CO_2 captured for on-site use, on-site storage, or transfer off site, in metric tons.

(g) For applicable fuel supplier categories in subparts WCI.XX [Transportation Fuels Combustion] and WCI.XX [Residential, Commercial and Industrial Fuels Combustion], total CO_2e emissions aggregated from all specified fuels.

(h) Emissions from each applicable source category or fuel supplier category in subparts WCI.20 through WCI.XX, expressed in metric tons per year of CO_2, CH_4, N_2O, HFC, PFC, and SF_6. CO_2 emissions from the combustion of biomass and biomass-derived fuels shall be reported separately.

(i) For electricity importers, the information required by WCI.XX [Electricity Imports].

(j) Emissions and other data for individual units, processes, activities, and operations as specified for each source category in sections WCI.20 through WCI.XX of this rule.

(k) Emission factors developed or measured by the operator using approved source testing as provided under sections WCI.20 through WCI.XX. Emission factors shall be provided in units of emissions per amount of fuel consumed, where fuel is reported in the units specified in this regulation.

(l) Mass emissions from each designated de minimis source or pollutant, reported in metric tons per year of each GHG for which an alternative emission calculation method is used.

(m) Name and contact information including e-mail address and telephone number of the person primarily responsible for preparing and submitting the emissions report.

(n) [only applicable in United States jurisdictions] A signed and dated statement provided by the owner or operator, or their designated representative, certifying that the report has been prepared in accordance with this rule and that, subject to verification, the statements and information contained in the emissions data report are true, accurate, and complete to the best of their knowledge.

(o) [only applicable in Canadian jurisdictions] A statement signed and dated by the operator's representative, certifying that:

    (1) The operator's representative has examined the emissions report and ensured that it is complete and accurate; and

    (2) The emissions report has been prepared in accordance with this rule and that the statements and information contained in the emissions report are true and fair to the best of the knowledge of the operator's representative.

§ WCI.4 DOCUMENT RETENTION AND RECORD KEEPING REQUIREMENTS

(a) The operator shall establish and maintain procedures for document retention and record keeping. The operator shall retain all documents regarding the design, development and maintenance of the GHG inventory in paper, electronic or other usable format for a period of not less than 7 years following submission of each emissions data report. The retained documents, including GHG emissions data, shall be sufficient to allow for the verification of each emissions data report.

(b) Upon request by *[jurisdiction]*, the operator shall provide within 10 working days all documents and data used to develop an emissions data report.

(c) In addition to information submitted as part of the emissions data report, each operator shall retain, at a minimum, the following information, if applicable, for at least 7 years after the submission of the report:

(1) A list of all GHG sources (i.e., units, operations, processes, and activities) included in the emission estimates.

(2) All records and documents used to calculate emissions for each source, categorized by process and fuel or material type.

(3) Documentation of the process for collecting emissions data.

(4) Any GHG emissions calculations and methods used;

(5) All emission factors used for emission estimates, including documentation for any factors not provided in the rule.

(6) All input data used for emission estimates.

(7) Documentation of biomass fractions for specific fuels.

(8) All other data submitted to the [*jurisdiction*] under this rule, including the GHG emissions report.

(9) All computations made to gap-fill missing data.

(10) Names and documentation of key facility personnel involved in emissions calculating and reporting;

(11) Any other information that is required for the verification of the GHG emissions report.

(12) A log to be prepared for each reporting year, beginning January 1, documenting all procedural changes made in GHG accounting methods and changes to instrumentation for GHG emissions estimation.

(13) ~~The GHG inventory data audit trail, data control policies and procedures, and supporting documentation.~~Documentation of the data acquisition and handling activities required by WCI.2(e).

(d) For measurement based methodologies, the following information, if applicable, also must be retained for at least 7 years after the submission of the emissions data report:

(1) List of all emission points monitored.

(2) Collected monitoring data.

(3) Any ~~Q~~quality assurance and quality control information collected in accordance with the data acquisition and handling activities required by ~~for the~~ WCI.2(e) ~~data audit trail and data controls section of this rule~~.

(4) A detailed technical description of the continuous measurement system, including documentation of any findings and approvals by federal, State or local agencies.

(5) Raw and aggregated data from the continuous measurement system.

(6) A log book of all system down-times, calibrations, servicing, and maintenance of the continuous measurement system.

(7) Documentation of any changes in the continuous measurement system over time.

§ WCI.5 COMPLIANCE AND ENFORCEMENT

(a) Submission of false or misleading information to the *[jurisdiction]* or a verification body shall constitute a single, separate violation of the requirements of this article for each day after the information has been received by the Executive Officer or verification body. *[Partners must be able to enforce this provision in the absence of evidence of intent, e.g., strict or absolute liability, depending on the jurisdiction.]*

(b) Each violation of this rule shall constitute a single, separate violation for each day the violation continues.

§ WCI.6 INCORPORATION BY REFERENCE

The following documents are incorporated by reference into this rule. These materials are incorporated as they exist on the date this article is adopted.

(a) The following materials are available for purchase from the following addresses: American Society for Testing and Material (ASTM), 100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428-B2959; and the University Microfilms International, 300 North Zeeb Road, Ann Arbor, Michigan 48106:

(1) ASTM D240-02, (Reapproved 2007), Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter.

(2) ASTM D388-05, Standard Classification of Coals by Rank.

(3) ASTM D396-08, Standard Specification for Fuel Oils.

(4) ASTM D975-08, Standard Specification for Diesel Fuel Oils.

(5) ASTM D1250-07, Standard Guide for Use of the Petroleum Measurement Tables.

(6) ASTM D1826-94 (Reapproved 2003), Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter.

(7) ASTM Specification D1835-05 (2005).

(8) ASTM D1945-03 (Reapproved 2006), Standard Test Method for Analysis of Natural Gas by Gas Chromatography.

(9) ASTM D1946-90 (Reapproved 2006), Standard Practice for Analysis of Reformed Gas by Gas Chromatography.

(10) ASTM D2013-07, Standard Practice of Preparing Coal Samples for Analysis.

(11) ASTM D2234/D2234M-07, Standard Practice for Collection of a Gross Sample of Coal.

(12) ASTM D2502-04 (Reapproved 2002), Standard Test Method for Estimation of Molecular Weight (Relative Molecular Mass) of Petroleum Oils from Viscosity Measurements.

(13) ASTM D2503-92 (Reapproved 2007), Standard Test Method for Relative Molecular Mass (Relative Molecular Weight) of Hydrocarbons by Thermoelectric Measurement of Vapor Pressure.

(14) ASTM D2880-03, Standard Specification for Gas Turbine Fuel Oils.

(15) ASTM D3176-89 (Reapproved 2002), Standard Practice for Ultimate Analysis of Coal and Coke.

(16) ASTM D3238-95 (Reapproved 2005), Standard Test Method for Calculation of Carbon Distribution and Structural Group Analysis of Petroleum Oils by the n-d-M Method.

(17) ASTM D3588-98 (Reapproved 2003), Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels.

(18) ASTM Specification D3699-07, Standard Specification for Kerosene.

(19) ASTM D4057-06, Standard Practice for Manual Sampling of Petroleum and Petroleum Products.

(20) ASTM D4809-06, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method).

(21) ASTM Specification D4814-08a, Standard Specification for Automotive Spark-Ignition Engine Fuel.

(22) ASTM D4891-89 (Reapproved 2006), Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion.

(23) ASTM D5291-02 (Reapproved 2007), Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants.

(24) ASTM D5373-08, Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal and Coke.

(25) ASTM D5865-07a, Standard Test Method for Gross Calorific Value of Coal and Coke.

(26) ASTM D6316-04, Standard Test Method for the Determination of Total, Combustible and Carbonate Carbon in Solid Residues from Coal and Coke.

(27) ASTM D6866-06a, Standard Test Methods for Determining the Biobased Content of Natural Range Materials Using Radiocarbon and Isotope Ratio Mass Spectrometry Analysis.

(28) ASTM E1019-03, Standard Test Methods for Determination of Carbon, Sulfur, Nitrogen, and Oxygen in Steel and in Iron, Nickel, and Cobalt Alloys.

(29) ASTM E1915-07a, Standard Test Methods for Analysis of Metal Bearing Ores and Related Materials by Combustion Infrared-Absorption Spectrometry.

~~(30)ASTM CS-104 (1985), Carbon Steel of Medium Carbon Content.~~

~~(31)~~(30) ASTM D~~-~~7459-08, Standard Practice for Collection of Integrated Samples for the Speciation of Biomass (Biogenic) and Fossil-Derived Carbon Dioxide Emitted from Stationary Emissions Sources.

~~(32)~~(31) ASTM D6060-96(2001) Standard Practice for Sampling of Process Vents With a Portable Gas Chromatograph.

~~(33)~~(32) ASTM D 2502-88(2004)e1 Standard Test Method for Ethylene, Other Hydrocarbons, and Carbon Dioxide in High-Purity Ethylene by Gas Chromatography.

~~(34)~~(33) ASTM C25-06 Standard Test Method for Chemical Analysis of Limestone, quicklime, and Hydrated Lime.

(34) C1271-99(2006) Standard Test Method for X-ray Spectrometric Analysis of Lime and Limestone.

(35) C1301-95(2001) Standard Test Method for Major and Trace Elements in Limestone and Lime by Inductively Coupled Plasma-Atomic Emission Spectroscopy (ICP) and Atomic Absorption (AA).

~~(35)~~(36) UOP539-97 Refinery Gas Analysis by Gas Chromatography.

~~(36)~~(37) ASTM D5468-02 (Reapproved 2007).

(b) The following materials are available for purchase from the American Society of Mechanical Engineers (ASME), 22 Law Drive, P.O.Box 2900, Fairfield, NJ 07007-2900:

(1) ASME MFC-3M-2004, Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi.

(2) ASME MFC-4M-1986 (Reaffirmed 1997), Measurement of Gas Flow by Turbine Meters.

(3) ASME-MFC-5M-1985, (Reaffirmed 1994), Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters.

(4) ASME MFC-6M-1998, Measurement of Fluid Flow in Pipes Using Vortex Flowmeters.

(5) ASME MFC-7M-1987 (Reaffirmed 1992), Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles.

(6) ASME MFC-9M-1988 (Reaffirmed 2001), Measurement of Liquid Flow in Closed Conduits by Weighing Method.

(c) The following materials are available for purchase from the American National Standards Institute (ANSI), 25 West 43rd Street, Fourth Floor, New York, New York 10036:

(1) ISO 8316: 1987 Measurement of Liquid Flow in Closed Conduits- Method by Collection of the Liquid in a Volumetric Tank.

(2) ISO/TR 15349-1:1998, Unalloyed steel-Determination of low carbon content. Part 1: Infrared absorption method after combustion in an electric resistance furnace (by peak separation).

(3) ISO/TR 15349-3: 1998, Unalloyed steel-Determination of low carbon content. Part 3: Infrared absorption method after combustion in an electric resistance furnace (with preheating).

(d) The following materials are available for purchase from the following address: Gas Processors Association (GPA), 6526 East 60th Street, Tulsa, Oklahoma 74143:

(1) GPA Standard 2172-~~96~~09, Calculation of Gross Heating Value, Relative Density and Compressibility Factor for Natural Gas Mixtures from Compositional Analysis.

(2) GPA Standard 2261-00, Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography.

(e) The following American Gas Association materials are available for purchase from the following address: ILI Infodisk, 610 Winters Avenue, Paramus, New Jersey 07652:

(1) American Gas Association Report No. 3: Orifice Metering of Natural Gas, Part 1: General Equations and Uncertainty Guidelines (1990), Part 2: Specification and Installation Requirements (1990).

(2) American Gas Association Transmission Measurement Committee Report No. 7: Measurement of Gas by Turbine Meters (2006).

(f) The following materials are available for purchase from the following address: American Petroleum Institute, Publications Department, 1220 L Street, NW., Washington, DC 20005-4070:

(1) American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 3- Tank Gauging:

(A) Section 1A, Standard Practice for the Manual Gauging of Petroleum and Petroleum Products, Second Edition, August 2005.

(B) Section 1B-Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Tanks by Automatic Tank Gauging, Second Edition June 2001 (Reaffirmed, October 2006).

(C) Section 3-Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Pressurized Storage Tanks by Automatic Tank Gauging, First Edition June 1996 (Reaffirmed, October 2006).

(2) Shop Testing of Automatic Liquid Level Gages, Bulletin 2509 B, December 1961 (Reaffirmed August 1987, October 1992).

(3) American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 4- Proving Systems:

(A) Section 2-Displacement Provers, Third Edition, September 2003.

(B) Section 5-Master-Meter Provers, Second Edition, May 2000 (Reaffirmed, August 2005).

(4) American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 22- Testing Protocol, Section 2-Differential Pressure Flow Measurement Devices, First Edition, August 2005.

(g) The following material is available for purchase from the following address: American Society of Heating, Refrigerating and Air-Conditioning Engineers, Inc., 1791 Tullie Circle, NE., Atlanta, Georgia 30329: ASHRAE 41.8-1989: Standard Methods of Measurement of Flow of Liquids in Pipes Using Orifice Flowmeters.

(h) California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities, California Air Pollution Control Officers Association (CAPCOA) and California Air Resources Board (ARB), February 1999.

(i) Control of Emissions from Refinery Flares, Rule 118, South Coast Air Quality Management District, Amended November 4, 2005.

(j) U.S. EPA TANKS Version 4.09D, US Environmental Protection Agency, October 2005.

(k) Gas Processors Association (GPA) Standard 2261-00, Revised 2000.

§ WCI.7 DESIGNATED REPRESENTATIVE (ONLY APPLICABLE TO WCI JURISDICTIONS IN THE UNITED STATES)

(a) General. Each fuel supplier, electricity importer, and owner or operator of a facility that is subject to this rule, shall select a designated representative that is responsible for certifying and submitting GHG emissions reports under this reporting rule.

(b) Authorization of a Designated Representative. The designated representative of the facility shall be selected by a certificate of representation agreement that is signed by the designated representative and owners or operators of the facility. The designated representative must be an individual having responsibility for the overall operation of the facility or activity such as the position of the plant manager, operator of a well or a well field, superintendent, position of equivalent responsibility, or an individual or position having overall responsibility for environmental matters for the company.

(c) Responsibility of the Designated Representative.

(1) The designated representative of the facility shall represent and by any representations, actions, inactions, or submissions, legally bind each owner and operator in all matters pertaining to this rule.

(2) Each GHG emission report submitted under this rule must be signed by the designated representative and must contain the following certification statement: “I have been authorized to make this submission on behalf of the owners and operators of the facility (or supply operation, as appropriate). I certify under penalty of law that I have personally examined the information submitted in this document. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(d) Changing a Designated Representative. The designated representative may be changed at any time upon submission of a superseding certificate of representation. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous designated representative before time of the superseding certificate of representation shall be binding on the new designated representative and the owners and operators.

(e) Changes in Owners and Operators. In the event of any change in ownership of the facility, any new owner or operator shall be deemed to be bound by the representations, actions, inactions, and submissions of the designated representative of the facility until such time as the designated representative is changed.

(f) Certificate of Representation. A certificate of representation must be submitted to *[the jurisdiction]* and kept on location by the facility, fuel supplier, or electricity importer. The certificate shall include the following information:

(1) Identification of the facility, fuel supplier, or electricity importer for which the certificate of representation is submitted.

(2) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the designated representative.

(3) A list of the owners and operators.

(4) Certification statements that the actions of the designated representative with respect to this rule are binding on the owners and operators, and that the designated representative has the necessary authority to carry out duties and responsibilities on behalf of the owners and operators.

(5) The signature of the designated representative and owner(s) and operator(s), and the dates signed.

§ WCI.8 REQUIREMENTS FOR VERIFICATION OF GREENHOUSE GAS EMISSIONS DATA REPORTS AND REQUIREMENTS APPLICABLE TO EMISSIONS DATA VERIFIERS

[See separate document.]

§ WCI.9 DEFINITIONS

[See separate document.]

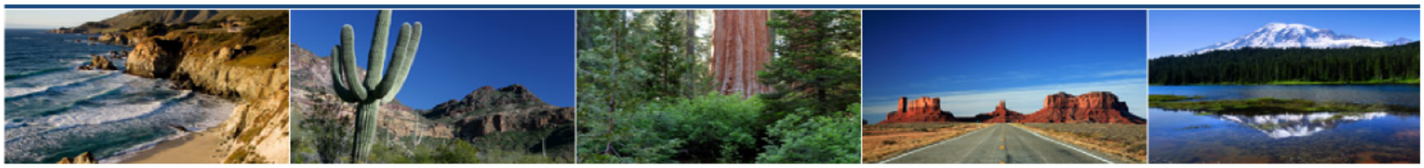
§ WCI.10 GLOBAL WARMING POTENTIALS

Owners and operators must use the global warming potential (GWP) values given in Table WCI.10-1 when converting emissions of greenhouse gases to metric tons of carbon dioxide equivalent (CO_2e), using Equation 1-1.

Table WCI.10-1. Global Warming Potential Factors for Greenhouse Gases

Common Name	Formula	Chemical Name	GWP
Carbon dioxide	CO_2		1
Methane	CH_4		21
Nitrous oxide	N_2O		310
Sulfur hexafluoride	SF_6		23,900
Hydrofluorocarbons (HFCs)			
HFC-23	CHF_3	trifluoromethane	11,700
HFC-32	CH_2F_2	difluoromethane	650
HFC-41	CH_3F	fluoromethane	150
HFC-43-10mee	$C_5H_2F_{10}$	1,1,1,2,3,4,4,5,5,5- decafluoropentane	1,300
HFC-125	C_2HF_5	pentafluoroethane	2,800
HFC-134	$C_2H_2F_4$	1,1,2,2-tetrafluoroethane	1,000
HFC-134a	$C_2H_2F_4$	1,1,1,2-tetrafluoroethane	1,300
HFC-143	$C_2H_3F_3$	1,1,2-trifluoroethane	300

HFC-143a	$C_2H_3F_3$	1,1,1-trifluoroethane	3,800
HFC-152	$C_2H_4F_2$	1,2-difluoroethane	43
HFC-152a	$C_2H_4F_2$	1,1-difluoroethane	140
HFC-161	C_2H_5F	fluoroethane	12
HFC-227ea	C_3HF_7	1,1,1,2,3,3,3- heptafluoropropane	2,900
HFC-236cb	$C_3H_2F_6$	1,1,1,2,2,3-hexafluoropropane	1,300
HFC-236ea	$C_3H_2F_6$	1,1,1,2,3,3-hexafluoropropane	1,200
HFC-236fa	$C_3H_2F_6$	1,1,1,3,3,3-hexafluoropropane	6,300
HFC-245ca	$C_3H_3F_5$	1,1,2,2,3-pentafluoropropane	560
HFC-245fa	$C_3H_3F_5$	1,1,1,3,3-pentafluoropropane	950
HFC-365mfc	$C_4H_5F_5$	1,1,1,3,3-pentafluorobutane	890
Perfluorocarbons (PFCs)			
Perfluoromethane	CF_4	tetrafluoromethane	6,500
Perfluoroethane	C_2F_6	hexafluoroethane	9,200
Perfluoropropane	C_3F_8	octafluoropropane	7,000
Perfluorobutane	C_4F_{10}	decafluorobutane	7,000
Perfluorocyclobutane	$c\text{-}C_4F_8$	octafluorocyclobutane	8,700
Perfluoropentane	C_5F_{12}	dodecafluoropentane	7,500
Perfluorohexane	C_6F_{14}	tetradecafluorohexane	7,400



§WCI.8 REQUIREMENTS FOR VERIFICATION OF GREENHOUSE GAS EMISSIONS DATA REPORTS AND REQUIREMENTS APPLICABLE TO EMISSIONS DATA VERIFIERS

Note: The verification requirements laid out in this section strive for consistency with ISO 14064-3[1] requirements and set forth a high standard for verification that will ultimately support a WCI cap and trade program. Due to differences in rulemaking procedures between jurisdictions, Supplement 1 provides supplemental text that jurisdictions must incorporate into either the jurisdiction's prescriptive rule language, replacing more general procedural language in Section WCI.8, or into enforceable guidance documents. There are notes in WCI.8 that direct readers to appropriate text in Verification Supplement 1 when applicable.

It ~~is imperative that~~would be ideal for all jurisdictions to enforce the same requirements and ~~have the same level of rigor and~~ have the same implementation processes for accreditation and verification to ensure that consistent accurate data exists throughout ~~to support a~~ the WCI regional program. Reporters and verifiers with operations throughout the WCI region will benefit from a consistent approach and such an approach would facilitate administration of the verification requirements by a central body or designee.

(a) Applicability and Scope.

(1) Except as provided in WCI.8(a)(2) through (4) ~~O~~owners or operators [Each jurisdiction will select the specific terminology for the regulated persons in accordance with their customary rule-writing practices] are required to obtain annual verification for a facility that emits 25,000 metric tons CO_2e or more per year in combined emissions from one or more of the source categories listed in WCI.1~~when the reported annual emissions of the operation subject to this rule are equal to or greater than 25,000 metric tons of CO_2e~~ in any calendar year starting ~~in~~ on or after 2010.

(2) When the operation of a facility, fuel supplier, or electricity importer subject to the requirements of this section is changed such that the operator has reported less than 25,000 metric tons of CO_2e emissions for a calendar year, the operator shall obtain verification of annual emissions reports for the lesser of three subsequent calendar years or for those years remaining in the current compliance period. If CO_2e emissions of a facility, fuel supplier, or electricity importer subject to the requirements of this section

[1] ISO (2006) ISO 14064-3: Greenhouse Gases-Part 3: Specification with guidance for the validation and verification of greenhouse gas assertions, March, 2006, International Organization for Standardization, Switzerland.

again exceed 25,000 metric tons in any calendar year the provisions of WCI.8(a)(1) apply.

(3) Carbon dioxide emissions from the combustion of biomass fuels shall be included in the determination regarding verification applicability, with the following exceptions:

(A) Until such time as [the jurisdiction] has made a determination regarding the carbon neutrality of any biomass fuels, a maximum of 15,000 metric tons of carbon dioxide emissions from the combustion of pure solid biomass fuel may be excluded from calculation of GHG emissions for comparison to the 25,000 metric ton CO_2e per year verification threshold in paragraph (a) of this section.

(B) After such time as [the jurisdiction] has made a determination regarding the carbon neutrality of any biomass fuels, the carbon dioxide emissions from the combustion of those fuels may be excluded from calculation of GHG emissions for determining whether the 25,000 metric tons CO_2e per year verification threshold in paragraph (a)(1) of this section has been met.

[Under Design Recommendation 1.3, carbon neutral biomass will be excluded from the cap-and-trade program. A WCI Partner jurisdiction, however, may, in its discretion, choose to require carbon dioxide emissions from the combustion of biomass fuel to be included in the determination of the verification threshold in order to obtain a complete inventory of the fuels being combusted in the jurisdiction.]

(4) Owners or operators may exclude carbon dioxide emissions from the combustion of biomass fuels that [jurisdiction] has deemed carbon neutral from the scope of verification.

[A WCI Partner jurisdiction may, in its discretion, choose to require carbon dioxide emissions from the combustion of biomass fuel to be included in the scope of verification.]

~~(3)~~(5) Notwithstanding WCI.8(a)(~~1~~2) and (~~2~~3), any facility, fuel supplier or electricity importer ~~included as a covered entity under the WCI~~subject to a cap-and-trade program for CO_2e emissions established by [the jurisdiction] shall obtain verification of reported annual emissions.

~~*[WCI is considering a deduction of pure biomass fuel combustion emissions that have occurred within a jurisdiction that has deemed them to be carbon neutral from the determination of whether the verification threshold has been met and from the scope of the verification when one is required.]*~~

(b) Requirements for Annual Verification of Emissions Data Reports.

(1) Verification bodies shall conduct verification processes and design verification procedures to determine whether there is a reasonable level of assurance for each separate emissions data report every year of the verification cycle. The verification team shall find that there is a reasonable level of assurance for an emissions data report if the report

(A) contains no material misstatement; and

(B) conforms to the requirements of this article.

(2) The verification body must provide verification services in compliance with WCI.8.

~~(1)~~(3) Facility owners or operators, fuel suppliers, and electricity importers required to obtain annual verification shall be subject to full verification requirements in the first year that verification is required for an emissions data report. Upon completion of a positive verification statement under full verification requirements, the facility owner or operator, fuel supplier, or electricity importer may be eligible for two years of less intensive verification services as described in section WCI.9. This cycle may be repeated in subsequent three-year cycles; however, full verification requirements shall apply at least once every three years.

~~(2)~~(4) Facility owners or operators, fuel suppliers, and electricity importers required to obtain annual verification will be required to obtain full verification services if any of the following apply:

(A) ~~Change~~ There has been a change in the verification body from the previous year; or

(B) A verification body issued an adverse verification statement for that facility's previous year's emissions data report.~~;~~

(c) Accreditation Requirements for Verification Bodies.

(1) The accreditation requirements specified in this subsection shall apply to all verification bodies~~,~~ that wish to provide verification services under this rule.

(2) A verification body is qualified to conduct verification services for the WCI if

(A) it has demonstrated knowledge of the WCI reporting requirements; and ~~if it is:~~

~~(A)Accredited by the California Air Resources Board under Title 17, California Code of Regulation, section 95132, or~~

(B) it is ~~A~~accredited to ISO 14065 through a program developed under ISO 17011 by an accreditation body that is a member of the International Accreditation Forum.

[Note the details of the WCI's specific accreditation process for verification bodies (which has yet to be developed) will be consistent with ISO 14065 through an accreditation program that will developed under ISO 17011 and will include demonstrated knowledge of the WCI reporting requirements. The WCI will explore additional accreditation requirements and/or other criteria for individual lead verifiers, general verifiers, and/or sector specialists.]

~~(C)The WCI will only grandfather in existing verification bodies that meet the requirements of WCI.8(c)(2)(A)-(B) if they are accredited by December 31, 2012 to provide verification services for programs other than the WCI.~~

(3) Prior to January 1, 2013, accreditation by the California Air Resources Board under Title 17, California Code of Regulation, section 95132, may be substituted for the accreditation required under WCI.8(c)(2)(B).

(d) Requirements for Verification Services. ~~Verification services shall be subject to the following requirements.~~ The following verification services must be provided for each emissions data report.

(1) As part of the verification services, the verification team shall review documents submitted, assess risks of a material misstatement, develop a verification plan (that includes a sampling plan), evaluate the emissions data report against the verification

requirements, and assess the materiality of errors, omissions and misstatements identified.

(2) The verification team shall request any information and documents needed for verification services. Such information shall include, but is not limited to original records and supporting data for the emissions data report.

~~(e)Level of Assurance. Verification bodies shall conduct verification processes and design verification procedures to provide a reasonable level of assurance for each separate emissions data report every year of the verification cycle.~~

~~(f)~~(e) A verification team must include the following:

(1) a Lead Verifier;

(2) an Independent Peer Reviewer;

(3) any subcontractor elected to provide verification services under WCI.8(f).~~at least one sector specialist with demonstrated knowledge and specific skills, if required per WCI [TBD];~~

~~*[Note, the WCI will identify industrial sectors where a subject matter expert must be part of the verification team as part of development of its accreditation requirements.]*~~

~~(g)~~(f) Subcontracting. The following requirements shall apply to any verification body that elects to subcontract verification services.

(1) The primary verification body must assume full legal responsibility for verification services performed by subcontracted verifiers or verification bodies.

(2) A verification body or verifier acting as a subcontractor to the primary verification body will not further subcontract that same work to another firm or individual.

(3) A~~ny~~ verification body or verifier acting as a subcontractor is ~~bound~~ subject to all Conflict of Interest requirements in Section WCI.8(~~h~~g).

(4) A verification body or verifier acting as a subcontractor ~~M~~must be identified by the primary verification body as part of the verification team.

~~(h)~~(g) Conflict of Interest Requirements for Verification Bodies. The conflict of interest provisions of this section shall apply to the verification body, entities related to the verification body, and the verification team accredited according to the requirements of the WCI to perform verification services for the WCI program. Member for purposes of this section means any employee or subcontractor of the verification body or entities related to the verification body. Member also includes any individual with a majority equity share in the verification body or entities related to the verification body.

(1) Prior to a jurisdiction accepting a verification statement, and prior to a jurisdiction accepting the associated emissions report for consideration for approval, the AVA must determine that the verification body has a low potential for conflict of interest as described under WCI.8(g)(6). To inform this determination by the AVA, ~~commencing verification services for an owner or operator, a verification body must first be authorized in writing by [*(e.g. WCI regional administrative body or other organization to be determined) or jurisdiction in which the entity reports* (TBD)]~~the AVA ~~to provide~~

~~verification services. To obtain authorization the verification body shall submit to [TBD]~~a self-evaluation of the potential for any conflict of interest that the verification body, entities related to the verification body, and members of the verification team, including subcontractors, may have with the owner or operator or their related entities for which ~~it will perform~~ verification services will be or have been provided shall be submitted to the AVA. This self-evaluation must include an evaluation of any threats to the verification body's independence including: [*note: a standardized Conflict of Interest Assessment form will be developed for the WCI*]

[To facilitate timely determinations of conflict-of-interest potential, and to reduce the risk of finding medium or high conflict-of-interest potential after verification services have been initiated, it is recommended that jurisdictions require that the self evaluations be submitted and evaluated by the AVA prior to the initiation of verification services. A jurisdiction may elect to allow verification services to commence prior to the determination of the conflict-of-interest potential by the AVA.~~A jurisdiction may elect to require the reporting entity to submit the conflict-of-interest along with the verification statement required under WCI.2(b)(2), rather than requiring its submission before commencement of verification services, as provided in WCI.8(g)(1).~~]

(A) Threats created by the reporting operation offering inducements to the verification body, subcontractors or verification team members for a positive opinion~~,~~;

(B) Threats created by members of the verification body, verification team members, subcontractors, or family of subcontractors or team members having a financial interest in the reporting operation or its operator~~,~~;

(C) Threats created by members of the verification body reviewing work of the verification body, subcontractors, members of the verification team, or related companies, including but not limited to any situation where the body, subcontractors, team members or companies have provided services related to greenhouse gases~~,~~;~~:~~

(D) Threats created by members of the verification body, verification team members, or subcontractors having a close relationship with the reporting operation, such that they might become too sympathetic to the interests of the reporting operation~~,~~; ~~or~~and

(E) Threats created by members of the verification body, verification team members, or subcontractors being deterred from acting objectively or exercising professional skepticism by threats, actual or perceived, from the reporting operation.

(2) The verification body shall deem the potential for conflict of interest to be low if

(A) No threats as listed in WCI.8(~~h~~g)(1) exist, and

(B) Any non-verification services provided by ~~all members of~~ the verification body ~~the verification team~~ to the owner or operator within the last three years are valued at less than ~~[percent TBD]~~five percent of the verification body's annual revenue in each of those years.

(3) The verification body shall deem the potential for conflict of interest to be high if threats as listed in WCI.8(~~h~~g)(1)(A) or (E) exist~~, unless it is a potential for individual~~

~~conflict of interest as provided in section WCI.8((h)(5) and may be mitigated per section WCI.8(h)(3)(B)~~.

[A jurisdiction may expand the list of high threats (i.e. un-mitigatable conflicts) with the items included in paragraph 2 of the Conflict of Interest section of Supplement 1 below.]

(4) The verification body shall deem the potential for a conflict of interest to be medium if the potential for a conflict of interest is not deemed to be either ~~high or low~~low or high as specified in sections WCI.8~~(h)(1)-(2)~~(g)(2)-(3).

~~(5)~~If a verification body deems the potential for conflict of interest to be medium and wishes to provide verification services for the owner or operator, then

~~(A)~~(5) the verification body shall submit, in addition to the ~~Conflict of Interest Assessment~~ self-evaluation~~form~~, a plan to avoid, neutralize, or mitigate the potential conflict of interest situation.

~~(B)the verification body may submit a plan to neutralize a high individual conflict of interest assessed under WCI.8(h)(1)(B).~~

~~(C)the [TBD] shall evaluate the conflict of interest mitigation plan and determine whether verification services may proceed, as provided in section WCI.8(h)(4).~~

(6) Conflict of Interest Determinations. The ~~*[TBD]*~~ AVA shall review the self-evaluation submitted by the verification body and determine ~~whether~~ the verification body's potential conflict of interest in ~~is authorized to~~ performing verification services for the owner or operator.

[In addition to the AVA determination, a jurisdiction may elect to conduct audits of conflict of interest submissions for compliance verification and enforcement purposes.]

(A) The ~~*[TBD]*~~AVA shall notify the verification body in writing when the conflict of interest evaluation information submitted under section WCI.8(~~h~~g)(1) is deemed complete. Within ~~*[Number of days TBD]*~~ 45 days after ~~of~~ deeming the evaluation information complete, ~~*[TBD]*~~the AVA shall determine the conflict-of-interest potential ~~whether the verification body is authorized to proceed with verification~~ and shall ~~so~~ notify the verification body or owner or operator if the potential conflict of interest is determined to be medium or high.

(B) If ~~*[TBD]*~~the AVA determines the verification body or any member of the verification team has any threats specified in section WCI.8(~~h~~g)(1), ~~*[TBD]*~~the AVA shall find a high potential conflict of interest and verification services may not proceed.

(C) If ~~*[TBD]*~~the AVA determines that there is a low potential conflict of interest prior to the verification services being provided, verification services may proceed.

(D) If ~~*[TBD]*~~the AVA determines that the verification body and verification team have a medium potential for a conflict of interest, ~~*[TBD]*~~the AVA shall evaluate the conflict of interest mitigation plan and may request additional information from the applicant to complete the determination. In determining potential conflict of interest~~whether verification services may proceed~~, ~~*[TBD]*~~the AVA may consider factors including, but not limited to, the nature of previous work performed, the current and past relationships between the verification body and its subcontractors with the owner or operator, and the cost of the verification services to be performed. ~~If *[TBD]*t~~The AVA will determine~~s~~ ~~that~~ whether these factors when considered in combination with the mitigation plan demonstrate a low level of potential conflict of interest~~,~~ or a high level. If the AVA determines that there is a low potential conflict of interest prior to the verification services being initiated, verification services may proceed. If a high potential is determined prior to verification services being initiated, verification services may not proceed. If a high potential is determined after verification services have been initiated, the verification statement shall not be accepted.~~then *[TBD]*~~~~the AVA~~ ~~will authorize the verification body to provide verification services~~.

(7) Monitoring Conflict of Interest Situations.

(A) After commencement of verification services, the verification body shall monitor and ~~–~~immediately make full disclosure in writing to ~~*[TBD]*~~the AVA regarding any potential for a conflict of interest situation that arises. This disclosure shall include a description of actions that the verification body has taken or proposes to take to avoid, neutralize, or mitigate the potential for a conflict of interest.

(B) The verification body shall monitor arrangements or relationships that may be present for a period of one year after the completion of verification services. During that period, within 30 calendar days of any change in arrangements or relationships with the owner or operator for which the verification body has provided verification services that may create a medium or high threat of conflict of interest, the verification body shall notify ~~*[TBD]*~~the AVA of the change and provide a description of the nature of the change. The AVA will make a conflict of interest determination under WCI.8(g)(6).

(C) The verification body shall report to ~~*[WCI Regional Body or jurisdiction TBD]*~~the AVA any changes in its organizational structure, including mergers, acquisitions, or divestitures~~,~~ that may have created a medium or high threat of conflict of interest for one year after completion of verification services within 30 days and submit an evaluation of how the change(s) impacts the potential for conflict of interest.

(D) ~~*[TBD]*~~The AVA may invalidate a verification finding if a medium or high ~~potential~~ threat of a conflict of interest has arisen for the verification body or any member of the verification team and, in the case of a medium threat, the threat has not been adequately mitigated. In such a case, the owner or operator shall be provided 180 calendar days to have their emissions report verified by a different verification body.

(E) If the verification body or its subcontractor(s) are found to have violated the conflict of interest requirements of this section, ~~*[Accreditation Body TBD]*~~the AVA may rescind its accreditation for any appropriate period of time ~~as provided in section WCI.8(aaw)~~. Additionally, ~~(WCI Regional Body *[TBD]*~~the AVA may separately ~~rescind~~ revoke its recognition of an accredited Verification Body under WCI.8(w). *[~~TBD –~~The WCI intends to develop more detailed accreditation requirements in the future.]*~~.~~

~~(i)~~(h) Notice of Verification Services. Prior to commencing verification services for a facility owner or operator, fuel supplier, and electricity importer, the verification body shall submit a notice of verification services to the ~~*[TBD]*~~ AVA. Verification activities shall not proceed for 15 business days or until the verification body receives written approval to proceed from the ~~*[TBD]*~~AVA, whichever is earlier. If the ~~*[TBD]*~~AVA does not respond to the verification body within 15 business days, the verification body may begin to conduct verification activities.

[The NOVS form will be standardized across WCI and developed later~~, ~~. ~~Supplement will include some minimum information to be contained in NOVS~~]

~~(j)~~(i) Verification Plan.

(1) Accounting for requirements set by WCI.8, the verification plan shall document:

(A) the scope of the verification;

(B) the level of assurance;

(C) the verification standard;

(D) the verification criteria;

(E) the objectives of the verification;

(F) the timing of the verification, including site visits;

(G) the nature of the communications required;

(H) the resources required to conduct the verification, including the role of verification team members;~~,~~ and

(I) the nature, timing and extent of the verification procedures, including the sampling plan.

(2) The verification body shall retain the verification plan in paper, electronic, or other format for a period of not less than seven years following the submission of each verification statement.

~~(k)~~(j) Site visits. In years for which full verification services are required under WCI.8(b)(3), at least one member of the verification team shall at a minimum make one onsite site visit to each facility or fuel supply location *[Note that exact location of fuel supplier site visits remains TBD]* for which an emissions data report is submitted. ~~If the verification team requires a sector specialist as required (TBD through accreditation), that specialist must participate in the onsite visit(s).~~ The verification team member(s) shall also conduct an onsite visit of the headquarters or other location of central data management, if different from the facility or fuel supply location, when the owner or operator is an electricity importer.

~~(l)~~(k) Owners or operators shall make available to the verification team all information and documentation used to calculate and report emissions, electricity transactions, and other information required under this rule, as applicable.

~~(m)~~(l) As applicable for electricity importers, the verification team shall review electricity transaction records, including receipts of power attributed to the Northwest or Southwest region as verifiable via North American Electric Reliability Corporation (NERC) E-Tags, settlements data, or other information as confirmation of the region of origin. [*Note that this procedure is subject to change pending WCI Electricity Committee review.*]

~~(n)~~(m) Data Checks. To determine the reliability of the submitted emissions data report, the verification team shall use data checks as ~~described~~ defined in WCI.9~~, Definitions~~. Verifiers will use their professional judgment in determining how many data checks are needed to provide a reasonable level of assurance.

~~(o)~~(n) Emissions Data Report Modifications. If as a result of review by the verification team and prior to completion of a verification statement the owner or operator chooses to make improvements or corrections to the submitted emissions data report, a revised emissions data report must be submitted to [the jurisdiction] as specified by section WCI.~~2~~8(~~f~~q). The owner or operator shall maintain documentation to support any revisions made to the initial emissions data report. Documentation for all emissions data report submittals shall be retained by the operator for seven years pursuant to section WCI.4.

(o) Materiality and Conformance Assessment Criteria. The verifier shall determine if the annual emissions report is prepared in such a way that it ~~conforms to the verification criteria~~satisfies WCI.8(b)(1).

(1) ~~To verify that the emissions data report~~A verification team shall determine that an emission data report contains a ~~is free of~~ material misstatement, if either of the following is true:

(A) Based on the verification team's ~~shall make its~~ own determination of the level of emissions ~~checked~~ subject to verification based on the sampling plan, ~~and shall determine whether there is reasonable assurance if the individual or aggregate effect of any errors, omissions or misrepresentation could have resulted in an underestimation or overestimation of emissions by more than five percent of the facility's, fuel supplier's, or electricity importer's total reported CO2e emissions.~~the verification team concludes that total reported emissions are less than 95 percent accurate using the following equation:

$$PA = 100 - (SOU/TRE * 100)$$

Where:

PA	=	Percent accuracy
SOU	=	The net result of summing overstatements and understatements resulting from errors, omissions and misreporting
TRE	=	Total reported emissions

(B) The individual or aggregate effect of one or more errors, omissions or misstatements identified in the course of verification make it probable that the judgment of a reasonable person regarding the total reported emissions would have been changed or influenced by the error, omission or misrepresentation.

(2) To assess conformance with this rule the verification team shall review the methods and factors used to develop the emissions data report for adherence to the requirements of this rule.

(3) The verification team shall keep a log of any issues identified in the course of verification activities that may affect determinations of material misstatement and nonconformance, and how those issues were resolved.

~~(q)~~(p) Completion of verification services shall include:

(1) Verification Statement. Upon completion of the verification services ~~specified in~~ required by ~~sections~~ WCI.8~~(d)(j) (s)~~, the verification body shall complete a verification statement for each emissions data report, and provide that statement to the owner or operator and [the jurisdiction or other body] according to the schedule specified in section WCI.2(b). Before that statement is completed, the verification body shall have the verification services and findings of the verification team independently reviewed and approved by an Independent Peer Reviewer.

(2) The verification body shall provide either a positive or adverse verification statement to the reporter and to the AVA *[~~the jurisdiction or other central body (~~alternatively, this could be the reporter's responsibility to submit the statement to the ~~jurisdiction~~AVA~~)~~]* based on its findings during the verification process.

(3) The lead verifier in the verification team shall attest on the verification statement that the verification team has carried out all verification services as required by this rule, and the Independent Peer Reviewer shall attest to his or her independent review on behalf of the verification body and his or her concurrence with the verification findings. If the Independent Peer Reviewer does not determine that ~~that~~ the verification team has carried out all verification services as required by the rule or if the Independent Peer Reviewer rejects the verification team's findings, then the verification body cannot issue a positive verification statement.

(4) The verification body shall provide to the owner or operator a detailed verification report. The verification report shall at minimum include the detailed comparison of the data checks with the submitted emissions data report, errors, omissions and misstatements identified during the course of the verification, any corrections made to the original annual emissions report as a result of the verification, and observations about the data management systems that are connected to the errors, omissions and misstatements identified, as well as any qualifying comments on findings during verification services. The detailed verification report shall be made available to [the jurisdiction] upon request.

~~(r)~~(q) Prior to the verification body providing an adverse verification statement ~~to [the jurisdiction]~~pursuant to WCI.8(p)(2), the owner or operator shall be provided at least 14 working days to modify the emissions data report to correct any material misstatement or nonconformance found by the verification team. The modified report and verification statement must be submitted to [the jurisdiction] before the applicable verification deadline, unless the operator makes a request to [the jurisidiction*]* as follows:

~~(s)~~(1) If the owner or operator and the verification body cannot reach agreement on modifications to the emissions data report that result in a positive verification statement, the operator may petition *~~[TBD]~~*the AVA to make a final decision as to the verifiability of the submitted emissions data report.

~~(1)~~(2) If ~~*[TBD]*~~the AVA determines that the emissions data report does not meet the standards and requirements specified in this ~~rule~~ article, the owner or operator shall have the opportunity to submit within 60 calendar days of the date of this decision *[Note that this time frame may need to be changed pending details of cap-and-trade system design and needs.]* any emissions data report revisions that address ~~*[TBD's]*~~the AVA's determination, for re-verification of the emissions data report. In re-verifying a revised emissions data report, the verification body and verification team shall be subject to the requirements in section WCI.8(q)-(s).

~~(2)~~(3) Upon provision of the verification statement to [the jurisdiction], the emissions data report shall be considered final and no changes shall be made except as provided in section WCI.~~2~~8(~~(f~~n) or (q). All verification requirements of this rule shall be considered complete upon provision of the verification statement.

~~(t)~~(r) In addition to initiating WCI's dispute resolution process, the operator and verification body must inform the applicable accreditation body of the dispute.

~~(u)~~(s) The ~~*[TBD]*~~AVA may make void the positive verification statement submitted by the verification body if:

(1) The ~~[TBD]~~AVA finds a high level of conflict of interest existed between a verification body and an owner or operator; or,

(2) An emissions data report that received a positive verification statement fails an audit by ~~*[TBD*~~]the AVA.

~~(v)~~(t) Upon request by ~~*[TBD]*~~the AVA, the owner or operator shall provide the data used to generate an emissions data report, including all data available to a verification body~~verifier in the conduct of verification services~~. ~~*[TBD]*~~The AVA may also review the full verification report given by the verification body to the owner or operator. The full verification report shall be provided to the ~~*[TBD]*~~AVA upon request.

~~(w)~~(u) Upon written notification by the ~~*[TBD]*~~AVA, the verification body shall make itself available for a verification services audit.

~~(x)~~(v) Duration of verification services by one verification body. Facility owners or operators, fuel suppliers, or electricity importers subject to annual verification shall not use the same verification body for a period of more than six consecutive years. If a facility owner or operator, fuel supplier, or electricity importer is required or elects to contract with another verification body, they may contract verification services from the previous verification body only after not using the previous verification body for at least three years. If a verification body or verification team member has been providing verification services for ~~a [operator/owner]~~an owner or operator in a greenhouse gas reporting or reductions program other than ~~WCI~~ [the jurisdiction's] within the previous three years, those years of services will count towards the six consecutive year limit in ~~the WCI~~this section.

~~(y)~~(w) ~~Suspension of Verification Bodies~~Revocation of Recognition. A jurisdiction may review, and for good cause, work to revoke or modify the accreditation status of a ~~WCI~~ recognized verification body. If a ~~WCI~~ recognized verification body is suspended in any other mandatory or voluntary GHG reporting or trading program, that verification body will not be allowed to provide any verification services ~~under the WCI~~ until that suspension ends. If a ~~WCI~~ recognized verification body has ~~their~~ its ~~verification body~~ accreditation revoked under any other mandatory or voluntary GHG reporting or trading program, that verification body will no longer be allowed to provide verification services under WCI.8 until ~~they are~~it is reaccredited.

~~NEW OR REVISED DEFINITIONS OF TERMS USED IN WCI.8 ARE SHOWN IN ATTACHMENT 1, GENERAL PROVISIONS, SECTION WCI.9.~~

Verification Supplement 1

Note: the additional content in this Supplement must either be included in regulatory text in the appropriate subsections of WCI.8 or enforceable guidance documents by jurisdictions. The language in this section provides further explanation of items required in WCI.8 or alternative, more prescriptive language of those requirements.

Preliminary Activities and Verification Plan

The verification team shall discuss with the owner or operator the scope and objective of the verification services and obtain information from the owner or operator necessary to develop a verification plan. Such information shall include but is not limited to:

- Information to allow the verification team to develop a general understanding of facility or entity boundaries, operations, emissions sources, electricity transactions, as applicable;
- Information about the data management system used to track GHG emissions, electricity transactions, and other required measurement data as applicable;
- Information regarding the training or qualifications of personnel involved in developing the GHG emissions data report;
- Description of the specific methodologies used to quantify and report GHG emissions, electricity transactions, and other required data as applicable;
- Records of measured data related to emissions and operations for the prior and current period;
- Inventory of sources and their associated emissions for the reporting period, and
- Any prior verification reports, if applicable.

~~(A)~~
~~(B)~~In developing the verification plan, the verifier shall:

- Gain an understanding of the organization and the process that emit greenhouse gases;
- Conduct a risk assessment to evaluate inherent, control and detection risk;
- Conduct preliminary analytical testing to identify anomalies in the data;
- Conduct a sensitivity analysis to assess the relative contribution of each source in the inventory to the reported annual emissions, and
- Consider any other relevant developments at the facility, in the regulations, or legal environment.

Sampling Plan

As part of the verification procedures, the verification team shall develop a sampling plan that, when combined with the other verification procedures, provides sufficient and appropriate evidence to allow the verifier to arrive at a conclusion. The sampling plan shall be designed to achieve the specified verification objective. The sample plan shall consider:

- Statistical versus non-statistical approaches
- Design of the sample, including the population characteristics
- Stratification (categorization of population into subgroups)
- Emission weighted selection
- Sample size

- Sample selection

As relevant information becomes available during the course of verification activities, the verification team must modify the sampling plan as necessary to address potential issues emerge of material misstatement or nonconformance with the requirements of this rule.

Data Checks

The verification team conducts data checks throughout the verification process and shall focus first on the largest and most uncertain estimates of emissions and electricity transactions.

- In establishing the verification plan, the verification team shall use professional judgment to determine the number of data checks required for the team to conclude with reasonable assurance whether the reported emissions and transactions are free of material misstatement and the emissions data report otherwise conforms to the requirements of this rule.
- The verification team shall choose emissions sources, and electricity transactions data as applicable, for data checks based on their relative sizes and risks of material misstatement as indicated in the verification plan;
- The verification team, through the conformance assessment, shall ensure that the appropriate methodologies and emission factors have been applied for the emissions sources and electricity transactions for sampled data covered under sections WCI.20 through WCI.XX;

Site Visits

During the site visit, the verification team member(s) shall conduct the following:

- Observe whether all sources at the site are represented in the emissions report as specified in sections WCI.20 to WCI.XX as applicable to the owner or operator.
- Assess whether the source inventory is identified, categorized, and reported appropriately. Collect evidence as to explanations for data anomalies identified in the verification plan.
- Understand the data trail used by the owner or operator to measure, quantify, and report greenhouse gas emissions and, when applicable, electricity transactions.
- Understand and evaluate the associated data controls used by the owner to ensure the completeness and accuracy of the data

Materiality Assessment

In assessing whether misstatements are material, the verification team shall determine whether the total reported emissions are at least 95 percent accurate using the following equation:

Percent accuracy = 100 – (sum of (errors, omissions, misreporting) * 100 / (total reported emissions))

To assess conformance with this rule the verification team shall review the methods and factors used to develop the emissions data report for adherence to the requirement of this rule. The verification team shall keep a record of any errors, omissions or misstatements identified in the course of verification activities that may affect determinations of material misstatement and nonconformance, and how those issues were resolved.

Conflict of Interest (*could replace more general procedural language in Section WCI.8*)

(1) Conflict of Interest Submittal Requirements for Accredited Verification Bodies.

(A) Before the start of any work related to providing verification services to an owner or operator, a verification body must first be authorized in writing by ~~[TBD]~~*the AVA* to provide verification services. To obtain authorization the verification body shall submit to ~~[TBD]~~*the AVA* a self-evaluation of the potential for any conflict of interest that the verification body, entities related to the verification body, and members of the verification team including, subcontractors may have with the owner or operator or their related entities for which it will perform verification services. For the purposes of this section, the term member refers to staff on the verification team, in the verification body and any subcontractors. The submittal shall include the following:

(i) Identification of whether the potential for conflict of interest is high, low, or medium based on factors specified in this section;

(ii) An organizational chart of the business structure of the verification body, including its related entities and brief description of the primary work done by the verification body and related entities;

(iii) iii. Identification of whether any member of the verification body, entities related to the verification body, or the verification team including subcontractors has previously provided verification services for the owner or operator or its related entities and, if so, the years in which such verification services were provided;

(iv) Identification of whether any member of the verification body, entities related to the verification body, or the verification team or including subcontractors has engaged in any non-verification services of any nature with the owner or operator or related entities either within or outside the WCI region during the previous three years. The verification body must also disclose any services listed under section (high COI list) it has provided to the owner or operator, regardless of when these services occurred. If non-verification services have previously been provided, the following information shall also be submitted:

(v) Identification of the nature and location of the work performed for the owner or operator and whether the work is similar to the type of work to be performed during verification, such as emissions inventory auditing, energy efficiency, renewable energy, or other work with implications for the operator's greenhouse gas emissions or the accounting of greenhouse gas emissions or electricity transactions;

(vi) The nature of past, present or future relationships the verification body, entities related to the verification body, and members of the verification team including subcontractors have with the owner or operator or related entity including:

- Instances when any member has performed or intends to perform work for the owner or operator;
- Identification of whether work is currently being performed for the owner or operator and, if so, the nature of the work;

- Whether any member has any contracts or other arrangements to perform work for the owner or operator or a related entity;
- Identify how much work was performed in each of the last three years, as a percentage of the verification body's total gross income for each of the last three years;
- Identify how much work related to greenhouse gases or electricity transactions was has performed for the owner or operator or related entities in each of the last three years, as a percentage of the verification body's income for each of the last three years;
- Identify how much work was performed by each subcontractor for the operator in each of the last three years, as a percentage of each subcontractor's total gross income for each of the last three years.

~~—~~(vii) Explanation of how the amount and nature of work previously performed is such that any member of the verification team's credibility and lack of bias should not be under question.

~~(v)~~(viii) A list of names of the verification team members that will perform verification services for the owner or operator and a description of any instances of personal or family relationships with management or employees of the owner or operator that potentially represent a conflict of interest; and,

~~(vi)~~(ix) Identification of any other circumstances or relevant information known to the verification body or owner or operator that could result in a conflict of interest, or any situation where the appearance of impartiality could undermine confidence in the verification body's ability to assess the reported emissions.

(2) The potential for a conflict of interest shall be deemed to be high where:

(A) The verification body and owner or operator share any management staff or board of directors membership, or any of the management staff of the owner or operator have been employed by the verification body, or vice versa, within the previous three years; or

(B) Within the previous three years, any member of the verification body, any entity related to the verification body, and the verification team has provided to the owner or operator any of the following non-verification services:

(i) Designing, developing, implementing, or maintaining an inventory or information or data management system for facility greenhouse gases, or, where applicable, electricity transactions;

(ii) Developing greenhouse gas emission factors or other greenhouse gas-related engineering analysis;

(iii) Designing energy efficiency, renewable power, or other projects which explicitly identify greenhouse gas reductions as a benefit;

(iv) Preparing or producing greenhouse gas-related manuals, handbooks, or procedures specifically for the reporting facility;

(v) Appraisal services of carbon or greenhouse gas liabilities or assets;

(vi) Brokering in, advising on, or assisting in any way in carbon or greenhouse gas-related markets;

(vii) Managing any health, environment or safety functions which explicitly identify greenhouse gas reductions as a benefit;

(viii) Bookkeeping or other services related to the accounting records or financial statements, unless those services limited to financial auditing;

(ix) Any service related to information systems, unless those systems will not be part of the verification process and excluding third-party auditor or registration services;

(x) Appraisal and valuation services, both tangible and intangible related to GHG emissions or reductions inventories;

(xi) Fairness opinions and contribution-in-kind reports in which the verification body has provided its opinion on the adequacy of consideration in a transaction, unless the resulting services shall not be part of the verification process;

(xii) Any actuarially oriented advisory service involving the determination of amounts recorded in financial statements and related accounts;

(xiii) Any internal audit service as provided under section (GHG plan) that has been outsourced by the operator that relates to the owner's or operator's internal accounting controls, financial systems or financial statements, unless no consulting or advice was provided as part of the audit;

(xiv) Acting as a broker-dealer (registered or unregistered), promoter or underwriter on behalf of the owner or operator;

(xv) Any legal services related to GHG emissions;

(xvi) Expert services to the owner or operator or his or her legal representative for the purpose of advocating his or her's interests in litigation or in a regulatory or administrative proceeding or investigation involving GHG emissions, unless providing factual testimony.

(C) The potential for a conflict of interest shall also be deemed to be high where any staff member of the verification body, entity related to the verification body, or the verification team has provided verification services for the owner or operator for six consecutive years or within three years of the termination of a previous GHG verification contract with the owner or operator. If a verification body or verification team member has been providing verification services for a [operator/owner] in a greenhouse gas reporting or reductions program other than WCI within the past three years, those years of services will count towards the six consecutive year limit in the WCI.

(D) The potential for a conflict of interest shall be deemed high where the Independent Peer Reviewer for the verification team has provided verification or non-verification services for the operator during the current reporting year.

(3) The potential for a conflict of interest shall be deemed to be low where~~:~~ no potential for a conflict of interest is found under section WCI.8(g) *[may need to be updated, depending upon final version of WCI.8)* and any non-verification services provided by all members of the verification body and the verification team to the owner or operator within the last three years are valued at less than five percent of the verification body's revenue.

~~(A)No potential for a conflict of interest is found under section WCI.8(h) *(may need to be updated, depending upon final version of WCI.8)* and any non-verification services provided by all members of the verification body and the verification team to the owner or operator within the last three years are valued at less than *[Percent TBD*] of the verification body's revenue.~~

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WCI.8 OPTIONAL GUIDANCE

Note: This text is supporting material and not intended as part of the essential requirements.

Collection of Evidence

The verification body shall obtain sufficient and appropriate evidence to be able to draw reasonable conclusions on which to base the verification statement. The verification body obtains evidence by performing verification procedures. Verification procedures are classified as:

- **Computation (or Recalculation)** is the checking of mathematical accuracy of documents or records
- **Observation** of a process or procedure
- **Confirmation** is obtaining representations from a third party
- **Enquiry** is seeking information from a knowledgeable person
- **Inspection** of Records or Documents/Assets
- **Re-performance** is the verifiers independent execution of procedures or controls
- **Analysis** is the evaluation of information made by studying the plausible relationships among different types of data

Some or all of these techniques can be used to obtain sufficient and appropriate evidence. Site visits are used to obtain evidence that is readily available at that location.

§ WCI.9 DEFINITIONS

"Accuracy" means the closeness of the agreement between the result of the measurement and the true value of the particular quantity (or a reference value determined empirically using internationally accepted and traceable calibration materials and standard methods), taking into account both random and systematic factors.

"Acid gas" means a gas mixture that has been separated from natural gas ~~that~~ and consists mostly of~~consists of~~ hydrogen sulphide or carbon dioxide and that may contain trace amounts of hydrocarbons, water, or other contaminants.

"Accreditation and Verification Authority" or "AVA" means [the jurisdiction] or any entity or entities to which [the jurisdiction] assigns any of the responsibilities for oversight and execution of the accreditation and verification program established in WCI.8.

"Adverse verification statement" means a verification statement rendered by a verification body stating that the verification body cannot ~~provide~~ conclude that there is a reasonable level of assurance ~~that the submitted~~for an emissions data report ~~is free of material misstatement, or that it cannot provide a positive statement that the emissions data report conforms to the requirements of this article~~.

["Article" is a placeholder for a jurisdiction-specific cross reference to whatever subdivision of its administrative code contains the WCI's Essential Requirements for Mandatory Reporting in their entirety.]

"Asphalt" means a highly viscous liquid or semi-solid consisting mostly of bitumen and which is a residue by-product of petroleum refining

~~"Asphalt blowing" means the process by which air is blown through asphalt flux to change the softening point and penetration rate.~~

"Asphalt blowing" means the process by which air is blown through liquid asphalt to remove contaminants such as volatile compounds and to increase viscosity.

~~"Associated gas" means a natural gas that is produced from gas wells or gas produced in association with the production of crude oil.~~
"Associated gas" means a natural gas which is found in association with crude oil, either dissolved in crude oil or as a cap of free gas above the crude oil.

"Barrel" or "bbl" means a volume equal to 42 U.S. gallons.

"Best available data and methods" means [the jurisdiction's] methods for emissions calculations set forth in this article; or [the jurisdiction's] approved next best alternative from the WCI source category quantification methodologies or other generally accepted methods for calculating greenhouse gas emissions organized by the same source categories and GHG species, using [jurisdiction] provided emission factors and other data.

"Compliance period" means, until such time as [the jurisdiction] adopts a cap-and-trade program covering sources subject to this article, a period of three calendar years.

"Biomass" means non-fossilized plants or parts of plants, animal waste, micro-organisms or any product made of either of these, and includes wood and wood products, agricultural residues and wastes, biologically derived organic matter found in municipal and industrial wastes, landfill gas, bio-alcohols, spent pulping liquor~~,~~ (black liquor),- pulp ~~fibres~~fibers, sludge gas, and animal- or plant-derived oils~~.~~ .~~(WCI – CEPA)~~

"Biomass fuels" or "biomass-derived fuels" means fuels whose entire heat generating capacity is derived entirely from biomass.

"Bottoming cycle plant" means a cogeneration ~~facility~~ plant in which the energy input to the system is first applied to a useful thermal energy application or process, and at least some of the reject heat emerging from the application or process is then used for ~~power~~ electricity production.

~~1. "British Thermal Unit" or "Btu" means the quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit at about 39.2 degrees Fahrenheit.~~

"Calcination" means the thermal decomposition of carbonate-based minerals, ~~such as calcium carbonate (the principal mineral in limestone)~~into ~~to form calcium~~ one or more oxides ~~in a cement kiln.~~and carbon dioxide

"Calcine" means to heat a substance to a high temperature but below its melting or fusion point causing oxidation or ~~reduction~~ reduction~~so that it oxidizes or reduces~~.

"Calcined byproduct/waste type" refers to lime kiln dust and other partially calcined materials and co-products generated during the production of one of the three types of quicklime.

"Calcined byproduct type sold" refers to lime kiln dust and other calcined materials and coproducts, such as off-spec lime, that enters commerce.

"Calcined co-product/waste not sold" refers to any partially calcined co-product or partially calcined material produced during the calcination of limestone or other highly calcareous material that does not enter commerce as its own product or as part of another lime product.

Types of calcined co-products/partially calcined material not sold include, but are not limited to, lime kiln dust, scrubber sludge, waste cores, and off-spec lime.

~~"Calendar year" means the period of twelve consecutive months commencing on January 1 through December 31.~~

"Carbon dioxide equivalent" or "CO_2 equivalent" or ~~"CO_2e"~~ "CO_2e" means a measure for comparing the global warming potentials of different greenhouse gases. By definition, carbon dioxide has a carbon dioxide equivalent of one, with the global warming potentials of other greenhouse gases stated relative to carbon dioxide. ~~other GHGs, based on the quantity of those gases multiplied by the appropriate global warming potential (GWP) factor and commonly expressed as metric tons of carbon dioxide equivalent.~~
~~"Catalyst" means a substance added to a chemical reaction, which facilitates or causes the reaction, and is not consumed by the reaction.~~

"Catalytic cracking" means ~~a refinery~~the process of breaking down larger, heavier, and more complex hydrocarbon molecules into simpler and lighter molecules~~. Catalytic cracking is accomplished by~~ through the use of a catalyst.

"Catalytic reforming" means ~~a refining~~the process of using controlled heat and pressure with catalysts to rearrange certain hydrocarbon molecules.

"Cement" means a building material that is produced by heating mixtures of limestone and other minerals or additives at high temperatures in a rotary kiln to form clinker, followed by cooling and grinding with blended additives to produce a finished powder ~~that is used with water, sand and gravel to make concrete and mortar~~.

"Cement kiln dust" or "CKD" means the fine-grained, solid, highly alkaline waste removed from cement kiln exhaust gas by air pollution control devices~~. CKD consists~~, consisting of partly calcined kiln feed material, ~~and includes all~~ dust from cement kilns and bypass systems, including bottom ash and bypass dust.

"Cement plant" means an industrial structure, installation, plant, or building primarily engaged in manufacturing Portland, natural, masonry, pozzolanic, and other hydraulic cements, and typically identified by NAICS code 327310.

"Chemical oxygen demand" or "COD" means the measure of the amount of organic compounds in water, in units of mass per unit volume of water, used to determine water quality. ~~chemical oxygen demand as determined using methods specified pursuant to 40 CFR 136.~~

"Clinker" means the mass of fused material produced in a cement kiln from which finished cement is manufactured by milling and grinding.

"Coal" means a combustible sedimentary rock composed primarily of carbon and~~all solid fuels~~ classified as anthracite, bituminous, sub-bituminous, or lignite by the American Society for Testing and Materials Designation ASTM D388–05 "Standard Classification of Coals by Rank".

2. ~~"Cogeneration emissions" means releases resulting from cogeneration units.~~

"Cogeneration unit" means a stationary fuel combustion device which simultaneously generates electrical and thermal energy that is (i) used by the operator of the facility where the cogeneration unit is located; or (ii) transferred to another facility for use by that facility.

"Cogeneration system" means individual cogeneration components including the prime mover (heat engine), generator, heat recovery, and electrical interconnection, configured into an integrated system that provides sequential generation of multiple forms of useful energy (usually ~~mechanical~~ electrical and thermal), at least one form of which the facility consumes on-site or makes available to other users for an end-use other than electricity generation.

"Coke ~~(petroleum)~~" means a solid residue consisting mainly of carbon which is derived either from~~results from~~ the cracking of petroleum hydrocarbons in ~~processes such as coking and fluid coking~~a refinery coker unit (petroleum coke) or from the destructive distillation of low-ash, low-sulfur bituminous coal (coal coke). ~~This includes catalyst coke deposited on a catalyst during the refining process which must be burned off in order to regenerate the catalyst.~~

"Coke burn-off" means the removal of coke ~~removal~~ from the surface of a catalyst ~~by~~ through combustion during catalyst regeneration.

3. ~~"Coke production" means the production of coke from coal in either a by-product coke oven battery or non-recovery coke oven battery.~~

"Combustion emissions" means greenhouse gas emissions occurring during the exothermic reaction of a fuel with oxygen.

4. ~~"Combustion source" means a source of combustion emissions.~~

"Conflict of interest" means a situation in which, because of financial or other activities or relationships with other persons or organizations, a person or body is unable or potentially unable to render an impartial verification opinion of a potential client's greenhouse gas emissions, or the person or body's objectivity in performing verification services is or might be otherwise compromised.

"Continuous emissions monitoring system (CEMS)" means the total equipment required to obtain a continuous measurement of a gas concentration or emission rate from combustion or industrial processes.

~~5. “Conveying system” means a device for transporting materials from one piece of equipment or location to another location within a facility. Conveying systems include but are not limited to the following: feeders, belt conveyors, bucket elevators and pneumatic systems.~~

~~6. “Cracking” means the process of breaking down larger molecules into smaller molecules, utilizing catalysts and/or elevated temperatures and pressures.~~

“Crude oil” means a combustible, liquid mixture ~~of hydrocarbons~~ found in natural underground reservoirs consisting of hydrocarbons and other organic compounds, or derived from tar sands, shale and coal. ~~that exists in the liquid phase and that is found in natural underground reservoirs.~~

“Data check” means an~~y~~ independent calculation or checking of data conducted by a verifier to recreate the emissions for a discreet source included in an emissions data report.

~~7. “De minimis” means those emissions reported for a source or sources that are calculated using alternative methods selected by the owner or operator in accordance with WCI.2(d).~~

~~8. “Diesel fuel” means a fuel composed of distillates obtained in petroleum refining operations.~~

~~9. “Direct emissions” means greenhouse gas emissions from sources that are under the operational control of the operator.~~

~~“Distillate fuel oil” of “distillate oil” means a general classification for a petroleum fraction produced in conventional distillation operations. It includes diesel fuels and fuel oils.~~

“Electricity generating unit” or “EGU” means any combination of physically connected generator(s), reactor(s), boiler(s), combustion turbine(s), or other prime mover(s) operated together to produce ~~electric power.~~electricity.

~~10. “Emission factor” means a unique value for determining an amount of a greenhouse gas emitted for a given quantity of activity (e.g., metric ton of carbon dioxide emitted per barrel of fossil fuel burned).~~

“Emissions” means the release of greenhouse gases into the atmosphere from sources and processes in a facility.

~~11. “Equipment” means any stationary article, machine, or other contrivance, or combination thereof, which may cause the issuance or control the issuance of air contaminants; equipment shall not mean portable equipment, tactical support equipment, or generating units designated as backup or emergency generators in a permit issued by an air pollution control district or air quality management district.~~

“Equipment leak” means releases of fugitive greenhouse gas emissions from equipment including valves, pump seals, flanges, compressors, sampling connections, and open-ended lines and excluding storage tank emissions.

“Exporter” means ~~…~~*[To be defined later for transportation and RCI fuels accounting.]*

“Facility” means all buildings, plants, structures, installations, and equipment that:

(a) Emit or may emit GHG(s);

(b) Are located on one or more contiguous or adjacent properties;

(c) Are under common control of the same owner(s) or operator(s); and

(d) Form a producing unit, function as a single integrated site, or have the same first two digits of the Standard Industrial Classification or same first three digits of the North American Industry Classification System.

[For this version of the Essential Requirements, the words “nonroad engine” have been deleted from the definition of “facility.” WCI, however, is considering the inclusion of a protocol for calculating nonroad engine emissions from certain facilities in a future version of the Essential Requirements. If and when that occurs, it may be appropriate to amend this definition to include nonroad engines in the list of covered activities at a stationary source.]

~~Facility” means any property, plant, building, structure, stationary source, stationary equipment or grouping of stationary equipment or stationary sources located on one or more contiguous or adjacent properties, in actual physical contact or separated solely by a public roadway or other public right-of-way, under common operational control, and having the same first two digits of the Standard Industrial Classification (SIC) or same first three digits of the North American Industry Classification System (NAICS) code.~~ ~~*[WCI is currently working to develop a definition that will harmonize common usages of the term in the U.S. and Canada. Some special facilities, such as oil and gas production fields will have separate definitions.]*~~

“Feed” means the prepared and mixed materials, which include but are not limited to materials such as limestone, clay, shale, sand, iron ore, mill scale, cement kiln dust, ~~and~~ green coke and fly ash, that are fed ~~to the kiln~~into a kiln, furnace, or other equipment type but which exclude ~~. Feed does not include the~~ fuels that are combusted.
~~used in the kiln to produce heat to form the clinker product.~~
“Feedstock” means any raw material that is used in or upgraded by an industrial process but not combusted.

~~“Flare” means a combustion device that uses an open flame to burn combustible gases with combustion air provided by uncontrolled ambient air around the flame and includes both ground-level and elevated flares.~~

~~12. “Flaring emissions” means controlled releases resulting from the combustion of a gas or liquid, the purpose for which is not producing energy.~~

“Flexigas” means a low BTU~~Btu~~ gaseous fuel produced through the gasification of coke ~~produced during flexicoking~~.

“Fluid catalytic cracking unit” or “FCCU” means a process unit in a refinery in which ~~petroleum derivative~~crude oil or a crude oil-derived feedstock is charged and fractured into smaller molecules in the presence of a catalyst, or reacts with a contact material to improve feedstock quality for additional processing, and in which the catalyst or contact material is regenerated by burning off coke and other deposits. The unit includes, but is not limited to, the riser, reactor, regenerator, air blowers, spent catalyst, and all equipment for controlling air pollutant emissions and recovering heat.

"Fluid coking" means a thermal cracking process utilizing the fluidized-solids technique to remove carbon (coke) for continuous conversion of heavy, low-grade oils into lighter products.

"Fossil fuel" means a fuel~~, such as coal, oil, and natural gas, produced by~~consisting of the decomposed remains of ~~the decomposition of~~ ancient ~~(fossilized)~~ plants and animals.

"Fuel" means solid, liquid or gaseous combustible material consisting of hydrocarbons and other compounds that is combusted or oxidized for the purpose of producing energy.

"Fuel analytical data" means any data collected about the mass, volume, flow rate, heat content, or carbon content of a fuel.

"Fuel gas system" means a system of compressors, piping, knock-out pots, mix drums, sulfur removal units (if necessary) and flaring units (if necessary) ~~and, if necessary, units used to remove sulfur contaminants from the fuel gas (e.g., amine scrubbers)~~ that collects fuel gas from one or more sources for treatment~~, as~~ (if necessary), and transports it to a stationary combustion unit. ~~A fuel gas system may have an overpressure vent to a flare but the primary purpose for the fuel gas system is to provide fuel to the various combustion units at the refinery.~~

"Fugitive emissions" means the unintended or incidental emissions of greenhouse gases from the transmission, processing, storage, use, or transportation of fossil fuels, greenhouse gases or other ~~materials~~substances, including but not limited to HFC~~s~~ emissions from refrigeration leaks, SF_6 from electric power distribution equipment, methane from mined coal, and CO_2 emitted from geyser steam and/or fluid used in geothermal generating facilities.

"Full verification" means all verification services as provided in section WCI.8(b).

"Generating unit" means any combination of physically connected generator(s), reactor(s), boiler(s), combustion turbine(s), or other prime mover(s) operated together to produce electricity ~~power~~.

"Global warming potential" or "GWP factor" means the ~~means the~~ radiative forcing of a greenhouse gas, calculated over a time interval of 100 years~~ratio of the time-integrated radiative forcing from the instantaneous release of one kilogram (kg) of a trace substance relative to that of one kg of a reference gas, i.e., CO_2.~~

"Greenhouse gas", ~~"greenhouse gases"~~ or "GHG" means any of the following: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), and perfluorocarbons (PFCs).

~~13. "Greenhouse gas source" means any physical unit, process, or other use or activity that releases a greenhouse gas into the atmosphere.~~

“High heat value” or “HHV” means the amount of heat energy released by the combustion of a unit quantity of a fuel, including the latent heat of vaporization of water embedded in the fuel

“Hydrocarbons” means chemical compounds ~~containing predominantly~~consisting entirely of carbon and hydrogen.

“Hydrofluorocarbons” or “HFCs” means a class of GHGs consisting of hydrogen, fluorine, and carbon and primarily used as refrigerants~~, consisting of hydrogen, fluorine, and carbon~~ specifically those listed in Table WCI.10-1.

“Hydrogen plant” means a ~~facility~~ plant that produces hydrogen with steam hydrocarbon reforming, partial oxidation of hydrocarbons, or other processes.

~~“High heat value” or “HHV” means the amount of heat produced by combustion of a unit quantity of a fuel where the water vapour resulting from the combustion is condensed and the heat is recovered.~~

“Importer” means *[To be defined later with input from the Electricity Subcommittee.]*

“Impregnated saw dust” means saw dust containing resins, preservatives or other substances derived from fossil fuels.

~~[WCI is developing a definition of impregnated saw dust, which generally refers to saw dust from wood treated or impregnated with resins, glues, or other substances derived from fossil fuels.]~~

“Independent Peer Reviewer” means a Lead Verifier within a Verification Body who has not participated in conducting verification services for the current reporting year who provides an independent review of verification services rendered as required in section WCI.8(f).

~~14. “Industrial process” means a process, a component of which involves (i) a chemical reaction other than stationary fuel combustion and not for the purpose of producing energy; or (ii) a physical action such as distillation, evaporation, friction, handling, impaction, or separation of a substance or feedstock that is subjected to the industrial process.~~

~~“Industrial process emissions” releases from an industrial process that involves chemical or physical reactions other than combustion, and the purpose of which is not to supply energy. (CEPA 46).~~

~~15. “ISO” means the International Organization for Standardization.~~

~~“Kerosene” means a light distillate fuel that includes No. 1-K and No. 2-K as well as other grades of range or stove oil that have properties similar to those of No. 1 fuel oil.~~

“Kiln” means thermally insulated chambers, or ovens, in which controlled temperature regimes are produced, used in the production of clinker, lime and other products, and which includes~~a~~

~~device, including~~ any associated preheater or precalciner devices.~~,~~ ~~that produce clinker by heating limestone and other materials for subsequent production of Portland or other cement.~~

~~"Lead verifier" means a person that has met all of the requirements in section WCI.8.~~

"Less Intensive Verification" means the verification services provided in interim years between full verifications; less intensive verification only requires risk assessment and data checks on an owner or operator's emissions data report based on the most current sampling plan developed as part of the most current full verification services. This level of verification may only be used if the verifier can provide findings with a reasonable level of assurance.

"Lime kiln dust" or "LKD" means lime dust produced in the course of production of quick lime.

"Lime type" refers to three types of quicklime derived from limestone containing varying percentages of magnesium carbonate. The three lime types are:

(a) High calcium quicklime, which is derived from limestone containing 0 to 5 percent magnesium carbonate.

(b) Magnesian quicklime, which is derived from limestone containing 5 to 35 percent magnesium carbonate

(c) Dolomitic quicklime, which is derived from limestone containing 35 to 46 percent magnesium carbonate.

"Liquefied petroleum gas" or "LPG" means a group of gaseous hydrocarbons ~~-based gases~~ derived from crude oil refining or natural gas fractionation~~.~~, and ~~They~~ includes propane, propylene, normal butane, butane, butylene, isobutene and isobutylene. ~~For convenience of transportation, these gases are liquefied through pressurization.~~

"Low ~~Btu~~ BTU gas" means gases recovered from casing vents, vapor recovery ~~-~~systems, ~~crude oil and petroleum product~~ storage tanks and other ~~parts~~ components within the production process of crude oil, natural gas and petroleum products.~~of petroleum refining and the crude oil and natural gas production process.~~

"Low Heat~~ing~~ Value" or "LHV" means the heat energy released through the combustion of a unit quantity of fuel, excluding the latent heat of vaporization of water embedded in the fuel.~~low or net heat content with the heat of vaporization excluded. The water is assumed to be in the gaseous state.~~

~~16. "Marketer" means a purchasing/selling entity that is not a retail provider, and that is the purchaser/seller at the first point of delivery in California for electric power imported into California, or the last point of receipt in California for power exported from California.~~

~~"Material misstatement" means (a) The individual or aggregate effect (overstatements and understatements offset each other) of one or more errors, omissions or misstatements identified in the course of verification that result in the total reported emissions being outside the 95~~

~~percent accuracy required to receive a positive verification statement. Material misstatement does not include any evaluation of acceptable measurement uncertainty of the monitoring equipment or quantification methodologies, or (b) The individual or aggregate effect of one or more errors, omissions or misstatements identified in the course of verification which make it probable that the judgment of a reasonable person judging the total reported emissions would have been changed or influenced by the error, omission or misrepresentation.~~“Material misstatement” means an error or omission, or a collection of errors or omissions, that results in a determination that a verification statement contains a material misstatement under WCI.8(o)(1)(A) or (B).

“Measurement-based” means any of the various emission quantification methodologies that involve the determination of emissions by means of direct measurement of the flue gas flow, as well as the concentration of the relevant GHG(s) in the flue gas.

“Measurement uncertainty” means the scientific uncertainty associated with measuring of GHG emissions due to limitations of monitoring equipment or quantification methodologies. ~~The WCI allows a measurement uncertainty of ±5 % for all measuring equipment which provides information underlying emissions reporting.~~

~~17. “MMBtu” means million British thermal units.~~

~~1. “Motor gasoline” means a complex mixture of relatively volatile hydrocarbons with or without small quantities of additives, blended to form a fuel suitable for use in spark-ignition engines. Motor gasoline is characterized as having a boiling range of 122 to 158 degrees Fahrenheit at the 10-percent recovery point to 365 to 374 degrees Fahrenheit at the 90-percent recovery point.~~

“Municipal solid waste” or “MSW” means waste products collected from ~~solid-phase~~ households, commercial/retail units, ~~and/~~or ~~institutional~~ institutions. ~~waste, such as, but not limited to, yard waste and refuse.~~

“NAICS” means the North American Industry Classification System.

“Nameplate generating capacity” means the maximum rated electrical power output of a generator under specific conditions designated by the manufacturer, expressed in megawatts (MW) or kilowatts (kW).

~~18. “Naphtha” means a generic term applied to a petroleum fraction with an approximate boiling range between 122 degrees Fahrenheit and 400 degrees Fahrenheit.~~

“Net power generated” means the gross electricity generation minus station service or unit service ~~power~~ electricity requirements, expressed in megawatt hours (MWh) per year. In the case of cogeneration, this value is intended to include internal consumption of electricity for the purposes of a production process, as well as power put on the grid.

“Nonroad equipment” means [WCI is addressing the definition for nonroad equipment as part of its development of a nonroad equipment rule].

~~"Owner or operator" means any person who owns, leases, operates, controls, or supervises a facility or fuel supply operation; or who imports electricity into the WCI region.~~ *["Owner or operator," as noted in WCI.1(a), is a placeholder. Each jurisdiction will select the specific terminology for the regulated persons in accordance with its customary rule-writing practices.]*

"Operator's representative" means:
(a) If the operator of the facility is an individual, the operator.
(b) If the operator of the facility is a corporation, either
  (1) Any officer of the corporation, whether or not the officer is also a director of the corporation, who performs a policy making function in respect of the corporation and who has the capacity to influence the direction of the corporation; or
  (2) The individual with primary responsibility for the operations and management of the facility.
(c) If the operator of the facility is not an individual or a corporation, the individual with primary responsibility for the operations and management of the facility.

"Perfluorocarbons" or "PFCs" means synthetic compounds derived from hydrocarbons through the replacement of hydrogen with fluorine atoms~~a class of greenhouse gases consisting on the molecular level of carbon and fluorine~~.

"Petroleum" means crude oil~~ removed from the earth and the oil derived from tar sands, shale and coal~~.

~~"Petroleum coke" means a solid residue consisting mainly of carbon which results from the cracking of petroleum hydrocarbons in processes such as coking and fluid coking. This includes catalyst coke deposited on a catalyst during the refining process which must be burned off in order to regenerate the catalyst.~~

"Petroleum refinery" or "refinery" means any facility engaged in producing gasoline, aromatics, kerosene, distillate fuel oils, residual fuel oils, lubricants, asphalt, or other products through distillation of petroleum or through redistillation, cracking, rearrangement or reforming of unfinished petroleum derivatives.

"Positive verification statement" means a verification statement rendered by a verification body stating that the verification body can say with reasonable assurance that the submitted emissions data report is free of material misstatement and that the emissions data report conforms to the requirements of this article.

"Power" means electricity, except where the context makes clear that another meaning is intended.

"Pressure swing adsorption" or "PSA" means a gas purification process which selectively concentrates target gas molecules using porous, high surface area solid adsorbents and elevated pressure.

“PSA off-gas” or “tail-gas” means the impurity stream resulting from the sequential PSA pressurization/depressurization purification process.

“Prime mover” means the type of equipment such as an engine or water wheel that drives an electric generator. “Prime movers” include, but are not limited to, reciprocating engines, combustion or gas turbines, steam turbines, microturbines, and fuel cells.

“Process” means the intentional or unintentional reactions between substances or their transformation, including, but not limited to, the chemical or electrolytic reduction of metal ores, the thermal decomposition of substances, and the formation of substances for use as product or feedstock.

“Process emissions” ~~means emissions~~ means the emissions from industrial processes (e.g., cement production, ammonia production) involving chemical or physical transformations other than fuel combustion. For example, the calcination of carbonates in a kiln during cement production or the oxidation of methane in an ammonia process results in the release of process CO2 emissions to the atmosphere. Emissions from fuel combustion to provide process heat are not part of process emissions, whether the combustion is internal or external to the process equipment. ~~(EPA – 98.6)~~
“Process vent” means an opening where a gas stream is continuously or periodically discharged during normal operation.

“Pure” means consisting of at least 97 percent by mass of a specified substance.
~~For facilities burning biomass fuels, this means the fraction of biomass carbon accounts for at least 97 percent of the total amount of carbon in the fuel burned at the facility.~~

“Purge gas” means nitrogen, carbon dioxide, liquefied petroleum gas, or natural gas used to maintain a non-explosive mixture of gases in a flare header or provide sufficient exit velocity to prevent regressive flame travel back into the flare header.

“Quick lime” means a substance that consists of oxides of calcium and magnesium resulting ~~, which results~~ from the calcination of limestone. ~~and is produced in a lime kiln.~~

~~“Raw material preparations” means, in respect of feedstock that is to be processed in the lime kiln, the preparation of the feedstock, which may include crushing, screening, washing, and sieving.~~

“Reasonable level of assurance” for an emissions data report means the report satisfies WCI.8(b)(1)~~means a high degree of confidence that submitted data and statements are valid and that the reported emissions are free from material misstatement (i.e. that the emissions report presents fairly, in all material respects, the annual emissions for the facility, fuel supplier, or electricity importer)~~.

“Recycled” means a material that is reused or reclaimed.

"Refinery fuel gas" or "still gas" means gas generated at a petroleum refinery or any gas generated by a refinery process unit, and that is combusted separately or in any combination with any type of gas or used as a chemical feedstock.

"Reporting year" means the calendar year for which emissions are being reported in the emissions data report.

19. ~~"Residual fuel oil" means a general classification for the heavier oils, known as No. 5 and No. 6 fuel oils, that remain after the distillate fuel oils and lighter hydrocarbons are distilled away in refinery operations.~~

"Retail provider" means an entity that provides electricity to retail end users.

"Senior officer" means:

(a) The chair of the board of directors, a vice-chair of the board of directors, the president, a vice-president, the secretary, the treasurer or the general manager of a corporation or any other individual who performs functions for a corporation similar to those normally performed by an individual occupying any such office, and

(b) Each of the five highest paid employees of a corporation, including any individual referred to in clause (a).

"Screening value ~~(SV)~~" or "SV" means the instrument reading (ppmv) obtained when components, including but not limited to valves, pump seals, connectors, flanges, open-ended lines and other equipment components, are evaluated for leakage as described in United States Environmental Protection Agency (U.S. EPA) Method 21 – Determination of Volatile Organic Compound Leaks.

"Sinter production" means a process that produces a fused aggregate of fine iron-bearing materials suited for use in a blast furnace. The sinter machine is composed of a continuous traveling grate that conveys a bed of ore fines and other finely divided iron-bearing material and fuel (typically coke breeze), a burner at the feed end of the grate for ignition, and a series of downdraft windboxes along the length of the strand to support downdraft combustion and heat sufficient to produce a fused sinter product.

"SI units" means the Système international d'unités (International System of Units).

"Small refiner" means any petroleum refiner who owns or operates a refinery that has a crude oil throughput ~~n oil~~ capacity ~~of~~ equal to or less than 55,000 barrels per day.
~~**[From Canadian EPA.]**~~

"Solid biomass fuel" means plants or parts of plants, in their natural state ~~or~~ that have been mechanically or chemically separated~~modified~~, but not chemically altered from the natural state.

20. ~~"Source" means greenhouse gas source, as defined in this section.~~

"Standard conditions" or "S<u>tandard Temperature and Pressure" or "S</u>TP" means <u>either </u>a temperature of 20 degrees Celsius (68 degrees Fahrenheit) and a~~n absolute~~ pressure of <u>101.325 kPa (14.696 PSI) according to IUPAC standards, or a temperature of 0 degrees Celsius (32 degrees Fahrenheit) and an absolute pressure of 100 kPa, according to NIST standards</u>~~760 mm (30 inches) of mercury or 60 degrees Fahrenheit and 1 atmosphere~~.

"Standard cubic foot" or "scf" means the amount of gas that would occupy a volume of one cubic foot if free of combined water at standard conditions.

~~"Stationary" means neither portable nor self propelled, and operated at a single facility.~~

"Stationary combustion unit" means any boiler, heater, furnace, kiln, turbine, internal combustion engine, incinerator or other non-mobile source device that combusts any solid, liquid, or gaseous fuel for purposes of producing useful heat or energy for industrial, commercial, or institutional use; or for purposes of reducing the volume of waste by removing combustible material.

"Stationary fuel combustion emissions" means ~~releases~~ <u>greenhouse gas emissions </u>from stationary combustion units, including cogeneration units.

"Steam reforming" means the process by which methane and other hydrocarbons in natural gas are converted into hydrogen and carbon monoxide by reaction with steam over a catalyst.

"Storage tank" means any tank, other container, or reservoir used for the storage of organic liquids, excluding tanks that are permanently affixed to mobile vehicles such as railroad tank cars, tanker trucks or ocean vessels.

"Sulfur hexafluoride" or "SF_6" means a ~~GHG~~ <u>greenhouse gas composed of a</u>~~consisting on the molecular level of a~~ single sulfur atom and six fluorine atoms<u>, commonly used as a dielectric medium.</u>

"Sulfur recovery unit" or "SRU" means a process unit that recovers elemental sulfur from gases that contain reduced sulfur compounds and other pollutants, usually by a vapor-phase catalytic reaction of sulfur dioxide and hydrogen sulfide.

<u>"Supplemental firing" means an energy input to the cogeneration facility used only in the thermal process of a topping cycle plant, or in the electricity generating or manufacturing process of a bottoming cycle plant.</u>

"Supplier" means . . . [To be defined later for transportation and RCI fuels accounting.].

"Topping cycle plant" means a cogeneration <u>plant</u>~~facility~~ in which the energy input to the ~~facility~~ <u>plant </u>is first used to produce ~~useful power output~~<u>electricity</u>, and at least some of the reject heat from the ~~power~~ <u>electricity </u>production process is then used to provide useful thermal output.

"Total organic carbon" or "TOC" means a measure of the amount of carbon in an ~~total~~ organic ~~carbon molecules present in a sample~~compound and is used as a measure of water quality.

"Uncertainty" means the degree to which data or a data system is deemed to be indefinite or unreliable.

"Useful thermal output" means the thermal energy made available in a cogeneration system for use in any industrial or commercial process, heating or cooling application, or delivered to other end users, i.e., total thermal energy made available for processes and applications other than electrical generation.

"Verification" means a systematic, independent and documented process for the evaluation of an operator's emissions data report against the WCI's reporting procedures and methods for calculating and reporting GHG emissions.

"Verification body" means a firm accredited by the [Accreditation Body TBD] and recognized by the jurisdiction or its designee, that is able to render a verification statement and provide verification services for operators subject to reporting under this article.

"Verification cycle" means three years of verification activities. Each verification cycle must include at least one year of full verification, and may include two years of less intensive verification, if eligible.

"Verification statement" means the final written declaration rendered by a verification body attesting whether an operator's emissions data report is free of material misstatement and whether the emissions data report conforms to the requirements of this article.

"Verification services" means services provided during verification as specified in WCI.8, including but not limited to reviewing an operator's emissions data report, verifying its accuracy according to the standards specified in this article, assessing the operator's compliance with this rule, and submitting a verification opinion to the *[jurisdiction or its agent]*.

"Verification team" means all of those working for a verification body, including all subcontractors, to provide verification services for an operator.

"Verifier" means an individual employed or contracted by an accredited verification body who has been deemed competent by the verification body to carry out verification services as specified in section WCI.8.

"Volatile Organic Compound" or "VOC" means an organic compound containing at least one carbon atom and which evaporates or vaporizes readily under normal conditions, participates in atmospheric photochemical reactions, and excludes ~~any volatile compound of carbon, excluding~~ carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate.~~, which participates in atmospheric photochemical reactions.~~

“Waste-derived fuel” means a fuel typically derived from waste(s) and generally used as a substitute for conventional fossil fuels. Waste-derived fuels can include substances derived from fossil fuels such as waste oil, plastics, or solvents. ~~;~~Waste-derived fuels can also include fuels containing ~~biomass such as dried sewage or impregnated saw dust; or~~ fractions of both fossil fuels and biomass, such as municipal solid waste, ~~or~~ tires, dried sewage or impregnated saw dust. Waste-derived fuel does not include fuels which are pure biomass.

“Wastewater” means any process water which contains oil, emulsified oil, or other organic compounds that are not recycled or otherwise used in a facility.

“Wastewater emissions” means releases of greenhouse gas emissions from wastewater and on-site wastewater treatment.

“Wastewater separator” means equipment used to separate oils and water from locations downstream of process drains.

§ WCI.20 GENERAL STATIONARY COMBUSTION

§ WCI.21 Source Category Definition

General stationary fuel combustion sources are devices that combust solid, liquid, or gaseous fuel for the purpose of generating steam (or providing useful heat or energy) for industrial, commercial, or institutional use; or reducing the volume of waste by removing combustible matter. General stationary combustion sources are boilers, combustion turbines, engines, incinerators, and process heaters, and any other stationary combustion device that is not specifically addressed under the provisions for another source category in this rule.

Note: The source category definition may need to be revised after the remaining ER sections are completed.

§ WCI.22 Greenhouse Gas Reporting Requirements

The emissions data report shall include the following information at the facility level:

(a) Annual greenhouse gas emissions in metric tons, reported as follows:

(1) Total CO2 emissions for fossil and biomass fuels, reported by fuel type.

(2) Total CH4 emissions, reported by fuel type.

(3) Total N_2O emissions, reported by fuel type.

(b) Annual fuel consumption:

(1) For gases, report in units of standard cubic feet.

(2) For liquids, report in units of gallons.

(3) For non-biomass solids, report in units of short tons.

(4) For biomass solid fuels, report in units of bone dry short tons or bone dry metric tons.

(c) Average carbon content of each fuel, if used to compute CO_2 emissions.

(d) Average ~~higher~~high heat~~ing~~ value of each fuel, if used to compute CO_2 emissions.

(e) Annual steam generation in pounds or kilograms, for units that burn biomass fuels or municipal solid waste.

§ WCI.23 Calculation of CO_2 Emissions

For each fuel, calculate CO_2 mass emissions using one of the four calculation methodologies specified in this section, subject to the restrictions in §WCI.23(e).

(a) Calculation Methodology 1. Calculate the annual CO_2 mass emissions by substituting a fuel-specific default CO_2 emission factor, a default high~~er~~ heat~~ing~~ value, and the annual fuel consumption into the Equation 20-1:

$$CO_2 = Fuel \times HHV \times EF \times CF \times 0.001$$ **Equation 20-1**

Where:

CO_2	=	Annual CO_2 mass emissions for the specific fuel type (metric tons).
Fuel	=	Mass or volume of fuel combusted per year (express mass in short tons for solid fuel, volume in standard cubic feet for gaseous fuel, and volume in gallons for liquid fuel).
HHV	=	Default higher ~~er~~ heating ~~ing~~ value of the fuel, from column 3 of Table 20-1 (mmBtu per mass or mmBtu per volume, as applicable).
EF	=	Fuel-specific default CO_2 emission factor, from column 5 of Table 20-1 (kg CO_2/mmBtu).
CF	=	Conversion factor of 0.024 (gallons to barrels) for petroleum products, only; 1.0 for all other fuels.
0.001	=	Conversion factor from kilograms to metric tons.

(b) Calculation Methodology 2. Calculate the annual CO_2 mass emissions using a default fuel-specific CO_2 emission factor, a high~~er~~ heat~~ing~~ value provided by the supplier or measured by the operator, using Equation 20-2, except for emissions from the combustion of biomass fuels and municipal solid waste, for which the operator may instead elect to use the method shown in Equation 20-3.

(1) For any type of fuel for which an emission factor is provided in Tables 20-1 or 20-2, except biomass fuels and municipal solid waste when the operator elects to use the method in WCI.23(b)(2), use Equation 20-2:

$$CO_2 = \sum_{p=1}^{n} Fuel_p \times HHV_p \times EF \times 0.001$$ **Equation 20-2**

Where:

CO_2	=	Annual CO_2 mass emissions for a specific fuel type (metric tons).
n	=	Number of required heat content measurements for the year as specified in WCI.25(a).
$Fuel_p$	=	Mass or volume of the fuel combusted during the measurement period "p" (express mass in short tons for solid fuel, volume in standard cubic feet for gaseous fuel, and volume in gallons for liquid fuel).
HHV_p	=	High~~er~~ heat~~ing~~ value of the fuel for the measurement period (mmBtu per mass or volume).
EF	=	Fuel-specific default CO_2 emission factor, from column 5 of Table 20-1 or from Table 20-2 (kg CO_2/mmBtu).
0.001	=	Conversion factor from kilograms to metric tons.

(2) For biomass solid fuels and municipal solid waste, use either Equation 20-2 above or Equation 20-3:

$$CO_2 = Steam \times B \times EF \times 0.001$$ **Equation 20-3**

Where:

CO_2	=	Annual CO_2 mass emissions from biomass solid fuel or municipal solid waste combustion (metric tons).
Steam	=	Total mass of steam generated by biomass solid fuel or municipal solid waste combustion during the reporting year (lb steam).
B	=	Ratio of the boiler's design rated heat input capacity to its design rated steam output capacity (mmBtu/lb steam).
EF	=	Default emission factor for biomass solid fuel or municipal solid waste, from column 5 of Table 20-1 (kg CO_2/mmBtu).
0.001	=	Conversion factor from kilograms to metric tons.

(c) Calculation Methodology 3. Calculate the annual CO_2 mass emissions by using measurements of fuel carbon content or molar fraction (for gaseous fuels only), conducted by the operator or provided by the fuel supplier, and the quantity of fuel combusted, using Equation 20-4. For emissions from the combustion of biomass fuels and municipal solid waste, the operator may instead elect to use the method shown in Equation 20-5.

(1) For a solid fuel, use Equation 20-4 of this section:

$$CO_2 = \sum_{i=1}^{n} Fuel_i \times CC_i \times 3.664 \times 0.907$$

Equation 20-4

Where:

CO_2	=	Annual CO_2 mass emissions from the combustion of the specific solid fuel (metric tons).
n	=	Number of carbon content determinations for the year as specified in WCI.25(a).
$Fuel_i$	=	Mass of the solid fuel combusted in measurement period "i" (short tons).
CC_i	=	Carbon content of the solid fuel, from the fuel analysis results for measurement period "i" (percent by weight, expressed as a decimal fraction, e.g., 95% = 0.95).
3.664	=	Ratio of molecular weights, CO_2 to carbon.
0.907	=	Conversion factor from short tons to metric tons.

(2) For biomass fuels or municipal solid waste, use either Equation 20-4 above or Equation 20-5:

$$CO_2 = Steam \times B \times EF \times 0.001$$

Equation 20-5

Where:

CO_2	=	Annual CO_2 mass emissions from biomass solid fuel or municipal solid waste combustion (metric tons).
Steam	=	Total mass of steam generated by biomass solid fuel or municipal solid waste combustion during the reporting year (lb steam).
B	=	Ratio of the boiler's design rated heat input capacity to its design rated steam output capacity (mmBtu/lb steam).

EF = Default emission factor for biomass solid fuel or municipal solid waste, from column 5 of Table 20-1, (kg CO_2/mmBtu), adjusted no less often than every third year as provided in WCI.25(a)(5)(B).
0.001 = Conversion factor from kilograms to metric tons.

(3) For a liquid fuel, use Equation 20-6 of this section:

$$CO_2 = \sum_{i=1}^{n} 3.664 \times Fuel_i \times CC_i \times 0.001$$ **Equation 20-6**

Where:
CO_2 = Annual CO_2 mass emissions from the combustion of the specific liquid fuel (metric tons).
n = Number of required carbon content determinations for the year, as specified in WCI.25(a).
$Fuel_i$ = Volume of the liquid fuel combusted in measurement period "i" (gallons).
CC_i = Carbon content of the liquid fuel, from the fuel analysis results for measurement period "i" (kg C per gallon of fuel).
3.664 = Ratio of molecular weights, CO_2 to carbon.
0.001 = Conversion factor from kg to metric tons.

(4) For a gaseous fuel, use Equation 20-7 of this section:

$$CO_2 = \sum_{i=1}^{n} 3.664 \times Fuel_i \times CC_i \times \frac{MW}{MVC} \times 0.001$$ **Equation 20-7**

Where:
CO_2 = Annual CO_2 mass emissions from combustion of the specific gaseous fuel (metric tons).
n = Number of required carbon content and molecular weight determinations for the year, as specified in WCI.25(a).
$Fuel_i$ = Volume of the gaseous fuel combusted in period "i" (a day or month, as applicable) (scf).
CC_i = Average carbon content of the gaseous fuel, from the fuel analysis results for the period "i" (day or month, as applicable) (kg C per kg of fuel).
MW = Molecular weight of the gaseous fuel, from fuel analysis (kg/kg-mole).
MVC = Molar volume conversion factor (849.5 scf per kg-mole for STP of 20°C and 1 atmosphere or 836 scf per kg-mole for STP of 60°F, and 1 atmosphere).
3.664 = Ratio of molecular weights, CO_2 to carbon.
0.001 = Conversion factor from kg to metric tons.

(d) Calculation Methodology 4. Calculate the annual CO_2 mass emissions from all fuels combusted in a unit, by using data from continuous emission monitoring systems (CEMS) as specified in (d)(1) through (d)(7).

(1) For a facility that combusts fossil fuels or biomass fuels and operates CEMS in response to federal, state, provincial, or local regulation, use CO_2 or O_2 concentrations and flue gas flow measurements to determine hourly CO_2 mass emissions using methodologies provided in 40 CFR Part 75, Appendix F or equivalent requirements as applicable in Canada.

(A) The operator shall report CO_2 emissions for the reporting year in metric tons based on the sum of hourly CO_2 mass emissions over the year, converted to metric tons.

(B) If the operator of a facility that combusts biomass fuels uses O_2 concentrations to calculate CO_2 concentrations, annual source testing must demonstrate that calculated CO_2 concentrations when compared to measured CO_2 concentrations meet the Relative Accuracy Test Audit (RATA) requirements in 40 CFR Part 60, Appendix B, Performance Specification 3.

(2) For a facility that combusts waste-derived fuels (as defined in the General Provisions and listed in Table 20-2, including municipal solid waste), and operates a CEMS in response to federal, state, provincial, or local regulations use CO_2 concentrations and flue gas flow measurements to determine hourly CO_2 mass emissions using methodologies provided in 40 CFR Part 75, Appendix F or equivalent requirements as applicable in Canada.

(A) Annual CO_2 emissions shall be reported in metric tons based on the sum of hourly CO_2 mass emissions over the year.

(B) Emissions calculations shall not be based on O_2 concentrations.

(3) The operator of a facility that combusts waste-derived fuels and calculates CO_2 emissions using the methodology provided in WCI.23(d)(2) shall determine the portion of emissions associated with the combustion of biomass~~-derived fuels~~ using the method provided in WCI.23(f).

(4) An operator who uses CEMS data to report CO_2 emissions from a facility that co-fires fossil fuels with biomass fuels or waste-derived fuels that are partly biomass ~~fuels~~ shall determine the portion of total CO_2 emissions separately assigned to the fossil fuel and the biomass ~~fuels~~ using the method provided in WCI.23(f), if applicable. The operator who co-fires pure biomass fuels with fossil fuels may elect to calculate CO_2 emissions for the fossil fuels using methods designated in WCI.23(a) or WCI.23(b)(1), as applicable, by fuel type and then calculate biomass fuel emissions by subtracting the fossil fuel related emissions from the total CO_2 emissions determined using the CEMS based methodology.

(5) For any units for which CO2 emissions are reported using CEMS data, the operator is relieved of the requirement to separately report process emissions from combustion emissions for that unit or to report emissions separately for different fossil fuels for that unit when only fossil fuels are co-fired. In this circumstance, operators shall still report fuel use by fuel type as otherwise required.

(6) If a facility is subject to requirements in 40 CFR Part 60 or 40 CFR Part 75 and the operator chooses to add devices to an existing CEMS for the purpose of measuring CO_2 concentrations or flue gas flow, the operator shall select and operate the added devices pursuant to the requirements in 40 CFR Part 60 or Part 75 that apply to the facility. If

the facility is subject to both 40 CFR Part 60 and 40 CFR Part 75, the operator shall select and operate the added devices pursuant to the requirements in 40 CFR Part 75.

(7) If a facility does not have a CEMS and the operator chooses to add one in order to measure CO_2 concentrations, the operator shall select and operate the CEMS pursuant to the requirements in 40 CFR Part 75 or equivalent requirements as applicable in Canada.

(A) The operator shall use CO_2 concentrations and flue gas flow measurements to determine hourly CO_2 mass emissions using methodologies provided in 40 CFR Part 75, Appendix F or equivalent requirements as applicable in Canada.

(B) The operator shall report CO_2 emissions for the report year in metric tons based on the sum of hourly CO_2 mass emissions over the year, converted to metric tons.

(C) Operators who add CEMS under this article are subject to specifications in WCI.23(d)(1)-(5), if applicable.

(e) Use of the Four CO_2 Calculation Methodologies. Use of the four CO_2 emissions calculation methodologies described in paragraphs (a) through (d) of this section is subject to the following requirements and restrictions:

(1) Calculation Methodology 1 may not be used by a facility that is subject to the verification requirements of WCI.8, except for stationary combustion units that combust natural gas with a high~~er~~ heat~~ing~~ value between 975 and 1,1~~5~~0 0 Btu per cubic foot. Otherwise, Calculation Methodology 1 may be used for any type of fuel for which a default CO2 emission factor and a default high~~er~~ heat~~ing~~ value for the fuel is specified in Table 20-1.

(2) Calculation Methodology 2 may not be used by a facility that is subject to the verification requirements of WCI.8, except for stationary combustion units that combust natural gas with a high~~er~~ heat~~ing~~ value between 975 and 1,1~~5~~0 0 Btu per cubic foot~~[CD1]~~. Otherwise, Calculation Methodology 2 may be used for any type of fuel combusted for which a default CO_2 emission factor for the fuel is specified in Table 20-1 or 20-2.

(3) Calculation Methodology 3 may be used for a unit of any size combusting any type of fuel, except when the use of Calculation Methodology 4 is required.

(4) Calculation Methodology 4 may be used for a unit of any size combusting any type of fuel, and must be used for: a combustion unit with a CEMS that is required by any federal, state, provincial, or local regulation and that includes both a stack gas volumetric flow rate monitor and a CO_2 concentration monitor.

(f) Mixtures of biomass or biomass fuel and fossil fuel.

(1) The owner or operator that combusts fuels or fuel mixtures for which the biomass fraction is known or can be documented shall use the applicable equations in WCI.23(a) through (c) to determine the fossil fuel fraction and shall determine the biomass fraction by subtracting the fossil fuel fraction from the total emissions.

(2) The owner or operator that combusts fuels or fuel mixtures for which the biomass ~~fuel~~ fraction is unknown or cannot be documented (for example, municipal solid waste or tire-derived fuels) shall determine the biomass ~~fuel~~ portion of CO_2 emissions using

ASTM D6866-06a, as specified in this paragraph. This procedure is not required for fuels that contain less than 5 percent biomass ~~fuel~~ by weight or for waste-derived fuels that are less than 30 percent by weight of total fuels combusted in the year for which emissions are being reported, except where the operator wishes to report a biomass fuel fraction of CO_2 emissions.

~~(1)~~(A) The operator shall conduct ASTM D6866-06a analysis on a representative fuel or exhaust gas sample at least every three months, and shall collect exhaust gas samples over at least 24 consecutive hours following the standard practice specified by ASTM D7459-08.

~~(2)~~(B) The operator shall divide total CO_2 emissions between biomass ~~fuel~~ emissions and non-biomass ~~fuel~~ emissions using the average proportions of the samples analyzed for the year for which emissions are being reported.

~~(3)~~(C) If there is a common fuel source to multiple units at the facility, the operator may elect to conduct ASTM D6866-06a testing for one of the units.

§ WCI.24 Calculation of CH_4 and N_2O Emissions

Calculate the annual CH_4 and N_2O mass emissions from stationary fuel combustion sources using the procedures in paragraph (a), (b), or (c), as appropriate.

(a) If the heat content of the fuel is not measured for CO_2 estimation, calculate CH_4 and N_2O emissions using Equation 20-8:

$$CH_4 \; or \; N_2O = Fuel \times HHV_D \times EF \times 0.001 \qquad \textbf{Equation 20-8}$$

Where:

CH_4 or N_2O	=	Combustion emissions from specific fuel type, metric tons CH_4 or N_2O per year.
Fuel	=	Mass or volume of fuel combusted ~~for the measurement period, p,~~ specified by fuel type, unit of mass (short tons) or volume (scf, barrel) per year~~units of mass or volume per unit time~~.
HHV_D	=	Default high~~er~~ heat~~ing~~ value specified by fuel type provided in Table 20-1, MMBtu per unit of mass or volume.
EF	=	Default CH_4 or N_2O emission factor provided in Table 20-3, kg CH_4 or N_2O per MMBtu.
0.001	=	Factor to convert kg to metric tons.

(b) If the heat content of the fuel is measured for CO_2 estimation, calculate CH_4 and N_2O emissions using Equation 20-9:

$$CH_4 \; or \; N_2O = \sum_{p=1}^{n} Fuel_p \times HHV_p \times EF \times 0.001 \qquad \textbf{Equation 20-9}$$

Where:

CH_4 or N_2O	=	CH_4 or N_2O emissions from a specific fuel type, metric tons CH_4 or N_2O per year.
$Fuel_p$	=	Mass or volume of fuel combusted for the measurement period, p, specified by fuel type, unit of mass (short tons) or volume (scf, barrel) per year.

HHV_p	=	Hi~~gh~~er heat~~ing~~ value measured for the measurement period, p, specified by fuel type, MMBtu per unit mass or volume.
EF	=	Default emission factor provided in Table 20-3, kg CH_4 or N_2O per MMBtu.
0.001	=	Factor to convert kg to metric tons.

(c) For biomass and municipal solid waste combustion, the operator may elect to use Equation 20-10 of this section to estimate CH_4 and N_2O emissions:

$$CH_4 \text{ or } N_2O = Steam \times B \times EF \times 0.001 \qquad \textbf{Equation 20-10}$$

Where:

CH_4 or N_2O	=	Annual CH_4 or N_2O emissions from the combustion of a municipal solid waste (metric tons).
Steam	=	Total mass of steam generated by municipal solid waste combustion during the reporting year (lb steam).
B	=	Ratio of the boiler's ~~maximum~~ design rated heat input capacity to its design rated steam output (mmBtu/lb steam).
EF	=	Fuel-specific emission factor for CH_4 or N_2O, from Table WCI.20-3 of this subpart (kg CH_4 or N_2O per mmBtu).
0.001	=	Conversion factor from kilograms to metric tons.

(d) The operator may elect to calculate CH_4 or N_2O emissions using source-specific emission factors derived from source tests conducted at least annually under the supervision of (*jurisdiction*). Upon approval of a source test plan, the source test procedures in that plan shall be repeated in each future year to update the source specific emission factors annually.

(e) Use of the Four CO_2 Calculation Methodologies. Use of the four CH_4 and N_2O emissions calculation methodologies described in paragraphs (a) through (d) of this section is subject to the following requirements and restrictions:

(1) WCI.24(a) may not be used by a facility that is subject to the verification requirements of WCI.8, except for stationary combustion units that combust natural gas with a higher heating value between 975 and 1,150 Btu per cubic foot. Otherwise, WCI.24(a) may be used for any type of fuel for which a default CH_4 or N_2O emission factor and a default higher heat value for the fuel is specified in Table 20-3.

(2) WCI.24(b) may be used for a unit of any size combusting any type of fuel.

(3) WCI.24(c) may only be used for biomass or municipal solid waste combustion.

(4) WCI.24(d) may be used for a unit of any size combusting any type of fuel.

§ WCI.25 Sampling, Analysis, and Measurement Requirements

(a) Fuel Sampling Requirements. Fuel sampling must be conducted or fuel sampling results must be received from the fuel supplier at the frequency specified in paragraphs (a)(1) through (a)(4) of this section.

(1) Once for each new fuel shipment or delivery or on a monthly basis for middle distillates (diesel, gasoline, fuel oil, kerosene), residual oil, liquid waste-derived fuels, and LPG (ethane, propane, isobutene, n-butane, unspecified LPG).

(2) Monthly for natural gas, associated gas, and mixtures of low Btu gas.

(3) Monthly for gases derived from biomass including landfill gas and biogas from wastewater treatment or agricultural processes.

(4) Monthly for solid fuels, as specified below:

(A) The monthly solid fuel sample shall be a composite sample of weekly samples.

(B) The solid fuel shall be sampled at a location after all fuel treatment operations but before fuel mixing and the samples shall be representative of the fuel chemical and physical characteristics immediately prior to combustion.

(C) Each weekly sub-sample shall be collected at a time (day and hour) of the week when the fuel consumption rate is representative and unbiased.

(D) Four weekly samples (or a sample collected during each week of operation during the month) of equal mass shall be combined to form the monthly composite sample.

(E) The monthly composite sample shall be homogenized and well mixed prior to withdrawal of a sample for analysis.

(F) One in twelve composite samples shall be randomly selected for additional analysis of its discrete constituent samples. This information will be used to monitor the homogeneity of the composite.

(5) For biomass fuels and waste-derived fuels, the following may apply in lieu of WCI.25(a)(4):

(A) If CO_2 emissions are calculated using WCI.23(c)(1), the source-specific carbon content is determined annually. Upon approval of a source test plan by [*jurisdiction*], the source test procedures in that plan shall be repeated in subsequent years to update the source specific emission factors annually.

(B) If CO_2 emissions are calculated using WCI.23(c)(2) (biomass fuels and municipal solid waste only), the operator shall adjust the emission factor, in kg CO2/MMBtu not less frequently than every third year, through a stack test measurement of CO2 and use of the applicable ASME Performance Test Code to determine heat input from all heat outputs, including the steam, flue gases, ash and losses.

(b) Fuel Consumption Monitoring Requirements.

(1) Facilities may determine fuel consumption on the basis of direct measurement or recorded fuel purchase or sales invoices measuring any stock change (measured in million Btu, gallons, million standard cubic feet, short tons or bone dry short, tons) using the following equation:

Fuel Consumption in the Report Year = Total Fuel Purchases – Total Fuel Sales + Amount Stored at Beginning of Year – Amount Stored at Year End

(2) Fuel consumption measured in Btu values shall be converted to the required metrics of mass or volume using heat content values that are either provided by the supplier, measured by the facility, or provided in Table 20-1.

(3) All oil and gas flow meters (except for gas billing meters) shall be calibrated prior to the first year for which GHG emissions are reported under this rule, using an applicable flow meter test method listed in section WCI.6 or the calibration procedures specified by the flow meter manufacturer. Fuel flow meters shall be recalibrated either annually or at the minimum frequency specified by the manufacturer.

(4) For fuel oil, tank drop measurements may also be used.

~~(4)~~(5) Equipment used to measure solid fuel consumption at a facility shall be calibrated prior to the first year for which GHG emissions are reported under this rule, using a test method listed in section WCI.6 or the calibration procedures specified by the equipment manufacturer. Equipment shall be recalibrated either annually or at the minimum frequency specified by the manufacturer.

(c) Fuel Heat Content Monitoring Requirements. ~~Higher heating~~High heat values shall be based on the results of fuel sampling and analysis received from the fuel supplier or determined by the operator, in either case using an applicable analytical method listed in section WCI.6.

(1) For gases, use ASTM D1826-94 (Reapproved 2003), ASTM D3588-98 (Reapproved 2003), ASTM D4891-89 (Reapproved 2006), GPA Standard 2261-00 "Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography." The operator may alternatively elect to use on-line instrumentation that determines heating value accurate to within ± 5.0 percent. Where existing on-line instrumentation provides only low heating value, the operator shall convert the value to ~~higher heating~~high heat value as follows:

$$HHV = LHV \times CF$$

Equation 20-11

Where:

HHV = fuel or fuel mixture ~~higher heating~~high heat value (Btu/scf).
LHV = fuel or fuel mixture low~~er~~ heat~~ing~~ value (Btu/scf).
CF = conversion factor.

For natural gas, a CF of 1.11 shall be used. For refinery fuel gas and mixtures of refinery fuel gas, a weekly average fuel system-specific CF shall be derived as follows:

(A) by concurrent LHV instrumentation measurements and HHV determined by on-line instrumentation or laboratory analysis as part of the daily carbon content determination; or,

(B) by the HHV/LHV ratio obtained from the laboratory analysis of the daily samples.

(2) For middle distillates and oil, or liquid waste-derived fuels, use ASTM D240-02 (Reapproved 2007), or ASTM D4809-06 (Reapproved 2005).

(3) For solid biomass-derived fuels, use ASTM D5865-07a.

(4) For waste-derived fuels, use ASTM D5865-07a or ASTM D5468-02 (Reapproved 2007). Operators who combust waste-derived fuels that are not pure biomass fuels shall determine the biomass fuel portion of CO_2 emissions using the method specified in section WCI.23(f), if applicable

(d) Fuel Carbon Content Monitoring Requirements. Fuel carbon content and either molecular weight or molar fraction for gaseous fuels shall be based on the results of fuel sampling and analysis received from the fuel supplier or determined by the operator, in either case using an applicable analytical method listed in section WCI.6.

(1) For coal and coke, solid biomass fuels, and waste-derived fuels; use ASTM 5373-08.

(2) For liquid fuels, use the following ASTM methods: For petroleum-based liquid fuels and liquid waste-derived fuels, use ASTM D5291-02 (Reapproved 2007) “Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants”, ultimate analysis of oil or computations based on ASTM D3238-95 (Reapproved 2005) and either ASTM D2502-04 or ASTM D2503-92 (Reapproved 2007).

(3) For gaseous fuels, use ASTM D1945-03 (Reapproved 2006) or ASTM D1946-90 (Reapproved 2006). The operator may alternatively elect to use on-line instrumentation that determines fuel carbon content accurate to ± 5 percent.

(e) Fuel Analytical Data Capture. When the applicable emissions estimation methodologies in sections WCI.20 through WCI.XXX require periodic collection of fuel analytical data for an emissions source, the operator shall demonstrate every reasonable effort to obtain a fuel analytical data capture rate of 100 percent for each report year.

(1) If the operator is unable to obtain fuel analytical data such that more than 20 percent of emissions from a source cannot be directly accounted for, the emissions from that source shall be considered unverifiable for the report year.

(2) If the fuel analytical data capture rate is at least 80 percent but less than 100 percent for any emissions source identified in sections WCI.20 through WCI.XXX, the operator shall use the mean of the fuel analytical data results captured to substitute for the missing values for the period of missing data.

(f) Procedure for Interim Fuel Analytical Data Collection.

(1) In the event of an unforeseen breakdown of fuel analytical data monitoring equipment required for the emissions estimation methodologies in sections WCI.20 through WCI.XXX, [jurisdiction] may authorize an operator to use an interim data collection procedure if [jurisdiction] determines that the operator has satisfactorily demonstrated that:

(A) The breakdown may result in a loss of more than 20 percent of the source’s fuel data for the reporting year, such that emissions for the affected source could not be verified under the provisions of section WCI.8;

(B) The fuel analytical data monitoring equipment cannot be promptly repaired or replaced without shutting down a process unit significantly affecting facility operations, or that the monitoring equipment must be replaced and replacement equipment is not immediately available;

(C) The interim procedure will not remain in effect longer than is reasonably necessary for repair or replacement of the malfunctioning data monitoring equipment; and

(D) The request was submitted within 30 calendar days of the breakdown of the fuel analytical data monitoring equipment.

(2) An operator seeking approval of an interim data collection procedure must, within 30 days of the monitoring equipment breakdown, submit a written request to [jurisdiction] that includes all of the following:

(A) The proposed start date and end date of the interim procedure;

(B) A detailed description of what data are affected by the breakdown;

(C) A discussion of the accuracy of data collected during the interim procedure compared with the data collected under the operator's usual equipment-based method;

(D) A demonstration that no feasible alternative procedure exists that would provide more accurate emissions data; and

(E) A demonstration that the proposed interim procedure meets the criteria specified in section ~~WCI.2(i)(1)~~WCI.25(f)(1).

(3) *[The jurisdiction]* may limit the duration of the interim data collection procedure or include other conditions of approval to ensure the criteria in section ~~WCI.2(i)(1)~~WCI.25(f)(1) are met.

(4) When approving an interim data collection procedure, [jurisdiction] shall determine whether the accuracy of data collected under the procedure is reasonably equivalent to data collected from properly functioning monitoring equipment, and if it is not, the relative accuracy to assign for purposes of assessing possible material misstatement under section WCI.8(o).

Table 20-1. Default Carbon Content, Heat Content, and Carbon Dioxide Emission Factors from Stationary Combustion by Fuel Type				
~~Fuel Type~~	~~Carbon Content~~	~~Higher Heat Value~~	~~CO_2 Emission Factor~~	~~CO_2 Emission Factor~~
Coal and Coke	**kg C / MMBtu**	**MMBtu / Short Ton**	**kg CO_2 / Short Ton**	**kg CO_2 / MMBtu**
Anthracite	28.26	25.09	2,597.94	103.54
Bituminous	25.49	24.93	2,328.35	93.40
Sub-bituminous	26.48	17.25	1,673.64	97.02
Lignite	26.30	14.21	1,369.32	96.36
Unspecified (Residential/Commercial)	26.00	22.07	2,118.67	95.26
Unspecified (Industrial Coking)	25.56	26.27	2,461.17	93.65
Unspecified (Other Industrial)	25.63	22.05	2,082.89	93.91
Unspecified (Electric Power)	25.76	19.93	1,884.86	94.38
Coke	27.85	24.80	2,530.65	102.04
Natural Gas (By Heat Content)	**kg C / MMBtu**	**MMBtu / 1,000 Standard cubic foot**	**kg CO_2 / 1,000 Standard cubic foot**	**kg CO_2 / MMBtu**
975 to 1,000 Btu / Standard cubic foot	14.73	n/a	n/a	53.97
1000 to 1,025 Btu / Std cubic foot	14.43	n/a	n/a	52.87
1025 to 1,050 Btu / Std cubic foot	14.47	n/a	n/a	53.02
1050 to 1,075 Btu / Std cubic foot	14.58	n/a	n/a	53.42
1075 to 1,100 Btu / Std cubic foot	14.65	n/a	n/a	53.68
Greater than 1,100 Btu / Std cubic foot	14.92	n/a	n/a	54.67
Unspecified (Weighted U.S. Average)	14.47	1.~~,~~027	~~0.0~~54.4	53.02

Table 20-1. Default Carbon Content, Heat Content, and Carbon Dioxide Emission Factors from Stationary Combustion by Fuel Type (continued)				
Petroleum Products	**kg C / MMBtu**	**MMBtu / Barrel**	**kg CO_2 / gallon**	**kg CO_2 / MMBtu**
Asphalt & Road Oil	20.62	6.636	11.94	75.55
Aviation Gasoline	18.87	5.048	8.31	69.14
Distillate Fuel Oil (#1, 2 & 4)	19.95	5.825	10.14	73.10
Jet Fuel	19.33	5.670	9.56	70.83
Kerosene	19.72	5.670	9.75	72.25
LPG (energy use)	17.19	3.861	5.79	62.98
Propane	17.20	3.824	5.74	63.02
Ethane	16.25	2.916	4.13	59.54
Isobutane	17.75	4.162	6.44	65.04
n-Butane	17.72	4.328	6.69	64.93
Lubricants	20.24	6.065	10.71	74.16
Motor Gasoline	19.33	5.218	8.80	70.83
Residual Fuel Oil (#5 & 6)	21.49	6.287	11.79	78.74
Crude Oil	20.33	5.800	10.29	74.49
Naphtha (<401 deg. F)	18.14	5.248	8.30	66.46
Natural Gasoline	18.24	4.620	7.35	66.83
Other Oil (>401 deg. F)	19.95	5.825	10.14	73.10
Pentanes Plus	18.24	4.620	7.35	66.83
Petrochemical Feedstocks	19.37	5.428	9.17	70.97
Petroleum Coke	27.85	6.024	14.64	102.04
Still Gas	17.51	6.000	9.17	64.16
Special Naphtha	19.86	5.248	9.09	72.77
Unfinished Oils	20.33	5.825	10.33	74.49
Waxes	19.81	5.537	9.57	72.58
Other Solid Fuels	**kg C / MMBtu**	**MMBtu / Short Ton**	**kg CO_2 / Short Ton**	**kg CO_2 / MMBtu**
Biomass Derived Fuels (Solid). Wood and Wood Waste (12% moisture content) or other solid biomass fuels (EPA)	25.60	15.38	1,442.62	93.80
Biomass Derived Fuels (Solid). Wood and Wood Waste (50% moisture content) ~~Biomass~~ (Environment Canada~~)~~	29.97	15.47	861.83	55.68
Municipal Solid Waste (MSW)	24.74	8.7	788.7	90.65
Peat	29.07	8.83	940.66	106.53
Biomass-derived Fuels (Gas)	**kg C / MMBtu**	**Btu / Standard cubic foot**	**kg CO_2 / Standard cubic foot~~.~~**	**kg CO_2 / MMBtu**
Biogas (includes landfill gas and manure biogas)*	28.4	Varies	Varies	104.06

Note: Heat content factors are based on ~~higher heating~~high heat values (HHV).

*The emission factors for biogas include both the CO_2 from combustion and the pass-through CO_2, which are assumed to be in equal proportions.

Sources:

U.S. EPA, *Inventory of Greenhouse Gas Emissions and Sinks: 1990-2007 (2009)*, Annex 2.1, Tables A-28, A-31, A-32, A-35, and A-36, except:

- Heat Content factors for Unspecified Coal (by sector), Coke, Naptha (<401 F°), and Other Oil (>401 F°), from U.S. Energy Information Administration, *Annual Energy Review 2007 (Released June 23, 2008)*, Tables A-1, A-4, and A-5;
- Heat Content factors for Coal (by type) and LPG, and all factors for Wood and Wood Waste, Landfill Gas, and Wastewater Treatment Biogas, from U.S. EPA Climate Leaders, *Stationary Combustion Guidance (May, 2008)*, Tables B-1 and B-2; and
- Municipal Solid Waste (MSW) factors, from Energy Information Administration, http://www.eia.doe.gov/oiaf/1605/coefficients.html.
- Peat Emission Factors ~~from Emission factors~~ are based on ~~higher heating~~high heat values (HHV). Values were converted from LHV to HHV assuming that LHV ~~are~~ is 5 percent lower than HHV for solid and liquid fuels.
- HHV calculated from net calorific values in Intergovernmental Panel on Climate Change, *2006 IPCC Guidelines for National Greenhouse Gas*

Inventories (2006), Volume 1, Tables 1.2~~,~~.

Table 20-2. Default Carbon Dioxide Emission Factors from Stationary Combustion for Waste Derived Fuels	
Fuel Type	**kg CO_2 / MMBtu**
Waste Oil	78
Tires	90
Plastics	79
Solvents	78
Impregnated Saw Dust	79
Other Fossil Based Wastes	84
Dried Sewage Sludge	116
Mixed Industrial Waste	88
Municipal Solid Waste	See Table 20-1

Note: Emission factors are based on ~~higher heating~~high heat values (HHV). Values were converted from LHV to HHV assuming that LHV are 5 percent lower than HHV for solid and liquid fuels.
Source: WBCSD/WRI, *The Cement CO_2 Protocol: CO_2 Accounting and Reporting Standard for the Cement Industry Calculation Tool (2004).*

Table 20-3. Default CH_4 and N_2O Emission Factors from Stationary Combustion by Fuel Type

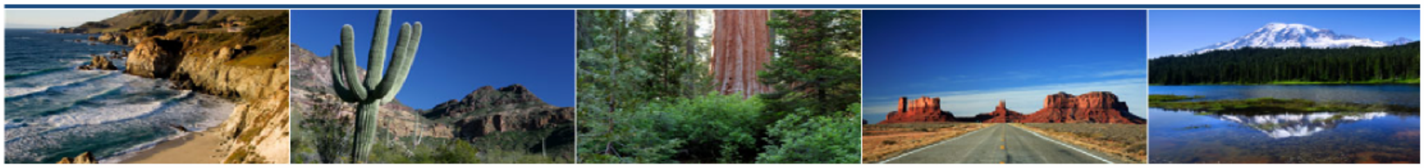
Fuel Type	CH_4 Emission Factor (kg CH_4/ MMBtu)	N_2O Emission Factor (kg N_2O / MMBtu)
Asphalt	0.003	0.0006
Aviation Gasoline	0.003	0.0006
Coal	0.01	0.0015
Crude Oil	0.003	0.0006
Digester Gas	0.0009	0.0001
Distillate	0.003	0.0006
Gasoline	0.003	0.0006
Jet Fuel	0.003	0.0006
Kerosene	0.003	0.0006
Kraft Black Liquor (ICFPA)	0.0026	0.0021
Kraft Black Liquor (Environment Canada)	0.0038	0.0015
Kraft Black Liquor (EPA)	0.03	0.005
Landfill Gas	0.0009	0.0001
LPG	0.001	0.0001
Lubricants	0.003	0.0006
Municipal Solid Waste	0.03	0.004
Naphtha	0.003	0.0006
Natural Gas	0.0009	0.0001
Natural Gas Liquids	0.003	0.0006
Other Biomass Fuels	0.03	0.004
Petroleum Coke	0.003	0.0006
Propane	0.001	0.0001
Refinery Gas	0.0009	0.0001
Residual Fuel Oil	0.003	0.0006
Tires	0.003	0.0006
Waste Oil	0.03	0.004
Waxes	0.003	0.0006

Table 20-3. Default CH_4 and N_2O Emission Factors from Stationary Combustion by Fuel Type		
Fuel Type	**CH_4 Emission Factor (kg CH_4/ MMBtu)**	**N_2O Emission Factor (kg N_2O / MMBtu)**
Wood (Dry)	0.03	0.004
Wood Waste (Environment Canada)	0.0029	0.001

Note: Heat content factors are based on ~~higher heating~~high heat values (HHV).
Source: Intergovernmental Panel on Climate Change, *2006 IPCC Guidelines for National Greenhouse Gas Inventories (2006)*, Volume 2, Tables 2.2, 2.3, and 2.4, except:

- Kraft Black Liquor emission factors, from International Council of Forest and Paper Associations, *Calculation Tools for Estimating Greenhouse Gas Emissions from Pulp and Paper Mills (2005)*, Appendix F, Table 8.

The RC notes the significant difference in both the kraft black liquor and solid biomass (wood waste) emission factors published by the EPA and Environment Canada (as well as those submitted by industry associations). In lieu of recommending a single emission factor at this time (as there is no certainty as to which is most accurate) the RC is presenting both for information purposes. The RC will be working with experts in the two federal agencies and other organizations to ascertain the most accurate emission factor to use for both ~~m~~Metric and English unit versions ~~imperial representations~~ of the Essential Requirements of Mandatory Reporting.~~rule.~~ ~~It is hoped that this can be completed in the two weeks prior to publication of the final Essential Requirements.~~



§ WCI.20 GENERAL STATIONARY COMBUSTION

§ WCI.21 Source Category Definition

General stationary fuel combustion sources are devices that combust solid, liquid, or gaseous fuel for the purpose of generating steam (or providing useful heat or energy) for industrial, commercial, or institutional use; or reducing the volume of waste by removing combustible matter. General stationary combustion sources are boilers, combustion turbines, engines, incinerators, and process heaters, and any other stationary combustion device that is not specifically addressed under the provisions for another source category in this rule.

Note: The source category definition may need to be revised after the remaining ER sections are completed.

§ WCI.22 Greenhouse Gas Reporting Requirements

The emissions data report shall include the following information at the facility level:

(a) Annual greenhouse gas emissions in metric tons, reported as follows:

(1) Total CO_2 emissions for fossil and biomass fuels, reported by fuel type.
(2) Total CH_4 emissions, reported by fuel type.
(3) Total N_2O emissions, reported by fuel type.

(b) Annual fuel consumption:

(1) For gases, report in units of standard cubic ~~feet~~meters.
(2) For liquids, report in units of kilo~~gallons~~liters.
(3) For non-biomass solids, report in units of ~~short~~metric tons.
(4) For biomass solid fuels, report in units of ~~bone dry short tons or~~ bone dry metric tons.

(c) Average carbon content of each fuel, if used to compute CO_2 emissions.

(d) Average ~~higher heating~~high heat value of each fuel, if used to compute CO_2 emissions.

(e) Annual steam generation in ~~pounds or~~ kilograms, for units that burn biomass fuels or municipal solid waste.

~~*Please note that most of the calculation methodologies in this section currently accommodate inputs in English units, only, and not SI units. The section will be revised to allow inputs in SI units, as well as to provide applicable Canadian emission factors from "National Inventory Report 1990-2007: Greenhouse Gas Sources and Sinks in Canada – The Canadian Government's Submission to the UN Framework Convention on Climate Change, April 2009." (http://www.ec.gc.ca/pdb/ghg/inventory_e.cfm)]*~~

§ WCI.23 Calculation of CO_2 Emissions

For each fuel, calculate CO_2 mass emissions using one of the four calculation methodologies specified in this section, subject to the restrictions in §WCI.23(e).

(a) Calculation Methodology 1. Calculate the annual CO_2 mass emissions by substituting a fuel-specific default CO_2 emission factor, a default ~~higher heating~~high heat value, and the annual fuel consumption into the Equation 20-1:

$$CO_2 = Fuel \times HHV \times EF \times 0.001$$ **Equation 20-1**

Where:

CO_2	=	Annual CO_2 mass emissions for the specific fuel type (metric tons).
Fuel	=	Mass or volume of fuel combusted per year (express mass in ~~short~~metric tons for solid fuel, volume in standard cubic ~~feet~~meters for gaseous fuel, and volume in kilo~~gallons~~liters for liquid fuel).
HHV	=	Default ~~higher heating~~high heat value of the fuel, from ~~column 3 of~~ Table 20-1 (~~mmBtu~~~~M~~GJ per ~~mass~~ metric ton for solid fuel, ~~or mmBtu~~~~M~~GJ per kiloliter for liquid fuel, or GJ per cubic meter for gaseous fuel~~volume, as applicable~~).
EF	=	Fuel-specific default CO_2 emission factor, from ~~column 5 of~~ Tables 20-~~1~~ 2, 20-3, 20-5, or 20-7, as applicable (kg CO_2/~~mmBtu~~~~M~~GJ).
0.001	=	Conversion factor from kilograms to metric tons.

(b) Calculation Methodology 2. Calculate the annual CO_2 mass emissions using a default fuel-specific CO_2 emission factor, a ~~higher heating~~high heat value provided by the supplier or measured by the operator, using Equation 20-2, except for emissions from the combustion of biomass fuels and municipal solid waste, for which the operator may instead elect to use the method shown in Equation 20-3.

(1) For any type of fuel for which an emission factor is provided in Tables 20-2, 20-3, 20-5, or 20-7, as applicable~~Tables 20-1 or 20-2~~, except biomass fuels and municipal solid waste when the operator elects to use the method in WCI.23(b)(2), use Equation 20-2:

$$CO_2 = \sum_{p=1}^{n} Fuel_p \times HHV_p \times EF \times 0.001$$ **Equation 20-2**

Where:

CO_2	=	Annual CO_2 mass emissions for a specific fuel type (metric tons).
n	=	Number of required heat content measurements for the year as specified in WCI.25.
$Fuel_p$	=	Mass or volume of the fuel combusted during the measurement period "p" (express mass in ~~short~~metric tons for solid fuel, volume in standard cubic ~~feet~~meters for gaseous fuel, and volume in kilo~~gallons~~liters for liquid fuel).
HHV_p	=	~~Higher heating~~High heat value of the fuel for the measurement period (~~mmBtu~~~~M~~GJ per metric ton for solid fuel, GJ per kiloliter for liquid fuel, or GJ per cubic meter for gaseous fuel~~J per mass or volume~~).

EF = Fuel-specific default CO_2 emission factor, from Tables 20-2, 20-3, 20-5, or 20-7, as applicable~~column 5 of Table 20-1 or from Table 20-2~~ (kg CO_2/~~mmBtu~~~~M~~GJ).

0.001 = Conversion factor from kilograms to metric tons.

(2) For biomass solid fuels and municipal solid waste, use either Equation 20-2 above or Equation 20-3:

$$CO_2 = Steam \times B \times EF \times 0.001$$ **Equation 20-3**

Where:

CO_2 = Annual CO_2 mass emissions from biomass solid fuel or municipal solid waste combustion (metric tons).

Steam = Total mass of steam generated by biomass solid fuel or municipal solid waste combustion during the reporting year (~~lb~~~~kg~~metric tons steam).

B = Ratio of the boiler's design rated heat input capacity to its design rated steam output capacity (~~mmBtu~~~~M~~GJ/~~lb~~ ~~kg~~metric ton steam).

EF = Default emission factor for biomass solid fuel or municipal solid waste, from ~~column 5 of~~ Table 20-~~1~~2 or Table 20-7, as applicable (kg CO_2/~~mmBtu~~~~M~~GJ).

0.001 = Conversion factor from kilograms to metric tons.

(c) Calculation Methodology 3. Calculate the annual CO_2 mass emissions by using measurements of fuel carbon content or molar fraction (for gaseous fuels only), conducted by the operator or provided by the fuel supplier, and the quantity of fuel combusted, using Equation 20-4. For emissions from the combustion of biomass fuels and municipal solid waste, the operator may instead elect to use the method shown in Equation 20-5.

(1) For a solid fuel, use Equation 20-4 of this section:

~~Delete Incorrect Top Equation~~ $$CO_2 = \sum_{i=1}^{n} Fuel_i \times CC_i \times 3.664 \times 0.907$$ **Equation 20-4**

~~Correct Equation on Bottom~~ $$CO_2 = \sum_{i=1}^{n} Fuel_i \times CC_i \times 3.664$$

Where:

CO_2 = Annual CO_2 mass emissions from the combustion of the specific solid fuel (metric tons).

n = Number of carbon content determinations for the year.

$Fuel_i$ = Mass of the solid fuel combusted in measurement period "i" (~~short~~ metric tons).

CC_i = Carbon content of the solid fuel, from the fuel analysis results for measurement period "i" (percent by weight, expressed as a decimal fraction, e.g., 95% = 0.95).

3.664 = Ratio of molecular weights, CO_2 to carbon.

~~0.907 = Conversion factor from short tons to metric tons.~~

(2) For biomass fuels or municipal solid waste, use either Equation 20-4 above or Equation 20-5:

$$CO_2 = Steam \times B \times EF \times 0.001$$

Equation 20-5

Where:

CO_2	=	Annual CO_2 mass emissions from biomass solid fuel or municipal solid waste combustion (metric tons).
Steam	=	Total mass of steam generated by biomass solid fuel or municipal solid waste combustion during the reporting year (~~lb~~ ~~kg~~metric tons steam).
B	=	Ratio of the boiler's design rated heat input capacity to its design rated steam output capacity (~~mmBtu~~~~M~~GJ/~~lb~~ ~~kg~~metric ton steam).
EF	=	Default emission factor for biomass solid fuel or municipal solid waste, from ~~column 5 of~~ Table 20-~~1~~ 2 or 20-7, as applicable~~,~~ (kg CO_2/~~mmBtu~~~~M~~GJ), adjusted no less often than every third year as provided in WCI.25(a)(5)(B).
0.001	=	Conversion factor from kilograms to metric tons.

(3) For a liquid fuel, use Equation 20-6 of this section:

$$CO_2 = \sum_{i=1}^{n} 3.664 \times Fuel_i \times CC_i$$

Equation 20-6

Where:

CO_2	=	Annual CO_2 mass emissions from the combustion of the specific liquid fuel (metric tons).
n	=	Number of required carbon content determinations for the year, as specified in WCI.25.
$Fuel_i$	=	Volume of the liquid fuel combusted in measurement period "i" (kilo~~gallons~~liters).
CC_i	=	Carbon content of the liquid fuel, from the fuel analysis results for measurement period "i" (~~kg~~ metric ton C per kilo~~gallon~~ liter of fuel).
3.664	=	Ratio of molecular weights, CO_2 to carbon.
~~0.001~~	~~=~~	~~Conversion factor from kg to metric tons.~~

(4) For a gaseous fuel, use Equation 20-7 of this section:

$$CO_2 = \sum_{i=1}^{n} 3.664 \times Fuel_i \times CC_i \times \frac{MW}{MVC} \times 0.001$$

Equation 20-7

Where:

CO_2	=	Annual CO_2 mass emissions from combustion of the specific gaseous fuel (metric tons).
n	=	Number of required carbon content and molecular weight determinations for the year, as specified in WCI.25.
$Fuel_i$	=	Volume of the gaseous fuel combusted in period "i" (a day or month, as applicable) (~~scf~~scm).
CC_i	=	Average carbon content of the gaseous fuel, from the fuel analysis results for the period "i" (day or month, as applicable) (kg C per kg of fuel).
MW	=	Molecular weight of the gaseous fuel, from fuel analysis (kg/kg-mole).

MVC	=	Molar volume conversion factor (~~849.5 scf per kg-mole~~24.1 scm per kg-mole for STP of 20°C and 1 atmosphere or ~~836 scf per kg-mole~~23.7 scm per kg-mole for STP of 60°F, and 1 atmosphere).
3.664	=	Ratio of molecular weights, CO_2 to carbon.
0.001	=	Conversion factor from kg to metric tons.

(d) Calculation Methodology 4. Calculate the annual CO_2 mass emissions from all fuels combusted in a unit, by using data from continuous emission monitoring systems (CEMS) as specified in (d)(1) through (d)(7).

(1) For a facility that combusts fossil fuels or biomass fuels and operates CEMS in response to federal, state, provincial, or local regulation, use CO_2 or O_2 concentrations and flue gas flow measurements to determine hourly CO_2 mass emissions using methodologies provided in 40 CFR Part 75, Appendix F or equivalent requirements as applicable in Canada.

(A) The operator shall report CO_2 emissions for the reporting year in metric tons based on the sum of hourly CO_2 mass emissions over the year, converted to metric tons.

(B) If the operator of a facility that combusts biomass fuels uses O_2 concentrations to calculate CO_2 concentrations, annual source testing must demonstrate that calculated CO_2 concentrations when compared to measured CO_2 concentrations meet the Relative Accuracy Test Audit (RATA) requirements in 40 CFR Part 60, Appendix B, Performance Specification 3.

(2) For a facility that combusts waste-derived fuels (as defined in the General Provisions and ~~listed in Table 20-2,~~ including municipal solid waste), and operates a CEMS in response to federal, state, provincial, or local regulations use CO_2 concentrations and flue gas flow measurements to determine hourly CO_2 mass emissions using methodologies provided in 40 CFR Part 75, Appendix F or equivalent requirements as applicable in Canada.

(A) Annual CO_2 emissions shall be reported in metric tons based on the sum of hourly CO_2 mass emissions over the year.

(B) Emissions calculations shall not be based on O_2 concentrations.

(3) The operator of a facility that combusts waste-derived fuels and calculates CO_2 emissions using the methodology provided in WCI.23(d)(2) shall determine the portion of emissions associated with the combustion of biomass~~-derived fuels~~ using the method provided in WCI.23(f).

(4) An operator who uses CEMS data to report CO_2 emissions from a facility that co-fires fossil fuels with biomass fuels or waste-derived fuels that are partly biomass ~~fuels~~ shall determine the portion of total CO_2 emissions separately assigned to the fossil fuel and the biomass ~~fuels~~ using the method provided in WCI.23(f), if applicable. The operator who co-fires pure biomass fuels with fossil fuels may elect to calculate CO_2 emissions for the fossil fuels using methods designated in WCI.23(a) or WCI.23(b)(1), as applicable, by fuel type and then calculate biomass fuel emissions by subtracting the fossil fuel related emissions from the total CO_2 emissions determined using the CEMS based methodology.

(5) For any units for which CO2 emissions are reported using CEMS data, the operator is relieved of the requirement to separately report process emissions from combustion emissions for that unit or to report emissions separately for different fossil fuels for that

unit when only fossil fuels are co-fired. In this circumstance, operators shall still report fuel use by fuel type as otherwise required.

(6) If a facility is subject to requirements in 40 CFR Part 60 or 40 CFR Part 75 and the operator chooses to add devices to an existing CEMS for the purpose of measuring CO2 concentrations or flue gas flow, the operator shall select and operate the added devices pursuant to the requirements in 40 CFR Part 60 or Part 75 that apply to the facility. If the facility is subject to both 40 CFR Part 60 and 40 CFR Part 75, the operator shall select and operate the added devices pursuant to the requirements in 40 CFR Part 75.

(7) If a facility does not have a CEMS and the operator chooses to add one in order to measure CO_2 concentrations, the operator shall select and operate the CEMS pursuant to the requirements in 40 CFR Part 75 or equivalent requirements as applicable in Canada.

(A) The operator shall use CO_2 concentrations and flue gas flow measurements to determine hourly CO_2 mass emissions using methodologies provided in 40 CFR Part 75, Appendix F or equivalent requirements as applicable in Canada.

(B) The operator shall report CO_2 emissions for the report year in metric tons based on the sum of hourly CO_2 mass emissions over the year, converted to metric tons.

(C) Operators who add CEMS under this article are subject to specifications in WCI.23(d)(1)-(5), if applicable.

(e) Use of the Four CO_2 Calculation Methodologies. Use of the four CO_2 emissions calculation methodologies described in paragraphs (a) through (d) of this section is subject to the following requirements and restrictions:

(1) Calculation Methodology 1 may not be used by a facility that is subject to the verification requirements of WCI.8, except for stationary combustion units that combust natural gas with a ~~higher heating~~high heat value between ~~975 and 1,150 Btu per cubic foot~~36.3 and ~~42.8~~40.98 MJ per cubic meter. Otherwise, Calculation Methodology 1 may be used for any type of fuel for which a default CO2 emission factor (Tables 20-2, 20-3, 20-5, or 20-7, as applicable) and a default ~~higher heating~~high heat value for the fuel (Table 20-1) is specified~~ in Table 20-1~~.

(2) Calculation Methodology 2 may not be used by a facility that is subject to the verification requirements of WCI.8, except for stationary combustion units that combust natural gas with a ~~higher heating~~high heat value between ~~975 and 1,150 Btu per cubic foot~~36.3 and ~~42.8~~40.98 MJ per cubic meter. Otherwise, Calculation Methodology 2 may be used for any type of fuel combusted for which a default CO2 emission factor for the fuel is specified in Tables 20-2, 20-3, 20-5, or 20-7, as applicable.~~Table 20-1 or 20-2.~~

(3) Calculation Methodology 3 may be used for a unit of any size combusting any type of fuel, except when the use of Calculation Methodology 4 is required.

(4) Calculation Methodology 4 may be used for a unit of any size combusting any type of fuel, and must be used for: a combustion unit with a CEMS that is required by any federal, state, provincial, or local regulation and that includes both a stack gas volumetric flow rate monitor and a CO_2 concentration monitor.

(f) Mixtures of biomass or biomass fuel and fossil fuel.

(1) The owner or operator that combusts fuels or fuel mixtures for which the biomass fraction is known or can be documented shall use the applicable equations in WCI.23(a)

through (c) to determine the fossil fuel fraction and shall determine the biomass fraction by subtracting the fossil fuel fraction from the total emissions.

(2) The owner or operator that combusts fuels or fuel mixtures for which the biomass fraction is unknown or cannot be documented (for example, municipal solid waste or tire-derived fuels) shall determine the biomass portion of CO_2 emissions using ASTM D6866-06a, as specified in this paragraph. This procedure is not required for fuels that contain less than 5 percent biomass by weight or for waste-derived fuels that are less than 30 percent by weight of total fuels combusted in the year for which emissions are being reported, except where the operator wishes to report a biomass fuel fraction of CO_2 emissions.

(A)~~(1)~~ The operator shall conduct ASTM D6866-06a analysis on a representative fuel or exhaust gas sample at least every three months, and shall collect exhaust gas samples over at least 24 consecutive hours following the standard practice specified by ASTM D7459-08.

(B) ~~(2)~~ The operator shall divide total CO_2 emissions between biomass fuel emissions and non-biomass fuel emissions using the average proportions of the samples analyzed for the year for which emissions are being reported.

(C) ~~(3)~~ If there is a common fuel source to multiple units at the facility, the operator may elect to conduct ASTM D6866-06a testing for one of the units.

§ WCI.24 Calculation of CH_4 and N_2O Emissions

Calculate the annual CH_4 and N_2O mass emissions from stationary fuel combustion sources using the procedures in paragraph (a), (b), or (c), as appropriate.

(a) If the heat content of the fuel is not measured for CO_2 estimation, calculate CH_4 and N_2O emissions using Equation 20-8 for all fuels except coal. For coal, use Equation 20-9:

$$CH_4 \; or \; N_2O = Fuel \times HHV_D \times EF \times 0.000001 \qquad \textbf{Equation 20-8}$$

$$CH_4 \; or \; N_2O = Fuel \times EF_c \times 0.000001 \qquad \textbf{Equation 20-9}$$

Where:

CH_4 or N_2O = Combustion emissions from specific fuel type, metric tons CH_4 or N_2O per year.

Fuel = Mass or volume of fuel combusted per year (express mass in metric tons for solid fuel, volume in standard cubic meters for gaseous fuel, and volume in kiloliters for liquid fuel).~~Mass or volume of fuel combusted for the measurement period, p, specified by fuel type, units of mass or volume per unit time.~~

HHV_D = Default ~~higher heating~~high heat value specified by fuel type provided in Table 20-1, ~~MMBtu~~ ~~M~~(GJ per metric ton for solid fuel, GJ per kiloliter for liquid fuel, or GJ per cubic meter for gaseous fuel)~~J per unit of mass or volume~~.

EF = Default CH_4 or N_2O emission factor provided in Tables 20-2 or 20-~~3~~4, as applicable, ~~k~~grams CH_4 or N_2O per ~~MMBtu~~~~M~~GJ.

EF_c = Default CH_4 or N_2O emission factor for coal provided in Table 20-6 (grams CH_4 or N_2O per metric ton of coal)

0.000001 = Factor to convert ~~k~~grams to metric tons.

(b) If the heat content of the fuel is measured or provided by the fuel supplier for CO_2 estimation, calculate CH_4 and N_2O emissions using Equation 20-~~9~~10 for all fuels except coal. For coal, use Equation 20-11:

$$CH_4 \ or \ N_2O = \sum_{p=1}^{n} Fuel_p \times HHV_p \times EF \times 0.000001 \qquad \textbf{Equation 20-10}$$

$$CH_4 \ or \ N_2O = \sum_{p=1}^{n} Fuel_p \times EF_c \times 0.000001 \qquad \textbf{Equation 20-11}$$

Where:

CH_4 or N_2O = CH_4 or N_2O emissions from a specific fuel type, metric tons CH_4 or N_2O per year.

$Fuel_p$ = Mass or volume of the fuel combusted during the measurement period "p" (express mass in metric tons for solid fuel, volume in standard cubic meters for gaseous fuel, and volume in kiloliters for liquid fuel).~~Mass or volume of fuel combusted specified by fuel type, unit of mass (short metric tons) or volume (scfscm, barrelliter) per year~~.

HHV_p = ~~Higher heating~~High heat value measured directly or provided by the fuel supplier for the measurement period, p, specified by fuel type ~~Default higher heating value of the fuel, from Table 20-1~~ (GJ per metric ton for solid fuel, GJ per kiloliter for liquid fuel, or GJ per cubic meter for gaseous fuel)~~Higher heating value measured for the measurement period, p, specified by fuel type, MMBtu MJ per unit mass or volume~~.

EF = Default CH_4 or N_2O emission factor provided in Tables 20-2 or 20-4, as applicable, ~~k~~grams CH_4 or N_2O per ~~M~~GJ.

EF_c = CH_4 or N_2O emission factor for coal, either measured directly or provided by the fuel supplier, grams CH_4 or N_2O per metric ton of coal

~~Default emission factor provided in Table 20-3, kg CH_4 or N_2O per MMBtuMJ.~~

0.000001 = Factor to convert ~~k~~grams to metric tons.

(c) For biomass and municipal solid waste combustion, the operator may elect to use Equation 20-10 of this section to estimate CH_4 and N_2O emissions:

$$CH_4 \ or \ N_2O = Steam \times B \times EF \times 0.000001 \qquad \textbf{Equation 20-10}$$

Where:

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a municipal solid waste (metric tons).

Steam = Total mass of steam generated by municipal solid waste combustion during the reporting year (~~lb~~ ~~kg~~metric tons steam).

B	=	Ratio of the boiler's ~~maximum~~ design rated heat input capacity to its design rated steam output (~~mmBtu/lbM~~GJ/metric ton~~kg~~ steam).
EF	=	Fuel-specific emission factor for CH_4 or N_2O, from Tables 20-2, 20-4 or 20-6, as applicable ~~WCI.20-3 of this subpart~~ (~~k~~grams CH_4 or N_2O per ~~mmBtu~~G~~M~~J).
0.000001	=	Conversion factor from ~~kilo~~grams to metric tons.

(d) The operator may elect to calculate CH_4 or N_2O emissions using source-specific emission factors derived from source tests conducted at least annually under the supervision of (*jurisdiction*). Upon approval of a source test plan, the source test procedures in that plan shall be repeated in each future year to update the source specific emission factors annually.

(e) Use of the Four CO_2 Calculation Methodologies. Use of the four CH_4 and N_2O emissions calculation methodologies described in paragraphs (a) through (d) of this section is subject to the following requirements and restrictions:

(1) WCI.24(a) may not be used by a facility that is subject to the verification requirements of WCI.8, except for stationary combustion units that combust natural gas with a higher heating value between 975 and 1,150 Btu per cubic foot. Otherwise, WCI.24(a) may be used for any type of fuel for which a default CH_4 or N_2O emission factor (Tables 20-2, 20-4 or 20-6) and a default higher heat value (Table 20-3)~~for the fuel i~~ is specified. ~~in Table 20-3.~~

(2) WCI.24(b) may be used for a unit of any size combusting any type of fuel.

(3) WCI.24(c) may only be used for biomass or municipal solid waste combustion.

(4) WCI.24(d) may be used for a unit of any size combusting any type of fuel.

§ WCI.25 Sampling, Analysis, and Measurement Requirements

(a) Fuel Sampling Requirements. Fuel sampling must be conducted or fuel sampling results must be received from the fuel supplier at the frequency specified in paragraphs (a)(1) through (a)(4) of this section.

(1) Once for each new fuel shipment or delivery or on a monthly basis for middle distillates (diesel, gasoline, fuel oil, kerosene), residual oil, liquid waste-derived fuels, and LPG (ethane, propane, isobutene, n-butane, unspecified LPG).

(2) Monthly for natural gas, associated gas, and mixtures of low ~~Btu~~ MJ gas.

(3) Monthly for gases derived from biomass including landfill gas and biogas from wastewater treatment or agricultural processes.

(4) Monthly for solid fuels, as specified below:

(A) The monthly solid fuel sample shall be a composite sample of weekly samples.

(B) The solid fuel shall be sampled at a location after all fuel treatment operations but before fuel mixing and the samples shall be representative of the fuel chemical and physical characteristics immediately prior to combustion.

(C) Each weekly sub-sample shall be collected at a time (day and hour) of the week when the fuel consumption rate is representative and unbiased.

(D) Four weekly samples (or a sample collected during each week of operation during the month) of equal mass shall be combined to form the monthly composite sample.

(E) The monthly composite sample shall be homogenized and well mixed prior to withdrawal of a sample for analysis.

(F) One in twelve composite samples shall be randomly selected for additional analysis of its discrete constituent samples. This information will be used to monitor the homogeneity of the composite.

(5) For biomass fuels and waste-derived fuels, the following may apply in lieu of WCI.25(a)(4):

(A) If CO_2 emissions are calculated using WCI.23(c)(1), the source-specific carbon content is determined annually. Upon approval of a source test plan by [*jurisdiction*], the source test procedures in that plan shall be repeated in subsequent years to update the source specific emission factors annually.

(B) If CO_2 emissions are calculated using WCI.23(c)(2) (biomass fuels and municipal solid waste only), the operator shall adjust the emission factor, in kg CO_2/~~MMBtu~~ MJ not less frequently than every third year, through a stack test measurement of CO_2 and use of the applicable ASME Performance Test Code to determine heat input from all heat outputs, including the steam, flue gases, ash and losses.

(b) Fuel Consumption Monitoring Requirements.

(1) Facilities may determine fuel consumption on the basis of direct measurement or recorded fuel purchase or sales invoices measuring any stock change (measured in ~~million Btu~~MJ, ~~gallons~~liters, million standard cubic ~~feet~~meters, ~~short~~ metric tons or bone dry ~~short,~~metric tons) using the following equation:

Fuel Consumption in the Report Year = Total Fuel Purchases – Total Fuel Sales + Amount Stored at Beginning of Year – Amount Stored at Year End

(2) Fuel consumption measured in ~~Btu~~ MJ values shall be converted to the required metrics of mass or volume using heat content values that are either provided by the supplier, measured by the facility, or provided in Table 20-1.

(3) All oil and gas flow meters (except for gas billing meters) shall be calibrated prior to the first year for which GHG emissions are reported under this rule, using an applicable flow meter test method listed in section WCI.6 or the calibration procedures specified by the flow meter manufacturer. Fuel flow meters shall be recalibrated either annually or at the minimum frequency specified by the manufacturer.

(4) For fuel oil, tank drop measurements may also be used.

(c) Fuel Heat Content Monitoring Requirements. ~~Higher heating~~High heat values shall be based on the results of fuel sampling and analysis received from the fuel supplier or determined by the operator, in either case using an applicable analytical method listed in section WCI.6.

(1) For gases, use ASTM D1826-94 (Reapproved 2003), ASTM D3588-98 (Reapproved 2003), ASTM D4891-89 (Reapproved 2006), GPA Standard 2261-00 "Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography." The operator may alternatively elect to use on-line instrumentation that determines heating value accurate to within ± 5.0 percent. Where existing on-line instrumentation provides only ~~low~~

~~heating~~low heat value, the operator shall convert the value to ~~higher heating~~high heat value as follows:

$$HHV = LHV \times CF$$

Equation 20-11

Where:

HHV	= fuel or fuel mixture ~~higher heating~~high heat value (~~Btu/scf~~MJ/scm).
LHV	= fuel or fuel mixture ~~lower heating~~low heat value (~~Btu/scf~~MJ/scm).
CF	= conversion factor.

For natural gas, a CF of 1.11 shall be used. For refinery fuel gas and mixtures of refinery fuel gas, a weekly average fuel system-specific CF shall be derived as follows:

(A) by concurrent LHV instrumentation measurements and HHV determined by on-line instrumentation or laboratory analysis as part of the daily carbon content determination; or,
(B) by the HHV/LHV ratio obtained from the laboratory analysis of the daily samples.

(2) For middle distillates and oil, or liquid waste-derived fuels, use ASTM D240-02 (Reapproved 2007), or ASTM D4809-06 (Reapproved 2005).
(3) For solid biomass-derived fuels, use ASTM D5865-07a.
(4) For waste-derived fuels, use ASTM D5865-07a or ASTM D5468-02 (Reapproved 2007). Operators who combust waste-derived fuels that are not pure biomass fuels shall determine the biomass fuel portion of CO_2 emissions using the method specified in section WCI.23(f), if applicable

(d) Fuel Carbon Content Monitoring Requirements. Fuel carbon content and either molecular weight or molar fraction for gaseous fuels shall be based on the results of fuel sampling and analysis received from the fuel supplier or determined by the operator, in either case using an applicable analytical method listed in section WCI.6.

(1) For coal and coke, solid biomass fuels, and waste-derived fuels; use ASTM 5373-08.
(2) For liquid fuels, use the following ASTM methods: For petroleum-based liquid fuels and liquid waste-derived fuels, use ASTM D5291-02 (Reapproved 2007) "Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants", ultimate analysis of oil or computations based on ASTM D3238-95 (Reapproved 2005) and either ASTM D2502-04 or ASTM D2503-92 (Reapproved 2007).
(3) For gaseous fuels, use ASTM D1945-03 (Reapproved 2006) or ASTM D1946-90 (Reapproved 2006). The operator may alternatively elect to use on-line instrumentation that determines fuel carbon content accurate to ± 5 percent.

(e) Fuel Analytical Data Capture. When the applicable emissions estimation methodologies in sections WCI.20 through WCI.XXX require periodic collection of fuel analytical data for an emissions source, the operator shall demonstrate every reasonable effort to obtain a fuel analytical data capture rate of 100 percent for each report year.

(1) If the operator is unable to obtain fuel analytical data such that more than 20 percent of emissions from a source cannot be directly accounted for, the emissions from that source shall be considered unverifiable for the report year.

(2) If the fuel analytical data capture rate is at least 80 percent but less than 100 percent for any emissions source identified in sections WCI.20 through WCI.XXX, the operator shall use the mean of the fuel analytical data results captured to substitute for the missing values for the period of missing data.

(f) Procedure for Interim Fuel Analytical Data Collection.

(1) In the event of an unforeseen breakdown of fuel analytical data monitoring equipment required for the emissions estimation methodologies in sections WCI.20 through WCI.XXX, [jurisdiction] may authorize an operator to use an interim data collection procedure if [jurisdiction] determines that the operator has satisfactorily demonstrated that:

(A) The breakdown may result in a loss of more than 20 percent of the source's fuel data for the reporting year, such that emissions for the affected source could not be verified under the provisions of section WCI.8;

(B) The fuel analytical data monitoring equipment cannot be promptly repaired or replaced without shutting down a process unit significantly affecting facility operations, or that the monitoring equipment must be replaced and replacement equipment is not immediately available;

(C) The interim procedure will not remain in effect longer than is reasonably necessary for repair or replacement of the malfunctioning data monitoring equipment; and

(D) The request was submitted within 30 calendar days of the breakdown of the fuel analytical data monitoring equipment.

(2) An operator seeking approval of an interim data collection procedure must, within 30 days of the monitoring equipment breakdown, submit a written request to [jurisdiction] that includes all of the following:

(A) The proposed start date and end date of the interim procedure;

(B) A detailed description of what data are affected by the breakdown;

(C) A discussion of the accuracy of data collected during the interim procedure compared with the data collected under the operator's usual equipment-based method;

(D) A demonstration that no feasible alternative procedure exists that would provide more accurate emissions data; and

(E) A demonstration that the proposed interim procedure meets the criteria specified in section ~~WCI.2(i)(1)~~WCI.25(f)(1).

(3) *[The jurisdiction]* may limit the duration of the interim data collection procedure or include other conditions of approval to ensure the criteria in section ~~WCI.2(i)(1)~~WCI.25(f)(1) are met.

(4) ~~Data collected pursuant to an approved interim data collection procedure shall be considered captured data for purposes of compliance with the capture rate requirements in section WCI.2(g).~~ When approving an interim data collection procedure, *[jurisdiction]* shall determine whether the accuracy of data collected under the procedure is reasonably equivalent to data collected from properly functioning monitoring equipment, and if it is not, the relative accuracy to assign for purposes of assessing possible material misstatement under section WCI.8(~~q~~o).

~~The original Tables 20-1 through 20-3 have been replaced with the following tables from: "The National Inventory Report – Greenhouse Gas Sources and Sinks in Canada 1990-2007." The table numbers need to be assigned, and citations in the text need to be adjusted.~~

Table 20-1: Default Carbon Content and High~~er~~ Heat~~ing~~ Value by Fuel Type

Liquid Fuels	**Carbon Content (kg C /GJ)**	**High~~er~~ Heat~~ing~~ Value (~~MJ~~GJ/~~KL~~kl)**
Asphalt & Road Oil	19.8	44.46
Aviation Gasoline	19.25	33.52
Diesel	19.06	38.3
Aviation Turbo Fuel	18.67	37.4
Kerosene	18.53	37.68
Propane	16.35	25.31
Ethane	15.61	17.22
Butane	16.67	28.44
Lubricants	19.66	39.16
Motor Gasoline - Off-Road	18.02	35
Light Fuel Oil	19.35	38.8
Residual Fuel Oil (#5 & 6)	20.07	42.5
Crude Oil	19.8	38.32
Naphtha	19.33	35.17
Petrochemical Feedstocks	19.33	35.17
Petroleum Coke - Refinery Use	22.71	46.35
Petroleum Coke - Upgrader Use	22.71	40.57
Solid Fuels	**Carbon Content (kg C /GJ)**	**High~~er~~ Heat~~ing~~ Value (~~MJ~~GJ/~~kg~~metric ton)**
Anthracite Coal	23.74	27.7
Bituminous Coal	20.97	26.33
Foreign Bituminous Coal	21.79	29.82
Sub-Bituminous Coal	25.05	19.15
Lignite	29.97	15
Coal Coke	23.69	28.83
Solid Wood Waste	28.41	18
Spent Puling Liquor	N/A	14
Gaseous Fuels	**Carbon Content (kg C /GJ)**	**~~Higher Heating~~High Heat Value (~~MJ~~GJ/m3)**
Natural Gas	14.12	0.038~~.~~32
Coke Oven Gas	23.03	0.019~~.~~14
Still Gas - Refineries	13.34	0.036~~.~~08
Still Gas - Upgraders	13.34	0.043~~.~~24
Landfill Gas	14.97	0.035~~.~~9
Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007; and Statistics Canada Report on Energy Supply and Demand in Canada.		

~~Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007; and Statistics Canada Report on Energy Supply and Demand in Canada~~

Table 20-2: Default Emission Factors by Fuel Type

Liquid Fuels	CO2 Emission Factor (kg /L)	CO2 Emission Factor (kg /GJ)	CH4 Emission Factor (g/L)	CH4 Emission Factor (g/GJ)	N20 Emission Factor (g/L)	N20 Emission Factor (g/GJ)
Aviation Gasoline	2.342	69.87	2.2	65.63	0.23	6.862
Diesel	2.663	69.53	0.133	3.473	0.4	10.44
Aviation Turbo Fuel	2.534	67.75	0.08	2.139	0.23	6.150
Kerosene						
- Electric Utilities	2.534	67.25	0.006	0.159	0.031	0.823
- Industrial	2.534	67.25	0.006	0.159	0.031	0.823
- Producer Consumption	2.534	67.25	0.006	0.159	0.031	0.823
- Forestry, Construction, and Commercial/Institutional	2.534	67.25	0.026	0.69	0.031	0.823
Propane						
- Residential	1.51	59.66	0.027	1.067	0.108	4.267
- All other uses	1.51	59.66	0.024	0.948	0.108	4.267
Ethane	0.976	56.68	N/A	N/A	N/A	N/A
Butane	1.73	60.83	0.024	0.844	0.108	3.797
Lubricants	1.41	36.01	N/A	N/A	N/A	N/A
Motor Gasoline - Off-Road	2.289	65.40	2.7	77.14	0.05	1.429
Light Fuel Oil						
- Electric Utilities	2.725	70.23	0.18	4.639	0.031	0.799
- Industrial	2.725	70.23	0.006	0.155	0.031	0.799
- Producer Consumption	2.643	68.12	0.006	0.155	0.031	0.799
- Forestry, Construction, and Commercial/Institutional	2.725	70.23	0.026	0.67	0.031	0.799
Residual Fuel Oil (#5 & 6)						
- Electric Utilities	3.124	73.51	0.034	0.800	0.064	1.506
- Industrial	3.124	73.51	0.12	2.824	0.064	1.506
- Producer Consumption	3.158	74.31	0.12	2.824	0.064	1.506
- Forestry, Construction, and Commercial/Institutional	3.124	73.51	0.057	1.341	0.064	1.820
Naphtha	0.625	17.77	N/A	N/A	N/A	N/A
Petrochemical Feedstocks	0.5	14.22	N/A	N/A	N/A	N/A
Petroleum Coke - Refinery Use	3.826	82.55	0.12	2.589	0.0265	0.572
Petroleum Coke - Upgrader Use	3.494	86.12	0.12	2.958	0.0231	0.569
Biomass and Other Solid Fuels	**CO2 Emission Factor**	**CO2 Emission Factor**	**CH4 Emission Factor**	**CH4 Emission Factor**	**N20 Emission Factor**	**N20 Emission Factor**

	(kg /kg)	(kg /GJ)	(g/kg)	(g/GJ)	(g/kg)	(g/GJ)
Landfill Gas	29.89	833	0.6	16.7	0.06	1.671
Wood Waste (Env. Canada)[1]	0.95	52.8	0.05	2.778	0.02	1.111
Wood Waste (U.S. EPA)[2]	1.590	88.9	0.51	28.4	0.068	3.79
Spent Pulping Liquor (Env.Canada)	1.428	102.0	0.05	3.571	0.02	1.429
Spent Pulping Liquor (U.S. EPA)	1.394	99.60	0.44	31.65	0.073	5.275
Coal Coke	2.48	86.02	0.03	1.041	0.02	0.694
Tires	N/A	85	N/A	N/A	N/A	N/A
Gaseous Fuels	**CO2 Emission Factor (kg /m3)**	**CO2 Emission Factor (kg /GJ)**	**CH4 Emission Factor (g/m3)**	**CH4 Emission Factor (g/GJ)**	**N20 Emission Factor (g/m3)**	**N20 Emission Factor (g/GJ)**
Coke Oven Gas	1.6	83.60	0.037	1.933	0.035	1.829
Still Gas - Refineries	1.75	48.50	N/A	N/A	0.0222	0.615
Still Gas - Upgraders	2.14	49.49	N/A	N/A	0.0222	0.513

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007, unless otherwise stated

[1] Assumes 50% moisture content of wood waste

[2] Assumes 12% moisture content of wood waste

Table 20-3: Default Carbon Dioxide Emission Factors for Natural Gas by Province

	Marketable Gas (kg/m3)	Marketable Gas (kg/GJ)	Non-Marketable Gas (kg/m3)	Non-Marketable Gas (kg/GJ)
Quebec	1.878	49.01	Not occurring	Not occurring
Ontario	1.879	49.03	Not occurring	Not occurring
Manitoba	1.877	48.98	Not occurring	Not occurring
British Columbia	1.916	50.00	2.151	56.13

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007

Table 20-4: Default Methane and Nitrous Oxide Emission Factors for Natural Gas

	CH4 (g/m3)	CH4 (g/GJ)	N20 (g/m3)	N20 (g/GJ)
Electric Utilities	0.49	12.79	0.049	1.279
Industrial	0.037	0.966	0.033	0.861
Producer Consumption (Non-marketable)	6.5	169.6	0.06	1.566
Pipelines	1.9	49.58	0.05	1.305
Cement	0.037	0.966	0.034	0.887
Manufacturing Industries	0.037	0.966	0.033	0.861
Residential, Construction, Commercial/Institutional, Agriculture	0.037	0.966	0.035	0.913

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007

Table 20-5: Default Carbon Dioxide Emission Factors for Coal ~~(kg/kg)~~

	Emission Factor (kg/kg)	Emission Factor (kg/GJ)
Quebec		
- Canadian Bituminous	2.25	85.5
- U.S. Bituminous	2.34	88.9
- Anthracite	2.39	86.3
Ontario		
- Canadian Bituminous	2.25	85.5
- U.S. Bituminous	2.43	81.5
- Sub-bituminous	1.73	90.3
- Lignite	1.48	98.7
- Anthracite	2.39	86.3
Manitoba		
- Canadian Bituminous	2.25	85.5
- U.S. Bituminous	2.43	81.5
- Sub-bituminous	1.73	90.3
- Lignite	1.42	94.7
- Anthracite	2.39	86.3
British Columbia		
- Canadian Bituminous	2.07	78.6
- U.S. Bituminous	2.43	81.5
- Sub-bituminous	1.77	92.4

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007

Table 20-6: Default Methane and Nitrous Oxide Emission Factors for Coal

	CH4 Emission Factor (g/kg)	N2O Emission Factor (g/kg)
Electric Utilities	0.022	0.032
Industry and Heat and Steam Plants	0.03	0.02
Residential, Public Administration	4	0.02

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007

Table 20-7: Other Emission Factors

	CO2 Emission Factor (kg/GJ)	CH4 Emission Factor (g/GJ)	N2O Emission Factor (g/GJ)
Municipal Solid Waste	91.7	30	4
~~Black Liquor~~	~~95.3~~	~~3~~	~~22~~
Peat	103	1	1.5
~~Black Liquor~~	~~95.3~~	~~3~~	~~22~~

Source: 2006 IPCC Guidelines for National Greenhouse Gas Inventories, unless otherwise stated

The ~~RC~~WCI notes the significant difference in both the black liquor and solid biomass emission factors published by the EPA and Environment Canada (as well as those submitted by industry associations). In lieu of recommending a single emission factor at this time (as there is no certainty as to which is most accurate) the RC is presenting both for information purposes. The RC will be working with experts in the two federal agencies and other organizations to ascertain the most accurate emission factor to use for both ~~m~~Metric and ~~imperial representations~~English unit versions of the ~~rule~~Essential Requirements of Mandatory Reporting.

§ WCI.30 REFINERY FUEL GAS COMBUSTION

WCI.31 Source Category Definition

This source category consists of any combustion device that is located at a petroleum refinery and that combusts refinery fuel gas, still gas, flexigas, or associated gas.

WCI.32 Greenhouse Gas Reporting Requirements

In addition to the information required by WCI.3, the emissions data report shall include the following information at the facility level:

(a) Annual CO_2, CH_4, and N_2O emissions from refinery fuel gas combustion in metric tons.

(b) Annual fuel consumption in units of million standard cubic feet or cubic meters.

(c) Average carbon content of each fuel, if used to compute CO_2 emissions.

(d) Average ~~high heating~~high heat value of each fuel, if used to compute CO_2 emissions.

WCI.33 Calculation of Greenhouse Gas Emissions

(a) Calculation of CO_2 Emissions. Owners and operators shall calculate daily CO_2 emissions for each fuel gas system using any of the methods specified in paragraphs (a)(1) through (a)(5) of this section. Calculate the total annual CO_2 emissions from combustion of all fuel gas by summing the CO_2 emissions from each fuel gas system.

(1) Use a CEMS that complies with the provisions in section WCI.23(d).

(2) Calculate CO_2 emissions from each refinery fuel gas system and flexigas system using measured carbon content and molecular weight of the gas and Equation 30-1.

$$CO_2 = \sum_{i=1}^{n} Fuel_i \times CC_i \times \frac{MW}{MVC} \times 3.664 \times 0.001$$

Equation 30-1 (English Units)

Where:

CO_2	=	Carbon dioxide emissions, metric tons/year.
$Fuel_i$	=	Daily refinery fuel or flexigas combusted (scf).
CC_i	=	Daily sample of carbon content of the fuel (kg C/kg fuel).
MW	=	Daily sample of molecular weight of fuel.
MVC	=	Molar volume conversion factor (849.5 scf/kg-mole for STP of 20°C and 1 atmosphere, or 836 scf/kg-mole for STP of 60°F and 1 atmosphere).
3.664	=	Conversion factor for carbon to carbon dioxide.
0.001	=	Conversion factor for kg to metric tons.
n	=	Number of days in a year.

$$CO_2 = \sum_{i=1}^{n} Fuel_i \times CC_i \times \frac{MW}{MVC} \times 3.664 \times 0.001$$

Equation 30-1 (Metric Units)

Where:

CO_2 = Carbon dioxide emissions, metric tons/year.
$Fuel_i$ = Daily refinery fuel or flexigas combusted (scm~~3~~).
CC_i = Daily sample of carbon content of the fuel (kg C/kg fuel).
MW = Daily sample of molecular weight of fuel.
MVC = Molar volume conversion factor (24.06 m^3/kg-mole for STP of 20°C and 1 atmosphere, or 23.67 m^3/kg-mole for STP of 60°F and 1 atmosphere).
3.664 = Conversion factor for carbon to carbon dioxide.
0.001 = Conversion factor for kg to metric tons.
n = Number of days in a year.

(A) For refinery fuel gas, the daily carbon content shall be determined a minimum of 3 times a day (once every 8 hours) using on-line instrumentation or discrete laboratory analysis using the methods specified in WCI.34.

(B) For flexigas, the daily carbon content shall be determined once per day using the methods specified in WCI.34.

(3) Calculate CO_2 emissions from each fuel gas system and flexigas system using Equation 30-2 and a daily average ~~high heating~~high heat value that is monitored using a continuous on-line instrument.

$$CO_2 = \sum_{i=1}^{n} HHV_i \times Fuel_i \times EF_{CO2,i} \times 0.000001$$

Equation 30-2 (English Units)

Where:

CO_2 = CO_2 emissions resulting from the combustion of fuel gas from an individual fuel gas system (metric tons/yr).
HHV_i = Daily average ~~high heating~~high heat value of fuel gas, derived from a continuous analyzer and integrated over a 24-hour period (Btu/scf).
$Fuel_i$ = Daily fuel consumption from all fuel combustion units burning gas from the system (scf/d).
$EF_{CO2,i}$ = Daily CO_2 emission factor for an individual fuel gas system, developed using Equation 30-3 (metric tons CO_2/MM-Btu).
0.000001 = Conversion factor for Btu to MMBtu.
n = Number of days per year.

Equation 30-2 (Metric Units)

$$CO_2 = \sum_{i=1}^{n} HHV_i \times Fuel_i \times EF_{CO2,i}$$

Where:

CO_2 = CO_2 emissions resulting from the combustion of fuel gas from an individual fuel gas system (metric tons/yr).
HHV_i = Daily average ~~high heating~~high heat value of fuel gas, derived from a continuous analyzer and integrated over a 24-hour period (MJ/m^3).
$Fuel_i$ = Daily fuel consumption from all fuel combustion units burning gas from the system (m^3/d).
$EF_{CO2,i}$ = Daily CO_2 emission factor for an individual fuel gas system, developed using Equation 30-3 (metric tons CO_2/MJ).
n = Number of days per year.

$$EF_{CO2,i} = CC/HHV \times MW/MVC \times 3.664 \times 1,000$$ **Equation 30-3 (English Units)**

Where:

$EF_{CO2,i}$ = Daily CO_2 emission factor for an individual fuel gas system (metric tons CO_2/MMBtu).
CC = Daily sample of gas carbon content for a fuel gas system, collected according to paragraph (a)(3)(A) of this section (kg carbon/kg fuel).
HHV = Daily sample of gas ~~high heating~~high heat value for a fuel gas system, collected according to paragraph (a)(3)(A) of this section (Btu/scf).
MW = Refinery fuel A molecular weight (kg/kg-mole).
MVC = Molar volume conversion (849.5 scf/ kg-mole, for STP of 20°C and 1 atmosphere, or 836 scf/kg-mole for STP of 60°F and 1 atmosphere).
3.664 = Conversion factor for carbon to carbon dioxide.
1,000 = Conversion factor for kg/Btu to metric tons/MMBtu.

$$EF_{CO2,i} = CC/HHV \times MW/MVC \times 3.664 \times 0.001\cancel{1,000}$$ **Equation 30-3 (Metric Units)**

Where:

$EF_{CO2,i}$ = Daily CO_2 emission factor for an individual fuel gas system (metric tons CO_2/MJ).
CC = Daily sample of gas carbon content for a fuel gas system, collected according to paragraph (a)(3)(A) of this section (kg carbon/kg fuel).
HHV = Daily sample of gas ~~high heating~~high heat value for a fuel gas system, collected according to paragraph (a)(3)(A) of this section (MJ/m^3).
MW = Refinery fuel A molecular weight (kg/kg-mole).
MVC = Molar volume conversion (24.06 m^3/kg-mole for STP of 20°C and 1 atmosphere, or 23.67 m^3/kg-mole for STP of 60°F and 1 atmosphere).
3.664 = Conversion factor for carbon to carbon dioxide.
0.001~~1,000~~ = Conversion factor for kg/MJ to metric tons/MJ.

(A) For Equation 30-3, the carbon content shall be determined once per day by on-line instrumentation or by laboratory analysis of a representative sample using the methods specified in WCI.34. The HHV shall be determined from either the same sample used to conduct the carbon analysis or from on-line instrumentation using the hourly average value that coincides with the same hour in which the carbon content was determined.

(B) For facilities that meet the definition of a small refiner in WCI.10, the emissions measurements and calculations for Equation 30-2 and 30-3 may be conducted weekly.

(4) For associated gas, low ~~Btu~~heat content gas, or other fossil fuels; follow the requirements for general stationary source combustion sources in WCI .23(b) or (c), as appropriate for each fuel.

(5) Where individual fuels are mixed prior to combustion, the operator may choose to calculate CO_2 emissions for each fuel prior to mixing instead of using the methods in paragraphs (a)(1), (a)(2), or (a)(3) of this section. In this case, the operator must determine the fuel flow rate and appropriate fuel specific parameters (e.g. carbon content, HHV) of each fuel stream prior to mixing, calculate CO_2 emissions for each fuel stream, and sum the emissions of the individual fuel streams to determine total CO_2 emissions from the mixture. CO_2 emissions for each fuel stream must be estimated using the following methods:

(A) For natural gas and associated gas, use the appropriate methodology specified in section WCI.23(b) or (c).

(B) For refinery fuel gas and flexigas, use the methodology in either paragraph (a)(2) or (a)(3) of this section.

(C) For low ~~Btu~~ heat content gas, use the methodology in paragraph (a)(2) of this section.

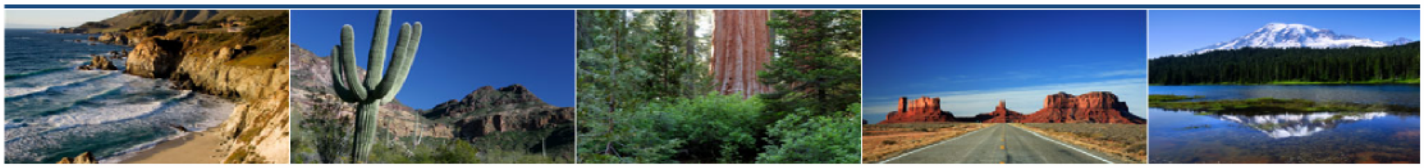
(b) Calculation of CH_4 and N_2O Emissions. Owners and operators shall use the methods specified in section WCI.24 to calculate the annual CH_4 and N_2O emissions.

WCI.34 Sampling, Analysis, and Measurement Requirements

(a) Measure the fuel consumption rate daily using methods specified in WCI.25(b).

(b) Measure the carbon content for fuel gas and flexigas using either ASTM D1945-03 (Reapproved 2006) or ASTM D1946-90 (Reapproved 2006). Where these methods do not adequately quantify all major –hydrocarbons, then an owner or operator may request use of an alternative ASTM or other method to be approved by *[the jurisdiction]*.

(c) Measure ~~high heating~~high heat value using the monitoring requirements specified in WCI.25(c) for gaseous fuels.



§ WCI.40 ELECTRICITY GENERATION (ENGLISH UNITS)

§ WCI.41 Source Category Definition

An electricity generating unit~~or~~ is any combustion device that combusts solid, liquid, or gaseous fuel for the purpose of producing electricity either for sale or for use onsite. This source category includes ~~excludes~~ cogeneration (combined heat and power) units~~ subject to WCI.50~~.

§ WCI.42 Greenhouse Gas Reporting Requirements

For each ~~facility~~electricity generating unit, the emissions data report shall include the following information:

(a) Annual greenhouse gas emissions in metric tons, reported as follows:

(1) Total CO_2 emissions for fossil fuels, reported by fuel type.

(2) Total CO_2 emissions for all biomass fuels combined.

(3) Total CH_4 emissions for fuels combined.

(4) Total N_2O emissions for all fuels combined.

(b) Annual fuel consumption:

(1) For gases, report in units of million standard cubic feet~~ or cubic meters~~.

(2) For liquids, report in units of gallons~~ or liters~~.

(3) For non-biomass solids, report in units of short tons~~ or metric tons~~.

(4) For biomass-derived solid fuels, report in units of bone dry short tons~~ or bone dry metric tons~~.

(c) Average carbon content of each fuel, if used to compute CO_2 emissions as specified in WCI.434.

(d) Average high heating value of each fuel, if used to compute CO_2 emissions as specified WCI.434.

(e) The nameplate generating capacity in megawatts and net power generated in the reporting year in megawatt hours.

(f) For each cogeneration unit, indicate whether topping or bottoming cycle and provide useful thermal output as applicable, in mmBtu~~mmBtu~~~~MJ~~. Where steam or heat is acquired from another facility for the generation of electricity, report the provider and amount of acquired steam or heat in mmBtu. Where supplemental firing has been applied to support electricity generation or industrial output, report this purpose and fuel consumption by fuel type using the units in WCI.42(b).

~~(f)~~(g) Process CO_2 emissions from acid gas scrubbers and acid gas reagent.

~~(g)~~(h) Fugitive emissions of HFC from cooling units that support power generation.

~~(h)~~(i) Fugitive CO_2 emissions from geothermal facilities.

~~(i)~~(j) Fugitive CO_2 emissions from coal storage at coal-fired electricity generating facilities shall be reported as specified in section WCI.100.

§ WCI.43 Calculation of Greenhouse Gas Emissions

(a) Calculation of CO_2 Emissions. Operators shall use CEMS to measure CO_2 emissions if required to operate a CEMS by any other federal, state, provincial, or local regulation. Operators not required to operate a CEMS by another regulation may use either CEMS or the calculation methods specified in paragraphs (a)(1) through (a)(7). Operators using CEMS to determine CO_2 emissions shall comply with the provisions in section WCI.23(d).

(1) Natural Gas. For electric generating units combusting natural gas, use one of the following methods:

(A) If the high heat value is greater than or equal to 975 ~~36.3~~ and less than or equal to 1,100 Btu/scf~~42.8 MJ/scm~~ use either:

(i) The measured carbon content of the fuel and calculation methodology 3 in section WCI.23(c); or

(ii) The measured heat content of the fuel and the calculation methodology 2 in section WCI.23(b) provided the facility is not subject to the verification requirements of WCI.8[BM1].

~~(D)~~(B) If the high heat value is less than 975 ~~36.3~~ or greater than 1,100 Btu/scf~~42.8 MJ/scm~~, use the measured carbon content of the fuel and the calculation methodology 3 in section WCI.23(c).

(2) Coal or Petroleum Coke. For electric generating units combusting coal or petroleum coke, use the measured carbon content of the fuel and calculation methodology 3 in section WCI.23(c).

(3) Middle Distillates, Gasoline, Residual Oil, or Liquid Petroleum Gases. For electric generating units combusting middle distillates (such as diesel, fuel oil, or kerosene), gasoline, residual oil, or LPG (such as ethane, propane, isobutene, n-butane, or unspecified LPG), use one of the following methods:

(A) The measured carbon content of the fuel and calculation methodology 3 in section WCI.23(c); or

(B) The measured heat content of the fuel and calculation methodology 2 in section WCI.23(b) provided the facility is not subject to the verification requirements of WCI.8.

(4) Refinery Fuel Gas, Flexigas, or Associated Gas. For electric generating units combusting refinery fuel gas, flexigas, or associated gas, use the methods specified in section WCI.30.

(5) Landfill Gas, Biogas, or Biomass. For electric generating units combusting landfill gas, biogas, or biomass, use one of the following methods:

(A) The measured carbon content of the fuel and calculation methodology 3 provided in section WCI.23(c); or

(B) The measured heat content of the fuel and calculation methodology 2 in section WCI.23(b) provided the facility is not subject to the verification requirements of WCI.8.

(6) Municipal Solid Waste. Electric generating units combusting municipal solid waste, may use the measured steam generated, the default carbon content emission factor in Table 20-1, and the calculation methodology in section WCI.23(b)(2) provided the facility is not subject to the verification requirements of WCI.8. If the facility is subject to the verification requirements of WCI.8, the operator shall use CEMS to measure CO_2 emissions in accordance with WCI.23(d), or calculate emissions using steam flow and a CO_2 emission factor~~mmBtu~~~~mmBtu~~~~MJ~~ according to the provisions of WCI.23(c)(2).

(7) Start-up Fuels. The operators of generating facilities that primarily combust biomass-derived fuels but combust fossil fuels during start-up, shut-down, or malfunction operating periods only, shall calculate CO_2 emissions from fossil fuel combustion using one of the following methods:

(A) The default emission factors from Tables 20-1 and 20-2 and calculation methodology 1 provided in section WCI.23(a);

(B) The measured heat content of the fuel and calculation methodology 2 provided in section WCI.23(b);

(C) The measured carbon content of the fuel and calculation methodology 3 provided in section WCI.23(c); or

(D) For combustion of refinery fuel gas, the measured heat content and carbon content of the fuel, and the calculation methodology provided in section WCI.30.

(8) Co-fired Electricity Generating Units. For electricity generating units that combust more than one type of fuel, the operator shall calculate CO_2 emissions as follows.

(A) For co-fired electricity generators that burn only fossil fuels, CO_2 emissions shall be determined using one of the following methods:

(i) A continuous emission monitoring system in accordance with calculation methodology 4 in section WCI.23(d). Operators using this method need not report emissions separately for each fossil fuel.

(ii) For units not equipped with a continuous emission system, calculate the CO2 emissions separately for each fuel type using the methods specified in paragraphs (a)(1) through (a)(4) of this section.

(B) For co-fired electricity generators that burn biomass-derived fuel with a fossil fuel, CO_2 emissions shall be determined using one of the following methods:

(i) A continuous emission monitoring system in accordance with calculation methodology 4 in section WCI.23(d). Operators using this method shall determine the portion of the total CO_2 emissions attributable to the biomass-derived fuel and portion of the total CO_2 emissions attributable to the fossil fuel using the methods specified in section WCI.23(d)(4).

(ii) For units not equipped with a continuous emission system, calculate the CO_2 emissions separately for each fuel type using the methods specified in paragraphs (a)(1) through (a)(7) of this section.

(b) Calculation of CH_4 and N_2O Emissions. Operators of electricity generating units shall use the methods specified in section WCI.24 to calculate the annual CH_4 and N_2O emissions. For coal combustion, use the default CH_4 emission factor in Table 20-3. ~~of 1g of CH_4/mmBtu [WCI will need to provide new factor in g of CH_4/MJ or other units].~~

(c) Calculation of CO_2 Emissions from Acid Gas Scrubbing. Operators of electricity generating units that use acid gas scrubbers or add an acid gas reagent to the combustion unit shall calculate the annual CO_2 emissions from these processes using Equation 40-1 if these emissions are not already captured in CO_2 emissions determined using a continuous emissions monitoring system.

$$CO_2 = S \times R \times \left(CO_{2\,MW} / Sorbent_{MW}\right)$$ **Equation 40-1**

Where:

CO_2	=	CO_2 emitted from sorbent for the report year, metric tons;
S	=	Limestone or other sorbent used in the report year, metric tons;
R	=	Ratio of moles of CO_2 released upon capture of one mole of acid gas;
$CO_{2\ MW}$	=	Molecular weight of carbon dioxide (44);
$Sorbent_{\ MW}$	=	Molecular weight of sorbent (if calcium carbonate, 100).

(d) Calculating Fugitive HFC Emissions from Cooling Units. Operators of electricity generating facilities shall calculate fugitive HFC emissions for each HFC compound used in cooling units that support power generation or are used in heat transfers to cool stack gases using either the methodology in paragraph (d)(1) or (d)(2). The Operator is not required to report GHG emissions from air or water cooling systems or condensers that do not contain HFCs.

(1) Use Equation 40-2 to calculate annual HFC emissions:

$$HFC = HFC_{inventory} + HFC_{purchases\,/\,acquisitions} - HFC_{sales\,/\,disbursements} + HFC_{\Delta capacity}$$ **Equation 40-2**

Where:

HFC	=	Annual fugitive HFC emission, metric tons;
$HFC_{inventory}$	=	The difference between the quantity of HFC in storage at the beginning of the year and the quantity in storage at the end of the year. Stored HFC includes HFC contained in cylinders (such as 115-pound storage cylinders), gas carts, and other storage containers. It does not include HFC gas held in operating equipment. The change in inventory will be negative if the quantity of HFC in storage increases over the course of the year.

$HFC_{purchases/acquisitions}$ = The sum of all HFC acquired from other entities during the year either in storage containers or in equipment.

$HFC_{sales/disbursements}$ = The sum of all the HFC sold or otherwise transferred offsite to other entities during the year either in storage containers or in equipment.

$HFC_{\Delta capacity}$ = The net change in the total nameplate capacity (i.e. the full and proper charge) of the cooling equipment). The net change in capacity will be negative if the total nameplate capacity at the end of the year is less than the total nameplate capacity at the beginning of the year.

(2) Use service logs to document HFC usage and emissions from each cooling unit. Service logs should document all maintenance and service performed on the unit during the report year, including the quantity of HFCs added to or removed from the unit, and include a record at the beginning and end of each report year. The operator may use service log information along with the following simplified material balance equations to quantify fugitive HFCs from unit installation, servicing, and retirement, as applicable. The operator shall include the sum of HFC emissions from the applicable equations in the greenhouse gas emissions data report.

$$HFC_{Install} = R_{new} - C_{new}$$

$$HFC_{Service} = R_{recharge} - R_{Recover}$$

$$HFC_{Retire} = C_{retire} - R_{retire}$$

Where:

$HFC_{Install}$ = HFC emitted during initial charging/installation of the unit, kilograms;
$HFC_{Service}$ = HFC emitted during use and servicing of the unit for the report year, kilograms;
HFC_{Retire} = HFC emitted during the removal from service/retirement of the unit, kilograms;
R_{new} = HFC used to fill new unit (omit if unit was pre-charged by the manufacturer), kilograms;
C_{new} = Nameplate capacity of new unit (omit if unit was pre-charged by the manufacturer), kilograms;
$R_{recharge}$ = HFC used to recharge the unit during maintenance and service, kilograms;
$R_{recover}$ = HFC recovered from the unit during maintenance and service, kilograms;
C_{retire} = Nameplate capacity of the retired unit, kilograms; and
R_{retire} = HFC recovered from the retired unit, kilograms.

(e) Fugitive CO_2 Emissions from Geothermal Facilities. Operators of geothermal electricity generating facilities shall calculate the fugitive CO_2 emissions using one of the following methods:

(1) Calculate the fugitive CO_2 emissions using Equation 40-3:

$$CO_2 = 7.53 \times Heat \times 0.001$$ **Equation 40-3**

Where:

CO_2 = CO_2 emissions, metric tons per year;
7.53 = Default fugitive CO_2 emission factor for geothermal facilities, kg per mmBtu~~MJ~~; and
Heat = Heat taken from geothermal steam and/or fluid, mmBtu~~MJ~~/yr.

(2) Calculate CO_2 emissions using [*insert jurisdiction*] approved source specific emission factor.

§ WCI.44 Sampling, Analysis, and Measurement Requirements

(a) CO_2, CH_4 and N_2O Emissions from Fuel Combustion. Operators using CEMS to estimate CO_2 emissions from fuel combustion shall comply with the requirements in section WCI.23(d). Operators using methods other than CEMS shall comply with the applicable fuel sampling, fuel consumption monitoring, heat content monitoring, and carbon content monitoring specified in section WCI.25.

(b) CO_2 Emissions from Acid Gas Scrubbing. Operators of electricity generating units that use acid gas scrubbers or add an acid gas reagent to the combustion unit shall measure the amount of limestone or other sorbent used during the reporting year.~~ using methods that comply with the measurement accuracy provisions in WCI.2(g).~~

(c) CO_2 Emissions from Geothermal Facilities. Operators of geothermal facilities shall measure the heat recovered from geothermal steam. If using source specific emission factor instead of the default factor, the operator shall conduct an annual test of the CO_2 emission rate using a method approved by [*insert jurisdiction*]. The operator shall submit a test plan to the [*insert jurisdiction*] for approval. Once approved, the annual tests shall be conducted in accordance with the approved test plan under the supervision of the [*insert jurisdiction*].

§ WCI.40 ELECTRICITY GENERATION (METRIC UNITS)

§ WCI.41 Source Category Definition

An electricity generating unit~~or~~ is any combustion device that combusts solid, liquid, or gaseous fuel for the purpose of producing electricity either for sale or for use onsite. This source category includes ~~excludes~~ cogeneration (combined heat and power) units~~ subject to WCI.50~~.

§ WCI.42 Greenhouse Gas Reporting Requirements

For each ~~facility~~electricity generating unit, the emissions data report shall include the following information:

(a) Annual greenhouse gas emissions in metric tons, reported as follows:

(1) Total CO_2 emissions for fossil fuels, reported by fuel type.

(2) Total CO_2 emissions for all biomass fuels combined.

(3) Total CH_4 emissions for fuels combined.

(4) Total N_2O emissions for all fuels combined.

(b) Annual fuel consumption:

(1) For gases, report in units of ~~million~~ standard ~~cubic feet or~~ cubic meters.

(2) For liquids, report in units of kilo~~gallons or~~ liters.

(3) For non-biomass solids, report in units of ~~short tons or~~ metric tons.

(4) For biomass-derived solid fuels, report in units of ~~bone dry short tons or~~ bone dry metric tons.

(c) Average carbon content of each fuel, if used to compute CO_2 emissions as specified in WCI.4~~4~~3.

(d) Average high heating value of each fuel, if used to compute CO_2 emissions as specified WCI.4~~4~~3.

(e) The nameplate generating capacity in megawatts and net power generated in the reporting year in megawatt hours.

(f) For each cogeneration unit, indicate whether topping or bottoming cycle and provide useful thermal output as applicable, in ~~mmBtu~~MJ. Where steam or heat is acquired from another facility for the generation of electricity, report the provider and amount of acquired steam or heat in MJ. Where supplemental firing has been applied to support electricity generation or industrial output, report this purpose and fuel consumption by fuel type using the units in WCI.42(b).

~~(f)~~(g) Process CO_2 emissions from acid gas scrubbers and acid gas reagent.

~~(g)~~(h) Fugitive emissions of HFC from cooling units that support power generation.

~~(h)~~(i) Fugitive CO_2 emissions from geothermal facilities.

~~(i)~~(j) Fugitive CO_2 emissions from coal storage at coal-fired electricity generating facilities shall be reported as specified in section WCI.100.

§ WCI.43 Calculation of Greenhouse Gas Emissions

(a) Calculation of CO_2 Emissions. Operators shall use CEMS to measure CO_2 emissions if required to operate a CEMS by any other federal, state, provincial, or local regulation. Operators not required to operate a CEMS by another regulation may use either CEMS or the calculation methods specified in paragraphs (a)(1) through (a)(7). Operators using CEMS to determine CO_2 emissions shall comply with the provisions in section WCI.23(d).

(1) Natural Gas. For electric generating units combusting natural gas, use one of the following methods:

(A) If the high heat value is greater than or equal to ~~975~~ 36.3 and less than or equal to ~~1,100 Btu/scf~~~~42.8~~40.98 MJ/scm use either:

~~(B)~~(i) The measured carbon content of the fuel and calculation methodology 3 in section WCI.23(c); or

~~(C)~~(ii) The measured heat content of the fuel and the calculation methodology 2 in section WCI.23(b) provided the facility is not subject to the verification requirements of WCI.8.

~~(D)~~(B) If the high heat value is less than ~~975~~ 36.3 or greater than ~~1,100 Btu/scf~~~~42.8~~40.98 MJ/scm, use the measured carbon content of the fuel and the calculation methodology 3 in section WCI.23(c).

(2) Coal or Petroleum Coke. For electric generating units combusting coal or petroleum coke, use the measured carbon content of the fuel and calculation methodology 3 in section WCI.23(c).

(3) Middle Distillates, Gasoline, Residual Oil, or Liquid Petroleum Gases. For electric generating units combusting middle distillates (such as diesel, fuel oil, or kerosene), gasoline, residual oil, or LPG (such as ethane, propane, isobutene, n-butane, or unspecified LPG), use one of the following methods:

(A) The measured carbon content of the fuel and calculation methodology 3 in section WCI.23(c); or

(B) The measured heat content of the fuel and calculation methodology 2 in section WCI.23(b) provided the facility is not subject to the verification requirements of WCI.8.

(4) Refinery Fuel Gas, Flexigas, or Associated Gas. For electric generating units combusting refinery fuel gas, flexigas, or associated gas, use the methods specified in section WCI.30.

(5) Landfill Gas, Biogas, or Biomass. For electric generating units combusting landfill gas, biogas, or biomass, use one of the following methods:

(A) The measured carbon content of the fuel and calculation methodology 3 provided in section WCI.23(c); or

(B) The measured heat content of the fuel and calculation methodology 2 in section WCI.23(b) provided the facility is not subject to the verification requirements of WCI.8.

(6) Municipal Solid Waste. Electric generating units combusting municipal solid waste, may use the measured steam generated, the default ~~carbon content~~ emission factor in WCI.20 Table 20-~~1~~7, and the calculation methodology in section WCI.23(b)(2) provided the facility is not subject to the verification requirements of WCI.8. If the facility is subject to the verification requirements of WCI.8, the operator shall use CEMS to measure CO_2 emissions in accordance with WCI.23(d), or calculate emissions using steam flow and a CO_2 emission factor ~~mmMJ~~according to the provisions of WCI.23(c)(2).

(7) Start-up Fuels. The operators of generating facilities that primarily combust biomass-derived fuels but combust fossil fuels during start-up, shut-down, or malfunction operating periods only, shall calculate CO_2 emissions from fossil fuel combustion using one of the following methods:

(A) The default emission factors from Tables ~~20-1 and 20-2~~20-2, 20-3, 20-5 or 20-7, as applicable, and calculation methodology 1 provided in section WCI.23(a);

(B) The measured heat content of the fuel and calculation methodology 2 provided in section WCI.23(b);

(C) The measured carbon content of the fuel and calculation methodology 3 provided in section WCI.23(c); or

(D) For combustion of refinery fuel gas, the measured heat content and carbon content of the fuel, and the calculation methodology provided in section WCI.30.

(8) Co-fired Electricity Generating Units. For electricity generating units that combust more than one type of fuel, the operator shall calculate CO_2 emissions as follows.

(A) For co-fired electricity generators that burn only fossil fuels, CO_2 emissions shall be determined using one of the following methods:

(i) A continuous emission monitoring system in accordance with calculation methodology 4 in section WCI.23(d). Operators using this method need not report emissions separately for each fossil fuel.

(ii) For units not equipped with a continuous emission system, calculate the CO2 emissions separately for each fuel type using the methods specified in paragraphs (a)(1) through (a)(4) of this section.

(B) For co-fired electricity generators that burn biomass-derived fuel with a fossil fuel, CO_2 emissions shall be determined using one of the following methods:

(i) A continuous emission monitoring system in accordance with calculation methodology 4 in section WCI.23(d). Operators using this method shall determine the portion of the total CO_2 emissions attributable to the biomass-derived fuel and portion of the total CO_2 emissions attributable to the fossil fuel using the methods specified in section WCI.23(d)(4).

(ii) For units not equipped with a continuous emission system, calculate the CO_2 emissions separately for each fuel type using the methods specified in paragraphs (a)(1) through (a)(7) of this section.

(b) Calculation of CH_4 and N_2O Emissions. Operators of electricity generating units shall use the methods specified in section WCI.24 to calculate the annual CH_4 and N_2O emissions. For coal combustion, use the default CH_4 emission factor(s) in Table 20-6. ~~(TBD; update along with other text after metric tables are finalized).~~ ~~of 1g of CH_4/mmBtu [WCI will need to provide new factor in g of CH_4/MJ or other units].~~

(c) Calculation of CO_2 Emissions from Acid Gas Scrubbing. Operators of electricity generating units that use acid gas scrubbers or add an acid gas reagent to the combustion unit shall calculate the annual CO_2 emissions from these processes using Equation 40-1 if these emissions are not already captured in CO_2 emissions determined using a continuous emissions monitoring system.

$$CO_2 = S \times R \times \left(CO_{2\,MW} / Sorbent_{MW} \right)$$ **Equation 40-1**

Where:

CO_2	=	CO_2 emitted from sorbent for the report year, metric tons;
S	=	Limestone or other sorbent used in the report year, metric tons;
R	=	Ratio of moles of CO_2 released upon capture of one mole of acid gas;
$CO_{2\,MW}$	=	Molecular weight of carbon dioxide (44);
$Sorbent_{MW}$	=	Molecular weight of sorbent (if calcium carbonate, 100).

(d) Calculating Fugitive HFC Emissions from Cooling Units. Operators of electricity generating facilities shall calculate fugitive HFC emissions for each HFC compound used in cooling units that support power generation or are used in heat transfers to cool stack gases using either the methodology in paragraph (d)(1) or (d)(2). The Operator is not required to report GHG emissions from air or water cooling systems or condensers that do not contain HFCs.

(1) Use Equation 40-2 to calculate annual HFC emissions:

$$HFC = HFC_{inventory} + HFC_{purchases/acquisitions} - HFC_{sales/disbursements} + HFC_{\Delta capacity}$$ **Equation 40-2**

Where:

HFC	=	Annual fugitive HFC emission, metric tons;
$HFC_{inventory}$	=	The difference between the quantity of HFC in storage at the beginning of the year and the quantity in storage at the end of the year. Stored HFC includes HFC contained in cylinders (such as 115-pound storage cylinders), gas carts, and other storage containers. It does not include HFC gas held in operating equipment. The change in inventory will be negative if the quantity of HFC in storage increases over the course of the year.

$HFC_{purchases/acquisitions}$ = The sum of all HFC acquired from other entities during the year either in storage containers or in equipment.

$HFC_{sales/disbursements}$ = The sum of all the HFC sold or otherwise transferred offsite to other entities during the year either in storage containers or in equipment.

$HFC_{\Delta capacity}$ = The net change in the total nameplate capacity (i.e. the full and proper charge) of the cooling equipment). The net change in capacity will be negative if the total nameplate capacity at the end of the year is less than the total nameplate capacity at the beginning of the year.

(2) Use service logs to document HFC usage and emissions from each cooling unit. Service logs should document all maintenance and service performed on the unit during the report year, including the quantity of HFCs added to or removed from the unit, and include a record at the beginning and end of each report year. The operator may use service log information along with the following simplified material balance equations to quantify fugitive HFCs from unit installation, servicing, and retirement, as applicable. The operator shall include the sum of HFC emissions from the applicable equations in the greenhouse gas emissions data report.

$$HFC_{Install} = R_{new} - C_{new}$$

$$HFC_{Service} = R_{recharge} - R_{Recover}$$

$$HFC_{Retire} = C_{retire} - R_{retire}$$

Where:

$HFC_{Install}$ = HFC emitted during initial charging/installation of the unit, kilograms;
$HFC_{Service}$ = HFC emitted during use and servicing of the unit for the report year, kilograms;
HFC_{Retire} = HFC emitted during the removal from service/retirement of the unit, kilograms;
R_{new} = HFC used to fill new unit (omit if unit was pre-charged by the manufacturer), kilograms;
C_{new} = Nameplate capacity of new unit (omit if unit was pre-charged by the manufacturer), kilograms;
$R_{recharge}$ = HFC used to recharge the unit during maintenance and service, kilograms;
$R_{recover}$ = HFC recovered from the unit during maintenance and service, kilograms;
C_{retire} = Nameplate capacity of the retired unit, kilograms; and
R_{retire} = HFC recovered from the retired unit, kilograms.

(e) Fugitive CO_2 Emissions from Geothermal Facilities. Operators of geothermal electricity generating facilities shall calculate the fugitive CO_2 emissions using one of the following methods:

(1) Calculate the fugitive CO_2 emissions using Equation 40-3:

$$CO_2 = 7.14 \times Heat \times 0.001$$ **Equation 40-3**

Where:

CO_2 = CO_2 emissions, metric tons per year;
7.~~53~~14 = Default fugitive CO_2 emission factor for geothermal facilities, kg per ~~mmBtu~~G~~M~~J; and
Heat = Heat taken from geothermal steam and/or fluid, ~~mmBtu~~G~~M~~J/yr.

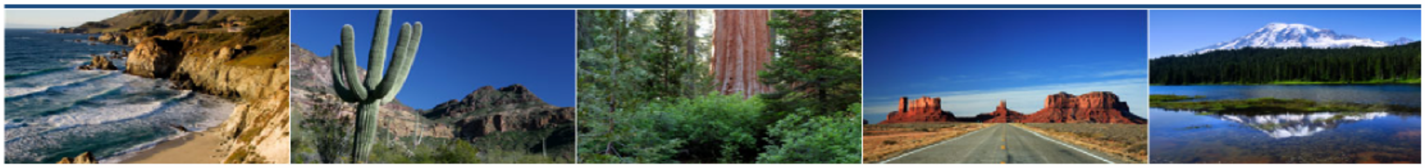
(2) Calculate CO_2 emissions using [*insert jurisdiction*] approved source specific emission factor.

§ WCI.44 Sampling, Analysis, and Measurement Requirements

(a) CO_2, CH_4 and N_2O Emissions from Fuel Combustion. Operators using CEMS to estimate CO_2 emissions from fuel combustion shall comply with the requirements in section WCI.23(d). Operators using methods other than CEMS shall comply with the applicable fuel sampling, fuel consumption monitoring, heat content monitoring, and carbon content monitoring specified in section WCI.25.

(b) CO_2 Emissions from Acid Gas Scrubbing. Operators of electricity generating units that use acid gas scrubbers or add an acid gas reagent to the combustion unit shall measure the amount of limestone or other sorbent used during the reporting year ~~using methods that comply with the measurement accuracy provisions in WCI.2(g)~~.

(c) CO_2 Emissions from Geothermal Facilities. Operators of geothermal facilities shall measure the heat recovered from geothermal steam. If using source specific emission factor instead of the default factor, the operator shall conduct an annual test of the CO_2 emission rate using a method approved by [*insert jurisdiction*]. The operator shall submit a test plan to the [*insert jurisdiction*] for approval. Once approved, the annual tests shall be conducted in accordance with the approved test plan under the supervision of the [*insert jurisdiction*].



~~Suggested Essential Requirements for Reporting of Imported~~

§ WCI.60 IMPORTED ELECTRICITY

[*The requirements in this attachment do not include the default emissions factors necessary for reporting imported electricity from asset-controlling suppliers or imports from unspecified sources. Default factors for unspecified sources are under development by the Electricity Committee and asset-controlling suppliers will need to approach each jurisdiction for approval of a differentiated default factor.*]

§ WCI.61 Definitions

"Asset-controlling supplier" means any entity that owns or operates electricity generating facilities or serves as an exclusive marketer for certain generating facilities even though it does not own them, and is assigned a supplier-specific identification number for its fleet of generating facilities by [*the jurisdiction*].

"Balancing authority" means a responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports interconnection frequency in real time.

"Balancing authority area" means the collection of generation, transmission, and loads within the metered boundaries of a balancing authority. A balancing authority maintains load-resource balance within this area.

"Busbar" means a power conduit of an electricity generating facility that serves as the starting point for the electricity transmission system.

"Electricity generating facility" means a facility that generates electricity and includes one or more electricity generating units at the same location.

"Electricity importer" means [common boundary FJD] an owner of imported electricity ~~generated outside the WCI region~~[*or electricity wheeled through the WCI Region*] as it is delivered to the first point of delivery in the WCI Region ~~for electricity having a final point of delivery in the WCI Region~~ or; [individual boundary FJD] an owner of imported electricity ~~generated outside the WCI region~~[*or electricity wheeled through the WCI Region*] as it is delivered to the first point of delivery in the WCI Partner jurisdiction of the final point of delivery ~~[Both definitions included until the Partners make a final decision on the boundary issue~~. [The definition used may vary by jurisdiction.]

"Electricity transaction" means the purchase, sale, import, export or exchange of electric power.

"Electricity wheeled through the WCI Region" means electricity that is imported into the WCI Region but is simultaneously exported out of the WCI Region and has a final point of delivery in a location outside of the WCI Region.

"Entity" means a person, firm, association, organization, partnership, business trust, corporation, limited liability company, company, or government agency.

"Exchange agreement" means a commitment between electricity market participants to swap energy for energy. Exchange transactions do not involve transfers of payment or receipts of money for the full market value of the energy being exchanged, but may include payment for net differences due to market price differences between the two parts of the transaction or to settle minor imbalances.

"Final point of delivery" means the last point of delivery for a given electricity transaction.

"First Jurisdictional Deliverer" means the owner or operator of an electricity generating facility in a WCI Partner jurisdiction or an electricity importer that is jurisdictional to the regulatory authority of a WCI Partner jurisdiction or the immediate downstream purchaser or recipient of electricity from a non-jurisdictional electricity importer.

"Gross generation" means the total electrical output of the generating unit, expressed in megawatt hours (MWh) per year.

"Imported ~~power~~electricity" means electric power generated ~~in a non-WCI location~~outside the WCI Region, delivered into the WCI Region and having a final point of delivery in the WCI Region.

"Megawatt hour" or "MWh" means the electrical energy unit of measure equal to one million watts of power supplied to, or taken from, an electric circuit steadily for one hour.

"Multi-jurisdictional retail provider" means a retail provider that provides electricity to consumers in ~~a WCI Partner~~[*the jurisdiction*] and in one or more other non-WCI ~~states and provinces~~jurisdictions in a contiguous service territory.

"Nameplate generating capacity" means the maximum rated output of a generator under specific conditions designated by the manufacturer, expressed in megawatts (MW) or kilowatts (kW).

"Net power generated" means the gross generation minus station service or unit service power requirements, expressed in megawatt hours (MWh) per year. In the case of cogeneration, this value is intended to include internal consumption of electricity for the purposes of a production process, as well as power put on the grid.

"NERC E-tag" means North American Electric Reliability Corporation (NERC) energy tag representing transactions on the North American bulk electricity market scheduled to flow between or across balancing authority areas.

"Point of delivery" means a point on an electricity transmission or distribution system where a power supplier delivers electricity to the receiver of that energy. This point can be an interconnection with another system or a substation where the transmission provider's transmission and distribution systems are connected to another system, or a distribution substation where electricity is imported into the WCI region over a multi-jurisdictional retail provider's distribution system.

"Power contract" means an arrangement for the purchase of electricity. Power contracts may be, but are not limited to, power purchase agreements and tariff provisions.

"Purchasing/selling entity" means an entity that purchases or sells energy or capacity and ~~reserve~~reserves transmission services between or among balancing authority areas.

"Renewable energy" means energy from sources that constantly renew themselves or that are regarded as practically inexhaustible. Renewable energy includes, but is not limited to, energy derived from solar, wind, geothermal, hydroelectric, wood, biomass, tidal power, sea currents, and ocean thermal gradients.

"Renewable energy certificate" or "renewable energy credit" means a certificate of proof issued by an approved generation information system or third-party verifier that one MWh of electricity was generated by a renewable energy source.

"Retail provider" means an entity that provides electricity to retail end users in [*the* ~~WCI Region~~*jurisdiction*].

"Specified source" means a specific electricity generating unit or electricity generating facility which can be matched to a reported electricity transaction due to full or partial ownership by the first jurisdictional deliverer or due to its identification in a power contract with the first jurisdictional deliverer.

~~"Stationary source" means any building, structure, facility, or installation that emits or may emit greenhouse gases.~~

"Unspecified source" means electricity generation that cannot be matched to a specific electricity generating facility or electricity generating unit. Unspecified sources of ~~power~~ electricity may include ~~power~~electricity purchased from entities that own fleets of generating facilities such as independent power producers, retail providers, and federal power agencies and power purchased from electricity marketers, brokers, and markets.

"Western Climate Initiative" or "WCI" means a collaborative effort of the U.S. states and Canadian provinces that comprise the WCI Region to reduce greenhouse gas emissions in their respective jurisdictions.

"WCI Region" means the Canadian provinces of British Columbia, Manitoba, Ontario, and Quebec plus the U.S. states of Arizona, California, Montana, New Mexico, Oregon, Utah, and Washington, excluding lands that are not subject to state or provincial jurisdiction.

§ WCI.62 Greenhouse Gas Emissions Data Report: First Jurisdictional Deliverers of Imported ~~Power~~Electricity

(a) General Requirements. First jurisdictional deliverers shall meet the following general requirements in preparing their greenhouse gas emissions data report for each report year. When reporting emissions and electricity transactions, first jurisdictional deliverers, excluding imported electricity that is imported at the distribution level by multi-jurisdictional retail providers, shall:

(1) Specify the amount of greenhouse gas emissions in metric tons CO_2e;

(2) Specify the amount of electricity in MWh;

~~(3)~~ Aggregate imported ~~power by point of delivery;~~

~~(4) Report the amount of~~ electricity ~~as measured at the first point of delivery in the WCI Region;~~

(3) ~~For electricity from unspecified sources, disaggregate imported power for each point of delivery by purchasing/seller entity from which the power was purchased, if~~ and emissions from specified sources by electricity generating facility or electricity generating unit, as applicable;

(4) For electricity from specified sources, specify the facility name, the facility ID, and, if applicable, the electricity generating unit ID for the unit generating the ~~power, if~~electricity;

(5) Report the amount of imported electricity from specified sources as measured at the busbar;

(6) For imported electricity transactions from specified sources where measurements at the busbar are not known, report the amount of imported electricity from the applicable~~;~~ specified sources as measured at the first point of delivery in [*the jurisdiction]* and report estimated transmission losses for each specified source;

(7) Report the amount of electricity from unspecified sources as measured at the first point of delivery in [*the jurisdiction*];

(8) For electricity from unspecified sources, disaggregate imported electricity by the balancing authority area or other geographic area as defined by [*the jurisdiction*] from which the electricity originated;

(9) Report the amount of electricity from asset-controlling suppliers as measured at the first point of delivery in [*the jurisdiction*];

(10) For electricity from asset-controlling suppliers, disaggregate imported electricity by the asset-controlling or asset-owning supplier from which the electricity was purchased;

(11) Report the number of renewable energy certificates from sources not in the WCI region that are retired, or whose greenhouse gas source specification fields are retired, as applicable, associated with imported electricity from an unspecified ~~imported power~~source or imported electricity from a specified ~~imported power~~source having an emission rate equal to or less than the default rate for the ~~region~~balancing authority where the specified generating facility is located;

(12) Specify electricity imported under exchange agreements as you would other import transactions;

(13) Report quantities of ~~imported~~ electricity wheeled through the WCI Region ~~to a final point of delivery outside the WCI Region~~ as measured at the first point of delivery inside ~~the WCI Region~~[*the jurisdiction*];

(14) Retain for purposes of verification NERC E-tags, power contracts, settlements data, and all other information needed to confirm the transactions.

(b) Report Content. First Jurisdictional Deliverers shall include the following information in the greenhouse gas emissions data report for each report year.

(1) Specified Imported ~~Power~~ Electricity Transactions. ~~Electricity~~ Imported electricity and emissions from specified sources for which the First Jurisdictional Deliverer is the electricity importer or that the First Jurisdictional Deliverer purchased or received immediately downstream from a non-jurisdictional electricity importer.

(A) ~~Power~~ Electricity imported into the WCI Region from a specified hydroelectric generating facility with nameplate capacity of greater than 30 MW that was operational prior to January 1, 2008 or from a specified nuclear facility that was operational prior to January 1, 2008 shall be listed as one of the following:

(i) ~~Power~~ Electricity purchased with a contract in effect prior to January 1, 2008 that remains in effect or has been renegotiated for the same facility for the same share or quantity of net generation within one year of contract expiration;

(ii) ~~Power~~Electricity purchased not meeting ~~(2~~WCI.62(b)(1)(A)~~1.a~~(i) and that is not associated with an increase in the facility's generating capacity;

(iii) ~~Power~~Electricity purchased not meeting ~~(2~~WCI.62(b)(1)(A)~~1.a~~(i) that is associated with an increase in the facility's generating capacity due to increased efficiencies or other capacity increasing actions;

(iv) ~~Power~~Electricity purchased from hydroelectric generating facilities during a "spill or sell" situation where power not purchased is lost;

(v) ~~Power~~Electricity purchased that does not meet ~~(2~~WCI.62(b)(1)(A)~~1.a~~(i) due to federal power redistribution polices for federally owned resources and not related to price bidding.

(2) Unspecified Imported ~~Power~~Electricity Transactions. ~~Electricity~~ Imported electricity and emissions from unspecified sources for which the First Jurisdictional Deliverer is the electricity importer or that the First Jurisdictional Deliverer purchased or received immediately downstream from a non-jurisdictional electricity importer~~ with final point of delivery in the WCI Region~~.

(3) ~~Electricity Wheeled Through the WCI Region. Power imported into the WCI Region~~Imported Electricity from Asset-Controlling Suppliers. Imported electricity and emissions from asset-controlling suppliers for which the First Jurisdictional Deliverer is the electricity importer or that the First Jurisdictional Deliverer purchased or received immediately downstream from a non-jurisdictional electricity importer~~ with a final point of delivery outside of the WCI Region, measured at the first point of delivery in the WCI Region~~.

(4) Electricity Wheeled Through the WCI Region. Electricity wheeled through the WCI Region for which the First Jurisdictional Deliverer is the electricity importer or that the First Jurisdictional Deliverer purchased or received immediately downstream from a non-jurisdictional electricity importer.

§ WCI.63 Calculation of Emissions from Specified Sources

For each specified source, calculate CO_2 mass emissions using one of the two calculation methodologies specified in this section.

(a) Calculation Methodology 1: If the specified source reports emissions to [*the jurisdiction*], The Climate Registry, the U.S.EPA under 40 CFR Part 75 or to Environment Canada under Section 71 of the Canadian Environmental Protection Act calculate emissions using Equation 60-1:

$$CO_2 = CO_{2t} \times \frac{MWh_{imp}}{MWh_t} \qquad \textbf{Equation 60-1}$$

Where:

CO_2 = Annual CO_2 mass emissions for imported electricity from the specified source (metric tons).

CO_{2t} = Total annual CO_2 mass emissions from the specified source (metric tons) reported, in order of preference, to [*the jurisdiction*], The Climate Registry, or to the U.S.EPA or Environment Canada.

MWh_{imp} = Megawatt-hours of electricity imported from the specified source, including estimated losses for transactions not measured at the busbar.

MWh_t = Total megawatt-hours of net power generated by the specified source.

(b) Calculation Methodology 2: If the specified source does not report emissions to [*the jurisdiction*], The Climate Registry, the U.S.EPA under 40 CFR Part 75 or to Environment Canada under Section 71 of the Canadian Environmental Protection Act, calculate emissions using Equation 60-2:

$$CO_2 = \sum HHV_f \times EF_f \times 0.001 \times \frac{MWh_{imp}}{MWh_t} \qquad \textbf{Equation 60-2}$$

Where:

CO_2 = Annual CO_2 mass emissions for a specific fuel type (metric tons).

HHV_f = Higher heating value of the fuel *f* consumed for electricity production as reported in U.S. EIA Form 923, or its successor (mmBtu).

EF_f = Fuel-specific default CO_2 emission factor, from column 5 of Table 20-1 or from Table 20-2 (kg CO_2/mmBtu).

0.001 = Conversion factor from kilograms to metric tons.

MWh_{imp} = Megawatt-hours of electricity imported from the specified source.

MWh_t = Total megawatt-hours of net power generated by the specified source as reported in U.S. EIA Form 923, or its successor.

§ WCI.64 Calculation of Emissions from Asset-Controlling Suppliers and Unspecified Sources

For imported electricity from asset-controlling suppliers or unspecified sources, calculate emissions using the methodology specified in this section.

(a) Calculation Methodology: Calculate the annual CO_2 mass emissions by multiplying the reported quantities of imported electricity from each asset-controlling supplier, balancing authority area, or other geographic region defined by [*the jurisdiction*] by the appropriate default emission factor according to Equation 60-3:

$$CO_2 = MWh \times DEF \qquad \text{Equation 60-3}$$

Where:

CO_2 = Annual CO_2 mass emissions for imported electricity from the specified source (metric tons).

MWh = Megawatt-hours of electricity imported from the asset-controlling supplier, balancing authority area, or other geographic region defined by [*the jurisdiction*].

DEF = The default emission factor corresponding to the asset-controlling supplier, balancing authority area, or other geographic region defined by [*the jurisdiction*].

§ WCI.65 Greenhouse Gas Emissions Data Report: Additional Requirements for Retail Providers Only

[*This section is optional. It is intended for any WCI jurisdiction that wishes to collect information about high-GHG generating facilities in other jurisdictions owned by retail providers serving its own jurisdiction.*]

Retail providers ~~that serve consumers in the WCI Region~~ shall include the following information in the greenhouse gas emissions data report for each report year, in addition to the information identified in the sections above.

~~(c)~~(a) If the retail provider holds a contract that entitles the retail provider to a specified percentage of the generation in the report year from an electricity generating facility not located in the WCI Region, the retail provider shall include ~~power~~ electricity purchased or sold from that facility as being from a partially owned facility.

(b) For electricity generating facilities not located in the WCI Region that are fully or partially owned by the retail provider that have CO2 emissions greater than 500 kg of CO2 per MWh based on the most recent greenhouse gas emissions data report that received a positive verification opinion or on CO2 emissions reported to U.S.EPA under 40 CFR Part 75 or reported to Environment Canada under Section 71 of the Canadian Environmental Protection Act, the retail provider shall include:

(1) Facility name, state/province designated facility ID, state/province designated generating unit ID as applicable, percent ownership share at the facility level, ownership share at the generating unit level as applicable, and both net and gross power generated in the report year;

~~(2)~~ Quantity of ~~power from the~~ electricity ~~generating facility or electricity generating unit measured at the busbar and imported into the WCI Region with a final point of delivery in the WCI Region;~~

(2) ~~Quantity of power~~ sold by the retail provider or on behalf of the retail provider from the electricity generating facility or electricity generating unit ~~measured at the busbar and with~~having a final point of delivery outside the WCI Region~~. These quantities shall be disaggregated by purchasing counterparty.~~, as measured at the busbar.

§ WCI.~~64~~66 Greenhouse Gas Emissions Data Report: Additional Requirements

for Multi-~~Jurisdiction~~Jurisdictional Retail Providers Only.

[*This section applies only to jurisdictions with Multi-Jurisdictional Retail Providers, as defined.*]

Multi-jurisdictional retail providers that import ~~power~~ electricity into the WCI Region at the distribution level shall include the following information in the greenhouse gas emissions data report for each report year~~,~~ in addition to the information identified in the sections above. Multi-jurisdictional retail providers meeting this condition shall provide:

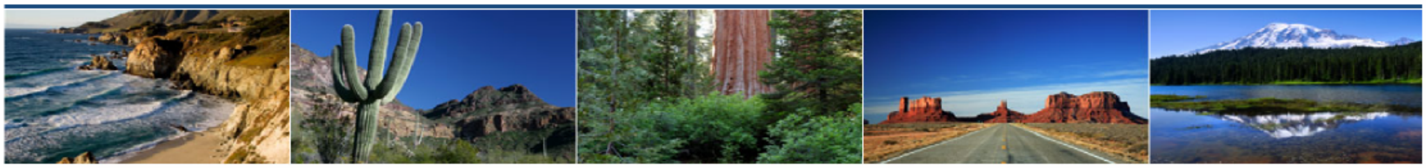
(a) A report of the greenhouse gas emissions associated with serving the load of the service territory that includes consumers in ~~the WCI Region~~[*the jurisdiction*] following [*the jurisdiction's*] reporting protocol for retail providers or The Climate Registry's Electric Power Sector Protocol ~~or the applicable state or provincial reporting protocol for retail providers~~;

(b) The total retail load served by the multi-jurisdictional retail provider in the service territory that includes consumers in ~~the WCI Region;~~[*the jurisdiction*];

(c) The retail load of customers served in ~~the WCI Region~~[*the jurisdiction's*] portion of the service territory; ~~and~~

(d) ~~A report on adjustments to~~The greenhouse gas emissions associated with the imported electricity as the quantity of emissions reported in WCI.64(a) multiplied by the ratio of the quantity of electricity reported in WCI.64(b) to the quantity of electricity reported in WCI.64(c); and

(e) If the ~~service territory's~~ average emission ~~rate that cause the average emission rate to~~ rates differ among the various state or provincial portions of the service territory due to mandatory factors such as different Renewable Portfolio Standard requirements in [*the jurisdiction*] and the ~~WCI state or province and~~other jurisdictions, the ~~non-WCI state(s) or province(s).~~multi-jurisdictional retail provider may report an adjusted quantity of greenhouse emissions and file a report that describes how the quantity reported in WCI.64(d) was adjusted.



§ WCI.70 PRIMARY ALUMINUM PRODUCTION

§ WCI.71 Source Category Definition

A primary aluminum production process converts alumina mineral to aluminum metal using electrolysis.

§ WCI.72 Greenhouse Gas Reporting Requirements

For each facility that includes a primary aluminum production process, the emissions data report must contain the following information:

(a) CO_2 emissions from anode consumption from prebaked and Søderberg electrolysis cells.

(b) CO_2 emissions from anode and cathode baking.

(c) CF_4 and C_2F_6 emissions for anode effects.

(d) CO_2 emissions from green coke calcination.

(e) SF_6 emissions from cover gas consumption.

(f) CO_2, N_2O, and CH_4 emissions from stationary combustion units as specified in WCI.20.

(g) Annual aluminum production.

§ WCI.73 Calculation of GHG Emissions

(a) Calculate CO_2 emissions from anode consumption using either Equation 70-1 or 70-2, as applicable.

(1) For Prebaked Anodes:

$$E_{CO_2} = \sum_{i=1}^{12} [NCC \times MP \times \frac{(100 - S_a - Ash_a - Imp_a)}{100} \times 3.664]_i$$ **Equation 70-1**

Where:

E_{CO2}	=	Annual CO_2 emissions (metric tons).
NCC	=	Net anode consumption per metric ton of aluminum for month i (metric ton/ metric ton aluminum).
MP	=	Aluminum production for month i (metric ton).
S_a	=	Sulfur content in baked anodes for month i (wt %).
Ash_a	=	Ash content in baked anodes for month i (wt %).
Imp_a	=	Content of fluorine and other impurities in baked anodes for month i (wt %).
3.664	=	Conversion factor from carbon to CO_2.

(2) For Søderberg Anodes:

$$E_{CO_2} = \sum_{i=1}^{12} \left[\begin{array}{l} (PC \times MP) - \left(BSM \times \frac{MP}{1000} \right) - \left(\frac{BC}{100} \times PC \times MP \times \left(\frac{S_p + Ash_p + H_p}{100} \right) \right) \\ - \left(\frac{100 - BC}{100} \times PC \times MP \times \frac{S_c + Ash_c}{100} \right) \end{array} \right]_i \times 3.664$$

Equation 70-2

Where:

E_{CO2}	=	Annual CO_2 emissions (metric tons).
PC	=	Paste consumption for month i (metric tons paste/metric ton aluminum).
MP	=	Aluminum production for month i (metric tons).
BSM	=	Emissions of benzene-soluble matter (kilograms benzene-soluble matter/metric ton aluminum).
BC	=	Average binder (pitch) content in paste for month i (wt %).
S_p	=	Sulfur content in pitch for month i (wt %).
Ash_p	=	Ash content in pitch (wt %).
H_p	=	Hydrogen content in pitch (wt %).
S_c	=	Sulfur content in calcinated coke (wt %).
Ash_c	=	Ash content in calcinated coke (wt %).
3.664	=	Conversion factor from carbon to CO_2.

(b) If anode or cathode baking is performed onsite, calculate CO_2 emissions as specified in paragraphs (b)(1) or (2) as applicable. Total emissions as specified in paragraph (b)(3) if both (b)(1) and (2) are applicable.

(1) Calculate CO_2 emissions from packing coke using Equation 70-3.

$$EC_{CO_2} = \sum_{i=1}^{12} \left(PCC \times BAP \times \frac{100 - Ash_{pc} - S_{pc} - Imp}{100} \right)_i \times 3.664$$

Equation 70-3

Where:

EC_{CO2}	=	Annual CO_2 emissions (metric tons pre year).
PCC	=	Packing coke consumption per metric ton of baked anode for month i (metric tons coke/metric ton anodes).
BAP	=	Baked anode production for month i (metric tons).
Ash_{pc}	=	Ash content in packing coke for month i (wt %).
S_{pc}	=	Sulfur content in packing coke for month i (wt %).
Imp	=	Content of other impurities for month i (wt %).
3.664	=	Conversion factor from carbon to CO_2.

(2) Calculate CO_2 emissions from pitch coking using Equation 70-4.

$$EP_{CO_2} = \sum_{i=1}^{12} \left(GAW - BAP - \left(\frac{H_p}{100} \times \frac{PC}{100} \times GAW \right) - RT \right)_i \times 3.664$$ **Equation 70-4**

Where:

EP_{CO2} = CO_2 emissions (metric tons pre year).
GAW = Green anode consumption for month i (metric tons).
BAP = Baked anode production for month i (metric tons).
H_p = Hydrogen content in pitch for moth i (wt %).
PC = Pitch content in green anode for month i (wt %).
RT = Recovered tar for month i (metric tons).
3.664 = Conversion factor from carbon to CO_2.

(3) Calculate total CO_2 emissions for anode baking using Equation 70-5.

$$E_{anodebaking} = EC_{CO2} + EP_{CO2}$$ **Equation 70-5**

Where:

$E_{anodebaking}$ = Total annual CO_2 emissions from anode baking (metric tons).

EC_{CO2} = Annual CO_2 emissions from packing coke (metric tons).

EP_{CO2} = Annual CO_2 emissions from pitch coking (metric tons).

(c) Calculate CF_4 and C_2F_6 emissions from anode effects for each pot line using either the Slope Method in paragraph (c)(1) or the Pechiney Method in paragraph (c)(2).

(1) **Slope Method:** Calculate the CF_4 and C_2F_6 emissions using Equation 70-6.

$$E_{CF_4, C_2F_6} = \sum_{i=1}^{n} [slope_{CF_4, C_2F_6} \times AEF \times AED \times MP]_i$$ **Equation 70-6**

Where:

$E_{CF4, C2F6}$ = Annual emissions of CF_4 or C_2F_6 (metric tons/yr).

$slope_{CF4, C2F6}$ = Measured slope coefficient ([Metric tons of CF_4 or C_2F_6 /metric ton Aluminum]/[anode effect minutes/pot-days]).
AEF = Anode effect frequency (number of anode effects per pot per day).
AED = Anode effect duration (minutes per anode effect).
MP = Aluminum production per day (metric tons).
n = Number of operating days per year.

(2) **Pechiney Method:** Calculate the CF_4 and C_2F_6 emissions using Equation 70-7.

$$E_{CF_4,C_2F_6} = \sum_{i=1}^{n}[Over-voltage\ \ coefficient_{CF_4,C_2F_6} \times \frac{AEO}{CE} \times MP]_i \qquad \textbf{Equation 70-8}$$

Where:

$Emission_{CF4, C2F6}$	=	Emissions of CF_4 or C_2F_6 (metric tons/yr).
Over-voltage $coefficient_{CF4, C2F6}$	=	Experimentally measured ([Metric tons of CF_4 or C_2F_6 /metric ton Aluminum]/mV).
AEO	=	Anode effect over-voltage (millivolts per pot per day).
CE	=	Current efficiency of aluminum production process, expressed as a fraction.
MP	=	Aluminum production per day (metric tons).
n	=	Number of operating days per year.

(d) Calculate CO_2 emissions from onsite green coke calcination furnaces using Equation 70-9.

$$E_{CO_2} = \sum_{n=1}^{12}\left[\left[GC \times \frac{\left(100 - H_2O_{gc} - V_{gc} - S_{gc}\right)}{100} - \left(CC + UCC + DE\right) \times \frac{\left(100 - S_{cc}\right)}{100}\right] \times 3.664\right]_i + \left[GC \times 0.035 \times \frac{44}{16}\right]_i \qquad \textbf{Equation 70-9}$$

Where:

E_{CO2}	=	CO_2 emissions (metric tons pre year).
GC	=	Green coke feed for month i (metric tons).
H_2O_{gc}	=	Humidity in green coke feed for month i (wt %).
V_{gc}	=	Volatiles in green coke feed for month i (wt %).
S_{gc}	=	Sulfur content in green coke feed in month i (wt %).
S_{cc}	=	Sulfur content in calcinated coke in month i (wt %).
CC	=	Calcinated coke produced in month i (metric tons).
UCC	=	Under-calcinated coke produced in month i (metric tons).
DE	=	Coke dust emissions for month i (metric tons).
3.664	=	Conversion factor from carbon to CO_2.
0.035	=	Assumed CH_4 and tar content in coke volatiles, contributing to CO_2 emissions.
44/16	=	Conversion factor from methane to CO_2.

(e) Calculate SF_6 emissions from cover gas consumption using one of the following methods:

(1) Calculate the annual SF_6 emissions using inventory records and Equation 70-10:

$$E_{SF6} = S_{Inv-Begin} - S_{Inv-End} + S_{Purchased} - S_{Shipped} \qquad \textbf{Equation 70-10}$$

Where:

E_{SF6}	=	SF_6 emissions from cover gas (metric tons).

$S_{Purchased}$ = Quantity of SF_6 purchased (metric tons).
$S_{Shipped}$ = Quantity of SF_6 shipped offsite (metric tons).
$S_{Inv\text{-}Begin}$ = Quantity of SF_6 in storage at the beginning of the year, (metric tons).
$S_{Inv\text{-}End}$ = Quantity of SF_6 in storage at the end of the year (metric tons).

(2) Calculate the annual SF_6 emissions using Equation 70-11 and direct measurement of the SF6 input to electrolysis cells and the SF6 waste gases collected and transferred off-site:

$$E_{SF6} = \sum_{i=1}^{12}[(Q_{Input} \times C_{Input}) - (Q_{Output} \times C_{Output})]_i \qquad \textbf{Equation 70-11}$$

Where:
E_{SF6} = SF_6 emissions from cover gas (metric tons).
$Q_{in;put}$ = Quantity of SF_6 input to the electrolysis cell for month i (metric tons).
C_{Input} = Concentration of SF_6 input to the electrolysis cell for month i (metric tons).
Q_{Output} = Quantity of SF_6 gas collected during month i (if applicable) (metric tons).
C_{Output} = Concentration of SF_6 gas collected and sent off-site during month i (metric tons).

§ WCI.74 Monitoring Requirements

(a) Except as specified in paragraphs (b) through (c) of this section, all parameters must be measured monthly. ~~using methods that comply with the measurement accuracy provisions in WCI.2(g).~~

(b) Conduct performance tests once every 36 months to determine the slope or Pechiney coefficients for each pot line using the *Protocol for Measurement of Tetrafluoromethane and Hexafluoroethane Emissions from Primary Aluminum Production*, U.S. Environmental Protection Agency and International Aluminum Institute. April 2008. The test must be repeat whenever:

(1) Thirty-six months have passed since the last measurements;

(2) A change occurs in the control algorithm that affects the mix of types of anode effects or the nature of the anode effect termination routine; or

(3) Changes occur in the distribution ~~of~~ or duration of anode effects (e.g. when the percentage of manual kills changes or if, over time, the number of anode effects decreases and results in a fewer number of longer anode effects) or, for Rio Tinto Alcan control technology, when the algorithm for bridge movements and anode effect overvoltage accounting changes.

~~(c)~~If using the direct measurement approach in WCI.73(e)(2) to calculate SF_6 emissions from cover gas consumption, you must measure the quantity of SF_6 gas input to the electrolysis cell month and the quantity and SF_6 concentration of any waste gas collected and sent off-site.

~~(d) Monitoring methods have not been specified in the available methodologies for the aluminum industry. There are several possible approaches to specifying monitoring methods:~~

~~(e)~~

~~**(f)**Specify the accuracy required for each datum and allow the source to select their own methodologies that meet the accuracy requirements, and require the verifiers to certify the accuracy requirements were achieved, [This approach is especially useful for monitoring that is currently being made with a wide variety of instruments and are likely being made with high accuracy, such as monitoring of raw material flows and product flows; however, much burden is placed on verifiers to ensure the accuracy of the methods used. This approach is used for monitoring fuel flow for combustion sources.]~~

~~**(g)**Specify the accuracy required for each datum and require the source to submit a monitoring plan that meets the accuracy requirements, and require the verifiers to certify the source followed the approved plan. [This approach places a lot of burden on WCI to approve individual monitoring plans.]~~

~~**(h)**Specify the methodologies that should be followed, selecting them from available ASTM, ISO, U.S. EPA, and EC methodologies; however, there are not established methods for all parameters. Listed below are examples of the available methodologies for monitoring the aluminum industry.~~

~~**(i)**~~

~~(j) ISO 9055:1988. Carbonaceous materials for the production of aluminum -- Pitch for electrodes -- Determination of sulfur content by the bomb method.~~

~~(k)~~

~~(l) ISO 10238:1999. Carbonaceous materials used in the production of aluminum -- Pitch for electrodes -- Determination of sulfur content by an instrumental method.~~

~~(m)~~

~~(n) ISO 8006:1985. Carbonaceous materials used in the production of aluminum -- Pitch for electrodes -- Determination of ash.~~

~~(o)~~

~~(p) ISO 8005-2005. Carbonaceous materials used in the production of aluminum -- Green and calcined coke -- Determination of ash content~~

~~(q)~~

~~(r) ISO 10237-1997. Carbonaceous materials for use in the production of aluminum -- Calcined coke -- Determination of residual hydrogen content.~~

~~(s)~~

~~(t) ISO 5931:2000. Carbonaceous materials used in the production of aluminum -- Calcined coke and calcined carbon products -- Determination of total sulfur by the Eschka method.~~

~~(u)~~

~~(v) Slope and Over-voltage Coefficient: Protocol for Measurement of Tetrafluoromethane and Hexafluoroethane Emissions from Primary Aluminum Production. U.S. Environmental Protection Agency and International Aluminum Institute. April 2008.~~

~~(w)~~

~~(x) ASTM D3173 Test Method for Moisture in the Analysis Sample of Coal and Coke~~

~~(y)~~

~~(z) The following parameters are not covered by a specific ASTM or ISO methodology. They are candidates for being addressed using one of the first two approaches listed above.~~

~~**(aa)**Mass flow rates or consumption of aluminum, paste, carbon, anodes, coke, recovered tar, and coke dust,~~

~~**(bb)**Emissions of benzene soluble matter,~~

~~**(cc)**Binder content in paste,~~

~~**(dd)**Pitch content in anodes,~~

~~**(ee)**Current efficiency,~~

~~**(ff)**Anode effect frequency,~~

~~**(gg)**Anode effect duration,~~

~~**(hh)**Anode effect over-voltage,~~

~~**(ii)**Current efficiency,~~

(c) ~~Volatile content in coke.~~

§ WCI.90 CEMENT MANUFACTURING

§ WCI.91 Source Category Definition

Cement manufacturing is comprised of all processes that are used to manufacture Portland, natural, masonry, pozzolanic, or other hydraulic cements.

§ WCI.92 Greenhouse Gas Reporting Requirements

In addition to the information required by WCI.3, the annual emissions data report shall contain the following information:

(a) Total emissions of CO_2, CH_4, and N_2O in metric tons.

(b) CO_2 process emissions from calcination (metric tons) and the following information:

(1) Plant specific c~~C~~linker emission factor (kg CO_2/metric ton clinker).

(A) Quantity of clinker produced (metric tons).

(B) Total lime (CaO) content of clinker (wt. fraction).

(C) Total magnesium Oxide (MgO) content of clinker (wt. fraction).

(D) Total carbonate ~~Uncalcined CaO~~(CO_2) content of clinker (wt. fraction).

~~(E) Uncalcined MgO (wt. fraction).~~

(2) Cement kiln dust (CKD) emission factor (kg CO_2/metric ton CKD discarded).

(A) Plant specific CKD calcination rate (unitless ratio).

(B) Quantity of CKD discarded (metric tons).

(c) CO_2 process emissions from organic carbon oxidation (metric tons) and the following information:

(1) Amount of raw material consumed in the report year (metric tons).
(2) Organic carbon content of raw material (wt. fraction).

(d) CO_2, CH_4, and N_2O emissions from fuel combustion in all kilns combined, following the calculation methods and reporting requirements specified in WCI.93(c) (metric tons).

(e) CO_2, CH_4, and N_2O emissions from all other fuel combustion units combined (kilns excluded), following the calculation methods and reporting requirements specified in WCI.20 (metric tons).

(f) If a continuous emissions monitor is used to measure CO_2 emissions from kilns, then the requirements of paragraphs (b), (c), and (d) of this section do not apply for CO_2. Cement plants that measure CO_2 emissions using CEMS shall report fuel usage by fuel type for kilns.

(g) Operators of cement plants shall also comply with the reporting requirements for any other applicable source category listed at WCI.1(a), including but not limited to the following:

(1) Coal fuel storage as specified in WCI.100.

(2) Electricity generating as specified in WCI.40.

(3) Cogeneration systems as specified in WCI.50.

§ WCI.93 Calculation of Greenhouse Gas Emissions From Kilns

(a) ~~(a)~~ Determine CO_2 emissions as specified under either paragraph (a)(1) or (a)(2) of this section.

(1) Use a continuous emissions monitoring system (CEMS) as specified in WCI.23(d).

(2) Calculate the sum of CO_2 process emissions from kilns and CO_2 fuel combustion emissions from kilns using the calculation methodologies specified in paragraph (b) and (c) of this section.

(b) Process CO_2 Emissions Calculation Methodology. Calculate total CO_2 process emissions as the sum of emissions from calcination, using the method specified in paragraph (b)(1) of this section; and from organic carbon oxidation, using the method specified in paragraph (b)(2) of this section (Equation 90-0).

$$CO_2 \text{ process} = CO_2 \text{ calcination} + CO_2 \text{ raw material} \qquad \textbf{Equation 90-0}$$

(1) Calcination Emissions. Calculate CO_2 process emissions from calcination using Equation 90-1 and a plant-specific clinker emission factor and a plant-specific cement kiln dust (CKD) emission factor as specified in this section.

$$CO_{2-C} = \sum_{i=1}^{12} [(Cli) \times (EF_{Cli})] + [(Q_{CKD}) \times (EF_{CKD})] \qquad \textbf{Equation 90-1}$$

Where:

$CO_{2\text{-}C}$ = CO_2 emissions from calcination, metric tones.
Cli = Monthly quantity of clinker produced, metric tons.
EF_{Cli} = Monthly clinker emission factor, metric tons CO_2/metric ton clinker computed as specified in paragraph (b)(1)(A) of this section.
Q_{CKD} = Monthly quantity CKD discarded (i.e., not recycled to the kiln), metric tons.
EF_{CKD} = Monthly CKD emission factor, computed as specified in paragraph (b)(1)(B) of this section.

(A) ~~Monthly~~ Clinker Emission Factor. Calculate a ~~monthly~~ plant-specific clinker emission factor (EF_{Cli}) for each report year based on monthly measurements of the ~~percent~~ weight fraction of ~~measured~~ CaO~~, and~~ MgO and CO_2 (carbonate) content in the clinker and using Equation 90-2, which assumes all carbonate remaining in the clinker is associated with the calcium.

$$EF_{Cli} = [(CaO\ content - \frac{CO2\ Content}{Molecular\ ratio\ CO2/CaO}) \times Molecular\ ratio\ of\ CO_2/CaO] + [(MgO\ Content) \times Molecular\ ratio\ of\ CO_2/MgO] \qquad \textbf{Equation 90-2}$$

Where:

CaO Content (by weight)	=	Total CaO content of Clinker (including calcined and uncalcined) (wt. fraction).
~~Non-carbonate CaO~~ CO_2 Content (by weight)	=	Total CO_2 content ~~Uncalcined CaO~~ of Clinker (wt. fraction).
Molecular ratio of CO_2/CaO	=	0.785.
MgO Content (by weight)	=	Total MgO content of Clinker (including calcined and uncalcined) (wt. fraction).
~~Non-carbonate MgO~~	~~=~~	~~Uncalcined MgO of Clinker (wt. fraction).~~
Molecular ratio of CO_2/MgO	=	1.092.

(B) ~~Monthly~~ CKD Emission Factor. If CKD is generated and not recycled back to the kiln, then calculate a ~~monthly~~ plant-specific CKD emission factor based on monthly sampling. The CKD emission factor shall be calculated using Equation 90-3 and a plant-specific CKD calcination rate as specified in Equation 90-4.

$$EF_{CKD} = \frac{\frac{EF_{Cli}}{1 + EF_{Cli}} \times d}{1 - \left(\frac{EF_{Cli}}{1 + EF_{Cli}} \times d\right)}$$

Equation 90-3

Where:

EF_{CKD}	=	Monthly CKD emission factor, kg CO_2/metric ton CKD discarded.
EF_{Cli}	=	Clinker emission factor, determined according to Equation 90-2.
d	=	CKD calcination rate, determined according to Equation 90-4.

$$d = 1 - \frac{fCO_{2CKD} \times (1 - fCO_{2RM})}{(1 - fCO_{2CKD}) \times fCO_{2RM}}$$

Equation 90-4

Where:

d	=	CKD calcination rate (unitless ratio).
fCO_{2CKD}	=	Weight fraction of carbonate CO_2 in the CKD.
fCO_{2RM}	=	Weight fraction of carbonate CO_2 in the raw material.

(2) Organic Carbon Oxidation Emissions. Calculate CO_2 process emissions from the total organic content in raw materials by using Equation 90-5.

$$CO_{2-RM} = TOC_{RM} \times RM \times 3.664$$

Equation 90-5

Where:

$CO_{2\text{-}RM}$ = CO_2 emissions from raw material oxidation, metric tons.
TOC_{RM} = Total organic carbon content in raw material (wt. fraction), measured using the method in WCI.94(c) or using a default of 0.002 (0.2%).
RM = Amount of raw material consumed (metric tons/yr).
3.664 = The CO_2 to carbon molar ratio.

(c) Fuel Combustion Emissions in Kilns. Calculate CO_2, CH_4, and N_2O emissions from stationary fuel combustion following the calculation methods specified in WCI.20. Cement plants that combust pure biomass-derived fuels and combust fossil fuels only during periods of start-up, shut-down, or malfunction may report CO_2 emissions from fossil fuels using the emission factor methodology in WCI.23(a). "Pure" means that the biomass-derived fuels account for 97 percent of the total amount of carbon in the fuels burned.

§ WCI.94 Sampling, Analysis, and Measurement Requirements

~~*Note: The sampling, analysis, and measurement procedures will be standardized for each calculation input to reduce variation between facilities within the cement industry. Material sampling frequency and technique is distinct from material analysis conducted in a laboratory. The WCI is seeking stakeholder feedback on this topic and is specifically interested in proposals from stakeholders with expertise in this industry related to sampling, analysis and measurement procedures already in use at these facilities for the material quantities and/or concentrations listed below. Those proposing procedures should include sampling frequency and technique, indicate the uncertainty associated with the procedures, and describe the application of the procedure at a facility.*~~

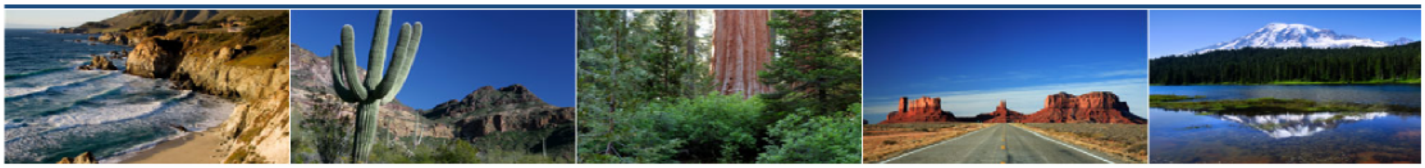
(a) Determine the plant-specific weight fractions of total CaO, total MgO, total carbonate CO_2~~uncalcined CaO, and uncalcined MgO~~ in clinker ~~from each kiln~~ using ASTM C114-07~~(method to be determined)~~. Determine the weight fraction of carbonate CO_2 in the CKD and the weight fraction of carbonate CO_2 in the raw material using ASTM C114-07. The monitoring must be conducted monthly ~~for each kiln~~ from~~ a~~ clinker and CKD samples drawn from bulk ~~clinker~~ storage.

(b) If not using the default value of 0.002 for TOC_{RM} in Equation 90-5, the total organic carbon contents of raw materials must be determined annually ~~*[monthly?]*~~ using ASTM Method C114-07. The analysis must be conducted on sample material drawn from bulk raw material storage for each category of raw material.

(c) The quantity of clinker produced must be determined by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.

(d) The quantity of CKD discarded must be determined by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.

(e) The quantity of raw materials consumed (i.e. limestone, sand, shale, iron oxide, and alumina) must be determined by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.



§ WCI.100 COAL STORAGE

§ WCI.101 Source Category Definition

Coal storage piles are located at any facilities that combust coal. Coal storage piles release fugitive CH_4 emissions. Within natural coal deposits, CH_4 is either trapped under pressure within porous void spaces or adsorbed to the coal. Coal mining, post-mining activities, and coal-handling activities release pressurized CH_4 to the atmosphere; adsorbed CH_4 is also released until the CH_4 in the coal reaches equilibrium with the surrounding atmospheric conditions.

§ WCI.102 Greenhouse Gas Reporting Requirements

The emissions data report shall include the following information at the facility level:

(a) Annual greenhouse gas emissions in metric tons, reported as follows:

(1) Total CH_4 emissions.

(b) Annual coal purchases ~~in~~ (tons for U.S.; metric tons for Canada).

(c) Source of coal purchases:

(1) Coal basin.

(2) State/province.

(3) Coal mine type (surface or underground).

§ WCI.103 Calculation of CH_4 Emissions

Note that this methodology for calculation of methane emissions uses emission factors for post-mining operations including all processes occurring after mining at the coal deposit and prior to combustion (e.g., preparation, handling, processing, transportation, storage, etc.) even though coal storage piles are only a subset of the overall post-mining operations. This follows the approach in the California Climate Action Registry, attributing all post-mining fugitive methane emissions to the facility combusting the coal, which is ultimately responsible for the coal having been processed and delivered to the facility. ~~*The Reporting Subcommittee is considering whether to require reporting of these emissions as indicated below, and whether to include these emissions in the total emissions of the coal-combusting facility. Stakeholder comment is requested.*~~

~~*Canadian-specific default fugitive methane emissions (i.e., a Canadian version of Table 100-1) will be developed.*~~

Calculate fugitive CH_4 emissions from coal storage piles as specified under paragraph (a), (b), or (c) of this section.

(a) For coal purchased from U.S. sources, ~~C~~calculate fugitive CH_4 emissions using Equation 100-1 (English) ~~and~~and Table 100-1, or Equation 100-1 (Metric) and Table 100-2.

(b) ~~C~~For coal purchased from Canadian sources, calculate fugitive CH_4 emissions using Equation 100-1 (M~~m~~etric) and ~~Table 100-2 and/or Table~~ Table 100-3.[BM1]

(c) For coal purchased from non-U.S. and non-Canadian sources, owners or ~~operations~~ operators should use either WCI.103(a) or WCI.103(b), whichever is the most applicable. This chosen approach is subject to approval by [*the jurisdiction*].

~~using the following equation:~~

$$CH_4 = \sum_i (PC_i \times EF_i) \times 0.04228 / 2{,}204.6$$ **Equation 100-1 (English Units)**

Where:

CH_4	=	Fugitive emissions from coal storage piles for each coal category *i* (~~,~~ metric tons CH_4 per year)~~.~~;
PC_i	=	Purchased coal for each coal category *i*~~,~~ (tons per year)~~.~~;
EF_i [BM2]	=	Default CH_4 emission factor for each coal category *i* specified by location and mine type that coal originated from, provided in Table 100-1~~,~~ (scf CH_4 per ton of coal)~~.~~;
0.04228	=	Methane conversion factor to convert scf to lbs~~.~~;
2,204.6	=	Factor to convert lbs to metric tons.

~~Calculate fugitive CH_4 emissions from coal storage piles using the following equation:~~

$$CH_4 = \sum_i (PC_i \times EF_i) \times 0.6772 / 1{,}000$$ **Equation 100-1 (~~m~~Metric Units)**

Where:

CH_4	=	Fugitive emissions from coal storage piles for each coal category *i*, (metric tons CH_4 per year);
PC_i	=	Purchased coal for each coal category *i* ~~-~~(metric tons per year);
EF_i	=	Default CH_4 emission factor for each coal category *i* specified by location and mine type that coal originated from, provided in Table 100-~~1~~2 or Table 100-3~~,~~ (m^3 CH_4 per metric ton of coal~~.~~);
0.6772	=	Methane conversion factor to convert m^3 to kg~~.~~;
1,000	=	Factor to convert kg to metric tons.

§ WCI.104 Sampling, Analysis, and Measurement Requirements

(a) Coal Purchase~~Fuel Consumption~~ Monitoring Requirements[BM3].

~~(1)~~Facilities may determine the quantity of coal purchased either using records provided by the coal supplier(s) or monitoring coal purchase quantities using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.~~consumption on the basis of recorded fuel purchase or sales invoices measuring any stock change (short tons) using the following equation:~~

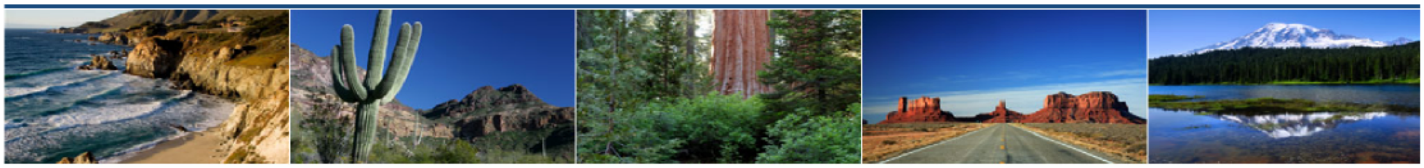
~~*Fuel Consumption in the Report Year = Total Fuel Purchases – Total Fuel Sales + Amount Stored at Beginning of Year – Amount Stored at Year End*~~

Table 100-1. U.S. Default Fugitive Methane Emission Factors from Post-Mining Coal Storage and Handling (CH_4 ft^3 per Short Ton)			
Coal Origin		**Coal Mine Type**	
Coal Basin	**States**	**Surface Post-Mining Factors**	**Underground Post-Mining Factors**
Northern Appalachia	Maryland, Ohio, Pennsylvania, West Virginia North	19.3	45.0
Central Appalachia (WV)	Tennessee, West Virginia South	8.1	44.5
Central Appalachia (VA)	Virginia	8.1	129.7
Central Appalachia (E KY)	East Kentucky	8.1	20.0
Warrior	Alabama, Mississippi	10.0	86.7
Illinois	Illinois, Indiana, Kentucky West	11.1	20.9
Rockies (Piceance Basin)	Arizona, California, Colorado, New Mexico, Utah	10.8	63.8
Rockies (Uinta Basin)		5.2	32.3
Rockies (San Juan Basin)		2.4	34.1
Rockies (Green River Basin)		10.8	80.3
Rockies (Raton Basin)		10.8	41.6
N. Great Plains	Montana, North Dakota, Wyoming	1.8	5.1
West Interior (Forest City, Cherokee Basins)	Arkansas, Iowa, Kansas, Louisiana, Missouri, Oklahoma, Texas	11.1	20.9
West Interior (Arkoma Basin)		24.2	107.6
West Interior (Gulf Coast Basin)		10.8	41.6
Northwest (AK)	Alaska	1.8	52.0
Northwest (WA)	Washington	1.8	18.9
Source: *Inventory of U.S. Greenhouse Gas Emissions and Sinks:1990 – 2005* April 15, 2007, U.S. Environmental Protection Agency. Annex 3, Methodological Descriptions for Additional Source or Sink Categories, Section 3.3, Table A-115, Coal Surface and Post-Mining CH_4 Emission Factors (ft^3 per Short Ton). (Only Post-Mining EFs used from Table). State assignments shown from Table 113 of Annex 3.			

Table 100-2. U.S. Default Fugitive Methane Emission Factors from Post-Mining Coal Storage and Handling (CH_4 m^3 per Metric Ton)			
Coal Origin		**Coal Mine Type**	
Coal Basin	**States**	**Surface Post-Mining Factors**	**Underground Post-Mining Factors**
Northern Appalachia	Maryland, Ohio, Pennsylvania, West Virginia North	0.6025	1.4048
Central Appalachia (WV)	Tennessee, West Virginia South	0.2529	1.3892
Central Appalachia (VA)	Virginia	0.2529	4.0490
Central Appalachia (E KY)	East Kentucky	0.2529	0.6244
Warrior	Alabama, Mississippi	0.3122	2.7066
Illinois	Illinois, Indiana, Kentucky West	0.3465	0.6525
Rockies (Piceance Basin)	Arizona, California, Colorado, New Mexico, Utah	0.3372	1.9917
Rockies (Uinta Basin)		0.1623	1.0083
Rockies (San Juan Basin)		0.0749	1.0645
Rockies (Green River Basin)		0.3372	2.5068
Rockies (Raton Basin)		0.3372	1.2987

N. Great Plains	Montana, North Dakota, Wyoming	0.0562	0.1592
West Interior (Forest City, Cherokee Basins)	Arkansas, Iowa, Kansas, Louisiana, Missouri, Oklahoma, Texas	0.3465	0.6525
West Interior (Arkoma Basin)		0.7555	3.3591
West Interior (Gulf Coast Basin)		0.3372	1.2987
Northwest (AK)	Alaska	0.0562	1.6233
Northwest (WA)	Washington	0.0562	0.5900
Source: *Inventory of U.S. Greenhouse Gas Emissions and Sinks:1990 – 2005* April 15, 2007, U.S. Environmental Protection Agency. Annex 3, Methodological Descriptions for Additional Source or Sink Categories, Section 3.3, Table A-115, Coal Surface and Post-Mining CH_4 Emission Factors (ft^3 per Short Ton; converted to m^3 per metric ton). (Only Post-Mining EFs used from Table). State assignments shown from Table 113 of Annex 3.			

Table 100-3. Canada Default Fugitive Methane Emission Factors from Post-Mining Coal Storage and Handling (CH_4 m^3 per Metric Ton)			
Coal Origin		**Coal Mine Type**	
Province	**Coalfield**	**Surface Post-Mining Factors**	**Underground Post-Mining Factors**
British Columbia	Comox	0.500	n/a
	Crowness	0.169	n/a
	Elk Valley	0.900	n/a
	Peace River	0.361	n/a
	Province Average	0.521	n/a
Alberta	Battle River	0.067	n/a
	Cadomin-Luscar	0.709	n/a
	Coalspur	0.314	n/a
	Obed Mountain	0.238	n/a
	Sheerness	0.048	n/a
	Smokey River	0.125	0.067
	Wabamun	0.176	n/a
	Province Average	0.263	0.067
Saskatchewan	Estavan	0.055	n/a
	Willow Bunch	0.053	n/a
	Province Average	0.054	n/a
New Brunswick	Province Average	0.060	n/a
Nova Scotia	Province Average	n/a	2.923
Source: *Management of Methane Emissions from Coal Mines: Environmental, Engineering, Economic and Institutional Implications of Options*. Prepared by Brian G. King, Neill and Gunter (Nova Scotia) Limited, Darmouth, Nova Scotia for Environment Canada. Contract Number K2031-3-7062. March 1994. This document is cited by Environment Canada in the NIR 1990-2007 (Final Submission, April 2009), ~~their greenhouse gas emission inventories~~, but post-mining emission factors are not provided, so they were developed for WCI purposes by Province.~~esented in those inventories.~~ Surface emission factors were derived from Table 3.1 (Coal production statistics [Column A] and post-mining emissions [Column F]). Underground emission factors were derived from Table 3.2 (Coal production statistics and post-mining emissions).			



§ WCI.130 HYDROGEN PRODUCTION

§ WCI.131 Source Category Definition

A hydrogen production process produces hydrogen gas by steam hydrocarbon reforming, partial oxidation of hydrocarbons, or other transformation of hydrocarbon feedstock. The hydrogen produced may be either transferred offsite or used onsite at petrochemical, ammonia production, refineries, and other plants.

§ WCI.132 Greenhouse Gas Reporting Requirements

For each facility, the annual emissions report must contain the following information:

(a) Process CO_2 Emissions. The CO_2 process emissions from the hydrogen produced process.

(b) Feedstock Consumption (if estimating emissions using mass balance approach in WCI.133(b)). Annual feedstock consumption by feedstock type (including petroleum coke) reported in units of million standard cubic feet for gases, gallons for liquids, short tons for non-biomass solids, and bone dry short tons for biomass-derived solid fuels.

(c) Production. Annual hydrogen produced.

(d) Stationary Combustion Units. Report CO_2, N_2O, and CH_4 emissions as specified in WCI.20.

§ WCI.133 Calculation of Greenhouse Gas Emissions

The owner or operator shall calculate and report CO_2 process emissions using the methods in paragraphs (a) or (b) of this section.

(a) Continuous Emission Monitoring Systems. The owner or operator may calculate CO_2 process emissions using CEMS. The owner or operator must comply with the requirements in section WCI.20.

(b) Feedstock Material Balance. The owner or operator may calculate CO_2 process emissions using the following method. The factor S shall be used only for CO_2 and/or CH_4 emissions that are calculated and reported using applicable methods specified in this regulation. For example, carbon species in uncoverted feedstock contained in PSA off-gas and hydrogen plant product that is diverted to fuel gas systems, fed to downstream units, or diverted to flare may be included in the factor S provided the CO_2 and/or CH_4 emissions are reported using other methods in this regulation.

$$CO_2(Feedstock) = \sum_{i=1}^{n} \sum_{j=1}^{y} \left[(FS_j * CF_j) - S_j \right] * 3.664 * 0.001$$

Equation 130-1 (English Units)

Where:

CO_2 (Feedstock)	=	CO_2 emitted from feedstock (metric tons/year).
n	=	Days of operation per year.
FS_j	=	Feedstock b consumption rate (scf/day).
CF_j	=	Carbon content of feedstock j (kg C/scf feedstock).
y	=	Total number of feedstocks.
S_j	=	Carbon accounted for elsewhere (kg C/day).
3.664	=	ratio of molecular weights, CO_2 to carbon
0.001	=	conversion factor – kg to metric tons

$$CO_2(Feedstock) = \sum_{i=1}^{n} \sum_{j=1}^{y} \left[(FS_j * CF_j) - S_j \right] * 3.664 * 0.001$$

Equation 130-1 (Metric Units)

Where:

CO_2 (Feedstock)	=	CO_2 emitted from feedstock (metric tons/year).
n	=	Days of operation per year.
FS_j	=	Feedstock b consumption rate (m^3/day).
CF_j	=	Carbon content of feedstock j (kg C/m^3 feedstock).
y	=	Total number of feedstocks.
S_j	=	Carbon accounted for elsewhere (kg C/day).
3.664	=	ratio of molecular weights, CO_2 to carbon
0.001	=	conversion factor – kg to metric tons

WCI.134 Sampling, Analysis, and Measurement Requirements

(a) Owners or operators using CEMS to estimate CO_2 emissions shall comply with the monitoring requirements in section WCI.20.

(b) Owners or operators using the method in section WCI.1~~0~~33 (b) shall perform the following monitoring:

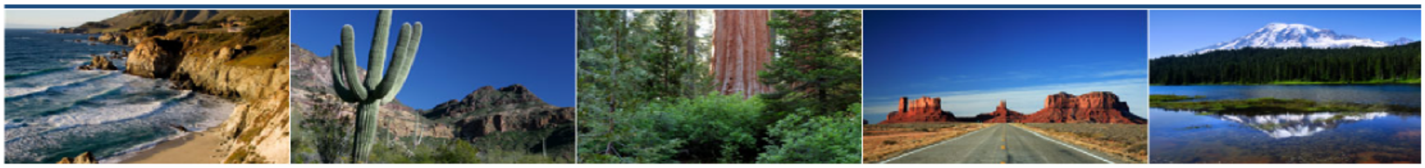
(1) The owner or operator shall measure the feedstock consumption rate daily ~~using methods that comply with the measurement accuracy provisions in WCI.2(g)~~.

(2) The owner or operator shall collect samples of each feedstock consumed and analyze each sample for carbon content using the methods specified in WCI.25(d). For natural gas feedstock not mixed with another feedstock prior to consumption, samples shall be

collected and analyzed once per month. For all other feedstocks, samples shall be collected and analyzed daily. The samples shall be collected from a location in the feedstock handling system that provides samples representative of the feedstock consumed in the hydrogen production process.

(3) Owners or operators shall measure the hydrogen produced daily. ~~using methods that comply with the measurement accuracy provisions in WCI.2(g).~~

(4) Owners or operators shall measure the CO_2 and CO collected daily ~~using methods that comply with the measurement accuracy provisions in WCI.2(g)~~.



§ WCI.150 IRON AND STEEL MANUFACTURING

§ WCI.151 Source Category Definition

Iron and steel manufacturing comprises four categories: primary facilities that produce both iron and steel, secondary steelmaking facilities, iron production facilities, and offsite production of metallurgical coke. These processes may occur together in an "integrated" facility or they may occur in separate offsite facilities.

§ WCI.152 Greenhouse Gas Reporting Requirements

In addition to the information required by WCI.3, the annual emissions data report shall contain the following information:

(a) Total emissions of CO_2 and CH_4 in metric tons at the facility level.

(b) CO_2 and CH_4 emissions from coke production (metric tons) and the following information:

(1) Quantity of coking coal consumed in coke production (metric tons)

(2) Quantity of other process materials (e.g., natural gas, fuel oil, etc.) consumed in coke production (metric tons)

(3) Quantity of blast furnace gas consumed in coke production (metric tons)

(4) Quantity of coke produced (metric tons)

(5) Quantity of coke oven gas transferred offsite (metric tons)

(6) Quantity of other coke oven by-products (e.g., coal tar, light oil, coke breeze, etc.) transferred offsite (metric tons)

(7) Carbon content of material inputs and outputs listed in (b)(1) through (b)(6) (metric tons of C per metric ton of material [equivalent to wt% C/100])

(c) CO_2 and CH_4 emissions from iron and steel production (metric tons) and the following information:

(1) Quantity of coke consumed in iron and steel production (excluding sinter production) (metric tons)

(2) Quantity of on-site coke oven by-products (e.g., coal tar, light oil, coke breeze, etc.) consumed in blast furnace (metric tons)

(3) Quantity of coal directly injected into blast furnace (metric tons)

(4) Quantity of limestone directly injected into blast furnace (metric tons)

(5) Quantity of dolomite directly injected into blast furnace (metric tons)

(6) Quantity of carbon electrodes consumed in EAFs (metric tons)

(7) Quantity of direct reduced iron introduced to an EAF or BOF (metric tons)

~~(7)~~(8) Quantity of other carbonaceous or process material (e.g., sinter, waste plastic, etc.) consumed in iron and steel production (metric tons)

~~(8)~~(9) Quantity of coke oven gas consume in blast furnace (metric tons)

~~(9)~~(10) Quantity of steel produced (metric tons)

~~(10)~~(11) Quantity of iron production not converted to steel (metric tons)

~~(11)~~(12) Quantity of blast furnace gas transferred offsite (metric tons)

~~(12)~~(13) Carbon content of material inputs and outputs listed in (c)(1) through (c)(12~~1~~) (metric tons of C per metric ton of material [equivalent to wt% C/100])

(d) Process CO_2 and CH_4 emissions from sinter production (metric tons) and the following information:

(1) Quantity of coke breeze (purchased and produced on-site) used for sinter production (metric tons)

(2) Quantity of coke oven gas consumed in blast furnace in sinter production (metric tons)

(3) Quantity of blast furnace gas consumed in sinter production (metric tons)

(4) Quantity of other process materials (e.g., natural gas, fuel oil, etc.) consumed in sinter production (metric tons)

(5) Quantity of sinter off gas transferred offsite (metric tons)

(6) Carbon content of material inputs and outputs listed in (d)(1) through (d)(5) (metric tons of C per metric ton of material [equivalent to wt% C/100])

(e) Process CO_2 and CH_4 emissions from direct reduced iron production (metric tons) and the following information:

(1) Energy from natural gas used in direct reduced iron production (gigajoules [GJ])

(2) Energy from coke breeze used in direct reduced iron production (GJ)

(3) Energy from metallurgical coke used in direct reduced iron production (GJ)

(4) Quantity of direct reduced iron produced (metric tons)

~~(4)~~(5) Carbon content of material inputs listed in (e)(1) through (e)(3) (metric tons of C per GJ)

(6) Carbon content of direct reduced iron produced per e(4) (metric tons of C per metric ton of material [equivalent to wt% C/100])

(f) CO_2, N_2O, and CH_4 emissions from stationary combustion units as specified in WCI.20.

§ WCI.153 Calculation of CO_2 Emissions

(a) Process CO_2 emissions. Determine process CO_2 emissions as specified under either paragraph (1) or (2) of this section.

(1) Continuous emissions monitoring systems (CEMS) as specified in WCI.23(d).

(2) Calculation methodologies specified in paragraph (b) of this section.

[CEMS and mass balance approach are based on IPCC Tier 3 methods.)

(b) Process CO_2 Emissions Calculation Methodology. Calculate total CO_2 process emissions using the following mass balance approach:

(b) Calculate the coke production CO_2 (either within integrated facilities or at offsite facilities) emissions using Equation 150-1 (if applicable):

$$E_{coke} = \left[(CC \times C_{CC}) + \sum_a (PM_a \times C_a) + (BG \times C_{BG}) - (CO \times C_{CO}) - (COG \times C_{COG}) - \sum_b (COB_b \times C_b) \right] \times 3.664$$

Equation 150-1

Where:

E_{coke}	=	Emissions of CO_2 from coke production (metric tons);
CC	=	Quantity of coking coal (metric tons);
PM_a	=	Quantity of other process material *a* (not included as separate terms), such as natural gas or fuel oil (metric tons);
BG	=	Quantity of blast furnace gas consumed in coke ovens (metric tons);
CO	=	Quantity of coke produced (metric tons)
COG	=	Quantity of coke oven gas transferred offsite (metric tons);
COB_b	=	Quantity of coke oven by-product *b* transferred offsite (metric tons);
C_x	=	Carbon content of material input or output *x* (metric tons C/metric tons of *x*);
3.664	=	Conversion factor from metric tons of C to metric tons of CO_2.

(c) Calculate the iron and steel production CO_2 emissions using Equation 150-2:

$$E_{iron,steel} = \left[(CO \times C_{CO}) + \sum_a (COB_a \times C_a) + (CI \times C_{CI}) + (L \times C_L) + (D \times C_D) + (CE \times C_{CE}) + (DRI \times C_{DRI}) + \sum_b (O_b \times C_b) + (COG \times C_{COG}) - (S \times C_S) - (IP \times C_{IP}) - (BG \times C_{BG}) \right] \times 3.664$$

[KES1]

Equation 150-2

Where:

$E_{iron,steel}$	=	Emissions of CO_2 from iron and steel production (metric tons);
CO	=	Quantity of coke consumed (excluding sinter production) (metric tons);
COB_a	=	Quantity of coke oven by-product *a* consumed in blast furnace (metric tons);
CI	=	Quantity of coal directly injected into blast furnace (metric tons);
L	=	Quantity of limestone consumed (metric tons);
D	=	Quantity of dolomite consumed (metric tons);
CE	=	Quantity of carbon electrodes consumed in EAFs (metric tons);
DRI	=	Quantity of direct reduced iron introduced to an EAF or BOF (metric tons)
O_b	=	Quantity of other carbonaceous and process material *b*, such as sinter or waste plastic (metric tons);
COG	=	Quantity of coke oven gas consumed in blast furnace (metric tons);

S	=	Quantity of steel produced (metric tons);
IP	=	Quantity of iron production not converted to steel (metric tons);
BG	=	Quantity of blast furnace gas transferred offsite (metric tons);
C_x	=	Carbon content of material input or output *x* (metric tons C/metric tons of *x*);
3.664	=	Conversion factor from metric tons of C to metric tons of CO_2.

(d) Calculate the sinter production CO_2 emissions using Equation 150-3 (if applicable):

$$E_{sinter} = \left[(CBR \times C_{CBR}) + (COG \times C_{COG}) + (BG \times C_{BG}) + \sum_a (PM_a \times C_a) - (SOG \times C_{SOG}) \right] \times 3.664$$

Equation 150-3

Where:

E_{sinter}	=	Emissions of CO_2 from sinter production (metric tons);
CBR	=	Quantity of purchased and onsite produced coke breeze used for sinter production (metric tons);
COG	=	Quantity of coke oven gas consumed in blast furnace for sinter production (metric tons);
BG	=	Quantity of blast furnace gas consumed for sinter production (metric tons);
PM_a	=	Quantity of other process material *a* consumed for sinter production (not included as separate terms), such as natural gas or fuel oil (metric tons);
SOG	=	Quantity of sinter off gas transferred offsite (metric tons);
C_x	=	Carbon content of material input or output *x* (metric tons C/metric tons of *x*);
3.664	=	Conversion factor from metric tons of C to metric tons of CO_2.

(e) Calculate the direct reduced iron production CO_2 emissions using Equation 150-4 (if applicable):

$$E_{DRI} = [(DRI_{NG} \times C_{NG}) + (DRI_{BZ} \times C_{BZ}) + (DRI_{CK} \times C_{CK}) - (DRI \times C_{DRI})] \times 3.664$$ [KES2]

Equation 150-4

Where:

E_{DRI}	=	Emissions of CO_2 from direct reduced iron production (metric tons);
DRI_{NG}	=	Energy from natural gas used in direct reduced iron production (GJ);
DRI_{BZ}	=	Energy from coke breeze used in direct reduced iron production (GJ);
DRI_{CK}	=	Energy from metallurgical coke used in direct reduced iron production (GJ);
DRI	=	Quantity of direct reduced iron produced (metric tons)
C_{NG}	=	Carbon content of natural gas (metric ton C/GJ);
C_{BZ}	=	Carbon content of coke breeze (metric ton C/GJ);
C_{CK}	=	Carbon content of metallurgical coke (metric ton C/GJ);
C_{DRI}	=	Carbon content of direct reduced iron produced (metric tons of C per metric ton of direct reduced iron)

3.664 = Conversion factor from metric tons of C to metric tons of CO_2.

(f) Calculate the total CO_2 emissions using Equation 150-5:

$$E_{CO2} = E_{coke} + E_{iron,steel} + E_{sinter} + E_{DRI}$$ **Equation 150-5**

Where:

E_{CO2} = Total CO_2 emissions (metric tons);
E_{coke} = Emissions from coke production (metric tons);
$E_{iron,steel}$ = Emissions from iron and steel production (metric tons);
E_{sinter} = Emissions from sinter production (metric tons);
E_{DRI} = Emissions from direct reduced iron production (metric tons).

§ WCI.154 Calculation of CH_4 Emissions

(a) Process CH_4 emissions. Determine process CH_4 emissions as specified under either paragraph (1) or paragraph (2) of this section.

(1) Continuous emissions monitoring systems (CEMS) as specified in WCI.23(d).

(2) Site-specific emission factors[KES3].

§ WCI.155 Sampling, Analysis, and Measurement Requirements

Measurements of carbon contents of the material balance input, output, and by-product materials shall be conducted as described below.

~~*Note: The sampling, analysis, and measurement procedures will be standardized for each calculation input to reduce variation between facilities within the iron and steel industry. Material sampling frequency and technique is distinct from material analysis conducted in a laboratory. The WCI is seeking stakeholder feedback on this topic and is specifically interested in proposals from stakeholders with expertise in this industry related to sampling, analysis and measurement procedures already in use at these facilities for the material quantities and/or concentrations listed below. Those proposing procedures should include sampling frequency and technique, indicate the uncertainty associated with the procedures, and describe the application of the procedure at a facility.*~~

(a) Fuel Carbon Content Requirements. Fuel carbon contents should be monitored in the following manner (from § WCI.25):

(1) For coal and coke, solid biomass-derived fuels, and waste-derived fuels; use ASTM 5373-02 (Reapproved 2007).

(2) For liquid fuels, use the following ASTM methods: For petroleum-based liquid fuels and liquid waste-derived fuels, use ASTM D5291-02 (Reapproved 2007) “Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in

Petroleum Products and Lubricants", ultimate analysis of oil or computations based on ASTM D3238-95 (Reapproved 2005) and either ASTM D2502-04 or ASTM D2503-92 (Reapproved 200~~2~~7).

(3) For gaseous fuels, use ASTM D1945-03 or ASTM D1946-90 (Reapproved 2006).

(b) By-Product Carbon Content Requirements. Carbon contents of by-products (e.g., blast furnace gas, coke oven gas, coal tar, light oil, coke breeze, sinter off gas, etc.) from all iron and steel production processes should be monitored in the following manner:

[Methodology to be determined.]

(c) Flux Carbon Content Requirements. Carbon contents of fluxes (i.e., limestone and dolomite) from all iron and steel production processes should be monitored in the following manner:

(1) For limestone and dolomite, use ASTM C25-06.

(d) Electrode Carbon Content Requirements. Carbon contents of carbon electrodes used in electric arc furnaces (EAFs) should be monitored in the following manner:

(1) Vendor specifications of carbon content in EAF carbon electrodes.

(e) Finished Product Carbon Content Requirements. Carbon contents of finished products (i.e., steel, iron not converted to steel, and direct reduced iron) from all iron and steel production processes should be monitored in the following manner:

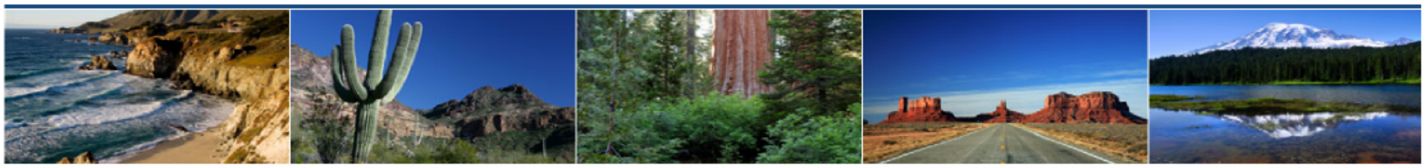
(1) For iron and steel, use ASTM E1019-08 or ASTM E351-93.

(f) Quantity Measurement Requirements. The quantities of process inputs, outputs, and by-products must be determined using the following methods:

(1) For solid process inputs, outputs, and by-products, quantities must be determined by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.

(2) For liquid process inputs, outputs, and by-products, quantities must be determined by direct volume measurement using the same plant instruments used for accounting purposes.

(3) For gaseous process inputs, outputs, and by-products, quantities must be determined by direct volume measurement using the same plant instruments used for accounting purposes.



§ WCI.170 LIME MANUFACTURING

§ WCI.171 Source Category Definition

Lime manufacturing is comprised of all processes that are used to manufacture quick lime (i.e. calcium oxide or calcium-magnesium oxide). Lime is produced via the calcination of limestone or other highly calcareous materials such as dolomite, aragonite, chalk, coral, marble, and shell.

§ WCI.172 Greenhouse Gas Reporting Requirements

In addition to the information required by WCI.3, the annual emissions data report shall contain the following information:

(a) Total emissions of CO_2, CH_4, and N_2O in metric tons.

(b) CO_2 process emissions from quick lime production (metric tons) and the following information:

~~(1)Quick lime emission factor (kg CO_2/metric ton quick lime).~~

~~(A)Quantity of quick lime produced (metric tons).~~

~~(B)Total Calcium Oxide (CaO) content of quick lime (weight fraction).~~

~~(C)Total Magnesium Oxide (MgO) content of quick lime (weight fraction).~~

~~(D)Uncalcined CaO (weight fraction).~~

~~(E)Uncalcined MgO (weight fraction).~~

~~(2)Lime kiln dust (LKD) emission factor (kg CO_2/metric ton LKD).~~

~~(A)Quantity of LKD discarded (metric tons).~~

~~(B)Total Calcium Oxide (CaO) content of LKD (weight fraction).~~

~~(C)Total Magnesium Oxide (MgO) content of LKD (weight fraction).~~

~~(D)Uncalcined CaO content of LKD (weight fraction).~~

~~(E)Uncalcined MgO content of LKD (weight fraction).~~

(1) For lime production:

(A) The emission factor (kg CO_2/metric ton) for each lime type for each month.

(B) The quantity of lime produced (metric tons) each month.

(C) The calcium oxide (CaO) content (weight fraction) of each lime type for each month.

(D) The magnesium oxide (MgO) content (weight fraction) of each lime type for each month.

(2) For the production of calcined byproducts and wastes:

(A) The emission factor (kg CO_2/metric ton) for each calcined byproduct/waste type for each month.

(B) The quantity of each type of calcined byproduct/waste type produced each month.

(C) The calcium oxide (CaO) content (weight fraction) of each calcined byproduct/waste type for each month.

(D) The magnesium oxide (MgO) content (weight fraction) of each calcined byproduct/waste type for each month.

(c) CO_2, CH_4, and N_2O emissions from fuel combustion in all kilns combined, following the calculation methods and reporting requirements specified in WCI.173(c) (metric tons).

(d) CO_2, CH_4, and N_2O emissions from all other fuel combustion units combined (kilns excluded), following the calculation methods and reporting requirements specified in WCI.20 (metric tons).

(e) If a continuous emissions monitor is used to measure CO_2 emissions from kilns, then the requirements of paragraphs (b) and (c) of this section do not apply for CO_2. ~~Lime plants that measure CO_2 emissions using CEMS shall report fuel usage by fuel type for kilns.~~

(f) Operators of lime plants shall also comply with the reporting requirements for any other applicable source category listed at WCI.1(a), including but not limited to the following:

(1) Coal fuel storage as specified in WCI.100.

(2) Electricity generating as specified in WCI.40.

(3) Cogeneration systems as specified in WCI.~~XX~~42(f).

§ WCI.173 Calculation of greenhouse Gas Emissions from Kilns

(a) Determine process CO_2 emissions as specified under either paragraph (a)(1) or (a)(2) of this section.

(1) Continuous emissions monitoring systems (CEMS) as specified in WCI.23(d).

(2) Calculate the sum of CO_2 process emissions from kilns and CO_2 fuel combustion emissions from kilns using the calculation methodologies specified in paragraph (b) and (c) of this section**.**

(b) Process CO_2 Emissions Calculation Methodology. Calculate total CO_2 process emissions as the sum of emissions from quick lime production, using the method specified in paragraph (b)(1) of this section.

(1) CO_2 Process Emissions. Calculate CO_2 emissions from quick lime production from each kiln using Equation 170-1 and a plant-specific quick lime emission factor and a plant-specific lime kiln dust (LKD) emission factor as specified in this section.

$$CO_2 = \sum_{i}^{12} \sum_{j}^{y} \left[QL_{ij} \times EF_{QL_{ij}}\right] + \sum_{k}^{4} \sum_{l}^{z} \left[LKD_{kl} \times EF_{LKD_{kl}}\right]$$ **Equation 170-1**

Where:

CO_2 = CO_2 emissions in metric tones/yr.
QL = Monthly Quantity of quick lime produced, metric tons.
EF_{QL} = Monthly Quick lime emission factor, metric tons CO_2/metric ton quick lime computed as specified in paragraph (b)(2~~1~~)~~(A)~~ of this section.
LKD = ~~Monthly~~ Quarterly Quantity ~~LKD~~ of calcined byproduct/waste, including LKD, scrubber sludge and other calcined wastes, produced annually~~discarded (i.e., not recycled to the kiln)~~, metric tons.
EF_{LKD} = ~~Monthly~~ Quarterly ~~LKD~~ calcined byproduct/waste emission factor, computed as specified in paragraph (b)(3~~1~~)~~(B)~~ of this section.
i = Month.
j = Lime type.
k = Quarter.
l = Calcined byproduct/waste type.
y = Total number of lime types.
z = Total number of calcined byproduct/waste types.

~~(A)~~(2) Monthly Quick Lime Emission Factor. Calculate a plant-specific quick lime emission factor _(EF_{QL}) for each kiln and month based on the percent of measured CaO and MgO content in quick lime and using Equation 170-2.

$$EF_{QL} = (CaO\ \ content \times Molecular\ \ ratio\ \ of\ CO_2 / CaO) + (MgO\ \ content \times Molecular\ \ ratio\ \ CO_2 / MgO)$$ **Equation 170-2**

Where:

CaO Content (by weight) = Total CaO content of Quick Lime~~, including calcined and uncalcined (weight fraction)~~.
~~Uncalcined CaO (by weight) = Uncalcined CaO content of Quick Lime (weight fraction).~~
Molecular ratio of CO_2/CaO = 0.785.
MgO Content (by weight) = Total MgO content of Quick Lime~~, including calcined and uncalcined (weight fraction)~~.
~~Uncalcined MgO = Uncalcined MgO content of Quick Lime (weight fraction).~~
Molecular ratio of CO_2/MgO = 1.092.

~~(2)~~ Monthly LKD Emission Factor. If LKD is generated and not recycled back to the kiln, then calculate a plant-specific LKD emission factor for each kiln and month. The LKD emission factor shall be calculated using Equation 170-3.

(3)

$$EF_{LKD} = [(CaO\ content - uncalcined\ \ CaO) \times Molecular\ ratio\ of\ CO_2 / CaO] + [(MgO\ Content - uncalcined\ \ MgO) \times Molecular\ ratio\ of\ CO_2 / MgO]$$

Equation 170-3

Where:

EF_{LKD}	=	LKD emission factor.
CaO Content (by weight)	=	Total CaO content of LKD, including calcined and uncalcined (weight fraction).
Uncalcined CaO (by weight)	=	Uncalcined CaO content of LKD (weight fraction).
Molecular ratio of CO_2/CaO	=	0.785.
MgO Content (by weight)	=	Total MgO content of LKD, including calcined and uncalcined (weight fraction).
Uncalcined MgO	=	Uncalcined MgO content of LKD (weight fraction).
Molecular ratio of CO_2/MgO	=	1.092.

(c) Fuel Combustion Emissions in Kilns. Calculate CO_2, CH_4, and N_2O emissions from stationary fuel combustion emissions following the calculation methods specified in WCI.20. Operators of lime manufacturing plants that primarily combust biomass-derived fuels and combust fossil fuels only during periods of start-up, shut-down, or malfunction may report CO_2 emissions from fossil fuels using the emission factor methodology in WCI.23(a). "Pure" means that the biomass-derived fuels account for 97 percent of the total amount of carbon in the fuels burned.

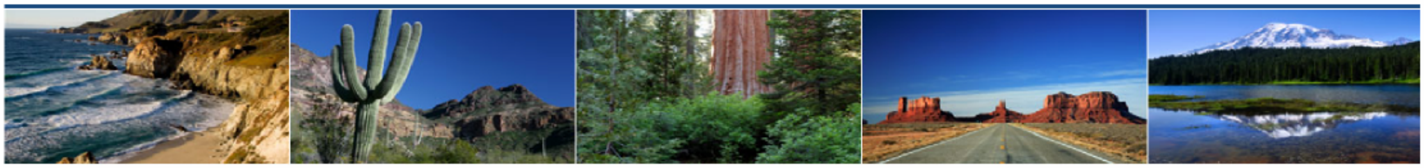
§ WCI.174 Sampling, Analysis, and Measurement Requirements

~~(a)Note: The sampling, analysis, and measurement procedures will be standardized for each calculation input to reduce variation between facilities within the lime industry. Material sampling frequency and technique is distinct from material analysis conducted in a laboratory. The WCI is seeking stakeholder feedback on this topic and is specifically interested in proposals from stakeholders with expertise in this industry related to sampling, analysis and measurement procedures already in use at these facilities for the material quantities and/or concentrations listed below. Those proposing procedures should include sampling frequency and technique, indicate the uncertainty associated with the procedures, and describe the application of the procedure at a facility.~~Determine the chemical composition (percent total CaO and percent total MgO) of each lime type and each calcined byproduct/waste type by laboratory analysis on a monthly basis for each lime type, and a quarterly basis for each calcined byproduct/waste type. This determination must be performed according to ASTM Methods C25, C1301 or C1271. Samples for analysis of the calcium oxide and magnesium oxide content of each lime type and each calcined byproduct/waste type should be collected during the same month or quarter as the production data. At least one sample must be collected monthly for each lime type produced during the month and quarterly for each calcined byproduct/waste type produced during the quarter.~~Determine the plant-specific weight fractions of CaO, MgO, uncalcined CaO, and uncalcined MgO in quick lime from each kiln using (method to be determined). Determine the plant-specific fraction of CaO, MgO, uncalcined CaO, and uncalcined MgO in LKD not recycled to the kiln using (method to be determined). The monitoring must be conducted monthly for each kiln from samples drawn from bulk storage.~~

~~(b)~~(a) ~~The quantity of quick lime produced must be determined by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.~~The quantity of lime produced and sold is to be estimated monthly using direct measurements (such as rail and truck scales) of lime sales for each lime type, and adjusted to take into account the difference in beginning- and end-of-period inventories of each lime type. The inventory period shall be annual at a minimum.

~~(b)The quantity of LKD discarded must be determined by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.~~ The quantity of calcined byproduct/waste sold is to be estimated quarterly using direct measurements (such as rail and truck scales) of byproduct/waste sales for each byproduct/waste type, and adjusted to take into account the difference in beginning- and end-of-period inventories of each calcined byproduct/waste type. The inventory period shall be annual at a minimum. The quantity of calcined byproduct/waste not sold is to be determined no less often than quarterly for each calcined/byproduct waste type using direct measurements (such as rail and truck scales), or a calcined byproduct/waste generation rate (i.e. calcined byproduct produced as a factor of lime production).

~~(d)~~(b) ~~The quantity of raw materials consumed (i.e. limestone, dolomite, aragonite, chalk, coral, marble, and shell.) must be determined by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.~~



§ WCI.200 PETROLEUM REFINERIES

§ WCI.201 Source Category Definition

A petroleum refinery consists of all processes used to produce gasoline, aromatics, kerosene, distillate fuel oils, residual fuel oils, lubricants, asphalt, or other products through distillation of petroleum or through redistillation, cracking, rearrangement or reforming of unfinished petroleum derivatives.

WCI.202 Greenhouse Gas Reporting Requirements

The annual emissions report must contain the following information reported at the facility level:

(a) Catalyst Regeneration. Report CO_2 emissions.

(b) Process Vents. Report CO_2, N_2O, and CH_4 emissions.

(c) Asphalt Production. Report CO_2 and CH_4 emissions.

(d) Sulfur Recovery. Report CO_2 emissions.

(e) Stationary Combustion Units Other than Flares and Control Devices. Report CO_2, N_2O, and CH_4 emissions as specified in WCI.23.

(f) Flares and Other Control Devices. Report CO_2, N_2O, and CH_4 emissions.

(g) Above-Ground Storage Tanks. Report CH_4 emissions.

(h) Wastewater Treatment. Report CH_4 and N_2O emissions.

(i) Oil-Water Separators. Report CH_4 emissions.

(j) Equipment Leaks. Report CH_4 emissions.

(k) Feedstock Consumption: Report feedstock consumption by type for all feedstocks which result in GHG emissions in the reporting year (including petroleum coke) in units of million standard cubic feet for gases, gallons for liquids, short tons for non-biomass solids, and bone dry short tons for biomass-derived solid fuels.

(l) Fuel Consumption: Report fuel consumption by fuel type consumed in the reporting year in units of million standard cubic feet for gases, gallons for liquids, short tons for non-biomass solids, and bone dry short tons for biomass-derived solid fuels.

WCI.203 Calculation of Greenhouse Gas Emissions

The operator shall calculate GHG emissions using the methods in paragraphs (a) through (i) of this section.

(a) Catalyst Regeneration. For units equipped with CEMS, operators shall calculate CO_2 process emissions resulting from catalyst regeneration using CEMS in accordance with WCI.20. In

the absence of CEMS data, the operator shall use the methods in paragraphs (a)(1) through (a)(3).

(1) The operator shall calculate process CO_2 emissions from the continuous regeneration of catalyst material in fluid catalytic cracking units (FCCU) and fluid cokers using Equations 200-1, 200-2, and 200-3.

$$CO_2 = \sum_{d=1}^{n} CR_d \times CF \times 3.664 \times 0.001 \qquad \textbf{Equation 200-1}$$

Where:

CO_2	=	CO_2 emissions (metric tons/yr)
n	=	number of days of operation in the report year
CR_d	=	-daily average coke burn rate (kg/day)
CF	=	-carbon fraction in coke burned
3.664	=	ratio of molecular weights, CO_2 to carbon
0.001	=	-conversion factor – kg to metric tons

$$CR_d = \left[\sum_{i=1}^{n} [K_1 Q_r \times (\%CO_2 + \%CO) + K_2 Q_a - K_3 Q_r \times [\%CO/2 + \%CO_2 + \%O_2] + K_3 Q_{oxy} \times (\%O_{oxy})]_i \right] / n$$

Equation 200-2

Where:

CR_d	=	daily average coke burn rate (kg/day or lb/day)
K_1, K_2, K_3	=	material balance and conversion factors (K_1, K_2, and K_3 from Table 200-1
n	=	number of hours per day
Q_r	=	volumetric flow rate of exhaust gas before entering the emission control system (dscm/min or dscf/min)
Q_a	=	volumetric flow rate of air to regenerator as determined from control room instrumentation (dscm/min or dscf/min)
$\%CO_2$	=	CO_2 concentration in regenerator exhaust, percent by volume – dry basis
%CO	=	CO concentration in regenerator exhaust, percent by volume – dry basis
$\%O_2$	=	O_2 concentration in regenerator exhaust, percent by volume – dry basis
Q_{oxy}	=	volumetric flow rate of O_2 enriched air to regenerator as determined from control room instrumentation (dscm/min or dscf/min)
$\%O_{xy}$	=	O_2 concentration in O_2 enriched air stream inlet to regenerator, percent by volume – dry basis

$$Q_r = (79 \times Q_a + (100 - \%Q_{xy}) \times Q_{oxy}) / (100 - \%CO_2 - \%CO - \%O_2) \qquad \textbf{Equation 200-3}$$

Where:

Q_r = volumetric flow rate of exhaust gas from regenerator before entering the emission control system (dscm/min or dscf/min)
Q_a = volumetric flow rate of air to regenerator, as determined from control room instrumentation (dscm/min or dscf/min)
$\%Q_{xy}$ = oxygen concentration in oxygen enriched air stream, percent by volume – dry basis
Q_{oxy} = volumetric flow rate of O_2 enriched air to regenerator as determined from catalytic cracking unit control room instrumentation (dscm/min or dscf/min)
$\%CO_2$ = carbon dioxide concentration in regenerator exhaust, percent by volume – dry basis
%CO = CO concentration in regenerator exhaust, percent by volume – dry basis. When no auxiliary fuel is burned and a continuous CO monitor is not required, assume %CO to be zero
$\%O_2$ = O_2 concentration in regenerator exhaust, percent by volume – dry basis

(2) The operator shall calculate process CO_2 emissions resulting from periodic catalyst regeneration using Equation 200-4.

$$CO_2 = \sum_{i=1}^{n} CRR \times \left(CF_{spent} - CF_{regen}\right)_i \times 3.664 \times 0.001 \qquad \textbf{Equation 200-4}$$

Where:

CO_2 = CO_2 emissions (metric tons/yr)
CRR = mass of catalyst regenerated (mass/regeneration cycle)
CF_{spent} = weight fraction carbon on spent catalyst
CF_{regen} = weight fraction carbon on regenerated catalyst (default = 0)
n = number of regeneration cycles
3.664 = ratio of molecular weights, CO_2 to carbon
0.001 = conversion factor – kg to metric tons

(3) The operator shall calculate process CO_2 emissions resulting from continuous catalyst regeneration in operations other than FCCUs and fluid cokers (e.g. catalytic reforming) using Equation 200-5.

$$CO_2 = CC_{irc} \times (CF_{spent} - CF_{regen}) \times H \times 3.664 \qquad \textbf{Equation 200-5}$$

Where:

CO_2 = CO_2 emissions (metric tons/yr)
CC_{irc} = average catalyst regeneration rate (metric tons/hr)
CF_{spent} = weight carbon fraction on spent catalyst
CF_{regen} = weight carbon fraction on regenerated catalyst (default = 0)
H = hours regenerator was operational (hr/yr)
3.664 = ratio of molecular weights, CO_2 to carbon

(b) Process Vents. Except for process emissions reported under other requirements of this regulation, the operator shall calculate process emissions of CO_2, CH_4, and N_2O from process vents using Equation 200-6.

Equation 200-6

$$E_x = \sum_{i=1}^{n} VR_i \times F_{xi} \times (MW_x / MVC) \times VT_i \times 0.001$$

Where:

E_x	=	emissions of x (metric tons/yr), where x = CO_2, N_2O, or CH_4
VR_i	=	vent rate for venting event i (scf/unit time or m^3/unit time)
F_{xi}	=	molar fraction of x in vent gas stream during event i
MW_x	=	molecular weight of x (kg/kg-mole)
MVC	=	molar volume conversion (849.5 scf/kg-mole for STP of 20°C and 1 atmosphere or 836 scf/kg-mole for STP of 60°F, and 1 atmosphere or (24.06 m^3/kg-mole for STP of 20°C and 1 atmosphere, or 23.67 m^3/kg-mole for STP of 60°F and 1 atmosphere)
VT_i	=	time duration of venting event i
n	=	number of venting events
0.001	=	conversion factor – kg to metric tons

(c) Asphalt Production. The operator shall calculate CO_2 and CH_4 process emissions from asphalt blowing activities using Equations 200-7 and 200-8.

Equation 200-7

$$CH_4 = (M_A \times EF \times MW_{CH4} / MVC) \times (1 - DE) \times 0.001$$

Where:

CH_4	=	CH_4 emissions (metric tons/yr)
M_A	=	mass of asphalt blown (10^3 bbl/yr)
EF	=	emission factor (EF = 2,555 scf $CH_4/10^3$ bbl or 72.35 m^3 $CH_4/10^3$ bbl)
MW_{CH4}	=	CH_4 molecular weight (16.04 kg/kg-mole)
MVC	=	molar volume conversion factor (849.5 scf/kg- mole, for STP of 20°C and 1 atmosphere or 24.06 m^3/kg-mole for STP of 20°C and 1 atmosphere, or 23.67 m^3/kg-mole for STP of 60°F and 1 atmosphere)
DE	=	control measure destruction efficiency (DE = 98% expressed as 0.98)
0.001	=	conversion factor – kg to metric tons

Equation 200-8

$$CO_2 = (M_A \times EF \times MW_{CH4} / MVC) \times DE \times 2.743 \times 0.001$$

Where:

CO_2	=	CO_2 emissions (metric tons/yr)
M_A	=	mass of asphalt blown (10^3 bbl/yr)
EF	=	emission factor (EF = 2,555 scf $CH_4/10^3$ bbl or 72.35 m^3 $CH_4/10^3$ bbl)
MW_{CH4}	=	CH_4 molecular weight (16.04 kg/kg-mole)

MVC	=	molar volume conversion factor (849.5 scf/kg mole, for STP of 20°C and 1 atmosphere or 24.06 m^3/kg-mole for STP of 20°C and 1 atmosphere, or 23.67 m^3/kg-mole for STP of 60°F and 1 atmosphere)
DE	=	control measure destruction efficiency (DE = 98% expressed as 0.98)
2.743	=	CH_4 to CO_2 conversion factor
0.001	=	conversion factor – kg to metric tons

(d) Sulfur Recovery. The operator shall calculate CO_2 process emissions from sulfur recovery units (SRUs) using Equation 200-9. For the molecular fraction (MF) of CO_2 in the sour gas, use either a default factor of 0.20 or a source specific molecular fraction value approved by [*insert jurisdiction*] and derived from source tests conducted at least once per calendar year under the supervision of [*insert jurisdiction*].

$$CO_2 = FR \times MW_{CO2} / MVC \times MF \times 0.001 \qquad \textbf{Equation 200-9}$$

Where:

CO_2	=	emissions of CO_2 (metric tons/yr)
FR	=	volumetric flow rate of acid gas to SRU (scf/year or m^3/year)
MW_{CO2}	=	molecular weight of CO_2 (44 kg/kg-mole)
MVC	=	molar volume conversion (849.5 scf/ kg-mole, for STP of 20°C and 1 atmosphere or 836 scf/kg-mole, for STP of 60°F, and 1 atmosphere or 24.06 m^3/kg-mole for STP of 20°C and 1 atmosphere, or 23.67 m^3/kg-mole for STP of 60°F and 1 atmosphere)
MF	=	molecular fraction (%) of CO_2 in sour gas (default MF = 20% expressed as 0.20)
0.001	=	conversion factor – kg to metric tons

(e) Flares and Other Control Devices. [ERG1]

(1) The operator shall calculate and report CO_2, CH_4 and N_2O emissions resulting from the combustion of flare pilot and purge gas using the appropriate method(s) specified in sections WCI.20.

(2) The operator shall calculate and report CO_2 emissions resulting from the combustion of hydrocarbons routed to flares for destruction as follows:

(A) Use ~~using:~~ Equation 200-10 if the flare is equipped with a continuous flow and ~~higher heating~~high heat value monitors:

$$CO_2 = Flare_N \times HHV \times (0.001 \times EmF) \qquad \textbf{Equation 200-10}$$

Where:

CO_2	=	CO_2 emissions (metric tons/year)
$Flare_N$	=	volume of flare gas (m^3/yr)
HHV	=	~~Higher heating~~High heat value for refinery fuel or flare gas (MMBtu/MMscf or J/m^3)
0.001	=	conversion factor – kg to metric tons
EmF	=	default CO_2 emission factor (60 kg CO_2/MMBtu or 5.7 kg/kJ)

(B) Use Equation 200-11 if the flare is equipped with a continuous flow and carbon content monitors:

$$CO_2 = Flare_N \times CC_N \times (MW_n / MVC) \times 3.664 \times 0.001$$ **Equation 200-11**

Where:

CO_2	=	CO_2 emissions (metric tons/year)
$Flare_N$	=	volume of flare gas (m^3/yr)
CC_N	=	carbon content of flare gas (kg of carbon/kg of fuel)
MW_N	=	molecular weight of flare gas
MVC	=	molar volume conversion factor (849.5 scf/kg- mole for STP of 20°C and 1 atmosphere or 836 scf/kg-mole~~,~~ for STP of 60°F, and 1 atmosphere or 24.06 m^3/kg-mole for STP of 20°C and 1 atmosphere, or 23.67 m^3/kg-mole for STP of 60°F and 1 atmosphere)
3.664	=	ratio of molecular weights, CO_2 to carbon
0.001	=	conversion factor – kg to metric tons

a. Use Equation 200-12 if the flare is not equipped with a continuous flow monitor and HHV or carbon content monitor~~.~~:

$$CO_2 = RFT \times EF_{NMHC} \times CF_{NMHC} \times 3.664 \times 0.001$$ **Equation 200-1~~0~~2**

Where:

CO_2	=	CO_2 emissions (metric tons/year)
RFT	=	refinery feed input (m^3/yr)
EF_{NMHC}	=	non-methane hydrocarbon emission factor (EF_{NMHC} = 0.002 kg/m^3 throughput)
CF_{NMHC}	=	conversion factor – NMHC to carbon (CF_{NMHC}= 0.6)
3.664	=	ratio of molecular weights, CO_2 to carbon
0.001	=	conversion factor – kg to metric tons

(3) The operator who uses methods other than flares (e.g. incineration, combustion as a supplemental fuel in heaters or boilers) to destroy low Btu gases (e.g. coker flue gas, gases from vapor recovery systems, casing vents and product storage tanks) shall calculate CO_2 emissions using Equation 200-13~~1~~. The operator shall determine CC_A and MW_A quarterly using methods specified in section WCI.20 and use the annual average values of CC_A and MW_A to calculate CO_2 emissions.

$$CO_2 = GV_A \times CC_A \times MW_A / MVC \times 3.664 \times 0.001$$ **Equation 200-1~~1~~3**

Where:

CO_2 = CO_2 emissions (metric tons/year)
GV_A = volume of gas A destroyed annually (scf/year or m^3/year)
CC_A = carbon content of gas A (kg C/kg fuel)
MW_A = molecular weight of gas A
MVC = molar volume conversion factor (849.5 scf/kg- mole for STP of 20°C and 1 atmosphere or 836 scf/kg-mole~~,~~ for STP of 60°F, and 1 atmosphere or 24.06 m^3/kg-mole for STP of 20°C and 1 atmosphere, or 23.67 m^3/kg-mole for STP of 60°F and 1 atmosphere)
3.664 = ratio of molecular weights, CO_2 to carbon
0.001 = conversion factor – kg to metric tons

(f) Storage Tanks. For above-ground storage tanks containing crude oil, asphalt, naphtha, and distillate oils that are not equipped with vapor recovery technology, the operator shall calculate CH_4 emissions using the U.S. EPA TANKS Model (Version 4.09D). For crude oil, naphtha, and distillate oils, use the default chemical databases for crude oil (RVP 5), distillate fuel oil No. 2, and jet naphtha (JP4), respectively. For asphalt, use the data in Table 200-4 to create an asphalt chemical database. The annual throughput for each storage tank must be distributed equally across the twelve months of the year and the single-component liquid option selected. The total VOC emission values generated by the model shall be converted to methane emissions using:

(1) A default conversion factor of 0.6 (CH_4 = 0.6 * VOC); or
(2) Species specific conversion factors determined by storage tank headspace vapor analysis using a sampling and analysis methodology approved by [*insert jurisdiction*].

(g) Wastewater Treatment.

(1) The operator shall calculate CH_4 emissions from wastewater treatment using Equation 200-14~~2~~.

$$CH_4 = [(Q \times COD_{qave}) - S] \times B \times MCF \times 0.001$$ **Equation 200-1~~2~~4**

Where:

CH_4 = emission of methane (tons/yr)
Q = volume of wastewater treated (m^3/yr)
COD_{qave} = average of quarterly determinations of chemical oxygen demand of the wastewater (kg/m^3)
S = organic component removed as sludge (kg COD/yr)
B = methane generation capacity (B = 0.25 kg CH_4/kg COD)
MCF = methane co~~nversion~~rrection factor for anaerobic decay (0-1.0) from Table 200-2
0.001 = conversion factor – kg to metric tons

(2) The operator shall calculate N_2O emissions from wastewater treatment using Equation 200-15~~3~~.

$$N_2O = Q \times N_{qave} \times EF_{N2O} \times 1.571 \times 0.001$$ **Equation 200-1~~53~~**

Where:

N_2O	=	emissions of N_2O (metric tons/yr)
Q	=	volume of wastewater treated (m^3/yr)
N_{qave}	=	average of quarterly determinations of N in effluent (kg N/m^3)
EF_{N2O}	=	emission factor for N_2O from discharged wastewater (0.005 kg N_2O-N/kg N)
1.571	=	conversion factor – kg N_2O-N to kg N_2O
0.001	=	conversion factor – kg to metric tons

(h) Oil-Water Separators. The operator shall calculate CH_4 emissions from oil-water separators using Equation 200-1~~6~~4. For the CF_{NMHC} conversion factor, operators shall use either a default factor of 0.6 or species specific conversion factors determined by analysis using a sampling and analysis methodology approved by [~~insert~~ *jurisdiction*].

$$CH_4 = EF_{sep} \times V_{water} \times CF_{NMHC} \times 0.001$$ **Equation 200-1~~6~~4**

Where:

CH_4	=	emission of methane (tons/yr)
EF_{sep}	=	NMHC (non methane hydrocarbon) emission factor (kg/m^3) from Table 200-3.
V_{water}	=	volume of waste water treated by the separator (m^3/yr)
CF_{NMHC}	=	NMHC to CH_4 conversion factor ~~(CF_{NMHC} = 0.6)~~
0.001	=	conversion factor – kg to metric tons

(i) Equipment leaks. The operator shall calculate CH_4 emissions for all components in natural gas, refinery fuel gas, and PSA off-gas systems as follows:

(1) Components shall be identified as one of the following classification types: valve, pump seal, connector, flange, open-ended line. Operators shall use the Component Identification and Counting Methodology and screening methods found in Method 3 in CAPCOA (1999) *[or the method in CCME EPC-73E for Canadian jurisdictions*], which ~~is~~are incorporated by reference in WCI.6. Operators shall conduct screenings at the frequency interval required by *[~~insert~~ jurisdiction].* Operators shall measure and record emissions using instrumentation capable of detecting methane.

(2) The VOC emissions shall be calculated using the following methods:

~~(A)~~(C) For components where the measured screening value (SV) is indistinguishable from zero when corrected for background, operators shall calculate VOC emissions using Equation 200-1~~5~~7:

$$E_{VOC-0} = \sum_{i=1}^{6} CC_i \times ZF_{i0} \times t$$ **Equation 200-1~~5~~7**

Where:

E_{VOC-0}	=	zero component VOC emission (kg/screening period)
i	=	component type (1 = valve, 2 = pump seal, 3 = other, 4 = connector, 5 = flange, 6 = open-ended line)
CC_i	=	number of i components where SV = 0
ZF_{i0}	=	zero VOC emission factor (kg/hr) for component i from Table 200-5
t	=	time (hours) since last screening

~~(B)~~(D) For leaking components, operators shall calculate VOC emissions using the following methods:

(i) For screening values between background and 9,999 ppmv, the operator shall calculate the VOC emissions using Equation 200-1~~6~~8.

$$E_{VOCL-C} = \sum_{i=1}^{6}\sum_{n=1}^{n}\left(\sigma_i \times SV_n^{\beta i}\right) \times t$$

Equation 200-1~~6~~8

Where:

E_{VOCL-C}	=	leaking components VOC emissions (kg/screening period)
i	=	component type (1=valve, 2=pump seal, 3=others, 4=connector, 5=flange, 6=open ended-line)
n	=	number of i components
σ_i	=	correlation equation coefficient for component type i from Table 200-5
SV_n	=	screening value for component n
βi	=	correlation equation exponent for component type i from Table 200-5
t	=	time (hours) component has been leaking – default value is time from last screening

(ii) For screening values greater than 9,999 ppmv, the operator shall calculate the VOC emissions using Equation 200-1~~7~~9.

$$E_{VOCP} = \sum_{i=1}^{6} CC_i \times PF_{iP} \times t$$

Equation 200-19~~7~~

Where:

E_{VOCP}	=	VOC emissions for components pegged over SV 9,999 ppmv (kg/screening period)
i	=	component type (1=valve, 2=pump seal, 3=others, 4=connector, 5=flange, 6=open-ended line)
CC_i	=	number of i components pegged over 9,999 ppmv
PF_{iP}	=	VOC emission factor (kg/hr) for component type i pegged over 9,999 ppmv from Table 200-5
t	=	time component has been leaking (hours) – default value is time since last screening

~~(C)~~(E) The operator shall calculate CH_4 emissions using Equation 200-~~18~~20. Operators shall use system specific determinations of gas composition and methane content (refinery fuel gas, natural gas, associated gas, flexigas, low Btu gas), where available, to determine a CF_{VOC} value. The sampling and analysis methodology must be approved by ~~the~~ [~~insert~~ jurisdiction]. When representative data is not available, operators shall use the default value of 0.6 for CF_{VOC}.

$$CH_4 = \sum_{1}^{n} \left(E_{VOC-0} + E_{VOC-LC} + E_{VOCP}\right)_n \times CF_{VOC} \times 0.001$$ **Equation 200-~~18~~20**

Where:

CH_4	=	methane emissions (metric tons/year)
n	=	number of screenings/year
E_{VOC-0}	=	zero component VOC emissions (kg/screening period)
E_{VOC-LC}	=	leaking component VOC emissions (kg/screening period)
E_{VOCP}	=	VOC emissions for components pegged over 9,999 ppmv (kg/screening period)
CF_{VOC}	=	VOC to CH_4 conversion factor (default CF_{VOC}=0.6)
0.001	=	conversion factor – kg to metric tons

WCI.204 Sampling, Analysis, and Measurement Requirements

(a) Catalyst Regeneration.

(1) For FCCUs and fluid coking units, the operators shall measure the following parameters: ~~using methods that comply with the measurement accuracy provisions in WCI.2(dg).~~

(A) The daily oxygen concentration in the oxygen enriched air stream inlet to the regenerator.

(B) Continuous measurements of the volumetric flow rate of air and oxygen enriched air entering the regenerator.

~~(C)Continuous measurement of the volumetric flow rate of exhaust gas leaving the regenerator.~~

~~(D)~~(C) Continuous or weekly periodic measurements of the CO_2, CO and O_2 concentrations in the regenerator exhaust gas, to be determined by individual jurisdictions.~~.~~

~~(E)~~(D) Daily ~~measurements~~determinations of the carbon content of the coke burned.

~~(F)~~(E) The number of days of operation.

(2) For periodic catalyst regeneration, the operators shall measure the following parameters ~~using methods that comply with the measurement accuracy provisions in WCI.2(gd)~~.

(A) The mass of catalyst regenerated in each regeneration cycle.

(B) The weight fraction of carbon on the catalyst prior to and after catalyst regeneration.

(3) For continuous catalyst regeneration in operations other than FCCUs and fluid cokers, the operators shall measure the following parameters ~~using methods that comply with the measurement accuracy provisions in WCI.2(dg)~~.

(A) The hourly catalyst regeneration rate.
(B) The weight fraction of carbon on the catalyst prior to and after catalyst regeneration.
(C) The number of hours of operation.

(b) Process vents. Operators shall measure the following parameters for each process vent ~~using methods that comply with the measurement accuracy provisions in WCI.2(dg)~~.

(1) The vent flow rate for each venting event.
(2) The molar fraction of CO_2, N_2O, and CH_4 in the vent gas stream during each venting event.
(3) The duration of each venting event.

(c) Asphalt Production. Operators shall measure the mass of asphalt blown ~~using methods that comply with the measurement accuracy provisions in WCI.2(gd)~~.

(d) Sulfur Recovery. The operator shall measure the volumetric flow rate of acid gas to the SRU. ~~using methods that comply with the measurement accuracy provisions in WCI.2(g).~~ If using source specific molecular faction value instead of the default factor, the operator shall conduct an annual test of the CO_2 content using methods approved by [insert jurisdiction]. The operator shall submit a test plan to the [~~insert~~ *jurisdiction]* for approval. Once approved, the annual tests shall be conducted in accordance with the approved test plan under the supervision of the [~~insert~~ *jurisdiction*].

(e) Flares and Other Control Devices. The operator shall measure the following:

(1) If using the method specified in WCI.203(e)(2)(a), monitor the flow rate and ~~higher heating~~high heat value of the flare gas using continuous monitors ~~that comply with the measurement accuracy provisions in WCI.2(d)~~.
(2) If using the method specified in WCI.203(e)(2)(b), monitor the flow rate and carbon content of the flare gas using continuous monitors ~~that comply with the measurement accuracy provisions in WCI.2(d).~~
(3) If using the method specified in WCI.203(e)(3), monitor the ~~The~~ volume of gas destroyed annually (determined to accuracy of ± 7.5%)~~.~~ ~~A~~and
~~(2) T~~the carbon content ~~using methods that comply with the measurement accuracy provisions in WCI.2(dg)~~.

(f) Storage Tanks. The operator shall measure the annual throughput of crude oil, naphtha, distillate oil, asphalt, and gas oil for each storage tank using flow meters ~~that comply with the measurement accuracy provisions in WCI.2(dg)~~.

(g) Wastewater Treatment. Operators shall measure the following parameters ~~using methods that comply with the measurement accuracy provisions in WCI.2(dg)~~.

(1) The daily volume of waste water treated.
(2) The quarterly chemical oxygen demand of the wastewater.
(3) The amount of sludge removed and the organic content of the sludge.
(4) The quarterly nitrogen content of the wastewater.

(h) Oil-Water Separators. Operators shall measure the daily volume of waste water treated by the oil-water separators using methods that comply with the measurement accuracy provisions in WCI.2(dg).

(i) Equipment Leaks. Operators shall measure screening values for each valve, pump seal, connector, flange, and open-ended line used in natural gas, refinery fuel gas, and PSA off-gas systems using the methods specified in CAPCOA (1999) Method 3: Correlation Equation Method *[or the method in CCME EPC-73E for Canadian jurisdictions]* and an instrument capable of detecting methane. Operators shall conduct screenings at the frequency interval required by *[~~insert~~ jurisdiction]*.

~~*Note: Comparability of the Canadian regulations to the leak detection and repair r regulations under 40 CFR 63, Subpart CC and 40 CFR 60, Subpart VV is under determination. These U.S EPA regulations require initially monthly monitoring for valves and pumps, which may be reduced to quarterly, semi-annual, or annual based on the percentage of leaking components.*~~

Table 200-1. Coke burn rate material balance and conversion factors

	(kg min)/(hr dscm %)	(lb min)/(hr dscf %)
K_1	0.2982	0.0186
K_2	2.0880	0.1303
K_3	0.0994	0.0062

Table 200-2. Default MCF Values for Industrial Wastewater			
Type of Treatment and Discharge Pathway or System	**Comments**	**MCF**	**Range**
Untreated			
Sea, river and lake discharge	Rivers with high organic loading may turn anaerobic, however this is not considered here	0.1	0 - 0.2
Treated			
Aerobic treatment plant	Well maintained, some CH_4 may be emitted from settling basins	0	0 – 0.1
Aerobic treatment plant	Not well maintained, overloaded	0.3	0.2 – 0.4
Anaerobic digester for sludge	CH_4 recovery not considered here	0.8	0.8 – 1.0
Anaerobic reactor	CH_4 recovery not considered here	0.8	0.8 – 1.0
Anaerobic shallow lagoon	Depth less than 2 meters	0.2	0 – 0.3
Anaerobic deep lagoon	Depth more than 2 meters	0.8	0.8 – 1.0

For CH_4 generation capacity (B) in kg CH_4/kg COD, use default factor of 0.25 kg CH_4/kg COD.

The emission factor for N_2O from discharged wastewater (EF_{N2O}) is 0.005 kg N_2O-N/kg-N.

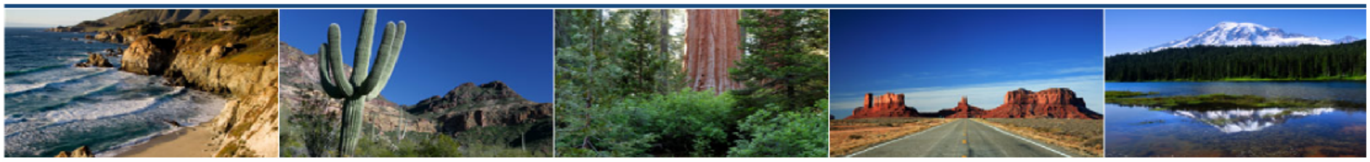
MCF = methane ~~correction~~conversion factor ~~–~~(the fraction of waste treated anaerobically).
COD = chemical oxygen demand (kg COD/m^3).

Table 200-3. Emission Factors for Oil/Water Separators	
Separator Type	**Emission factor (EF_{sep})[a] kg NMHC/m^3 wastewater treated**
Gravity type - uncovered	1.11e-01
Gravity type - covered	3.30e-03
Gravity type – covered and connected to destruction device	0
DAF[b] of IAF[c] - uncovered	4.00e-03[d]
DAF or IAF - covered	1.20e-04[d]
DAF or Iaf – covered and connected to a destruction device	0

[a] EFs do not include ethane
[b] DAF = dissolved air flotation type
[c] IAF = induced air flotation device
[d] EFs for these types of separators apply where they are installed as secondary treatment systems

Table 200-4. Data for Preparing the Asphalt Chemical Database	
Parameter	**Database Entry**
Liquid Molecular Weight	**1000**
Vapor Molecular Weight	**105**
Liquid Density (lb/gal. at 60 ^oF)	**8.0925**
Antoine's Equation Constants (using K)	**A = 75350.06**
	B = 9.00346

Table 200-5. Gas Service Components Fugitive Emissions			
Component Type / Service Type	**Default Zero Factor (kg/hr)**	**Correlation Equation (kg/hr)**	**Pegged Factor (kg/hr)**
			10,000 ppmv
	Zf_{i0}	**σ_i and β_i**	**(SV > 9,999) PF_{iP-10}**
Valves (1)	7.8×10^{-6}	$2.27 \times 10^{-6}(SV)^{0.747}$	0.064
Pump seals (2)	1.9×10^{-5}	$5.07 \times 10^{-5}(SV)^{0.622}$	0.089
Others (3)	4.0×10^{-6}	$8.69 \times 10^{-6}(SV)^{0.642}$	0.082
Connectors (4)	7.5×10^{-6}	$1.53 \times 10^{-6}(SV)^{0.736}$	0.030
Flanges (5)	3.1×10^{-7}	$4.53 \times 10^{-6}(SV)^{0.706}$	0.095
Open-ended lines (6)	2.0×10^{-6}	$1.90 \times 10^{-6}(SV)^{0.724}$	0.033



§ WCI.210 PULP AND PAPER MANUFACTURING

§ WCI.211 Source Category Definition

The pulp and paper manufacturing source category consists of facilities that produce pulp either at stand-alone pulp facilities or integrated pulp and paper mills.

§ WCI.212 Greenhouse Gas Reporting Requirements

In addition to the information required by WCI.3, the annual emissions report must contain the following information:

(a) Annual biogenic CO_2 process emissions from all recovery furnaces and kilns in metric tons, as specified in WCI.213.

(b) Annual fossil CO_2 process emissions from all recovery furnaces and kilns in metric tons, as specified in WCI.213

~~(b)~~(c) CO_2, N_2O, and CH_4 emissions from stationary combustion units in metric tons, as specified in WCI.23.

~~(c)~~(d) Annual consumption of carbonate in metric tons.

~~(d)~~(e) Annual black liquor production in metric tons.

~~(e)~~(f) Under consideration: Annual N_2O, and CH_4 emissions from onsite wastewater treatment plants in metric tons, as specified in WCI.200(g).

§ WCI.213 Calculation of GHG Emissions

(a) ~~You must c~~Calculate biogenic CO_2 process emissions from recovery furnaces and kilns using Equation 210-1:

$$CO_{2,biogenic} = \sum_{i=1}^{12}(BL_i \times CC_i \times 3.664) \qquad \textbf{Equation 210-1}$$

~~[A1]~~Where:

$CO_{2,biogenic}$	=	Biogenic CO_2 process emissions from recovery furnaces and kilns (metric tons/year).
BL_i	=	Black liquor produced in month i (metric tons/month).
CC_i	=	Carbon content of the black liquor (~~percent by~~ weight ~~expressed as a decimal~~ fraction).
~~RM_j~~	~~=~~	~~Amount of carbonate j consumed in month i (metric tons/month).~~
~~EF_j~~	~~=~~	~~Carbonate content of carbonate material j for month i (percent by weight, expressed as a decimal fraction as CO_2)~~.
3.664	=	Ratio of molecular weights, CO_2 to carbon.

(b) ~~You must c~~Calculate fossil CO_2 process emissions from make-up carbonates used in the recovery furnace and kiln system using Equation 210-2:

$$CO_{2,\,fossil} = \sum_{i=1}^{12} \left(\sum_{j=1}^{n} RM_j \times EF_j \right)_i \qquad \textbf{Equation 210-2}$$

Where:

$CO_{2,\,fossil}$ = Fossil CO_2 process emissions from recovery furnace and kiln systems (metric tons/year).
RM_j = Amount of make-up carbonate j consumed in month i (metric tons/month).
EF_j = Carbonate content of carbonate material j for month i (weight fraction as CO_2).
3.664 = Ratio of molecular weights, CO_2 to carbon.

§ WCI.214 Monitoring Requirements

~~*Note: The sampling, analysis, and measurement procedures will be standardized for each calculation input to reduce variation between facilities within the pulp and paper industry. Material sampling frequency and technique is distinct from material analysis conducted in a laboratory. The WCI is seeking stakeholder feedback on this topic and is specifically interested in proposals from stakeholders with expertise in this industry related to sampling, analysis and measurement procedures already in use at these facilities for the material quantities and/or concentrations listed below. Those proposing procedures should include sampling frequency and technique, indicate the uncertainty associated with the procedures, and describe the application of the procedure at a facility.*~~

(a) Measure the quantity of black liquor produced each month. ~~using methods that comply with the measurement accuracy provisions in WCI.2(g)~~

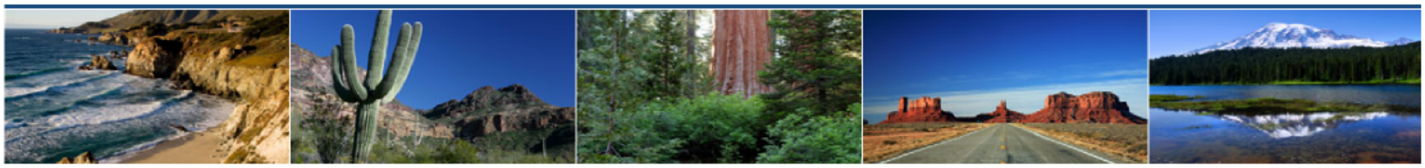
(b) Collect monthly samples of black liquor and analyze each sample for carbon content using ASTM D5373-08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal.~~ASTM [*To be determined*].~~

(c) For the amount of carbonate material consumed, ~~you must~~ either use records provided by the material supplier or monitor carbonate material consumption using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders. ~~using methods that comply with the measurement accuracy provisions in WCI.2(g).~~

(d) For the carbonate content of each carbonate material consumed, ~~you must~~ either use carbonate content data provided by the supplier, the appropriate default factor from Table 1, or collect monthly samples of each carbonate material consumed and analyze each sample for carbonate content using ASTM Methods C25, C1301 or C1271 ~~[*To be determined*]~~.

Table 1: Formulae, Formula Weights, and Carbon Dioxide Emission Factors for Common Carbonate Species.

Carbonate	Mineral Name	Formula Weight	Emission Factor (metric tons CO_2/metric ton Carbonate)
$CaCO_3$	Calcite	100.1	0.4397
$CaMg(CO_3)_2$	Dolomite	184.4	0.4773
Na_2CO_3	Soda ash (sodium carbonate)	106.0	0.4149



§ WCI.230 SODA ASH PRODUCTION

§ WCI.231 Source Category Definition

The soda ash production source category consists of facilities that produce soda ash by calcining sodium carbonate bearing ore or brine.

§ WCI.232 Greenhouse Gas Reporting Requirements

In addition to the information required by WCI.3, the annual emissions report must contain the following information:

(a) Annual CO_2 process emissions from all soda ash calcining kilns combined, as specified in WCI.233 (metric tons).

(b) CO_2, N_2O, and CH_4 emissions from combustion of fuels in the calcining kilns, as specified in WCI.20 (metric tons).

(c) Annual consumption of trona ore or sodium carbonate-rich brine (metric tons).

(d) Annual soda ash production (metric tons).

(e) Annual mass of waste material output from calcining kilns (metric tons).

(f) For plants recycling the CO_2 generated from calcination for use in the carbonation towers, report annual CO_2 recycled within the process (metric tons).

§ WCI.233 Calculation of GHG Emissions

(a) You must calculate CO_2 emissions using the methods in either paragraphs (a)(1) or (a)(2) of this section.

(1) **Continuous Emission Monitoring Systems.** The owner or operator may measure CO_2 emissions using CEMS, as specified WCI.23(d).

(2) **Feedstock Material Balance.** The owner or operator may estimate CO_2 process emissions using Equation 230-1 and the measured carbon content and feedstock input of the trona ore or carbonate-rich brine.

$$CO_2 = \sum_{j=1}^{12} (3.664)[(Ci_j \times Ti_j) - (Cs_j \times Ts_j) - (Cw_j \times Tw_j)] \qquad \textbf{Equation 230-1}$$

Where:

CO_2 = CO_2 process emissions from soda ash production (metric tons/year).
Ci_j = Carbon content of feedstock (trona ore or carbonate-rich brine) input (percent by weight, expressed as a decimal fraction).
Ti_j = Weight of feedstock (trona ore or carbonate-rich brine) input (metric tons/month).
Cs_j = Carbon content of soda ash output (percent by weight, expressed as a decimal fraction).
Ts_j = Weight of soda ash output (metric tons/month).
Cw_j = Carbon content of waste material output from the kiln (i.e. kiln dust collected in control devices and not combined with the soda ash product) (percent by weight, expressed as a decimal fraction).
Tw_j = Weight of waste material output from the kiln (i.e. kiln dust collected in control devices and not combined with the soda ash product) (metric tons/month).
3.664 = Ratio of molecular weights, CO_2 to carbon.

(b) If you operate a soda ash production facility in which CO_2 generated in calcining kilns is recycled to carbonate towers for brine pre-treatment, you must calculate recycled CO_2 using Equation 230-2.

$$CO_2 = \sum_{j=1}^{12} (3.664)[(Ci_j \times Ti_j) - (Cb_j \times Tb_j)]$$ **Equation 230-2**

Where:

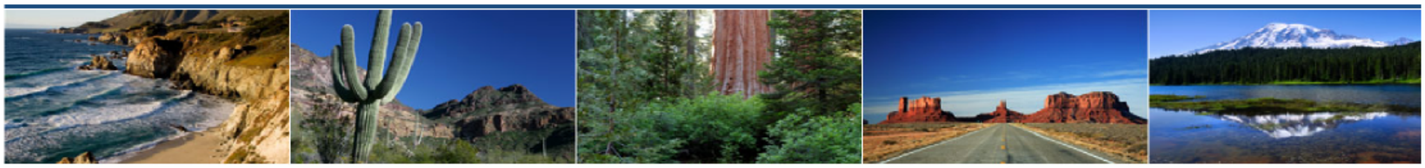
CO_2 = Recycled CO_2 from the ore calcining kiln (metric tons/year).
Ci_j = Carbon content of ~~ore~~ bicarbonate kiln input (percent by weight, expressed as a decimal fraction).
Ti_j = Weight of bicarbonate kiln~~ore~~ input (metric tons/month).
Cb_j = Carbon content of sodium carbonate-rich brine input (percent by weight, expressed as a decimal fraction).
Tb_j = Weight of sodium carbonate-rich brine input (metric tons/month).
3.664 = Ratio of molecular weights, CO_2 to carbon.

§ WCI.234 Monitoring Requirements

Owners and operators using the mass balance method must comply with the following monitoring requirements:

(a) Measure the quantity of ore, soda ash, waste material, and carbonate-rich brine (as applicable) by direct measurement using the same instruments used for accounting purposes.

(b) Collect monthly samples of ore, soda ash, waste material, and carbonate-rich brine (as applicable) and analyze each sample for carbon content. For the carbon content of the brine ore and carbonate-rich brine, use a total organic carbon analyzer according to the ultraviolet light/chemical (sodium persulfate) oxidation method in ASTM D4839-03. Use method ASTM E359-00(2005) for the carbon content of trona ore, soda ash, and waste material.



§ WCI.300 PETROCHEMICAL MANUFACTURING

§ WCI.301 Source Category Definition

The petrochemical manufacturing source category consists of any facility that manufacturers petrochemicals, including acrylonitrile, propylene, ethylene, ethylene dichloride, ethylene oxide, or methanol, from feedstocks derived from petroleum, or petroleum and natural gas liquids.

§ WCI.302 Greenhouse Gas Reporting Requirements

In addition to the information required by WCI.3, the annual emissions report must contain the following information:

(a) CO_2, N_2O, and CH_4 emissions from combustion of fuels in the stationary combustion unit in metric tons, as specified in WCI.20.

(b) CO_2, N_2O, and CH_4 emissions from flares and other oxidizers in metric tons, as specified in WCI.303(a).

(c) CO_2, N_2O, and CH_4 emissions from process vents in metric tons, as specified in WCI.303(b).

(d) CH_4 emissions tons from equipment leaks in metric, as specified in WCI.303(c).

(e) Annual consumption of feedstock by type for all feedstocks that result in GHG emissions in million standard cubic feet for gases, gallons for liquids, short tons for non-biomass solids, and bone dry short tons for biomass-derived solid fuels.

§ WCI.303 Calculation of GHG Emissions

(a) **Flares and Other Oxidizers.** You must calculate GHG emissions from flares and oxidation control devices as follows:

(1) Calculate CO_2, CH_4 and N_2O emissions resulting from the combustion of flare pilot and purge gas using the appropriate method(s) specified in WCI.20.

(2) Calculate CO_2 emissions for each gas destroyed in a flare or other oxidation control device using Equation 300-1.

Equation 300-1

$$CO_2 = \sum_{i=1}^{n} GV_i \times CC_i \times MW_i / MVC \times 3.664 \times 0.001$$

Where:

CO_2 = CO_2 emissions (metric tons/year).
GV_i = Volume of gas *i* destroyed annually (scf/year).
CC_i = Average annual carbon content of gas *i* (kg C/kg fuel).
MW_i = Average annual molecular weight of gas *i*.

MVC	=	Molar volume conversion factor (849.5 scf/kg- mole for STP of 20°C and 1 atmosphere or 836 scf/kg-mole, for STP of 60°F, and 1 atmosphere).
3.664	=	Ratio of molecular weights, CO_2 to carbon.
0.001	=	Conversion factor, kg to metric tons.
n	=	Number of gases destroyed.

(b) **Process Vents.** Except for process emissions calculated pursuant to WCI.303(a) or (c), you must calculate process emissions of CO_2, CH_4, and N_2O from process vents using Equation 300-2.

$$E_x = \sum_{i=1}^{n} VR_i \times F_{xi} \times (MW_x / MVC) \times VT_i \times 0.001$$ **Equation 300-2**

Where:

E_x	=	Emissions of x (metric tons/yr), where x = CO_2, N_2O, or CH_4.
VR_i	=	Vent rate for venting event i (scf/unit time).
F_{xi}	=	Molar fraction of x in vent gas stream during event i.
MW_x	=	Molecular weight of x (kg/kg-mole).
MVC	=	Molar volume conversion (849.5 scf/kg-mole for STP of 20°C and 1 atmosphere or 836 scf/kg-mole for STP of 60°F, and 1 atmosphere).
VT_i	=	Time duration of venting event i (same units of time used for VR_i).
n	=	Number of venting events.
0.001	=	Conversion factor, kg to metric tons.

(c) **Equipment Leaks.** You must calculate CH_4 emissions for each valve, pump seal, connector, flange, open-ended line, and other components in natural gas, fuel gas, and off-gas systems as follows:

(1) Identify and screen each valve, pump seal, connector, flange, open-ended line, and other components in natural gas, fuel gas, and off-gas systems using the monitoring method in WCI.304. Components identified as “other” components include instruments, loading arms, pressure relief valves, vents, compressors, dump lever arms, diaphragms, drains, hatches, meters, and polished rods stuffing boxes.

(2) Use the results of the component screening and the following equations to calculate VOC emissions:

(A) For components where the measured screening value is equal to zero when corrected for background, calculate VOC emissions using Equation 300-3 and the appropriate default emission factors from Table 300-1:

$$E_{VOC-0} = \sum_{i=1}^{6} CC_i \times ZF_{i0} \times t$$ **Equation 300-3**

Where:

$E_{VOC\text{-}0}$ = Emissions from components with a screening value equal to zero, when corrected for background (kg/screening period).

i = Component type (valve, pump seal, other, connector, flange, open-ended line).

CC_i = Number of i components where the screening value is 0.

ZF_{i0} = Default zero factor for component i from Table 300-1 (kg/hr).

t = Time since last screening (hours/screening period).

(B) For components where the measured screening value, corrected for background, is between 0 and 10,000 ppmv, calculate VOC emissions using Equation 300-4 and the appropriate default factors from Table 300-1:

$$E_{VOCL-C} = \sum_{i=1}^{6} \sum_{n=1}^{n} \left(\sigma_i \times SV_n^{\beta i} \right) \times t$$ **Equation 300-4**

Where:

$E_{VOCL\text{-}C}$ = Emissions from components with screening values, corrected for background, between 0 and 10,000 (kg/screening period).

i = Component type (valve, pump seal, others, connector, flange, open ended-line).

n = Number of *i* components.

σ_i = Correlation equation coefficient for component type *i* from Table 300-1.

SV_n = Screening value for component *n.*

βi = Correlation equation exponent for component type *i* from Table 300-1.

t = Time component has been leaking (default value is time from last screening) (hours/screening period).

(C) For components where the screening value, corrected for background, is greater than or equal to 10,000 ppmv, calculate VOC emissions using Equation 300-5 and the appropriate default factors from Table 300-1:

$$E_{VOCP} = \sum_{i=1}^{6} CC_i \times PF_{iP} \times t$$ **Equation 300-5**

Where:

E_{VOCP} = Emissions from components with screening values, corrected for background, greater than or equal to 10,000 ppmv (kg/screening period).

i = Component type (1=valve, 2=pump seal, 3=others, 4=connector, 5=flange, 6=open-ended line).

CC_i = Number of *i* components with screening values greater than 9,999 ppmv.

PF_{iP} = VOC emission factor for component type *i* pegged over 9,999 ppmv from Table 300-1 (kg/hr).

t = Time component has been leaking (default value is time since last screening) (hours/screening period).

(3) Calculate CH_4 emissions using Equation 300-6 and either a default factor of 0.6 for CF_{VOC} or a site-specific conversion factor calculated from the composition and methane content of the gas.

$$CH_4 = \sum_{1}^{n} \left(E_{VOC-0} + E_{VOC-LC} + E_{VOCP}\right)_n \times CF_{VOC} \times 0.001 \qquad \textbf{Equation 300-6}$$

Where:

CH_4	=	CH_4 emissions (metric tons/year).
n	=	Number of screenings/year.
E_{VOC-0}	=	Emissions from components with a screening value equal to zero, when corrected for background (kg/screening period).
E_{VOC-LC}	=	Emissions from components with screening values, corrected for background, between 0 and 10,000 (kg/screening period).
E_{VOCP}	=	Emissions from components with screening values, corrected for background, greater than or equal to 10,000 ppmv (kg/screening period).
CF_{VOC}	=	VOC to CH_4 conversion factor (default $CF_{VOC} = 0.6$).
0.001	=	Conversion factor (kg to metric tons).

§ WCI.304 Monitoring Requirements

(a) Flares and Other Oxidizers. You must measure:

(1) The volume of each gas destroyed annually determined to an accuracy of ± 5 percent.

(2) The carbon content and molecular weight of each gas quarterly using the methods specified in WCI.25 and calculate the annual average values for carbon content and molecular weight for each gas destroyed.

(b) Process **Vents.** You must measure the following parameters for each process vent:~~, using methods that comply with the measurement accuracy provisions in WCI.2(g):~~

(1) The gas flow rate for each venting event.

(2) The molar fraction of CO2, N2O, and CH4 in the vent gas stream during each venting event.

(3) The duration of each venting event.

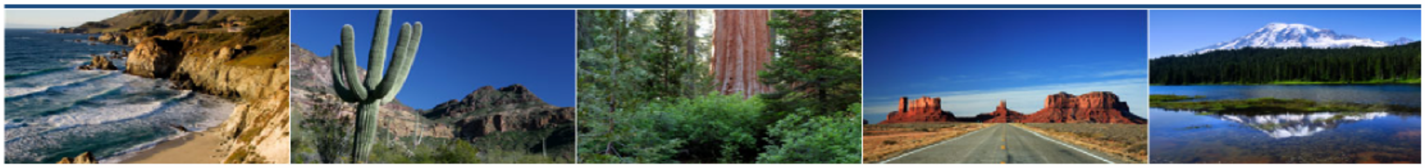
(c) **Equipment Leaks.** You must screen each valve, pump seal, connector, flange, and open-ended line used in natural gas, fuel gas, and off-gas systems using the methods specified in CAPCOA (1999) Method 3: Correlation Equation Method and an instrument capable of detecting methane. Screenings must be performed at the frequency interval required by [*insert jurisdiction*]. The instrumentation used for screening must be capable of detecting methane.

(d) **Feedstock Consumption.** You must measure the feedstock consumption ~~using methods that comply with the measurement accuracy provisions in WCI.2(g).~~ using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.

Table 300-1. Fugitive Emissions from Gas Service Components

Component Type / Service Type	Default Zero Factor (kg/hr)	Correlation Equation (kg/hr)	Pegged Factor (kg/hr)
	(SV = 0) Zf_{i0}	(SV > 0 and < 10,000) σ_i and β_i	(SV ≥ 10,000) PF_{iP-10}
Valves	7.8×10^{-6}	$2.27 \times 10^{-6}(SV)^{0.747}$	0.064
Pump seals	1.9×10^{-5}	$5.07 \times 10^{-5}(SV)^{0.622}$	0.089
Others[a]	4.0×10^{-6}	$8.69 \times 10^{-6}(SV)^{0.642}$	0.082
Connectors	7.5×10^{-6}	$1.53 \times 10^{-6}(SV)^{0.736}$	0.030
Flanges	3.1×10^{-7}	$4.53 \times 10^{-6}(SV)^{0.706}$	0.095
Open-ended lines	2.0×10^{-6}	$1.90 \times 10^{-6}(SV)^{0.724}$	0.033

[a] The "other" component type should be applied to any component type other than connectors, flanges, open-ended lines, pump seals, or valves. The "other" component type includes: instruments, loading arms, pressure relief valves, vents, compressors, dump lever arms, diaphragms, drains, hatches, meters, and polished rods stuffing boxes.



§ WCI.XX0 ADIPIC ACID MANUFACTURING

§ WCI.XX1 Source Category Definition

Adipic acid ($HOOC(CH_2)_4COOH$) is a dicarboxylic acid used in the production of a large number of products including synthetic fibers (primarily nylon 6,6), coatings, plastics, urethane foams, and synthetic lubricants. Adipic acid is produced by oxidizing a mixture of cyclohexanone ($(CH_2)_5CO$) and cyclohexanol ($(CH_2)_5CHOH$) with nitric acid in the presence of a catalyst; nitrous oxide (N_2O) is formed as an unwanted by-product.

§ WCI.XX2 Greenhouse Gas Reporting Requirements

In addition to the information required by WCI.3, the annual emissions data report shall contain the following information:

(a) Total emissions of N_2O at the facility level (metric tons)

(b) Total quantity of adipic acid production (metric tons)

(c) Facility-specific N_2O emission factor derived from periodic emissions monitoring or irregular emissions sampling (metric tons N_2O per metric ton of adipic acid)

(d) Destruction factor for facility-specific abatement technology (e.g., catalytic destruction, thermal destruction, nitric acid recycling, adipic acid recycling, etc.)

(e) Abatement system utilization factor for facility-specific abatement technology

(f) CO_2, N_2O, and CH_4 emissions from stationary combustion units as specified in WCI.20

§ WCI.XX3 Calculation of N_2O Emissions

(a) Process N_2O emissions. Determine process N_2O emissions as specified under either paragraph (1) or (2) of this section.

(1) Continuous emissions monitoring systems (CEMS).

(2) Calculation methodologies specified in paragraph (b) of this section.

(b) Process N_2O Emissions Calculation Methodology. Calculate total N_2O process emissions using the following equation:

$$E_{N2O} = EF \times AAP \times \left(1 - DF \times ASUF\right)$$

Equation XX0-1

Where:

E_{N2O}	=	Emissions of N_2O from adipic acid production (metric tons);
EF	=	N_2O emission factor (metric tons N_2O/metric ton of adipic acid produced) derived from periodic emissions monitoring or irregular emissions sampling;
AAP	=	Adipic acid production (metric tons);
DF	=	Destruction factor (dimensionless);
ASUF	=	Abatement system utilization factor (dimensionless).

§ WCI.XX4 Sampling, Analysis, and Measurement Requirements

The following measurement methods shall be used.

(a) Facility N_2O emissions tests. All facilities must conduct testing using:

(1) U.S. EPA Method 320 (40 CFR part 63, Appendix A) or ASTM D6348-03; or

~~(This is a possible change for WCI based on §98.54 of the Mandatory Reporting Rule);~~

(2) Continuous emissions monitor system (CEMS) to determine either the uncontrolled emissions to derive an emission factor (for use with the documented abator destruction efficiency), or the controlled emissions. The CEMS shall be operated in accordance with quality assurance and quality control program approved by the [jurisdiction].

(b) Adipic acid production rates. Production rates may be determined through sales records, or through direct measurement using flow meters or weigh scales.

ANNOUNCEMENT CONCERNING
FIRST JURISDICTIONAL DELIVERER APPROACH

July 15, 2009

The *Design Recommendations for the WCI Regional Cap-and-Trade Program* describe the point of regulation for electricity imported into a WCI jurisdiction as the First Jurisdictional Deliverer (FJD). An FJD is defined as "the first entity that delivers… electricity [imported from non-WCI jurisdictions] over which the consuming partner WCI jurisdiction has regulatory authority."

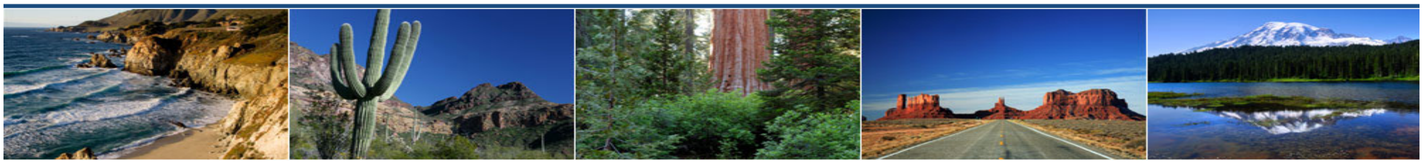
Stakeholders in the electricity sector expressed concern about this approach—referred to as the "individual boundary" approach–because the compliance obligation changes as power moves across the WCI Partner jurisdictions. As a result, the WCI Electricity Committee worked with stakeholders to craft an alternative "common boundary" approach that proposed to impose the compliance obligation on electricity importers at the first point of entry in any WCI Partner jurisdiction, regardless of where the electricity was consumed in the WCI.

The Electricity Committee and Partners from the WCI jurisdictions carefully considered the practical and administrative aspects of both approaches, as well as their enforcement implications. Several problems were identified while continuing to work on this issue. There were serious questions regarding whether the common boundary approach would be workable and enforceable. The electricity could be coming into a WCI jurisdiction but the importer may not have any "presence" in that jurisdiction. The ability of a WCI Partner jurisdiction to require allowances for electricity that is not produced or consumed in its jurisdiction also raised questions of enforceability. It would also be possible that a given Partner could be required to cover the costs of monitoring and enforcing electricity that was generated and consumed outside that jurisdiction.

As a result of these issues, the WCI Partners determined that even with its shortcomings, the individual boundary option will be the approach used in the WCI region. The Partners identified an administrative variation where instead of directly regulating electricity importers, a state or province may directly retire allowances associated with those emissions. This may be a particularly useful approach for those states and provinces that have a small amount of imported power. The details of this approach have yet to be worked out. The WCI Electricity Committee will discuss this option with stakeholders in the following weeks. In addition, the eastern Canadian provinces are examining if it is feasible to have a sub-region with a common boundary by combining their efforts. For all of these approaches, the goal, as recommended by stakeholder feedback, is to apply a consistent price signal that treats imported and domestic electricity on a level playing field.

The WCI Partners appreciate the work that stakeholders and the Electricity Committee have put into developing approaches to including emissions from imported electricity in the cap-and-trade program scope. This has proven to be a particularly difficult issue to resolve, but the lessons we have learned will be useful in our on-going work on WCI and with the U.S. federal proposals. The Partners are committed to continue working with stakeholders to develop strategies that maintain a consistent price signal in the implementation of the individual boundary cap-and-trade program.

Western Climate Initiative



July 21, 2009
The Nines Hotel, Portland
www.thenines.com
525 SW Morrison, Portland, OR 97204

[For remote access, call 1-800-868-1837 toll free in the U.S. and Canada (1-404-920-6440 for outside the U.S. and Canada), participant code 659537#]

1:00 pm	**Convene – *(The Culture Room)*** Welcome and Introductions Agenda Review
1:15 pm	**Approve Materials for Public Release** • CSAD – Competitiveness Statement of Principles • Offsets – Essential Elements for Offset Criteria White Paper • Reporting – Regional Emissions Database Options White Paper
2:00 pm	**Presentation of First Jurisdictional Recommendation and Discussion Followed by Stakeholder Q&A**
2:45 pm	**Break**
3:00 pm	**Next Steps on Three Regional Program Coordination** *Purpose:* Confirm the follow up to the meeting of the three regional programs in Washington (June 23), including activities, leads, schedules.
3:30 pm	**The Role of North American Forests in Climate Change** • Introduction and Overview • Manufacturing • Landowners
4:30 pm	**Open Comments**
5:00 pm	**Adjourn** Informal reception to follow

The Washington Forest Protection Association

North American Forest Land Ownership

Adrian Miller

Director of Forest Management

Western Climate Initiative Partners Meeting

July 21, 2009

Ca. and U.S. Forest Ownership

- Canada
  - 7% Private
  - 93% Government
- United States
  - 56% Private
  - 44% Government

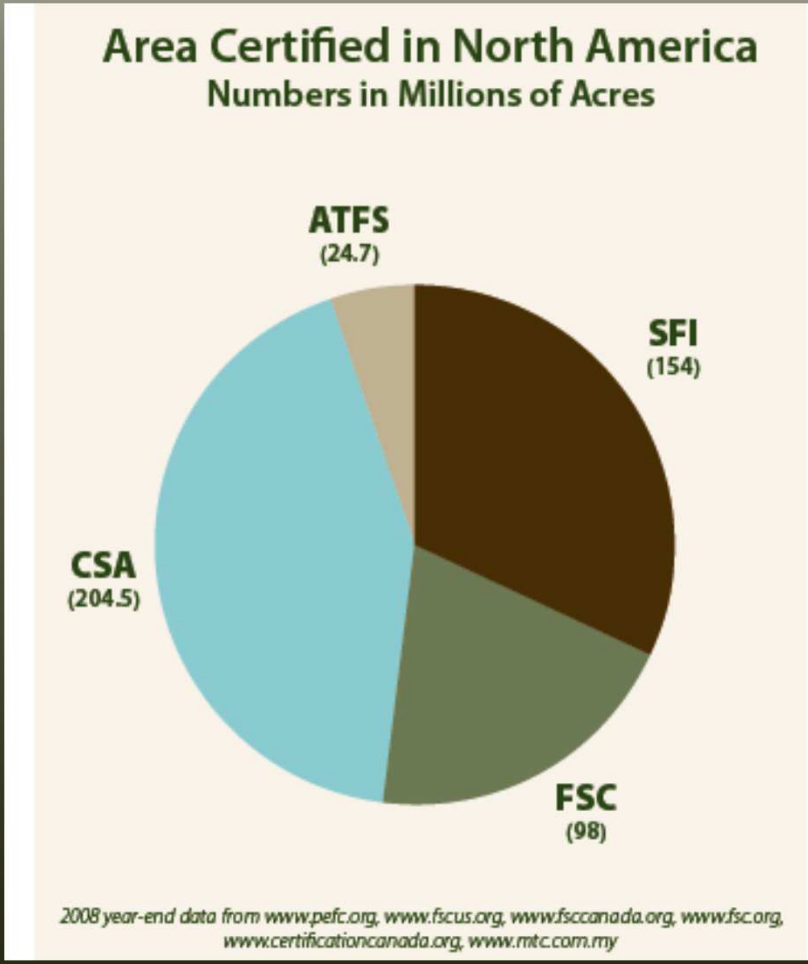
Forest Reservoir

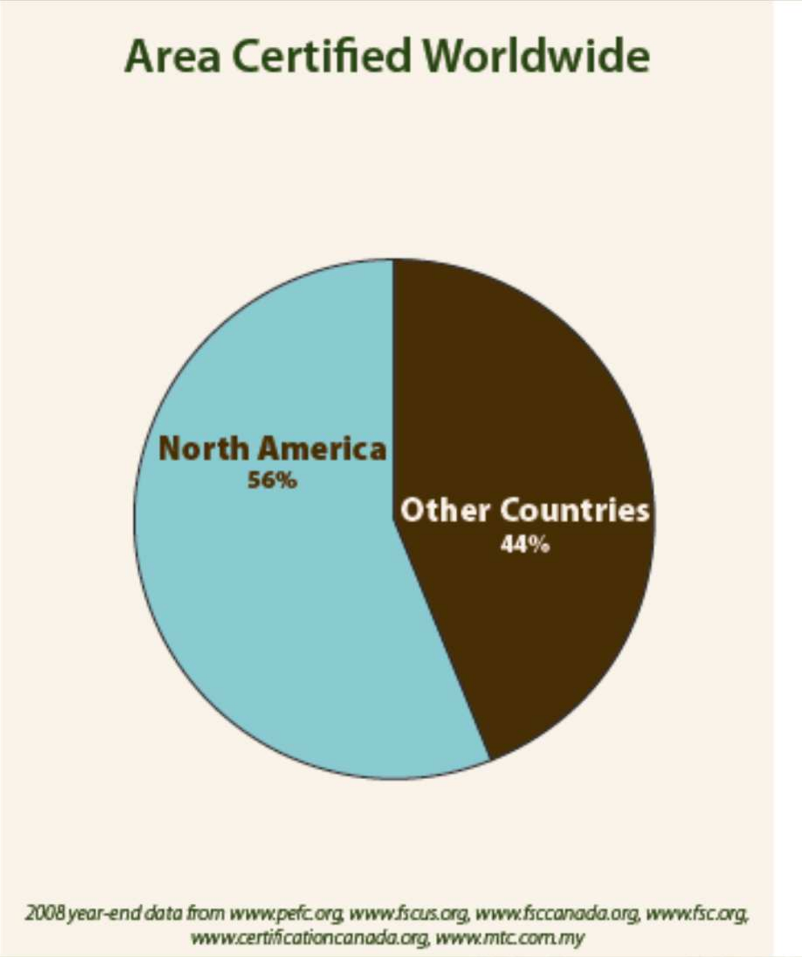
- Sequestration and Storage

Forest Sources

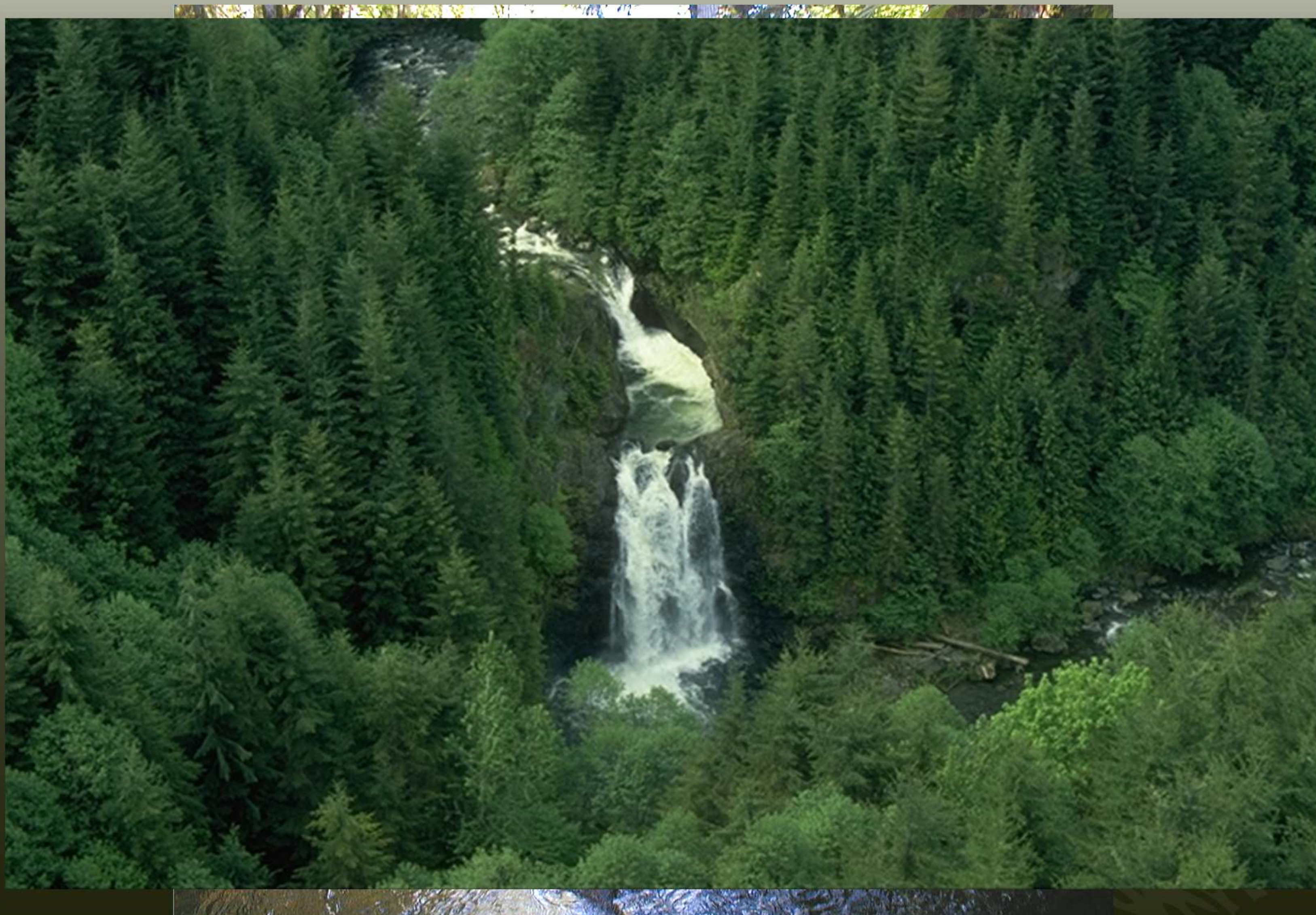
- Avoided Emissions

Sustainability





Co-benefits of Managed Forests



IPCC 4th Assessment Report

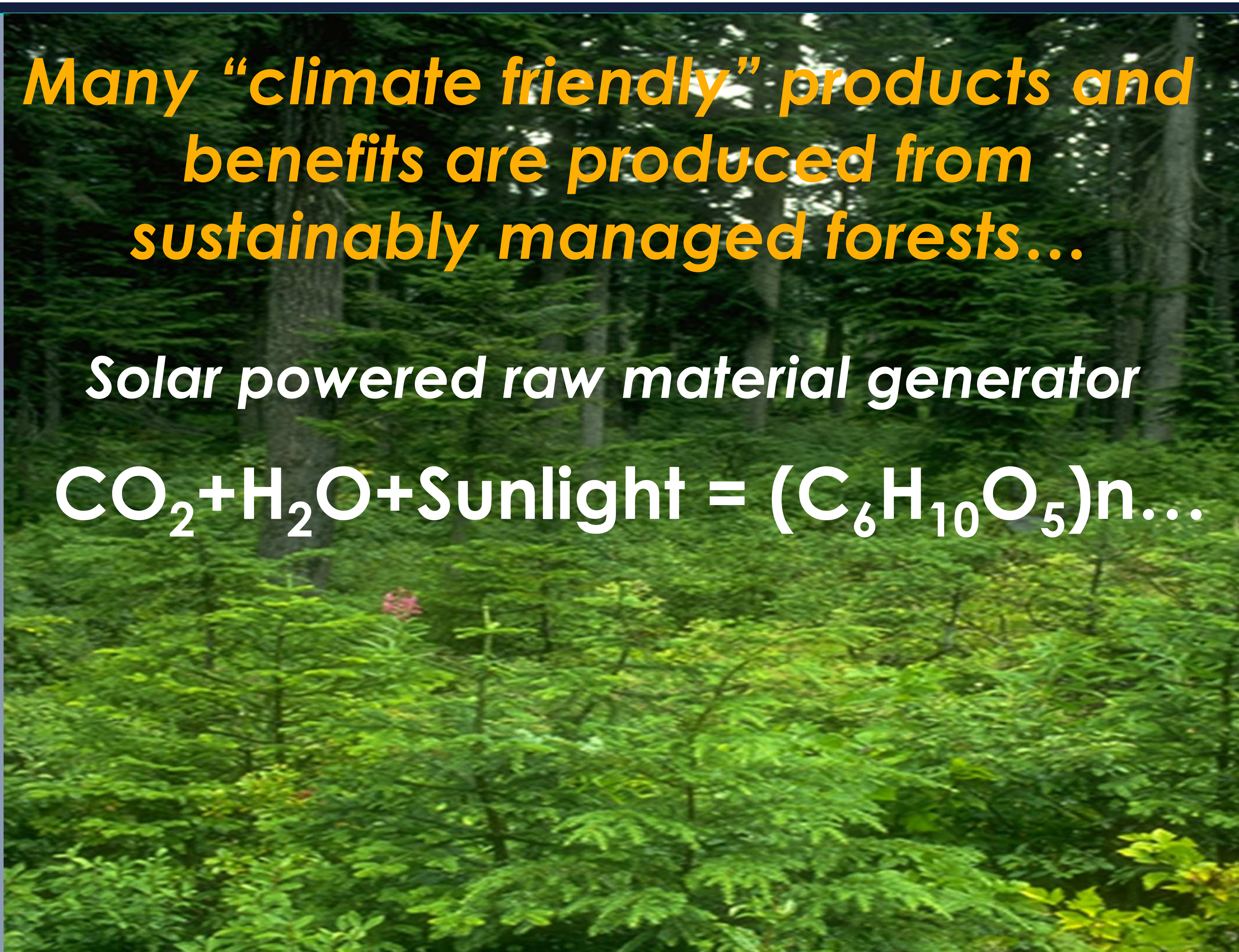
"In the long-term, a sustainable forest management strategy aimed at maintaining or increasing forest carbon stocks, while producing an annual sustained yield of timber, will generate the largest sustained mitigation benefit".

Forest Products & Climate Change

An overview…

Products & Markets
GHG Footprint
Opportunities

WCI Partner Meeting, Portland, OR – June 21, 2009
By: Robert S. Prolman, President, Bellefield Advisors LLC



Many "climate friendly" products and benefits are produced from sustainably managed forests…

Solar powered raw material generator

CO_2+H_2O+Sunlight = $(C_6H_{10}O_5)n$…

Lumber, boards and panels…

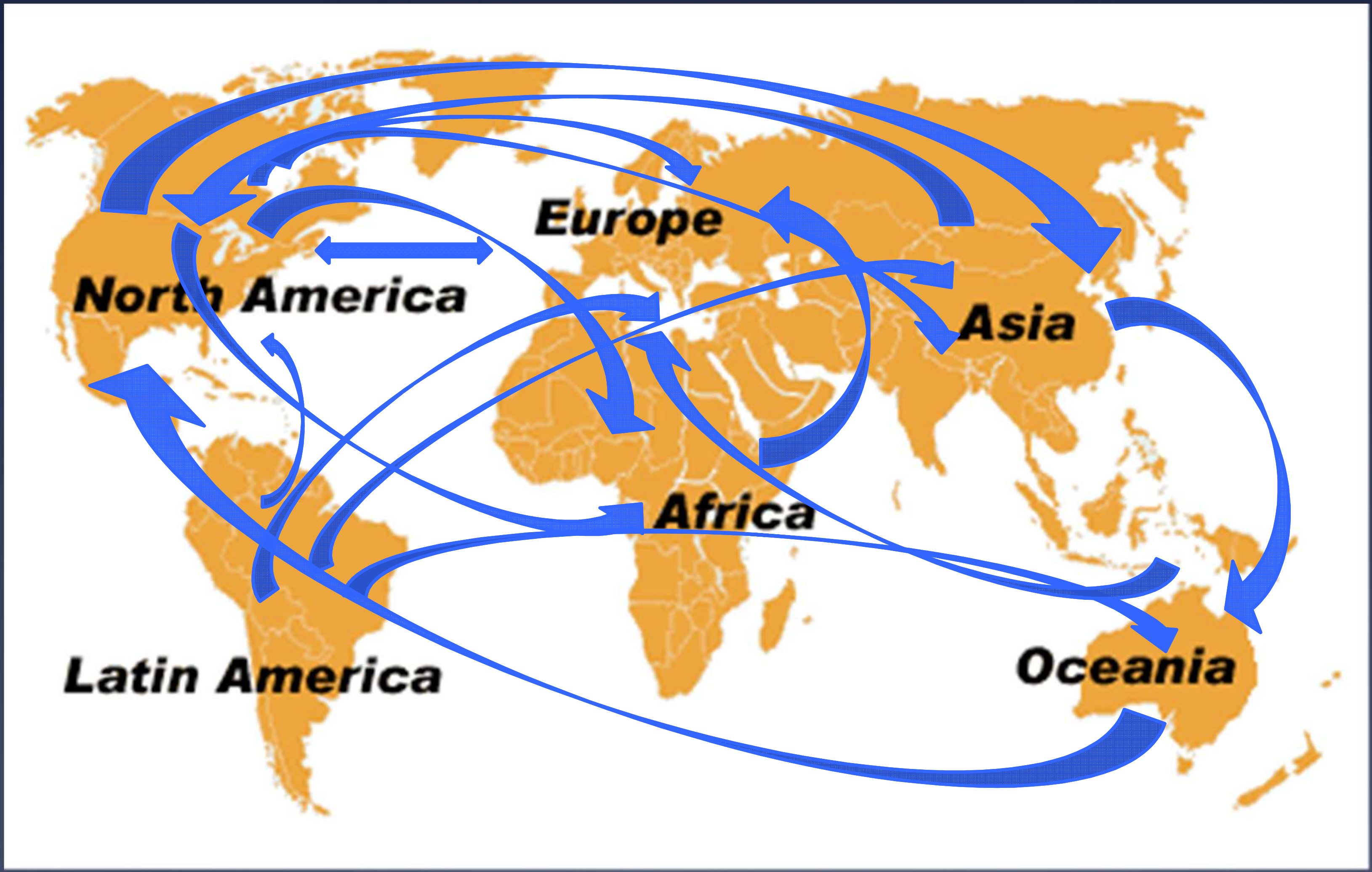
…for homes & other low-rise structures

Pulps, paper and packaging…

Recycling of pre- and post consumer paper and packaging…

Global, highly competitive industry

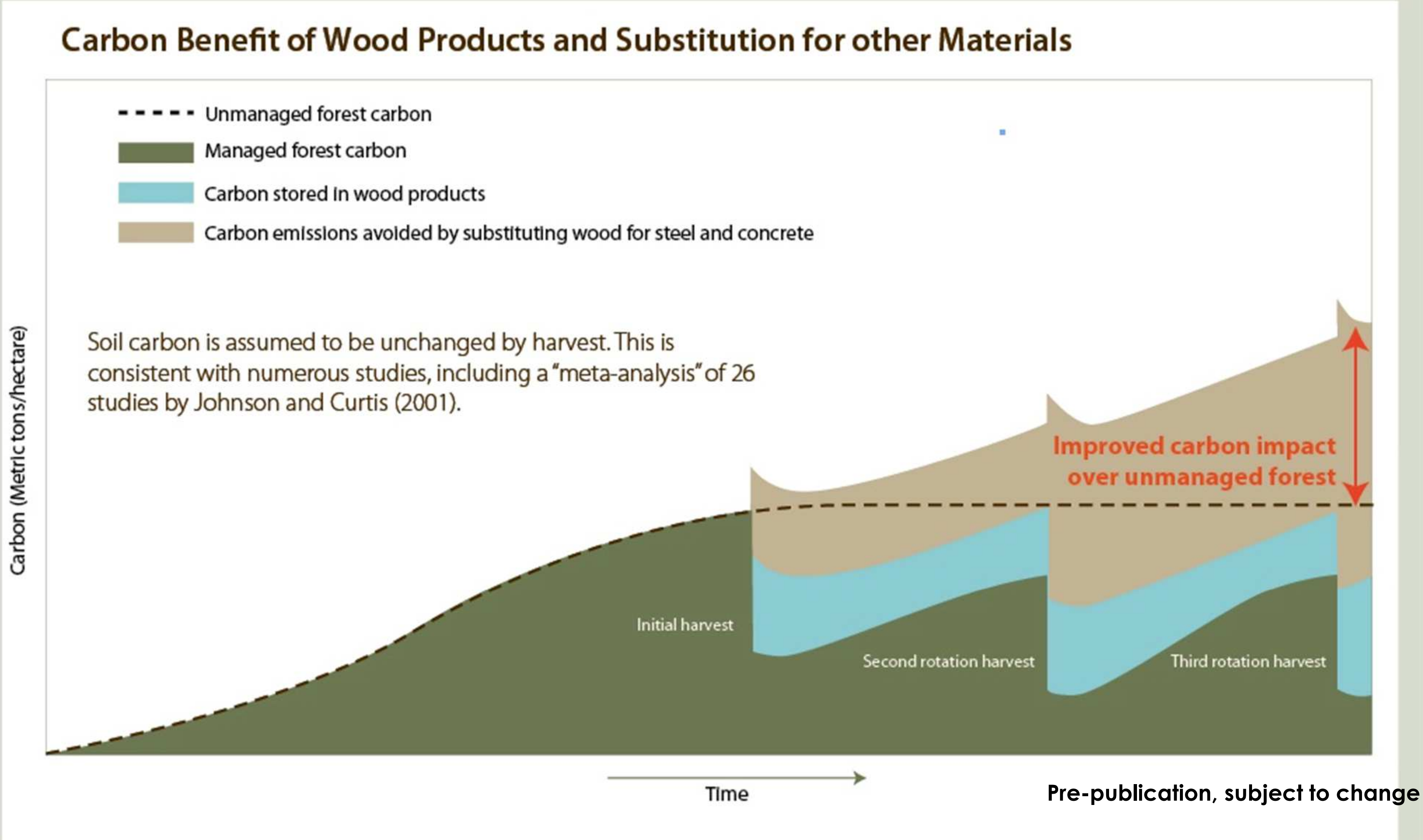
Approximately 3% of all international trade*



* Source: UN FAO: 2005 Forest Products International Trade Data

GHG benefit of wood products is substantial

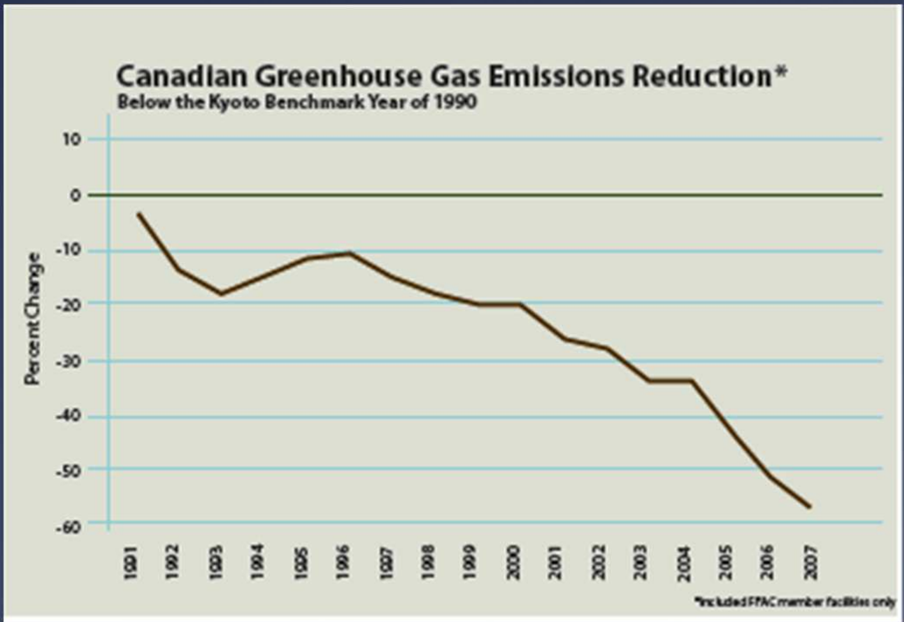
Exceeds GHG reduction impact of unmanaged forest

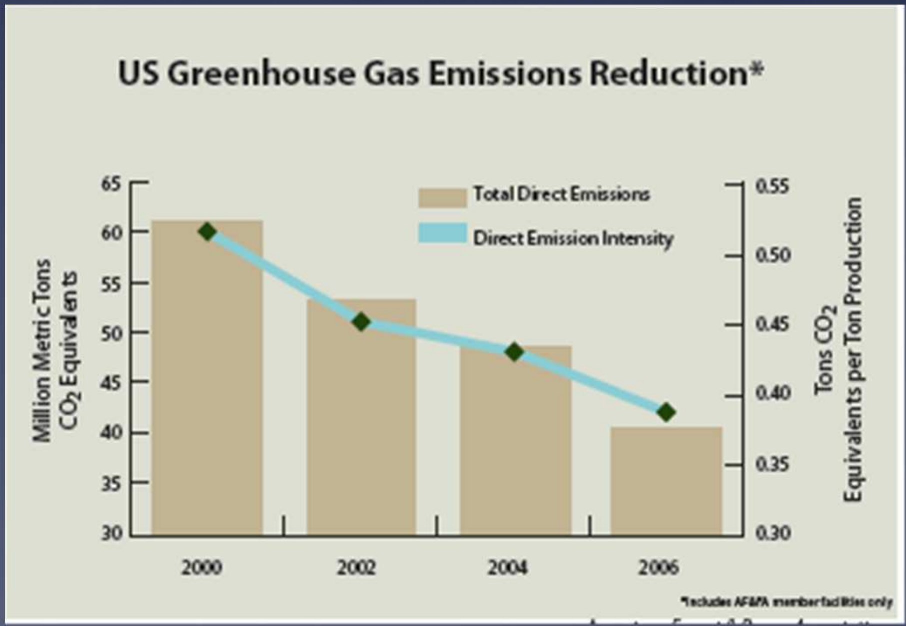


Adapted from: Perez-Garcia, J., B. Lippke, J. Comnick, and C. Manriquez (2005); J. Wilson (2006); E. Oneil and B. Lippke, (2009).

Forest product industry's GHG footprint is getting smaller

The industry has reduced emissions substantially

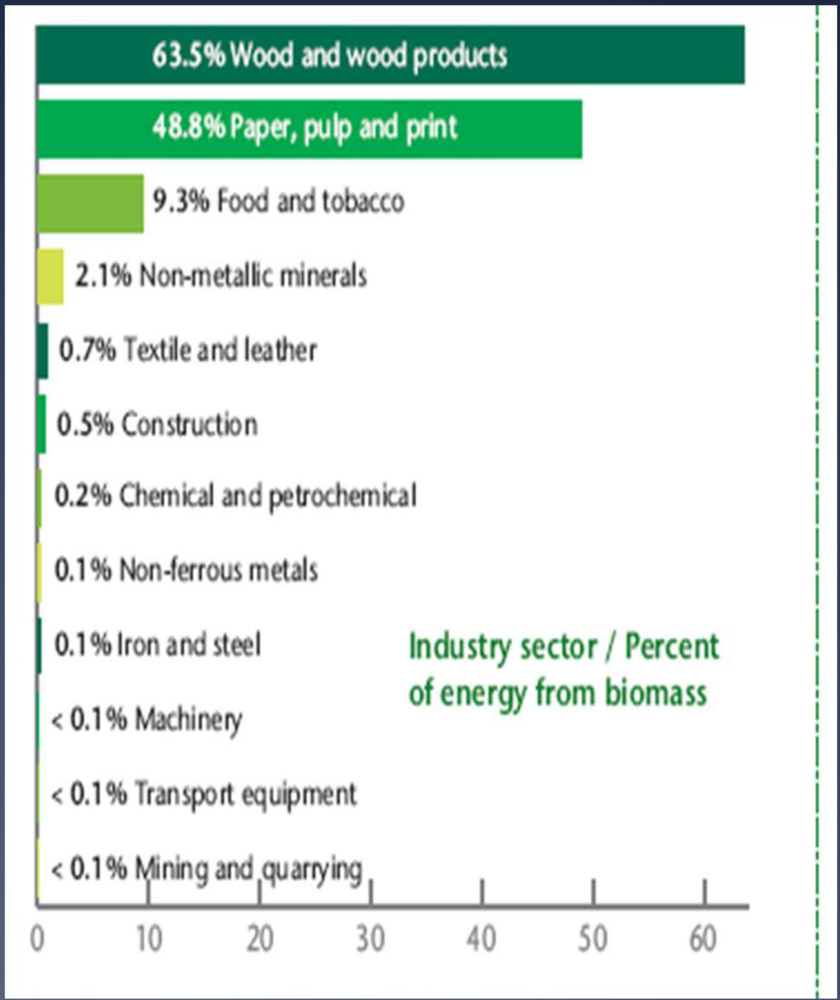




* Source: FPAC and AF&PA

Biomass provides most of the energy to produce forest products

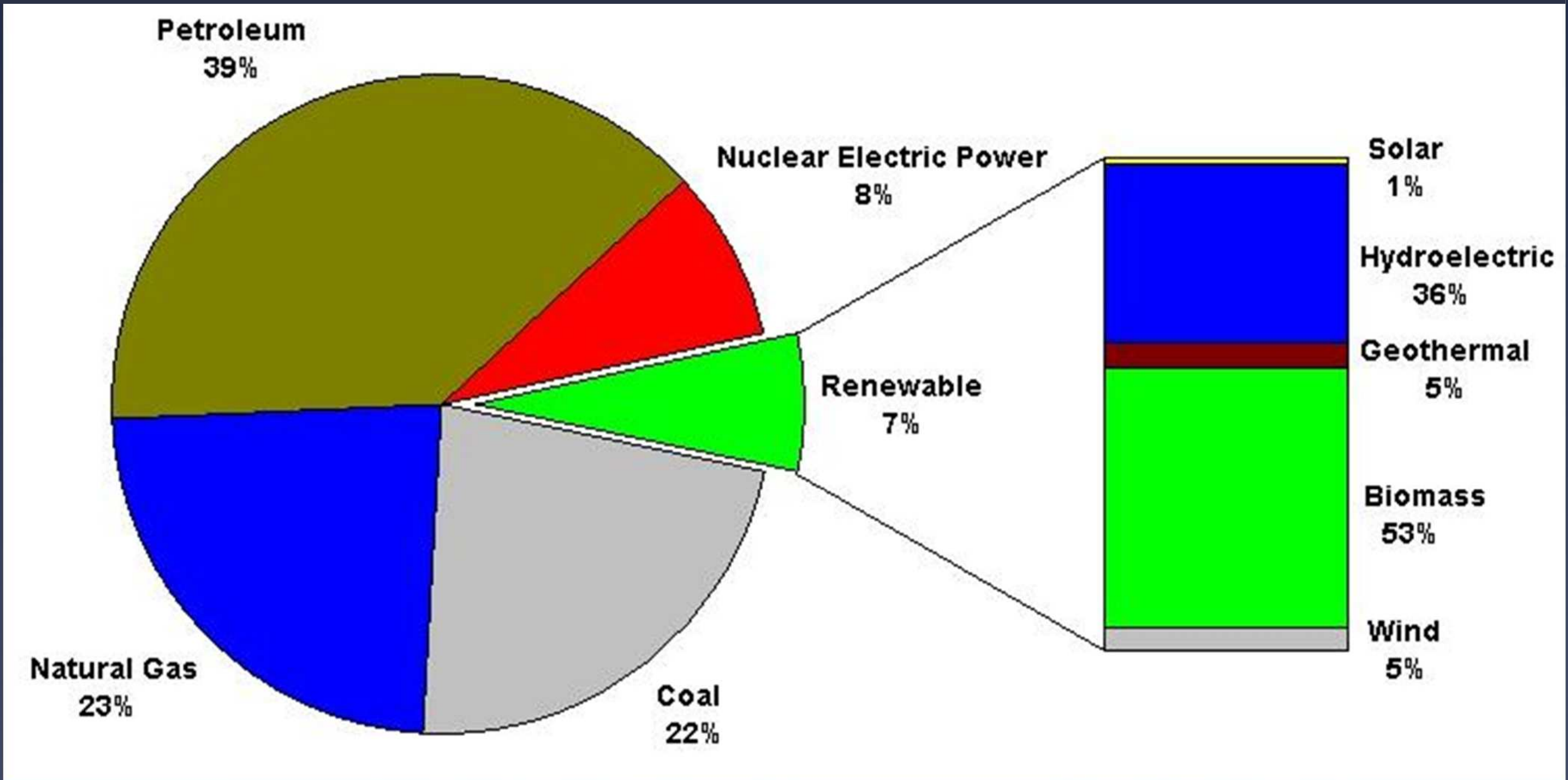
- In developed countries, on average, the forest products sector obtains more than half its energy from biomass.
- The forest products industry derives a greater fraction of its energy requirements from biomass than any other industry.
- Opportunity to make and sell surplus biomass power



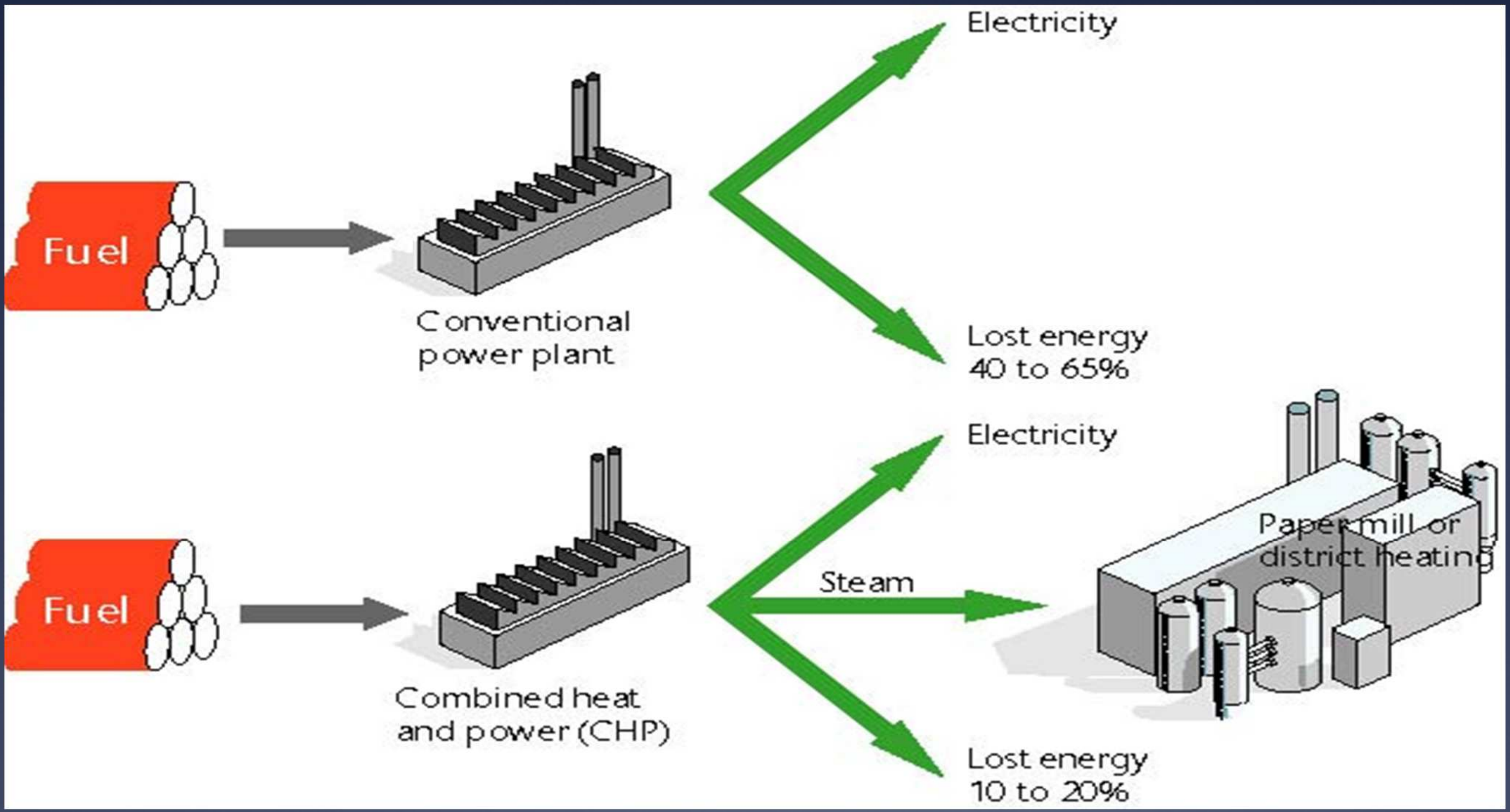
WBCSD, 2005

Biomass is a major source of renewable energy

US Energy Information Agency – 2007 Renewable Energy Consumption



Biomass CHP (Co-Gen): Twice as efficient & GHG-Neutral

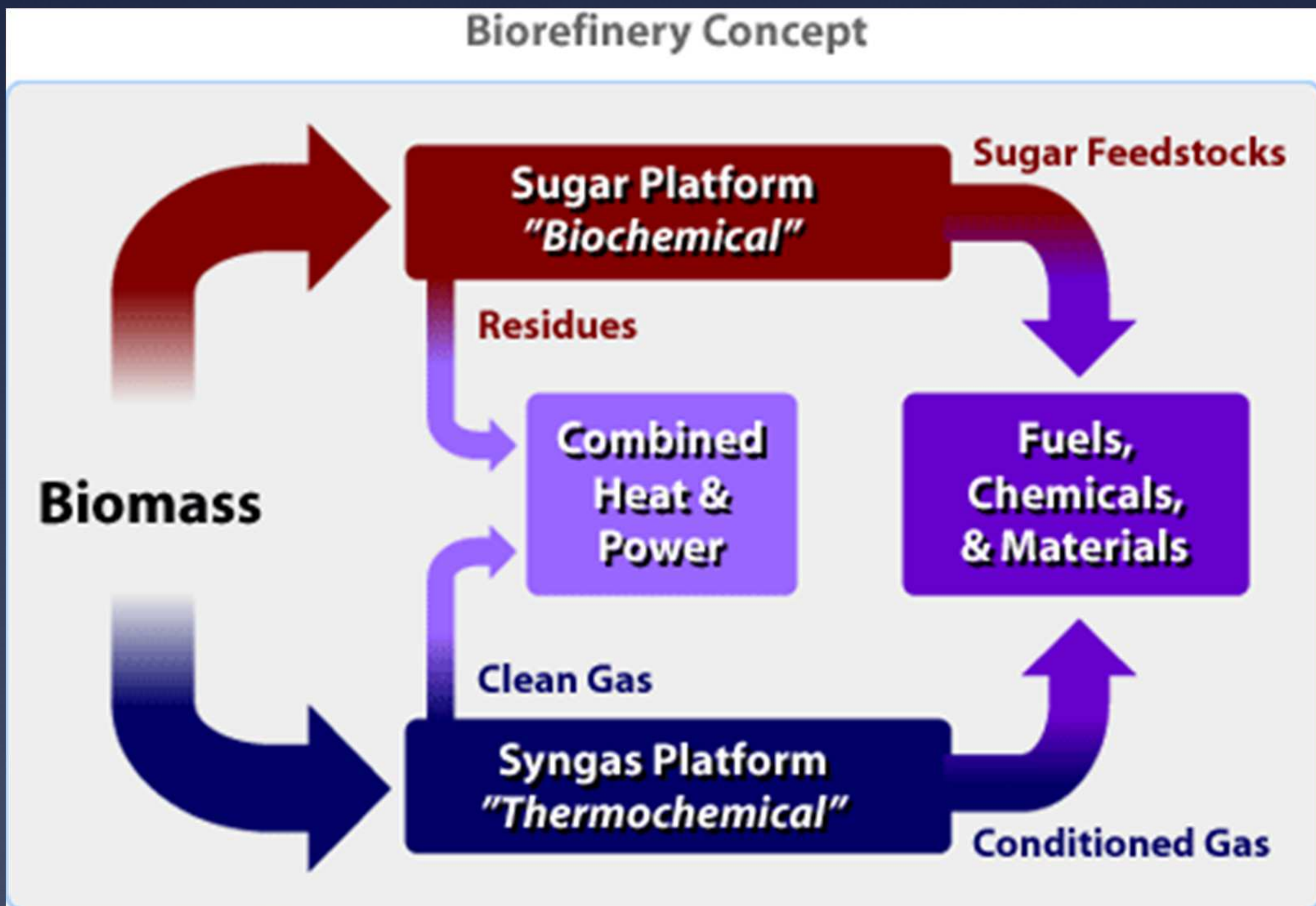


Source: WBCSD 2005

Modern CHP (Co-Gen) Unit…

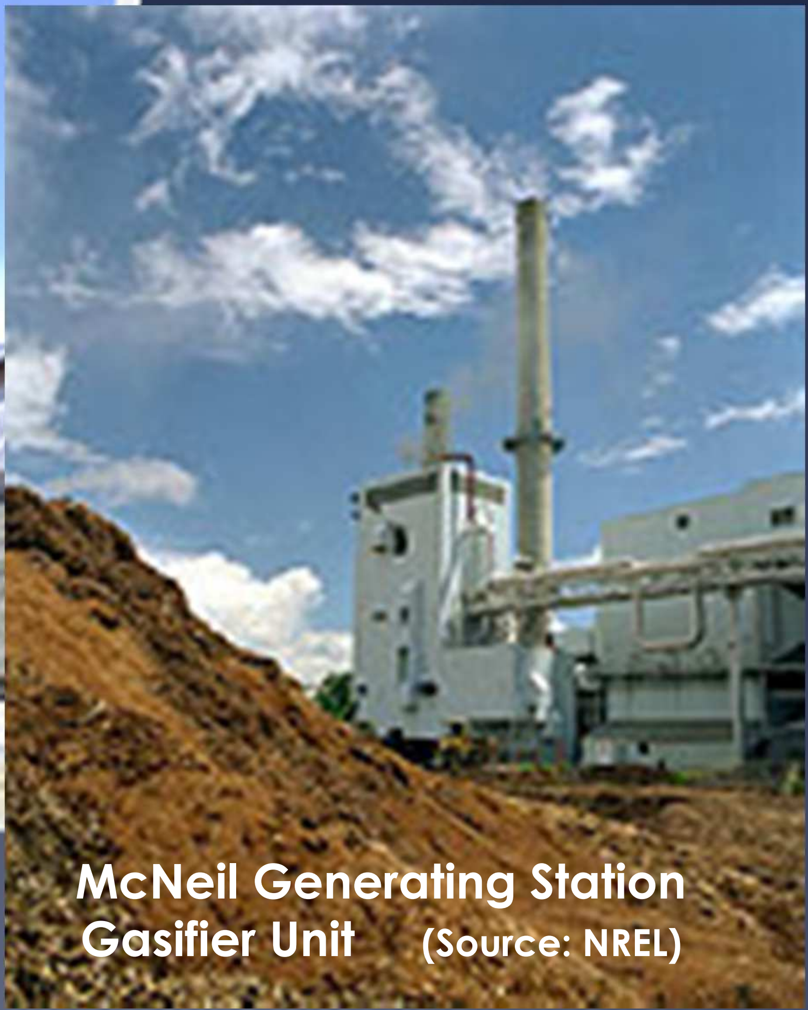
The promise of additional benefits…

Cellulosic ethanol and biodiesel will add climate, energy and economic benefits.



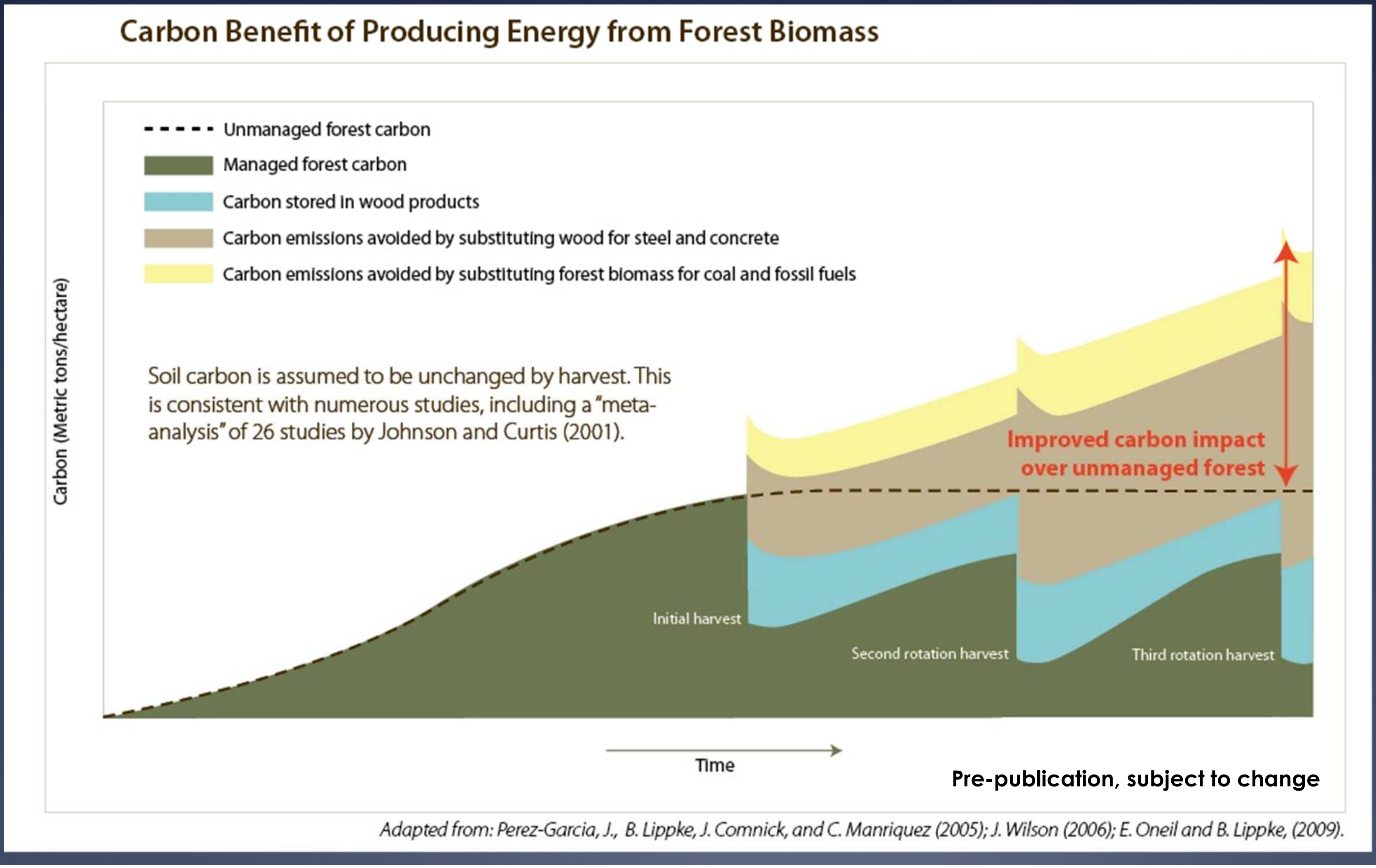
SOURCE: http://www.nrel.gov/biomass/biorefinery.html

Pre-commercial and small scale plants are already being developed



Cumulative GHG benefit from forests, wood products and forest residuals is substantial

Untapped bio-energy opportunity from managed forests



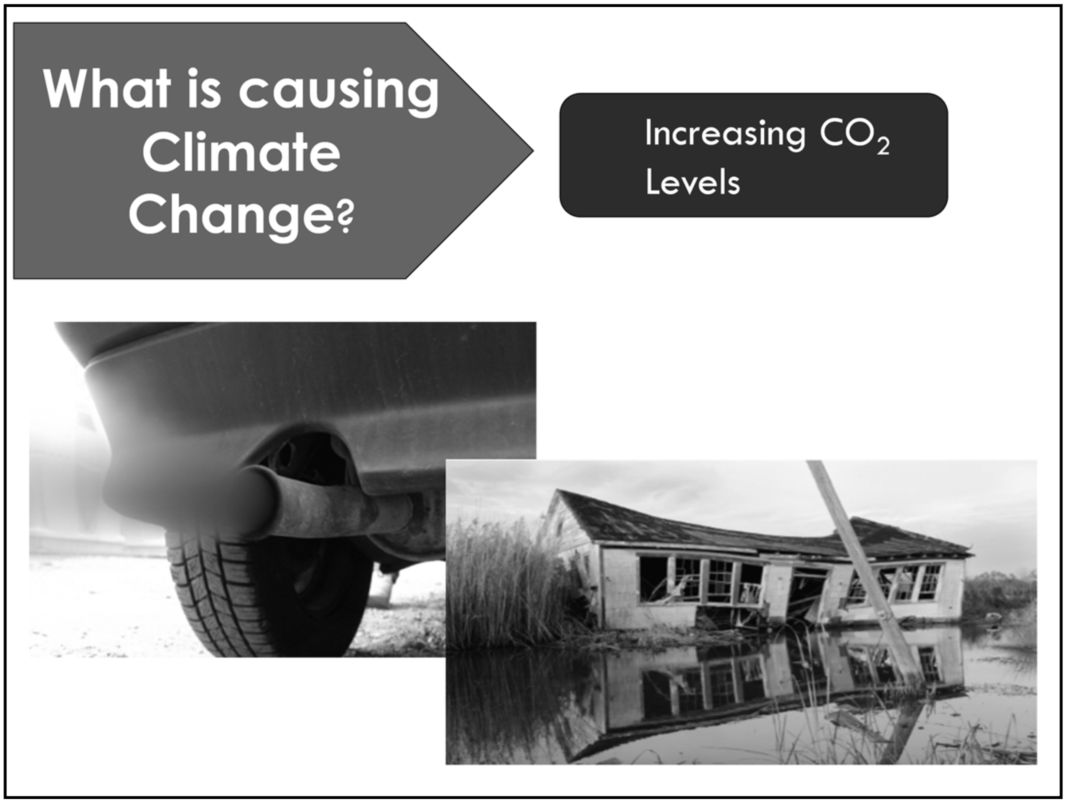
Thank You!

Robert S. Prolman
President
Bellefield Advisors LLC
P.O. Box 53131
Bellevue, WA 98015-3131
PH: 206 – 920 – 9458
bob.prolman@ comcast.net

WCI Forest Stakeholders Meeting

Portland, Oregon

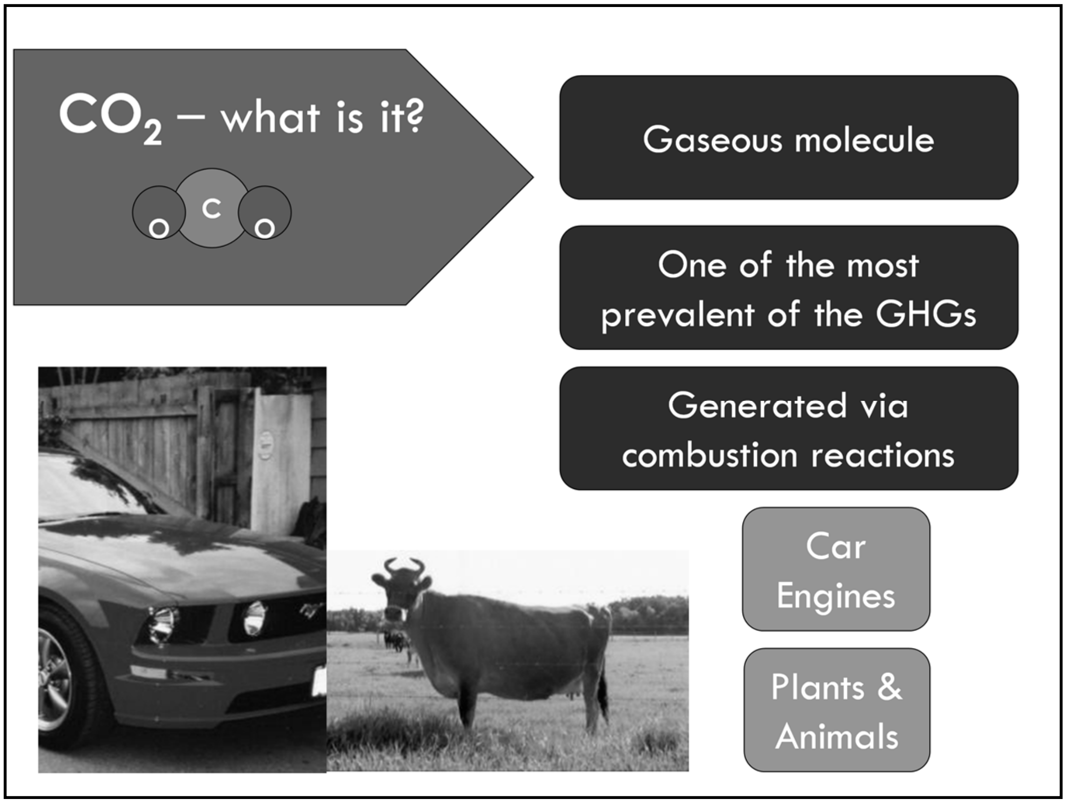
July 22, 2009



Carbon dioxide (CO_2) is one of the most prevalent greenhouse gases in the Earth's atmosphere. Prior to the industrial revolution, the concentration of CO_2 was stable for millions of years. But in the last 100 years, we have seen the concentration increase by 35%.

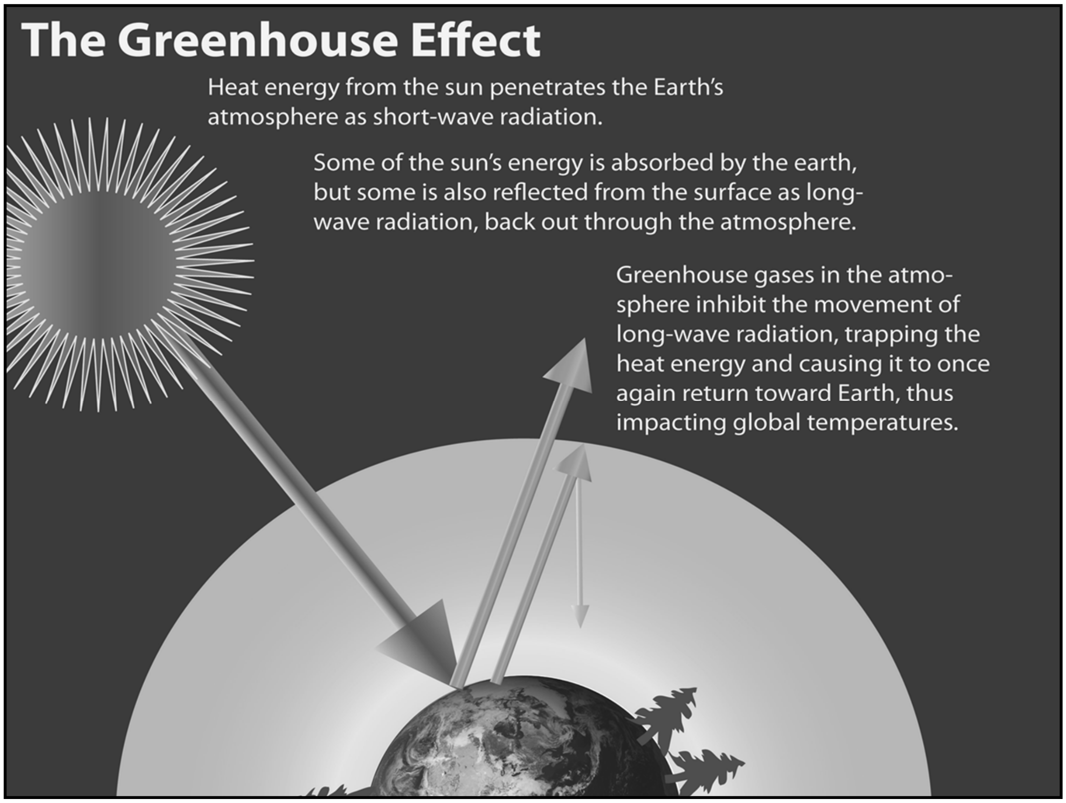
What is causing this increase in CO_2 levels?

We are! Through industrialization in the developed world and deforestation in developing regions. (define deforestation).



Carbon dioxide is a common gas in the air around us. It is produced when organic compounds such as fuels are burned in the presence of oxygen – we call this combustion. Combustion reactions take place in the engine of your car, in machinery required to run our manufacturing facilities, and it even takes place in our own bodies, when we break down food to produce the energy we need to move and grow.

Humans—through their personal and industrial activities—emit close to eight billion tonnes of CO_2 every year, which accounts for more than 75 per cent of total greenhouse gas emissions.



All that accumulated carbon dioxide, along with other greenhouse gases create what is called The Greenhouse Effect in our outer atmosphere.

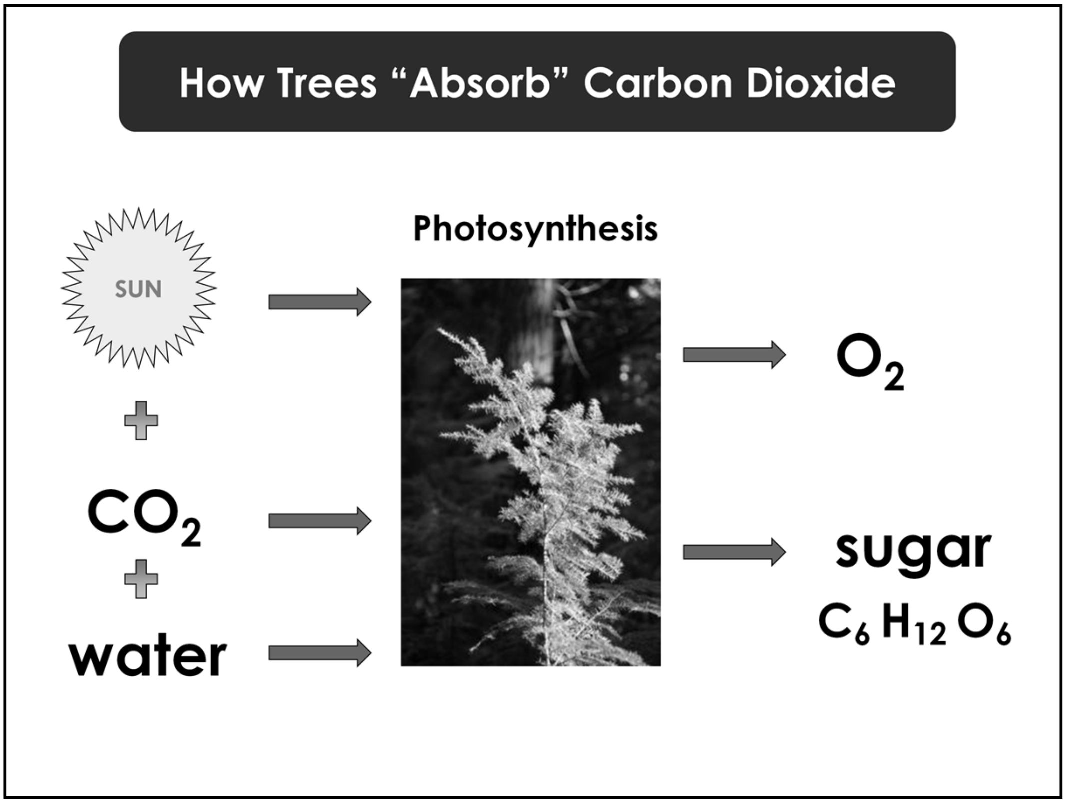
This is how it works. Our earth is heated from energy radiating from the sun. This energy is typically called short-wave radiation, and it has no problem passing through our planet's atmosphere and hitting the surface of the earth. However, not all the sun's heat energy is absorbed by the surfaces that it hits, some is reflected back into the atmosphere once again. But, in the process this energy is converted from short-wave radiation, into long-wave radiation.

When the long-wave radiation reaches in outer layer of the atmosphere, where the greenhouse gases are held by our gravitational field, this energy is trapped. It does not easily penetrate the concentrated gases, and is instead, reflected yet again, back toward the earth. Thus accounting for increases in the temperature in our atmosphere.

How can we reduce all this CO2?

CO2
CO2
CO2
O2
CO2 STORAGE

Trees are the climate change heros!

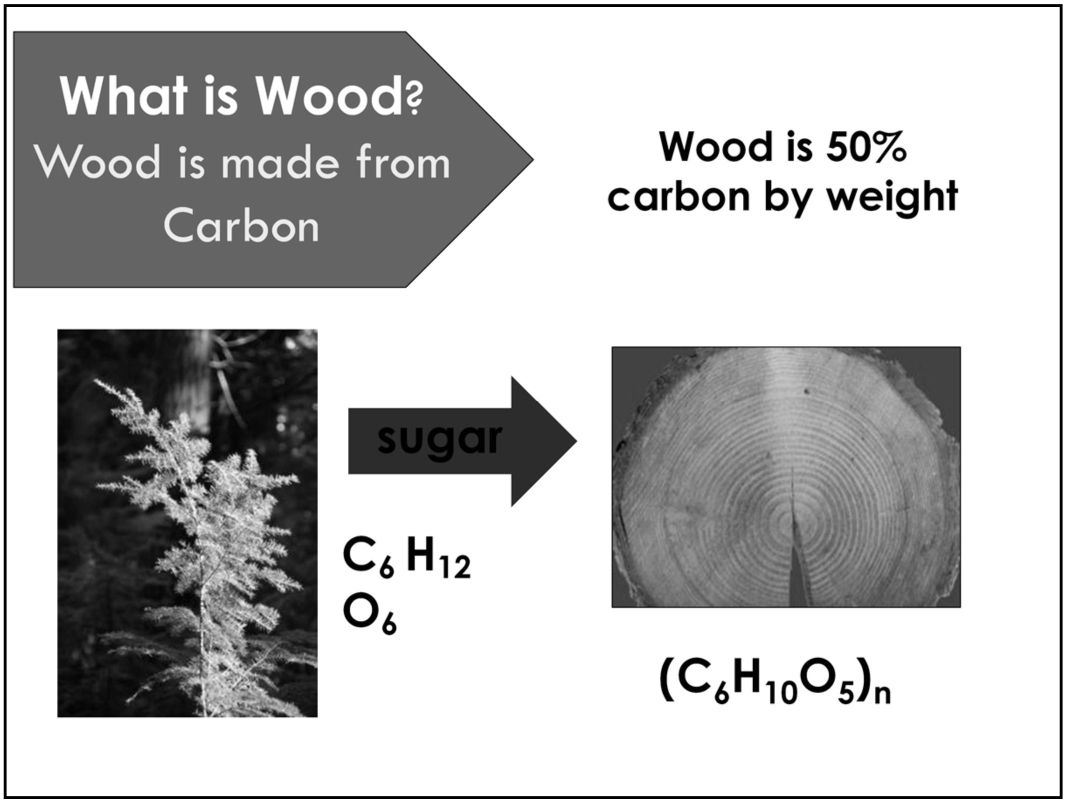


If you remember back to your high school biology classes – you will remember that plants and in particular trees, absorb CO_2 from the atmosphere, and using the energy of the sun, complete a complex chemical transformation that converts carbon dioxide and water vapour, into oxygen and sugar molecules. This is the process of photosynthesis.

The oxygen is released as a gas and diffuses out of the leaves, but the sugar remains in the tree. Why are trees so keen on making sugar – what do they do with all this sugar?

They use it to grow - it is their food source. Trees eat sugar, they make their own food. They can't chase down prey, they can't order large fries at McDonalds, trees are primary producers, they make their own food – and this food is a glucose or sugar molecule formed from carbon dioxide and water.

What happens when trees eat lots and lots of sugar? They grow, and produce wood.



WHAT IS WOOD?

Wood is a complex solid made up of fibres, or wood cells, which are in turn made primarily of cellulose, and cellulose is a carbon based complex carbohydrate made from carbon. That exact same carbon that was once part of a carbon dioxide molecule floating in our atmosphere.

[Hold up a piece of wood]. Wood is 50% carbon by mass. 50% of this wood is carbon, carbon that was in our atmosphere – contributing to global warming – and is now physically converted into a solid form that we call wood.

When I harvest a tree – is this carbon released back into the atmosphere? No – it is no longer a gas, it is a solid component of the wood.

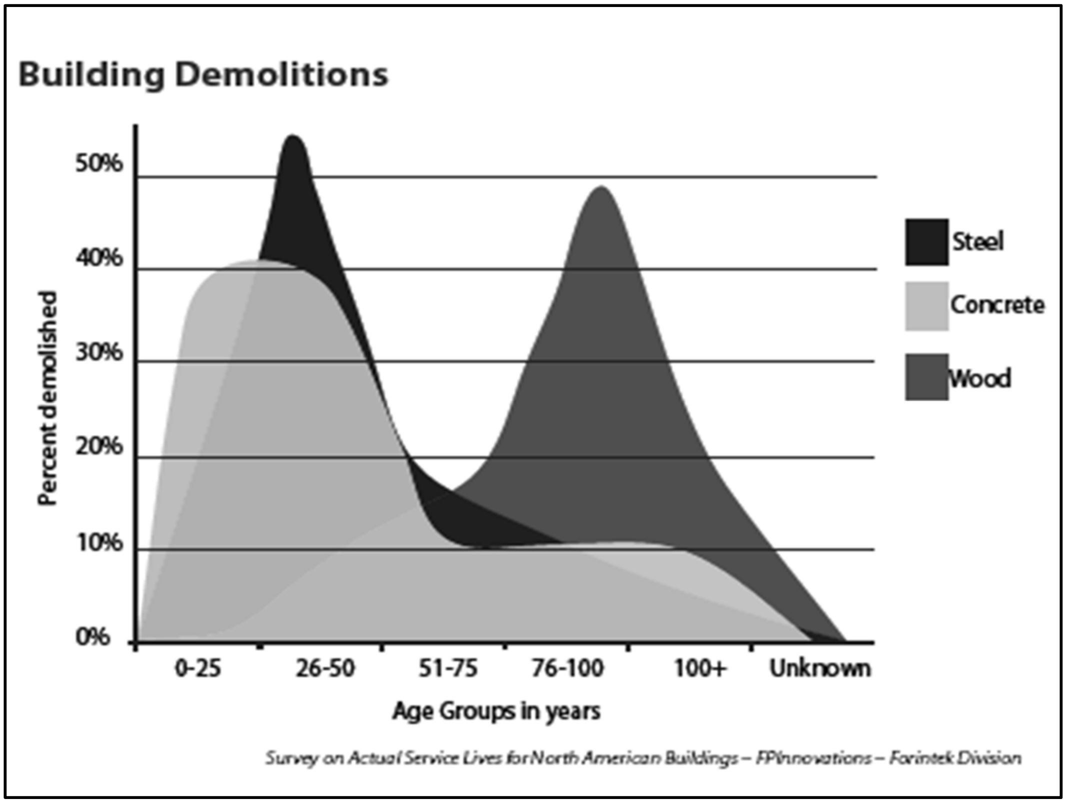
How could I release this carbon back into the atmosphere?

Wood carbon is stored indefinitely

When wood is made into solid wood products like the lumber for your home, furniture for your office, books for your library, the carbon in those products is stored indefinitely. Think of it as making a deposit into your carbon bank account. Every wood product you use is a long-term savings account, accumulating carbon, and keeping it from returning to the atmosphere in the form of carbon dioxide.

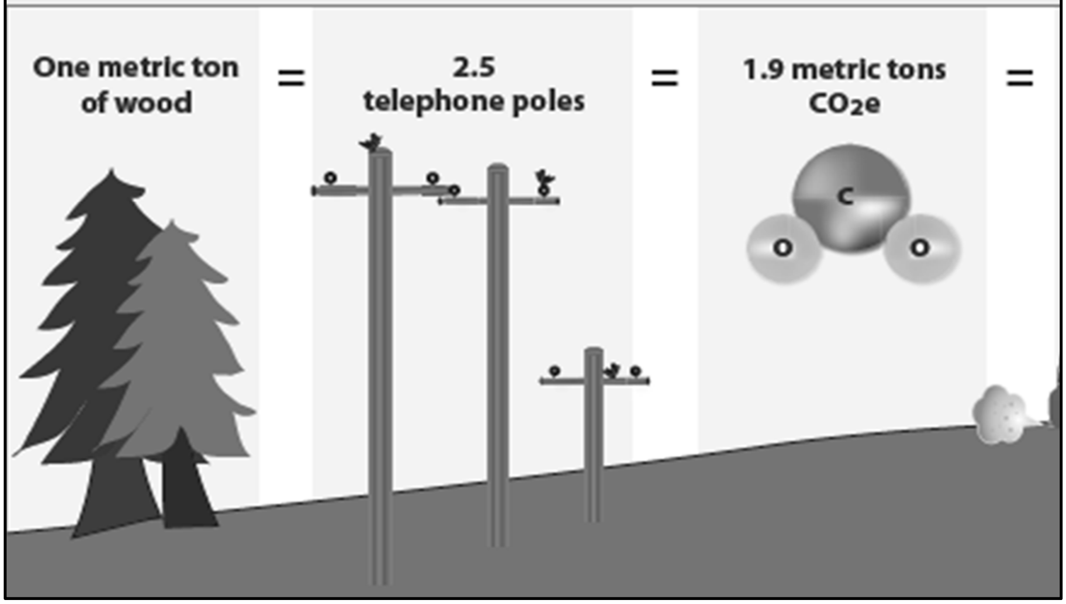
This is such a popular and supported scientific concept, that whole new forms of economic trade are being developed around the concept of carbon credits, which helps to further reduce carbon emissions, while at the same time encourages more forest development and research into more ways we can use wood, and keep making deposits into our carbon bank account.

What is your carbon balance?

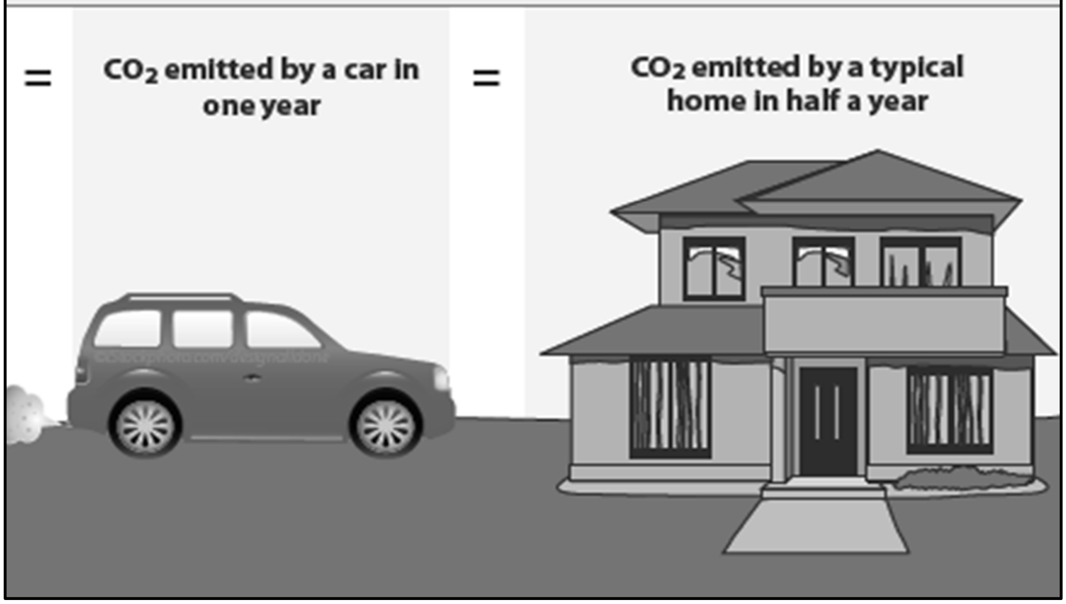


Building Demolitions
50%
40%
30%
20%
10%
0%
Percent demolished
0-25
26-50
51-75
76-100
100+
Unknown
Age Groups in years
Steel
Concrete
Wood
Survey on Actual Service Lives for North American Buildings – FPInnovations – Forintek Division

Carbon Equivalencies for Wood and CO_2



Carbon Equivalencies for Wood and CO_2



Check out our website.

Thank you.

WCI Regional Emissions Database Options White Paper Overview

The Climate Registry

Christine Condit

Director Registry Information Systems

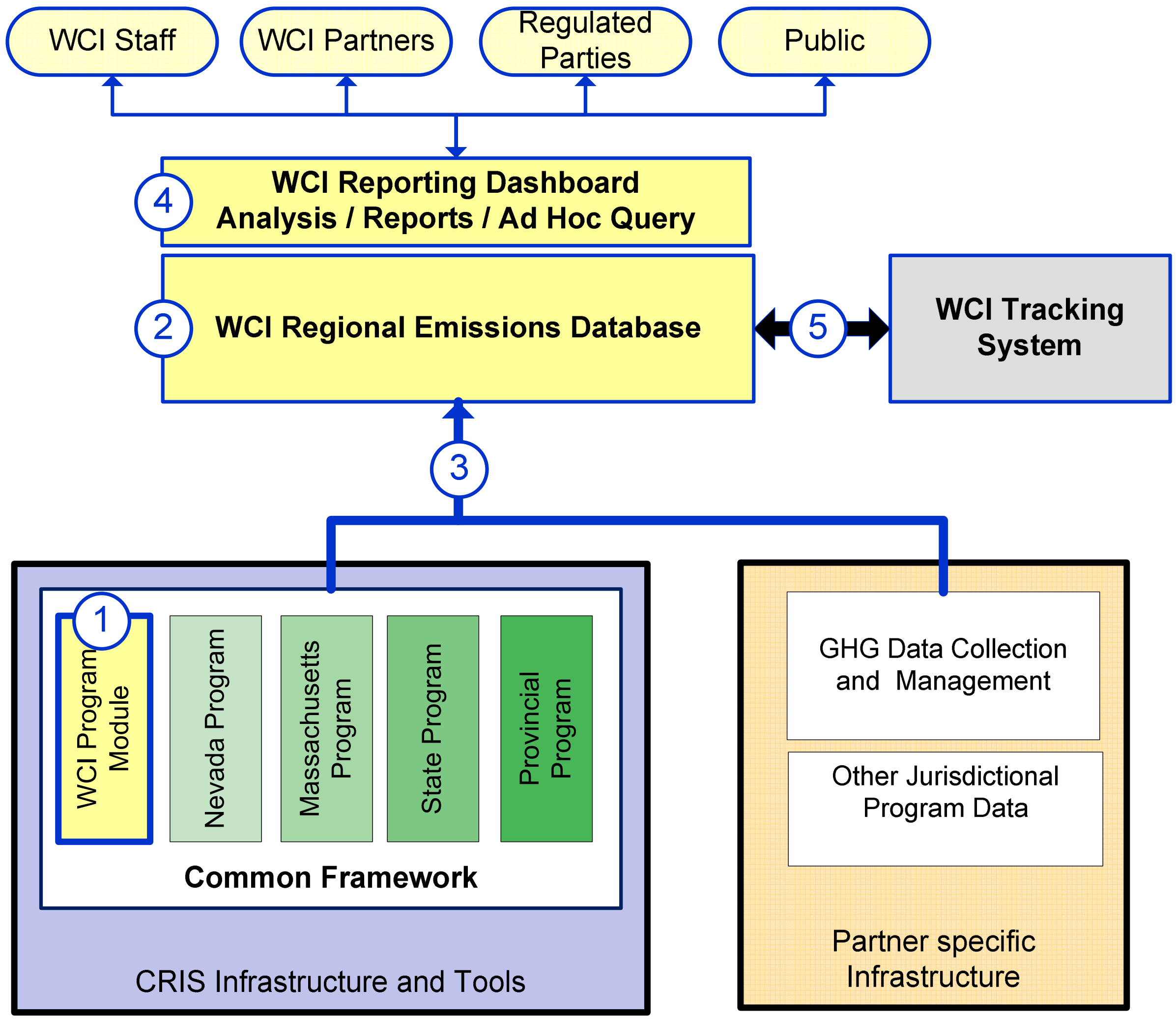
The Climate Registry

July 28th, 2009

Options White Paper Overview

- Purpose and Background
- Assumptions and Principles
- Options for the Regional Emissions Database
  - WCI Common Framework Program Module
  - Regional Emissions Database
  - Data Collection from Partner jurisdictions
  - Analysis, Report Preparation and User Interface Tools
  - Integration with the Tracking System
  - General Considerations
- White Paper Summary
- Public Stakeholder Feedback

Regional Emissions Database Components



The Climate Registry

WCI Common Framework Program Module:

- A module in The Registry's Common Framework that enables reporting for WCI's Essential Reporting Requirements
- Individual Partners adopt, configure and customize the module according to jurisdictional requirements
- Reporters with facilities in different jurisdictions use the same interface to report
- Infrastructure development is streamlined
- Implementation cost is shared across participating Partners

Regional Emissions Database

- Emissions Data is aggregated from all Partners into a centralized Database
- The data model supports analytical processing to respond to different user categories
- Platform Security provides a high level of data protection and user authentication
- Internationalization provides multiple languages, currencies etc.
- Operational support is centralized

Data Collection from Partner Jurisdictions

- Data is transferred from WCI Partner Modules in the Common Framework and Partner specific systems to the Regional Emissions Database
- Data Communications are standardized to simplify processing
- A common data schema is shared by all Partners
- Data is transported on a secure communications network

Analysis, Report Preparation and User Interface Tools

- Data analysis will be developed to accommodate the needs of WCI Staff, Partners, Regulated Parties and Public Stakeholders including:
  - Geographical Analysis
  - Sector Analysis
  - Entity and Facility Analysis
  - Analysis for each GHG
  - Threshold Analysis
  - Support for determining allowances
  - And others as needed
- Standard Reports for each user category

Integration with the Tracking System

- Data in the Regional Emissions Database will be transferred to the tracking system at appropriate time intervals
- As the tracking system evolves other requirements will be defined

Questions

- Contact:
  - Chris Condit – Director Registry Information Systems
    The Climate Registry
    ccondit@theclimateregistry.org
  - Steve Burr – Executive Consultant
    Arizona Department of Environmental Quality
    sb5@azdeq.gov

Cover Letter

July 24, 2009

The Western Climate Initiative (WCI) Partner jurisdictions have released the following white paper on Offset Definition and Eligibility Criteria. The Offsets Committee is working toward recommending the design and operation of an offset system as outlined in the WCI 2009/10 Workplan released February 2009.

This white paper is the first stage in developing a definition of a WCI emissions offset and related eligibility criteria for offset projects. The process is to:

1. Identify options for a definition of a WCI emissions offset and related eligibility criteria for offset projects
   - White paper released July 24, 2009 for stakeholder input
2. Analyze options and stakeholder input
   - Draft Recommendations paper released September 2009 for stakeholder input
3. Finalize recommendation with stakeholder input and any further analysis required
   - Final Recommendations paper released December 2009

The white paper examines options for defining an offset, as well as options for each of the offset criteria required by the WCI Program Design Recommendations: real, additional, verifiable, and permanent. The Offset Committee provides in this white paper an overview of approaches that other systems have taken in defining them, an evaluation of the policy and operational considerations, and a discussion of implementation options of the criteria.

The Offset Committee is soliciting stakeholder feedback on the options presented in this white paper to help inform its recommendations to the WCI Partner jurisdictions. In addition to general feedback, the Offsets Committee is interested in stakeholder responses to the following questions:

- What has been your experience with the offset system examples cited in this paper? What have been the advantages and disadvantages to their approaches?
- Are the appropriate criteria listed?
- Does the paper include the appropriate options for each criteria?
- Are the implications of the options appropriately covered?

The Offset Committee looks forward to stakeholder input on this white paper. Written comments will be received through the WCI website until August 21, 2009. Stakeholders may also provide comment during a conference call on July 30, 2009 from 9:30 to 10:30 a.m. Pacific time, during which this white paper will be presented and discussed. To join this call, dial 1-800-868-1837 toll free in the U.S. and Canada (1-404-920-6440 for outside the U.S. and Canada), participant code 659537#.

WCI Offsets Committee White Paper
Task 1: Offset System Essential Elements
Offset Definition (Task 1.1) and Eligibility Criteria (Task 1.2)

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1 Executive Summary

This paper examines options for defining an offset and options for each of the offset criteria required by the WCI Program Design Recommendations. This paper is the first step in developing the offset definition and criteria that will be recommended to the WCI Partner jurisdictions. One goal of this aspect of the Offset Committee's efforts is to enable each of the WCI Partner jurisdictions to adopt a common offset definition and criteria for program implementation. By achieving this goal, the WCI Partner jurisdictions can help assure the quality of the offsets within the program and enable offsets to be tradable throughout the region.

This paper approaches the topic within the framework defined in the WCI Program Design Recommendations. In particular the Design Recommendations require that the criteria ensure offsets result in a GHG reduction, removal, or avoidance that is real, additional, verifiable, and permanent.[1] The WCI Partner jurisdiction's design principles also require that offsets must be enforceable by the WCI Partner jurisdictions.[2]

To identify and describe options that may be considered within the WCI framework, the Offsets Committee reviewed 11 offset systems:

- Alberta-based Offset Credit System
- British Columbia Emission Offset Regulation
- California Global Warming Solutions Act of 2006 (AB 32)
- Clean Development Mechanism (CDM)
- Gold Standard
- ISO 14064-2; 14064-3; 14065
- Offsets Quality Initiative (OQI)
- Oregon Offset Standard
- Regional Greenhouse Gas Initiative (RGGI)
- Voluntary Carbon Standard (VCS 2007)
- World Business Council for Sustainable
- Development and World
- Resources Institute
- (WBCSD/WRI) GHG Protocol for Project Accounting

As discussed in this paper, these systems provide examples of how others have addressed the issues necessary to define an offset and its criteria.

Offset Definition: Options for defining an offset are framed in terms of the level of detail or specificity required and the manner in which the definition is represented in regulatory language. The Offsets Committee has identified the following parameters or requirements that could be considered as part of the definition of a WCI offset:

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[1] WCI. 2009. Design Recommendations for the WCI Regional Cap-and-Trade Program. September 23, 2008; revised March 13, 2009. p. 10 Available at: http://www.westernclimateinitiative.org/ewebeditpro/items/O104F21252.pdf.

[2] WCI. 2007. WCI Workplan. October 27, 2007. p. 3 Available at: http://www.westernclimateinitiative.org/ewebeditpro/items/O104F13792.pdf

- Offset Measurement: specifying that offsets are generated in units of metric tons of carbon dioxide equivalent (CO_2e) with each offset representing one metric ton CO_2e.
- WCI Specified Criteria: specifying that offsets must be GHG emission reductions, removals or avoidances that are real, additional, permanent, verifiable and enforceable.
- Offset Projects: specifying that offsets are generated from registered projects through individual project activities that reduce GHG emissions outside the cap.
- Verification and Certification: specifying that offsets represent reductions that are verified and/or certified in a defined manner (e.g., a numbering system, verification statement, or other recognition requirements).
- Issuance and Fungibility: specifying that offsets are issued by an authority in recognition of verified reductions and become fungible compliance units with tracking numbers.

Real: The WCI Design Recommendations state that emission reductions or removals must be real in order to assure that they actually occurred. The Offsets Committee has identified the following considerations for purposes of defining "real": quantification; uncertainty and accuracy; conservativeness; and leakage. Examples from other systems show a range of methods are used to apply these concepts to demonstrate that emission reductions or removals are real.

Additional: The concept and application of the criterion of "additionality" has been among the most controversial and difficult implementation issues in offset systems. The purpose of requiring additionality has generally been recognized as the desire to only credit reductions that would not have otherwise occurred in the absence of the offset project. There are many factors that affect whether a project is additional. As a result creating an operational definition for this criterion is a challenge.

The Offsets Committee summarized how "additional" is implemented in the other systems. The Offsets Committee identified "baseline," "eligbility date," and "crediting period" as potentially important in determining additionality. The Offsets Committee also identified examination of regulations, access to financing and other investment issues, technological and other barriers to market entry, and assessment of common practices as potentially assisting in evaluating projects for additionality. These concepts could be combined in different ways and applied to the WCI offset system. Several options have been identified for consideration:

- <u>Option A - Project Specific</u>: The additionality of each individual project activity is scrutinized through application of specific additionality tests.
- <u>Option B - Performance Standard</u>: For each sector or project type a performance standard is established where projects meeting or exceeding the standard are considered to be additional. Performance standards may be uniform among the WCI Partner jurisdictions or differentiated by jurisdiction to reflect regulatory and economic differences.
- <u>Option C - Protocol Specific Approach</u>: The approach to additionality assessment may vary by protocol, seeking to adopt the best approach for each sector or class of activities.
- <u>Option D - Hybrid Approach</u>: A combination of Options A, B and C; a hybrid approach would set a performance standard but still include some aspects of a project-specific additionality analysis and may vary by protocol. A single

approach may limit project types and inhibit innovation. A hybrid approach may be better able to cover more possibilities.

Permanent: Permanence refers to the duration of an emission reduction. It may be defined based on the reduction being maintained through a given period of time, for instance a 100-year standard. A permanence requirement helps to ensure equivalency of emissions reductions across all sectors and project types.

Based on the examples reviewed in other systems, the Offsets Committee suggests that implementing a permanence requirement generally means addressing the risk of reversal. Two approaches have been identified for addressing this risk:

- *Ex ante* obligations establish an up-front commitment by the project proponent to permanently maintain transacted tons and is achieved through a legally recorded and binding instrument prior to the project.
- An *ex post* permanence mechanism provides assurance in the case of failure of permanence and is achieved through replacement of lost transacted tons.

Under both options, policy considerations include establishing, regulating and enforcing liability for permanence along a chain of offset custody.

Verifiable: The Offsets Committee examined the requirement that offsets be verifiable subject to defining a process for verification. The Essential Requirements (ER) for Mandatory Reporting developed by the Reporting Committee provide one example of a detailed approach to verification, which is defined in the ER as "the process used to ensure that an operator's emissions data report is free of material misstatement and complies with WCI's reporting procedures and methods for calculating and reporting GHG emissions."

Based on the work of the Reporting Committee and a review of the examples from other systems, the concepts identified by the committee for consideration as part of the verification process include:

- Project Validation: the assessment of a project document and its conformity with project protocol.
- Enforcement: regulatory oversight by partner jurisdictions.
- Materiality: a threshold where differences above that number in reported emissions/reductions would make a verifier suspect the reliability of an entire project.

WCI Partner jurisdictions have recommended third-party verification of emissions reports. A similar use of accredited third party verifiers is an option for consideration as part of the process for offsets as well.

In addition to these primary criteria, the Offsets Committee identified several factors from its review of other systems that may be considered, including: transparency of program implementation; co-benefits; and assessment of environmental or social impacts. Options for addressing these factors are discussed.

The Offset Committee is soliciting stakeholder feedback on the options presented to help inform its recommendations to the WCI Partner jurisdictions through the release of this paper. In addition to general feedback, the Offsets Committee is interested in stakeholder responses to the following questions:

- What has been your experience with the offset system examples cited in this paper? What have been the advantages and disadvantages to their approaches?
- Are the appropriate criteria listed?
- Does the paper include the appropriate options for each criteria?
- Are the implications of the options appropriately covered?

The Offset Committee looks forward to stakeholder input on this white paper.

2 Introduction

The Western Climate Initiative (WCI) is a comprehensive regional effort by the governors and premiers of seven U.S. states and four Canadian provinces to reduce greenhouse gas emissions to 15 percent below 2005 levels by 2020, promot environmental sustainability and ensure economic growth.[3] It would cover nearly 90 percent of the region's emissions, including those from electricity, industry, transportation, and residential and commercial fuel use. Together, the seven states and four provinces represent over 70 percent of the Canadian economy and 20 percent of the U.S. economy.

The first phase of the cap-and-trade program begins on January 1, 2012, covering emissions from electricity (including imported electricity), industrial combustion at large sources and industrial process emissions for which adequate measurement methods exist. The second phase begins in 2015, when the program expands to include other sources. The WCI cap-and-trade program will include a rigorous offsets system. The primary role of the offsets system is to reduce the compliance costs for the cap-and-trade program while ensuring the environmental integrity of the cap. The system should be designed to encourage emission reductions, innovation, and technology development in sectors not covered by the cap-and-trade program.

The purpose of the Offset Committee is to make recommendations to the WCI Partner jurisdictions on the design and operation of the offset system as part of the WCI cap-and-trade program, including the criteria necessary for offset projects to be used to meet compliance obligations within the regional program. The Offsets Committee workplan has been subdivided into four task groups. This white paper serves as the first deliverable under Task 1. Deliverables for all Offsets Committee tasks are outlined in Table 2.0.

Table 2.0 Offsets Committee Workplan

Task Number	Offsets Committee	Deliverables
Task 1	Offset System Essential Elements	Recommend and define the essential elements for the offsets system, including the necessary rules and infrastructure, to create and operate the offset system as part of the cap-and-trade program.
Task 2	Offsets and Allowances from Systems Other than the WCI	Recommend standards and a process for accepting offsets from other GHG trading programs and recognizing emission allowances from other GHG trading systems.
Task 3	Offset Protocols	Coordinate the joint review, development, and approval of offset protocols and initiate the establishment of a process to coordinate the review and recommendation of protocols proposed by project developers.

[3] WCI. U.S. States, Canadian Provinces Announce Regional Cap-and-Trade Program to Reduce Greenhouse Gases. September 23, 2008. Available at: http://www.westernclimateinitiative.org/ewebeditpro/items/O104F19871.PDF

Task Number	Offsets Committee	Deliverables
Task 4	Offset Supply Analysis	In conjunction with any further economic modeling, provide input to the Economic Modeling Team on projected offset supply (tonnes CO_2e/year) and costs.

This white paper is the first stage in developing a clear definition of a WCI greenhouse gas (GHG) offset and the detailed eligibility criteria for GHG offset projects used for compliance purposes as identified in the WCI 2009/10 Workplan released February 2009. Environmental integrity and a system designed to encourage offset projects are critical outcomes for the Offset Committee to consider in recommending criteria for offsets used to meet a compliance obligation. The WCI included in its September 2008 Design recommendations that the criteria ensure offsets result in a GHG reduction, removal, or avoidance that is real, additional, verifiable, and permanent.[4] The design of the offsets system must also ensure that the quantification of the GHG reduction, removal, or avoidance is accurate and not double-counted. According to the WCI's design principles, reductions from offsets must also be enforceable by the WCI Partner jurisdictions.[5]

For each of the aforementioned essential offset criteria (real, additional, verifiable, and permanent), this white paper provides an overview of approaches that other offset systems have taken in:

a. defining them;
b. evaluation of the policy and operational considerations resulting from different definitions; and
c. discussion of implementation options for the criteria.

The systems discussed in this white paper were choosen to provide examples of different approaches, some for a compliance approach and others for a voluntary approach. While the cited examples may not be directly comparable, they offer important insights into system design. To keep this white paper to an appropriate length, the Offsets Committee selected a subset of systems to be included. Table 2.1 provides a brief synopsis of each system cited in this paper. For each of the WCI criteria examined in the following sections of this white paper, definitions from each of the systems listed in Table 2.1 are presented for comparison.

[4] WCI. 2009. Design Recommendations for the WCI Regional Cap-and-Trade Program. September 23, 2008; revised March 13, 2009. p. 10 Available at: http://www.westernclimateinitiative.org/ewebeditpro/items/O104F21252.pdf.

[5] WCI. 2007. WCI Workplan. October 27, 2007. p. 3 Available at: http://www.westernclimateinitiative.org/ewebeditpro/items/O104F13792.pdf

Table 2.1 Offset system examples cited in this paper

Offset System	Description
Alberta-based Offset Credit System[6]	Unlimited compliance mechanism for entities regulated under the province's mandatory GHG emission intensity-based regulatory system.
British Columbia Emission Offset Regulation[7]	Sets out requirements for GHG reductions and removals to be recognized for the purposes of fulfilling the provincial government's commitment to a carbon-neutral public sector by 2010 under the BC Greenhouse Gas Reduction Target Act, which came into force in January 2008.
California Global Warming Solutions Act of 2006 (AB 32)[8]	Establishes a statewide GHG cap for 2020 in California. Offsets serve as a limited compliance mechanism for capped sources regulated under AB 32.
Clean Development Mechanism (CDM)[9]	A project-based GHG offset mechanism under the Kyoto Protocol. The scheme aims to assist Annex-I parties (industrialized countries with binding emission reduction targets) to meet their Kyoto compliance obligation by allowing them to invest in offset projects in non-Annex I parties (developing countries without binding targets).
Gold Standard[10]	A voluntary carbon offset standard for renewable energy and energy efficiency projects that can be applied to voluntary offset projects and to CDM projects. It was developed under the leadership of the World Wildlife Fund (WWF), with a focus on offset projects that provide lasting social, economic and environmental benefits.

[6] http://www,environment.alberta.ca/1238.html

[7] http://www.env.gov.bc.ca/epd/codes/ggrta/pdf/offsets-reg.pdf

[8] http://www.arb.ca.gov/cc/docs/ab32text.pdf

[9] http://cdm.unfccc.int/index.html

[10] http://www.cdmgoldstandard.org

Offset System	Description
ISO 14064-2; 14064-3; 14065[11]	A policy-neutral, GHG project accounting standard that provides specification with guidance at the organizational level for quantification, monitoring and reporting of greenhouse gas emission reductions and removal enhancements. It was developed by the International Organization for Standardization (ISO). ISO 14064-2 provides general process guidance and does not prescribe specific program requirements. Specific requirements are left to be defined by the GHG program (voluntary or mandatory) that uses ISO 14064-2. This standard is used as the framework standard for the Canadian offsets system design, Climate Action Reserve, BC Emission Offsets Regulation and many other voluntary and mandatory North American programs. Training in ISO 14064-3 provides framework and tools for validation and verification of offset projects. In addition, ISO 14065 provides specifications for accreditation and other forms of recognition of validation and verification service providers.
Offsets Quality Initiative (OQI)[12]	A collaborative, consensus-based initiative of its six nonprofit member organizations: the Climate Trust, the Pew Center on Global Climate Change, the California Climate Action Registry, the Environmental Resources Trust, the Greenhouse Gas Management Institute and The Climate Group. OQI was founded in November 2007 to provide guidance on greenhouse gas offset policy and best practices.
Oregon Offset Standard[13]	Energy facilities in Oregon must meet mandatory CO_2 emissions standards. Regulated facilities have the option of meeting their emission reduction obligations through the purchase of eligible offsets.
Regional Greenhouse Gas Initiative (RGGI)[14]	A multi-state mandatory cap and trade program to reduce CO_2 emissions from electricity generation, which went into effect in January of 2009 with 10 participating US states. Under the RGGI program, offsets serve as a limited alternative compliance mechanism for regulated facilities.
Voluntary Carbon Standard (VCS 2007)[15]	A full-fledged carbon offset standard for the voluntary offset market including standards for accounting, monitoring, verification, certification, as well as registration and enforcement systems. It focuses on GHG reduction attributes only and does not require projects to have other environmental or social benefits.

[11] www.iso.org

[12] http://www.offsetqualityinitiative.org/

[13] http://www.oregon.gov/ENERGY/SITING/rules.shtml#Division_1

[14] http://www.rggi.org/

[15] http://www.v-c-s.org

Offset System	Description
World Business Council for Sustainable Development and World Resources Institute (WBCSD/WRI) GHG Protocol for Project Accounting[16]	An offset accounting protocol for quantifying and reporting GHG emission reductions from GHG mitigation projects. It does not focus on verification, enforcement or co-benefits.

This paper also examines additional principles and technical considerations that are important in establishing offsets criteria as set out in the WCI Design Recommendations.[17] Each of these principles and technical considerations are nested under the related essential criteria or included in Section 7 entitled "Other considerations." These principles and technical considerations include ownership, use of approved protocols, and geographic limits (Section 2); quantification, uncerntainty and accuracy, conservativeness, and leakage (Section 3); additionality tests, baseline, eligibility date, and crediting period (Section 4); validation, enforcement, and material under verifiable (Section 6); and transparency and co-benefits/impacts (Section 7).

3 Definition of an offset

This section considers how to best define an offset within the WCI program. The definition of an offset should establish the tradability of offsets and provide guidance about their fungibility within the WCI program. If these aspects of an offset system are not appropriately defined, then emitters may not be able to realize the reduced costs from offsets. The WCI offsets criteria should address fundamental questions about how offsets are generated[18] and recognized. As stated in the WCI Design Recommendations, all offsets in the WCI program will be required to meet criteria specified by the WCI Partner Jurisdictions to ensure that offset projects result in a GHG reduction, removal, or avoidance that is real, additional, permanent, verifiable, and enforceable.

3.1 Policy and operational considerations in defining an offset

The offset definition may not need to include all specific details regarding offsets. Instead the definition may reference a specific part of the essential elements or further provisions or requirements of the offset system that are outside the definition itself.

Table 3.0 below illustrates how several different existing programs have chosen different levels of detail to include within the offset definition itself. RGGI and CDM

[16] www.ghgprotocol.org

[17] Western Climate Initiative. September 23, 2008; revised March 13, 2009. Design Recommendations for the WCI Regional Cap-and-Trade Program, http://www.westernclimateinitiative.org/ewebeditpro/items/O104F21252.pdf.

[18] The "generation" of offsets is not a technical term. Rather, it is a short-hand to describe the multi-step process which includes how projects are approved, reductions occur, and the appropriate credit is issued. These steps will be described in more detail in the second white paper from the WCI Offsets Committee Task 1 work.

systems do not specify all offset requirements within their offset definition but instead refer to requirements or provisions of the offset system that are defined elsewhere in the regulation or program design. Alternatively many of the other systems, including the BC Emission Offset Regulation and Oregon Offset Standard, include specified criteria within the definition itself, including defining an offset as a reduction/removal of GHG emissions CO_2e. A WCI offset definition could, for example, include a specification that offsets must meet all WCI requirements (such as is done in the RGGI and CDM definition), or include the WCI specified criteria for offsets within the definition.

Table 3.0 Definitions of a greenhouse gas offset

Offset System	Definition
Alberta-based Offset Credit System	A "emission offset" means a reduction in the release of specified gases, expressed in tonnes on a CO_2e basis, that meets the requirements of section 7(1), but does not include an emission performance credit
British Columbia Emission Offset Regulation	A "Greenhouse gas reduction" is (a) a reduction of GHG emissions, or (b) an enhancement of GHG removals. Section 8 - A greenhouse gas reduction is recognized as an equivalent amount of emission offsets for the purposes of the Act if (a) the GHG reduction is equal to the project reduction in a project verified in accordance with this regulation, (b) the proponent of the project has transferred any title the proponent has in the GHG reduction to the Pacific Carbon Trust, and (c) the GHG reduction has not previously been recognized as an emission offset under the Act or other another emission-offset recognition scheme or for the purposes of another voluntary or mandatory greenhouse gas reduction program.
California Global Warming Solutions Act of 2006 (AB 32)	Not defined
Clean Development Mechanism (CDM)	A "Certified Emission Reduction" or CER is a unit issued pursuant to Article 12 and requirements there under, as well as the relevant provisions in the CDM modalities and procedures, and is equal to one metric tonne of carbon dioxide equivalent, calculated using global warming potentials defined by decision 2/CP.3 or as subsequently revised in accordance with Article 5 of the Kyoto Protocol.
Gold Standard	(Glossary) A unit of GHG emissions reduction equal to one ton of CO_2e in one part of the world that offsets an equivalent amount of GHG emissions in another part of the world. Offsets by themselves do not lead to a net reduction in global emissions although they can prevent the rate of emissions from increasing.
ISO 14064-2	Not defined

Offset System	Definition
Offsets Quality Initiative (OQI)	An offset represents the reduction, removal or avoidance of GHG emissions from a specific project that is used to compensate for GHG emissions occurring elsewhere...The essential promise of an offset is the achievement of a real and verifiable reduction in global GHG emission levels beyond what would have otherwise occurred that is equally effective as on-site emission reductions by regulated entities.
Oregon Offset Standard	"Offset" means an action that will be implemented by the applicant, a third party or through the qualified organization to avoid, sequester or displace emissions of carbon dioxide.
Regional Greenhouse Gas Initiative (RGGI)	A "CO_2 offset allowance" is awarded to the sponsor of a CO2 emissions offset project pursuant to section XX10.7 and is subject to the relevant compliance deduction limitations of section XX6.5(a)(3).
Voluntary Carbon Standard (VCS 2007)	Not defined
WBCSD/WRI GHG Protocol for Project Accounting	A "GHG Reduction" is a decrease in GHG emissions or an increase in removal or storage of GHGs from the atmosphere, relative to baseline emissions. Primary effects will result in GHG reductions, as will some secondary effects. A project activity's total GHG reductions are quantified as the sum of its associated primary effect(s) and any significant secondary effects (which may involve decreases or countervailing increases in GHG emissions). A GHG project's total GHG reductions are quantified as the sum of the GHG reductions from each project activity.

3.2 Supporting principles and technical considerations

There are several supporting principles and technical considerations which can further define a WCI offset. This section briefly discusses why clarification of ownership issues, use of approved protocols, and georgraphic limits may be included within the definition of a WCI offset.

3.2.1 Ownership Issues

Establishing clear ownership of an emission reduction is important prior to the issuance and acceptance of offsets in the WCI program. By establishing ownership it provides a measure of certainty that offsets are only counted once for compliance purposes. Ownership of an emission reduction is often established through a contract. The WCI should consider whether it is necessary to explicitly require a contract or type of contract, or to require other specific documentation or registration of documents that evidence ownership. Establishing clear ownership of an offset once it is created relies on a means of registering and tracking offsets[19] which could include the tracking of ownership, trades, and retirement.

[19] The "registration" of offset projects, as well as the tracking of offsets, is a process that will be described in more detail in the second white paper from the WCI Offsets Committee Task 1 work.

3.2.2 Use of Approved Protocols

WCI Partner jurisdictions will adopt protocols that will be detailed specific instructions for project developers that describe standard approaches, equipment, procedures and requirements for projects. The protocols will apply to all aspects of the project life cycle, including: development, operation, monitoring, calculation, reporting and verification. Protocols must meet the criteria and requirements that are adopted by the WCI Partner jurisdictions.

3.2.3 Geographic Limits

Establishing a geographic limit places restrictions on offsets from a particular geographic area. WCI jurisdictions will recognize offsets meeting the agreed upon criteria in the WCI Design Document (September 23, 2008). Offsets issued[20] by any WCI Partner jurisdiction must be equivalent and fungible throughout the WCI.

As part of work under Task 2, The Offsets Committee will recommend standards for evaluating and (if appropriate) accepting tradable units (offsets and allowances) from programs other than the WCI cap-and-trade program.

3.3 Implementation options

The Offsets Committee has formulated three options for defining an offset, all with distinct policy and operational considerations. These options differ in whether the system requirements are specified in the offset definition itself or referred to in other parts of the regulation(s) or program design.

- Option A: specific parameters or requirements in the definition;
- Option B: general parameters or requirements with specific requirements elsewhere; and
- Option C: specific parameters or requirements with the condition that additional requirements specified in the WCI offset system must be met.

Options B and Cmay provide more flexibility for program design and future refinement by referring to specific WCI parameters or requirements but not specifying all of them in the offset definition itself,. Defining a set of offset system parameters or requirements in the offset definition itself could result in unintended consequences as WCI further develops policies and designs key elements of the cap-and-trade program. As the management and administration of the offset system develops over time, option C may allow the most flexibility to refine the system as needed.

Options A and Cmay provide a clear signal about how offsets are generated and traded, as well as their use in the WCI program, by defining a set of specific offset system parameters or requirements in the offset definition itself,. After reviewing how other emission reduction programs have defined an offset, the Offsets Committee has developed the following parameters or requirements that could be included in the definition of a WCI offset:

[20] The “issuance” of offsets is a process that will be described in more detail in the second white paper from the WCI Offsets Committee Task 1 work.

- Offset Measurement: specifying that offsets are generated in units of metric tons of carbon dioxide equivalent (CO_2e) with each offset representing one metric ton CO_2e
- WCI Specified Criteria: specifying that offsets must be GHG emission reductions, removals or avoidances that are real, additional, permanent, verifiable and enforceable
- Offset Projects: specifying that offsets are generated from registered projects through individual project activities that reduce GHG emissions outside the cap
- Verification and Certification: specifying that offsets represent reductions that are verified and/or certified in a defined manner (e.g., a numbering system, verification statement, or other recognition requirements)
- Issuance and Fungibility: specifying that offsets are issued by an authority in recognition of verified reductions and become fungible compliance units with tracking numbers

The list above provides some examples of clauses that may be included within the definition of a WCI offset. Some of the examples may provide greater clarity in an offset definition, such as defining the units of an offset in CO_2e metric tons. Additional parameters could be included in the offsets definition, but this could adversely affect the fungibility of offsets. For this reasonit will be important to identify which criteria are useful to include in the definition and which criteria are best referenced as part of the offset program requirements if the WCI decides to use Option C to define an offset,.

4 Real

This section considers criteria to define reductions as "real". The WCI Design Recommendations state that emission reductions or removals must be real, in order to assure that they actually occurred. Robust accounting methods are essential to an offsets program because inaccurate or incomplete accounting could lead to crediting reductions that did not actually occur. Ensuring that reductions are real is critical for ensuring the integrity of the cap-and-trade program, as WCI offsets may be used in place of emissions reductions in capped sectors.

4.1 Policy and operational considerations in defining real

Table 4.0 outlines approaches from other programs in defining real: including specifying that emission reductions represent "actual emission reductions" (OQI) or "all the GHG emission reductions and removals … must be proven to have genuinely taken place" (VCS 2007).

Table 4.0 Definitions of real in other offset systems

Offset System	Definition
Alberta-based Offset Credit System	Required – an offset project must have specific and identifiable actions that reduce or remove GHGs. The project cannot simply result in emissions moving to another part of the facility or operation. The project must also demonstrate that it causes a net reduction of all greenhouse gases involved in the project.
British Columbia Emission Offset Regulation	Not included

Offset System	Definition
California Global Warming Solutions Act of 2006 (AB 32)	Required - Not defined
Clean Development Mechanism (CDM)	Not defined
Gold Standard	Required - Not defined
ISO 14064-2	From 5.4 - In developing the baseline scenario, the project proponent shall select the assumptions, values and procedures that help ensure that GHG emissions reductions or removal enhancements are not over-estimated.
Offsets Quality Initiative (OQI)	Project-based offsets should represent actual emission reductions and not simply be artifacts of incomplete or inaccurate accounting.
Oregon Offset Standard	Not included
Regional Greenhouse Gas Initiative (RGGI)	Required - Not defined
Voluntary Carbon Standard (VCS 2007)	All the GHG emission reductions and removals and the projects that generate them must be proven to have genuinely taken place.
WBCSD/WRI GHG Protocol for Project Accounting	Not included

The policy considerations for assuring that reductions are real are closely related to other criteria of the offsets program such as permanent (i.e. not reversible), verifiable and quantifiable. Permanence is discussed in Section 5, verification in Section 6, and quantification later in this section. Principles and technical considerations that may be useful for defining real, such as conservativeness, accuracy, uncertainty, and leakage, are also considered in this section.

In order to ensure that offsets are real they must be quantifiable and measurable. It is important to be able to verify that emission reductions or removals actually took place through a rigorous verification process that includes physical inspection of the project. Similarly, the potential leakage of emissions due to the implementation of a project and the uncertainty associated with the methodologies used to measure reductions need to be accounted for when determining the number of offsets to be credited to a project.

It is important that reductions claimed as reducing a ton of CO_2e in the WCI program are not being double counted within the cap-and-trade system and not being simultaneously claimed in other GHG trading programs regardless of whether that program is of a regulatory or voluntary nature. There must be appropriate mechanisms in place to register, track, and retire offsets to prevent double counting. Enforcement penalties could also be applied to target project developers attempting to sell reductions as offsets more than once. The WCI could also consider allowing for some explicit linkage between GHG emissions reduction registries to circumvent potential double counting issues. For example, there is currently a link between the European Union Emissions Trading Scheme (EU ETS) and the CDM electronic registries to allow transfers of offsets to occur and be updated in both systems as requirred.

4.2 Supporting principles and technical considerations

It is useful to consider several supporting principles and technical considerations in the context of defining real. The principles of "uncertainty," "accuracy," and "conservativeness" and the technical considerations that account for "leakage" may be included as a part of what the WCI considers to be a "real" reduction or removal. If such terms are included, the WCI will need to define and clarify what is meant by these terms. The WCI Offsets Committee recognizes that some of the principles such as accuracy and conservativeness will be factors in other WCI criteria (e,g., additionality). Discussion of these terms in the context of the criteria "real" is not meant to imply that they are limited in scope.

4.2.1 Quantification

The notion that emissions reductions, removals or avoidances must be quantifiable comes from the need to ensure that offsets represent real reductions and that the reductions can be converted into a common currency (i.e., offsets) that accurately reflect a project's environmental benefits. The Design Recommendations for the WCI Program also specify that criteria for the offsets program need to "ensure that the quantification of the GHG reduction, removal or avoidance is accurate and not double counted."

The concept of quantifiable can be thought of in two ways. First, sound methods to measure and quantify GHG reductions must exist for each project type. There should be sufficient scientific research and expert review to support the use of a given methodology and monitoring. Furthermore, measurement techniques must be capable of tracking GHG emissions and/or sequestration within the project's boundary. Second, these methods must be sufficiently accurate. There may be quantification methodologies that are not accurate enough for crediting offsets. For example, a relatively simple methodology for calculating a forest carbon inventory based on reasonable assumptions and some field data may be only accurate enough to make an order of magnitude calculation. A more detailed method would likely be necessary for calculations in support of issuing offsets. Accuracy is discussed further below.

Quantification methods for project types should be subject to periodic review to ensure that they reflect the latest science and GHG accounting practices. This implies that the WCI will need a mechanism for regularly and periodically reviewing and updating the GHG quantification. This review is particularly important in cases where additionality performance standards or guidance on developing baselines exists in protocols, as the regulatory and economic conditions that were used to develop them can change over time.

It is also useful to have uniformity among quantification and monitoring procedures across project types to the extent feasible. There is obviously a trade off in terms of flexibility for project developers. However uniformity in quantification methodologies could decrease the administrative burden for methodological review and could help prevent project developers from shopping around for the most favorable methodologies. Quantification methods in protocols should still be capable of taking local conditions into account that may affect GHG offset calculations. Variations based on local conditions are likely to be especially important for projects involving biological sinks where species compositions or other local factors affect carbon sequestration.

4.2.2 Uncertainty and accuracy

The greater the uncertainty in calculating emission reductions from project activities, the less confidence there will be that all offsets generated by a project are real. For this reason, when defining what makes an offset real, it is important to consider how uncertainty should be addressed in the program and in each project specific protocol. Uncertainty in emission reductions or removals may result from uncertainty in baseline calculations, as well as uncertainty in calculating, modeling, or measuring emission reductions or removals. Uncertainty may also be greater for some project types than others. For example, there is likely to be greater inherent uncertainty in calculating carbon stored in biological sinks or reservoirs than in calculating emissions from fossil fuel combustion.

Uncertainty may be factored into the design of offset programs and protocols and assessments of uncertainty may also be required of individual project developers. Several examples of how uncertainty is addressed are shown in Table 4.1. British Columbia's offset regulation must include results of an assessment of uncertainty associated with the estimation of the GHG reduction to be achieved by carrying out an offset project. The Gold Standard requires affirmation that there is no uncertainty related to data sets used. Several other programs state that uncertainty should be taken into account, including ISO 14062-2 and VCS. The OQI recommends the adoption of conservative quantification methodologies to reduce uncertainty.

Table 4.1 Approaches to managing uncertainty in offset systems

Offset System	Approach
Alberta-based Offset Credit System	Managed through use of accepted quantitification protocols, use of national inventory data, and use of good practice guidance.
British Columbia Emission Offset Regulation	Requires an uncertainty assessment and a description of the procedures use to conduct the assessment.
California Global Warming Solutions Act of 2006 (AB 32)	Not mentioned
Clean Development Mechanism (CDM)	Not specified
Gold Standard	Affirmation that there is no material uncertainty over the numerical data sets applied is a required element of the Gold Standard conservative approach.
ISO 14064-2	Defined as: parameter associated with the result of quantification which characterizes the dispersion of the values that could be reasonably attributed to the quantified amount. Quantification of GHG emissions/removals shall take into account the quantification uncertainty.
Offsets Quality Initiative (OQI)	Methodological selection should be conservative to ensure that offsets are not overestimated and uncertainties are reduced as far as practicable.
Oregon Offset Standard	Not mentioned

Offset System	Approach
Regional Greenhouse Gas Initiative (RGGI)	Uncertainty factored in to design of offset program. (addressed in document analyzing offset limits)
Voluntary Carbon Standard (VCS 2007)	Project proponent shall select or develop GHG emissions or removal factors that take account of the quantification uncertainty.
WBCSD/WRI GHG Protocol for Project Accounting	Not addressed - beyond scope of project protocol

The discussion of uncertainty is closely connected with the concept of accuracy. Accuracy relates to how close a measured or calculated quantity is to the true value. Given that all measurements are estimates, the more accurate a method is, the less uncertainty there will be. There will often be tradeoffs between increasing the accuracy of measurements and the time and resources involved in making the measurements. An offset program should strive for methods that are as accurate as possible while taking into account that there will always be some degree of uncertainty.

Several programs strive to balance accuracy and practicality in the quantification of offset project benefits. ISO defines accuracy in order to "reduce bias and uncertainty as far as is practical." The IPCC Good Practice and Guidance and Uncertainty Management in National Greenhouse Gas Inventories defines accuracy as a relative measure of the exactness of an emission or removal estimate. Alberta's-Based Offset Credit System acknowledges that there are different levels of accuracy associated with different measurements, stating: "the more accurate the data measurement, the better; however, this must take into consideration costs and other practicalities of measurement." The WBCSD/WRI GHG protocol for project accounting states that acceptable levels of uncertainty will depend on the objectives for implementing a GHG project and the intended use of quantified GHG reductions. It recommends that where accuracy is sacrificed, that data and estimates used to quantify GHG reductions should be conservative.

To ensure accuracy, offset programs require detailed documentation, monitoring and verification of a project's anticipated benefits. British Columbia's program requires project developers to include an assertion that selected sources, sinks and reservoirs ensures that the total of the emission reduction and removals enhancement is an accurate and conservative estimation of GHG reduction. Methodology is also considered in determining accuracy under British columbia's program. RGGI requires detailed monitoring and verifications for offset projects to ensure accuracy. The New South Wales Greenhouse Gas Abatement Scheme (NSW GGAS) requires emissions calculations for certain projects to include a confidence factor reflecting accuracy of the engineering study completed. The confidence factor is higher if calculations are based on accurate records and lower if assessment is based on estimated data.

The use of standard calculation and measurement methods, as detailed in project protocols, would be useful for ensuring the reproducibility of measurements and calculations. However, it is also important that these methods be sufficiently accurate by minimizing inherent uncertainty. To improve quality, each offset project could have an individual monitoring plan that clearly defines technical methods such as how, when, and who collects data and quantifies emissions.

4.2.3 Conservativeness

Several offset systems have adopted a principle of conservativeness to address uncertainty and ensure that emission reductions are real. The premise is that when uncertainty exists, it is best to only credit reductions where there is high confidence that the reductions actually occurred. This is distinct from imposing an arbitrary discount factor. While both potentially result in less offsets being credited for a project, an approach based on conservativeness directly relates the degree of discounting to uncertainty. If uncertainty is reduced by improved measurements, then there would be less discounting.

Conceptually, when there is a range of possible values (from baseline assumptions to emission reduction calculations), a principle of conservativeness would imply using values at the lower end of the range so that there is higher confidence that all credited reductions are real. Embedded in the concept of conservativeness is the understanding that - the lower the number that is claimed, the higher the certainty that the true value is at least that much. Conservativeness could also involve statistical confidence factors or uncertainty-based discount factors. This contrasts with using values that represent the "most-likely" outcome which have a greater risk of overestimating reductions when uncertainty exists. If adopted as a principle, it would be important to define or explain what is meant by conservative, as there can be varying interpretations of the term in practice. Conservative assumptions can increase the probability that a project will over-perform and that the overall emission trading system will achieve even more reductions for a given target or cap level.

4.2.4 Leakage

Leakage of emissions occurs when there is an increase of emissions outside a project boundary as a result of project activity inside the project boundary. Essentially, emissions are displaced from one area to another with no net decrease in emissions. The risk for leakage differs among project types. For example, leakage may be more of a concern for a forestry project than in a coalmine methane project because altering forestry practices in one area may affect land use in other areas and because timber is a global commodity. Alternately, projects capturing methane may be less likely to shift activities and result in increased emissions from other activities outside the project boundary. However, affecting the economics of coal production in one jurisdiction, could potentially result in a shift of coal production (and methane emission) to/from another jurisdiction.

If an offset project results in an increase in emissions outside of the project boundary, then these emissions must be accounted for to ensure that all offsets generated by the project represent real emission reductions. Even within a project's boundary, increases in emissions that indirectly result from project activities should be accounted for. In this sense, the term real can be interpreted broadly because if the full effect of a project's activities on greenhouse gas emissions is not considered, then the reductions claimed as a result of an offset project would not all be truly real. Leakage outside of a project's boundary can be difficult to assess in practice. In the context of defining real, it may be sufficient to require that leakage and indirect effects on emissions be accounted for in offset projects to the extent possible.

Some offset programs define and address leakage broadly, while others distinguish between types of leakage. California's AB32 defines "Leakage" as a reduction in emissions of greenhouse gases within the state that is offset by an increase in emissions of greenhouse gases outside the state. The state plans to minimize leakage through regulations adopted to implement AB32. The CAR's forestry protocol differentiates between two types of leakage – activity shifting and market leakage. Activity shifting leakage is a displacement of activities from within the project's physical boundaries to locations outside of it and reporting of this type of leakage is required. Market leakage occurs when the project activity affects an established market for goods, causing substitution or replacement of goods from elsewhere with a corresponding increase in GHG emissions elsewhwere and reporting is strongly encouraged. ISO uses a similar definition, and states that the project proponent is responsible for leakage. NWS GGAS incorporates impacts of offset projects on other operations into the amount of offsets issued for a project.

Several options could be considered to address leakage in offset projects. One option would be to require that each approved protocol have a method to account for potential leakage in emission reductions, removals or avoidance calculations specific to that project type. A second option would be to have a project validator provide an opinion on whether there is a leakage risk associated with the project by providing a leakage assessment. This method would require further elaboration, including what the implications of the validator's opinion would be. Other options for assessing leakage include standard algorithms and methods for leakage quantification (as done for some CDM methodologies), and requiring an initial de minimis assessment to state whether a leakage assessment is recommended or not

4.3 Implementation options

Elaborating the requirements of what constitutes real emission reductions, removals or avoidances will provide a reference point when setting other criteria and evaluating protocols. Ensuring that offsets meet the requirements of "real" may involve requirements such as that conservative estimation methods be employed, that monitoring is conducted at adequate frequencies, that verification and enforcement requirements are sufficiently stringent, and that potential leakage is accounted for. Further clarification would likely be needed as to the details of supporting criteria such as conservative methods and accounting for leakage and indirect effects.

5 Additional

This section discusses the criteria that offset reductions be additional. Additionality has generally been the most controversial criteria in the implementation of other offset systems. Not coincidentally, this is the longest section in this paper.

How the WCI chooses to define additionality and evaluate whether a project is additional will play a critical role in ensuring the integrity of WCI offsets. This section considers the issues related to defining additionality for the WCI offset system and options for its implemention. It will also consider policy issues surrounding several concepts related to additionality such as types of additionality tests, baselines, crediting periods, and eligibility dates.

The purpose of requiring additionality in the WCI offsets system is the desire to only credit projects that would not have otherwise occurred in the absence of an offsets mechanism. Because there are many factors that affect whether a project is additional, operationalizing additionality is a challenge.

5.1 Policy and operational considerations in defining additional

An important question to consider in defining additionality is how specific the definition should be and what specific evaluations or other criteria to include in the definition. A definition could be general, such as requiring that emission reductions are additional to any GHG emission reduction that would otherwise occur as a result of business-as-usual activities or regulatory requirements. The definition could also be more specific. For example, stating specific requirements in the definition that must be met, such as passing certain additionality tests or proving that the express purpose of implementing the project was to generate GHG offsets. If additionality is defined prescriptively it would provide direction to the stringency and type of additionality tests that may be included in the evaluation. However, a more prescriptive definition would not necessarily provide direction on how to evaluate additionality in practice. Table 5.0 provides several examples of additionality requirements from other select offset programs.

Table 5.0 Additionality requirements in offset systems

Offset System	Requirements
Alberta-based Offset Credit System	Not explicitly defined, by requires that emissions reductions "must be from an action taken that is not otherwise required by law at the time the action is initiated".
British Columbia Emission Offset Regulation	Not explicitly defined, but requires "an assertion by the proponent that there are financial, technological or other obstacles to carrying out the project that are overcome or partially overcome by the incentive of having a GHG reduction recognized as an emission offset under the Act, and a justification for the assertion" S3(k)
California Global Warming Solutions Act of 2006 (AB 32)	…the reduction is in addition to any greenhouse gas emission reduction otherwise required by law or regulation, and any other greenhouse gas emission reduction that otherwise would occur [from 38562(d)(2)]
Clean Development Mechanism (CDM)	A PoA is additional if it can be demonstrated that in the absence of the CDM (i) the proposed voluntary measure would not be implemented, or (ii) the mandatory policy/regulation would be systematically not enforced and that noncompliance with those requirements is widespread in the country/region, or (iii) that the PoA will lead to a greater level of enforcement of the existing mandatory policy /regulation. This shall constitute the demonstration of additionality of the PoA as a whole.
Gold Standard	Additionality – All Gold Standard project activities must be demonstrated to be additional, meaning that they shall reduce anthropogenic emissions of greenhouse gases below those that would have occurred in the absence of the registered Gold Standard project activity.

Offset System	Requirements
ISO 14064-2	From 5.4 - The project proponent shall select or establish, justify and apply criteria and procedures for demonstrating that the project results in GHG emissions reductions or removal enhancements that are additional to what would occur in the baseline scenario.
Offsets Quality Initiative (OQI)	Offsets Should Be Additional. Because offsets are used to compensate for emission reductions that an entity operating under an emissions cap would otherwise have to make itself, the reductions resulting from offset projects must be shown to be "in addition to" reductions that would have occurred without the incentive provided by offsets. The revenue from selling the project's emission reductions should be reasonably expected to have incentivized the project's implementation for an offset project to be considered additional.
Oregon Offset Standard	Offsets must be regulatory surplus and will be evaluated based on the "extent to which the CO_2 reductions would have occurred in the absence of the offset project"
Regional Greenhouse Gas Initiative (RGGI)	Except as provided with respect to specific offset project standards in section XX10.5, the following general requirements shall apply. (1) CO2 offset allowances shall not be awarded to an offset project or CO2 emissions credit retirement that is required pursuant to any local, state or federal law, regulation, or administrative or judicial order. If an offset project receives a consistency determination under section XX10.4 and is later required by local, state or federal law, regulation, or administrative or judicial order, then the offset project shall remain eligible for the award of CO2 offset allowances until the end of its current allocation period but its eligibility shall not be extended for an additional allocation period. (2) CO2 offset allowances shall not be awarded to an offset project that includes an electric generation component, unless the project sponsor transfers legal rights to any and all attribute credits (other than the CO2 offset allowances awarded under section XX10.7) generated from the operation of the offset project.
Voluntary Carbon Standard (VCS 2007)	"Project-based GHG emission reductions and removals must be additional to what would have happened under a business as usual scenario if the project had not been carried out." The VCS has requirements that a project pass one of three additionality tests, a "Project Test", a "Performance Test" or a "Technology Test". All protocols specify at a minimum that the project cannot be required by any law or regulation.
WBCSD/WRI GHG Protocol for Project Accounting	A criterion often applied to GHG projects, stipulating that project-based GHG reductions should only be quantified if the project activity "would not have happened anyway"—i.e., that the project activity (or the same technologies or practices it employs) would not have been implemented in its baseline scenario and/or that project activity emissions are lower than baseline emissions.

Once additionality has been defined, the WCI will need to develop an approach to ensure that offset projects can be evaluated against it. There are various methods of evaluating additionality, but the two most common approaches are project-specific and performance standard additionality tests. Project-specific tests (Option A below) seek to scrutinize the particular circumstances of an individual project to ensure that it would not have occurred in the absence of offsets. This approach is used by the CDM. Alternatively, a performance standard approach (Option B) seeks to determine through initial study of a sector or project type what level of performance is necessary to provide confidence that projects meeting or exceeding the standard are additional. The standard may be the identification of a particular technology (such as a methane digester) that is nearly always additional to common practice or the establishment of a set performance baseline that project reductions are measured against. Performance standards have been employed by the CAR. The WCI could also choose to have the additionality assessment vary by protocol, which would be advantageous if some sectors or activities are better suited to developing performance standards while others are more suited to project-specific analyses.

Summary of approaches to assessing additionality:

- Option A: Project Specific –
  The additionality of each individual project activity is scrutinized through application of specific additionality tests
- Option B: Performance Standard –
  For each sector or project type, a performance standard is established where projects meeting or exceeding the standard are considered to be additional. Performance standards may be uniform among the WCI Partner jurisdictions or differentiated by jurisdiction to reflect regulatory and economic differences.
- Option C: Protocol Specific Approach –
  Approach to additionality assessment may vary by protocol, seeking to adopt the best approach for each sector or class of activities
- Option D: Hybrid Approach –
  A combination of Options A, B, and C; a hybrid approach would set a performance standard, but still include some aspects of a project-specific additionality analysis, and may vary by protocol. A single approach may limit project types and inhibit innovation; a hybrid approach may be better able to cover more possibilities.

Options A and B have advantages and disadvantages. A combination of those two options may also be possible (Option C). Project-specific approaches have the advantage of looking more closely at individual projects and in theory they should be more effective in reducing the risk of non-additional projects being credited. However, the additional scrutiny increases transaction and oversight costs, as well as investor uncertainty, and it is not clear whether a project-specific approach would achieve better results than a performance standard approach. The CDM has developed rigorous project-specific additionality tests that include investment analysis, barrier analysis, common practice analysis and the identification of project alternatives. Performance standards provide greater clarity and investor certainty and require less administrative scrutiny once a standard has been set. They may however, require significant initial study to set an appropriate standard for a class of projects under certain circumstances (for example, if the performance standard for a project type in one state/province differs in another state/province) and would need to be periodically reviewed and revised as necessary. The performance standard approach accepts that some projects meeting the standard may not be additional, but that these would be few in number and be compensated by the benefits of having a clear standard that ensures most projects meeting the standard are additional. If a performance standard approach is adopted, regulatory additionality would likely still be evaluated on a project-by-project basis to ensure that a given project is not required by any laws, regulations, or permitting agreements. New technologies or practices will likely need a case-by-case approach. Once investments and implementation in specific new innovations become more established, a performance standard approach can be more readily applied.

5.2 Supporting principles and technical considerations

This section discusses three supporting principles and technical considerations in the context of defining additional. The concepts of "baseline," "eligbility date," and "crediting period" will likely have a role in which reductions the WCI considers to be additional.

5.2.1 Baseline

A baseline is commonly viewed as the business-as-usual (BAU) scenario that would likely occur in the absence of offset project activity. There are two key issues with respect to baseline determinations. First, offsets credited to a project are often calculated as the difference between baseline scenario emissions and project activity emissions. In this sense, correctly modeling the baseline scenario is crucial to ensuring that the offsets generated are both real and quantifiable. Second, as illustrated in Table 5.1, several programs define additionality in relation to a baseline (e.g., CDM and CAR), where reductions beyond what occurs in the baseline scenario are considered to be additional. This concept represents an alternative or complementary way of evaluating additionality when compared to other additionality tests.

A question the WCI will need to answer is to what extent baseline modeling will be considered together with additionality evaluations and whether this should vary by project type. Defining and determining a baselineis not always straightforward and an appeal to baseline modeling to evaluate additionality may not be any less complicated than employing project-specific additionality tests. One example of this complication is determining how many scenarios should be considered when determining the baseline.

Any project activity that would have occurred without offsets is by definition part of the baseline scenario and thereby would not be eligible as an offset even if it did result in emission reductions. Baseline scenario definitions are included in Table 5.1. The project-specific additionality tests discussed previously attempt to answer these questions and help to identify what would be the most likely outcome by taking into account financial information, common practices, and barriers to the offset project under consideration. Protocols that favor a performance standard approach may provide a standardized approach to modeling a baseline based on common practices in a region and regulatory requirements. This approach avoids much of the subjectivity involved in baseline modeling, but has the tradeoff that an "average" baseline for a project type will not necessarily reflect the actual baseline for a particular project. Some existing protocols also assume that current conditions represent the baseline conditions, which may not always be a valid assumption.

Table 5.1 Definitions of baseline in offset systems

Offset System	Definition
Alberta-base Offset Credit System	Hypothetical reference case that best represents the conditions (GHG emissions) most likely to have occurred in the absence of a GHG reductions/removals project.
British Columbia Emission Offset Regulation	Baseline emissions, in relation to a project, means an estimate of GHG emissions from all selected sources and reservoirs, assuming the project is not carried out.
California Global Warming Solutions Act of 2006 (AB 32)	Not defined
Clean Development Mechanism (CDM)	'Baseline methodology' is an application of an approach as defined in paragraph 48 of the CDM modalities and procedures, to an individual project activity, reflecting aspects such as sector and region. No methodology is excluded a priori so that project participants have the opportunity to propose any methodology. In considering paragraph 48, the Executive Board agreed that, in the two cases below, the following applies: (a) Case of a new methodology: In developing a baseline methodology, the first step is to identify the most appropriate approach for the project activity and then an applicable methodology; (b) Case of an approved methodology: In opting for an approved methodology, project participants have implicitly chosen an approach.
Gold Standard	'Baseline' means the amount of greenhouse gas emissions that would be produced in the absence of the carbon credit project, also known as the 'Business as usual' scenario, which forms the basis for calculating a project's emissions reductions and helps determine additionality.
ISO 14064-2	Baseline Scenario - hypothetical reference case that best represents the conditions most likely to occur in the absence of a proposed greenhouse gas project.
Offsets Quality Initiative (OQI)	Offsets Should Be Based on a Realistic Baseline. A GHG emission baseline must be established in order to quantify an offset project's GHG reductions. A baseline represents forecasted emission levels in the absence of the offset project; this is sometimes referred to as the baseline scenario, or the "without-project" case. The difference between the baseline and the actual emissions after the offset project is implemented represents the reductions achieved by the project, and this amount is credited as an offset. Offsets are only as credible as their baselines.
Oregon Offset Standard	Required but not specified.
Regional Greenhouse Gas Initiative (RGGI)	Each approved offset methodology has a unique "Emission baseline determination" method.

Offset System	Definition
Voluntary Carbon Standard (VCS 2007)	Baseline Scenario - hypothetical reference case that best represents the conditions most likely to occur in the absence of a proposed greenhouse gas project (from ISO 14064-2). Also, "The project proponent shall select the most conservative baseline scenario for the methodology. This shall reflect what most likely would have occurred in the absence of the project. The principle of conservativeness as set out in clause 3.7 of ISO 14064-2:2006 shall apply."
WBCSD/WRI GHG Protocol for Project Accounting	A hypothetical description of what would have most likely occurred in the absence of any considerations about climate change mitigation. Baseline emissions are an estimate of GHG emissions, removals, or storage associated with a baseline scenario or derived using a performance standard (see baseline procedures).

5.2.2 Eligibility Date

In the context of additionality, the beginning date of a project has important implications as to whether it would have occurred without the possibility of offsets. The most conservative approach in setting an eligibility date would be to only allow projects that have been undertaken after the initiation of a WCI offset program and that meet all of the requirements specified in the program design. However, such an approach would exclude projects that were undertaken in advance of the offset program's implementation that may still be additional if project developers either took the risk of implementing early projects with the expectation of being able to generate offsets under the WCI program, or if the projects are additional as a result of revenue from other GHG offsets not related to the WCI. To be eligible for WCI offsets, it may not be necessary that the offset project would have been undertaken without the WCI, just that the project would not have been undertaken without the expectation of carbon finance. Projects that were undertaken without initially seeking to register offsets or that were undertaken before the existence of a relevant carbon market would generally not be considered additional. The attempt to register may be an easy test/demonstration of offset considerations.

The issues regarding eligibility date can be divided into two key questions:

- What is the earliest date that offset projects may been undertaken to be eligible for crediting?
- What is the earliest year in which reductions may be credited as offsets?

The first question seeks to identify a cut-off date, where projects initiated before that date would not be eligible on the basis of additionality or other considerations. The second question to resolve is the earliest year in which reductions may be credited as offsets if the date identified in the first question is before the start of the first compliance period in 2012. For example, if 2007 is chosen to be the earliest year for eligibility purposes and a project that began in 2009 is deemed to be eligible - would reductions that take place between 2009 and 2012 be counted as WCI offsets - or will only reductions occurring after January 1, 2012 be registered as offsets? The consideration behind this question is whether reductions need to occur over the same time period as the emissions that they are offsetting. For projects undertaken before

2012, one approach would be to consider the reductions occurring before 2012 to be early actions, while reductions after 2012 would generate offsets (subject to crediting period limits). Alternatively, all verified reductions occurring after the eligibility date could be credited as offsets. A key distinction between an offset and any other type of early action recognition is that offsets are generated in addition to the total number of emission allowances in the capped sectors. Other types of recognition do not alter the total number of allowances and offsets available for use in the capped sectors. This paper does not seek to address what consideration early actions would receive.

In summary, there are three general options for eligibility dates:
1. Eligibility date and offset generation coincide with initiation of WCI cap-and-trade program in 2012
2. Offset eligibility date precedes 2012, but offsets are only generated for reductions in vintage years beginning in 2012
3. Offset eligibility date precedes 2012, and all reductions occurring as a result of the project activity may generate offsets, including in the period before 2012.

5.2.3 Crediting Period

A crediting period determines how long an offset project is eligible to receive offsets. Crediting periods may vary by project type. They may be fixed or renewable. For example, under the CDM most projects may be registered for a fixed period of ten years or may be registered for a period of seven years with the possibility of renewal for two additional seven-year periods. A renewable crediting period allows regulators to reevaluate a project after a number of years to determine if it is still eligible given current regulatory and market conditions and if there are any other issues regarding the project that would alter its ability to receive offsets (e.g., if an updated quantification methodology were required). A clearly defined crediting period is important for project developers and investors to have greater certainty in evaluating project financials. For example, OQI has endorsed the idea of conservative, multi-year, and potentially renewable crediting periods to provide certainty to market participants and allow for periodic review of a projects ongoing eligibility. Though additionality is one of many considerations that may be used to set crediting periods, crediting periods should in general reflect the amount of time that project activities would be additional.

If a previously additional technology used in an offset project becomes required, then the project would generally not be renewed for an additional crediting period. A provision in the program could allow regulators to void any project's eligibility as soon as a law or regulation would cease to make it additional, without waiting until the end of a crediting period. Alternatively, a declining sunset trajectory could be assigned to ease transition for project developers. An ongoing review of additionality could be a part of annual project verification and monitoring. However, this may have the effect of increasing investor uncertainty and decreasing early actions. If the time between crediting renewals is not too long, then it may be less important to review ongoing additionality each year. This may also be addressed through baseline considerations (i.e, the baseline and project activity become the same).

Different crediting periods for different project types are also possible. Sequestration projects tend to have longer crediting periods because their gradual GHG removals occur over longer timescales and provide an incentive to avoid reversals. In the

CDM, land use change and forestry projects may be credited for a single thirty year period, or up to three twenty year periods. Other programs such as CAR, allow up to a one-hundred year crediting period for these projects. Given changing global and regulatory conditions one may question how realistic these longer crediting periods may be. However this becomes less of an issue if crediting period renewals take place at an adequate frequency.

Crediting periods can affect the financial viability of a project. Shorter crediting periods tend to bias against projects that reduce emissions by a relatively lower quantity per year but that accrue reductions over many years. Projects that may not be financially viable with shorter crediting periods could become viable with longer crediting periods. Renewable periods provide less investor certainly relative to fixed crediting periods and longer crediting periods will tend to provide greater financial returns.

Crediting periods have tended to be conservative and may result in fewer offsets being issued compared to GHG reductions that occur over a project's lifetime. This results when an additional GHG offset project continues to achieve real emission reductions or removals beyond the end of the crediting period. While this may be true for many projects, a crediting period is necessary to prevent the opposite from occurring (allowing projects that are no longer additional to continue to generate offset credits). Therefore, the WCI will need to strike the appropriate balance when setting crediting periods. Improved quantification or improved project performance may yield more emission reductions eligible in subsequent crediting periods.

5.3 Implementation options

The WCI offset system must ensure that emission reductions from registered offset projects are additional to any GHG emission reduction that would otherwise occur as a result of business-as-usual activities or regulatory requirements. Most existing programs have excluded any project activities required by law or regulation from generating offsets in their programs. However, some GHG emission reduction activities not required by law or regulation are still expected to occur under a business-as-usual scenario. Although it is possible that such business-as-usual projects could pass a regulatory additionality test, most existing definitions of additionality include language that excludes these activities, as shown in Table 5.2.

There may be legitimate reasons for incentivizing project activities that do not meet the additionality requirements of the compliance offsets system, such as rewarding voluntary early action or providing incentives for further reductions. However, such reductions are better addressed with other policy instruments, such as early reduction allowance being assessed by the Cap Setting and Allowance Distribution Committee (CSAD).

There are several types of specific additionality tests that could be considered as part of a project-specific or hybrid additionality evaluation. Investment additionality attempts to determine in the absence of carbon finance if a project is financially attractive or the financially preferred alternative. However, this can be difficult to evaluate or verify in practice. Not all financially attractive projects would necessarily occur in the absence of an offset program and an "attractive" rate of return may vary by investor and project type. It may be unclear how much carbon revenue would be needed to make a project additional. A financial additionality test could exclude projects that receive funding from specified sources, such as overseas development assistance for international projects. For example, projects that receive government grant monies for a given technology could be excluded.

With a financial additionality test it may be difficult to precisely know to what degree offset financing was the unique and precise trigger that caused a project 'no' to become a 'yes' decision. In this case, WCI might consider a reverse test such as: "if the incremental offset financing were absent, would the project have not proceeded?"

Barrier removal additionality tests seek to determine if the ability to generate offsets removes realistic and credible barriers to project implementation. Examples of barriers may be investment barriers, such as lack of project capital due to perceived risks, technological barriers and barriers due to a prevailing practice. Under the CDM, a project that is "the first of its kind" also satisfies this criterion. However there has been much debate regarding how unique a project must be in order to be considered the first of its kind. In considering various types of additionality tests, the best approach may depend on program design. For example, a barrier test would be more appropriate for a program that allows unique projects and methodologies to be considered for crediting; while a performance standard approach may be more effective in conjunction with specific protocols.

Table 5.2 Additionality tests in offset programs

Additionality Test	Description
Regulatory	Is the project activity required by any law, regulation, or permitting agreement? (note: does not necessarily exclude project activities that over perform compared to what is required)
*Investment/ Financial	Is the project activity unlikely to be financially attractive or the most financially attractive alternative without revenue from the sale of offsets? Or: does the project go away if the offset financing goes away?
Restricted Financing Sources	Does the project receive financing from specified sources restricted by the offset program (e.g. Overseas Development Assistance, but could theoretically could include others)?
Barrier Analysis	Are there barriers (investment, technological, prevailing practice, etc.) to implementing project activities that are overcome by the ability to register offsets?
Common Practice	Are similar activities observed in the sector/region? Is the project activity common or widespread within the sector/region? Are there essential distinctions between the proposed activity and observed similar activities?

*Note: The terms financial and investment additionality are often used interchangeably. Financial additionality frequently has the same meaning as the description here for investment additionality.

An alternative to an emphasis on additionality tests is to focus on the concept of a baseline when determining additionality. In this case, all emission reductions relative to an established baseline would be considered additional and eligible to generate offsets. The challenge in this case becomes determining what should be used in modeling the baseline scenario. Thus, a focus on baselines does not avoid the problem of determining additionality but rather changes the focus to how to properly model the baseline scenario. A project activity that would have occurred without offsets is by definition the same as the baseline project scenario and therefore would not generate offsets (even if it did result in emission reductions).

The Offsets Quality Initiative (OQI) has argued that national or regional programs should develop "cost-effective, robust, and flexible additionality assessment tools that provide a standardized, transparent, and rigorous framework for the eligibility of offset projects. These tools should account for variations in different project types and other factors, such as project location, market conditions, and existing regulation(s)."[21] It can be difficult in practice to develop appropriate additionality tests across various sectors; financial additionality can be difficult to verify, and appropriate performance standards may be difficult to set in some sectors and could bias against original projects. Additionality in some sectors can be more readily evaluated than in other sectors. For other project types, the distinction is not so clear, such as when there is uncertainty regarding the baseline scenario. The WCI will need to determine the extent to which additionality tests can vary by protocol or if it will have one standard approach to evaluating additionality. Any additionality test or performance standard will need to be rigorous enough to ensure that additionality assessments go beyond regulatory additionality and are consistent with the additionality criteria defined in this task.

6 Permanent

This section describes the criteria that offset reductions be permanent. As an offset element, permanence refers to the duration of an emission reduction. A reduction is said to be permanent if the reduction is maintained through a given period of time (e.g., a 100-year standard). A permanence requirement helps to ensure equivalency of emissions reductions across all sectors and project types. Permanence may be an issue in projects with a risk of GHG reversal, such as sequestration projects (e.g., forestry), controlled sink projects (e.g., carbon capture and storage), or avoided emissions from controlled carbon reservoirs (e.g., deforestation). Concern over the perceived lack of permanence of forest offsetshas so far prevented forest projects from entering into in the European Union Emissions Trading Scheme (EU ETS).

6.1 Policy and operational considerations in defining permanent

The term greenhouse gas reversals implies the release of stored GHGs to the atmosphere. Reversals can includeemissions from natural disturbances such as: fire, insects, disease, and earthquakes. Reversals may also occur as a result of project mismanagement or failure. These risks of reversal challenge project permanence and as a result mechanisms must be invoked to ensure offset permanence. Permanence mechanisms vary among offset programs. Furthermore, risks of reversal are not limited to specific project types but can occur in a number of project settings including: forestry, agriculture, wetlands, rangelands or carbon capture and storage.

It may be useful to consider the legal obligations of permanence, which can be divided into two classes: *ex ante* and *ex post*. Although both are important, it is the latter that carries the bulk of the policy considerations. *Ex ante* obligations establish an up-front commitment by the project proponent to permanently maintain transacted tons[22] and is achieved through a legally recorded and binding instrument

[21] Offsets Quality Initiative. "Ensuring Offset Quality". White Paper, July 2008.

[22] Transacted tons are tons from the legal transaction of an offset, that is tons that have

(conservation easement, contract, etc.) prior to the project. In the case of land-based projects, this document should "run with the land" and hold subsequent land owners liable for the conditions of the legal obligation. An *ex post* permanence mechanism provides assurance in the case of failure of permanence and is achieved through replacement of lost transacted tons. *Ex post* mechanisms can include buffer pools, set asides, third-party insurance contracts, and/or replacement by other offsets.

All legal instruments have differing policy considerations around attributes such as duration, intent, implementation, enforceability and liability in the case of a breach of terms. Policy considerations include establishing, regulating and enforcing liability for permanence along a chain of offset custody. Establishing where ultimate responsibility for permanence rests will impact who makes the greatest effort to ensure permanence. Ultimately, the risk of impermanence may impact emissions if transacted tons are lost and the liable party is not able to make good on their obligation. Therefore, the regulatory authority may establish an institutional offset insurance pool to ensure the reductions.

Several examples of how permanent is defined and/or managed in other offset systems are presented in Table 6.0.

Table 6.0 Definitions of permanent and/or requirements for managing permanence in offset systems

Offset System	Definition/Requirements
Alberta-based Offset Credit System	Assurance factors used to discount the volume of offsets achieved by projects considered to have a reversal risk. Liability for reversal is transferred from the project developer to the Gov. of Alberta. All offsets issued are considerd permanent.
British Columbia Emission Offset Regulation	Though permanence is not explicitly defined, it requires for capture and storage/sequestration projects, controlled sinks projects, or avoided emissions from controlled reservoirs projects, "a risk management and contingency plan for the purpose of ensuring that the atmospheric effect of a GHG reduction achieved by the project will endure for a period (iv) comparable to the period that the atmospheric effect of a GHG reduction achieved by carrying out [a non-sequestration/sink/ reservoir project], or (v) at least 100 years."
California Global Warming Solutions Act of 2006 (AB 32)	Required – not defined
Clean Development Mechanism (CDM)	*Though not explicitly defined in the CDM Glossary, non-permanence is addressed through the issuance of temporary (tCERs) or long-term (lCERs) certified emission reduction credits.
Gold Standard	Not mentioned (No bio-sequestration projects are eligible)
ISO 14064-2	5.7 - The project proponent shall establish and apply criteria, procedures, and/or methodologies to assess the risk of a reversal of a GHG emission reduction or removal enhancement (i.e. permanence of GHG emission reduction or removal enhancement).
Offsets Quality	Offsets Should Address Permanence. There is a risk that emission

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been sold, retired, or otherwise released from a registry.

Offset System	Definition/Requirements
Initiative (OQI)	reductions generated by certain offset project types can be reversed, and thus are not permanent. Permanence is a type of project risk most often associated with biological and geologic sequestration of emissions. For example, reductions realized through a forest sector project could be reversed through a forest fire. Regulatory regimes should address permanence through policy mechanisms that ensure the minimization of loss in the case of project reversal. Such mechanisms include reserve pools, buffer accounts, and insurance, among others. Permanence is explored in greater detail in section IV, which is titled "GHG Reduction Project Categories and Considerations."
Oregon Offset Standard	Not mentioned
Regional Greenhouse Gas Initiative (RGGI)	Carbon sequestration permanence - The offset project shall meet the following requirements to address permanence of sequestered carbon. (i) The project sponsor shall place the land within the offset project boundary under a legally binding permanent conservation easement, approved by the REGULATORY AGENCY, that requires the land to be maintained in a forested state in perpetuity. (ii) The conservation easement shall include a requirement that the carbon density within the offset project boundary be maintained at long-term levels at or above that achieved as of the end of the CO2 offset crediting period … The conservation easement shall require that the land be managed in accordance with environmentally sustainable forestry practices.
Voluntary Carbon Standard (VCS 2007)	The project proponent shall establish and apply criteria, procedures and/or methodologies to assess the risk of a reversal of a GHG emission reduction or removal enhancement (i.e. permanence of GHG emission reduction or removal enhancement). VCS provides a tool for assessing the risk of non-permanence in agriculture, forestry, and other land use related projects.
WBCSD/WRI GHG Protocol for Project Accounting	Not mentioned

6.2 Implementation Options

Implementing a permanence requirement generally means addressing the risk of reversal. The risk of reversal can be taken on by various entities, including the offset buyer, the project proponent, a registry, or a third party. These options are not exhaustive, but represent some of the leading solutions. The options have differing policy considerations. When the offset buyer assumes the risk of reversal, the buyer's willingness to buy the offsets will be lessened. Where the project proponent assumes the risk, the risk can be managed through risk-mitigating activities such as self monitoring, reporting, inventory verification, or within-project set-asides to replace lost tons. Registries can manage buffer pools made up of non-transactable tons contributed from each of their at-risk projects, used to replace lost tons in the case of a reversal. Risk of reversal may also be taken on by a third party insurance entity. A knowledge and understanding of a range of typical business risk management strategies can inform this element. The transacted tons must be maintained through their permanence period regardless of the duration of the project.

There are several legally binding *ex ante* implementation options. A conservation easement (a legal document binding the land to a project in perpetuity) is an *ex ante* legal instrument used in some land-based projects (RGGI, CAR forest protocols version 2.0). Such a mechanism does not guarantee against reversal of stored carbon due to catastrophic disturbance or other risk factors, but it does commit the land base to the project and can serve to reduce the risk of non-permanence.

Replacing lost carbon through an *ex post facto* obligation is the only real form of permanence and can be achieved through buffer pools, set asides, third party insurance contracts, and/or replacement by other offsets. Offset programs and GHG protocols that require a buffer pool/set-aside or a reversal contingency plan include VCS 2007, CAR, CCX, WCSBD/WRI, and the BC Emission Offset Regulation. Establishing a buffer pool requires removing a percentage of additional CO2 tons (above a baseline) from the project annually and placing them in a reserve, based on the project's risk assessment, or seeking reserve offsets elsewhere. A set-aside is a portion of an individual project which serves as a back-up to transacted project tons.

For offset programs that use buffer pools, the size of a contribution to a buffer pool for a given project is usually established through evaluation of the project's risk of reversal, using a risk assessment procedure. Risk assessment can include these factors:

- Financial risk
- Management risk (illegal removals of forest biomass, conversions, and over-harvesting)
- Social risk (change in climate policy or government stability, social justice issues, employment, environmental perceptions)
- Natural disturbance risk (wildfire, pests, other)

In lieu of risk assessment, a standardized contribution to a buffer pool can be required (e.g., 20% CCX). There are monitoring, verification, and enforcement policy needs that accompany the implementation of a buffer pool.

7 Verifiable

This section discusses verifiable — the final of the four main criteria considered in this paper (i.e. that reductions from offsets be real, additional, permanent, and verifiable). An offset program should seek to minimize uncertainty related to the quantification and assurance of any reductions or removals from offset projects. To establish a high level of trust in the program and address public concerns related to the quality of offset projects, every effort to provide transparency in the offset system should also be pursued. In terms of verification, that means developing clear criteria and definitions for 'verifiable' and its related terms. It also means developing an accreditation process and conflict of interest process that ensure quality in evaluation and prevent potential bias when projects are verified (and possibly validated) by any independent third-parties.

The WCI design document states that an offset must meet the criteria of being verifiable. There are no existing definitions for the term verifiable. For WCI, the idea of verifiable may need to be expressed as a derivative of the definition for verification or of the verification process itself. In the WCI's Final Draft Essential Requirements of Mandatory Reporting document (ER), verification is defined as "the process used to ensure that an operator's emissions data report is free of material misstatement and complies with WCI's reporting procedures and methods for calculating and reporting GHG emissions."

7.1 Policy and operational considerations in defining verifiable

The ER document addresses verification in great detail. For consistency within the entire WCI program it may be prudent to ensure that any definitions relating to verifiable (verification) are consistent with the ER document and with international best practices to the extent possible. If there is some deviation from any existing WCI language it should be reviewed carefully to ensure that changes do not reduce the credibility of the offset program.

Several existing programs have defined verification or established a verification process as noted in the Table 7.0 below.

Table 7.0 Definitions of verifiable from offset systems

Offset System	Definition
British Columbia Emission Offset Regulation	Section 6 (1) A verification body may verify a submitted project report if the verification body is satisfied that (a) the assertions in the project report are materially correct and are a fair and reasonable representation of the project's GHG reductions, and (b) there have been no material changes to how the project was carried out compared to the description of the project in the validated project plan... (2) A verification body may not make a verification under subsection (1) if the verification body considers the project report is subject to material errors, omissions or misrepresentations. [Note: there are several criteria for materiality in subsection (3), including that "the individual or aggregate effect of an error, omission or misrepresentation related to the project report could have resulted in an overestimation of project reductions by more than 5%"]
California Global Warming Solutions Act of 2006 (AB 32)	Operators shall obtain the services of an accredited [third-party] verification body for purposes of verifying emissions data reports submitted under this article. "Verification" means the process used to ensure that an operator's emissions data report is free of material misstatement and complies with ARB's procedures and methods for calculating and reporting GHG emissions. "Verification body" means a firm or AQMD/APCD, accredited by ARB, that is able to render a verification opinion and provide verification services for operators subject to reporting under this article. [From the Mandatory GHG Emission Reporting Regulation] Consistent with ISO 14064-3.
Clean Development Mechanism (CDM)	Verification is the periodic independent review and ex post determination by a designated operational entity of monitored reductions in anthropogenic emissions by sources of greenhouse gases (GHG) that have occurred as a result of a registered CDM project activity during the verification period. There is no prescribed length of the verification period. It shall, however, not be longer than the crediting period.
Gold Standard	Required – not defined.
ISO 14064-3	Verification - systematic, independent and documented process for the evaluation of a greenhouse gas assertion against agreed verification criteria. (ISO 14064-3)

Offset System	Definition
Offsets Quality Initiative (OQI)	Recommended – All GHG reductions should be verified by an independent, qualified, third-party verifier according to approved methodologies and regulations. Verifiers should be entities whose compensation is not in any way dependent on the outcomes of their decisions. Regulatory regimes should have an approved list of offset project verifiers and should have procedures in place to ensure that conflicts of interest are avoided. Ex post monitoring and verification reports should be used as the basis for issuing offsets.
Oregon Offset Standard	Not required
Regional Greenhouse Gas Initiative (RGGI)	Verification - The third-party verification by an independent verifier that certain parts of a CO2 emissions offset project consistency application and/or measurement, monitoring or verification report conforms to the requirements of this Subpart.
Voluntary Carbon Standard (VCS 2007)	Required – following ISO 14064-3:2006 and 14065:2007 process. Verification process: The validator or verifier select samples of data and information to be validated or verified to provide reasonable assurance and to meet the materiality requirements of the specific project
WBCSD/WRI GHG Protocol for Project Accounting	Available data used should be… verifiable. All possible sources for obtaining the necessary information should be documented. Verification – beyond scope of project protocol not addressed

While the WCI will need to clearly define the term verifiable, the practical challenge that exists is to develop meaningful language that can apply broadly to all possible project types but still allows some flexibility to tweak requirements based on individual project characteristics. For some project types a verification schedule with annual site visits may be appropriate. For others a less frequent schedule for site visits may still provide sufficient assurance that reductions are occuring. A distinction may be made between schedules for site visits versus the schedule for verification statements, where having annual reporting and crediting of reductions would not necessarily imply annual site visits for verification. The role of an auditing function, as part of the verification process, may also need to be elaborated and could add to system credibility (as when linked to an enforcement/penalty structure).

Having a verification requirement will require the use of 'verifiers'. The WCI has indicated in the Design Recommendations and Essential Requirements documents that it will pursue third-party verification for annual GHG emission data reports for facilities subject to mandatory reporting. The offset system may incorporate that accreditation process for verifiers of offset projects. This may involve sector or protocol specific training for verifiers accredited under the reporting program. The American National Standards Institute is currently working with representatives from VCS 2007, CCX, British Columbia, and CAR to develop accreditation scopes for their program project protocols. It may be efficient to look at that accreditation scheme when developing scopes for WCI offset verifier accreditation requirements and build on it as needed. This work could be done concurrently with the efforts of the Reporting Committee in developing criteria for its accreditation requirements.

The Offset Committee may want to identify tasks related to administering a verification program that could be delegated to a regional body to ensure consistency in decision making and thus greater efficiency in the overall program. Areas in the offset system that would benefit greatly from consistency in decision making include dispute resolution, conflict of interest determinations and any other areas where decisions become subjective in nature.

7.2 Supporting principles and technical considerations

An established verification process for offsets usually introduces additional terms of art. Some of these verification-related terms may be specific to offsets (e.g., validation). Other verification-related terms may not be specific to offsets (e.g., material misstatement and assurance level). These terms should be consistent with the ER document and international best practices, where possible. Not only would this provide consistency within the WCI program as a whole but would help ensure that the same level of rigor and standards are held for both capped and non-capped sources.

7.2.1 Validation

In basic terms, project validation is the assessment of a project document and its conformity with project protocol as well as assessing the likelihood that implementation of the planned GHG project will result in the GHG emission reductions/removals as stated by the responsible party. For example, CDM and British Columbia have a validation step in their offset systems; but CAR does not require a preliminary validation step, instead requiring verifiers to affirm the project's eligibility during initial verification.

Validation can provide some upfront confidence to potential investors that a proposed project will provide offsets once implemented. It can also provide upfront information to a project developer about any potential issues related to the implementation of a project that could impact the project's ability to provide offsets in a WCI offset system. Validation can help ensure an initial quality standard is met for new projects and help provide information to the public. Potential downsides to validation may be that it imposes additional program costs, has the potential to slow down project development, and may be perceived as an unnecessary step if approved protocols exist and/or projects are subject to rigorous verification their first year.

If required in a WCI offset system, WCI could require the use of third-party validators or implement validation through government agency review. Capacity to conduct validation also becomes a potential issue; if there are insufficient validation bodies or insufficient staff resources to conduct agency reviews, then there is the potential to slow down project development. Validation delays due to high demand may be less likely to occur for third-party validation than for agency review because private sector firms may be able to respond more quickly to market demand in terms of staff and resources.

A hybrid option for validation is currently being employed in another regulatory program. The NSW GGAS utilizes a hybrid approach that includes reviews by both regulators and independent third party validators. In this program, the regulator identifies key areas of potential weakness that must be validated by an accredited third party as opposed to full validation of all documents and conformity requirements.

WCI could also design a system without a validation step. With clearly defined offset protocols such as the performance based protocols in CAR, a validation step could be folded into the initial project verification. In this case, activities that would have been conducted during a project validation, such as review of calculation methodologies and evaluation of conformance with a protocol, would generally still be conducted during the first year of verification. This could also remove an additional cost in the implementation of a reduction protocol and make for a more efficient, less resource intensive program to administer. Investor uncertainty becomes more of an issue for projects developed without validation because they must fully finance and undertake an offset project before it is formally reviewed during verification. As a result, under CAR, project developers may still independently opt for project review by technical assistance providers in the absence of a validation step if they are concerned about ensuring conformance with offset project requirements. Investors are paying for tonnes and need to satisfy themselves that the counts are correct and the quality meets their needs. A validation step would likely be more necessary for an offset program structured like the CDM that allows new methodologies to be proposed by project developers. Allowing carbon financing for new methodologies acts as an incentive for early implementation and commercialization of emerging technologies and practices.

7.2.2 Enforcement

The WCI partners will need to ensure the WCI offsets system is enforceable, which involves regulatory oversight by partner jurisdictions. The WCI stated in its design recommendations that "each WCI Partner jurisdiction will retain and/or enhance its regulatory and enforcement authority and responsibilities to enforce compliance with the cap-and-trade program within its own jurisdiction" and similarly that, "offset projects must also be enforceable by the individual WCI partner jurisdiction that is issuing the credit and the credit must be verifiable by the individual WCI Partner jurisdiction that is accepting it." As a component of the broader cap-and-trade program the offset system provisions must be enforced to ensure that participating parties, project developers and verifiers, follow the rules and do not harm the integrity of the offsets system. Enforcement implies that sufficient enforcement mechanisms are contained in offset provisions and protocols to allow action to be taken against a party who violates the offset rules or protocol requirements. The World Resources Institute also connects the concept of enforceability with the necessity for transparent offset ownership and tracking mechanisms, as well as clarity in identifying who is responsible for project performance, project verification, and potential liability in the case of reversals.[23]

WCI Partners will need to have the staff and capacity in place to enforce various provisions of the offset program. WCI Partner jurisdictions will also need to ensure that enforcement and oversight is consistent among jurisdictions in order to create a "level playing field" where all participants are subject to the same rules regardless of location. One option for this would be to have a regional body address select enforcement issues. However, as enforcement issues are closely related to jurisdictional sovereignty, the WCI Design Document recommended that enforcement not be associated with a regional body. For offset projects that take place outside of a WCI Partner jurisdiction, there will need to be clarity regarding who has oversight and enforcement authority. It may be necessary to have MOUs with other states and

[23] Broekhoff, D. and K. Zyla. 2008. Outside the Cap: Opportunities and Limitations of Greenhouse Gas Offsets. World Resources Institute. Policy Series. December 2008.

provinces to address this.

Enforcement actions may range in scope from revoking accreditation of verification bodies who fail to competently perform their duties, to issuing fines or other penalties to project developers that falsify or misrepresent information. Enforcement may also involve requiring compensation for any offsets that an enforcement audit demonstrates not to have been real. Depending on program design, enforcement may or may not be related to compensation for losses in emission reductions or removals due to reversals. Reversal and permanence issues can also be addressed through mechanisms other than enforcement as discussed in Section 5.

7.2.3 Material

A term of art specific to verification is 'materiality.' This term relates to a threshold where differences above that number in reported emissions/reductions would make a verifier suspect the reliability of an entire project. The WCI ER document has a materiality threshold of +-5%, consistent with EU ETS and The Climate Registry. The WCI offset system could consider a lower materiality threshold to be conservative and could consider applying bound. That would entail not allowing any errors individually or cumulatively that overestimate the emission reductions but accepting errors that underestimate reductions within a prescribed materiality threshold.

The term 'material misstatement' describes any errors that cumulatively exceed the materiality threshold. For the ER document any errors in the emissions data report that could over or underestimate the facility emissions by 5% are considered material misstatements and require correction. In the context of the offset system, the practical criteria of this term would change if the materiality threshold were changed.

The WCI ER document also sets accuracy requirements for metering equipment that provide data for emissions calculations. For the purposes of verification of annual emissions data reports, there is no requirement to assess the propagation of errors through a calculation. As such, any inherent uncertainty within the allowed accuracy level of the metering equipment is an accepted uncertainty. The offset program could consider adopting a similar approach. This approach is already adopted by some existing offset programs.

When a verifier renders their final decision, they provide a level of assurance. There are two levels of assurance provided in the ISO documentation. The WCI reporting ER document only allows for reasonable assurance, which is a more stringent level than limited assurance. The WCI offset system may consider only allowing reasonable assurance to provide the most certainty for any WCI offsets and to remain consistent with other parts of the WCI program.

7.3 Implementation Options

The WCI reporting ER document will require verification to be conducted by accredited, independent third-party verification bodies. A consistent option with the reporting requirements and with existing offset systems is to require third-party verification for the WCI offset system. All accreditation work used to provide qualified professionals for conducting verification activities under the Reporting program may provide a basis for developing accreditation requirements for WCI offset verifiers or verification bodies. The mechanisms that the reporting committee will rely on for the oversight of that verification program (including oversight of verifiers) could be expanded to include offset verifiers.

The WCI offset system could rely on Partner jurisdictions to verify any emissions reductions projects within their boundaries. This would contrast with the approach of third-party verification for facility emissions data reporting. There may be significant cost or capacity issues for all jurisdictions to 'ramp up' to verify offset projects in a manner consistent with existing offset systems or international best practices. In this case, the cost for verification of offsets may be borne by regulatory agencies and the public at large, as opposed to the project developer who can recoup costs for verification from the market program. However, depending on how the program is structured, there may still be mechanisms for jurisdictions to recover costs of running verification programs. In terms of capacity, it may require additional staff within each jurisdiction to oversee verification. WCI will have to weigh the tradeoffs between running verification internally versus harmonizing verification among all jurisdictions to reduce administrative redundancies. This approach would also need to clarify who would be responsible for verification of offset projects that occur in North America outside of a partner jurisdiction.

There is also the option of self-certification by a project developer. In this approach, oversight would likely be coordinated by partner jurisdictions who would conduct periodic reviews or random audits of offset projects. Penalties for audit failure would need to be clarified and provide proper incentives for compliance. This would likely be the least costly approach to administer, but would not be without its potential criticisms and tradeoffs. A self-certification approach would be inconsistent with the requirements of reporters subject to the cap and with international best practice. Because not every project would be subject to a detailed review, the approach may be perceived to lack transparency and consequently may not provide the desired level of confidence needed for the offsets market to function properly.

8 Other considerations

The previous sections of this document have described the key offsets criteria noted in the Design Document. There are other factors worth considering that generally aside from these criteria. This section discusses those other considerations.

8.1 Transparency

An open and transparent offsets system builds confidence in the long-term success of cap-and-trade programs. Ensuring the credibility of an offset system and reducing market uncertainty entails that offset projects be developed and implemented in an open manner. Transparency may include public access to information and public involvement in the project review process. The rules of an offset system may facilitate having project developers gather feedback from stakeholders via public comments and meetings on specific offset projects and document any outreach efforts and responses to feedback from the public. Clear regulations play a key role in building a quality offsets system while also reducing uncertainty for investors and project developers. Transparent offset systems typically provide access to offset project assessments, except in those cases where important confidentiality issues exist.

The implementation of transparency considerations impacts the environmental integrity and administration of an offset system. As a key principle that interacts with offsets criteria, limited implementation of transparency considerations may limit the ability of stakeholders to assess the overall environmental integrity of the offset system and the credibility of the reductions from it.

Other offset programs strive for transparency to create certainty for potential project developers and to build public confidence in the environmental integrity of the offsets. The Canadian Domestic Offset system and ISO guidelines define transparency as disclosing sufficient and appropriate GHG-related information to allow intended users to make decisions with reasonable confidence. U.S. EPA Climate Leaders' guidance primarily addresses public confidence in offsets, stating that "offset procurement best practices include a comprehensive and transparent registry system; partners should transparently and publicly report on their use of offsets when announcing the achievement of their reduction goal."

To achieve transparency, programs have allowed significant stakeholder involvement during the development of project protocols and have pledged to maintain clear offset guidelines to allow users to make decisions with reasonable confidence. The development of the Regional Greenhouse Gas Initiative model rule, which includes an offset program, involved several years of stakeholder involvement and input. Similarly, CAR's project protocol development process is designed to involve a variety of stakeholders and allow public comment on draft protocols. In addition, some programs have made information about individual offset projects accessible to the public. New South Wales allows public access to a searchable registry of offset projects.

8.2 Co-Benefits of Offsets

Besides the direct benefits that an offset project can provide, the project may also lead to a number of other benefits beyond the greenhouse gas reductions or removals from the project. These other benefits ("co-benefits") may include air quality improvements, economic development activity, and other types of benefits. Co-benefits can also help to justify projects and help projects proceed. The WCI recognized the importance of co-benefits in its design principles, which call for maximizing total benefits from the design. When the WCI identified the project types it would initially look at whether projects were chosen primarily for their greenhouse gas reduction potential; and then at their co-benefits.

Although co-benefits have been an important motivating force in the development of offset systems to date, the degree to which a project may or may not offer co-benefits has not been part of the fundamental design criteria of offset systems. Those exceptions are:

- In the Clean Development Mechanism sustainable development benefits are a pre-requisite for project approval, as well as alignment with host country sustainable development objectives.

- All Gold Standard projects must demonstrate clear sustainable development co-benefits, which include environmental, social, and economic benefits. Project developers must use the sustainability matrix provided by the Gold Standard to develop and present their sustainability criteria. Both project developers and stakeholders are consulted to score projects against the sustainability criteria and identify potential positive and negative project impacts.

8.3 *Assessment of Environmental or Social Impacts*

Offset projects are intended to reduce or remove greenhouse gas emissions. However, any project activity has the potential to impact the environment or social environment in which the project is located. Transparency is enhanced with informed stakeholder knowledge about the positive and negative impacts of an offset project on environmental, social, and sustainability factors. Such information can range from qualitative to quantitative description/analysis and is not normally envisaged to cross into environmental assessment territory in scope or scale unless required by law.

The degree to which assessment of these impacts is required varies from one offset system to another. A summary of these requirements follows:

Table 8.0 Impact assessment requirements in offset systems

Offset System	Requirements
British Columbia Emission Offset Regulation	Project plan must contain a description of any analysis undertaken to determine the environmental impact of carrying out the project
California Global Warming Solutions Act of 2006 (AB 32)	No specific requirements related to offset projects.
Clean Development Mechanism (CDM)	Projet participants must submit documentation of the environmental impacts of the project activity, including transboundary impacts. If impacts are considered to be significant an environmental impact assessment is required following procedures set by the host Party.
Gold Standard	In addition to meeting all local environmental regulations, all small and large scale projects must carry out an Environmental Impact Assessment (EIA).
ISO 14064-2	If law requires, a summary environmental impact assessment.
Offsets Quality Initiative (OQI)	Offsets Should Do No Net Harm. Offset projects should not cause or contribute to adverse effects on human health or the environment, but should instead seek to provide health and environmental co-benefits whenever possible.
Oregon Offset Standard	Not required
Regional Greenhouse Gas Initiative (RGGI)	Afforestation projects: must be managed in accordance with widely accepted environmentally sustainable forestry practices and designed to promote the restoration of native forests by using mainly native species and avoiding the introduction of invasive non-native species. If commercial timber harvest activities are to occur, certification must be obtained, prior to any harvest activities at the site, through the Forest Stewardship Council (FSC), Sustainable Forestry Institute (SFI), American Tree Farm System (ATFS), or such other similar organizations as may be approved by the REGULATORY AGENCY.
Voluntary Carbon Standard (VCS 2007)	All applicable environmental regulations must be met.
WBCSD/WRI GHG Protocol for Project Accounting	Not addressed

9 Conclusion

This white paper provides background information for defining a WCI GHG offset and its eligibility criteria: real, permanent, additional, and verifiable. Principles and technical considerations important to establishing offsets criteria are also examined. The WCI Partners invite stakeholders to comment on the options presented in this white paper or alternative options not included here. There are two avenues for stakeholder comments. Written comments will be received via the WCI website until August 21, 2009. Stakeholders may also provide comment during a conference call on July 30, 2009 from 9:30 to 10:30 a.m. Pacific time, during which this white paper will be presented and discussed.

As noted previously in the introduction, the Offsets Committee poses these questions for stakeholders to address in their comments:

- What has been your experience with the offset system examples cited in this paper? What have been the advantages and disadvantages to their approaches?
- Are the appropriate criteria listed?
- Does the paper include the appropriate options for each criteria?
- Are the implications of the options appropriately covered?

As shown in Table 9.0, this white paper offers the first deliverables for Task 1 from the Offsets Committee. Following an opportunity for stakeholder comment and the Offsets Committee's review of those comment, the next deliverable for subtasks 1.1 and 1.2 will be a draft recommendations paper. The Committee plans to release that document in September 2009. While stakeholders comment on this white paper, the Offsets Committee will draft its other Task 1 white paper, laying out options for subtasks 1.3, 1.4, and 1.5.

Table 9.0 Offsets committee task 1 workplan

Task 1 Subtasks	Subtask Description	Deliverables (Dates)
1.1	Define a WCI GHG offset	This white paper – 2009 Q2 Draft recommendations – 2009 Q3
1.2	Develop detailed eligibility criteria for GHG offset projects for compliance purposes under the cap-and-trade system	This white paper – 2009 Q2 Draft recommendations – 2009 Q3
1.3	Develop detailed requirements for the registration, validation, monitoring, quantification, reporting, verification, certification, and issuance of offsets	Next white paper – 2009 Q3 Draft recommendations – 2009 Q4
1.4	Recommend aspects of regulation and enforcement related to offsets that should be included in the cap-and-trade essential elements	Next white paper – 2009 Q3 Draft recommendations – 2009 Q4
1.5	Recommend functions of the regional administrative body and tracking system related to the offset system	Next white paper – 2009 Q3 Draft recommendations – 2009 Q4
1.6	Final recommendation of essential elements for the offsets system	Final recommendations - 2009 Q4

This white paper will support the Offsets Committee draft recommendations on how to define a WCI GHG offset and the detailed eligibility criteria for GHG offset projects for compliance purposes. The development of this white paper and the future development of draft recommendations under Task 1 of the Offsets Committee will continue to be done in coordination with the Task 2 (offsets and allowances from systems other than the WCI) and Task 3 (offset protocols) as presented in the WCI workplan.

July 24, 2009 Offsets Committee White Paper Task 1, Offset System Essential Elements, Offset Definition (Task 1.1), and Eligibility Criteria (Task 1.2) comments

List of Commenters

3Degrees

Alcoa, Inc.

American Carbon Registry

Arizona Public Service Company

BC Agriculture Council

BC Forestry Climate Change Working Group

Canadian Wind Energy Association

City of Seattle

C-Lock Technology, Inc

E.J. Bentz & Associates

Independent Energy Producers Association

Industry Provincial Offset Group

International Rivers

Morgan, Scott

Pacific Carbon Trust

Pacific Gas and Electric Company

PacifiCorp

Public Utility District No. 1 of Chelan County

Puget Sound Energy

Quebec Business Council for the Environment

RÉSEAU environnement

Seventh Generation Advisors

Society of Energy Professionals, IFPTE Local 160

Southern California Edison

TerraPass

The Climate Trust

The Delphi Group

Utah Business Climate Change Coalition

Washington Forest Protection Association

Waste Management, Inc.

WEST Associates

Western Climate Advocates Network

Western States Petroleum Association

Western States Petroleum Association

Weyerhaeuser

Zini, Gian

GHG Offset Protocols by Project Type and Program

Note: The WCI Offsets Committee has identified the following existing offset protocols as potentially suitable for use in the WCI cap-and-trade program, and will evaluate these proposals against WCI draft offset criteria.

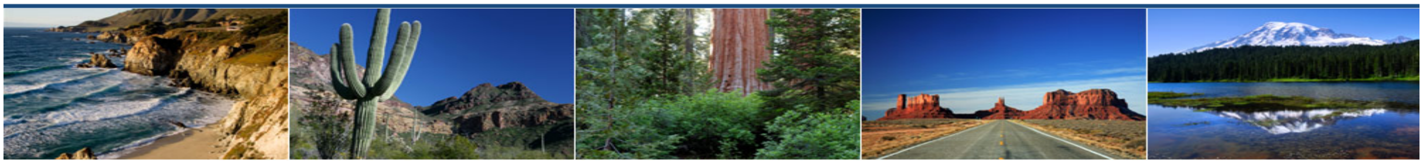
● = Approved protocol or methodology
◉ = protocol or methodology under development
○ = protocol or methodology considered for future

	Alberta Offset System	American Carbon Registry (ACR)	Chicago Climate Exchange (CCX)	Clean Development Mechanism (CDM)[i]	Climate Action Reserve (CAR)	GE Energy Financial Services & AES (GE-AES)	New South Wales (NSW)	Regional Greenhouse Gas Initiative (RGGI)	U.S. DOE 1605 (b)	U.S. EPA Climate Leaders	Voluntary Carbon Standard (VCS)[ii]
Agriculture											
Soil sequestration	●[iii]		●[iv]		○[v]				●[vi]		●[vii]
Manure management (including anaerobic digestion)	●[viii]	◉[ix]	●[x]	●[xi]	●[xii]	●[xiii]		●[xiv]		●[xv]	
Rangeland management	○[xvi]	○[ix]	●[iv]		○[v]				●[vi]		●[vii]
Forestry											
Afforestation / Reforestation	◉[xvii]	●[xviii]	●[xix]	●[xx]	●[xxi]	○[xxii]	●[xxiii]	●[xiv]	●[vi]	●[xxiv]	●[vii]
Forest management		●[xviii]	●[xix]		●[xxi]				●[vi]	◉[xxv]	●[vii]
Forest pres. /conservation		●[xviii]	●[xix]		●[xxi]	○[xxii]			●[vi]		●[vii]
Forest products		●[xxvi]	●[xix]		●[xxvi]				●[vi]		●[xxvi]
Urban forestry	◉[xvii]		●[xix]		●[xxvii]				●[vi]		
Waste Management											
Landfill gas	●[xxviii]	◉[ix]	●[x]	●[xxix]	●[xxx]	●[xxxi]		●[xiv]		●[xxxii]	
Waste and wastewater treatment	●[xxxiii]			●[xxxiv]		●[xxxv]					

Note: in some cases, a dot in this table represents more than one protocol. In other cases, a protocol addresses more than one project type or dot.

[i] We have not attempted to characterize methodologies under consideration (but not yet approved) by CDM, due to the high volume of such methodologies.
[ii] VCS approves the use of both CDM and CAR methodologies. In addition, VCS has developed specific guidance for agriculture, forestry, and other land use projects as noted.
[iii] Alberta Environment, 2009. Quantification Protocol for Tillage System Management: Version 1.3. February 2009.
[iv] CCX's Exchange Soil Offsets include methodologies for conservation tillage, grassland planting, and rangeland management, all documented in Chapter 9 of the CCX rulebook.
[v] Climate Action Reserve is currently addressing some key methodological questions pertaining to soil carbon within its update to the forest protocol. Pending this process, it expects to further assess the potential for soil/rangeland project types by fall, 2009.
[vi] All U.S. DOE methodologies are documented in its *Technical Guidelines: Voluntary Reporting of Greenhouse Gases: 1605(b) Program* (US DOE, 2007).
[vii] Standards for "Agricultural Land Management" (soil sequestration through cropland management, grassland management, or cropland or grassland conversions), "Improved Forest Management", Afforestation/Reforestation, and "Reduced Emissions from Deforestation and Degradation" are included in VCS's 2008 *Guidance for Agriculture, Forestry, and Other Land Use Projects.*
[viii] Alberta Environment, 2007. *The Anaerobic Decomposition Of Agricultural Materials: Version 1.* September 2007.
[ix] ACR standards for Livestock Waste Management and Landfill Methane are in peer review and forthcoming public comment. A rangeland standard is in early stage development.
[x] CCX's Exchange Methane Offsets include methodologies for landfill gas collection, agricultural (i.e., manure) methane destruction, and capture of coal mine methane.
[xi] Among other CDM methodologies, AMS-III.D: "Methane recovery in animal manure management systems", addresses manure.
[xii] Manure management is addressed in CAR's Livestock Protocol: Version 2.1 from August 20, 2008. A minor revision is planned for summer 2009.
[xiii] GE-AES's *Methodology for Agricultural Livestock Manure Management System Methane Capture and Destruction Projects* addresses manure management.
[xiv] The RGGI Model Rule (December 2008) lists standards for landfill methane, afforestation, and avoided methane emissions from agricultural manure management
[xv] Climate Leaders Greenhouse Gas Inventory Protocol Offset Project Methodology For Managing Manure with Biogas Recovery Systems. Version 1.3. August 2008.
[xvi] Alberta is considering development of a "Pasture Management" protocol (http://www.carbonoffsetsolutions.ca/offsetprotocols/protocolsreview.html)
[xvii] As of early July, 2009, the Alberta Offset System afforestation protocol was retracted for revisions. It includes language for converting "urban land to plantations".
[xviii] Version 1 of ACR's *Forest Carbon Project Standard* (March 2009) addresses afforestation/reforestation, forest management, and
[xix] CCX's Exchange Forestry Offsets can be issued for afforestation/reforestation, forest products ("long lived wood products"), forest management, urban forestry ("widely spaced tree plantings") and "Combined Forestation and Forest Conservation Projects", which requires forest conservation activities to be on contiguous sites to forestation.
[xx] Among other CDM methodologies, AR-ACM0001: "Afforestation and reforestation of degraded land (Version 3)" addresses afforestation/deforestation.
[xxi] Afforestation/reforestation, forest management, and forest conservation are included in the Forest project protocol v. 2.1 (September, 2007); Version 3.0 is expected to be adopted in July 2009.
[xxii] Afforestation/reforestation and "land and habitat conservation" project types are being considered for future methodology development.
[xxiii] NSW's *Greenhouse Gas Benchmark Rule (Carbon Sequestration) No. 5 of 2003* addresses afforestation / reforestation.
[xxiv] Climate Leaders Greenhouse Gas Inventory Protocol Offset Project Methodology for Project Type: Reforestation/Afforestation. Version 1.3. August 2008.
[xxv] EPA Climate Leaders fact sheet, http://www.epa.gov/stateply/documents/offsets_factsheet.pdf, and recent presentations by EPA staff.
[xxvi] Forest products are not a unique project type in ACR, CAR, or VCS but they are included as a carbon pool within the forest management project type.
[xxvii] CAR's Urban Forestry protocol version 1.0 was adopted August 12, 2008. A minor revision is planned for summer 2009.
[xxviii] Alberta Environment, 2007. *Quantification Protocol for Landfill Gas Capture And Combustion:* Version 1. September 2007.
[xxix] Among other CDM methodologies, ACM0001: "Consolidated baseline and monitoring methodology for landfill gas project activities" address landfill gas.
[xxx] CAR's U.S. landfill protocol version 2.0 was issued November 17, 2008. A draft version 2.1 is out for public comment until July 10, 2009.
[xxxi] GE-AES's *Methodology for Landfill Gas Methane Capture and Destruction Projects* addresses landfill gas.
[xxxii] Climate Leaders Greenhouse Gas Inventory Protocol Offset Project Methodology For Project Type: Landfill Methane Collection and Combustion. Version 1.3. August 2008
[xxxiii] Alberta Environment, 2009. *Quantification Protocol for Anaerobic Treatment Of Wastewater Projects: Version 1.0.* March 2009. Alberta also has a *Quantification Protocol for Aerobic Composting Projects: Version 1.1.* December 2008.
[xxxiv] Among other CDM methodologies, AMS-III.H: "Methane Recovery in Wastewater Treatment", addresses wastewater. CDM also has methodologies to address organic municipal solid waste, such as AM0025: "Avoided emissions from organic waste through alternative waste treatment processes", address solid waste.
[xxxv] GE-AES's *Methodology for Waste Water Treatment Plant Capture and Destruction Projects* addresses wastewater treatment.

Western Climate Initiative



STAKEHOLDER REVIEW DRAFT

WCI Regional Emissions Database Options White Paper

August 6, 2009

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1 Purpose and Background

The purpose of the Options White Paper is to present the fundamental design choices for the WCI Regional Emissions Database (RED). The RED will be a system of database components developed by The Climate Registry (The Registry) for collecting, transferring, storing and analyzing greenhouse gas (GHG) emissions data from facilities and entities in WCI states and provinces. This system is described in greater detail in section 1.3 below.

This White Paper will explore numerous options for managing data and designing database functions in order to provide guidance to The Registry. As noted in section 2.3, a key function of the RED will be to meet WCI partner jurisdiction data collection, recovery and analysis needs while at the same time minimizing the burden of satisfying WCI partner jurisdictions' collective and individual GHG reporting requirements as well as the federal GHG reporting requirements.

After engaging in internal review and discussions of, and receiving stakeholder comments on, the White Paper, WCI will provide The Registry with guidance and direction on how it should proceed in defining detailed specifications for the RED. The options that are suggested throughout the White Paper are based on realistic expectations for the cost and schedule of the project.

Chapter 4 provides a high level summary of this document.

This chapter will identify the review process, the work plan that will support the requirements analysis, and provide an overview of the RED Project.

1.1 Regional Emissions Database Review Process

A number of different groups will be involved in the development of the RED:

- RED Workgroup – A subgroup of the Reporting Committee has been formed to focus on this project. It has broad participation from Canadian Provinces and US States so that many perspectives will be represented. The role of the workgroup is to guide the content and requirements that are included, focus on specific issues, review early drafts of documentation, and provide detailed feedback that informs all recommendations and decisions.
- Reporting Committee – Since this project represents Task 2 of the Reporting Committee's objectives as contained in "WCI's Work Plan for 2009-10," all deliverables will be presented to the full committee for interim review and approval before recommendations are presented to Partners. While feedback from the Reporting

Committee is essential, discussions are expected to focus on high level issues. After review by the full committee deliverables will be submitted for Partner review.

- Markets Committee – The RED will have interfaces to the Tracking System developed under Task 4 of the WCI Work Plan for the Markets Committee. Some deliverables will be presented to the Reporting Committee to ensure that the two tasks are aligned and that the Markets Committee has an opportunity to comment on recommendations that may impact the Tracking System. In addition to this, The Registry will participate in Markets Committee calls as an advisor to make the committee aware of potential issues or areas of overlap between the two tasks.
- Partners – Since this initiative will have a broad impact on the implementation of WCI's cap-and-trade program, all deliverables will be made available to Partners to review recommendations and make final decisions.
- Public Stakeholders – Following Partner review, a final version of this Options White Paper will be presented to public stakeholders for comment.

1.2 Regional Emissions Database Work Plan

The RED work plan has been broken into two major phases. Phase 1 will include development and review of the Options White Paper in addition to the preparation of the final requirements specification. Phase 2 will include the system design, implementation and rollout of the completed application.

A high level work plan for Phase 1 is included below to identify major milestones and illustrate how different groups will be involved in the review process. Phase 1 will need to be completed before the work plan for Phase 2 can be developed.

Figure 1 RED Phase 1 Work Plan

WCI Regional Emissions Database - Phase I Review Process	
Project Task	**Group Involved**
Reporting Options White Paper	
Prepare outline of issues for the options White Paper	The Registry
Review options White Paper outline	RED Workgroup
Prepare draft of White Paper	The Registry
Review draft White Paper	RED Workgroup
Revisions to the White Paper	The Registry
WCI Reporting Committee call to review Final Draft	Reporting Committee
Review Options White Paper with the Markets Task 4 Workgroup	Markets Task 4 Workgroup
Review Options White Paper with the Markets Task 2 Workgroup	Markets Task 2 Workgroup
Review Options White Paper with the Electricity Committee	Electricity Committee

Review by Partners prior to release for public comment	WCI Partners
Revision following Partner review	The Registry, RED Workgroup
Review by Public Stakeholders	Public Stakeholders
Call for Public Stakeholders	Public Stakeholders
Public stakeholders submit written comments to the Reporting Committee	Public Stakeholders
Revise Options White Paper based on public stakeholder comments	The Registry
Requirements Analysis:	
Draft preliminary requirements for the major components of RED	The Registry
Review preliminary requirements	RED Workgroup
Review integration of RED with Tracking System	Markets Committee
Discuss budget options	Reporting Committee Chair, Partners
Incorporate revisions and prepare RED requirements document	The Registry
Review draft requirements specification	RED Workgroup
Incorporate revisions from RED Workgroup	The Registry
Review RED requirements document with the Reporting Committee	Reporting Committee
Revisions, Executive Summary and Recommendations for WCI Partners	The Registry
WCI Partner call to review Executive Summary and Recommendations	WCI Partners
Final revisions to all requirements and recommendations	The Registry
WCI Partner Call to adopt RED requirements recommendations	WCI Partners
Draft Recommended Plan for Phase II	The Registry

1.3 Regional Emissions Database Overview

Based on the requirements outlined under Task 2 of the WCI's 2009 Work Plan for the Reporting Committee, The Registry will develop the RED infrastructure to support the consolidation of GHG emissions from each of the WCI Partner jurisdictions and provide the required data transfer, analysis and user interface tools to support the program.

The Scope of Work for developing this infrastructure can be divided into five major components described below (*See Figure 2, WCI Regional* Emissions *Database Components)*. The term Regional Emissions Database (RED) refers to all five of these components, while the term WCI Central Database refers only to component number 2.

1. **WCI Common Framework Program Module**: Since a number of WCI Partner jurisdictions will use The Registry's Common Framework to collect GHG emissions data from regulated parties in their jurisdiction, The Registry will develop a WCI Program Module that supports the reporting requirements of the WCI Partner jurisdictions. This module will then be used as the basis for WCI states and provinces that adopt the Common Framework to collect and manage emissions data from regulated parties. The module will provide a persistent database for each regulated party's emissions data that exists independently of the WCI Central Database described below. The WCI Common Framework will also provide reporting capabilities for Staff, Regulated parties, and the Public.

2. **WCI Central Database**: The Registry will design and implement the WCI Central Database, which will be used to consolidate all WCI Partners' emissions data. This will serve as a data warehouse that supports the data analysis required for the cap-and-trade program. It will also allow each of the partner jurisdictions to observe measurements over time to track changing trends. The WCI Central Database will also provide source data for reports that are used by key WCI participants, such as the Partners, Staff, Regulated parties, and the Public.

3. **Data Collection from WCI Partner jurisdictions**: Consolidation of WCI emissions data will require the transfer of data from Partner jurisdictions to the WCI Central Database. This data transfer will happen either via The Registry's Common Framework or through data exchanges with programs that collect GHG emissions data using Partner-specific databases. The latter will be based on The Registry's GHG Secure Data Transfer mechanism to the voluntary registry, but will be adapted to meet a WCI Partner jurisdiction's specific needs.

4. **Analysis, Report Preparation and User Interface Tools for WCI Participants**: Each WCI participant will need access to the WCI Central Database for different types of information. Additional requirements planning is necessary to define these tools, but some of the general stakeholder requirements follow:
   a. The WCI Regional Administrative Body will need to manage WCI emissions data and provide information to the cap-and-trade program.
   b. WCI Partner jurisdictions will need to access information at the state or provincial level.
   c. Regulated parties will need to understand their emission footprint across the entire WCI region.
   d. Public stakeholders will need access to data that has not been designated as confidential business information.

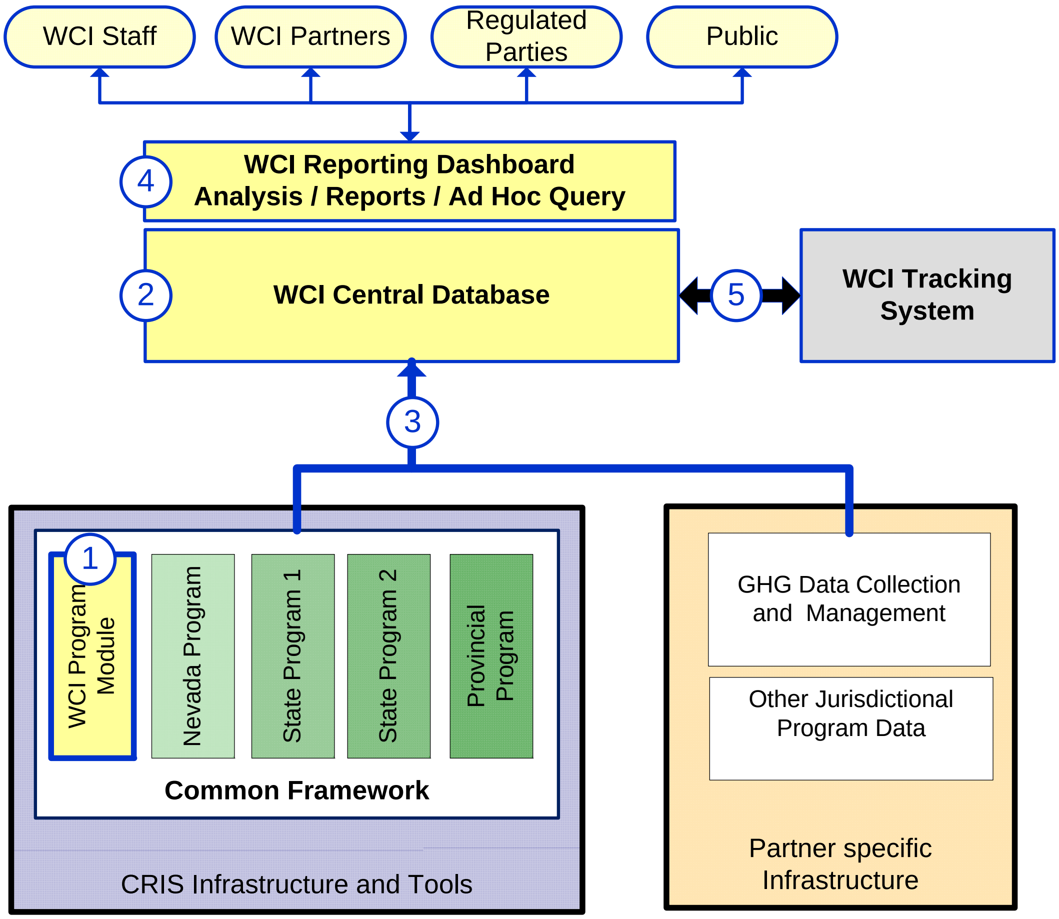
5. **Integration with the Tracking System:** The WCI Central Database will need to be integrated with the WCI Tracking System to share data, identify the relationship of regulated parties with organizations in the tracking system and to ensure compliance. Since the Tracking System will be developed later than the RED, this component will be covered at a high level only.

The diagram below shows an initial view of the components of the complete WCI RED infrastructure. Each of the components in yellow shows additions to The Registry's existing tools that The Registry will create under the Reporting Committee's Task 2 work plan. The numbers in the diagram refer to the infrastructure components outlined above.

The diagram is a conceptual view, and does not make any assumptions about the final technical architecture of the database or the granularity of the data that will be transferred from the program modules or Partner-specific databases to the RED. Stakeholders are invited to comment on the design choices reflected in the diagram.

NOTE: The WCI Tracking System component is shown in the diagram as a conceptual illustration to explain the basic relationship and communications that will be required between it and the WCI RED in order to successfully support WCI's cap-and-trade program. Although the development of this component is outside the scope of work for this Task, The Registry will be asked to work with the Markets Committee to ensure that the development of the tracking system database is compatible with the WCI RED.

Figure 2. WCI Regional Emissions Database Components



2 Assumptions and Principles

As the stakeholders evaluate the options presented in this White Paper, it is important to understand the assumptions that have been made about the RED application that will be developed and the principles that should guide the evaluation. This chapter provides an overview of each, as well as a discussion of the key principle of alignment with federal GHG reporting programs.

2.1 Assumptions

The issues that will be discussed in the Options White Paper are based on the following assumptions that are fundamental to the RED project:

- Development of the WCI RED will be based on The Climate Registry's Common Framework for mandatory reporting.
- WCI Partner jurisdictions will be responsible for collecting WCI GHG emissions data from regulated parties in their individual jurisdictions. Jurisdictions may collect WCI data via their own jurisdictional database or through a Common Framework module.
- All WCI Partner jurisdictions will submit a common set of GHG emissions data and regulated party information to the WCI Central Database. The common set of data will be defined based on the data required for coordinated regional implementation of the program.
- All WCI Partner jurisdictions will transfer the common set of GHG data to the WCI Central Database by a specified date each year.
- All WCI Partner jurisdictions will be able to view and analyze aggregated WCI emissions data in the WCI Central Database. (Individual Partners will have unrestricted access only to data from their regulated parties via their jurisdictional emission databases or Common Framework modules.)
- The WCI Central Database will share emissions data with the WCI Tracking System as needed.
- The WCI Central Database will have an interface to permit all participants to access relevant data, subject to confidentiality restrictions.
- The final (July 2009) WCI Essential Reporting Requirements and individual WCI Partner reporting requirements form the basis of the data collection components of the RED project.
- The WCI Essential Reporting Requirements may require modifications after the proposed U.S. EPA Mandatory Reporting Rule becomes final or when Canadian federal requirements are adopted. If this occurs, new database requirements may need to be developed.

- The WCI Partner jurisdictions are funding the development of a generic module in the Common Framework that may be adopted by WCI Partner jurisdictions to minimize the cost and time required to implement a GHG reporting application that is compatible with WCI. For Partners to maximize this investment, those wishing to develop a Common Framework module to serve as their data collection system will reap the most cost savings if they develop their modules after the WCI Program Module is launched (Q1 2010)
- All partners will follow the same data and communication standards for transferring data to the WCI Central Database.
- Third party verification (where required) and WCI Partner jurisdiction government agency review of emissions data will take place at the jurisdictional level prior to data being transferred to the Central Database.
- The RED will be developed to include multilingual support, initially in English and French.
- WCI Identifiers will be assigned to all facilities and entities that report emissions. These identifiers may be associated in the Program Modules or Central Database with jurisdiction-specific identifiers for the same facilities and entities.
- WCI must provide requirements for minimum QA and compliance checks that all Partner systems for collecting emissions data should adopt to ensure consistency of data quality.
- Stakeholders will have access to reports from the Program Modules and the Central Database.
- The implementation phase of the RED will engage reporters, verification bodies and other participant groups to contribute to the design process and to beta test the application.

2.2 Principles

It is critical to the success of Phase 1, as well as the application that is ultimately developed, to define common principles that will guide how options are evaluated and recommendations are made. The principles are:

- Each of the Partners may have different perspectives on how requirements are defined for the RED. The final requirements should focus on the stated goals of WCI and the shared requirements. At a minimum, the Partners will agree to a set of shared functionality and follow data specifications based on the essential reporting requirements.
- It is important to minimize the reporting burden for regulated parties and promote consistency.

- It is always necessary to balance cost with the depth of functionality in a software application. Cost effective solutions should be identified whenever possible, with approaches to extend functionality when it is needed, or funding is available.
- The RED will need to provide solutions that fulfill requirements of both Canadian and US jurisdictions where differences exist in how specifications (i.e. unit measures, currency, code systems etc.) are documented.
- Technology decisions will favor approaches that maximize flexibility and can be adapted using configurable tools. Technology infrastructure will adopt standards-based approaches when possible.
- The data available to a particular jurisdiction's stakeholders through the Program Modules and the WCI Central Database will be consistent with that jurisdiction's public records laws. Data that is required to be public under the jurisdiction's laws must be readily available through the RED databases. Data that is entitled to protection from public disclosure, such as confidential business information, must be protected.

All application development will adopt intuitive approaches to the user interface, and best practices for security, availability, scalability and performance.

2.3 Alignment with Federal GHG Reporting

The WCI is committed to achieving the maximum possible level of consistency and integration with federal GHG reporting programs, including the final version of EPA's final Mandatory Reporting Rule (MRR). Unlike the WCI essential reporting requirements, the MRR is not being developed at this point to support a cap-and-trade program. Thus, there may be some differences between the two programs. In addition, the WCI and some of the states and provinces in the WCI have other reporting requirements that EPA's proposed rule does not cover, such as the requirement to report emissions from facilities with total CO_2e emissions between 10,000 and 25,000 metric tons per year.

The following list identifies the options for achieving consistency and integration with federal GHG reporting programs that WCI may consider in developing the RED. WCI Partner jurisdictions and The Registry will discuss these options with appropriate representatives from EPA and Environment Canada. Stakeholder comment is also specifically requested on these options.

- Direct reporting to the states and provinces with transmission of data to the federal program, as recommended in WCI's comments on the proposed MRR.
- WCI acceptance of copies of reports submitted under the MRR or Environment Canada regulations in lieu of reports under the essential reporting requirements, to the extent such reports satisfy WCI program needs.

- Dual purpose single window reporting of regulated parties to WCI and federal agencies; EPA's draft rule should be considered in the development of the reporting window.
- Data exchange with EPA or Environment Canada.
- Technical design of the RED to facilitate future harmonization:
  - Collaboration on a harmonized submission template and process so that regulated parties can submit their data once and have the data routed to the appropriate agency.
  - Flexible approach to the configuration of calculation tools.
  - Development of tools based on the WCI Reporting Requirements with flexibility to adapt to EPA and Environment Canada requirements when either or both are final.

3 Options for the Regional Emissions Database

This chapter raises a number of issues and questions that will influence the requirements for different components of the RED. Each section provides background, presents options, and discusses the factors that influence the approach

Options will be presented in six categories:

- WCI Common Framework Program Module
- WCI Central Database
- Data Collection from Partner jurisdictions
- Analysis, Report Preparation and User Interface Tools
- Integration with the Tracking System
- General Considerations

3.1 WCI Common Framework Program Module Options:

Refer to Figure 2 Component #1.

Options for the WCI Program Module are focused on data collection by the Partners but may influence other components in the RED application. Many of the requirements will be determined by the WCI essential reporting requirements. The primary goals of providing a shared data collection module are to minimize cost and develop a consistent approach that simplifies reporting for regulated parties.

3.1.1 Data Submission Interface

Submitting emissions data to the Program Modules should be as simple as possible for regulated parties and leverage existing technology infrastructure when possible to promote consistency and minimize cost. The choices for this option are:

- Online web interface
- Bulk Upload of emissions data
- Allowing a regulated party to select either the online web interface or a bulk upload procedure

An online web interface provides helpful user interface tools that assist reporters in submitting accurate data, calculating data based on the reporting requirements and allowing them to progress through the process at their own rate. An online interface also simplifies the process of changing the data as errors are identified during a QA process. Bulk upload of submissions allows all data to be submitted in one package using an automated process. While it is faster than using an online tool, it requires the reporter to spend time preparing data for transfer. A similar QA process would be provided for bulk upload as in the online system. A reporter should have the option of correcting the data and resubmitting it through bulk upload or of using the online tool to modify the data directly.

Reporter preferences for this option are often determined by the volume of data that needs to be submitted, and even though regulation is at the facility level, many regulated parties will submit emissions data for many facilities. An online web interface is often preferred by reporters with fewer regulated facilities because they gain the advantages of the reporting tools without spending excessive time entering data. Reporters with large numbers of facilities typically prefer to bulk upload data to streamline the process. They are also more likely to use in-house emissions data management systems that simplify the process of preparing the data that will be submitted. While there is a higher cost to support both options, the WCI Program module could leverage the Common Framework to minimize the expense of an online interface.

3.1.2 Data Submissions Formats

Assuming that a bulk upload of submissions to the WCI Program Module is supported, one or more templates will need to be adopted to allow reporters to map their emissions data to a predictable format that can be processed and loaded into the WCI Program Module's database. The options for this format are:

- Consolidated Emissions Reporting Schema (CERS)
- A template that has been standardized across Canadian Provinces

It will simplify the process and reduce the overhead of bulk upload to have a single template for formatting and submitting data that is shared by all Partners using the Program Modules. Data standards for GHG emissions are still evolving and there is no internationally recognized standard yet. In the US, CERS (an XML schema that incorporates GHG data with all other air emissions data) has been adopted for data exchange between agencies at the state and federal level. It is also used by programs that support emissions reporting such as The Climate Registry. It has not been determined if the CERS, at least in its current form will be adopted by the US federal program. While there is no Canadian equivalent for this template, developing a schema that can be shared across North America would be a strong step towards consensus on an international approach.

It is also important to consider the investment that regulated parties may have made in preparing emissions data for submissions to other regulatory programs. Further investigation should be made to ensure that any standard templates that surface during this process are considered.

3.1.3 Accountability for Electronic Certification of Submissions:

Systems for electronic data submission must provide a framework enabling electronic signatures to replace hand-written signatures as a means of ensuring individual and corporate accountability and responsibility. Since emissions reported to WCI will be used to determine compliance with its cap-and trade system, it is critical to provide a high level assurance for all electronic submissions. Defining allowable practices in this type of environment requires specialized expertise in security and identity management technologies based on significant experience with the problems likely to be encountered. It may also be necessary to vary the approach depending on the type of submission (i.e., online system or bulk data upload).

The options presented for electronic submission offer a broad range of accountability and cost:

- Cross-Media Electronic Reporting Regulation (CROMERR) support - US
- One Window to National Environmental Reporting System (OWNERS) - Canada
- Independent Electronic signature support
- Printed copy with signature that is mailed to administrator
- Printed letter with signature that refers to the electronic submission
- Third party solution for certificates and identity management

The US EPA's CROMERR is a set of information technology standards that acts as a legal framework for electronic reporting. Different approaches may be adopted under CROMERR as long as the standards are met and approved by EPA. The Canadian OWNERS solution has similar standards to CROMERR but is implemented through a common portal for all submissions from industry rather that a set of standards. WCI could define its own standards for electronic reporting but this is likely to be time consuming, expensive and require ongoing administrative responsibilities. Adopting a strategy for electronic submission also raises the question of how or if WCI will identify standards for Partners that implement their own systems for reporting emissions rather than adopt the WCI Program Module.

Many emissions reporting programs have relied on hand written signatures on certification statements that accompany reports. While these approaches will cost less to implement it is unlikely that they provide the level of assurance that may be required for this type of program once the cap-and-trade program is operational. The most efficient approach may be to adopt a simple solution for the first year of reporting 2010 data such as a wet ink signature process and to identify a solution that is comparable to both OWNERS and CROMERR for future years. This allows more time to evaluate whether WCI can leverage CROMERR or OWNERS directly, particularly for bulk data submissions.

When an emissions report is certified by the regulated party, a copy of the report will automatically be stored in the database and will be available for review with appropriate access privileges; if data are changed and resubmitted, a new report will also be stored. All versions of the report will remain in the database.

For more information on OWNERS Security see:
http://www.owners.gc.ca/default.asp?lang=En&n=00C654BE-1

For more information on CROMERR see:
http://www.epa.gov/cromerr/about.html

3.1.4 Quality Assurance and Compliance checks:

In this context, quality assurance checks are automated tools that are used to identify conditions suggesting inconsistencies or errors in the emissions data and can be utilized to ensure compliance. Pre-submission check results are automatically presented to a user so that issues can be corrected before final submission. Post-submission check results allow agencies to check for compliance. The Common Framework has a number of standard quality assurance checks that are common to most programs. Individual modules in the Common Framework typically include additional quality assurance checks that are specific to their programs. Options for quality assurance checks are:

- Pre and post-submission quality assurance and compliance checks will be incorporated into the WCI Program Module to minimize third party verification cost and agency review consistently across all programs.
- Quality assurance checks will include options for customization by each WCI Partner jurisdiction in addition to common checks for all jurisdictions.

If WCI Partners expect to implement the reporting requirements without major changes, then the most cost effective approach would be to include quality assurance checks that isolate as many conditions as possible that conflict with the reporting rules. If the WCI reporting requirements will be extended by many of the Partners to accommodate jurisdictional-specific requirements , then they may want to customize quality assurance checks to accommodate individual programs. Since these options depend more on jurisdictional requirements, this is likely to be the deciding factor. It should be noted that Partner customization of QA checks may result in additional cost.

3.1.5 Public, Private and Agency Reports:

Reports are created for all modules in the Common Framework that serve different participants. These reports are available to the different participants at different times based on what stage of the reporting process has been completed. The options listed below reflect the approach the Common Framework uses for most programs. In this case there is not a selection of one option over another, rather the list is presented to develop consensus that all the conditions presented are appropriate for the WCI program Module.

- Regulated parties will have access to all data they have entered into the WCI Program Module at all times. After submission to a jurisdiction the access will be read only, unless corrections are required.
- Agency staff will have access to reports with all facility and unit level data after the data have been submitted to the jurisdiction.
- Stakeholders will have access to all facility and unit reports after the data have been third party verified (if required) and accepted by the Partner Jurisdiction. Confidentiality flags will be included that protect certain types of data from disclosure to public stakeholders.

The reports discussed here should not be confused with reports that will be implemented for the WCI reporting Dashboard for the Central Database, although it may be desirable to minimize overlap between reports generated in the two different components.

The table below outlines the types of reports that might be available to different groups. Stakeholders are invited to suggest additional reports that might be included.

Regulated Party Reports	Agency Reports	Public Reports	Description
Entity Emissions Summary	Entity Emissions Summary	Entity Emissions Summary	A report of Entity or Facility level emissions totals for all facilities for a given entity.
Entity Emissions Detail	Entity Emissions Detail	Entity Emissions Detail	A report of activity level emissions data for all facilities and activities for a given entity.
Facility Emissions Detail	Facility Emissions Detail	Facility Emissions Detail	A report of activity level emissions data for all activities for a given facility.

Other Reported Data	Other Reported Data, including a list of supporting documents	Other Reported Data to the extent required by the laws of the jurisdiction to which the data was reported	Data the ERs require to be submitted in order to allow the agency to evaluate the emissions data.

Reports for stakeholders will respect confidentiality flags in the system. Some Partners require that confidential data be available to the public unless the jurisdiction authorizes the data to be treated as confidential. Other Partners allow regulated parties to declare that data are confidential unless the jurisdiction overrides the decision. The data collection system will need to accommodate the different approaches.

3.2 WCI Central Database

Refer to Figure 2 Component #2.

Many of the decisions that are made about the design of the RED will determine what analysis the Partners will be able to perform on the aggregated data and what information will be available to reporters through the reporting dashboard. With the assistance of the RED Workgroup, The Registry will work with all participants to do further analysis to develop more detailed specifications during the Phase 2 Requirements Analysis for this project.

3.2.1 Technical Implementation

Best practices for all aspects of the technology infrastructure will be followed in the implementation of the Central Database. Expectations for the Service Level Agreements (SLAs) will be determined during the requirements analysis. SLAs establish specific metrics or conditions for performance levels, system availability, security, timeframes for issue resolution and other operational features of the platform.

- Platform Security: An end-to-end security model that incorporates identity management, secure communications, firewalls, and data security in the database and application server tiers will be enforced.
- Availability: High availability of the application will be ensured using appropriate failover technologies and a reliable hosting partner.
- Backups: Both onsite and offsite backup procedures will be in place.
- Technical architecture: The architecture that is adopted for each component will rely on current technologies that are well tested and widely used.
- Data Model: The data model will be designed to provide flexibility, ease of data access and to anticipate future needs.
- Internationalization: The platform will include internationalization that provides support for multiple languages, currencies etc.

- Hosting: A hosting partner that is recognized for excellence of service and comprehensive options for SLAs will be selected.
- The hosting location will be selected to provide optimal service to the WCI Regional Administrative Body, all Partners and the technical support staff.

The Central Database will operate primarily as a data warehouse used for analysis and reporting so the technical architecture and data model should support this requirement. Data will be structured to maximize efficiencies for analysis, query performance and to facilitate inquiry from a broad range of constituencies. The system should support access with ad hoc query and reporting tools using an Open Database Connectivity (ODBC) connection, although this capability may be limited to specific user roles within the system. The system will also support the ability to download data into a spreadsheet for further analysis by WCI Partner jurisdictions.

Hosting is likely to be provided through a third party hosting partner with excellent credentials for reliability and vulnerability protection. It may make sense for the Central Database to be co-located with the tracking system to maximize efficiency of operations for WCI; The Registry will continue to work with the Task 4 Workgroup of the WCI Markets Committee to understand how this would work.

WCI has the option to adopt specific standards for the technical implementation of all systems that support the program. It is also not known yet if there are any legal obligations that will influence the physical location of the servers.

3.2.2 Data Analysis Requirements

The level of data that is transferred to the Central Database will be determined by what analysis the Partners and other participants will need to perform at the regional level. With the assistance of the RED Workgroup, The Registry will identify key members of each stakeholder group to do further analysis to develop more detailed requirements.

The data model should accommodate all data captured at the jurisdictional level, even if not all such data is actually transferred, and also allow new attributes and tags to be added that will make the model extensible.

Types of data that can be stored in the Central Database

1. Regulated party information
    a. Facility name
    b. Facility WCI ID
    c. Facility Alternate Identifiers
    d. Facility address
    e. Facility contact

2. Facility level emissions data
    a. CO2e
    b. Individual GHG's
3. Source level emissions data
    a. CO2e
    b. Individual GHG's
4. Activity data (multiple records per activity)
    a. Fuel type
    b. Fuel consumed
    c. Process data required for emission calculations
    d. Calculation method
    e. Emission factors
    f. Source Category Code
5. Supporting Documentation consistent with the essential reporting requirements:
    a. Entity level documents (e.g. Annual Reports, Organizational Structure)
    b. Facility Level Documents (e.g. Facility Operations)
    c. Emissions Submission Documents (e.g. calculation methodology, verification support)
6. Verification information
    a. Verification Body
    b. Lead Verifier
    c. Verification statement
    d. Date verification completed
7. Agency Review information
    a. Agency staff identifier
    b. Action taken (e.g., review, acceptance, rejection, facility contact, referral for CVE)
    c. Date action taken
    d. Notes

The WCI essential reporting requirements will help define the data that can be stored in the Central Database. For example, precision for reporting emissions data (e.g., fuel quantities, emissions, etc.) will reflect final guidance from the Reporting Committee. In other cases, the Markets Committee or the Cap Setting and Allowance Committee may need to be consulted to ensure interoperability with other WCI functions.

An additional consideration for data analysis is the need to respect that the essential reporting requirements will present a new and demanding challenge to some regulated parties. In the initial years of reporting, the Central Database may need to accommodate data that does not strictly conform to all of the essential reporting requirements. If this is the case, all data points should be stored in the Central Database and made available for research and analysis.

3.3 Data Aggregation from WCI Partner Jurisdictions

Refer to Figure 2 Component #3.

Data will be collected from each of the Partner jurisdictions in the Central Database through transfers of data from Common Framework or Partner-specific databases. Developing standards that are consistent for all transfers is critical to maintain the accuracy of data in the Central Database and to minimize the cost of the process.

3.3.1 Partner Submissions to the Regional Emissions Database

Business rules will guide the date and frequency of Partner submissions of data to the WCI Central Database. Since a complete set of commonly defined data from all Partners is required to manage allowances, clear expectations will be set for when transfers need to be finalized. Options for how Partner jurisdictions are likely to transfer emissions are:

- When the Partner data collection process is complete
- Multiple submissions as regulated parties complete their submissions to the Partner

Once an automated data transfer process between a jurisdiction and the Central Database is in place, repeated submissions from a Partner to the Central Database should be supported, as a number of conditions may cause emissions reports by regulated parties to change (e.g. late submissions, verification changes). As data is updated by any of the Partners, the transfer process should allow all emissions or a subset of the data from the Partner to be submitted. To simplify this process a complete set of data should be included for any facility for which data is transferred.

3.3.2 Data Transfer Schema Usage

As discussed earlier in the paper, data standards for GHG emissions are still evolving. However, it is essential that data are transferred using consistent and stable methodologies. Options for schemas that will support data transfer to the Central Database (from jurisdictional databases) include:

- Consolidated Emissions Reporting Schema (CERS)
- WCI Custom template
- Combination of multiple options

The CERS was developed to support inter-agency transfers of all emissions data and was extended to incorporate GHG emissions. Developing consensus on a shared schema like the CERS is a time consuming process requiring broad participation. Therefore, it may difficult for WCI to develop its own standard given the timeframe allowed. Although it is still necessary to confirm that the CERS will accommodate all of the WCI essential reporting requirements, it does form the basis of a largely complete template. The CERS has also been implemented by The Registry to support the transfer of data from jurisdictions to The Registry, so there is an opportunity to leverage existing work.

3.3.3 Communications Infrastructure

Creating a communications infrastructure that accommodates transfers of high volumes of data in a secured, predictable environment requires extensive investment and WCI will want to leverage existing platforms. Opportunities to do this are:

- Exchange Network only
- Exchange Network plus an additional option for Partners that do not have a node on the Exchange Network

In the US the Exchange Network is managed by EPA to support data exchange to and from federal programs as well as between jurisdictions. All agencies that utilize the Exchange Network for data exchange have nodes on the network that enable secure communications according to standard protocols. The Registry has an Exchange Network node and is completing a pilot project using it this summer.

Exchange Network users who want only to submit data over the Exchange Network do not need a fully functional node but instead would only require a node client. A node is only required if you want to allow other systems to request data from you. This may simplify use of the network by Canadian Partners if there are no other barriers to adoption of this approach. The OWNERS system might also establish a connection to the RED to support data exchange, although existing GHG data collection in Canada is not currently using the OWNERS system.

3.4 Analysis, Report Preparation and User Interface Tools

Refer to Figure2 Component #4.

The ability to provide information to the different participants in the WCI program is fundamental to the success of this project. It is however, difficult to anticipate all of the reports and analysis that will be useful until the system exists. For this reason, it will be advisable to rely heavily on prototyping early deliverables for reports and the user interface to the Central Database during the requirements planning and design phases. The sections that follow attempt to lay the groundwork for options of this component, but they are likely to evolve considerably throughout the rest of the project. As this process evolves, it will also inform the other components of the RED project.

3.4.1 GHG Emissions Data Analysis

Many forms of GHG emissions analysis will be used to manage WCI operations, inform stakeholders, and mine the Central Database for information that will help WCI achieve GHG reduction goals. Some of these are presented here for review; the RED workgroup welcomes additional suggestions as others review this White Paper.

- Geographic Analysis: WCI Program, State, Province, Participant: It is strongly advised that accurate spatial coordinates are incorporated so that a broad array of options for geographic analysis can be supported.
- Sector Analysis: The North American Industry Classification System (NAICS) is one form of sector analysis that is often used and will be incorporated. A more simplified list of industry sectors that is derived from an external standard may also be advisable.
- Analysis by Source Category Code (SCC): SCC codes are used by most WCI Partners to analyze data. Since they classify low level information about fuels and the scale of emissions they are very useful. However, each source activity needs to be classified accurately for the analysis to provide value. Individual Partners will be responsible for ensuring that sources are categorized accurately before the data is aggregated in the Central Database.
- Entity Analysis: Although WCI will apply reporting requirements at the facility level, many entities will report for multiple facilities. This type of analysis will be needed by regulated parties, Partners and public stakeholders.
- Facility Analysis: Facility level analysis will help to determine if the essential reporting requirements are providing the information needed to support the cap-and-trade program. A detailed list of facility-level requirements will be included in the requirements specification phase of this project.
- Individual Gas Analysis: Emissions by each GHG, categories of GHG and total CO_2e will be provided.
- Threshold Analysis: Emissions summarized at the facility level for all facilities with CO_2e emissions of 25,000 metric tons or more, 10,000 metric tons or more, or other increments specified by the user.
- Analysis for Stakeholders: The RED workgroup will seek guidance from stakeholders to determine requirements for this analysis.

3.4.2 Stakeholders

Various stakeholders will be interested in accessing some/all of the GHG data in the WCI RED. In proposing requirements for the system, it is important for WCI to understand the type and form of data that key public stakeholders will be interested in accessing. While WCI's RED may not be able to meet all of the stakeholders' GHG data needs, it aims to make the data it collects as useful and meaningful as possible. In order to prevent duplication of effort, WCI hopes that many stakeholders will be able to use the data contained in the WCI's RED in a way that prevents duplication of effort and promotes centralized consistent GHG data.

As a result, the Partners and Reporting Committee must first work to identify the various needs of stakeholders and then to prioritize their needs to ensure that the scope of WCI's RED is not expanded unnecessarily.

The RED Subcommittee has identified the following stakeholders as potentially interested parties in the RED data.

- Western Regional Air Partnership (WRAP): The WRAP currently manages the Emissions Data Management System (EDMS). The EDMS is an emission inventory data warehouse that provides a consistent and comparable approach to regional emissions tracking to meet the requirements for State Implementation Plan (SIP) and Tribal Implementation Plan (TIP) development and periodic review and updates across the U.S. states in the region. The WRAP has expressed interest in utilizing the data from WCI's RED to supplement its EDMS system.
- Western Governors' Association (WGA): The WGA addresses important policy and governance issues in the West, advances the role of the Western states in the federal system, and strengthens the social and economic fabric of the region. All of the American WCI Partners are members of the WGA. The WGA currently collects emissions data via the WRAP.
- Western Renewable Energy Generation Information System (WREGIS): The WREGIS is an independent, renewable energy tracking system for the region covered by the Western Electricity Coordinating Council (WECC). WREGIS could be interested in utilizing RED data, specifically power related emissions.
- Environmental organizations (Natural Resources Defense Council (NRDC), Environmental Defense Fund (EDF), Union of Concerned Scientists (UCS), Sierra Club, etc.): Environmental organizations have long supported GHG data collection, and will likely be interested in analyzing emission trends, the carbon market, and the overall program effectiveness.
- US Environmental Protection Agency (US EPA): The US EPA is currently finalizing their GHG Mandatory Reporting Rule. Depending on how US EPA chooses to work with states, US EPA may permit GHG data transfer, data sharing or combined data collection.
- Environment Canada: Environment Canada is also currently working on federal regulation of GHG emissions. Like US EPA, depending on the relationship between the Canadian provinces and territories and Environment Canada, Environment Canada may permit GHG data transfer, data sharing, or combined data collection.

- Other GHG Cap-and-Trade Programs (RGGI, EU ETS, etc.): Depending on the programmatic relationship with other cap and trade programs (RGGI, MGGRA, EUETS, etc.), WCI may wish to permit GHG data transfer, data sharing, or combined data collection with other programs.
- Secretaría de Medio Ambiente y Recursos Naturales (Semarnat): Semarnat is the federal agency responsible for environmental protection in Mexico. If the Mexican states (currently WCI Observers) became Partners, Semarnat might permit GHG data transfer, data sharing, or combined data collection with related Mexican programs.
- Carbon Market: A variety of carbon market experts (brokers, traders, offset providers, etc) will be interested in accessing various GHG data information about regulated parties.
- Industries and Trade Associations - These are the facility owners or operators and their representative trade groups that will be either reporting to the RED in compliance with their respective jurisdiction's requirements, or interested in reviewing data submitted by others to support the cap-and-trade program.

Options:
Given the number and diversity of identified stakeholders, WCI has several options to consider when designing the system requirements and resulting data analyses of the WCI RED. WCI could:

- Meet all the stakeholder needs
- Ensure that key stakeholder needs are met within the initial RED, and work to support additional needs in the future
- Focus solely on WCI's needs

Public Stakeholders: The WCI welcomes feedback from all stakeholders on reports and data analysis that would be helpful.

3.4.3 Standard WCI Reports

Reports provided in this section may appear to overlap with reports with the WCI Program Module reports. Since the Central Database will have data for all Partners it will be possible to include more comprehensive views of data and comparative analysis by geography, sector and other categories that provide more value to WCI.

Options for developing Common WCI Emission Reports:
- Canned reports for each of the different groups involved in WCI
- Partner specific reports
- Ad hoc reports (i.e., user defined parameters)
- Public reports

- Consult stakeholder groups to solicit feedback on content to be included in the reports

3.4.4 User Interface

The online user interface for the RED must contribute to a positive experience for the user and ensure efficient access to information. Fortunately, there are a number of open source frameworks that simplify the development of an intuitive user interface. The approach will need to provide flexibility, so that different types of users can view data at the appropriate level of granularity, and in a format that is easy to understand (e.g. graphs, charts, summary data, detailed data). The approach should also ensure consistent views for different users in the same category (i.e. WCI Staff, WCI Partner, Regulated Party, Public Stakeholder).

The interface will enforce access privileges for users with different roles, as well as respect data confidentiality rules. Users with the appropriate privileges should also be able to perform ad hoc queries, or download data using an ODBC connection.

Whenever possible the interface should comply with World Wide Web Consortium (WC3) web accessibility standards.

3.5 Integration with the Tracking System

Refer to Figure 2 Component #5.

The Central Database may need to transfer emissions data to the tracking system, but the details about the schedule, frequency and granularity of information will depend on the findings of other WCI committees. The RED Workgroup will continue to work with the Markets Committee, the Cap Setting and Allowance Distribution Committee and others as need to determine the requirements for integration with the Tracking System.

3.6 System Administration and Support

Once the Central Database has been deployed and is available to use it will require ongoing administration and support services. This includes services such as hosting, technical support, training and call or email response services. It should be noted that the services that support the WCI Program Module are not included in this discussion. Each Partner that adopts the Program Module in The Registry’s Common Framework will make these arrangements individually. Possible options for administration and support are:

- WCI Regional Administrative Body
- The Registry
- Third Party contractor

- Designated Partner staff

Technical support services ensure system continuity, ongoing security upgrades, routine maintenance, performance monitoring, issue resolution and incremental enhancements to the system. Application specific services such as issue resolution and enhancements can be provided more efficiently by staff members who have been involved with the development of the software. System level services such as security upgrades or performance monitoring should be provided by the hosting partner. Since The Registry will have the most familiarity with the application services they are likely to provide the most efficient support during the initial implementation. They can also provide a single point of contact for the hosting partner to minimize overhead for WCI.

Program Services such as call center support, email response and training on how to access data in the Central Database should be provided by staff with significant subject matter expertise and familiarity with the user interface for each type of user. Demand for these types of services vary at different times of the year, so the provider will need to adapt to the WCI the reporting schedule. This is probably easiest for a provider who spreads the staff across multiple programs that have peak activity at different times during the year.

4 Summary of RED White Options Paper

1. **Purpose and Background**

    1.1. Regional Emissions Database (RED) Review Process: A description of the roles that different groups will have in the requirements analysis for the RED.

    1.2. Regional Emissions Database Work Plan: An outline of the milestones in the RED work plan and the participants involved.

    1.3. Regional Emissions Database Overview: Review this section to understand the different components that the project is broken into.

2. **Assumptions and Principles**

    2.1. Assumptions: Note that many assumptions were developed as the RED Workgroup discussed options and recognized that it was necessary to make assumptions about how to proceed.

    2.2. Principles: Common principles that will guide how options are evaluated and recommendations are made.

    2.3. Alignment with Federal GHG Reporting: The WCI will design the RED to achieve the maximum possible level of consistency and integration with federal GHG reporting programs.

3. **Options for the Regional Emissions Database** - Options are presented for the five components of the RED and for system administration and support:

    3.1 WCI Common Framework Program Module: Options for the WCI Program Module are focused on data collection by the Partners but may influence other components in the application. Many of the requirements will be determined by the WCI essential reporting requirements. The primary goals of providing a data collection module that is shared is to minimize cost and develop a consistent approach that simplifies reporting for regulated parties.

    3.2 WCI Regional Emissions Database: The RED will adopt industry standard best practices for technical infrastructure components. The RED must be designed to ensure that the data transferred from program modules and Partner-specific databases supports the WCI's data analysis needs.

3.3 Data Aggregation from WCI Partner Jurisdictions: The Central Database must incorporate business rules for the submission of data from program modules and Partner-specific databases to the Central Database, a schema or schemas for data transfers and a communications infrastructure.

3.4 Analysis, Report Preparation and User Interface Tools: The design of data analysis tools meeting the needs of the WCI, reporters and public stakeholders is likely to evolve considerably over time to adapt to other elements of the RED design.

3.5 Integration with the Tracking System: The Central Database will need to transfer emissions data to the tracking system, but the details for the schedule, frequency and granularity of information will depend on the findings of other WCI committees. The RED Workgroup will continue to work with the Markets Committee, the Cap Setting and Allowances Committee and others as need to determine the requirements for integration with the Tracking System.

3.6 System Administration and Support: Options for implementing system administration and support of the RED include WCI Regional Administrative Body, The Registry, a third-party contractor or designated Partner jurisdiction staff.

5 Public Stakeholder Feedback on Options

This section will be completed following the public stakeholder review of the Options White Paper.

6 Recommendations / Decisions

A summary of all recommendations following feedback

August 5, 2009 Regional Emissions Database Options White Paper

List of Commenters

Power Workers' Union

Southern California Edison Company

Utah Business Climate Change Coalition

Western Climate Advocates Network

August 7, 2009 Draft Statement of Principles on Competitiveness and the Review of Proposed Options for Addressing Industrial Competitiveness Impacts

List of Commenters

Canadian Lime Institute

Cement Association of Canada

Nucor Steel - Utah

Power Workers' Union

Southern California Edison Company

Utah Business Climate Change Coalition

Waste Management

WEST Associates

Western Climate Advocates Network

Western States Petroleum Association

Western Climate Initiative

August 6, 2009

To All Interested Parties:

Today, the Western Climate Initiative (WCI)'s Cap Setting and Allowance Distribution (CSAD) Committee released the *Draft Statement of Principles on Competitiveness* and the *Review of Proposed Options for Addressing Industrial Competitiveness Impacts.*

Under a cap-and-trade program, the cost of switching to cleaner energy and lowering emissions may disproportionately affect competition for sectors that are emissions-intensive and operate in global markets. In contrast, the costs of inaction on climate change in the long term are high and potentially catastrophic. The CSAD Committee, among other things, is responsible for developing the WCI approach to address competitiveness issues. The purpose of CSAD's work in this area is twofold:

- To seek, receive, review and perform analyses from sectors or sources identified (by WCI or through self-identification) as facing a cost within the WCI that their competitors outside the WCI do not. Those sectors or sources may be vulnerable to competitiveness pressures because of the short term regulatory imbalance and could lead to increased emissions outside the WCI, which we seek to minimize.
- To assess options that WCI Partner jurisdictions may use to address competitiveness issues within identified sectors. If a common allowance distribution method is recommended, the CSAD Committee will recommend a distribution method or methods for consideration by the WCI Partner jurisdictions.

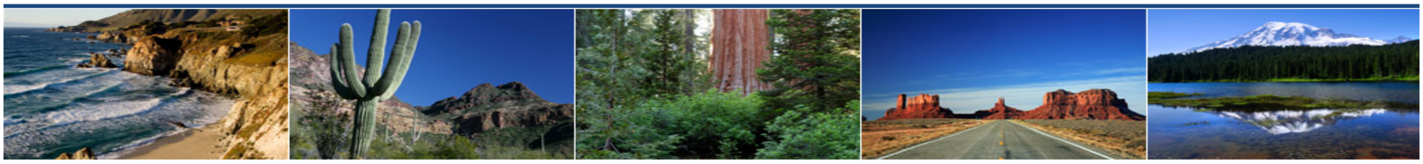
The purpose of the draft statement of principles is to guide the process by which WCI will evaluate competitiveness effects of a regional cap-and-trade program. The principles shall serve as the foundation for a common approach to addressing competitiveness issues agreed upon by the WCI Partner jurisdictions.

In addition, the CSAD Committee reviewed how other programs currently address or propose to address competitiveness issues. These policy options are evaluated in a three page summary and table entitled *Review of Proposed Options for Addressing Industrial Competitiveness Impacts.* Legislative proposals, reports, and programs on competitiveness which the Committee analyzed include:

- Inslee-Doyle Carbon Leakage Prevention Act (H.R. 7146)
- American Clean Energy and Security Act of 2009 (H.R. 2454)
- Australia's Carbon Pollution Reduction Scheme
- Lieberman-Warner Climate Security Act of 2008 (S. 3036)

- California’s AB 32 Global Warming Solutions Act
- The European Union cap-and-trade program – EU ETS Phase III
- RGGI Northeastern cap-and-trade program on the electricity sector
- Two reports published by the Pew Center on Global Climate Change

These programs and proposals provide key background information for Committee’s work on competitiveness. Public comment on the *Draft Statement of Principles on Competitiveness* should be submitted via the WCI website by August 28.



Draft Statement of Principles on Competitiveness

August 6, 2009

The WCI Partner Jurisdictions have developed a Draft Statement of Principles (SOP) to help guide the process by which WCI will evaluate competitiveness effects and leakage due to the regional cap-and-trade program. This draft SOP is primarily informed by the February 2009 work plan as well as an examination of principles used by other regional, national and international carbon management initiatives.

Concerns regarding competitiveness are often expressed as the potential for companies covered by the cap and trade program to lose market share to companies in regions with less stringent carbon constraints. A common measure of competitiveness impacts is a decrease in net exports that results from the carbon constraint of the cap and trade program. For a full list of metrics used in other programs or recommended by the literature as well as options to address competitiveness, please see the summary table: *Review of Proposed Options for Addressing Industrial Competitiveness Impacts*.

Guidance contained in the February 19, 2009 CSAD Work Plan indicates that workgroups on competitiveness will assess how WCI jurisdictions should address competitiveness issues. The CSAD Competitiveness group was also directed to seek, receive, review and perform analyses on competitiveness issues for sectors or sources that have been identified and/or that self-identify as having competitiveness issues related to a regional cap-and-trade program. The WCI Program Design Recommendations specify a process to address competitiveness issues between WCI Partner jurisdictions (Section 8.5):

> *If analysis demonstrates that allocations to a particular sector should be treated uniformly by some WCI Partner jurisdictions in order to address competition among like facilities or entities within that sector, and if from that analysis some WCI Partner jurisdictions determine that it is necessary to address those competitiveness issues between the WCI Partner jurisdictions where the facilities or entities operate, those WCI Partner jurisdictions will standardize the distribution of allowances as necessary to address competitive impacts sufficiently, in advance of the first compliance period.*

Guidance from other regional, national and international carbon management initiatives also provides a starting point for developing principles to address potential competitiveness impacts of the WCI program and risks to emissions-intensive, trade-exposed industries. Notably the proposed Inslee-Doyle Carbon Leakage Prevention Act (H.R. 7146), and key competitiveness elements reflected within the American Clean Energy and Security Act of 2009 (H.R. 2454) provide a solid foundation for the principles.

Specifically, the focus on compensating sectors that demonstrate trade-exposure and emissions-intensity with free allocations and other means are common across GHG cap-and-trade programs, notably the European Union Emissions Trading Scheme or EU-ETS. Also consistent with other carbon management programs is a focus on avoiding carbon leakage and smoothing transitional impacts.

The following Draft Statement of Principles flows from WCI guidance to date, initial stakeholder feedback from the May 28, 2009 CSAD Workshop in Seattle, and a review of other carbon management programs. WCI Partners will:

- Minimize leakage of GHG emissions and the transfer of production and jobs attributable to a regional cap and trade program to the extent feasible, while still rewarding innovation and facility-level GHG intensity improvements.
- Address transitional challenges faced by entities from within covered sectors that may be subject to disproportionate competitiveness risk under a regional cap and trade program.
- Consider a harmonized approach across WCI when identifying and addressing potential competitiveness risks attributable to a regional cap and trade program.

These principles will guide the common approach to competitiveness undertaken by the Partner Jurisdictions.

Summary of Review of Proposed Options for Addressing Industrial Competitiveness Impacts

August 6, 2009

The CSAD Task 3 team reviewed ten major policies, proposals, and analyses on how to address competitiveness risks under greenhouse gas cap-and-trade systems, including two operational cap-and-trade programs (the EU-ETS and RGGI) and five proposed systems including Waxman-Markey and Australia's Carbon Pollution Reduction Scheme. The objective of the review was to inform the development of the Statement of Principles. The results of the review are provided in the table/annex to this summary, and are organized under three major headings:

1) **Policy goals:** what the policy or proposal seeks to achieve regarding competitiveness and leakage impacts;
2) **Assessing competitiveness impacts and defining vulnerability**: which methods and metrics the policy or proposal uses to identify sectors or firms that may be vulnerable to competitiveness impacts and significant emissions leakage; and,
3) **Options for addressing competitiveness impacts**: how the policy proposes to address competitiveness impacts and minimize leakage risks (e.g., through measures including free allocations and border carbon adjustments).

Below is a summary of the review, organized under the three major headings identified above.

1) Policy Goals

Most policies and proposals seek to address competitiveness and leakage concerns, where there is a risk that production and jobs shift or emissions increase outside of the jurisdiction implementing a carbon policy. A second goal is to provide transitory assistance to particular industrial sectors to help them cope temporarily with higher energy and production costs as they transition to more efficient practices or low-carbon technologies, and mitigate competitiveness impacts until outside jurisdictions and trading partners adopt similar carbon constraints. Each of these goals is discussed below.

Leakage to Outside Jurisdictions: Most of the reviewed policies and proposals focus on how to avoid emissions leakage to outside jurisdictions that arise from cost increases due to compliance with carbon mitigation policies. For example:

- **The EU phase III**: The primary EU policy goal is to address competitiveness concerns in energy-intensive and trade-exposed industries, where some might be "exposed to a significant risk of carbon leakage";
- **Waxman-Markey (American Clean Energy and Security Act of 2009)**: ''Carbon leakage'' means any substantial increase in GHG emissions by manufacturing entities located in countries without commensurate GHG regulation, provided that such increase is caused by an incremental cost of production resulting from the carbon mitigation policy; and
- **RGGI**: "A cost increase due to a carbon cap could drive geographic changes in the operation of the electric power system."

Competitiveness Impacts as a Transitory Concern: Many of the policies and proposals reviewed stated that competitiveness impacts resulting from carbon constraints are transitory. They often include provisions, phased out over time, to help industry transition to a lower carbon future while also basing assistance levels or duration on carbon mitigation efforts in other jurisdictions:

- **RGGI**. Leakage is cited as a concern only if no national cap-and-trade system is operating, "a scenario where RGGI sunsets once a national program is implemented, would obviate any potential for emissions leakage."
- **Waxman-Markey**: The proposed program states that assistance to eligible industries would be sufficient to prevent carbon leakage while still rewarding innovation and facility-level energy efficiency improvements. The assistance provided phases out over time, and a number of provisions are contingent on the status of international negotiations on climate mitigation policies and whether carbon constraints have been instituted in other countries.
- **Australia's Carbon Pollution Reduction Scheme**: Australia's proposed system seeks to address transitional challenges faced by emissions-intensive, trade-exposed industries, and would also reduce rates of assistance to these industries on an annual basis.

2) Assessing Competitiveness Impacts and Defining Vulnerability

All policies, proposals, and analyses reviewed provide methods and metrics to measure the likely impacts of the carbon policy on industry, using a mix of quantitative and qualitative information. While a number of different approaches are employed, the review indicates a common set of questions to identify who might be at risk and evaluate the extent of the risk:

- Many policies describe a means for analyzing the extent to which industries may experience production cost increases (often due to their energy- or emissions-intensive nature) and trade exposure (competing in global or inter-jurisdictional markets);
- Many policies then assess the ability of industry to make reductions and/or pass on incremental cost increases resulting from carbon mitigation policies; and
- Many policies then define the extent of exposure as a function of the impact on profits relative to some acceptable threshold level.

Examples from the review include:

- **Waxman-Markey:** Qualifying industrial sectors are determined on the following basis:
    - o The sector has an energy intensity of at least 5 percent, or a greenhouse gas intensity of at least 5 percent; and
    - o The sector must also have a trade intensity of at least 15 percent (sectors with an energy-intensity of 20 percent are eligible regardless of trade exposure).
- **EU ETS Phase III**: In addition to metrics regarding trade-exposure and costs impacts resulting from carbon constraints (defined as a trade exposure of 10 percent, and a cost impact of 5 percent, respectively), the EU has proposed additional metrics to identify those with a significant carbon leakage risk:
    - o The extent to which it is possible for affected industrial sectors to reduce emission levels or electricity consumption;
    - o Market characteristics (current and projected), including when trade exposure or direct and indirect cost increase rates are close to identified thresholds;

- Profit margins as a potential indicator of long-run investment and/or relocation decisions.

With the methods and metrics established to identify who may be at significant risk of carbon leakage and competitiveness impacts, all of the programs and policies then identify what is to be done to address these impacts.

3) Options for Addressing Competitiveness Impacts

With a focus on reducing emissions leakage, policies and proposals provide measures to help ameliorate the competitiveness impact on firms resulting from an imbalance between stronger GHG constraints (and their impacts on costs) within a jurisdiction and weaker GHG constraints outside it. There are two basic approaches common among the policies and proposals reviewed:

- **Granting some amount of free allowances,** as in the case of the EU ETS, Waxman-Markey and the Australian proposal;
- **The option to apply border carbon adjustments** that equalize GHG-related costs for producers within jurisdiction and those without by imposing a cost or other requirement on energy-intensive imports from outside jurisdictions with weaker or no GHG constraints. This option is employed in both the EU ETS and the Waxman-Markey bill.

As mentioned in the goals section above, the policies and proposals reviewed have a provision that recognizes leakage risks may be transitory by providing for an on-going assessment of the leakage risk. For example, the EU-ETS list of sectors or subsectors exposed to a significant risk of carbon leakage shall be determined after taking into account:

> *"… the extent to which third countries, representing a decisive share of world production of products in sectors deemed to be at risk of carbon leakage, firmly commit to reducing GHG emissions ... and the extent to which carbon efficiency of installations located in these countries is comparable to that of the EU."*

Similarly, Waxman-Markey stipulates that unless a binding international agreement requires all major emitters to contribute equitably to reducing GHGs and addresses imbalances in competitiveness, in 2020 importers will be required to hold emission allowances (called international reserve allowances) for the import of products in energy-intensive, trade-exposed sectors. The reserve program would be established automatically in all eligible sectors unless the President determines that it is not in the national interest and Congress concurs. It would not apply if at least 85 percent of imports in a given sector are from countries that: have emission targets as stringent as the United States'; are parties to a sectoral agreement; or have energy or GHG intensities in that sector no higher than in the US. International reserve allowances could not be used by domestic entities for compliance purposes.

Detail on all of the above points is provided in the review tables.

Review of Proposed Options for Addressing Industrial Competitiveness Impacts

Policy, Proposal or Analysis	
"Addressing Competitiveness in U.S. Climate Change Policy." Pew Center Congressional Policy Brief. 2008. Available at http://www.pewclimate.org/DDCF-Briefs/Competitiveness.	
Goals	
Explore the options for minimizing competitiveness impacts to energy-intensive, trade-exposed industries (heavy energy users whose goods are traded globally, such as steel, aluminum, cement, paper, and glass).	
Metrics/Methods for Assessing Competitiveness Impacts and Defining Vulnerability	**Options for Addressing Competitiveness Impacts**
Energy-intensive industries defined as those whose energy costs are 4 percent or more of shipped value. The brief notes need to distinguish the "competitiveness" effect of climate policy from its broader economic impact; the competitiveness impact is the portion of the total impact resulting from an imbalance between carbon constraints in one region and the lack of such constraints in other regions. Assessing direct (compliance) costs: the cost of purchasing allowances needed to cover direct emissions regulated under the cap Assessing indirect costs: includes higher electricity and natural gas prices For most energy-intensive industries, the largest potential cost of carbon constraints is higher energy prices.	Options include: 1. Compensating firms for the costs of GHG regulation through allowance allocation or tax rebates. • Need to consider the scope, form, and means of how this compensation would be calculated, and whether (or if) it gets phased out over time. • Could include generous grandfathering of allowance allocations (to help mitigate direct costs), and additional allowances to compensate for indirect costs. Free allocation of allowances does not necessarily help guard against emissions leakage or job losses, as firms could maximize profits by selling their allowances and reducing production. • Compensation could also be "output-based," meaning it is a based on actual production levels and/or energy consumption. Firms could be fully compensated, or an output-based approach might apply a performance standard (i.e. energy or emissions per unit of production) that rewards or encourages lower-GHG intensive production. • Another option would be to provide tax credits or rebates, perhaps using proceeds from the auction of emission allowances. A tax rebate would be a direct payment to compensate a firm for GHG regulatory costs; a tax credit could alternatively offset those costs by reducing other taxes (such as corporate or payroll taxes) or healthcare or retirement costs. • Phasing out compensation over time can provide an additional incentive for firms to improve their GHG emission performance. 2. Transition assistance to help firms adopt lower-GHG technologies, and to help workers and communities adjust to changing labor markets • For firms, this might include tax incentives, such as accelerated depreciation to encourage the retirement of inefficient technologies, or tax credits for the development or adoption of lower-GHG alternatives. Firms could also be incentivized to switch to low carbon

	energy sources by providing subsidies to purchase or generate low-carbon electricity 3. Border measures such as taxes on energy-intensive imports from countries or regions lacking GHG controls (raises interstate commerce clause considerations for WCI or other states) 4. Exempting potentially vulnerable firms from the cap-and-trade system (e.g., excluding coverage of process emissions for energy-intensive industries) • Exclusions could relieve trade-exposed industries of direct regulatory costs (they would still face indirect costs from higher energy prices) • However, exclusions would also undermine the goal of economy-wide GHG reductions and make the overall program less efficient

Policy, Proposal or Analysis
Inslee-Doyle Carbon Leakage Prevention Act (H.R. 7146). Available at http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=110_cong_bills&docid=f:h7146ih.txt.pdf
Goals
Aims to avoid leakage of GHG emissions to countries outside the United States. Also seeks to compensate the owners and operators of entities in eligible domestic industrial sectors and subsectors for carbon emission control costs.

Metrics/Methods for Assessing Competitiveness Impacts and Defining Vulnerability	**Options for Addressing Competitiveness Impacts**
	Approach now incorporated into Waxman-Markey ACESA (with some modification); see below Allocates allowances to compensate for both direct and indirect costs based on a facility's level of output, adjusted by an "efficiency factor" set at 85 percent of emissions/energy use per unit of production within the sector • Eligible energy-intensive industries covered by the cap receive allowances for direct emissions based on a facility's level of production in the previous two years multiplied by 85 percent of average GHG emission per unit of production across the sector • Both covered and non-covered facilities receive allowances for indirect emissions based on their level of production multiplied by 85 percent of the average amount of electricity per unit of production for all facilities in the sector or subsector (adjusted by the average GHG emissions per kilowatt hour of electricity purchased by the facility) • Facilities whose GHG performance is at the sector average would be reimbursed for 85 percent of their costs, while those performing above or below average would be

	compensated for a greater or lesser of their costs, respectively • Provides firms an incentive to switch to lower-GHG processes and energy sources, while providing compensation and lowering risks of emissions leakage and competitiveness impacts. • Total allowances to eligible facilities in any year not to exceed 15% of total allowances available in the first year

Policy, Proposal or Analysis

American Clean Energy and Security Act of 2009 (Waxman-Markey Substitute Amendment) – June 2009. Available at http://energycommerce.house.gov/Press_111/20090701/hr2454_house.pdf.

Goals

Aims to promote a strong global effort to reduce GHG emissions and avoid dangerous climate change.

Aims to avoid leakage of GHG emissions to countries outside the United States as a result of direct, indirect compliance costs.

Would also compensate ("rebate") the owners and operators of entities in eligible domestic industrial sectors and subsectors for GHG emission control costs, but not for costs resulting from other market dynamics. Compensation would be sufficient to prevent carbon leakage while still rewarding innovation and facility-level energy efficiency improvements.

Would eliminate or reduce assistance when it is no longer necessary.

Notes importance of international negotiation in mitigating leakage and threats to industrial competitiveness; pledges that US will work towards an agreement that includes binding agreements, including sectoral agreements, committing all major emitters to equitable contributions to GHG reductions (recognizing that this is the most effective way to meet the purposes outline in the bill).

Metrics/Methods for Assessing Competitiveness Impacts and Defining Vulnerability	Options for Addressing Competitiveness Impacts
Owners of qualifying industrial facilities would receive annual emission allowance rebates (free allowances) to help compensate them for compliance costs and prevent carbon leakage. The total number of allowances distributed under these provisions cannot exceed a maximum limit established by the program. Qualifying industrial sectors are determined on the following basis: 1. Must have a 6-digit classification under NAICS 2. The sector or subsector must have an energy intensity of at least 5 percent, calculated by dividing the cost of purchased electricity and fuel costs of the sector or subsector by the value of the shipments or the sector or subsector, or a greenhouse gas intensity of at least 5 percent, calculated by dividing the number 20, multiplied by the CO2e emissions (including direct emissions from fuel combustion, process emissions, and indirect emissions from the generation of electricity used to produce the output of a sector or subsector) by the value of the shipments of the sector or subsector. 3. The sector or subsector must also have a trade intensity	Rebates are provided in the form of free emission allowances. The quantity of emission allowances rebates provided to a covered and eligible industrial entity would be equal to the sum of the covered entity's direct carbon factor and its indirect carbon factor (for non-covered, eligible entities, the rebates would be based on an entity's indirect carbon factor only). However, in years 2012 and 2013, allowance distribution will be based only on entities' indirect carbon factor (described below). • The direct carbon factor is calculated by multiplying the average output of the covered entity for the two years preceding the rebate distribution year by the average direct greenhouse gas emissions (in CO_2e) per unit of output for all covered entities in the sector. • The indirect carbon factor for an entity is the product of its average output (for the two years preceding the rebate distribution year) multiplied by both its electricity emissions intensity factor (the emissions intensity of each facility's electric power supplier) and the electricity efficiency factor (the sector average electricity use per unit of output). o The electricity emissions intensity factor (in tons of CO_2e/kWh) is determined by dividing 1) the annual sum

of at least 15 percent, calculated by dividing the value of the total imports and exports of such sector/subsector by the value of the shipments plus the value of imports or the sector/subsector.

4. Sectors are also eligible if they have an energy intensity of 20 percent (regardless of trade intensity).

Provision is made for administrative determination of additional eligible sectors or subsectors. Any person may petition the program administrator to grant rebates to a given sector/subsector, provided the petitioner can demonstrate that the sector/subsector is subject to carbon leakage comparable to that of sectors or subsectors that already meet the criteria for determination laid out in the bill.

of the hourly product of the electricity purchased by an entity, multiplied by the cost the seller of the electricity passes to the entity per ton of CO_2e per kWh, by 2) the total kWh of electricity purchased by the entity from that seller in that year.

- o The electricity efficiency factor is the average amount of electricity (in kWh) used per unit of output for all entities in the relevant sector/subsector.

Direct and indirect carbon factors for eligible facilities are calculated using average output data for the two years preceding the year of distribution, and the most recent sectoral emissions intensity data (GHG per unit of production). Average direct GHG emissions per unit of output, for all covered entities in each eligible sector, are calculated every four years using the most recent two years of data.

- The average direct GHG emissions per unit of output for a sector will never by greater than it was in a previous calculation
- When recalculated, the electric emissions intensity factor will not be greater than it was in a previous year

There is a maximum limit on the number of allowances available for these purposes. In years 2012 and 2013, up to 2 percent of the total allowances available in those years could be used for industrial assistance. Starting in 2014, 15 percent of total allowances are available for industrial assistance; this percentage declines based on the percent reductions in the emissions cap. Starting in 2026, this decline is accelerated as the number of allowances distributed under this section will be reduced by a further 10 percent/year (phasing out completely in 2035) unless the President alters the phase-out schedule (the President must make a determination as to whether a given sector still requires assistance). For a year in a which the total emission allowance rebates calculated under this section exceed the number allocated for these purposes in a given year, the Administrator shall reduce each entity's distribution on a pro rata basis so that the total distribution equals the number of allowances available for this distribution in a given year.

Unless a binding international requires all major emitters to contribute equitably to reducing GHGs and addresses imbalances in competitiveness, beginning in 2020 the bill requires emission allowances (called international reserve allowances) for the import of products in energy-intensive, trade-exposed sectors. The reserve program would be established automatically in all eligible sectors unless the President determines that it is not in the national interest and Congress concurs. It would not apply if at least 85 percent of imports in a given sector are from countries that: have emission targets as stringent as the United States'; are parties to a sectoral agreement; or have energy or GHG intensities in that sector no higher than in the US. International reserve

	allowances could not be used by domestic entities for compliance purposes.

Policy, Proposal or Analysis

Australia's Carbon Pollution Reduction Scheme: Proposed Cap and Trade System (NOTE: This is subject to change as negotiations continue over the design details of the system). Information on latest proposals available at http://www.climatechange.gov.au/emissionstrading/index.html

Goals

Two goals to address competitiveness concerns:

- Avoid leakage associated with carbon pricing
- Address transitional challenges faced by emissions-intensive, trade-exposed industries

Metrics/Methods for Assessing Competitiveness Impacts and Defining Vulnerability	**Options for Addressing Competitiveness Impacts**
Measuring the impacts. Trade exposure assessed through quantitative and qualitative tests: **Step 1:** Define exposed sources based on activity • Activities defined through stakeholder process **Step 2:** Assess emissions intensity • To derive emissions intensity, direct and indirect emissions are evaluated relative to employment, revenue or value added. • Emissions intensity sectoral assessment based on average emissions per million dollars of revenue or emissions per million dollars of value-added (uses 2006-2007, 2007-2008 for emissions data) **Step 3:** Assess competition from lower cost products and ability to pass-through costs (trade exposure) • Responsiveness of customers to price changes (price elasticity) • Parity of import and export prices • Share of trade in the market • Potential for international competition	Output-based allocation of allowances (based on a facility's previous year's level of production). The Australian government expects this will account for about 25 percent of all allowances initially, increasing to around 45 percent of all allowances available in 2020 • Covers both direct and indirect costs • Applies to existing and new facilities (allows for continued industry growth) • If a facility closes, it must relinquish permits for production that did not occur in that year • Initial rates of assistance: 90 percent to sectors with emissions intensity of at least 2000t of CO2e per million dollars of revenue or 6000t of CO2e per million dollars value-added; 60 percent to sectors with emissions intensity between 1000t and 1999t CO2e per million dollars of revenue, OR between 3000t and 5999t CO2e per million dollars value-added (see below for recent amendments) • Initial rates of assistance will be reduced by a carbon productivity contribution of 1.3 percent per year In addition, in May 2009 the Australian government announced changes to its cap and trade system, due in part to the global recession. Changes relevant to industrial competitiveness include: • A more stringent target; Australia's government will commit to reduce emissions by 25 per cent of 2000 levels by 2020 (the original target was 5-15 percent below 2000 levels by 2020) if a global agreement can be reached that will stabilize levels of CO_2 equivalent in the atmosphere at 450 parts per million or less by 2050. • A delay in the start date of the Carbon Pollution Reduction Scheme of one year (from 2010 to 2011).

	• A one year fixed price period, during which allowances will cost \$10 per tonne of carbon in 2011-12, with the transition to full market trading from 1 July 2012. • A new Global Recession Buffer will be provided as part of the assistance package for emissions intensive trade exposed industries. Industries eligible for 60 per cent assistance will receive a 10 percent buffer, while industries eligible for 90 per cent assistance will receive a 5 per cent buffer (see above for assistance thresholds). In practice, the buffer means that where particular industries were before eligible for 60 percent assistance, they will now receive up to 70 percent, and industries that were eligible for 90 percent assistance will receive up to 95 percent. • Eligible businesses will receive funding to undertake energy efficiency measures from 1 July 2009.
Policy, Proposal or Analysis	
Lieberman-Warner Climate Security Act of 2008 (S. 3036). Available at http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=110_cong_bills&docid=f:s3036pcs.txt.pdf	
Goals	
Avoid carbon leakage to regions/countries outside the U.S., and help firms transition to lower-carbon practices	
Metrics/Methods for Assessing Competitiveness Impacts and Defining Vulnerability	**Options for Addressing Competitiveness Impacts**
Energy-intensive industries defined as iron, steel, aluminum, pulp, paper, cement, and chemicals	Process emissions of many energy-intensive industries are exempt from the cap; only process and combustion emissions from use of coal (more than 5000 tons/year per facility) are covered. Energy-intensive industries initially receive 11 percent of total allowances for any covered process emissions and to compensate for higher energy costs, declining to 1 percent of total allowances in 2030. Allowances allocated based on sectors' relative energy intensity and facilities' level of employment.

Review of Proposed Options for Addressing Industrial Competitiveness Impacts

<table>
<tr><th colspan="2">Policy, Proposal or Analysis</th></tr>
<tr><td colspan="2">AB 32 Global Warming Solutions Act and supporting public consultation material, California Air Resources Board (CARB). Legislative text available at http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_0001-0050/ab_32_bill_20060927_chaptered.pdf. Updates on implementation and other materials at http://www.arb.ca.gov/cc/cc.htm.</td></tr>
<tr><th colspan="2">Goals</th></tr>
<tr><td colspan="2">Two key indicators of leakage risk:
• Assess potential cost increases due to program compliance costs. Increased costs associated with compliance could result either from the costs of actions taken to reduce emissions at the facility, and/or costs of acquiring emission allowances to cover remaining emissions after all actions to reduce emissions are taken at the facility.
• Assess the ability of industries to pass compliance costs on to their customers. If industries have limited ability to pass on costs because their competitors are not subject to similar emission reduction requirements or compliance costs, then the risk of leakage may be heightened. Existing producers may lose market share, and new investment may shift to regions that do not have similar program requirements.</td></tr>
<tr><th>Metrics/Methods for Assessing Competitiveness Impacts and Defining Vulnerability</th><th>Options for Addressing Competitiveness Impacts</th></tr>
<tr><td>Identify potentially affected industries
• Industries that compete in global markets that are not able to pass on the costs of the GHG emissions reduction program.
• Industries in this category may include non-ferrous metals smelting, iron and steel-making, cement, and other energy and/or emissions intensive activities.
Evaluate possible impacts
• These industries may face significant compliance costs from carbon intensive combustion processes and fuel use.
o Limited ability to reduce costs due to fewer opportunities for emission reductions.
• Inability to pass through costs to consumers.
o Competition from those without similar compliance requirements (trade exposure).

Reviewing EU ETS, Australia CPRS, Waxman-Markey discussion draft and other relevant materials and reporting back with a proposal in summer 2009.
Incorporate appropriate features in the program design (on-going).</td><td>Start stakeholder process in Fall 2009 to discuss different options to address the risk of leakage.</td></tr>
</table>

Review of Proposed Options for Addressing Industrial Competitiveness Impacts

Policy, Proposal or Analysis

EU ETS Phase III (final directive and materials available at http://ec.europa.eu/environment/climat/emission/ets_post2012_en.htm)

Goals

A potential concern with competitiveness in energy-intensive industries, with some "exposed to a significant risk of carbon leakage"

Defined as meaning that they could be forced by international competitive pressures to relocate production to countries outside the EU that did not impose comparable constraints on emissions.

Metrics/Methods for Assessing Competitiveness Impacts and Defining Vulnerability

Eligible industries criteria:

"A sector or sub-sector is deemed to be at a significant risk of carbon leakage if the sum of direct and indirect additional costs induced by the implementation of the Directive would lead to an increase in production costs exceeding 5% of Gross Value Added and if the total value of its exports and imports divided by the total value of its turnover and imports exceeds 10%.

- Those experiencing more than a 5 percent cost impact as a result of carbon constraints
- Those with a greater than 10 percent trade exposure (defined as [total imports + exports]/[total production + imports]

By way of derogation, a sector or sub-sector is also deemed to be exposed to a significant risk of carbon leakage if the sum of the direct and indirect additional costs induced by the implementation of the Directive would lead to an increase in production costs exceeding 30% of its Gross Value Added or if the total value of its exports and imports divided by the total value of its turnover and imports exceeds 30%."

Further sectors or subsectors deemed to be exposed to a significant risk of carbon leakage may be added after the completion of a qualitative assessment, "taking into account, when the relevant data are available, the following criteria:

- the extent to which it is possible for individual installations in the sector and/or subsector concerned to reduce emission levels or electricity consumption, including, as appropriate, the increase in costs of production that related investment may entail, for instance on the basis of the most efficient techniques;
- market characteristics (current and projected), including when trade exposure or direct and indirect cost increase rates are close to one of the thresholds mentioned [the threshold that non-EU Trade intensity is above 10%];
- profit margins as potential indicator of long-run investment and/or relocation decisions".

Options for Addressing Competitiveness Impacts

Sector Allocation	EC Proposal, 23 January 2008	Final Directive, April 2009
Electricity Generation, Carbon Capture and Storage	100% auctioning from 2013**	100% from 2013 in electricity generation but with a derogation of at least 30%, rising linearly to 100% in 2020, for certain Member States*** 100% auctioning for CCS
Sectors "at significant risk of carbon leakage"*	Will receive up to 100% of their allowances for free in 2013-2020	100% free allowances "to the extent that they use the most efficient technology" (based on the average of the top 10 percent most efficient facilities in the EU)
Sectors not "at significant risk of carbon leakage"*	20% auctioning 2013, linear increase to 100% in 2020	20% auctioning 2013, linear increase to 70% in 2020 with a view to reaching 100% by 2027

*Defined as meaning that they could be forced by international competitive pressures to relocate production to countries outside the EU that did not impose comparable constraints on emissions. This would simply increase global emissions without any environmental benefit. **Takes account of the sectors ability to pass on the increased cost of emission allowances. ***Member States who, "fulfil conditions relating to their interconnectivity or their share of fossil fuels in electricity production and GDP per capita in relation to the EU-27 average, have the option to temporarily deviate from this rule with respect to existing power plants". The provision refers to new Member States in the east of the European Union. They are required to submit national plans showing how the value of their free allocations will be spent on retrofitting and upgrading infrastructure and clean technologies (submitting an annual

	report detailing investments) and diversifying their energy mix. Free allocation of allowances based on an efficiency benchmark multiplied by historical production multiplied by an exposed or non-exposed factor (trade-exposed industries have a factor of 100 percent); • Benchmark is based on average emissions per unit of production, using data from the top 10 percent most efficient facilities within a given industrial sector in the EU (based on 2007 data). This is what is meant by "best available technology." Benchmark level remains the same through 2020 (this provides planning certainty; sources know exactly how many allowances will be available through 2020). • Total allowances available for free to industry in a given year is based on the average share of industrial emissions from covered industries for baseline years 2005-2007, multiplied by the overall cap in that year (e.g., if industrial emissions accounted for 15 percent of total EU average emissions in for 2005-2007, then in 2013 the total number of allowances available to industry would be 15 percent of the 2013 cap). Added to this are average annual emissions for 2005-2007 for installations that were not part of the EU-ETS in those years (but have since joined) reduced by an annual reduction factor. The list of sectors or subsectors exposed to a significant risk of carbon leakage shall be determined after taking into account, *"the extent to which third countries, representing a decisive share of world production of products in sectors deemed to be at risk of carbon leakage, firmly commit to reducing GHG emissions ... and the extent to which carbon efficiency of installations located in these countries is comparable to that of the EU* Evaluations of exposure are scheduled to be on-going: • no later than December 31, 2009 and every 5 years thereafter; • no later than June 30 2010 (for decisions relating to the outcome of international agreements). Three further conditions relate to the outcome of international agreements: 1. that the Commission will study the possibility of granting additional allowances free of charge to industrial sectors exposed to a significant risk of carbon leakage; 2. "*In its impact assessment of the negotiations of an international climate change agreement, the Commission will take account of the impact of carbon leakage on Member States' energy security, in particular where the electricity connections with the rest of the European Union are insufficient and where there are electricity connections*

	with third countries. The Commission may take appropriate measures in this regard"; 3. The option of applying border measures was added to the possible actions for redress (which were previously the granting of free allowances and including product importers within the ETS). In common with allocation, the net effect of these conditions is to add some uncertainty to the questions of which (sub-)sectors will receive free allocations and how the quantity they receive may change with time. The revised Directive, Article 10a6 also provides for the possibility for Member States to compensate the most electro-intensive sectors for increases in electricity costs resulting from the ETS through national state aid schemes. Therefore, the Commission will correspondingly modify the Environmental State Aid Guidelines by 31 December 2010.
Policy, Proposal or Analysis	
RGGI (Model Rule and other documents available at http://rggi.org/home).	
Goals	
Concern over production leakage, with shifting production to higher emitting sources not covered by RGGI. Implicit in this concept is the notion of causality; specifically that a cost increase due to a carbon cap could drive geographic changes in the operation of the electric power system. This is distinct from a shift in the geographic distribution of electric generation resulting from other market variables and the dynamic nature of the electric power market. Only applicable with no operating national system (i.e. transitional): The implementation of a national CO2 cap-and-trade program for the electric power sector that is equivalent to RGGI, or a scenario where RGGI sunsets once a national program is implemented, would obviate any potential for emissions leakage.[1]	
Metrics/Methods for Assessing Competitiveness Impacts and Defining Vulnerability	**Options for Addressing Competitiveness Impacts**
Ongoing measurement of leakage using electricity market information (regional market data). Changes relative to a historical baseline used to identify impacts.	Participating states have agreed to prioritize leakage mitigation measures that have demonstrated effectiveness and that can be implemented quickly, and do not seek to implement a relative to more complex measures that would require greater implementation lead times and pose significant implementation challenges that may limit their effectiveness.[2]
Policy, Proposal or Analysis	
Achieving 2050: A Carbon Pricing Policy For Canada, 2009. National Roundtable on Environment and Economy. Available at http://www.nrtee-trnee.com/eng/publications/carbon-pricing/carbon-pricing-advisory-note/carbon-pricing-advisory-note-eng.pdf.	

[1] Potential Emissions Leakage and the Regional Greenhouse Gas Initiative (RGGI): Evaluating Market Dynamics, Monitoring Options, and Possible Mitigation Mechanisms (Initial Report)

[2] Potential Emissions Leakage and the Regional Greenhouse Gas Initiative (RGGI) http://rggi.org/docs/20080331leakage.pdf

Review of Proposed Options for Addressing Industrial Competitiveness Impacts

Goals	
Transitional support to trade and carbon exposed sectors who can demonstrate hardship impacts with carbon pricing As more jurisdictions increase carbon price, exposure reduces and transitional support is phased-out	
Metrics/Methods for Assessing Competitiveness Impacts and Defining Vulnerability	**Options for Addressing Competitiveness Impacts**
Firms must be trade and energy exposed, and have demonstrate hardship relative for baseline firm profits.	Output-based allocations (gratis) transitioning to an increasing share of auction as risks mitigate. Other measures such as border carbon adjustments and income tax relief (tax shifting from allowances) are viable options, but secondary strategies beyond OBA. Safety value in place to address rising concerns over misalignment with trading partners. A new governance structure monitors relative carbon prices and competitiveness risks, and adjusts policy accordingly on five year increments.
Policy, Proposal or Analysis	
Aldy, Joseph E. and William A. Pizer. *The Competitiveness Impacts of Climate Change Mitigation Policies*. Pew Center on Global Climate Change, 2009. Available at http://www.pewclimate.org/international/CompetitivenessImpacts.	
Goals	
Quantify the potential competitiveness effect of domestic greenhouse gas regulation on U.S. manufacturing industries, and outline range of policy options for addressing these impacts	
Metrics/Methods for Assessing Competitiveness Impacts and Defining Vulnerability	**Options for Addressing Competitiveness Impacts**
The competitiveness effect is the economic impact on a firm arising from the fact that it faces a carbon price while its competitor in another state or country faces no or a lesser carbon price. It is important to distinguish the "competitiveness" effect from the broader economic impact on a given industry or firm. Mandatory climate policy will present costs for firms regardless of what action is taken by other countries or regions. In the case of energy-intensive industries, one potential impact of pricing carbon could be a decline in demand for their products as consumers substitute less GHG-intensive products. This is distinct, however, from the international or inter-regional "competitiveness" impact of GHG regulation The Pew report analyzes 20 years of data in order to discern the historical relationship between electricity prices and production and consumption in more than 400 U.S. manufacturing industries. On that basis, the analysis then projects the potential competitiveness impacts of a U.S. carbon price, assuming no comparable action in other countries. The analysis assumes a CO_2 price of $15 per ton. (The U.S.	A number of targeted measures can be pursued within a cap and trade program • Allowances revenue could be used to provide targeted relief through lower taxes on capital for affected energy-intensive firms, or lower payroll taxes on workers. • Free allocation of allowances could be scaled to offset output losses resulting from competitiveness impacts due to climate policy (e.g., if a plant's production drops by 10 percent – 7 percent from a shift in consumption and 3 percent due to competitiveness impacts, then free allowances could be granted equal in value to 3 percent loss in output). • Emissions allowances can also be freely allocated in a manner that subsidizes production (similar to output based allocation of Inslee-Doyle and Waxman-Markey approaches, above).

Energy Information Administration's core case analysis of the Lieberman-Warner cap-and-trade bill estimated a 2012 allowance price of $16.88 per ton CO_2). The analysis finds an average production decline of 1.3 percent across U.S. manufacturing, but a 0.6 percent decline in consumption, suggesting a competitiveness effect of 0.7 percent. For energy-intensive industries (those whose energy costs exceed 10 percent of shipment value), the analysis projects that average U.S. output declines about 4 percent. However, consumption declines 3 percent, so that only a 1 percent decline in production (or one-fourth of the total decline) can be attributed to an increase in imports, or a loss of competitiveness. For specific energy-intensive industries, including chemicals, paper, iron and steel, aluminum, cement, and bulk glass, the analysis projects a competitiveness impact ranging from 0.6 percent to 0.9 percent, although within certain subsectors, the impact could be higher. The analysis demonstrates very clearly that most of the projected decline in production stems from a reduction in domestic demand, not an increase in imports. Most of the projected economic impact on energy-intensive industries reflects a move toward less emissions-intensive products. At the price level studied, the projected competitiveness impacts, as well as the broader economic effects on energy-intensive industries, were fairly modest.	

Western Climate Initiative News

August 7, 2009

This status report is issued monthly from WCI Partner jurisdictions to all interested stakeholders via the WCI listserv and website.

In This Issue

Regional Emissions Database White Paper Released

Draft Statement of Principles on Competitiveness Released

Other Documents Recently Released

Eastern Electricity Emissions Leakage Study Underway

Offset Protocol RFP

WCI Reporting Committee Releases Regional Emissions Database White Paper

The white paper, prepared by The Climate Registry, is intended to educate the Committee and stakeholders on fundamental design choices for the WCI regional emissions database, including options for managing data and designing functions. A stakeholder conference call to review and discuss the white paper will be held on August 17. (See Upcoming Events for details.) Stakeholder comments should be submitted through the WCI website by September 4.

WCI Cap Setting and Allowance Distribution Committee Releases Draft Statement of Principles on Competitiveness

The purpose of the statement of principles is to guide the process by which the WCI Partner jurisdictions will evaluate the competitiveness effects of a regional cap-and-trade program. The principles serve as the foundation for a common approach to addressing competitiveness issues agreed upon by WCI partner jurisdictions. As part of the principle development process, the Committee analyzed how other program and proposals address competitiveness. A summary of these other programs and proposals in addition to the draft statement of principle are posted on the WCI website. Public comments should be submitted through the website by August 28.

Other Documents Recently Released by the WCI

Other documents recently released by the WCI and distributed via the WCI listserv include:

Upcoming Events

August 17: WCI Stakeholder Call to Discuss Regional Emissions Database White Paper

The WCI Reporting Committee will be hosting a call on August 17, from 9:30 - 10:30 a.m. (Pacific) to review and discuss its recently-released Regional Emissions Database White Paper. To join the call, dial 1-800-868-1837 (toll free) or 1-404-920-6440 (direct dial), and enter participant code 659537#.

August 20: WCI Stakeholder Update Call

The WCI Partners will be hosting a stakeholder update call on August 20 at 12:30 p.m. Pacific. To join the call, dial **1-800-868-1837** (toll free) or 1-404-920-6440 (direct dial), and enter participant code **659537#.**

September 16: WCI Partners Meeting

The next WCI Partners meeting will be at the Radisson Hotel Admiral Toronto-Harbourfront, 249 Queen's Quay West, Toronto, Ontario. Stakeholders are invited to attend in-person or via teleconference from 9:00 a.m. to 4:00 p.m. Eastern time. To join by teleconference, dial 1-800-868-1837 (toll free) or 1-404-920-6440 (direct dial), and enter participant code 659537#. Further details will be posted to the WCI website when available.

- Announcement on implementing the first jurisdictional deliverer approach,
- Final Essential Requirements for Mandatory Reporting, and
- Offset Definition and Eligibility Criteria White Paper.

These documents are available on the WCI website. Written comments are being accepted on the offset white paper and should be submitted through the WCI website by August 21. Phase III economic modeling results are not likely to be available until September.

WCI Undertakes Eastern Electricity Emissions Leakage Study

With technical assistance from Navigant Consulting, the WCI has initiated an eastern electricity emissions leakage study for Manitoba, Ontario, and Quebec. The study will address the concern that reductions in fossil-fired electricity generation within these jurisdictions may be offset by increases in fossil-fired generation in non-WCI jurisdictions that is then imported into WCI jurisdictions. The study should be completed in October.

Offsets Committee Seeking Proposals to Review Existing Protocols

The Offsets Committee has identified a number of existing offset protocols potentially suitable for use in the WCI cap-and-trade program and is seeking contractor support to evaluate these proposals against WCI draft offset criteria and identify which are suitable for adoption as-is and which could be suitable for adoption with minor modifications. The Committee's request for proposals is posted on the WCI website. Proposals are due August 21.

Western Climate Initiative News

August 28, 2009

Upcoming Events

September 16: WCI Partners Meeting in Toronto

The next WCI Partner meeting will be on September 16 in Toronto, Ontario at the Radisson Hotel Admiral Toronto Harbourfront. Stakeholders are invited to attend in-person or via teleconference from 9:00 a.m. to 4:00 p.m. **Eastern** time. Registration is not required. To join the teleconference, dial 1-800-868-1837 (toll free in the U.S. and Canada), participant code 659537#. Partners are currently developing the agenda, which will be announced on the listserv and posted to the website when available.

October 15: WCI Stakeholder Update Call

The WCI Partners will be hosting their next bimonthly stakeholder update call on October 15 at 12:30 p.m. Pacific. To join the call, dial 1-800-868-1837 (toll free) or 1-404-920-6440 (direct dial), and enter participant code 659537#.

This status report is issued monthly from WCI Partner jurisdictions to all interested stakeholders via the WCI listserv and website.

In This Issue

Recently Released Materials

Recently Achieved Program Design Milestones

WCI Submits Comments on Canadian Proposed Offsets System

Analysis and Studies Underway

WCI Priorities in Light of Federal Activities

Recently Released Materials

Partners are continuing to develop the materials described in the 2009-2010 work plan to meet their objective of putting the WCI program in place by January 1, 2012. Recently released documents include:

- *Offset Limit White Paper* - released on May 19. Final recommendations will be coming in September.
- *Early Reduction Allowances White Paper* - released on May 19. Final recommendations are anticipated in October.
- *Offset Definition and Eligibility Criteria White Paper* - released on July 23. Comments were requested by August 21 and discussed on a stakeholder call held August 27.
- *Draft Statement of Principles on Competitiveness and Review of Options* - released on August 6 and currently open for comment. Comments are requested by August 28.
- *Regional Emissions Database Options White Paper* - released August 6 and currently open for comment. Comments are requested by September 4.

As always, the WCI Partners appreciate stakeholder review of these and future documents

Program Design Milestones

WCI Partners recently achieved two program design milestones:

- The Essential Requirements for Mandatory Reporting were released on July 16.
- A decision on how to implement the First Jurisdictional Deliverer (FJD) approach was announced on July 21.

Comments on Canadian Proposed Offsets System

WCI recently submitted written comments to Environment Canada on the Canadian Offsets System draft documents: Program Rules and Guidance for Project Proponents and Program Rules for Verification and Guidance for Verification Bodies. The letter accounts for WCI's perspectives and concerns on the current draft federal offset system design. The letter focuses on areas of the offset program design that the WCI has completed, although other areas are of interest, such as the length of the liability period, the mechanism to ensure replacement of credits in the event of a reversal, and the application of incrementality.

Analysis and Studies Underway

- WCI Partners recently released two RFPs to support program development. An RFP to develop methods and conduct data analysis to support cap setting was awarded to Pechan, and work is underway on this effort. Partners are currently evaluating proposals that were received for an RFP to review existing offset protocols.
- The WCI Partners have initiated a study of leakage potential for the electricity system in the eastern Canadian provinces, which should be completed in October.
- The Economic Modeling Team is completing the Phase III Economic Modeling Results and Revised Assumptions Book. Results will be released this fall.

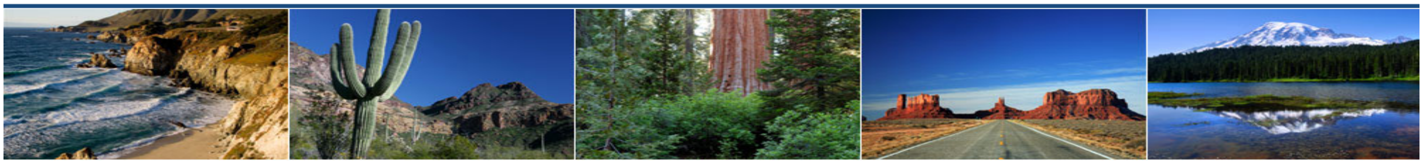
WCI Priorities in Light of Federal Activities

WCI Partners are mindful of the developments in both the Canadian and United States national governments. The WCI program design recommendations were developed to stand-alone as a regional program, to be a model for national action, to be integrated into national programs, or be implemented in conjunction with programs that might ultimately emerge from the federal governments of Canada and the United States. Some of the ways WCI Partners are working to influence the federal debate are noted below. See the WCI website for further details.

- ***Comments on Federal Activities*** - WCI Partners have commented and are continuing to comment on federal activities in both Canada and the U.S. In addition to submitting written comments on the Canadian Offsets System draft documents (see article, above), WCI has submitted written comments on the Waxman-Markey legislation (April), oral and written comments on the U.S. EPA proposed mandatory reporting rule (June), and written comments on U.S. EPA's proposed endangerment findings for GHGs (June) Partners are currently working on comments to the U.S. Senate for its deliberations on a pending energy and climate bill.

- ***Regional Collaboration*** - As discussed at the Partner meeting in Portland in July, WCI Partner jurisdictions have initiated discussions with the other two regional programs in North America: the Regional Greenhouse Gas Initiative (RGGI) and the Midwestern Greenhouse Gas Reduction Accord. Collaborating in key areas will expand the footprint of each of the regional program designs, particularly in the area of offsets, and helps influence developments in the national programs.
- ***Development of a Mandatory Reporting Program***- The WCI Partner jurisdictions recognize that an initial point of intersection between federal efforts in the U.S. and the WCI program is the mandatory reporting program. The WCI Partner jurisdictions have advocated that U.S. EPA adopt the WCI Essential Requirements. However WCI expects that the final U.S. EPA reporting rule will deviate in some respects from the WCI Essential Requirements, and consequently expects to harmonize some aspects of the WCI Essential Requirements with U.S. federal requirements once the EPA rules are final. The WCI is committed to doing so as quickly as possible after the EPA rules are final, and is equally committed to preventing double reporting burdens for entities that would potentially be required to report to both a state and U.S. EPA. Similarly in Canada, there is a dialogue underway between the four WCI provinces and the Canadian federal government to inform them about the WCI Essential Requirements.
- ***Focusing Work to Influence the National Program*** - WCI Partners are focusing current work on those areas with a high potential to influence the national programs. These areas include: Offsets, including the quantity and quality of offsets included in the program; Competitiveness Analysis, focusing on approaches for identifying risk of leakage and program design options to address the risks; and Complementary Policies, recognizing that states and provinces have been and will continue to be leaders in areas essential to a comprehensive climate change program. In each of these areas, WCI work is timely and important for the national debate.

Western Climate Initiative



Radisson Hotel Admiral
Toronto-Harbourfront
249 Queen's Quay West
Toronto, Ontario

For remote access, call 1-800-868-1837 toll free in the U.S. and Canada (1-404-920-6440 for outside the U.S. and Canada), ***participant code 659 537#***

<u>**Wednesday, September 16, 2009**</u>

9:00 am	**Convene (Salon B – 3rd Floor)** Welcome and Introductions Agenda Review
9:15 am	**Offset Limit White Paper** Purpose: Discuss Partner comments on the draft recommendations for the offset limit mechanism. Approve release for stakeholder review and comment.
10:15 am	**Mandatory GHG Reporting Protocol for the Oil and Gas Sector** Purpose: Discuss options for WCI Reporting Committee development of a mandatory GHG reporting protocol for the oil and gas sector.
10:45 am	**Break**
11:00 am	**Offset Definition and Eligibility Critera** Purpose: Update from the Committee on the comments received and approach for developing recommendations on the proposed definition and criteria. Provide Partner direction for continued Committee deliberation.
12:00 pm	**Lunch (***attendees are on their own for lunch***)**
1:30 pm	**WCI Interaction with Federal Governments** Purpose: Discuss ongoing activities to interact with federal governments in U.S. and Canada.

2:00 pm **Update on WCI Electricity Team**

Purpose: Apprise stakeholders of modified organization and new leadership.

2:15 pm **Briefing on Market Oversight Issues**

Purpose: Receive Partner feedback on market oversight issues being examined by the Markets Committee.

2:45 pm **Break**

3:00 pm **Briefing on Auction Design Issues**

Purpose: Receive Partner feedback on auction design issues being examined by the Markets Committee.

3:30 pm **Open Comment Period**

4:00 pm **Adjourn**

Western Climate Initiative

Markets Committee
Parameters of Auction Design

Markets Committee Overview

September 16, 2009
Toronto, Ontario

Markets Committee Mission

- Coordinate the development of recommendations on issues and elements needed to guide the proper development and operation of a robust allowance and offset credit trading market.

Auction Parameters

- following parameters are essential in defining the structure of the auction:

Auction Format
Reserve Price
Unsold Allowances
Vintages
Lot Size

Timing and Frequency of Auctions
Participant Access
Financial Assurance
Information and Transparency
Preventing Market Manipulation

Parameters Discussion

Auction Format:

- how participants can bid on allowances, for example:

  a) Sealed Bid Single Round

  b) Ascending/Descending Clock multiple rounds

Reserve Price:

- the minimum allowance price that the seller will accept.
- the existing WCI position is that the first 5% of allowances auctioned will have a reserve price.

Parameters Discussion Cont.

Unsold Allowances:

- may occur if the reserve price is higher than the auction market clearing price.
- can be retired, rolled forward, or held as a contingency.

Vintages:

- vintage allowances are sold prior to the compliance period for which they become valid.
- vintages help with price discovery but also increase the complexity of auction.

Parameters Discussion Cont.

Lot Size:

- refers to the number of allowances bundled together for offering as an action unit.
- smaller lot size allows flexibility in the bidding strategy and makes auction participation more affordable for non-compliance entities.
- smaller lot size would increase auction transaction costs due to an increase in the number of lots for sale.

Timing and Frequency of Auctions:

- benefits to frequent auctions include market liquidity, price stabilization and discouraging collusion.
- frequent auctions also increase administrative costs.

Parameters Discussion Cont.

Participant Access:

- restricting access to the auction may benefit compliance entities.
- open access increases market liquidity.

Financial Assurance:

- often required from bidders to ensure they are able to cover the value of their bids (e.g., bonds, letters of credit).
- prequalification of participants is essential to the integrity of the auction.
- prevents defaults.

Parameters Discussion Cont.

Information and Transparency:

- transparency builds trust with stakeholders, covered entities and increases the integrity of the auction program.

Preventing Market Manipulation:

- there are several ways to minimize collusion, manipulation and hoarding. For example:
  - Encouraging many bidders to participate in the auction.
  - auction monitoring, single round bidding, sealed bidding and uniform price method.
  - Preventing participants from purchasing more than a certain amount of allowances at a single auction.
  - Maintaining an open and transparent auction.

Other Jurisdictions

- Regional Greenhouse Gas Initiative (RGGI)
- United Kingdom – European Trading System (UK ETS)
- Australia: Carbon Pollution Reduction Scheme
- US Environmental Protection Agency: SO_2
- US Treasury: Sale of Treasury Bills

Jurisdictional Review:

Regional Greenhouse Gas Initiative

Auction Format	Single round, uniform-price sealed-bid auction
Reserve Price	$1.86
Unsold Allowances	Are to be sold at the next auction
Vintage	Sells future vintages
Lot Size	1,000 tons
Timing and Frequency	Auctions are held quarterly, in each year of the compliance period
Participant Access	Interested entities must register to obtain access to auctions
Financial Assurance	Participants must submit financial assurance before the auction
Information and Transparency	After each auction, results and auction assessment are released. This is produced by a third party
Monitoring	Third party observation

Jurisdictional Review Cont.

UK European Trading System (ETS)

Auction Format	Single round uniform price auction and a non-competitive bid process
Reserve Price	Not announced in advance. Based on a prevalent secondary market price at the time of the auction
Unsold Allowances	Unsold allowances are sold in future phase II auction
Vintage	No yearly vintages
Lot Size	1,000 in the competitive portion. Max bid of 10,000 allowances in the non-competitive portion
Timing and Frequency	Quarterly. May increase frequency
Participant Access	Mandatory use of primary participants (also called intermediaries)
Financial Assurance	Handled through primary participants
Information and Transparency	Limited information released after the auction
Monitoring	Independent third party monitors the auction and reports on the execution

Jurisdictional Review Cont.

Australia: Carbon Pollution Reduction Scheme

Auction Format	Sealed proxy bids
Reserve Price	Based on market price
Unsold Allowances	Currently being finalized
Vintage	One of the monthly auctions will sell allowances for the current year plus the three following compliance periods
Lot Size	Details are currently being finalized
Timing and Frequency	Held monthly, 16 auctions per vintage
Participant Access	No intermediaries, open to all
Financial Assurance	Subject to financial assurance to participate in auction
Information and Transparency	Auction results will be made public
Monitoring	Independent panel to review operation after it launches. Market manipulation will be investigated and prosecuted

Jurisdictional Review Cont.

US Environmental Protection Agency SO_2

Auction Format	Single round discriminatory price. Descending order
Reserve Price	No reserve price
Unsold Allowances	EPA returns proceeds and unsold allowances
Vintage	Both spot allowance auction and an advance auction (that can be used for compliance 7 years after the transaction date
Lot Size	Can purchase as little as 1 allowance. 1 allowance = 1 ton
Timing and Frequency	Occurs once per year
Participant Access	Open to any qualified bidder
Financial Assurance	Each bid must include a wire transfer or certified check or letter of credit for the total bid cost
Information and Transparency	Share as much data as possible. Details are available through online queries
Monitoring	No rule preventing a buyer from purchasing all allowances sold via auction

Jurisdictional Review Cont.

US Treasury: Sale of Treasury Bills

Auction Format	Sealed bid uniform price. Competitive and non-competitive bids. In a single auction, an investor can buy up to $5 million in bills by non-competitive bidding or up to 35% of the initial offering amount by competitive bidding
Reserve Price	N/A (treasury bills typically sold at a discount from the par amount)
Unsold Bills	
Vintage	N/A
Lot Size	$100.00
Timing and Frequency	All bills except 52-week bills and cash management bills are auctioned every week
Participant Access	Competitive and non-competitive bidders (Corporation, Government-related entity, trust or fiduciary estate, individual, foreign and international monetary authority, other)
Financial Assurance	Depends on bidding method. Treasury direct requires debit entry to a deposit account or submission payment with a bid
Information and Transparency	Results of all public auctions are released in a press release after each auction. Available on website
Monitoring	Penalty for non-compliance of the auction rules or failure to pay for issued securities

Questions?

Western Climate Initiative

National Clean Car Standards

WCI Partners Meeting
Toronto, Ontario
September 16, 2009

Introduction

- An agreement was successfully struck between the Obama administration, the auto makers and the California Air Resources Board.
- The agreement was announced by President Obama on May 19, 2009.

Three Part Agreement

- The agreement has three parts:
  - Federal notice of intent for joint rulemaking by the U.S. Environmental Protection Agency (EPA) and National Highway Traffic Safety Administration (NHTSA).
  - A commitment letter from the California Air Resources Board.
  - Commitment letters from each auto manufacturer and their industry groups.

Overview of the Agreement

- The national 50 states GHG standards will be developed by EPA and NHTSA and will start in model-year 2012, and go to 2016.
- In 2016, the national standard will be the same as the California (Pavley 1) standard.
- Expectation California's waiver for model-years 2009 to 2016 will be approved by EPA.

Overview of the Agreement (con't)□

- California does not give up any authority under the Clean Air Act.
- California will amend its rule to allow compliance with the national standard between 2012 and 2016 to be recognized as complying with the California (Pavley 1) standard.
- The auto industry will drop its lawsuits challenging the California (Pavley 1) standards.

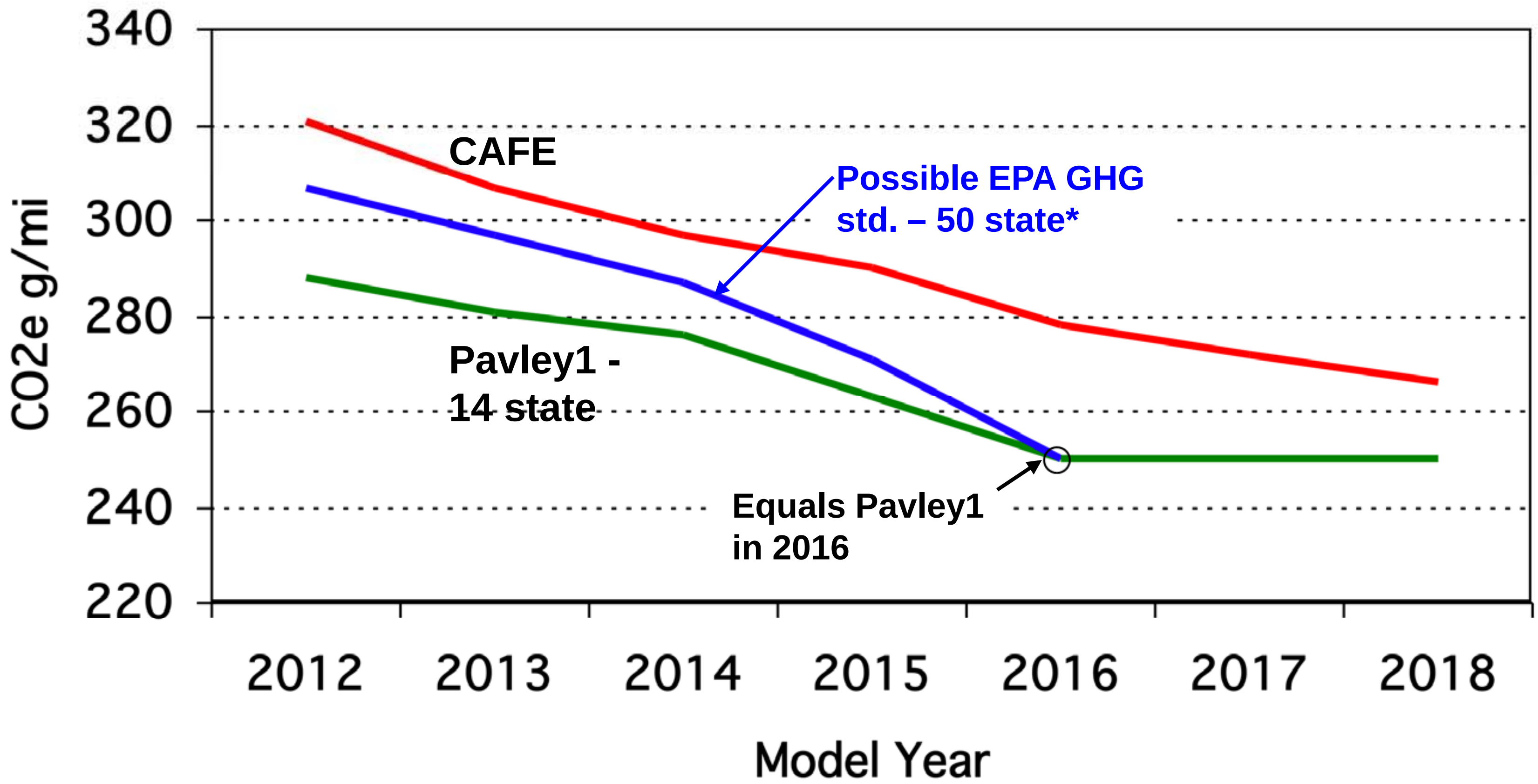
Status of the Agreement

- EPA NPRM for national vehicle GHG standards
  - Released this week (September 15)
- ARB amendments to Pavley 1
  - Board hearing on pooling – September 24
  - Board hearing on accepting National compliance – December 2009
- California Waiver
  - Granted by USEPA on June 30, 2009
  - Dealers/Chamber filed suit last week
- Autos drop lawsuits
  - Done, except NM suit by dealers

GHG Reductions Impact

- California will enforce GHG standards for model-years 2009 to 2011.
- For model-years 2012 to 2016, the national GHG standards developed jointly by EPA and NHTSA will be in effect.
- In 2016 the California (Pavley) standard and the national standard will be the same (250 g/mi).
- ARB/EPA coordinating on post-2016 standards

Pavley 1 – CAFÉ - National GHG Comparison of Stringency



*Pre-NPRM understanding

Pavley 2

- Development of GHG standards for 2017-2025 has begun
  - Likely technologies to further reduce GHG emissions:
    - Wider-spread use of conventional hybrids
    - Lighter weight vehicles
- Schedule
  - Workshops begin this fall
  - Hearing - summer 2010

ZEV 2

- New focus on GHG emission reduction
  - Complements Pavley 2
- Goal: Assure very low carbon vehicles achieve early commercialization
  - Vehicles capable of 80% less GHG emissions
  - BEVs, PHEVs, FCVs
  - Needs to happen by ~2020 to achieve 2050 goal of 80% GHG reduction for 1990 levels
- Schedule
  - Preview of ZEV2 policies: December 2009
  - Board hearing to adopt: October 2010

Western Climate Initiative

Market Architecture and Oversight

Partner Meeting, Toronto, Canada

September 16, 2009

Objectives

- "The recommended design will provide opportunities to obtain low-cost emission reductions through emission trading, allowance banking, and inclusion of an offsets component."

WCI Design Recommendations, September 23, 2008

- "The WCI Partner jurisdictions and stakeholders want appropriate safeguards and oversight of the allowance and offset credit trading markets and want them to function efficiently."

Materials for Markets Workshop, April 9, 2009

Architecture and Oversight

- “Market Architecture:” Market participants and institutions, and the connections between them
- “Market Oversight:” The regulators’ relationship with the market

Markets Committee

- Purpose of Market Architecture and Oversight task is "to provide recommendations that are designed to ensure that the allowance and offset credit trading market is organized properly to operate reliably and prevent or minimize manipulation."
- Public workshop April 9, 2009 in Seattle
  - Principles to guide Committee
  - Questions for stakeholders

Types of Markets: A Convenient Taxonomy

- Primary: Initial distribution of allowances issued by governments (auction, sale, or allocation).
- Secondary: Trading of allowances by participants for immediate delivery
- Derivatives: Value based on another instrument (e.g., a contract based on the price of allowances)

Secondary Markets

- WCI tracking system
  - Major part of architecture of market
  - Rules for system a significant part of oversight choices
  - Important resource for monitoring

Ways to Trade Allowances

- "Over the Counter" (OTC) transactions
  - Between two (or more) parties
- Exchanges
  - Standardized terms
  - Clearing
    - Centralized counterparty
    - Margin requirements
  - Data recording and disclosure requirements
  - Position limits

Derivatives

- Allowance market expected to have some volatility
- Derivatives can be used for risk management
  - E.g., electricity generators may lock in power prices and fuel prices for a period of time, and ensure an operating margin
- OTC and exchange structures similar
- Derivatives markets can be larger and more active than spot markets

Market Participants

- Could be a wide variety: Compliance entities, brokers, investors
- Have heard calls to limit access to markets to compliance entities
  - Could be difficult to implement
  - Counterarguments are that broad participation can add liquidity, reduce opportunities for exercise of market power
  - Requires assumption that compliance entities form an exclusive class that is somehow different from class of all participants

Monitoring

- Develop WCI in-house capacity
- Rely on existing regulators (US Commodity Futures Trading Commission, provincial Securities Commissions)
- Contract with independent monitor
- Role of public information

Questions?

WCI Markets Committee

Co-Chair Jim Whitestone, Ontario

Jim.Whitestone@ontario.ca

Co-Chair Michael Gibbs, California

mgibbs@calepa.ca.gov

April 9, 2009 Stakeholder consultation documents and comments available at http://westernclimateinitiative.org/public-comments/document/2

Offset Committee Task 1

Task 1.1: Definition of a WCI emissions offset and Task 1.2: related eligibility criteria for offset projects

1. Identify options for a definition of a WCI emissions offset and related eligibility criteria for offset projects
   - White paper released July 24, 2009 for stakeholder input
2. Analyze options and stakeholder input
   - Draft Recommendations paper Sept/Oct 2009 for stakeholder input
3. Recommendation with stakeholder input and any further analysis required
   - Final Recommendations paper December 2009

Offsets Committee White Paper

The Offset Committee solicited stakeholder feedback on options to inform recommendations to WCI Partner jurisdictions.

- What has been your experience with the offset system examples cited in this paper?
- What have been the advantages and disadvantages to their approaches?
- Are the appropriate criteria listed?
- Does the paper include the appropriate options for each criteria?
- Are the implications of the options appropriately covered?

Definition of an offset

Many suggestions offered on definitional issues.

Supporting principles and technical considerations:

1. Ownership Issues
   - Need clear expectations for evidence of ownership
2. Use of Approved Protocols
   - Strong support to adopt and adapt existing protocols
3. Geographic Limits
   - Support for WWCI approach
4. Implementation options
   - Majority of support for general description of an offset with detailed requirements in a separate section

Real

Some suggestions of what constitutes Real

Supporting principles and technical considerations

1. Quantification
   - Support for rigorous, scientifically sound approached building on existing knowledge
2. Uncertainty and accuracy
   - Support for assessing uncertainty with guidance and standard approaches in protocols
3. Conservativeness
   - Support for the principle with guidance on evidence
4. Leakage
   - Support to address in protocols to streamline

Additional

Strong support for performance standards with the understanding that they will not apply in all cases and some flexibility should be incorporated

Supporting principles and technical considerations

1. Baseline
   - Main concern is interpretation of additionality in baseline development
2. Eligibility Date
   - General support for pre-2012 start
3. Crediting Period
   - Support for 10 years or less with opportunity to renew, longer for forest projects

Permanent

Support for 100 year definition

Support for a buffer pool, reserve or holdback.

Other options for risk mitigation

Verifiable

Strong support for third party verification

Supporting principles and technical considerations

1. Validation
   - Less support for validation
2. Enforcement
   - Few comments, likely indicates agreement with necessity (white paper contained discussion only, no explicit options)
3. Material
   - Support for 5%, no objections

Other considerations

Supporting principles and technical considerations

1. Transparency
   - Support for transparent process, different interpretations
   - Public involvement/consultation at important decision points highlighted
   - Support for publicly available documents
2. Co-Benefits
   - Near-universal lack of support for requiring
3. Environmental and social impacts
   - Mixed support for assessment

Offset Committee Task 1

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Western Climate Initiative

Offset Limit Recommendation Paper

September 16, 2009

CSAD Committee Recommendation to Partners

CSAD Task 5 Committee
Scope of work

- The September 2008 Design Recommendations for the WCI Regional Cap-and-Trade Program specify that a majority of emission reductions required under the program occur at covered entities and facilities :
  - limit use of offset credits and allowances from other systems to no more than 49% of the total emission reductions from 2012-2020.
- The committee limited its work at how this limit could be implemented.

5 Principles

- **Fairness** : to provide fair access to offset markets for offsets offset project developers and covered entities.
- **Economic Efficiency** : to assure efficient market operations and least cost reductions (an offset limit should not unduly inhibit the realization of the least-cost offsets).
- **Cost containment** : help contain compliance costs and maintain fungibility across the WCI.
- **Effectiveness and enforceability** : to ensure that the limit is enforceable and is effective at achieving the WCI goal that offsets are supplemental to emission reductions at covered sources.
- **Administrative simplicity and cost** : to provide a clear path forward and to minimize administrative costs to all parties.

Offset Limit White Paper

- **White Paper issued May 19, 2009**
- **Options for implementing the limit :**
  - general approach (use vs. supply)
  - across jurisdiction (common vs. differentiated)
  - over time (equal absolute number, percent, 49%, ...)
- **Workshop in Seattle (Washington) May 28th, 2009**
- **Consultation period :**
  - about 20 written comments from industry associations, environmental NGOs, electric utilities, power industry representatives, financial institutions, carbon market participants, and individual firms in the cement, aluminum, forest product, and petroleum industries.

Stakeholders' input

- **General approach to limiting offsets :**
  - Strong preference for limiting the use rather than the supply and for reflecting this limit as a percentage of an entity's compliance obligation;
  - Few support for a "surrender certificate" approach.

- **Implementation across jurisdictions :**
  - Split between common and differentiated limits.

- **Implementation over time :**
  - Range of options : equal absolute amount, fixed percentage, higher percentage in early years, no restriction, ...
  - Carry-over of unused offsets from one compliance period to the next.

Committee recommendation (1)

- The Committee recommends a **use limit** be applied at the **entity level**, more precisely as a **percentage of compliance obligations** (i.e. emissions):
  - Compared to a supply limit, a use limit should result in lower overall compliance costs for covered entities;
  - Provides predictability for covered entities;
  - Administratively simple to implement; and
  - Tends to minimize both administrative and compliance costs of the program relative to a supply limit.

Committee recommendation (2)

- The Committee recommends a **common use limit** be implemented **across Partner jurisdictions** :
  - Provides equal access to offsets to entities across the WCI cap-and-trade system, and helps to ensure that the overall limit would not be exceeded.

- Jurisdictions could still adopt a lower limit lower.

- The CSAD Task 3 (competitiveness) group will consider whether the common use limit might pose competitiveness concerns for entities in jurisdictions that have adopted lower emission targets relative to historical levels, and if so, how to address these concerns.

Committee recommendation (3)

- The Committee recommends that the limit be set at an **equal percentage of compliance obligations across compliance periods**:
  - This option would allow for the use of a greater absolute number of offset credits in earlier compliance periods (adjusting for the expansion of program scope in 2015), thus easing the transition into the cap and trade program.

Committee recommendation (4)

- The Committee also recommends the implementation of region-wide "**carry-over**" approach:
  - Under such an approach, if the total amount of offsets used across WCI in a given compliance period are less than the total amount of offsets allowed, then the difference in these two amounts would be added to the subsequent period's offset limit (in absolute terms), with the percentage offset limit adjusted appropriately.

- The committee recommends adopting a "**region-wide**" rather than "entity-specific" carry-over approach:
  - simplicity, lower administrative cost, transparency, and ability to enable fuller overall use of offsets.

"Region-wide Carry-over" : an example

- Offset limit : 5% of compliance obligations (i.e. emissions)
- First compliance period : 1 000 kt
  - allow up to 52 631 offset credits to be used
- Second compliance period : 900 kt
  - allow up to 47 368 offset credits to be used

- If only 40 000 offset credits are used for compliance in the first period then, under a carry-over mechanism :
  - we would allow 59 999 offset credits (47 368 + 12 631) to be used in the second compliance period
  - which would increase the offset limit to 6.25% of compliance obligations (1-(900 000/959 999))

EU ETS
Setting the Cap

Jill Duggan
Visiting Senior Fellow
World Resources Institute
September 2009

Phase I 2005 – 2007

- In line with the Directive – *Prior to 2008, the quantity shall be consistent with a path towards achieving or over-achieving each Member State's target under Decision 2002/358/EC and the Kyoto Protocol*
- And *consistent with the potential, including the technological potential, of activities covered by this scheme to reduce emissions.*

UK experience Phase I

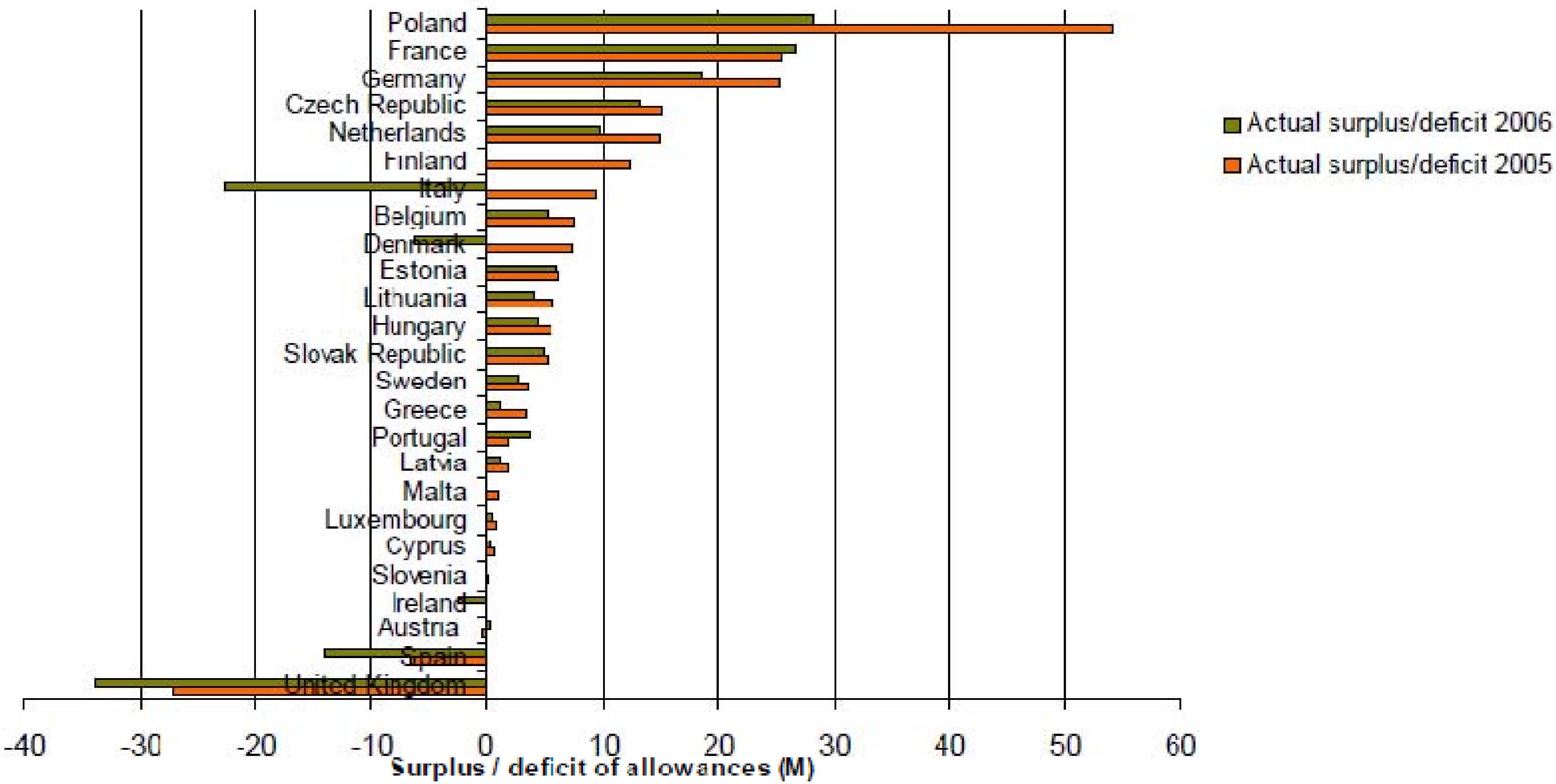
- Sector level data
- Projections of BAU
- Political decision
- Top down bottom up approach – cap top down, share of allocation – bottom up
- using historical emissions data 1999 – 2002 average dropping lowest year (but other MSs used different methods)
- The total quantity of allowances allocated in the first phase of the EU ETS (2005-7) was 736.3 MtCO2.
- This was around 65 MtCO2 (around 8%) below projected emissions of the installations covered by for that period.

Process for approval

- Member States presented plans to Committee of all states for challenge and then to the Commission
- European Commission called for cuts to total allocation equivalent to 220 million per annum
- Process was long and drawn out – Polish and Italian plans approved in 2006!

What happened

- During 2005 and early 2006 prices had jumped whenever a plan was approved or allowances came onto the market
- the average price across 2005 was 17 euros a tonne, but the price had been as high as 31 euros a tonne.
- Reconciliation of first annual data – spring 2006 – and results of allocations and actual emissions in May that year
- No banking in this learning phase
- Excess allocations across most of Europe
- Price of allowances plummeted



Poland
France
Germany
Czech Republic
Netherlands
Finland
Italy
Belgium
Denmark
Estonia
Lithuania
Hungary
Slovak Republic
Sweden
Greece
Portugal
Latvia
Malta
Luxembourg
Cyprus
Slovenia
Ireland
Austria
Spain
United Kingdom
-40
-30
-20
-10
0
10
20
30
40
50
60
Surplus / deficit of allowances (M)
Actual surplus/deficit 2006
Actual surplus/deficit 2005

What Happened Next

- European Commission announced that the plans for 2008-2012 would have to be in line with
  - Kyoto targets under the effort sharing agreement
  - The proportion of emissions covered by ETS in any member state and
  - Implementation of mitigation policy in other sectors
  - And would use verified 2005 compliance data as basis for assessment

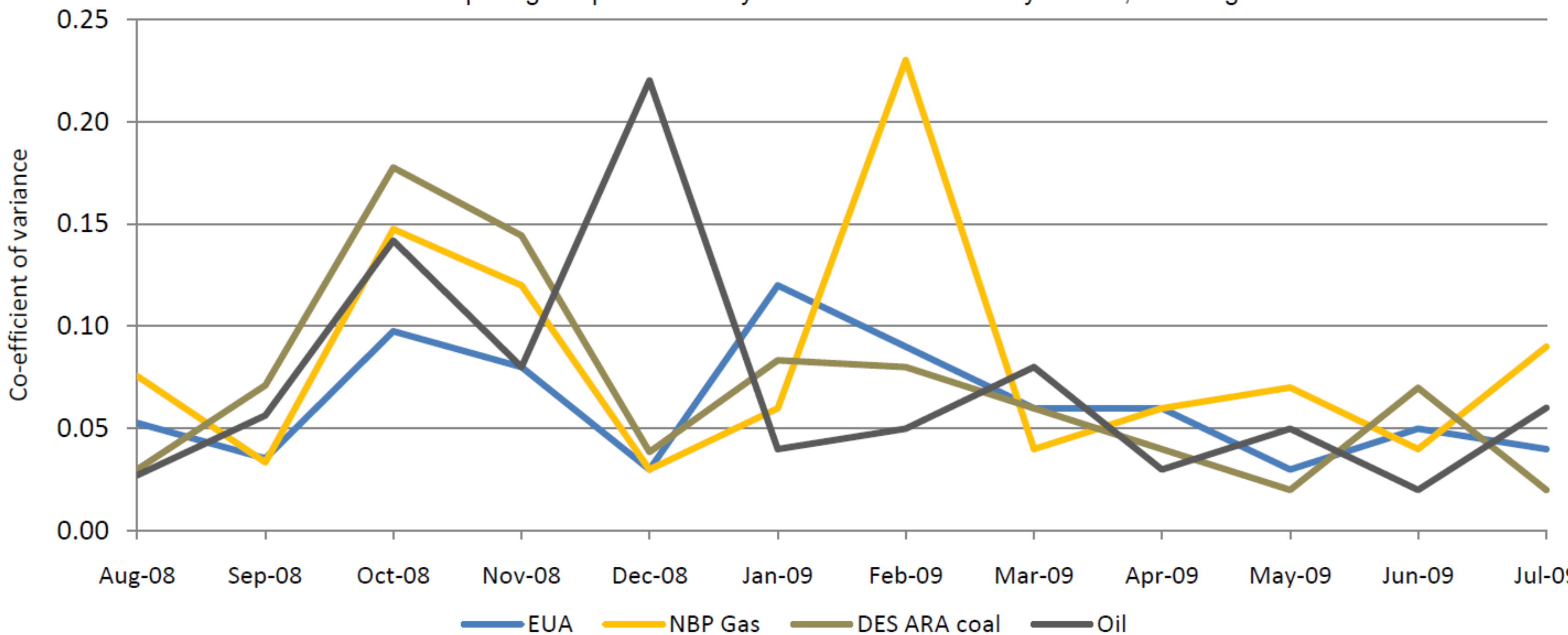
Which meant

- All but two (UK and Sweden) of first Phase II plans rejected or withdrawn – strong political will to make the ETS work (backed by UK and then by Germany)
- Harmonisation of scope brought new emissions into the system (in UK 9 mtonnesCo2, in Germany 11 mtonnes CO_2)
- Restrictions on the use of credits introduced – and a nod to the principle of supplementarity
- **But the political will following the fall helped stabilise prices and provided certainty for industry**

How's this worked to date

- Fairly stable carbon price
- Recession caused drop in price – but stabilised around 14 – 15 euros a tonnne
- 2008 – across EU only 29% of CERs allowance used for compliance – 24% in UK
- But further changes with amended legislation…..

Chart 8. Comparing the price volatility of EUAs to the volatility of coal, oil and gas



Phase III – 2012 and beyond

- 2020 package performed an ‘efficient split’ to divide the overall effort of 14% below 2005 levels (20% below 1990 levels) between the ETS and the non-ETS.
- This led to reduction targets of 21% for the ETS and 10% for the non-ETS (against 2005). Common rules for allocation – and full auctioning for electricity generators (~50% emissions)
- Effort sharing for the non traded sector

Setting the cap Phase III

- Unlike EU ETS Phases I and II, the overall cap not aggregate of the Member State caps, but set centrally, and divided up among the Member States.
- Starting point for the linear reduction factor is the average quantity of allowances issued by MSs under their NAPs – the Phase II annual cap.
- This was then increased to reflect the expanded scope of Phase III compared with Phase II, and decreased to reflect any small emitters that are opted-out of the scheme for Phase III.

ETS cap

- The Commission has published an ETS cap that is consistent with the Phase II scope of the system,
- the full cap for 2013-2020, including new sectors, by 30 June 2010.
- No end-point for linear factor but will be reviewed between 2020 and 2025.
- Therefore linear factor can be revised if new scientific evidence.
- Or the cap and linear factor will be reconsidered if the EU makes reduction commitments deeper than 20% as part of an international agreement on climate change.
- If the linear trajectory of 1.74% were followed long-term, then the EU ETS cap would reach zero in the early 2060s.

Determining Free Allocation and Auction Pot

- The Phase III annual cap will be divided free allocation for competitively traded sectors, with the remainder to be auctioned.
- This split will be done on the basis of the share of emissions in sectors eligible for free allocation over the base period 2005-2007, compared with the share of emissions in those sectors not eligible for free allocation.

Benchmarking Free Pot

- Any free allocation will be distributed according to harmonised methodologies (most likely to be product based benchmarks) and the percentage of that benchmark that the sector will receive, depending on whether the sector is determined to be at significant risk of carbon leakage or not.
- The allocation according to benchmarks could = the free allocation pot,
  - be greater, in which case the allocation will be scaled down by applying an adjustment factor
  - or smaller, in which case the remainder will be added to the auction pot.
- A very few MSs could receive free allocation for electricity production. These allowances will deducted from the auction pot that those MSs would otherwise receive

Auction Rights Allocation

- After applying the benchmarks and the percentages remainder from the free allocation pot will be added to the auction pot.
- 5% of the annual cap will be deducted from this amount and placed into the new entrant reserve to provide any free allocation to which new entrants are entitled.
  - 300m of the allowances will be set aside to fund projects to demonstrate CCS or innovative renewable technologies.
  - Any allowances remaining in the NER at the end of the phase shall be distributed to MSs to auction, taking into account the levels to which installations in those MSs have benefitted from the NER
- Remainder in the auction pot shall be divided up in the following way:
- 88% distributed among MSs according to their share of 2005 or 2005-2007 emissions.
- 10% shall be distributed to MSs according to GDP/capita
- 2% shall be distributed to MSs that in 2005, had emission levels at least 20% below their base year under the Kyoto Protocol.
- Lithuania (and countries that import more than 15% of their electricity from Lithuania), may auction some of the NER to compensate for possible increased emissions with respect to electricity production following the planned closure of a large nuclear power plant in 2009.

Member States’ *de facto* Cap

- Individual Member States will be able to estimate their *de facto* cap by combining the free allocation that would be given to industry in the various sectors in that MS, and the share of the auction pot given to that MS.
- It will be possible to calculate each Member State’s *de facto* cap more accurately towards the end of 2011, once the Community-level cap has been adjusted to take account of the change in scope of the system and the National Allocation Measures have been approved by the Commission.

The agreement on offsets

- The 50% supplementarity principle was applied to the ETS as part of the 20% target, allowing for a limited amount of additional access which can be provided in Phase III. This additional access is likely to amount to approximately 150mtCO2e and will be distributed in the following way:
  - The first method grants additional access to operators that had low levels of access in Phase II, such that all operators have access of at least 11% of their allocation in Phase II.
  - The second method considers levels of free allocation in addition to levels of access to credits.
  - New sectors and new entrants will be allowed access equivalent to at least 4.5% of their verified emissions, while Aviation will be allowed access equivalent to at least 1.5% of their verified emissions.

Qualitative restrictions on offsets

- 2013-2020 Phase of EU ETS applies same qualitative restrictions as Phase II. This means that nuclear and forests are not eligible in the system.
- All credits that were eligible for use in Phase II are eligible for use in Phase III, subject to the following additional restrictions.
  - Installations may use credits issued in respect of emission reductions that took place before 2013 or from project registered before 2013.
  - Can use CDM from projects in Least Developed Countries.
  - If no international deal Member States may use credits which have been acceptable for use in the EU ETS in 2008-12 <u>or</u> are from new projects where the baseline used is below the level of free allocation in the ETS
  - Once an international agreement can only use credits from countries which have ratified agreement.

Flowchart showing steps in division of cap

Key:
S = Sector
MS = Member State

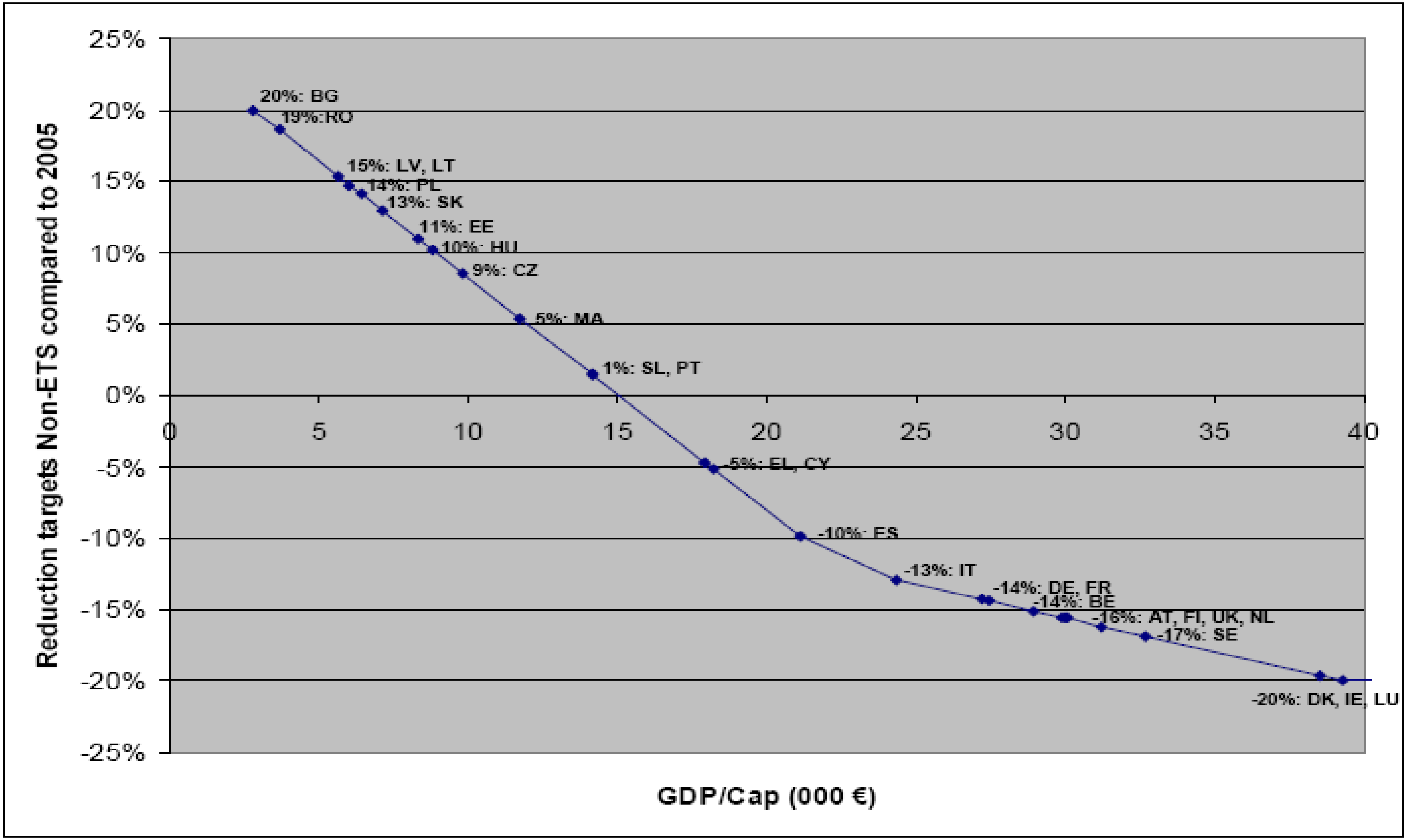
Effort Sharing Decision

- The Effort Sharing Decision covers the emissions from all sectors that are not covered by the ETS.
- This includes transport, domestic heating, agriculture, small emitters etc.
- EU Member States are legally responsible for meeting their quantified targets, and have control over their policies to deliver the reductions.

Effort sharing in the non ETS sectors

- To allocate effort to achieve 10% reduction on 2005 by 2020 in the non ETS sectors.
- For non ETS sectors a Member State’s share is based on BAU weighted by GDP per capita.
- Therefore some Member State’s emissions can increase (tho’ below BAU) whilst others have absolute emissions reductions – to achieve overall absolute emissions reductions in Europe.
- UK must reduce emissions in the non ETS sectors by 16% by 2020

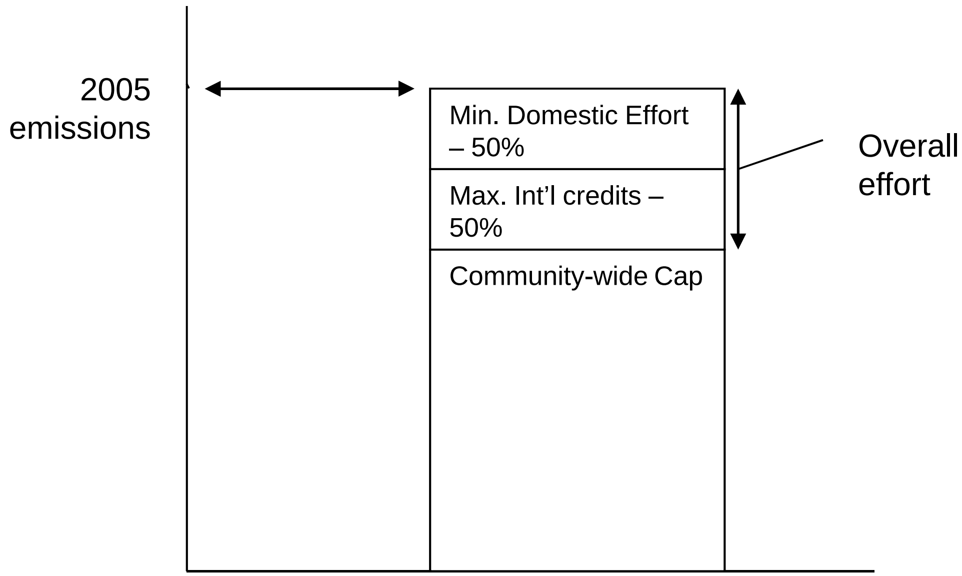
Effort sharing in the non-traded sector



Flexibilities to help meet the non ETS targets

- **Borrowing**: Member States are able to borrow a up to 5% of their emissions allocation from the following year to allow for emissions exceeding the annual allocation. In the first 2 years (2013 & 2014) before countries have had a chance to build up a stock of banked surplus, and in case of extreme meteorological conditions that have led to an increase in GHG emissions, Member States may borrow more than 5%.
- **Banking**: any unused allocation can be banked for use in subsequent years. There are no limits on the amount that can be banked or the length of time they can be banked for, up to 2020.
- **Trading**: a Member State may transfer up to 5% of their annual allocation to another Member State. There are no restrictions on level of allocations that Member State can receive this way.
- Member States may use **international project credits** up to an annual limit of 3% of their 2005 emissions. This is subject to the same qualitative requirements as for the ETS
- However, Member States are also permitted to use credits from **forestry** activities (tCERs & lCERs) provided that they are replaced by credits of equal value when they expire.

Use of offsets



Use of Auction revenues

- Member States can determine how to use auctinoing revenues, but the ETS Directive indicates that they should spend at least 50% of the proceeds from auctions on measures to tackle climate change within the EU and in developing countries.
- Appropriate use of revenues for this purpose includes: contributing to funds under the UNFCCC; development of renewable energy; afforestation, reforestation and avoiding deforestation in developing countries; forestry in the EU; CCS; low-emission transport; development of energy efficiency and low-carbon technologies; and measures to promote energy efficiency in vulnerable groups.

Useful links

- http://ec.europa.eu/environment/climat/emission/implementation_en.htm Original ETS directive
- http://www.decc.gov.uk/en/content/cms/what_we_do/change_energy/tackling_clima/emissions/eu_ets/phase_1/phaseI_nap/phaseI_nap.aspx UK Phase I National Allocation Plan
- http://www.decc.gov.uk/en/content/cms/what_we_do/change_energy/tackling_clima/emissions/eu_ets/euets_phase_ii/phaseII_nap/phaseII_nap.aspx Phase II National Allocation Plan
- http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2009:140:0063:0087:EN:PDF revised ETS directive for post 2012

Western Climate Initiative

Offset Limit Recommendation Paper

CSAD Task 5 Committee Recommendation to Partners

October 6, 2009

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1 Background and Purpose

As part of the design for the WCI Regional Cap-and-Trade Program, the WCI Partner jurisdictions recommended that a rigorous offset system be developed and implemented. The purpose of the offset system is to reduce compliance costs while encouraging emission reductions, innovation, and technology development for sources and sinks not covered by the cap-and-trade program.

Offsets are GHG emission reductions, GHG emissions avoided, or GHG removals from the atmosphere, measured in metric tons of CO2e. Offsets are achieved through activities that are often referred to as “offset projects.” Offset credits (also measured in metric tons of CO2e) are issued for offsets that are achieved by offset projects that meet certain criteria. Offset credits can be traded and can be used for compliance purposes or as part of voluntary actions. When used within a cap-and-trade program, offset credits used for compliance purposes come from emission sources or sinks not covered by the cap.

The Design Recommendations for the WCI Regional Cap-and-Trade Program specify that a majority of emission reductions required under the program occur at covered entities and facilities. Consequently, for compliance purposes, the WCI Partner jurisdictions set a limit on the use of offset credits issued by WCI Partner jurisdictions, as well as the use of offset credits and allowances from other GHG emission trading systems that are recognized by the WCI Partner jurisdictions, to no more than 49 percent of the total emission reductions from 2012 to 2020. [1] This limit and rationale are established in the WCI’s Design Recommendations (September 23, 2008). This paper addresses how this limit could be implemented, rather than discussing the limit itself.

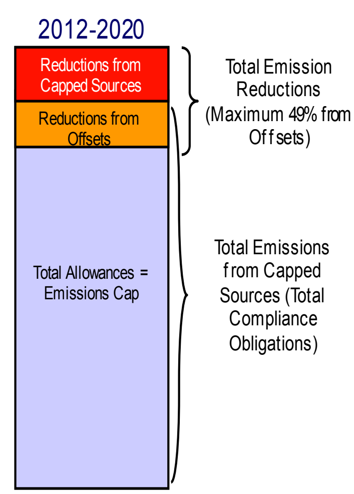

Figure 1. Illustration of the WCI Offset Limit

The offset limit is conceptually illustrated in Figure 1. The bar is comprised of three pieces. The bottom part of the bar is the total number of emission allowances issued from 2012 to 2020, a direct reflection of the emissions cap. The top two pieces combined equal the total emission reductions required of

[1] It is important to note that while we refer to the “offset limit” throughout this paper, it should be understood to encompass not only offsets issued by WCI Partner jurisdictions, but also offsets and allowances issued by other GHG emission trading systems approved for use in the system by the WCI Partner jurisdictions.

the covered entities and facilities for the period 2012 to 2020. The total required emission reductions are divided into two parts: the top part is the total emission reduction achieved at the covered entities and facilities; the second part is the total emission reduction that was achieved through offsets or allowances from other GHG emission trading systems. As specified in the program design recommendations, this second part, the offsets and allowances from other systems, can be no more than 49 percent of total emission reductions.

On May 19, 2009, the WCI Cap Setting and Allowance Distribution (CSAD) Committee issued a white paper describing options to address the following questions related to implementation of the WCI offset limit:

1. What mechanism should be used to impose the limit?
2. How should the offset limit be applied across jurisdictions?
3. How should the limit be applied across compliance periods?

On May 28, 2009, the CSAD Committee held an in-person stakeholder event in Seattle to present the options paper and solicit feedback, and since then, has received numerous written comments. On the basis of this input and further deliberations, the Committee has developed a recommendation on how to implement the offset limit, as presented in Section 6.

The purpose of this recommendation paper is to seek stakeholders' input on the committee's recommendations prior to a final WCI decision. As outlined and explained below, the committee's recommendations include:

- limiting the use of offsets rather than limiting the supply
- implementing a common use limit across WCI Partner jurisdictions
- setting the limit at an equal percentage of compliance obligations across compliance periods; and
- implementing a region-wide "carry-over" approach, which should be construed narrowly, applying only to the specific circumstances of the WCI program design .

2 Offset Limits in Other Trading Schemes

The CSAD Committee reviewed other existing or proposed cap-and-trade programs limit offsets in order to identify options for implementing the offset limit and the implications of these options. In our review, we considered the following programs and federal proposals:

- Regional Greenhouse Gas Initiative
- European Union Emissions Trading Scheme
- The American Clean Energy and Security Act of 2009 – ACESA
- Dingell-Boucher Discussion Draft
- Boxer substitute of Lieberman-Warner (S. 3036)
- Lieberman-Warner Climate Security Act (S.2191)
- US Climate Action Partnership Proposal

Table 1 summarizes how offset limits were designed or proposed in these programs and proposals. As illustrated in Table 1, there is wide variation in how the limits would be applied and how the availability of offsets changes over time. More detailed descriptions of these offset programs and proposals can be found in the Annex to this paper.

Table 1. Summary of Offset Limit Provisions of Cap-and-Trade Systems and Proposals

Cap-and-trade program or proposed legislation	Overall limit description and mechanism of application	Difference in limit across jurisdictions	Change in limit over time
US Regional			
Regional GHG Initiative (RGGI)	3.3% of a covered entity's emissions (in order to contain allowance price, overall offset limit increases as the allowance price exceeds threshold levels)	No difference	No change in % over time (unless price triggers increase limit). Absolute amount of allowable offsets decreases as the number of allowances available decreases.
European Union			
EU Emissions Trading System (EU ETS)	No more than 50% of emission reductions, EU-wide, typically implemented by member states as a percentage of covered entities' emissions (e.g., as a percentage of allowances distributed).	Phase II (2008-2012): Varies across member states from 0% to 20% of allowances distributed	Phase II (2008-2012): Based on National Allocation Plans (NAPs) Phase III (2013-2020): NAPs replaced by EU-wide caps and allocation rules.
US National Legislation and Proposals			
The American Clean Energy and Security Act of 2009 – ACESA	~2 billion metric tons per year. Implemented as a fraction of covered entity's emissions (compliance obligation) that increases from ≈30% in 2012 to ≈60% by 2050 as cap declines.	Not applicable (single jurisdiction)	Allowed offsets increase as a fraction of allowances issued over time.
Dingell-Boucher Discussion Bill	5-35% of a covered entity's emissions		Increasing percentage over time from 5% starting in 2013 to 35% by 2025.
Boxer Substitute of Lieberman-Warner (S. 3036)	Up to 15% of total emission allowances issued per year		No change in % over time. Absolute amount of allowable offsets decreases with cap. Includes a roll-over for unissued allowances for use in subsequent years.
Lieberman-Warner Climate Security Act (S. 2191)	Up to 15% of a covered entity's emissions		No change in % over time. Absolute amount of allowable offsets decreases with cap.
US Climate Action Partnership Proposal (US CAP)[2]	2 billion metric tons per year. A Carbon Market Board would have authority to increase limit to 3 billion metric tons.		No major change in absolute amount of offsets allowed.

[2] USCAP Blueprint for Legislative Action: Consensus Recommendations for U.S. Climate Protection Legislation, January, 2009. USCAP is "an expanding alliance of major businesses and leading climate and environmental groups that have come together to call on the federal government to enact legislation requiring significant reductions of greenhouse gas emissions." http://www.us-cap.org/about/index.asp

3 Principles in Evaluating Offset Limit Options

The CSAD committee applied the following principles in defining the design and operation of an offset limit:

- **Fairness**: An offset limit should be designed to apply fairly to covered entities and not create competitiveness concerns. An offset limit should be implemented in a manner that provides fair access to offset markets for offset project developers and covered entities, as well as other market participants.
- **Economic efficiency**: An offset limit should be implemented so that the market operates efficiently and that greenhouse gas emission reductions can be achieved at the least cost. An offset limit should not unduly inhibit the realization of the least-cost offsets.
- **Cost Containment**: The offset limit should be implemented in a manner that helps to contain compliance costs and maintains offset fungibility across the WCI. Recognizing that offset supply is essential for achieving cost containment, the offset limit should not unduly restrict the ability of offset project proponents to finance and develop prospective projects, the ability of jurisdictions to issue, or market participants to acquire, offsets in a timely manner.
- **Effectiveness and enforceability**: The offset limit should be implemented to ensure that the limit is enforceable and is effective at achieving the WCI goal that offsets are supplemental to emission reductions at covered sources, and thus that no more than 49% of total emissions reductions 2012-2020 are achieved by the use of offsets (and allowances and offsets from other emission trading systems).
- **Administrative simplicity and cost**: Implementation of the limit should provide as clear a path forward as possible for all parties, including administrative bodies, offset project developers, and covered entities. Administrative costs and transaction costs should be minimized for all parties, consistent with the need to ensure effective limit compliance.

4 Options

While the WCI design document specifies a limit on the amount of offsets that may be used for compliance purposes in the WCI regional cap-and-trade program, it does not indicate:

- What offset limit mechanism to implement and how to apply it across WCI Partner jurisdictions, or,
- How to apply the offset limit over time (across the three compliance periods).

These questions are addressed below.

4.1 Options for Implementing the Limit across Jurisdictions

The question of jurisdictional limits is unique to multi-jurisdictional emission trading programs, such as RGGI, the EU ETS and WCI.

There are two approaches Partners could employ to limit the total amount of offsets used. They could either limit the *use* of offsets (e.g., the number of offset credits a covered entity can use for compliance) or they could limit the *supply* of offsets (e.g., the total number of offset credits available to use for compliance). Within these two categories many detailed mechanisms are conceivable.

This paper will consider four detailed mechanisms - three that we categorize as usage limits:

- 'percentage limits' based on total compliance obligations, i.e. on actual emissions;
- 'percentage limits' based on freely distributed allowances;
- 'offset surrender certificates',

and one as a supply limit:

- 'first-come, first-issued'.

For each of these approaches there are also two broad options for addressing offset limits across jurisdictions - a *common* or a *differentiated* approach - and also multiple ways in which the limits could change over time.

Limiting the *use* of offsets

The offset limit could be set as a *percentage use limit* at the individual entity with a compliance obligation. The limit could be applied on a *common* basis across all jurisdictions, whereby the same entity-based percentage limit would apply across jurisdictions to any WCI-covered entity. Under this option, a common entity-based offset use limit specified as a percent of compliance obligations would be applied across the WCI. This is the approach taken by RGGI. The common percentage use limit would be calculated by dividing the total offsets allowed by the sum of the total number of allowances to be issued plus the total offsets allowed within a given time period (see section 4.2).

Alternatively, the WCI could adopt jurisdictionally *differentiated* percentage use limits, whereby the limit in each jurisdiction would differ based on one or more factors, such as the emission reductions below 2012 (or 2005) levels represented by a partner's emission goal. An example of the latter would be to apply the WCI-wide limit—no more than 49% of emission reductions between 2012-2020 from offsets—at the individual partner level. In such a case, jurisdictions with deeper targets relative to a base year level would allow proportionately more offset use per entity.

With a differentiated percentage-use approach, there is a risk that the total regional limit could be exceeded if the limit is specified as a percent of compliance obligations (i.e., total emissions, for which allowances and offsets have been surrendered). This risk occurs because allowances can be traded among jurisdictions, thus actual emissions that will occur in a given jurisdiction—and the corresponding amount of offsets—cannot be known in advance.[3]

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[3] The following provides an example of how exceedance might occur under a differentiated percentage-use approach. Assume, for instance, a region with only two jurisdictions (K and L) and a total emissions goal of 95 tons for a specific compliance period. Assume also that 49% of region-wide emission reductions equals 5 tons, and thus the total amount of covered emissions in the region could not exceed 100 tons (with 95 tons in allowances plus 5 tons in offsets surrendered). Let's say that jurisdiction K has a emissions cap of 46 tons, and that 49% of emission reductions in jurisdiction K equals 4 tons. Jurisdiction L, in contrast has an emissions cap of 49 tons, and 49% of emission reductions equals only 1 ton. Therefore, jurisdiction K would set an offset percentage use rate of 8% ((4/(46+4)*100), while jurisdiction L would set an offset percentage use rate of 2% ((1/(49+1))*100).

If offsets were fully used in each jurisdiction, and neither jurisdiction was a net buyer of allowances from the other, then the region-wide offset limit would be respected (0.08*50 + 0.02*50 = 5 tons). However, if entities in jurisdiction K were to buy more allowances from jurisdiction L than they sold to it, *and* if all entitles fully used the amount of offsets allowed under its jurisdictional limit, then the overall region-wide offset limit would be exceeded. For example, assume that entities in jurisdiction K were to acquire a net 14 tons of allowances from jurisdiction L:

- Jurisdiction K entities could then surrender 60 tons of allowances (46+14). The offset use ratio is set at 0.08, also equal to x/(60 + x) where x is the amount of offsets that can be claimed along with 60 tons of allowances so that the offset use ratio is still 0.08. Re-arranging so that x appears only on the left hand side of the equation, we get x = 0.08*60/(1-0.08) = 5.2 tons of offsets to cover total emissions of 65.2 tons, and
- Jurisdiction L entities could then surrender 35 tons of allowances (49-14). The offset use ratio is set at 0.02, also equal to y/(35 + y) where x is the amount of offsets that can be claimed along with 35 tons of allowances so that the offset use ratio is still 0.02. Re-arranging so that y appears only on the left hand side of the equation, we get y = 0.02*35/(1-0.02) =and 0.7 tons of offsets)) to cover total emissions of 35.7 tons.

Total offsets used would then total 5.9 tons (5.2+0.7), greater than the region-wide offset limit of 5 tons.

An alternative would be to specify the offset limit as a percent of the number of allowances that are distributed directly to covered entities within a given Partner jurisdiction. This way, the risk of exceedance would be avoided, since the number of free allowances and corresponding number of allowable offsets would be specified in advance.[4] This approach would provide access to offset use only to covered entities that receive allowances directly (and in some proportion to allowances received).

The EU has, thus far, largely taken a differentiated percentage use approach to offset use limits.[5] As noted in the Annex, in Phase II of the EU ETS each member state was allowed to propose an offset limit as part of its National Allocation Plan. These plans are then subject to EU review and approval. As a result, the fraction of compliance obligations that emitters can fulfill using offsets varies from country to country.

The choice between common and differentiated percentage approaches to jurisdictional limits has implications in terms of how offset opportunities and risks are distributed across partners. This comparison is summarized in Table 2.

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[4] As illustrated in the prior footnote, the reason that the offset limit could be exceeded under a differentiated percentage-use approach is that, while the offset limit percentages are fixed at the outset of a compliance period, the total compliance obligations (i.e. emissions) in each jurisdiction to which they apply will be unknown until the compliance periods ends. If instead the ability to use offsets were applied to the number of allowances that were distributed (a known quantity at the outset) rather than to the number of allowances and offsets surrendered (unknown until the end of the compliance period), the absolute amount of offsets that each entity could use would be known and fixed, and the potential for overage would be avoided.

[5] The EU percentage use limit is specified as the percent of allowance received for free by any given regulated emitter rather than as a percentage of compliance obligations.

Table 2. Comparison of Jurisdictional Percentage Use Offset Limit Options and Implications

Option:	Common % Use	Differentiated % Use
Example	X% of compliance obligations in all jurisdictions	49% of emission reductions in each jurisdiction translated to different percentages of compliance obligations in each jurisdiction
Fairness	Covered entities can use the same percentage of offset across the WCI region. Entities that emit more GHGs could use more offset credits for compliance.	Emitters from jurisdictions that have a deeper reduction goal for 2020 relative to a base year would be allowed a higher percentage of offsets. Within a given jurisdiction, entities that emit more GHGs could use more offset credits for compliance. If the limit is based on allowance distribution (rather than % of compliance obligation), then entities receiving more free allowances would have greater access to offsets.
Efficiency	To the extent that offset use falls short of the overall limit as a result of the mechanism used to implement the offset limit, opportunities for efficiency gains may be unrealized. The relative efficiency impact of each option remains to be evaluated.	
Cost Containment	The relative cost containment impact of each option remains to be evaluated.	
Effectiveness and Enforceability	WCI region-wide limit met. Individual partner limits may not be met.	WCI region-wide limit could be exceeded if individual Partners' limits are specified as a percent of compliance obligations.
Administrative Simplicity	Administratively simple to implement.	Slightly more complex to implement than the common % use approach.

As an alternative to the percentage use limit, the WCI Partner jurisdictions could choose to employ a usage limit which we will refer to as the *offset surrender certificates* mechanism. In this approach, the WCI Partner jurisdictions would issue and distribute (auction, sell or give for free) a number of certificates equal to the offset limit in tons. Covered entities would have to surrender one certificate for each offset credit they desire to use for compliance.

Under this mechanism, individual entities need not be limited by a percentage limit on their use of offsets. This approach could simplify the implementation of limits differentiated at the jurisdictional level and ensure that any regional limit on offsets would be maintained. This mechanism would also increase the likelihood that the full allowed amount of offsets (49% of emission reductions) would be used; under a percentage use limit, all entities not in need of offsets may need to engage in allowance-to-offset arbitrage in order to make the full amount of offsets available.[6]

[6] Assuming that offset credits are available for less than allowance prices, under a percent use approach an arbitrage opportunity could arise. If an individual entity does not need to use the maximum amount of offsets allowed (perhaps due to a generous free allocation of allowances), this entity would have the opportunity to acquire offsets (not needed for its own compliance purposes) up to the percentage limit and free up allowances to trade to others. However, there is no guarantee that this action would be taken by all market participants. If this

In contrast to limits on supply (see below), the offset surrender certificate approach would not inhibit the creation of offset projects or issuance of credits. However, the surrender certificate approach creates an additional market of compliance instruments which would be accompanied by increases in complexity, transaction costs, and associated concerns related to topics such as market manipulation.

Limiting the *supply* of offsets

Another option is to limit the supply of offset credits. Under a common supply limit, the same pool of offset credits would be available to any covered entity in the WCI region. Under a differentiated supply limit, each Partner would have its own pool of offset credits and those offset credits could either be restricted to their covered entities or could be available for any covered entities throughout the WCI Partner jurisdictions.

Conceptually, a supply limit approach would simplify the implementation of jurisdictional differentiated limits. However, limiting the issuance of offset credits especially through a *first-come, first-issued*, mechanism could create significant uncertainty for offset project developers. There is also no guarantee that the lowest cost projects would be the first to enter the market. Furthermore, a supply limit may hamper a regulated entity's ability to ensure that an offset supplier can deliver in a specific year (due to first come, first serve basis).

Similar to the surrender certificate approach described above, individual entities need not have a percentage limit on the number of offsets used for compliance and a supply limit would ensure that no amount of offsets available under the limit would be left on the table due to the lack of allowance-to-offset arbitrage by individual entities. Unlike all of the use approaches described above, a supply limit would allow individual entities to treat offset credits and allowances as perfect substitutes.

opportunity was not acted on by all entities, some offsets could be ”left on the table” from a system-wide viewpoint.

4.2 Options for Applying the Offset Limit over Time

The offset limit could be set at a common level across all three compliance periods or it could be designed to vary over time. Some stakeholders have argued for more offsets in early years in case rapid reductions prove difficult to implement. It has also been suggested that offsets may be more valuable in early years as emerging low-GHG technologies mature and their costs decline. Other stakeholders have argued for greater offsets in later years to provide cost containment as emission caps are tightened and allowance prices might be expected to rise. Another rationale for greater offset availability in later years is that offsets could be more abundant and reliable as offset markets and rules mature over time.

There are several options for addressing variation in time, including, but not limited to, the following:

- **Equal absolute number of offsets in each compliance period:** This is the approach embodied in the US CAP proposal and conceptually in the American Clean Energy and Security Act of 2009 (ACESA) formula described in Table 1.
- **Equal percent of use across compliance periods.** This approach is used by RGGI and was proposed in the Lieberman-Warner Bill (S.2191). While the fraction of emissions that could be covered by offsets would remain constant, the absolute amount of offsets that could be used would decline if and as the number of available allowances declines over time.[7]
- **49% of Emission Reductions in each period.** This option would impose a different absolute or percent offset limit for each compliance period in order to ensure that no more than 49% of emission reductions are in the form of offsets in each period. Since the cap declines over time (for a given scope of covered sources), the amount of emission reductions increases over time as the cap declines, as would the amount of offsets available.[8]
- **No restrictions across compliance periods:** This approach would provide the most flexibility by imposing no restrictions across compliance periods. The total amount of offset credits that can be used under the limit could be available for use in any compliance period. Entities with compliance obligations would decide when they want to use offset credits, so that the distribution of offset credit use over time would be determined by the market as a whole. This option could be implemented using a supply

[7] In the case of the WCI, the introduction of transportation, residential, and commercial fuels leads to an increase in the emissions cap in 2015, and the absolute amount of allowable offsets would increase significantly from the first (2012-2014) to the second (2015-2017) compliance period.

[8] The increase in the 2015-2017 will be even greater due to the introduction of transportation, residential, and commercial fuels in 2015.

limit, a certificate surrender mechanism, or by an offset use limit expressed in tons rather than % use (e.g. if offset use were linked with allowance distribution). However, it would be incompatible with a straight percentage use limit.

- **Other Ramp Up or Ramp Down:** There are other options for specifying increases or decreases in the amount of allowable offsets over time. For example, the Dingell-Boucher draft discussion bill provided a schedule for increasing the percentage of offsets that could be used over time (see Table 1).
- **Carry-over:** Any unused or unissued offsets (under the limit) could carry over to next compliance period and be added to that period's offset limit. This approach, included in the Boxer amendment (S.3036) for adjusting an issuance limit and in EU Phase III directive on a compliance entity-specific basis[9], could be implemented in conjunction with the options above.

A carry-over provision could increase the ability to fully use the total amount of offsets allowed across all three compliance periods (2012 to 2020), especially in the case that offsets are not available in early compliance periods in sufficient quantity at costs competitive with allowances. The banking of allowances also increases the flexibility in the timing of offset use, by enabling entities to acquire and retire more offsets in early periods than they might otherwise need, and as a result, carry forward banked allowances to the subsequent compliance periods (see footnote 6). Allowance banking increases offset use flexibility in the particular case that offsets are abundant and lower cost compliance options in early compliance periods,

Figure 2 provides a visual comparison of the differences in offsets over time among the first three temporal options listed above, relative to the overall emissions budgets for the three compliance periods. It assumes full offset use (up to the limit in each compliance period) and no carry-over). Offset limit options are grouped by compliance period in order to compare them more easily within each period.

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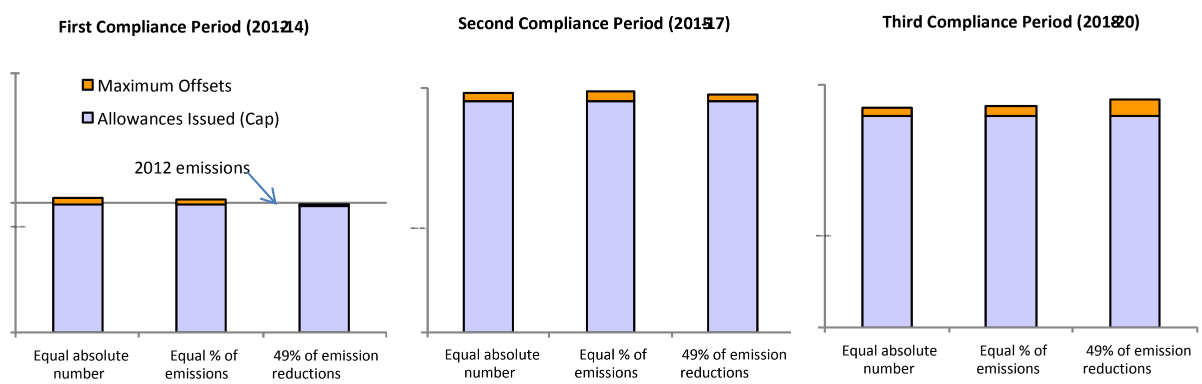
[9] To the extent that covered entities do not use their full allowable amount of offsets in Phase II (2008-12), they would be able to use these remaining amounts in Phase III (2012-2020). "In order to provide predictability, operators should be provided with certainty about the possibility to use after 2012 CERs and ERUs up to the remainder of the level which they were allowed to use in the period from 2008 to 2012…" L 140/67, May 6, 2009, http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2009:140:0063:0087:EN:PDF

Figure 2. Illustration of offset limit options across compliance periods (grouped by compliance period)



(The higher bars in the 2nd and 3rd compliance periods reflect the expansion of program scope in 2015. All figures shown are illustrative)

Figure 3 has two panels. The upper panel shows the same data as Figure 2, but grouped by offset option in order to illustrate how maximum offset use varies for each option across compliance periods. The lower panel zooms in on the maximum offset amounts. (The charts are illustrative only, since the cap has yet to be established.) As shown, the equal absolute amount and equal percentage limit options allow greater offset availability in early periods. As illustrated in Figure 2, these options would allow emissions to exceed 2012 levels in the first compliance period.

Figure 3. Illustration of offset limit options across compliance periods (grouped by offset option)

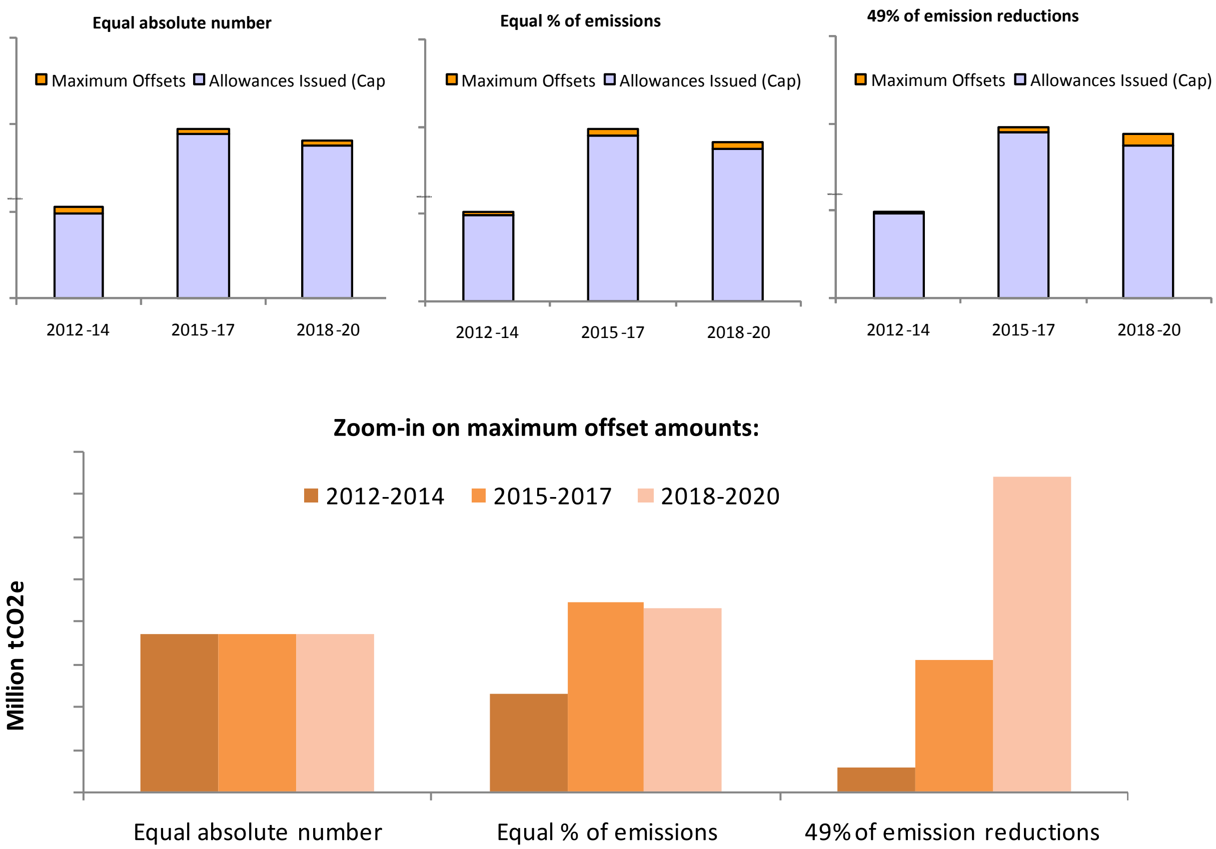


Table 3 compares each of the three options depicted above in terms of the principles listed in Section 3. In terms of fairness, the differences are a matter of perspective: the first two approaches would make more offsets available to covered sources that enter the program in 2012, whereas the third approach shown (49% of emission reductions in each period) would distribute offset availability in accordance with the extent of emission reductions needed (more in last period when deeper reductions are required). With respect to cost containment, as described in the table, the optimal approach will depend on future allowance prices. In terms of effectiveness, each of the first two options (equal absolute number and equal % of emissions) would allow more than 49% of emission reductions to come from offsets during the first two compliance periods, and much less in the third period. While this outcome could be avoided by setting the limit at 49% of emission reductions in each period (the third option), depending on how the limit is implemented (see previous section) this option could enable total emission reductions met by offsets to exceed 49% under the percentage use limit.

While all options shown in the table should be similar in terms of enforceability and administrative simplicity and cost, the carry-over approach noted above might require added administrative effort in the case of the percentage use mechanism, and create could some added uncertainty for the offset market. Data on the total amount of offsets used during a prior compliance period would be needed prior to setting the offset limit for the current period, and this information might not be fully available for several months into the period. Either a supply limit or the surrender certificate mechanism could address concerns about carry-over of excess offset capacity between compliance periods in a more straightforward way.

Table 3. Comparison of options for limiting offsets across compliance periods

Option→ ↓ Principle	**Equal absolute number of offsets in each period**	**Equal % of emissions in each period**	**49% of emission reductions in each period**
Fairness	Would make more offsets available to entities covered in the first compliance period (relative to other options)	Would make more offsets available to entities covered in first compliance period, but less so than the "equal absolute" option	Would make offsets available to covered entities in accordance with the extent of emission reductions required in a given period.
Economic Efficiency	Any proscription of offset use by compliance period has the potential to lead to unrealized efficiency gains.		
Cost Containment	Might provide greater cost containment if internal emission reductions turn out to be more costly in the early period (s).		Might provide greater cost containment if internal emission reductions turn out to be more costly in the final period.
Effectiveness and Enforceability	Would meet WCI 49% limit across all periods, but could exceed it in first and second compliance periods if sufficient offsets are available and are extensively used.		Could exceed overall 49% limit (across 2012-2020) under the percentage use limit, if allowances are banked in early periods and used in later periods when the percentage of allowed offsets is higher. Exceedance could be avoided through a supply limit or surrender certificate approach or linking offset use to allowance distribution (see Section 4).
Administrative Simplicity and Cost	No significant difference among options		

If a supply limit or surrender certificate use limit is chosen instead of a percentage use limit (see Section 4), then the options for spreading offset availability across compliance periods could be set by how certificates are distributed or offsets issued in each period. As noted above, these options could more easily allow for the full targeted amount of offsets to be available across all three periods.

5 Stakeholder Feedback on Options

The CSAD Committee has received considerable feedback on the Offset Limit White Paper. The Committee hosted a stakeholder workshop in Seattle, Washington on May 28th, 2009, and received written comments from approximately twenty stakeholders during the public consultation period. Stakeholders providing input have included industry associations, environmental NGOs, electric utilities, power industry representatives, financial institutions, carbon market participants, and individual firms in the cement, aluminum, forest product, and petroleum industries. This section summarizes this input.

Several stakeholders remarked on the overall stringency or desirability of the offset limit. The limit itself has already been established by WCI, and is not the focus of this paper; no further discussion is provided here.

On the question of the mechanism used to impose the limit, stakeholders generally indicated a preference for limiting the use rather than the supply of offsets, and for reflecting this limit as a percentage of an entity's compliance obligations. Common reasons for this preference included predictability and flexibility for covered entities, concern that the least costly or promising offsets would be those in line to get approval, and concern that a supply limit would result in higher prices than a usage limit. Some of them supported a supply limit, as it would not constrain facilities to a specific usage limit.

Few stakeholders expressed their support for the use of offset surrender certificates, due to the potential to increase offset fungibility across compliance periods and to maximize the number of offsets allowed in the system. However, many of them objected to this approach, citing the potential for reduced cost containment (due to the added costs to compliance entities of acquiring certificates), added complexity, and the potential for market manipulation.

On the question of how the offset limit should be applied across jurisdictions, stakeholders were split in preference between common and differentiated limits. Many favored a differentiation of limits among jurisdictions, on the grounds that it would provide jurisdictions with greater flexibility or provide entities with more access to offsets where tighter emission reduction targets have been adopted. Many also argued for a common percentage use limit, in order to create harmonization among jurisdictions and equal access to offsets by all market participants.

On the question of how the limit should be applied across compliance periods, stakeholders presented a range of opinions, from "fixed and uniform over time" to an equal absolute amount to front-loading with a higher percentage of use in earlier periods. Many stakeholders expressed a desire to have no restrictions across compliance periods. However, as noted above (Section 4), complete flexibility among compliance periods would require that a supply limit, the use of offset certificates, or another form of distributing the "right" to use offsets, such as on the basis of allowance distribution. As noted above, stakeholder support for offset surrender certificates or for a supply limited was relatively limited. On the question of whether access to offsets should be linked with the distribution of allowances, all stakeholders who commented on this approach objected to it, suggesting there is no rationale for such a distribution.

Many stakeholders favored a "carry-over" of unused offsets from one compliance period to the next, as a means to provide flexibility across compliance periods and increase the overall utilization of offsets. One commenter suggested that a carry-over mechanism might be unnecessary, arguing that the market could ensure maximum utilization of offsets through the banking of allowances.

Finally, the Committee asked stakeholders to describe any specific competiveness impacts the Committee should consider in evaluating options to apply the offset limit. Many of the suggestions here were made in reference to comments noted above, and ensuring that the approach to setting the limit does not result in higher prices, and makes offsets available during periods when other compliance options (internal reductions, allowance purchases) are more expensive.

6 Recommendation

The Cap Setting and Allowance Committee offers the following recommendations for implementing the offset limit.

1. The Committee finds that limiting the use of offsets would be preferable to limiting the supply of offsets. Compared to a supply limit, a use limit should result in lower overall compliance costs for covered entities. Furthermore, the Committee recommends a use limit be applied at the entity level, more precisely as a percentage of compliance obligations (i.e. emissions). This option provides predictability for covered entities, is administratively simple to implement, and tends to minimize both administrative and compliance costs of the program relative to a supply limit.

2. The Committee recommends a common use limit be implemented across Partner jurisdictions. A common limit provides equal access to offsets to entities across the WCI cap-and-trade system, and helps to ensure that the overall limit would not be exceeded. (See Section 4 for a discussion of how this might occur with differentiated limits) With a common use limit, a jurisdiction could still adopt a limit lower than this level, an option established in the WCI design recommendations. The CSAD Task 3 (competitiveness) group will consider whether the common use limit might pose competitiveness concerns for entities in jurisdictions that have adopted lower emission targets relative to historical levels, and if so, how to address these concerns.

3. The Committee recommends that the limit be set at an equal percentage of compliance obligations across compliance periods. This option would allow for the use of a greater absolute number of offset credits in earlier compliance periods (adjusting for the expansion of program scope in 2015), thus easing the transition into the cap and trade program.

4. The Committee also recommends the implementation of region-wide "carry-over" approach. Under such an approach, if the total amount of offsets used across WCI in a given compliance period are less than the total amount of offsets allowed, then the difference in these two amounts would be added to the subsequent period's offset limit (in absolute terms), with the percentage offset limit adjusted appropriately.[10] The committee recommends adopting a "region-wide", rather than "entity-specific" carry-over approach due its simplicity, lower administrative cost, transparency, and ability to enable fuller overall use of offsets.[11]

   Fundamental to this recommendation for a carry-over feature is the stringency of the limit on the use of offsets in the WCI program design. Under a program with more generous offset limit provisions, like the one proposed under the American Clean Energy Security Act (ACES), the carry-over feature could be counterproductive in its effect on long-term investment in emission reductions by covered sources. Of particular concern is that unused portions of an offset use limit could accumulate in early years to such an extent that covered sources could rely on offsets in later years to meet most or all required reductions. In the specific case of WCI, this outcome is not of concern, since the implementation of a carry-over will still result in over half of emission reductions occurring at covered sources. Consequently, this recommendation should be construed narrowly, applying only to the specific circumstances of the WCI program design.

[10] A numerical example of a carry-over system is presented in Annex 2.
[11] Under an entity-specific carry-over approach, entities that ceased or significantly reduce operations, and thus emissions, might not be able to use their "carried over" offset amount.

5. While there is some interest in adopting an offset surrender certificates approach, which would permit regulated entities to sell and buy (trade) the right to use offsets, the Committee does not recommend this approach. Compared to a percentage of compliance approach, the surrender certificate approach could be more administratively complex and may increase the overall compliance cost for some regulated entities.

In summary, the Committee recommends that Partners limit the use of offsets and that this limit be expressed as a percentage of compliance obligations at the entity level. The same percentage of compliance obligations should be applied across jurisdictions and compliance periods with a regional “carry-over” system that would permit the unused portion of the limit to be transferred to the following compliance period.

Annex 1: Detailed Description of Offset Limits in Other Trading Schemes

Regional Greenhouse Gas Initiative (RGGI)[12]

Limits: The Regional Greenhouse Gas Initiative (RGGI) allows entities to use carbon offsets to cover a portion of their compliance obligation. Entities can use offsets to cover up to 3.3% of their total compliance obligation. This limit increases to 5% if the carbon price is over $7 per ton, and further increases to 10% if the allowance price exceeds $10 per ton.

Project Eligibility: The RGGI Model Rule identifies five project types that are eligible for offsets:

- Landfill methane capture
- Sulfur hexafluoride (SF6) capture
- Forest sequestration
- Energy efficiency for natural gas, propane and heating oil
- Animal methane management

New project categories will be adopted if they are approved by each of the RGGI states.

In order to receive offset credit, emission reductions from these project types must be:

- Real and quantifiable
- Additional beyond business as usual assumptions
- Verifiable
- Permanent
- Enforceable

Offset Limit Methodology: In order to strike a balance between achieving real emission reductions in covered sectors and providing entities with a flexible compliance option, RGGI states decided that offset use should be limited to 50% of the total emission reduction amount. According to the Staff Working Group (SWG) analysis, the 50% goal was not viewed as a hard target, but rather as a guiding principle in determining a quantitative offset limit. The SWG recommended an entity level offset limit, rather than a state-wide or system-wide limit. The SWG modeled the impact of different offset limit amounts to determine an entity level limit that would approximate the 50% goal. The final SWG analysis recommended limiting offsets to

[12] Sources for this section include: Regional Greenhouse Gas Initiative Model Rule (12/31/08 final with corrections. (www.rggi.org); Analysis Supporting Offsets Limit Recommendation (5.1.06). (www.rggi.org); Offsets Summary: the Regional Greenhouse Gas Initiative. Environment Northeast (http://www.env-ne.org/public/resources/pdf/ENE_RGGI_offset-design.pdf)

3.3% of an entities' total compliance obligation. This recommendation was adopted in the RGGI Model Rule.

The price trigger provision recognizes this modeling uncertainty by making the offset limit a function of the factors that drive price increases. Allowance price increases are partially a factor of the trajectory and the starting cap—allowing the offset limit to increase when the price increases serves as a means of correcting for inaccuracies in setting of these factors. This allows the offset limit to more closely align with the overall RGGI goal of controlling compliance costs.

European Union Emission Trading Scheme

Summary of Limits: The European Union Emissions Trading Scheme (EU ETS) imposes limits on the amount of offset credits that may be used for compliance in both Phase II and III. These limits are percentage use limits applied at the facility level.

The actual limit is different in each phase, for each Member State, and may differ by type of installation. The Phase III limits are likely to be more stringent than the Phase II limits and may be harmonized across the EU; actual limits for Phase III are contingent on the results of international climate change negotiations.

Project Eligibility and Geographic Limitations:
Phase II: The permissible offset credits in Phase II are certified emission reductions (CERs) from the clean development mechanism (CDM) and emission reduction units (ERUs) from joint implementation (JI) projects.[13]

Phase III: Limits on the use of CERs and ERUs in Phase III are contingent on the evolution of these programs as a result of international negotiations. The EU may also begin to explore other types of domestic offsets.[14]

Offset Limit Methodology:
Phase II: In international climate negotiations it was decided that internal (domestic) abatement of emissions should take precedent over external participation in flexible

[13] For a list of approved CDM methodologies see:
http://cdm.unfccc.int/methodologies/PAmethodologies/approved.html

[14] See point 22 of the following document:
http://europa.eu/rapid/pressReleasesAction.do?reference=MEMO/08/796&format=HTML&aged=0&language=EN&guiLanguage=en

mechanisms such as the CDM and JI.[15] In the context of the Kyoto Protocol this concept is referred to as "supplementarity."

The requirement to take significant action domestically was included in the international agreements partially at the behest of European nations. Therefore, the concept of prioritizing domestic action (from capped sources located in the EU) was included in the design of the EU ETS.

Each member state in the EU ETS has a different limit on the use of offsets credits from the international flexible mechanisms (CDM and JI credits) in the second phase of the EU ETS.[16] These limits are usually specified as a percentage of the total amount of allowances freely allocated to an installation.[17]

There is currently no EU-wide agreement on the definition of supplementarity. It is roughly interpreted that at least 50% of reductions (also referred to as the "level of effort") should be met by direct reductions at covered facilities. However, in actual implementation it appears that the levels set for use of offsets in Phase II may allow for more than 50% of reductions to be met through offsets.[18]

Wide discretion was given to the Member States as limits on the use of CDM/JI credits were set in Phase II. The European Commission considered that, as a rule of thumb, installations should be allowed to use JI and CDM credits to supplement their allowance allocation by up to 10%.[19] However, each member state set the actual binding limit in its national allocation plan, which was then subject to approval by the Commission. Some approved limits were 20% and above.[20] In aggregate these limits would allow operators in the EU ETS to import approximately 1.4 billion metric tons of credits from 2008-2012.[21]

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[15] See the Kyoto Protocol. Available from: http://unfccc.int/resource/docs/convkp/kpeng.pdf
[16] Phase II of the EU ETS runs from 2008-2012.
[17] For example, the United Kingdom limits on project credits in Phase II is 9.3% of allocation for large electricity producers and 8% of allocation for all other installations. See page 16 of the DEFRA's *An Operator's Guide to the EU Emissions Trading System* available from:
http://www.defra.gov.uk/environment/climatechange/trading/eu/pdf/events-guide.pdf
[18] Some environmental groups estimate that between 88-100% of the emission reductions required under the combined cap for the EU ETS could theoretically take place outside of the EU through the use of offset credits. See for example, WWF, *Emission Impossible: access to JI/CDM credits in phase II of the EU Emissions Trading Scheme* June 2007. Available from: http://assets.panda.org/downloads/emission_impossible___final_.pdf
[19] European Commission. *Questions and Answers on Emissions Trading and National Allocation Plans from 2008 to 2012*. Page 4. Available from: http://ec.europa.eu/environment/climat/pdf/m06_452_en.pdf
[20] According to the WWF analysis, Irelands limit is 21.9%, Spain and Germany's limit is 20%. See each country's Phase II NAP for more details.
[21] The Carbon Trust (2008) *Cutting Carbon in Europe: The 2020 plans and the future of the EU ETS* Available from: http://www.carbontrust.co.uk/publications/publicationdetail.htm?productid=CTC734

Phase III: The EU has recognized that the level of offsets allowed in Phase II is likely to prevent achievement of the supplementarity goal and has proposed changes to prevent this in Phase III of the EU ETS. Beyond the supplementarity considerations, motivations for this increase in stringency are strategic in nature. The EU is attempting to use the EU ETS's influence on the demand for CERs as a tool in the international negations. The goal is to motivate large-emitting non-annex 1 countries (e.g., China) to increase action on climate change, including considering firm caps on emissions.

The rules for Phase III have recently been established as part of a comprehensive Climate and Energy Package.[22, 23] This package specifies that the level and type of offset credits allowed in Phase III is contingent on a successful implementation of an international agreement on climate change that will cover this period (post-2012). In the absence of an international agreement, the offset limit will be much tighter than in Phase II.

Limits proposed in US National Cap-and-Trade Legislation

Lieberman-Warner Climate Security Act (US Senate Bill 2191, 110th Congress)[24]

Senators Lieberman and Warner introduced the Climate Security Act, which was referred to the Environment and Public Works Committee, on October 18, 2007. Hearings were held to discuss the bill at the subcommittee and committee level in the fall of 2007.

Summary of limits: The Lieberman-Warner Climate Security Act stipulates that the owner or operator of a covered entity may meet up to 15% of their total compliance obligation using offset allowances. This percentage use limit is applied to each year or each compliance period. The limit does not change from year to year and there is no roll-over option for unused allowances to be used in future years or compliance periods.

Offset limit methodology: Covered entities may submit offset allowances that satisfy up to 15% of their total allowance submission requirement each year. These offsets must be generated in accordance with the bill—specifically the eligibility criteria and provisions in

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[22] See: http://www.euractiv.com/en/climate-change/mixed-reactions-parliament-approves-eu-climate-deal/article-178163

[23] The revisions to the EU ETS in perpetration for Phase III were made as part of the climate and energy package proposed by the European Commission (EC), as accepted by the European Parliament on Dec. 17, 2008. See: http://www.europarl.europa.eu/sides/getDoc.do?pubRef=-//EP//TEXT+TA+P6-TA-2008-0610+0+DOC+XML+V0//EN&language=EN#BKMD-12

[24] S.2191 bill http://thomas.loc.gov/cgi-bin/query/z?c110:S.2191

Subtitle D (the offsets section). This option may be provided as a means to contain cost while also creating an administratively simple offsets program.

Boxer Substitute of the Lieberman-Warner Climate Security Act (US Senate Bill 3036, 110th Congress)[25]

The Boxer Substitute of Lieberman-Warner's Climate Security Act (S. 3036) was reported to the US Senate on May 20, 2008. The Boxer Substitute made considerable changes to the Climate Security Act in general and specifically the offsets provisions in the original bill. The Boxer Substitute was debated on the US Senate in the summer of 2008 and did not pass on the floor. The Boxer version shifted to an aggregate supply limit on total offsets allowed in the market, rather than a use based limit.

Summary of limits: The Boxer Substitute sets a supply limit on offsets allowed in the proposed cap-and-trade system. The supply limit would allow EPA to control the issuance of offset credits and cap the total supply to the cap-and-trade market. Language in the bill places an aggregate limit on how many offsets are available for purchase from three categories: domestic, international, and forestry offsets. The total supply limit for each of these categories is 30%: 15% domestic, 5% international, and 10% international forest offsets. The bill proposes the following:

- EPA limits the creation of ***domestic offsets*** to 15% of the total quantity of emission allowances issued in each year. The limit applies to the total number of offsets, not to an individual entity's compliance obligation.
    - Any unissued portion of the offsets for one year may be added to the 15% limit for the following year.
    - Offsets will be issued (at an appropriate discount rate determined by EPA) for each offset issued under RGGI.
- EPA limits the use of ***international offsets*** to 5% of the total quantity of emission allowances.
    - Any unused portion of international offsets may be added to the 5% limit for the following year.
    - International offsets from a project at a facility that competes directly with a US facility will not be allowed.
- EPA limits the use of ***international forest offsets*** to 10% of the total quantity of emission allowances for each year.

[25] S.3030 bill http://thomas.loc.gov/cgi-bin/query/z?c110:S.3036; ; Summary of S. 2191: Lieberman-Warner Climate Security Act of 2008 Manager's Substitute Amendment by the World Resources Institute. URL: http://www.wri.org/publication/summary_lieberman_warner_climate_security_act_2008_substitute_managers_amendment

- Forest offsets can be generated from reductions in deforestation and forest degradation as compared to caps or reference scenarios used by foreign countries.
- After enactment of the bill, EPA will periodically review the performance of the forestry offset program.
- Ten years after enactment, the EPA may discount offset credits from countries that have not reduced total emissions from forests.

Project eligibility: Section 2403 lists projects eligible to generate offset allowances, including:

- Afforestation and reforestation
- Altered tillage practices
- Capture of fugitive emissions
- Capture or combustion of methane at non-agricultural facilities
- Conversion of cropland to rangeland or grassland
- Cover cropping
- Forest management
- Manure management
- Reduced carbon emissions from organic soils
- Reduction of fertilizer use
- Rice-paddy flood management

Offset limit methodology: The Boxer Substitute creates flexibility for covered entities to use offset credits from a variety of projects and locations. The issuance limit was designed to increase the supply of offsets and thus, reduce costs for those sources that have a compliance obligation. By allowing more project types, international offsets, and a roll over clause—the bill seeks to create a large supply of offsets and contain costs.

Dingell-Boucher Draft Discussion Bill (House Draft Bill)[26]

The draft Dingell-Boucher bill was released to the public for discussion purposes by the US House Committee on Energy and Commerce in October 2008. The bill has not been officially introduced in the US House of Representatives.

Summary of limits: Regulated entities may use verified domestic or international offsets for a portion of surrendered allowances rising from 5% starting in 2013 up to 35% by 2024. The percentage of allowable domestic and international offsets increases in each compliance period.

[26] energycommerce.house.gov/images/stories/Documents/PDF/selected_legislation/clim08_001_xml.pdf

Project eligibility: The draft bill permits regulated entities to purchase EPA-approved offset credits for domestic and international emission reduction projects. The proposal requires EPA to recognize domestic offset credits for

- Afforestation or reforestation on acreage not forested after January 1, 2008
- Landfill methane
- Manure management
- Methane collection at coal mines

Other project types will be reviewed for future consideration in the offsets program:

- Controlled wastewater treatment
- Conversion of cropland to rangeland or grassland
- Forest management resulting in an additional increase in forest stand volume
- Methane reduction from reclamation of abandoned surface mines
- Practices that increase agricultural soil carbon sequestration
- Recycling and waste minimization
- Reduced deforestation
- Reduction of nitrogen fertilizer or increase in nitrogen use efficiency

Offset limit methodology: Offsets play a greater role in each compliance period. Covered entities will submit offset allowances that represent up to 5%-35% of their total submission requirement during each compliance period:

- Up to 5% (domestic or international) in 2013-2017
- Up to 15% (domestic or international) in 2018-2020
- Up to 30% in 2021-2024 (15% domestic/15% international)
- Up to 35% in 2025-2050 (20% domestic/15% international)

The American Clean Energy and Security Act of 2009 – ACESA (passed by the House – June 26, 2009)

Summary of limits: ACESA establishes an entity-based limit that is calculated on an annual basis. Covered entities collectively may use offset credits to demonstrate compliance for up to a maximum of 2 billion tons of GHG emissions annually. The use limit is split evenly between domestic and international offsets each. The EPA can increase the allowable percentage for international offsets (up to 1.5 billion), if the agency determines use of domestic offsets will not be maximized (at current emission allowance prices) in a particular year. Starting in 2018, international offsets are discounted such that 1.25 international offsets would be equivalent to 1 allowance for compliance purposes.

Project eligibility: Additionality is determined by the following criteria: 1) not required by law or regulation, 2) not commenced prior to January 1, 2009, except for projects that commenced after January 1, 2001 and that were registered with the EPA as of the date of enactment or are readily reversible and 3) based on activity baselines based on a standardized baseline that reflect “a conservative estimate of business as usual” performance or practice.

Other key project eligibility criteria include:

- Accounting for leakage
- Activity baselines
- Addressing reversals, including mechanisms such as an offsets reserve and/or insurance
- Approval via crediting periods
- Auditing
- Verification and verification accreditation

Offset project types, including international offset projects, will be reviewed and approved within two years with consultation from the offset integrity advisory board. This board will prioritize offset project types for consideration.

Offset limit methodology: Offsets could play a greater role over time in the proposed program—increasing from approximately 30% use limit in 2012 to 67% by 2050. The formula to calculate the use limit requires EPA to divide the number 2 billion by 2 billion plus the emission allowances available in the previous year and multiply by 100 (for a percentage limit). The President may make a recommendation to Congress as to whether the number 2 billion should be increased or decreased. In addition, the program will recognize offsets for reduced deforestation that meet specific eligibility criteria.

Annex 2: Illustration of a Region-Wide "Carry-Over" mechanism

The WCI Partners limit offsets to no more than 49 % of the overall reductions, in order to ensure that a majority of emission reductions required under the program occur at covered entities and facilities. Considering the important role of offsets in reducing the overall compliance cost of the system, the Partners recommend the implementation of a region-wide carry-over mechanism that can help to maximize the number of offsets used for compliance under the proposed limit. As noted above, such a mechanism is only appropriate to consider where the overall offset limit is sufficiently stringent.

Under the region-wide carry-over approach, if the total amount of offsets used across WCI in a given compliance period is less than the total amount of offsets allowed, then the difference in these two amounts would be added to the subsequent period's offset limit (in absolute terms), with the percentage offset limit adjusted appropriately. The numerical example below illustrates how the offset limit would be adjusted by the carry-over mechanism.

For simplicity of illustration, assume a cap-and-trade system with three compliance periods. Assume also that 49% of emission reductions across the three periods is estimated to be 142 105 tCO_2e (referred to as "tons" below), which is equivalent to an offset limit set at 5.0% of compliance obligations (i.e. emissions) across all periods, as follows:

1st compliance period cap (allowances distributed): 1 000 000 tons
2nd compliance period cap (allowances distributed): 900 000 tons
3rd compliance period cap (allowances distributed): 800 000 tons

Total allowances distributed (all periods): 2 700 000 tons
Offset use percentage limit = (offset credits allowed) / [(total allowances) + (offset credits allowed) = 142 105/(2 700 000 + 142 105) = 5.00%

Since the limit is expressed in terms of compliance (i.e. emissions), the "carry-over" is calculated based on the number of allowances surrendered for compliance. Example 1 shows how the "carry-over" works when all allowances are surrendered at the end of a compliance period and example 2 when regulated entities retain some allowances for use in a future period.

Example 1: Carry-over assuming no banking of allowances

1st compliance period :

If all allowances are surrendered at the end of the first compliance period, then the maximum amount of offset credits that could be used during the first compliance period would be 52 632 tons. (In other words, 1 000 000 allowances and 52 632 offset credits could be surrendered to cover total emissions of 1 052 632 tons of emissions; 52 632 offset credits represents 5.00% of 1 052 632 tons of total emissions.)

If all allowed offset credits are use during the first compliance period (i.e. 52 632 tons), then there would be no carry-over and the limit would stay at 5.00% during the second compliance period.

If all first period allowances are used (none banked), but not all allowed offsets are used, let say only 40 000 tons instead of 52 632 tons of offsets, then, with a carry-over, the new offset limit would be calculated as follows:

> Total allowances remaining in the system = (total number of allowances to be issued) – (number of allowances used for compliance) = 2 700 000 – 1 000 000 = 1 700 000 allowances
>
> Total allowed offsets remaining = (total number of offset credits allowed for compliance in the system) – (offset credits used for compliance) = 142 105 – 40 000 = 102 105 offset credits
>
> Offset use percentage limit = (remaining offset credits) / [(remaining allowances) + (remaining allowed offset credits)] = 102 105 / (1 700 000 + 102 105) = 5.67%
>
> Therefore, the use of offsets in the second compliance period would be limited to 5.67% of compliance obligations.
>
> A similar calculation would be performed at the end of the second compliance period to adjust the offset limit percentage for the third compliance period. The third compliance period offset limit would be greater than or equal to the percentage set for the second compliance period (5.67% in the case shown).

Example 2: Carry-over assuming banking of allowances

Following example 1, suppose at the end of the first compliance period only 950 000 allowances are surrendered for compliance purposes (i.e. 50 000 allowances are banked for use in the second or third compliance period). Suppose also that only 40 000 offset credits are used for compliance. Under the carry-over the new offset limit for the second and third compliance period would be:

Total allowances remaining in the system = (total number of allowances to be issued) – (number of allowances used for compliance) = 2 700 000 –950 000 = 1 750 000 allowances

Total allowed offsets remaining = (total number of offset credits allowed for compliance in the system) – (offsets credits used for compliance) = 142 105 – 40 000 = 102 105 offset credits

New offset limit = (remaining offset credits) / [(remaining allowances) + (remaining allowed offsets credits)] = 102 105 / (1 750 000 + 102 105) = 5.51%

Therefore, the use of offsets in the second compliance period will be limited to 5.51% of compliance obligations.

Again, a similar calculation would be performed at the end of the second compliance period, and the third compliance period offset limit would be greater than or equal to the percentage set for the second compliance period (5.51% in the case shown here).

From a stakeholder perspective

If we use this example, a covered entity knows a) that the offset limit will be set at 5.00% of compliance obligations for the first compliance period, and b) that over the subsequent compliance periods, the offset limit will either increase or stay the same as the prior period's limit.

For example, suppose covered entity A emits 50 000 tons during the first compliance period. At the end of the period, the facility will have to surrender a combination of allowances and offset credits equal to emissions (or compliance obligation), i.e. 50 000 tons. Entity A can comply without the use offsets, by surrendering 50 000 allowances (which it may have received through a free allocation and/or purchased in the market or at auction). Alternatively, the entity can acquire and surrender up to 2 500 offset credits, which reflects the region-wide offset limit of 5.00% multiplied times its emissions (5.00% of 50 000 tons) along with 47 500 allowances (50 000 tons minus 2 500 offset credits). If entity A uses fewer than 2 500 offset credits -- for example, 1 700 offset credits -- then the remainder (800 offset credits) are used to calculate the *region-wide* carry-over for the remaining compliance periods.

Let's assume in the second compliance period that entity A emits 45 000 tons. Let's also assume as in example 1 above, that several entities did not use the full amount of allowed offset credits and that, as a result, the second compliance period's offset limit increases to 5.67%. In this case, entity A could use up to 2 552 offset credits (5.67% of 45 000 tons) for compliance in the second period. Because of the region-wide carry-over, entity A has an additional 302 offset credits that it can use, as compared with a system without a carry-over, in which case the allowable offset amount would have been 2 250 (5.00% of 45 000 tons), if the limit stayed at 5.00%.

This example also points out the difference between a *region-wide* (recommended) and an *entity-specific* (not recommended) carry-over mechanism. Under an entity-specific carry-over, entity A in the example described here would have had an additional 800 offset credits to use in the second and/or third compliance periods. The amount of additional offsets available to an entity would be solely a function of how many offsets it had been allowed and (not) used in the past. In contrast, a region-wide carry-over mechanism would adjust the offset limit for *all* entities in subsequent periods.

October 6, 2009 Offset Limit Recommendation Paper

List of Commenters

Business Council for Sustainable Energy

E.J. Bentz & Associates

Independent Energy Producers Association

Morgan Stanley Capital Group, Inc.

National Alliance of Forest Owners, California Forestry Association, Oregon Forest Industries Council, Washington Forest Protection Association

Offsets Working Group

Pacific Gas and Electric Company

Power Workers' Union

Southern California Edison Company

Waste Management, Inc.

Western Climate Advocates Network

Western Power Trading Forum

Zini, Gian

Western Climate Initiative News

October 6, 2009

This status report is issued monthly from WCI Partner jurisdictions to all interested stakeholders via the WCI list server and website.

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Draft Recommendations for WCI Offset Limits

In May 2009, the WCI Cap Setting & Allowance Distribution Committee released a white paper and hosted a workshop describing options to limit the use of offsets issued by the WCI, as well as offsets and allowances issued by other trading systems, to no more than 49 percent of the total emission reductions from 2012 to 2020 that are called for by the regional cap. The Draft Offset Limit Recommendation Paper builds on the white paper by summarizing stakeholder feedback from the white paper and workshop and offering the Committee's recommendations for implementing the offset limit.

The purpose of the Recommendation Paper is to seek stakeholder input prior to a final WCI decision. Click here to download and provide comments on the document. Comments should be provided by October 30, 2009.

In addition, a teleconference has been scheduled for 9:00 a.m. Pacific on October 21 to garner further stakeholder input. To join the call, dial 1-800-868-1837 (toll free) or 1-404-920-6440 (direct dial) and enter participant code 659537#.

Formation of the WCI Electricity Team

The WCI Partners reviewed options for continued work on issues related to the electricity sector following their July 21, 2009 announcement concerning implementation of the first jurisdictional deliverer (FJD) approach for regulating emissions associated with imported electricity. Addressing the point of regulation for electricity was the original purpose of the Electricity Committee. With that task largely completed, the Partners considered assigning the remaining electricity issues to other

Upcoming Events

October 15: WCI Stakeholder Update Call

The WCI Partners will be hosting their next bimonthly stakeholder update call on October 15 at 12:30 p.m. Pacific. To join the call, dial 1-800-868-1837 (toll free) or 1-404-920-6440 (direct dial) and enter participant code 659537#.

October 21: Stakeholder Call on Offset Limits

The Cap Setting & Allowance Distribution Committee will host a call with stakeholders on October 21 at 9:00 Pacific to review and discuss its recommendations to Partners for limiting the use of offsets in the WCI cap-and-trade program. To join the call, dial 1-800-868-1837 (toll free) or 1-404-920-6440 (direct dial) and enter participant code 659537#.

November 18: WCI Partners Meeting

The next WCI Partner meeting will be on November 18 in Santa Fe, NM at the La Posada Resort. Stakeholders are invited to attend in-person or via teleconference. More information will be distributed soon through the WCI website and list server.

relevant committees.

However, to ensure that critical issues related to the electricity sector receive adequate attention, and in order to continue the involvement of the Electricity Technical Advisory Group, the WCI Partners decided to maintain a technical staff group dedicated to electricity issues. The Electricity Team will be led by Doug MacCallum, Manager, Energy Markets, Ontario Ministry of Energy and Infrastructure. To read more about the proposed structure and work of the Electricity Team, click here.

November 19: Oil and Gas Industry Collaborative
The WCI is sponsoring an oil and gas industry collaborative in Santa Fe, NM at the La Posada Resort. The collaborative will focus primarily on emissions from exploration, production, and refining. Stakeholders are invited to attend in-person or via teleconference. More information will be distributed soon through the WCI website and list server.

WCI Offsets Committee Launches Effort to Evaluate Existing Protocols

The WCI Offsets Committee has initiated an effort to evaluate existing offset protocols for agriculture, forestry, and waste management against the WCI Offset Draft Criteria. Also of interest is whether the existing protocols are aligned with the ISO framework, as defined by ISO 14064-2, 14064-3, and 14065. The result of this work will identify the existing protocols that are aligned with the ISO framework and satisfy the WCI draft criteria for inclusion in the WCI program as is, or with modifications. The Committee will be assisted in this effort by Det Norske Veritas.

Presentations Available from WCI Cap-Setting Webinar

On September 21, the WCI Cap Setting & Allowance Distribution Committee hosted a public webinar to hear from representatives of the Regional Greenhouse Gas Initiative (RGGI) and European Union Emission Trading System (ETS) on the experience and lessons learned in setting emission caps in those programs. Presentations by the representatives can be downloaded from the WCI website.

Benchmarking Workshop Presentations Available

On September 17, 2009, the Provinces of Ontario and Quebec hosted a workshop in Toronto, Ontario to bring together experts, governments, and sector representatives from across North America and internationally to share experiences, information, and best practices as they relate to cap-and-trade allocations and benchmarking. Several WCI committees are considering some aspect of benchmarking, either through the creation of benchmarks or the use of them as a mechanism for addressing competitiveness issues created by a regional cap. Presentations from the workshop are available here. The WCI Partners anticipate future work on this issue.

WCI Electricity Team Releases Prototype Default Emission Factor Calculator for Stakeholder Review and Comment

The WCI Electricity Team has posted two versions of a default emission factor calculator on the WCI website for stakeholder review and comment:

- The "lite" version contains only the calculator worksheet and its data table and is available at http://www.westernclimateinitiative.org/component/remository/Electricity-Team-Documents/Prototype-Default-Emissions-Calculator-(Lite-Version).
- The full version contains all of the underlying data that were used to create the data table for the calculator, and an embedded document from the original Energy Information Administration files that provides additional information on the data and the codes used to identify fuels and generation technologies (note that the full version is nearly 6 MB). The full version is available at http://www.westernclimateinitiative.org/component/remository/Electricity-Team-Documents/Prototype-Default-Emissions-Calculator/ .

To submit comments go to http://www.westernclimateinitiative.org/public-comments/document/12.

The Electricity Team will host a stakeholder call on October 30th at 10:00 a.m. Pacific Daylight Time to receive initial feedback from stakeholders and answer any questions about the spreadsheet or the process for determining the default emission factors. To join the call, dial **1-800-868-1837** (toll free) or 1-404-920-6440 (direct dial) and enter participant code **659537#.** Written comments are due November 13th and should be submitted via the public comments page on the WCI website.

Default emission factors for attributing emissions to unspecified electricity are needed by WCI jurisdictions for three related reasons. First, WCI jurisdictions must quantify the emissions associated with imported electricity during the base years used for establishing their 2020 caps. Second, emissions associated with imported electricity need to be quantified during recent years leading up to 2012, the first year of the cap and trade program, in order to estimate 2012 emissions and set allowance budgets accordingly. Third, default emission factors are needed on an ongoing basis in order to establish the compliance obligations of first jurisdictional deliverers that deliver unspecified power or determine the number of allowances that must be retired by jurisdictions using the administrative option to account for electricity imports.

Various methodologies can be used to calculate default emission factors. The WCI Electricity Team discussed these options with stakeholders on a conference call in December 2008. The Electricity Team would like to receive stakeholder feedback on a simplified spreadsheet approach that approximates the load duration curve modeling methodology discussed with stakeholders.

The spreadsheet is meant to serve as a proof of concept for stakeholder feedback. This illustrative version only covers 2007 data for plants in the WECC region and does not include data on plants in Canada or Mexico. If the Team, in consultation with stakeholders, determines that this approach is sufficiently robust and the Partners approve, the Team will finalize the 2007 WECC spreadsheet and develop other spreadsheets for additional years and the Eastern Interconnect for stakeholder review. The Team will then calculate the default emission factors that will be recommended to the Partners for use by WCI jurisdictions.

The default emission factor spreadsheet draws on two publicly available data sources: the Energy Information Agency's Form 860 and the Form 923. Together, these two forms contain information on electricity generating facilities including generator types, generator capacities, quantities of fuel consumed, whether the facility is a CHP unit, and net generation produced.

Using the EIA information, the spreadsheet calculates default emission factors by assigning facilities to either a marginal or non-marginal category. The default emission factor is calculated as the total emission divided by the total net generation of all marginal sources. The Team relied on certain rules of thumb in order to determine a facility's "marginality." The first rule of thumb is that a plant is considered categorically non-marginal if it is a CHP unit or uses renewable sources of energy (including hydro).[1] The remaining non-CHP plants using fossil fuels as their main source of energy are considered marginal when their capacity factors are below 60%.[2]

Most of the calculations and database functions in the workbook are performed automatically by formulas or pivot tables, but some important manual corrections were necessary. Facilities listed in the Form 923 data as consuming both coal and natural gas are often actually two facilities collocated on one site. The coal-fired facility uses steam turbines while the gas-fired facility generally uses combustion turbines or a combination of combustion turbines and one or more steam turbines operating in a combined cycle. If these collocated facilities are treated as one facility, the resulting capacity factor misrepresents the true operations of the plants. For example, using 2007 data, the combined capacity factor of the Apache plant in Colorado is 53%, which indicates that it is a marginal power plant. Closer examination reveals that the coal units operated at an 83% capacity factor, and the gas units operated at a 5% capacity factor. In cases where such collocated facilities occur, they were manually separated into two distinct units in the data table that underlies the default emission factor pivot table.

The Electricity Team asks stakeholders to address the questions below in their comments, but stakeholders are not limited to responding to these questions.

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[1] While hydro is on the margin at times in the Pacific Northwest, the vast majority of hydro generation in that region is produced in jurisdictions that are WCI members. It seems reasonable to assume that the relatively small amount of hydro power generated in non-WCI locations would rarely, if ever, serve as the marginal resource for power imported from those locations into WCI jurisdictions.

[2] This is the threshold used to distinguish baseload and non-baseload plants in California's and Washington's emission performance standards.

1. Is this approach sufficiently analytically rigorous? If not, do you think more sophisticated models are likely to produce significantly different results?
2. Is there any reason that this simplified approach is more appropriate for either the Eastern Interconnect or the Western Interconnect?
3. Are the rules of thumb used to classify plants as marginal or non-marginal appropriate? What specific changes do you recommend?
4. Are there any specific plants that have been misclassified with respect to whether they are marginal? If so, which ones and why?
5. Are there any other corrections or improvements that you suggest?

The following pages document the steps undertaken to create the default emission factor calculator from the EIA data sources. Instructions for using the calculator are provided on the "Instructions" worksheet in both versions of the calculator.

Documentation for Preparing the Default Emission Factor Calculator

Preparation of the "GenY07" and "GenY07PvtTable" Worksheets
Download 2007 EIA-860 from http://www.eia.doe.gov/cneaf/electricity/page/eia860.html

In the Form EIA-860 2007 data folder, open workbook GenY07

Delete columns T – AU (Cogenerator – Planned_Retirement_Year)

Add Column "OP_NAMEPLATE" and insert formula:
=IF(N2<>"RE",K2,IF(S2<>2007,0,R2/12*K2))
[This column lists a unit's operational capacity. If a unit was retired during 2007, it is attributed a partial capacity based on the number of months it was still operational.]

Create pivot table on new sheet: Facility ID in rows; sum of OP_NAMEPLATE in data

Copy data from pivot table and paste on same sheet

Creating the Default Emission Factor Workbook

Download 2007 Form EIA-923 from
http://www.eia.doe.gov/cneaf/electricity/page/eia906_920.html

Open workbook

Return to the GenY07 workbook and move the worksheets into EIA-923 workbook using "Move or Copy Sheet" from the Edit menu

Rename "Page 1 Generation and Fuel Data" as "Generation and Fuel Data"

Delete worksheet "Page 2 Stocks Data"

Insert worksheet "Emission Factors" and add table of factors

Insert names [as indicated in formula below] for cells containing conversion factor values

Preparation of the "Generation and Fuel Data" Worksheet

On "Generation and Fuel Data" delete monthly fuel and output data

Add column for emission factor and insert formula:
=IF(O9="bit",BIT,IF(O9="sub",SUB,IF(O9="ng",NG,IF(O9="pc",PC,IF(OR(O9="jf",O9="KER",O9="dfO"),DFO,IF(OR(O9="WC",O9="lig"),LIG,IF(OR(O9="rfo",O9="WO"),RFO,0)))))))

Add column “Tonnes CO2” and insert formula:
= Q9*S9/1000 and copy to entire column

Add Column U “Mixed Coal/Gas Flag” and insert formula:
=IF(AND(A9=A8,OR(AND(K9="NG",K8="SUB"),AND(K9="NG",K8="BIT"))),"F",""
)
[This formula is used to flag plants for possible separation into distinct coal and natural gas facilities.]

Sort by Facility ID ascending and Elec Fuel Consumption MMBtus descending

Preparation of the “Plant Info” Worksheet

Create Pivot Table on new sheet using the data from “Generation and Fuel Data” as the source

Put Facility ID in rows and SUM OF “NET GENERATION” in the data section.
Copy and paste into “Plant Info”

Return to Pivot Table and replace Sum of NET GENERATION with Sum of TONNES CO2

Copy CO2 values and paste next to NET GENERATION values on “Plant Info”

Add column “OP_NAMEPLATE” on “PlantInfo” and insert formula:
=VLOOKUP($A2,GenY07PvtTable!D$4:E$5745,2,FALSE)

Add column “State” and insert formula:
=VLOOKUP($A2,'Generation and Fuel Data'!A$9:F$2009,6,FALSE)

Add column “NERC Region” and insert formula:
=VLOOKUP($A2,'Generation and Fuel Data'!A$9:H$2009,8,FALSE)

Add column “Primary Fuel” and insert formula:
=VLOOKUP($A2,'Generation and Fuel Data'!A$9:K$2009,11,FALSE)

Add column “CHP” and insert formula:
=VLOOKUP($A2,'Generation and Fuel Data'!$A$9:$C$2009,2,FALSE)

Add column “Facility Name” and insert formula:
=VLOOKUP($A2,'Generation and Fuel Data'!$A$9:$C$2009,3,FALSE)

Add column “WCI Member” and insert formula:
=IF(OR(I8="WA",I8="OR",I8="CA",I8="MT",I8="UT",I8="NM",I8="AZ"),"Y","N")

Add column “Resource Type” and insert formula:

=IF(AND(B2="n",OR(F2="bit",F2="sub",F2="dfo",F2="ng",F2="lig",F2="rfo",F2="ker",F2="jf",F2="pc")),2,1)

Add column “Capacity Factor” and insert formula:
=E2/(J2*8760)

Add column “Marginal” and insert formula:
=IF(AND(G2=2,K2<0.6),"Y","N")

Preparation of the “PlantInfoStatic” Worksheet

Copy all cells from “PlantInfo” and Paste Special/Values in “PlantInfoStatic”

Perform the following manual corrections in PlantInfoStatic:

Plants identified by the coal/gas flag
Split plants having different coal and gas combustion technologies listed on Generation and Fuel Data into two different plants on PlantInfoStatic. [These plants are highlighted in yellow.] Split operational capacities into different gas and coal facilities based on the information in GenY07. Using the data from Generation and Fuel Data, attribute all natural gas emissions and generation to the gas facility, and attribute all coal and fuel oil generation and emissions to the coal facility. Based on the adjusted capacity and net generation data, calculate new capacity factors.

Plants on tribal lands
Change the WCI membership status from Y to N for three plants on tribal lands in WCI member states: Bonanza, Four Corners, and Navajo

Preparation of the “EmFacPvtTable” Worksheet

Create new worksheet “EmFacPvtTable” and create a pivot table using the data from “PlantInfoStatic” as the source

Use Primary Fuel as the column heading, State as the row heading, and Sum of Tonnes CO2 and Sum of Net Gen as the data fields

Use WCI Member and Marginal as page fields

From the Pivot Table menu bar, use Formulas/Calculated Field to create the Emission Factor Field as Tonnes CO2 / Net Gen

October 9, 2009 Prototype Default Emissions Calculator to Calculate Default Emissions Factors for Imported Electricity

List of Commenters

Arizona Public Service Co.

Independent Energy Producers Association

Northern California Power Agency

Origin Energy

Power Workers' Union

Public Power Council

Redding Electric Utility, Modesto Irrigation District, and Turlock Irrigation District

Southern California Edison Company

Western Climate Advocates Network

Western Power Trading Forum

WCI Prototype Default Emission Factor Calculator, Lite Version

Beta for Public Comment

Created by Scott Murtishaw,
California Public Utilities Commission

October 5, 2009

Instructions for the Default Emission Factor Pivot Table

The next worksheet, "EmFacPvtTable," contains a pivot table that allows the user to calculate emission factors according to various criteria. When the workbook is first opened, the pivot table is set to display the total CO_2 emissions, net generation, and weighted average emission rate of all U.S. facilities in non-WCI jurisdictions of the Western Electricity Coordinating Council (WECC) deemed to be marginal. The table disaggregates the results by primary fuel type as well as showing the total.

You can change the set of plants the pivot table uses to calculate average emission rates by choosing different parameters from the drop-down boxes above and in the data table. For example, choosing "all" from the "WCI Member" drop-down box will recalculate the default emission factor using all marginal U.S. plants in WECC. Similarly, you can choose to recalculate the factor based on all plants, both marginal and non-marginal, or non-marginal plants only.

Factors based on any combination of states can be calculated by using the "State" drop-down box and selecting any set of states desired. A user in one state can calculate an emission factor for unspecified imports from all other states by simply deselecting his or her own state from the list. Note that if the "WCI Member" drop-down is not set to "all," then the states that appear in the "State" drop-down list will be limited to either member or non-member states.

The pivot table is based on the data in the "PlantInfoStatic" worksheet. If you would like to change the "marginal" classification of a particular power plant, you must do so manually in this worksheet. For example, to change the capacity factor rule-of-thumb (set by default at 60%) to 50%, sort the data in "PlantInfoStatic" by resource type and capacity factor (to sort by two criteria at a time, you must use the Data menu at the top of the screen) and change the value in the "Marginal" column to "Y" for all type 2 plants (leaving the type 1 plants categorically excluded) with a capacity factor between 50% and 60%. Any time that data in "PlantInfoStatic" are altered, you must select a cell in the pivot table, right-click, and choose "Refresh Data" for the changes to be reflected in the pivot table.

Default Emission Factor Pivot Table

WCI Member	N
Marginal	Y

Default Factor: 0.443

		Primary Fuel		
State	Data	BIT	DFO	NG
CO	Sum of Tonnes CO2		6,956	4,193,020
	Sum of Net Gen		5,083	8,979,268
	Sum of Emission Factor	#DIV/0!	1.368	0.467
ID	Sum of Tonnes CO2		103	614,277
	Sum of Net Gen		134	1,516,288
	Sum of Emission Factor	#DIV/0!	0.770	0.405
NV	Sum of Tonnes CO2	0	687	8,439,289
	Sum of Net Gen	-19,624	-1,294	20,022,330
	Sum of Emission Factor	0.000	-0.531	0.421
SD	Sum of Tonnes CO2			6,858
	Sum of Net Gen			6,843
	Sum of Emission Factor	#DIV/0!	#DIV/0!	1.002
TX	Sum of Tonnes CO2		56	1,176,312
	Sum of Net Gen		97	2,122,766
	Sum of Emission Factor	#DIV/0!	0.576	0.554
WY	Sum of Tonnes CO2		275	93,204
	Sum of Net Gen		367	150,734
	Sum of Emission Factor	#DIV/0!	0.748	0.618
Total Sum of Tonnes CO2		0	8,077	14,522,960
Total Sum of Net Gen		-19,624	4,387	32,798,229
Total Sum of Emission Factor		0.000	1.841	0.443

metric tons CO2/MWh

Grand Total
4,199,975
8,984,351
0.467
614,380
1,516,422
0.405
8,439,977
20,001,412
0.422
6,858
6,843
1.002
1,176,367
2,122,863
0.554
93,479
151,101
0.619
14,531,037
32,782,992
0.443

Facility ID	CHP	Facility Name	Tonnes CO2	Net Gen	Primary Fuel	Resource Type	WCI Member	State	Capacity	Capacity Factor	NERC Region	Marginal
9	N	Copper	13,802	16,046	NG	2	N	TX	81	0.02	WECC	Y
34	N	Rollins	0	55,766	WAT	1	Y	CA	12	0.53	WECC	N
72	N	Venice	0	22,458	WAT	1	Y	CA	10	0.25	WECC	N
87	N	Escalante	1,973,978	1,854,368	SUB	2	Y	NM	257	0.82	WECC	N
99	N	Frederickson	5,696	8,908	NG	2	Y	WA	178	0.01	WECC	Y
100	N	South Consolidated	0	1,633	WAT	1	Y	AZ	1	0.13	WECC	N
104	N	J S Eastwood	0	37,660	WAT	1	Y	CA	200	0.02	WECC	N
113	N	Cholla	8,071,891	7,940,365	SUB	2	Y	AZ	1,129	0.80	WECC	N
114	N	Douglas	187	135	DFO	2	Y	AZ	21	0.00	WECC	Y
116	N	Ocotillo	113,813	178,375	NG	2	Y	AZ	334	0.06	WECC	Y
117	N	West Phoenix	906,551	2,042,514	NG	2	Y	AZ	1,207	0.19	WECC	Y
118	N	Saguaro	80,082	116,339	NG	2	Y	AZ	436	0.03	WECC	Y
120	N	Yucca	190,763	318,562	NG	2	Y	AZ	265	0.14	WECC	Y
124	N	Demoss Petrie	13,765	17,916	NG	2	Y	AZ	85	0.02	WECC	Y
126	N	H Wilson Sundt Genera	915,897	1,037,780	BIT	2	Y	AZ	505	0.23	WECC	Y
126	N	H Wilson Sundt Genera	1,363	1,206	NG	2	Y	AZ	54	0.00	WECC	Y
141	N	Agua Fria	132,229	200,689	NG	2	Y	AZ	614	0.04	WECC	Y
143	N	Crosscut	0	3,134	WAT	1	Y	AZ	33	0.01	WECC	N
145	N	Horse Mesa	0	64,580	WAT	1	Y	AZ	130	0.06	WECC	N
147	N	Kyrene	341,173	826,568	NG	2	Y	AZ	574	0.16	WECC	Y
148	N	Mormon Flat	0	35,529	WAT	1	Y	AZ	64	0.06	WECC	N
149	N	Roosevelt	0	92,457	WAT	1	Y	AZ	36	0.29	WECC	N
150	N	Stewart Mountain	0	39,192	WAT	1	Y	AZ	13	0.34	WECC	N
151	N	McClure	11,160	9,779	NG	2	Y	CA	142	0.01	WECC	Y
152	N	Davis Dam	0	1,130,791	WAT	1	Y	AZ	255	0.51	WECC	N
153	N	Glen Canyon Dam	0	3,441,281	WAT	1	Y	AZ	1,312	0.30	WECC	N
154	N	Hoover Dam	0	1,959,593	WAT	1	N	NV	1,039	0.22	WECC	N
159	N	Lake Creek	0	3,242	WAT	1	Y	UT	2	0.25	WECC	N
160	N	Apache Station	3,001,154	2,958,028	SUB	2	Y	AZ	408	0.83	WECC	N
160	N	Apache Station	76,551	103,368	NG	2	Y	AZ	253	0.05	WECC	Y
161	N	Turlock Lake	0	9,541	WAT	1	Y	CA	3	0.33	WECC	N
162	N	Hickman	0	4,171	WAT	1	Y	CA	1	0.48	WECC	N
180	N	Volta 2	0	470	WAT	1	Y	CA	1	0.05	WECC	N
214	N	Alta Powerhouse	0	2,709	WAT	1	Y	CA	2	0.15	WECC	N
215	N	Angels	0	4,661	WAT	1	Y	CA	1	0.38	WECC	N
217	N	Balch 1	0	39,655	WAT	1	Y	CA	31	0.15	WECC	N
218	N	Balch 2	0	235,538	WAT	1	Y	CA	97	0.28	WECC	N
219	N	Belden	0	266,369	WAT	1	Y	CA	118	0.26	WECC	N
220	N	Bucks Creek	0	129,649	WAT	1	Y	CA	66	0.22	WECC	N
221	N	Butt Valley	0	113,459	WAT	1	Y	CA	40	0.32	WECC	N
222	N	Caribou 1	0	95,353	WAT	1	Y	CA	74	0.15	WECC	N
223	N	Caribou 2	0	407,383	WAT	1	Y	CA	118	0.39	WECC	N
224	N	Centerville	0	14,873	WAT	1	Y	CA	6	0.27	WECC	N
225	N	Chili Bar	0	20,487	WAT	1	Y	CA	7	0.33	WECC	N
227	N	Coleman	0	60,136	WAT	1	Y	CA	12	0.57	WECC	N
228	N	Contra Costa	81,364	137,547	NG	2	Y	CA	718	0.02	WECC	Y
229	N	Cow Creek	0	8,459	WAT	1	Y	CA	1	0.69	WECC	N
231	N	Cresta	0	196,134	WAT	1	Y	CA	74	0.30	WECC	N
232	N	De Sabla	0	85,157	WAT	1	Y	CA	18	0.53	WECC	N
233	N	Deer Creek	0	21,321	WAT	1	Y	CA	6	0.44	WECC	N
235	N	Drum 1	0	56,167	WAT	1	Y	CA	49	0.13	WECC	N
236	N	Drum 2	0	223,416	WAT	1	Y	CA	53	0.48	WECC	N
237	N	Dutch Flat	0	76,550	WAT	1	Y	CA	22	0.40	WECC	N
238	N	El Dorado	0	62,166	WAT	1	Y	CA	20	0.35	WECC	N
239	N	Electra	0	283,834	WAT	1	Y	CA	103	0.32	WECC	N
240	N	Haas	0	201,085	WAT	1	Y	CA	135	0.17	WECC	N
241	N	Halsey	0	47,923	WAT	1	Y	CA	14	0.40	WECC	N
242	N	Hamilton Branch	0	7,856	WAT	1	Y	CA	5	0.17	WECC	N
243	N	Hat Creek 1	0	35,788	WAT	1	Y	CA	10	0.41	WECC	N
244	N	Hat Creek 2	0	49,483	WAT	1	Y	CA	10	0.56	WECC	N
246	N	Humboldt Bay	352,690	482,399	NG	2	Y	CA	102	0.54	WECC	Y
248	N	Inskip	0	44,279	WAT	1	Y	CA	8	0.67	WECC	N
249	N	James B Black	0	633,276	WAT	1	Y	CA	169	0.43	WECC	N
250	N	Kerckhoff	0	-3,701	WAT	1	Y	CA	34	-0.01	WECC	N
253	N	Kilarc	0	16,047	WAT	1	Y	CA	3	0.61	WECC	N
254	N	Kings River	0	75,535	WAT	1	Y	CA	49	0.18	WECC	N
255	N	Lime Saddle	0	5,286	WAT	1	Y	CA	2	0.30	WECC	N
258	N	Merced Falls	0	11,386	WAT	1	Y	CA	3	0.38	WECC	N
259	N	Dynegy Morro Bay LLC	270,776	521,217	NG	2	Y	CA	1,056	0.06	WECC	Y
260	N	Dynegy Moss Landing	3,016,636	7,551,995	NG	2	Y	CA	2,802	0.31	WECC	Y
261	N	Murphys	0	10,591	WAT	1	Y	CA	5	0.27	WECC	N
262	N	Narrows	0	18,932	WAT	1	Y	CA	10	0.21	WECC	N
264	N	Phoenix	0	4,524	WAT	1	Y	CA	2	0.32	WECC	N
265	N	Pit 1	0	259,470	WAT	1	Y	CA	69	0.43	WECC	N
266	N	Pit 3	0	318,508	WAT	1	Y	CA	80	0.45	WECC	N
267	N	Pit 4	0	446,866	WAT	1	Y	CA	103	0.49	WECC	N
268	N	Pit 5	0	762,513	WAT	1	Y	CA	142	0.61	WECC	N
269	N	Pit 6	0	292,074	WAT	1	Y	CA	79	0.42	WECC	N
270	N	Pit 7	0	413,824	WAT	1	Y	CA	110	0.43	WECC	N
271	N	Pittsburg Power	120,617	191,680	NG	2	Y	CA	1,404	0.02	WECC	Y
272	N	Poe	0	396,592	WAT	1	Y	CA	143	0.32	WECC	N
273	N	Potrero Power	303,621	492,301	NG	2	Y	CA	382	0.15	WECC	Y
274	N	Potter Valley	0	20,850	WAT	1	Y	CA	9	0.25	WECC	N
275	N	Rock Creek	0	290,661	WAT	1	Y	CA	125	0.27	WECC	N
276	N	San Joaquin 2	0	2,650	WAT	1	Y	CA	3	0.11	WECC	N
277	N	San Joaquin 3	0	3,606	WAT	1	Y	CA	4	0.10	WECC	N
279	N	Salt Springs	0	116,759	WAT	1	Y	CA	42	0.32	WECC	N
280	N	South	0	48,570	WAT	1	Y	CA	7	0.83	WECC	N
281	N	Spaulding 1	0	27,902	WAT	1	Y	CA	7	0.46	WECC	N
282	N	Spaulding 2	0	9,126	WAT	1	Y	CA	4	0.28	WECC	N
283	N	Spaulding 3	0	24,435	WAT	1	Y	CA	7	0.42	WECC	N
284	N	Spring Gap	0	24,074	WAT	1	Y	CA	6	0.46	WECC	N
285	N	Stanislaus	0	280,297	WAT	1	Y	CA	82	0.39	WECC	N
286	N	Geysers Unit 5-20	0	4,809,006	GEO	1	Y	CA	1,273	0.43	WECC	N
287	N	Tiger Creek	0	202,507	WAT	1	Y	CA	52	0.44	WECC	N
289	N	Tule River	0	9,681	WAT	1	Y	CA	8	0.13	WECC	N
290	N	Volta 1	0	44,540	WAT	1	Y	CA	9	0.60	WECC	N
291	N	West Point	0	60,185	WAT	1	Y	CA	14	0.51	WECC	N
292	N	Wise	0	72,971	WAT	1	Y	CA	16	0.51	WECC	N
293	N	A G Wishon	0	23,153	WAT	1	Y	CA	13	0.21	WECC	N
294	N	Copco 1	0	95,316	WAT	1	Y	CA	20	0.54	WECC	N
295	N	Copco 2	0	119,854	WAT	1	Y	CA	27	0.51	WECC	N
296	N	Fall Creek	0	13,049	WAT	1	Y	CA	2	0.71	WECC	N
297	N	Iron Gate	0	119,206	WAT	1	Y	CA	18	0.76	WECC	N

299	N	Blundell	0	163,925	GEO	1	Y	UT	38	0.49	WECC	N
301	N	El Cajon	1,314	1,250	NG	2	Y	CA	16	0.01	WECC	Y
302	N	Encina	474,019	708,068	NG	2	Y	CA	999	0.08	WECC	Y
303	N	Kearny	12,374	13,319	NG	2	Y	CA	149	0.01	WECC	Y
305	N	Miramar	3,248	3,626	NG	2	Y	CA	38	0.01	WECC	Y
310	N	Dynergy South Bay Po	414,655	711,772	NG	2	Y	CA	729	0.11	WECC	Y
314	N	Drop 5	0	14,222	WAT	1	Y	CA	4	0.41	WECC	N
315	N	AES Alamitos LLC	867,635	1,476,333	NG	2	Y	CA	1,922	0.09	WECC	Y
316	N	Sepulveda Canyon	0	41,502	WAT	1	Y	CA	9	0.56	WECC	N
317	N	Big Creek 1	0	199,088	WAT	1	Y	CA	88	0.26	WECC	N
318	N	Big Creek 2	0	279,027	WAT	1	Y	CA	66	0.48	WECC	N
319	N	Big Creek 3	0	422,450	WAT	1	Y	CA	174	0.28	WECC	N
320	N	Big Creek 4	0	215,964	WAT	1	Y	CA	100	0.25	WECC	N
321	N	Big Creek 8	0	169,978	WAT	1	Y	CA	75	0.26	WECC	N
322	N	Big Creek 2A	0	286,672	WAT	1	Y	CA	110	0.30	WECC	N
323	N	Bishop Creek 2	0	13,881	WAT	1	Y	CA	7	0.22	WECC	N
324	N	Bishop Creek 3	0	19,156	WAT	1	Y	CA	8	0.28	WECC	N
325	N	Bishop Creek 4	0	18,771	WAT	1	Y	CA	8	0.28	WECC	N
326	N	Bishop Creek 5	0	10,164	WAT	1	Y	CA	5	0.26	WECC	N
327	N	Bishop Creek 6	0	7,213	WAT	1	Y	CA	2	0.51	WECC	N
328	N	Borel	0	38,305	WAT	1	Y	CA	12	0.36	WECC	N
329	N	Coolwater	371,397	672,653	NG	2	Y	CA	727	0.11	WECC	Y
330	N	El Segundo Power	323,566	547,141	NG	2	Y	CA	684	0.09	WECC	Y
331	N	Etiwanda Generating S	382,162	607,132	NG	2	Y	CA	666	0.10	WECC	Y
332	N	Fontana	0	4,578	WAT	1	Y	CA	3	0.19	WECC	N
335	N	AES Huntington Beach	754,815	1,270,186	NG	2	Y	CA	888	0.16	WECC	Y
336	N	Kaweah 2	0	7,017	WAT	1	Y	CA	2	0.45	WECC	N
337	N	Kaweah 1	0	6,603	WAT	1	Y	CA	2	0.34	WECC	N
338	N	Kaweah 3	0	15,192	WAT	1	Y	CA	5	0.36	WECC	N
339	N	Kern River 3	0	47,774	WAT	1	Y	CA	40	0.14	WECC	N
340	N	Kern River 1	0	102,739	WAT	1	Y	CA	26	0.45	WECC	N
341	N	Long Beach Generatio	22,464	24,705	NG	2	Y	CA	252	0.01	WECC	Y
342	N	Lundy	0	4,417	WAT	1	Y	CA	3	0.17	WECC	N
344	N	Mammoth Pool	0	259,100	WAT	1	Y	CA	190	0.16	WECC	N
345	N	Mandalay	249,344	450,686	NG	2	Y	CA	574	0.09	WECC	Y
350	N	Ormond Beach	555,444	1,018,082	NG	2	Y	CA	1,612	0.07	WECC	Y
353	N	Poole	0	18,694	WAT	1	Y	CA	11	0.19	WECC	N
354	N	Portal	0	39,228	WAT	1	Y	CA	11	0.41	WECC	N
356	N	AES Redondo Beach L	291,166	529,292	NG	2	Y	CA	1,316	0.05	WECC	Y
357	N	Rush Creek	0	22,599	WAT	1	Y	CA	13	0.20	WECC	N
358	N	Mountainview Power Ll	2,464,452	6,308,447	NG	2	Y	CA	1,108	0.65	WECC	N
360	N	San Onofre	0	17,204,000	NUC	1	Y	CA	2,254	0.87	WECC	N
361	N	Santa Ana 1	0	2,217	WAT	1	Y	CA	3	0.08	WECC	N
363	N	Santa Ana 3	0	2,363	WAT	1	Y	CA	3	0.09	WECC	N
365	N	Tule River	0	10,494	WAT	1	Y	CA	2	0.50	WECC	N
371	N	Columbia Generating S	0	8,108,560	NUC	1	Y	WA	1,200	0.77	WECC	N
376	N	Pardee	0	31,718	WAT	1	Y	CA	24	0.15	WECC	N
377	N	Grayson	70,421	177,273	LFG	1	Y	CA	287	0.07	WECC	N
380	N	Dion R Holm	0	682,334	WAT	1	Y	CA	165	0.47	WECC	N
381	N	Moccasin	0	343,268	WAT	1	Y	CA	100	0.39	WECC	N
382	N	R C Kirkwood	0	402,272	WAT	1	Y	CA	118	0.39	WECC	N
383	N	Brawley	1	0	DFO	2	Y	CA	23	0.00	WECC	Y
385	N	Drop 2	0	51,445	WAT	1	Y	CA	10	0.59	WECC	N
386	N	Drop 3	0	45,862	WAT	1	Y	CA	10	0.53	WECC	N
387	N	Drop 4	0	104,872	WAT	1	Y	CA	20	0.61	WECC	N
388	N	Pilot Knob	0	13,597	WAT	1	Y	CA	33	0.05	WECC	N
389	N	El Centro	239,701	431,444	NG	2	Y	CA	256	0.19	WECC	Y
391	N	Big Pine	0	10,820	WAT	1	Y	CA	3	0.39	WECC	N
392	N	Castaic	0	585,127	WAT	1	Y	CA	1,331	0.05	WECC	N
393	N	Control Gorge	0	67,636	WAT	1	Y	CA	38	0.21	WECC	N
394	N	Cottonwood	0	2,900	WAT	1	Y	CA	2	0.14	WECC	N
396	N	Foothill	0	25,350	WAT	1	Y	CA	11	0.26	WECC	N
397	N	Franklin	0	2,017	WAT	1	Y	CA	2	0.12	WECC	N
398	N	Haiwee	0	5,363	WAT	1	Y	CA	6	0.11	WECC	N
399	N	Harbor	124,847	223,176	NG	2	Y	CA	462	0.06	WECC	Y
400	N	Haynes	1,797,302	4,003,233	NG	2	Y	CA	1,750	0.26	WECC	Y
401	N	Middle Gorge	0	68,682	WAT	1	Y	CA	38	0.21	WECC	N
402	N	Pleasant Valley	0	5,618	WAT	1	Y	CA	3	0.20	WECC	N
403	N	San Fernando	0	8,197	WAT	1	Y	CA	6	0.17	WECC	N
404	N	Scattergood	639,178	1,243,348	NG	2	Y	CA	823	0.17	WECC	Y
407	N	Upper Gorge	0	67,724	WAT	1	Y	CA	38	0.21	WECC	N
408	N	Valley	1,183,433	3,088,421	NG	2	Y	CA	788	0.45	WECC	Y
409	N	Exchequer	0	427,934	WAT	1	Y	CA	94	0.52	WECC	N
410	N	McSwain	0	220,371	WAT	1	Y	CA	9	2.80	WECC	N
412	N	Chicago Park	0	106,685	WAT	1	Y	CA	44	0.28	WECC	N
413	N	Dutch Flat 2	0	50,982	WAT	1	Y	CA	27	0.21	WECC	N
414	N	Beardsley	0	27,550	WAT	1	Y	CA	10	0.31	WECC	N
415	N	Donnells	0	175,254	WAT	1	Y	CA	72	0.28	WECC	N
416	N	Tulloch	0	108,851	WAT	1	Y	CA	17	0.73	WECC	N
417	N	Forbestown	0	91,971	WAT	1	Y	CA	29	0.36	WECC	N
418	N	Kelly Ridge	0	70,247	WAT	1	Y	CA	10	0.80	WECC	N
419	N	Woodleaf	0	162,322	WAT	1	Y	CA	59	0.31	WECC	N
420	N	Broadway	8,531	12,982	NG	2	Y	CA	75	0.02	WECC	Y
422	N	Glenarm	23,178	41,658	NG	2	Y	CA	179	0.03	WECC	Y
424	N	French Meadows	0	32,112	WAT	1	Y	CA	15	0.24	WECC	N
425	N	Middle Fork	0	255,360	WAT	1	Y	CA	116	0.25	WECC	N
426	N	Oxbow	0	15,864	WAT	1	Y	CA	6	0.30	WECC	N
427	N	Ralston	0	194,732	WAT	1	Y	CA	79	0.28	WECC	N
428	N	Parker	0	63,124	WAT	1	Y	CA	3	2.67	WECC	N
430	N	Camino	0	230,308	WAT	1	Y	CA	158	0.17	WECC	N
431	N	Jaybird	0	358,229	WAT	1	Y	CA	162	0.25	WECC	N
432	N	Loon Lake	0	58,657	WAT	1	Y	CA	74	0.09	WECC	N
433	N	Robbs Peak	0	26,565	WAT	1	Y	CA	26	0.12	WECC	N
435	N	White Rock/Slab Creel	0	300,815	WAT	1	Y	CA	266	0.13	WECC	N
436	N	Devil Canyon	0	1,154,475	WAT	1	Y	CA	276	0.48	WECC	N
437	N	Edward C Hyatt	0	1,807,966	WAT	1	Y	CA	644	0.32	WECC	N
438	N	Thermalito	0	249,879	WAT	1	Y	CA	115	0.25	WECC	N
439	N	Don Pedro	0	288,932	WAT	1	Y	CA	171	0.19	WECC	N
440	N	La Grange	0	15,621	WAT	1	Y	CA	5	0.40	WECC	N
441	N	Folsom	0	371,371	WAT	1	Y	CA	199	0.21	WECC	N
442	N	Judge F Carr	0	291,941	WAT	1	Y	CA	154	0.22	WECC	N
443	N	Keswick	0	419,599	WAT	1	Y	CA	117	0.41	WECC	N
444	N	Nimbus	0	41,262	WAT	1	Y	CA	13	0.35	WECC	N
445	N	Shasta	0	1,914,173	WAT	1	Y	CA	697	0.31	WECC	N
446	N	ONeill	0	5,404	WAT	1	Y	CA	25	0.02	WECC	N
447	N	Parker Dam	0	449,643	WAT	1	Y	CA	120	0.43	WECC	N

448	N	W R Gianelli	0	-19,957	WAT	1	Y	CA	424	-0.01	WECC	N
450	N	Spring Creek	0	271,583	WAT	1	Y	CA	180	0.17	WECC	N
451	N	Trinity	0	364,532	WAT	1	Y	CA	140	0.30	WECC	N
454	N	Colgate	0	888,555	WAT	1	Y	CA	315	0.32	WECC	N
455	N	Narrows 2	0	146,169	WAT	1	Y	CA	47	0.36	WECC	N
457	N	Bear Valley	0	968	WAT	1	Y	CA	1	0.08	WECC	N
460	N	Pueblo	16,917	22,637	NG	2	N	CO	33	0.08	WECC	Y
462	N	W N Clark	296,163	240,064	BIT	2	N	CO	44	0.63	WECC	N
464	N	Alamosa	446	263	NG	2	N	CO	33	0.00	WECC	Y
465	N	Arapahoe	1,144,180	986,495	SUB	2	N	CO	160	0.70	WECC	N
466	N	Boulder Canyon Hydro	0	9,491	WAT	1	N	CO	10	0.11	WECC	N
467	N	Cabin Creek	0	-77,471	WAT	1	N	CO	300	-0.03	WECC	N
468	N	Cameo	552,618	410,037	BIT	2	N	CO	66	0.71	WECC	N
469	N	Cherokee	4,474,487	4,772,412	BIT	2	N	CO	807	0.68	WECC	N
470	N	Comanche	4,563,742	4,450,973	SUB	2	N	CO	779	0.65	WECC	N
471	N	Fruita	8,162	4,298	NG	2	N	CO	19	0.03	WECC	Y
472	N	Georgetown	0	5,159	WAT	1	N	CO	1	0.42	WECC	N
473	N	Palisade	0	11,949	WAT	1	N	CO	3	0.45	WECC	N
474	N	Salida	0	3,924	WAT	1	N	CO	1	0.37	WECC	N
476	N	Shoshone	0	36,157	WAT	1	N	CO	14	0.29	WECC	N
477	N	Valmont	1,170,913	1,334,806	BIT	2	N	CO	192	0.79	WECC	N
477	N	Valmont	4,229	5,815	NG	2	N	CO	45	0.02	WECC	Y
478	N	Zuni	10,251	6,397	NG	2	N	CO	115	0.01	WECC	Y
479	N	Temescal	0	10,535	WAT	1	Y	CA	3	0.41	WECC	N
480	N	Corona	0	10,243	WAT	1	Y	CA	3	0.40	WECC	N
481	N	Perris	0	26,860	WAT	1	Y	CA	8	0.39	WECC	N
482	N	Rio Hondo	0	8,563	WAT	1	Y	CA	2	0.51	WECC	N
483	N	Coyote Creek	0	6,478	WAT	1	Y	CA	3	0.24	WECC	N
484	N	Red Mountain	0	14,927	WAT	1	Y	CA	6	0.29	WECC	N
487	N	Valley View	0	1,284	WAT	1	Y	CA	4	0.04	WECC	N
489	N	Upper Dawson	0	10,988	WAT	1	Y	CA	4	0.29	WECC	N
490	N	Burlington	0	0	DFO	2	N	CO	8	0.00	WECC	Y
491	N	Center	0	0	DFO	2	N	CO	2	0.00	WECC	Y
492	N	Martin Drake	1,980,783	1,929,703	BIT	2	N	CO	257	0.86	WECC	N
493	N	George Birdsall	6,314	8,841	NG	2	N	CO	60	0.02	WECC	Y
494	N	Manitou Springs	0	19,276	WAT	1	N	CO	6	0.37	WECC	N
495	N	Ruxton Park	0	1,319	WAT	1	N	CO	1	0.13	WECC	N
496	N	Delta	221	378	NG	2	N	CO	5	0.01	WECC	Y
502	N	Holly	34	50	DFO	2	N	CO	1	0.01	WECC	Y
504	N	Julesburg	0	0	DFO	2	N	CO	4	0.00	WECC	Y
505	N	Boysen	0	36,035	WAT	1	N	WY	15	0.27	WECC	N
506	N	La Junta	0	-1,216	DFO	2	N	CO	17	-0.01	WECC	Y
507	N	Las Animas	0	0	DFO	2	N	CO	6	0.00	WECC	Y
508	N	Lamar Plant	0	17,110	WND	1	N	CO	37	0.05	WECC	N
510	N	Sonoma California Gec	0	331,362	GEO	1	Y	CA	78	0.48	WECC	N
511	N	Trinidad	12	15	DFO	2	N	CO	13	0.00	WECC	Y
512	N	Blue Mesa	0	237,546	WAT	1	N	CO	86	0.31	WECC	N
513	N	Estes	0	129,648	WAT	1	N	CO	45	0.33	WECC	N
514	N	Morrow Point	0	293,304	WAT	1	N	CO	173	0.19	WECC	N
515	N	Big Thompson	0	2,518	WAT	1	N	CO	5	0.06	WECC	N
516	N	Green Mountain	0	61,146	WAT	1	N	CO	26	0.27	WECC	N
517	N	Marys Lake	0	47,125	WAT	1	N	CO	8	0.66	WECC	N
518	N	Flatiron	0	246,799	WAT	1	N	CO	95	0.30	WECC	N
519	N	Pole Hill	0	201,501	WAT	1	N	CO	38	0.60	WECC	N
520	N	Lower Molina	0	16,378	WAT	1	N	CO	5	0.39	WECC	N
521	N	Upper Molina	0	27,961	WAT	1	N	CO	9	0.37	WECC	N
525	N	Hayden	3,627,058	3,588,242	BIT	2	N	CO	465	0.88	WECC	N
527	N	Nucla	776,471	690,544	BIT	2	N	CO	114	0.69	WECC	N
529	N	Solar	0	2,049	SUN	1	Y	CA	2	0.12	WECC	N
531	N	Camp Far West	0	11,810	WAT	1	Y	CA	7	0.19	WECC	N
534	N	Jones Fork	0	6,716	WAT	1	Y	CA	10	0.08	WECC	N
535	N	McClellan	2,609	3,474	NG	2	Y	CA	77	0.01	WECC	Y
537	N	Camanche	0	17,803	WAT	1	Y	CA	11	0.19	WECC	N
550	N	Kettle Falls Generating	1,177	300,879	WDS	1	Y	WA	58	0.59	WECC	N
584	N	Navajo Dam	0	162,243	WAT	1	Y	NM	30	0.62	WECC	N
585	N	Drop 1	0	19,548	WAT	1	Y	CA	6	0.39	WECC	N
586	N	East Highline	0	4,185	WAT	1	Y	CA	2	0.20	WECC	N
607	N	Fredonia	17,857	27,575	NG	2	Y	WA	376	0.01	WECC	Y
622	N	South Fork Tolt	0	55,798	WAT	1	Y	WA	17	0.38	WECC	N
626	N	Oak Flat	0	5,332	WAT	1	Y	CA	1	0.43	WECC	N
632	N	Newcastle	0	24,252	WAT	1	Y	CA	13	0.22	WECC	N
674	N	Pilot Butte	0	3,564	WAT	1	N	WY	2	0.25	WECC	N
682	N	Kerckhoff 2	0	212,584	WAT	1	Y	CA	140	0.17	WECC	N
692	N	Medicine Bow	0	16,880	WND	1	N	WY	9	0.22	WECC	N
714	N	Toadtown	0	4,024	WAT	1	Y	CA	2	0.26	WECC	N
745	N	Etiwanda	0	127,703	WAT	1	Y	CA	24	0.61	WECC	N
751	N	Moccasin Low Head Hy	0	1,456	WAT	1	Y	CA	3	0.06	WECC	N
776	N	Sly Creek	0	17,551	WAT	1	Y	CA	12	0.17	WECC	N
790	N	Gem State	0	110,135	WAT	1	N	ID	23	0.54	WECC	N
809	N	American Falls	0	262,405	WAT	1	N	ID	92	0.32	WECC	N
810	N	Bliss	0	318,932	WAT	1	N	ID	75	0.49	WECC	N
811	N	Brownlee	0	1,827,060	WAT	1	N	ID	585	0.36	WECC	N
812	N	C J Strike	0	390,080	WAT	1	N	ID	83	0.54	WECC	N
813	N	Cascade	0	37,158	WAT	1	N	ID	12	0.34	WECC	N
814	N	Clear Lake	0	17,091	WAT	1	N	ID	3	0.78	WECC	N
815	N	Lower Malad	0	104,582	WAT	1	N	ID	14	0.88	WECC	N
816	N	Lower Salmon	0	214,615	WAT	1	N	ID	60	0.41	WECC	N
817	N	Salmon Diesel	103	134	DFO	2	N	ID	5	0.00	WECC	Y
818	N	Shoshone Falls	0	55,613	WAT	1	N	ID	13	0.51	WECC	N
819	N	Swan Falls	0	117,791	WAT	1	N	ID	25	0.54	WECC	N
820	N	Thousand Springs	0	52,825	WAT	1	N	ID	9	0.69	WECC	N
821	N	Twin Falls	0	87,588	WAT	1	N	ID	53	0.19	WECC	N
822	N	Upper Salmon A	0	120,713	WAT	1	N	ID	18	0.77	WECC	N
823	N	Upper Malad	0	58,993	WAT	1	N	ID	8	0.81	WECC	N
825	N	Ashton	0	30,914	WAT	1	N	ID	7	0.52	WECC	N
826	N	Cove	0	707	WAT	1	N	ID	0	#DIV/0!	WECC	#DIV/0!
827	N	Grace	0	76,033	WAT	1	N	ID	33	0.26	WECC	N
829	N	Oneida	0	36,899	WAT	1	N	ID	30	0.14	WECC	N
831	N	Soda	0	15,156	WAT	1	N	ID	14	0.12	WECC	N
833	N	Cabinet Gorge	0	1,088,206	WAT	1	N	ID	265	0.47	WECC	N
835	N	Post Falls	0	83,374	WAT	1	N	ID	15	0.66	WECC	N
839	N	Scott Flat	0	3,191	WAT	1	Y	CA	1	0.36	WECC	N
840	N	Dworshak	0	1,828,011	WAT	1	N	ID	400	0.52	WECC	N
841	N	City Power Plant	0	43,421	WAT	1	N	ID	8	0.62	WECC	N
843	N	Lower No 2	0	1,601	WAT	1	N	ID	3	0.06	WECC	N
844	N	Upper Power Plant	0	46,947	WAT	1	N	ID	8	0.67	WECC	N

846	N	Combie South	0	2,680	WAT	1	Y	CA	2	0.20	WECC	N
850	N	Palisades	0	467,124	WAT	1	N	ID	176	0.30	WECC	N
851	N	Albeni Falls	0	216,768	WAT	1	N	ID	42	0.59	WECC	N
902	N	Bottle Rock Power	0	55,426	GEO	1	Y	CA	55	0.12	WECC	N
905	N	Alamo	0	56,775	WAT	1	Y	CA	20	0.33	WECC	N
917	N	Quincy Chute	0	29,738	WAT	1	Y	WA	9	0.36	WECC	N
925	N	Hydro Plant No 3	0	6	WAT	1	Y	UT	3	0.00	WECC	N
987	N	Last Chance	0	3,006	WAT	1	N	ID	2	0.20	WECC	N
1020	N	Manti Lower	0	6,716	WAT	1	Y	UT	1	0.64	WECC	N
2181	N	Black Eagle	0	124,084	WAT	1	Y	MT	24	0.59	WECC	N
2182	N	Cochrane	0	233,765	WAT	1	Y	MT	48	0.56	WECC	N
2185	N	Hauser	0	118,972	WAT	1	Y	MT	17	0.80	WECC	N
2186	N	Holter	0	223,234	WAT	1	Y	MT	38	0.66	WECC	N
2187	N	J E Corette Plant	1,223,066	1,186,136	SUB	2	Y	MT	173	0.78	WECC	N
2188	N	Kerr	0	1,088,593	WAT	1	Y	MT	212	0.59	WECC	N
2191	N	Morony	0	241,470	WAT	1	Y	MT	45	0.61	WECC	N
2192	N	Mystic	0	48,577	WAT	1	Y	MT	12	0.45	WECC	N
2193	N	Rainbow	0	228,869	WAT	1	Y	MT	36	0.73	WECC	N
2194	N	Ryan	0	384,540	WAT	1	Y	MT	48	0.91	WECC	N
2195	N	Thompson Falls	0	509,373	WAT	1	Y	MT	88	0.66	WECC	N
2196	N	Old Faithful	121	156	DFO	2	N	WY	2	0.01	WECC	Y
2199	N	Noxon Rapids	0	1,590,451	WAT	1	Y	MT	510	0.36	WECC	N
2203	N	Hungry Horse	0	777,371	WAT	1	Y	MT	428	0.21	WECC	N
2204	N	Yellowtail	0	380,434	WAT	1	Y	MT	250	0.17	WECC	N
2322	N	Clark	707,546	1,345,026	NG	2	N	NV	651	0.24	WECC	Y
2324	N	Reid Gardner	3,946,314	3,719,914	BIT	2	N	NV	637	0.67	WECC	N
2326	N	Sunrise	42,502	66,009	NG	2	N	NV	167	0.05	WECC	Y
2330	N	Fort Churchill	523,412	932,590	NG	2	N	NV	230	0.46	WECC	Y
2336	N	Tracy	687,661	1,284,815	NG	2	N	NV	560	0.26	WECC	Y
2341	N	Mohave	0	-19,624	BIT	2	N	NV	1,636	0.00	WECC	Y
2442	N	Four Corners	14,366,772	14,597,307	SUB	2	N	NM	2,270	0.73	WECC	N
2444	N	Rio Grande	398,019	639,514	NG	2	Y	NM	267	0.27	WECC	Y
2447	N	Las Vegas	91	48	DFO	2	Y	NM	20	0.00	WECC	Y
2450	N	Reeves	45,625	66,647	NG	2	Y	NM	154	0.05	WECC	Y
2451	N	San Juan	12,114,814	11,216,014	SUB	2	Y	NM	1,848	0.69	WECC	N
2465	N	Animas	71,210	137,871	NG	2	Y	NM	50	0.31	WECC	Y
2468	N	Raton	4,600	9,632	NG	2	Y	NM	16	0.07	WECC	Y
3013	N	Hells Canyon	0	1,560,339	WAT	1	Y	OR	392	0.45	WECC	N
3014	N	Oxbow	0	782,019	WAT	1	Y	OR	190	0.47	WECC	N
3020	N	Clearwater 1	0	34,647	WAT	1	Y	OR	15	0.26	WECC	N
3021	N	Clearwater 2	0	45,315	WAT	1	Y	OR	26	0.20	WECC	N
3024	N	Eagle Point	0	18,520	WAT	1	Y	OR	3	0.76	WECC	N
3025	N	East Side	0	10,528	WAT	1	Y	OR	3	0.38	WECC	N
3026	N	Fish Creek	0	35,712	WAT	1	Y	OR	11	0.37	WECC	N
3028	N	John C Boyle	0	279,767	WAT	1	Y	OR	99	0.32	WECC	N
3029	N	Lemolo 1	0	127,469	WAT	1	Y	OR	33	0.44	WECC	N
3032	N	Prospect 1	0	14,729	WAT	1	Y	OR	4	0.44	WECC	N
3033	N	Prospect 2	0	271,507	WAT	1	Y	OR	32	0.97	WECC	N
3034	N	Prospect 3	0	44,199	WAT	1	Y	OR	7	0.70	WECC	N
3035	N	Prospect 4	0	2,024	WAT	1	Y	OR	1	0.23	WECC	N
3036	N	Slide Creek	0	81,721	WAT	1	Y	OR	18	0.52	WECC	N
3037	N	Soda Springs	0	41,295	WAT	1	Y	OR	11	0.43	WECC	N
3040	N	Toketee Falls	0	209,075	WAT	1	Y	OR	43	0.56	WECC	N
3041	N	Wallowa Falls	0	6,162	WAT	1	Y	OR	1	0.64	WECC	N
3044	N	Bull Run	0	80,434	WAT	1	Y	OR	21	0.44	WECC	N
3045	N	Faraday	0	153,275	WAT	1	Y	OR	37	0.48	WECC	N
3047	N	North Fork	0	183,165	WAT	1	Y	OR	41	0.51	WECC	N
3048	N	Pelton	0	415,104	WAT	1	Y	OR	110	0.43	WECC	N
3049	N	River Mill	0	97,790	WAT	1	Y	OR	19	0.59	WECC	N
3050	N	Round Butte	0	965,950	WAT	1	Y	OR	247	0.45	WECC	N
3053	N	Sullivan	0	122,451	WAT	1	Y	OR	15	0.91	WECC	N
3067	N	Carmen Smith	0	211,378	WAT	1	Y	OR	114	0.21	WECC	N
3068	N	Leaburg	0	97,012	WAT	1	Y	OR	14	0.82	WECC	N
3071	N	Walterville	0	58,625	WAT	1	Y	OR	8	0.84	WECC	N
3074	N	Big Cliff	0	81,264	WAT	1	Y	OR	18	0.52	WECC	N
3075	N	Bonneville	0	4,558,978	WAT	1	Y	OR	1,093	0.48	WECC	N
3076	N	Cougar	0	121,802	WAT	1	Y	OR	26	0.53	WECC	N
3077	N	Detroit	0	134,562	WAT	1	Y	OR	100	0.15	WECC	N
3078	N	Dexter	0	76,805	WAT	1	Y	OR	15	0.58	WECC	N
3080	N	Green Peter	0	229,443	WAT	1	Y	OR	80	0.33	WECC	N
3081	N	Hills Creek	0	147,813	WAT	1	Y	OR	30	0.56	WECC	N
3082	N	John Day	0	8,928,904	WAT	1	Y	OR	2,160	0.47	WECC	N
3083	N	Lookout Point	0	302,859	WAT	1	Y	OR	120	0.29	WECC	N
3084	N	McNary	0	5,356,361	WAT	1	Y	OR	991	0.62	WECC	N
3325	N	Ben French	192,288	137,892	SUB	2	N	SD	25	0.63	WECC	N
3325	N	Ben French	6,858	6,843	NG	2	N	SD	110	0.01	WECC	Y
3456	N	Newman	1,162,509	2,106,720	NG	2	N	TX	575	0.42	WECC	Y
3643	N	Upper Beaver	0	0	WAT	1	Y	UT	3	0.00	WECC	N
3644	N	Carbon	1,433,084	1,339,343	BIT	2	Y	UT	189	0.81	WECC	N
3646	N	Cutler	0	44,309	WAT	1	Y	UT	30	0.17	WECC	N
3648	N	Gadsby	438,802	633,149	NG	2	Y	UT	393	0.18	WECC	Y
3651	N	Granite	0	1,796	WAT	1	Y	UT	2	0.10	WECC	N
3655	N	Olmstead	0	20,164	WAT	1	Y	UT	10	0.22	WECC	N
3656	N	Pioneer	0	12,263	WAT	1	Y	UT	5	0.28	WECC	N
3658	N	Snake Creek	0	2,837	WAT	1	Y	UT	1	0.27	WECC	N
3659	N	Stairs	0	4,139	WAT	1	Y	UT	1	0.47	WECC	N
3661	N	Weber	0	16,483	WAT	1	Y	UT	4	0.50	WECC	N
3665	N	Bountiful City	6,581	11,458	NG	2	Y	UT	19	0.07	WECC	Y
3666	N	Brigham City	0	6,903	WAT	1	Y	UT	2	0.44	WECC	N
3675	N	Hydro III	0	4,395	WAT	1	Y	UT	2	0.33	WECC	N
3676	N	Manti Upper	0	4,744	WAT	1	Y	UT	2	0.34	WECC	N
3686	N	Provo	3,080	4,615	NG	2	Y	UT	18	0.03	WECC	Y
3688	N	Bartholomew	0	2,133	WAT	1	Y	UT	2	0.16	WECC	N
3691	N	Spanish Fork	0	8,801	WAT	1	Y	UT	4	0.28	WECC	N
3697	N	Gateway	0	10,612	WAT	1	Y	UT	4	0.30	WECC	N
3698	N	Wanship	0	6,422	WAT	1	Y	UT	2	0.39	WECC	N
3699	N	Boulder	0	21,962	WAT	1	Y	UT	4	0.60	WECC	N
3704	N	Uintah	0	6,814	WAT	1	Y	UT	1	0.65	WECC	N
3845	N	Transalta Centralia Ge	8,947,345	8,527,284	SUB	2	Y	WA	1,460	0.67	WECC	N
3845	N	Transalta Centralia Ge	152,932	353,885	NG	2	Y	WA	322	0.13	WECC	Y
3846	N	Condit	0	84,395	WAT	1	Y	WA	10	0.94	WECC	N
3847	N	Merwin	0	473,458	WAT	1	Y	WA	136	0.40	WECC	N
3850	N	Swift 1	0	629,150	WAT	1	Y	WA	240	0.30	WECC	N
3852	N	Yale	0	539,916	WAT	1	Y	WA	134	0.46	WECC	N
3853	N	Crystal Mountain	259	313	DFO	2	Y	WA	3	0.01	WECC	Y
3854	N	Electron	0	88,729	WAT	1	Y	WA	23	0.44	WECC	N

3855	N	Lower Baker	0	436,208	WAT	1	Y	WA	85	0.59	WECC	N
3860	N	Snoqualmie	0	52,146	WAT	1	Y	WA	12	0.50	WECC	N
3861	N	Upper Baker	0	402,800	WAT	1	Y	WA	105	0.44	WECC	N
3866	N	Little Falls	0	192,921	WAT	1	Y	WA	32	0.69	WECC	N
3867	N	Long Lake	0	471,412	WAT	1	Y	WA	70	0.77	WECC	N
3868	N	Meyers Falls	0	7,952	WAT	1	Y	WA	1	0.76	WECC	N
3869	N	Nine Mile	0	99,421	WAT	1	Y	WA	26	0.43	WECC	N
3878	N	Yelm	0	63,750	WAT	1	Y	WA	12	0.61	WECC	N
3883	N	Rocky Reach	0	6,303,741	WAT	1	Y	WA	1,300	0.55	WECC	N
3886	N	Wells	0	4,309,536	WAT	1	Y	WA	774	0.64	WECC	N
3887	N	Priest Rapids	0	5,042,153	WAT	1	Y	WA	956	0.60	WECC	N
3888	N	Wanapum	0	5,300,140	WAT	1	Y	WA	1,038	0.58	WECC	N
3891	N	Box Canyon	0	453,561	WAT	1	Y	WA	60	0.86	WECC	N
3895	N	The Dalles	0	6,492,283	WAT	1	Y	OR	1,820	0.41	WECC	N
3913	N	Alder	0	201,137	WAT	1	Y	WA	50	0.46	WECC	N
3914	N	Cushman 1	0	132,514	WAT	1	Y	WA	43	0.35	WECC	N
3915	N	Cushman 2	0	241,780	WAT	1	Y	WA	81	0.34	WECC	N
3916	N	LaGrande	0	311,936	WAT	1	Y	WA	64	0.56	WECC	N
3917	N	Mayfield	0	647,229	WAT	1	Y	WA	162	0.46	WECC	N
3918	N	Mossyrock	0	940,545	WAT	1	Y	WA	300	0.36	WECC	N
3921	N	Chief Joseph	0	11,561,215	WAT	1	Y	WA	2,456	0.54	WECC	N
3925	N	Ice Harbor	0	1,444,811	WAT	1	Y	WA	603	0.27	WECC	N
3926	N	Little Goose	0	1,702,799	WAT	1	Y	WA	810	0.24	WECC	N
3927	N	Lower Monumental	0	1,682,562	WAT	1	Y	WA	810	0.24	WECC	N
3929	N	Packwood	0	84,555	WAT	1	Y	WA	28	0.35	WECC	N
4150	N	Neil Simpson	205,896	148,790	SUB	2	N	WY	22	0.78	WECC	N
4151	N	Osage	365,684	233,662	SUB	2	N	WY	35	0.77	WECC	N
4158	N	Dave Johnston	6,287,675	5,696,857	SUB	2	N	WY	817	0.80	WECC	N
4162	N	Naughton	5,456,938	5,210,618	SUB	2	N	WY	707	0.84	WECC	N
4176	N	Fremont Canyon	0	174,150	WAT	1	N	WY	67	0.30	WECC	N
4177	N	Glendo	0	57,815	WAT	1	N	WY	38	0.17	WECC	N
4178	N	Guernsey	0	16,021	WAT	1	N	WY	6	0.29	WECC	N
4180	N	Kortes	0	115,529	WAT	1	N	WY	36	0.37	WECC	N
4182	N	Seminoe	0	96,784	WAT	1	N	WY	52	0.21	WECC	N
4183	N	Shoshone	0	19,412	WAT	1	N	WY	3	0.74	WECC	N
4185	N	Fontenelle	0	39,676	WAT	1	N	WY	10	0.45	WECC	N
4204	N	Island Park	0	17	WAT	1	N	ID	5	0.00	WECC	N
4213	N	PHP 1	0	0	WAT	1	Y	OR	24	0.00	WECC	N
4214	N	PHP 2	0	74,897	WAT	1	Y	OR	12	0.72	WECC	N
4251	N	Logan City	6,582	8,698	NG	2	Y	UT	16	0.06	WECC	Y
4256	N	Walnut	860	309	NG	2	Y	CA	50	0.00	WECC	Y
4263	N	Echo Dam	0	7,623	WAT	1	Y	UT	4	0.20	WECC	N
4941	N	Navajo	16,654,883	17,616,339	BIT	2	N	AZ	2,409	0.83	WECC	N
6008	N	Palo Verde	0	26,782,391	NUC	1	Y	AZ	4,209	0.73	WECC	N
6013	N	Olive	1,486	2,122	NG	2	Y	CA	110	0.00	WECC	Y
6021	N	Craig	9,909,361	10,243,874	SUB	2	N	CO	1,339	0.87	WECC	N
6060	N	Coachella	1,306	1,465	NG	2	Y	CA	92	0.00	WECC	Y
6076	N	Colstrip	16,478,134	15,840,087	SUB	2	Y	MT	2,272	0.80	WECC	N
6088	N	North Loop	6,069	6,488	NG	2	Y	AZ	108	0.01	WECC	Y
6099	N	Diablo Canyon	0	18,588,490	NUC	1	Y	CA	2,323	0.91	WECC	N
6100	N	Helms Pumped Storag	0	-286,510	WAT	1	Y	CA	1,053	-0.03	WECC	N
6101	N	Wyodak	3,130,686	2,895,955	SUB	2	N	WY	362	0.91	WECC	N
6106	N	Boardman	4,169,033	4,355,071	SUB	2	Y	OR	601	0.83	WECC	N
6112	N	Fort St Vrain	1,636,380	4,051,089	NG	2	N	CO	743	0.62	WECC	N
6120	N	Whitehorn	9,417	13,208	NG	2	Y	WA	169	0.01	WECC	Y
6158	N	New Melones	0	469,681	WAT	1	Y	CA	300	0.18	WECC	N
6159	N	Crystal	0	168,239	WAT	1	N	CO	28	0.69	WECC	N
6163	N	Grand Coulee	0	21,632,495	WAT	1	Y	WA	6,809	0.36	WECC	N
6165	N	Hunter	9,612,003	9,599,815	BIT	2	Y	UT	1,472	0.74	WECC	N
6172	N	Libby	0	2,344,156	WAT	1	Y	MT	525	0.51	WECC	N
6174	N	Lost Creek	0	287,571	WAT	1	Y	OR	49	0.67	WECC	N
6175	N	Lower Granite	0	1,681,723	WAT	1	Y	WA	810	0.24	WECC	N
6177	N	Coronado	5,800,710	5,813,324	SUB	2	Y	AZ	822	0.81	WECC	N
6196	N	W E Warne	0	464,271	WAT	1	Y	CA	74	0.71	WECC	N
6200	N	Rock Island	0	2,585,581	WAT	1	Y	WA	624	0.47	WECC	N
6202	N	Ross	0	857,197	WAT	1	Y	WA	360	0.27	WECC	N
6204	N	Laramie River Station	12,282,966	12,286,482	SUB	2	N	WY	1,710	0.82	WECC	N
6206	N	Tacoma	0	21,999	WAT	1	N	CO	8	0.32	WECC	N
6207	N	Ames Hydro	0	12,450	WAT	1	N	CO	4	0.39	WECC	N
6208	N	Mount Elbert	0	-90,590	WAT	1	N	CO	200	-0.05	WECC	N
6210	N	Northeast	1,579	2,308	NG	2	Y	WA	62	0.00	WECC	Y
6211	N	Dynergy Oakland Powe	24,048	24,007	JF	2	Y	CA	224	0.01	WECC	Y
6212	N	Mobile GT	0	0	DFO	2	Y	CA	30	0.00	WECC	Y
6248	N	Pawnee	3,836,786	3,751,728	SUB	2	N	CO	552	0.78	WECC	N
6359	N	Felt	0	22,161	WAT	1	N	ID	1	1.95	WECC	N
6393	N	Strawberry Creek	0	8,765	WAT	1	N	WY	2	0.67	WECC	N
6395	N	Anderson Ranch	0	123,997	WAT	1	N	ID	40	0.35	WECC	N
6396	N	Black Canyon	0	65,530	WAT	1	N	ID	10	0.73	WECC	N
6397	N	Boise R Diversion	0	9,337	WAT	1	N	ID	3	0.32	WECC	N
6398	N	Minidoka	0	107,878	WAT	1	N	ID	28	0.44	WECC	N
6400	N	Canyon Ferry	0	285,725	WAT	1	Y	MT	50	0.65	WECC	N
6402	N	Elephant Butte	0	56,003	WAT	1	Y	NM	28	0.23	WECC	N
6403	N	Green Springs	0	64,195	WAT	1	Y	OR	17	0.43	WECC	N
6404	N	Deer Creek	0	23,713	WAT	1	Y	UT	5	0.56	WECC	N
6405	N	Flaming Gorge	0	280,008	WAT	1	Y	UT	152	0.21	WECC	N
6406	N	Chandler	0	25,486	WAT	1	Y	WA	12	0.24	WECC	N
6407	N	Roza	0	76,127	WAT	1	Y	WA	13	0.67	WECC	N
6408	N	Heart Mountain	0	13,867	WAT	1	N	WY	5	0.32	WECC	N
6409	N	Alcova	0	92,293	WAT	1	N	WY	41	0.25	WECC	N
6421	N	Lemolo 2	0	148,711	WAT	1	Y	OR	33	0.51	WECC	N
6422	N	Madison	0	60,099	WAT	1	Y	MT	9	0.78	WECC	N
6424	N	Chelan	0	430,778	WAT	1	Y	WA	48	1.02	WECC	N
6430	N	Cedar Falls	0	65,865	WAT	1	Y	WA	20	0.38	WECC	N
6431	N	Gorge	0	1,075,082	WAT	1	Y	WA	207	0.59	WECC	N
6432	N	Diablo	0	833,695	WAT	1	Y	WA	153	0.62	WECC	N
6433	N	Boundary	0	3,624,709	WAT	1	Y	WA	1,040	0.40	WECC	N
6449	N	Azusa	0	60	WAT	1	Y	CA	3	0.00	WECC	N
6459	N	Big Fork	0	24,435	WAT	1	Y	MT	4	0.68	WECC	N
6479	N	San Francisquito 1	0	57,899	WAT	1	Y	CA	69	0.10	WECC	N
6480	N	San Francisquito 2	0	17,839	WAT	1	Y	CA	42	0.05	WECC	N
6481	N	Intermountain Power P	12,743,097	14,426,479	BIT	2	Y	UT	1,640	1.00	WECC	N
6482	N	Cline Falls	0	0	WAT	1	Y	OR	1	0.00	WECC	N
6484	N	Bend	0	2,863	WAT	1	Y	OR	1	0.30	WECC	N
6505	N	Oak Grove	0	244,527	WAT	1	Y	OR	51	0.55	WECC	N
6506	N	Moyie Springs	0	28,821	WAT	1	N	ID	4	0.84	WECC	N
6507	N	Drop 2	0	2	WAT	1	Y	WA	3	0.00	WECC	N

6508	N	Drop 3	0	1	WAT	1	Y	WA	2	0.00	WECC	N
6509	N	Battle Mountain	157	-255	DFO	2	N	NV	8	0.00	WECC	Y
6510	N	Brunswick	286	29	DFO	2	N	NV	6	0.00	WECC	Y
6513	N	Fleish	0	15,959	WAT	1	N	NV	2	0.91	WECC	N
6514	N	Gabbs	132	-263	DFO	2	N	NV	5	-0.01	WECC	Y
6515	N	Valencia	4,138	3,174	NG	2	Y	AZ	70	0.01	WECC	Y
6516	N	Rocky Ford	1,052	1,235	DFO	2	N	CO	10	0.01	WECC	Y
6518	N	Kings Beach	10	-509	DFO	2	Y	CA	16	0.00	WECC	Y
6521	N	Lahontan	0	0	WAT	1	N	NV	2	0.00	WECC	N
6524	N	Portola	0	0	DFO	2	Y	CA	1	0.00	WECC	Y
6530	N	Valley Road	112	-805	DFO	2	N	NV	6	-0.02	WECC	Y
6531	N	Verdi	0	17,531	WAT	1	N	NV	2	0.83	WECC	N
6532	N	Washoe	0	10,108	WAT	1	N	NV	1	0.82	WECC	N
6533	N	Winnemucca	289	50	NG	2	N	NV	15	0.00	WECC	Y
6537	N	Little Cottonwood	0	9,732	WAT	1	Y	UT	5	0.23	WECC	N
6552	N	Foster	0	53,904	WAT	1	Y	OR	20	0.31	WECC	N
6553	N	Little Mountain	108,910	10,735	NG	2	Y	UT	16	0.08	WECC	Y
6612	N	Union Valley	0	76,311	WAT	1	Y	CA	39	0.23	WECC	N
6619	N	Burlington	5,760	5,178	DFO	2	N	CO	129	0.00	WECC	Y
6623	N	Fort Peck	0	609,731	WAT	1	Y	MT	185	0.38	WECC	N
6643	N	Greg Avenue	0	254	WAT	1	Y	CA	1	0.03	WECC	N
6644	N	Lake Mathews	0	18,157	WAT	1	Y	CA	5	0.42	WECC	N
6645	N	Foothill Feeder	0	45,457	WAT	1	Y	CA	9	0.58	WECC	N
6646	N	San Dimas	0	49,709	WAT	1	Y	CA	10	0.57	WECC	N
6647	N	Yorba Linda	0	31,567	WAT	1	Y	CA	5	0.71	WECC	N
6704	N	Pebbly Beach	23,861	30,989	DFO	2	Y	CA	9	0.38	WECC	Y
6761	N	Rawhide Coal	2,216,350	2,251,167	SUB	2	N	CO	294	0.88	WECC	N
6761	N	Rawhide Gas	64,264	93,717	NG	2	N	CO	357	0.03	WECC	Y
7012	N	Lower No 1	0	40,616	WAT	1	N	ID	8	0.58	WECC	N
7015	N	Unit 4	0	3,357	WAT	1	Y	UT	1	0.32	WECC	N
7028	N	Whitehead	11,537	18,371	NG	2	Y	UT	34	0.06	WECC	Y
7034	N	Hydro II	0	17,948	WAT	1	Y	UT	7	0.31	WECC	N
7039	N	Lake	154	211	DFO	2	N	WY	3	0.01	WECC	Y
7066	N	Stampede	0	11,103	WAT	1	Y	CA	4	0.35	WECC	N
7072	N	Mojave Siphon	0	73,646	WAT	1	Y	CA	33	0.26	WECC	N
7079	N	Upper Salmon B	0	105,444	WAT	1	N	ID	17	0.73	WECC	N
7080	N	St George Red Rock	481	655	DFO	2	Y	UT	14	0.01	WECC	Y
7082	N	Harry Allen	51	67	NG	2	N	NV	187	0.00	WECC	Y
7111	N	Heber City	22,587	28,316	NG	2	Y	UT	11	0.31	WECC	Y
7113	N	PEC Headworks	0	19,372	WAT	1	Y	WA	7	0.34	WECC	N
7127	N	Wynoochee	0	35,518	WAT	1	Y	WA	13	0.32	WECC	N
7129	N	Thermalito Diverson Da	0	19,011	WAT	1	Y	CA	3	0.64	WECC	N
7132	N	Pine View Dam	0	3,216	WAT	1	Y	UT	2	0.20	WECC	N
7147	N	Mill Creek 3	0	6,866	WAT	1	Y	CA	3	0.26	WECC	N
7151	N	Stony Gorge	0	7,228	WAT	1	Y	CA	5	0.17	WECC	N
7164	N	Waddell	0	47,380	WAT	1	Y	AZ	40	0.14	WECC	N
7179	N	Headgate Rock	0	80,013	WAT	1	Y	AZ	20	0.47	WECC	N
7189	N	Whiskeytown	0	24,742	WAT	1	Y	CA	3	0.88	WECC	N
7190	N	Milner Hydro	0	66,918	WAT	1	N	ID	60	0.13	WECC	N
7229	N	Black Butte	0	7,986	WAT	1	Y	CA	6	0.15	WECC	N
7231	N	Gianera	680	815	NG	2	Y	CA	65	0.00	WECC	Y
7232	N	Santa Clara Cogen	46,627	54,489	NG	2	Y	CA	8	0.80	WECC	N
7233	N	Tesla	0	55,487	WAT	1	N	CO	28	0.23	WECC	N
7259	N	Skookumchuck	0	0	WAT	1	Y	WA	1	0.00	WECC	N
7266	N	Woodland	178,687	378,082	NG	2	Y	CA	149	0.29	WECC	Y
7307	N	Redding Power	90,478	189,587	NG	2	Y	CA	136	0.16	WECC	Y
7315	N	Almond Power Plant	47,567	82,629	NG	2	Y	CA	50	0.19	WECC	Y
7317	N	Buffalo Bill	0	39,511	WAT	1	N	WY	18	0.25	WECC	N
7338	N	Grizzly	0	24,874	WAT	1	Y	CA	22	0.13	WECC	N
7350	N	Coyote Springs	579,025	1,430,593	NG	2	Y	OR	266	0.61	WECC	N
7368	N	Geothermal 1	0	506,448	GEO	1	Y	CA	110	0.53	WECC	N
7369	N	Geothermal 2	0	468,694	GEO	1	Y	CA	110	0.49	WECC	N
7372	N	McPhee	0	5,335	WAT	1	N	CO	1	0.51	WECC	N
7373	N	Towaoc	0	3,179	WAT	1	N	CO	11	0.03	WECC	N
7408	N	Payson	1,619	3,503	NG	2	Y	UT	10	0.04	WECC	Y
7413	N	Short Mountain	0	14,339	LFG	1	Y	OR	3	0.51	WECC	N
7427	N	Cowlitz Falls	0	223,182	WAT	1	Y	WA	70	0.36	WECC	N
7431	N	The Dalles Fishway	0	44,388	WAT	1	Y	OR	7	0.78	WECC	N
7449	N	Combustion Turbine Pl	34,387	71,256	NG	2	Y	CA	50	0.16	WECC	Y
7450	N	Alameda	5,942	6,827	NG	2	Y	CA	55	0.01	WECC	Y
7451	N	Lodi	488	574	NG	2	Y	CA	27	0.00	WECC	Y
7452	N	Roseville	1,521	1,648	NG	2	Y	CA	55	0.00	WECC	Y
7456	N	Rathdrum	12,307	18,228	NG	2	N	ID	166	0.01	WECC	Y
7458	N	Ruedi	0	17,145	WAT	1	N	CO	5	0.39	WECC	N
7489	N	Lake Mendocino	0	3,285	WAT	1	Y	CA	4	0.11	WECC	N
7504	N	Neil Simpson II	783,187	677,196	SUB	2	N	WY	80	0.97	WECC	N
7504	N	Neil Simpson II	29,824	55,025	NG	2	N	WY	40	0.16	WECC	Y
7507	N	Deadwood Creek	0	0	WAT	1	Y	CA	2	0.00	WECC	N
7508	N	Stone Creek	0	64,975	WAT	1	Y	OR	12	0.62	WECC	N
7511	N	McNary Fish	0	68,709	WAT	1	Y	WA	10	0.78	WECC	N
7526	N	Solano Wind	0	117,197	WND	1	Y	CA	100	0.13	WECC	N
7527	N	Carson Ice-Gen Projec	224,672	386,814	NG	2	Y	CA	126	0.35	WECC	Y
7541	N	Spirit Mountain	0	16,002	WAT	1	N	WY	5	0.41	WECC	N
7548	N	Causey	0	2,683	WAT	1	Y	UT	2	0.15	WECC	N
7551	N	SCA Cogen 2	317,256	641,825	NG	2	Y	CA	193	0.38	WECC	Y
7552	N	SPA Cogen 3	465,070	1,084,670	NG	2	Y	CA	174	0.71	WECC	N
7588	N	H M Jackson	0	431,305	WAT	1	Y	WA	112	0.44	WECC	N
7593	N	El Vado Dam	0	24,485	WAT	1	Y	NM	8	0.35	WECC	N
7605	N	River Road Gen Plant	586,645	1,521,879	NG	2	Y	WA	248	0.70	WECC	N
7627	N	Everett Cogen	31,390	175,907	WDS	1	Y	WA	42	0.48	WECC	N
7646	N	Monticello	0	44,686	WAT	1	Y	CA	12	0.44	WECC	N
7693	N	Anaheim GT	24,865	49,414	NG	2	Y	CA	49	0.11	WECC	Y
7725	N	Coffin Butte	0	25,044	LFG	1	Y	OR	6	0.51	WECC	N
7730	N	SECC	0	0	DFO	2	N	CO	2	0.00	WECC	Y
7767	N	Bloomington Power Pla	179	234	DFO	2	Y	UT	12	0.00	WECC	Y
7789	N	Abiquiu Dam	0	25,209	WAT	1	Y	NM	13	0.23	WECC	N
7790	N	Bonanza	3,396,667	3,450,695	BIT	2	N	UT	500	0.79	WECC	N
7824	N	Rockwood	2,666	3,182	NG	2	Y	CA	50	0.01	WECC	Y
7832	N	Roosevelt Biogas 1	0	81,021	LFG	1	Y	WA	11	0.88	WECC	N
7867	N	Snoqualmie 2	0	176,100	WAT	1	Y	WA	34	0.59	WECC	N
7870	N	Encogen	84,151	143,066	NG	2	Y	WA	176	0.09	WECC	Y
7907	N	Pine Flat	0	194,812	WAT	1	Y	CA	165	0.13	WECC	N
7911	N	Kern Canyon	0	44,641	WAT	1	Y	CA	10	0.54	WECC	N
7931	N	Coyote Springs II	604,268	1,622,778	NG	2	Y	OR	287	0.65	WECC	N
7936	N	Nine Canyon	0	162,716	WND	1	Y	WA	64	0.29	WECC	N
7937	N	Ponnequin	0	41,721	WND	1	N	CO	26	0.18	WECC	N

7942	N	Diamond Valley Lake	0	41,607	WAT	1	Y	CA	40	0.12	WECC	N
7945	N	Finley Combustion Tur	0	0	NG	2	Y	WA	11	0.00	WECC	Y
7953	N	Evander Andrews Pow	27,287	38,346	NG	2	N	ID	100	0.04	WECC	Y
7967	N	Lordsburg Generating	55,842	87,717	NG	2	Y	NM	88	0.11	WECC	Y
7975	N	Pyramid	42,436	105,871	NG	2	Y	NM	186	0.06	WECC	Y
7987	N	Lake	4,550	8,004	NG	2	Y	CA	61	0.02	WECC	Y
7994	N	Randolph Road	2	2	DFO	2	Y	WA	27	0.00	WECC	Y
7995	N	Airport Industrial	98	-179	DFO	2	N	CO	10	0.00	WECC	Y
7998	N	Tri Cities	0	14,766	LFG	1	Y	AZ	5	0.34	WECC	N
8010	N	Murray Turbine	18,572	28,545	NG	2	Y	UT	42	0.08	WECC	Y
8022	N	Boulder Park	11,955	23,313	NG	2	Y	WA	25	0.11	WECC	Y
8026	N	Hartzog	19,553	26,192	NG	2	N	WY	23	0.13	WECC	Y
8028	N	Arvada	15,690	23,512	NG	2	N	WY	23	0.12	WECC	Y
8030	N	Barber Creek	16,995	24,378	NG	2	N	WY	23	0.12	WECC	Y
8066	N	Jim Bridger	15,113,124	15,119,379	SUB	2	N	WY	2,318	0.74	WECC	N
8067	N	Fort Lupton	5,522	8,355	NG	2	N	CO	78	0.01	WECC	Y
8068	N	Santan	1,683,619	4,222,789	NG	2	Y	AZ	1,326	0.36	WECC	Y
8069	N	Huntington	6,800,252	7,127,001	BIT	2	Y	UT	996	0.82	WECC	N
8073	N	Beaver	191,521	362,903	NG	2	Y	OR	611	0.07	WECC	Y
8076	N	Ellwood	1,005	1,360	NG	2	Y	CA	58	0.00	WECC	Y
8100	N	Springfield	0	0	DFO	2	N	CO	3	0.00	WECC	Y
8219	N	Ray D Nixon	1,514,374	1,492,747	SUB	2	N	CO	207	0.82	WECC	N
8219	N	Ray D Nixon	5,296	6,400	NG	2	N	CO	72	0.01	WECC	Y
8223	N	Springerville	5,977,527	5,912,107	SUB	2	Y	AZ	1,305	0.52	WECC	Y
8224	N	North Valmy	3,334,925	3,391,541	BIT	2	N	NV	567	0.68	WECC	N
8902	N	Hoover Dam	0	1,787,092	WAT	1	Y	AZ	1,039	0.20	WECC	N
9095	N	Monroe Street	0	100,338	WAT	1	Y	WA	15	0.77	WECC	N
9096	N	Upper Falls	0	62,668	WAT	1	Y	WA	10	0.72	WECC	N
9842	N	Newhalem	0	5,208	WAT	1	Y	WA	2	0.26	WECC	N
10002	Y	ACE Cogeneration Fac	756,421	838,936	BIT	1	Y	CA	108	0.89	WECC	N
10003	Y	Colorado Energy Natio	116,950	221,450	BIT	1	N	CO	35	0.71	WECC	N
10005	N	Dinosaur Point	0	26,709	WND	1	Y	CA	17	0.18	WECC	N
10014	N	Lucky Peak Power Plai	0	272,599	WAT	1	N	ID	101	0.31	WECC	N
10018	N	Desert Peak Power Pla	0	84,498	GEO	1	N	NV	26	0.37	WECC	N
10026	Y	Encina Water Pollution	1,713	5,999	OBG	1	Y	CA	2	0.46	WECC	N
10027	N	EUIPH Wind Farm	0	40,983	WND	1	Y	CA	25	0.18	WECC	N
10028	N	Felt Hydroelectric Plant	0	22,161	WAT	1	N	ID	7	0.34	WECC	N
10031	Y	General Mills Operatioi	4,961	20,298	NG	1	Y	CA	5	0.50	WECC	N
10034	Y	Gilroy Power Plant	125,428	281,291	NG	1	Y	CA	130	0.25	WECC	N
10048	Y	Central Utilities Plant L	14,303	45,690	NG	1	Y	CA	8	0.65	WECC	N
10049	N	Little Mac Project	0	4,253	WAT	1	N	ID	2	0.32	WECC	N
10052	N	Fairhaven Power	1,770	111,805	WDS	1	Y	CA	19	0.68	WECC	N
10070	N	Foothills Hydro Plant	0	6,010	WAT	1	N	CO	3	0.22	WECC	N
10074	Y	Pulp Mill Power House	5	134,576	BLQ	1	Y	CA	20	0.77	WECC	N
10081	N	Strontia Springs Hydro	0	6,366	WAT	1	N	CO	1	0.73	WECC	N
10090	N	Commerce Refuse To	1,497	66,222	MSB	1	Y	CA	12	0.63	WECC	N
10091	Y	Total Energy Facilities	3,409	155,753	OBG	1	Y	CA	35	0.51	WECC	N
10110	Y	Frito-Lay Cogen Plant	8,287	31,118	NG	1	Y	CA	6	0.59	WECC	N
10115	Y	Grossmont Hospital	3,165	10,796	NG	1	Y	CA	2	0.77	WECC	N
10128	N	Gosselin Hydro Plant	0	4,570	WAT	1	Y	CA	2	0.26	WECC	N
10138	N	South Dry Creek Hydrc	0	6,579	WAT	1	Y	MT	2	0.38	WECC	N
10139	N	Isabella Hydro Project	0	8,103	WAT	1	Y	CA	12	0.08	WECC	N
10140	N	Birch Creek Power	0	8,734	WAT	1	N	ID	3	0.38	WECC	N
10144	Y	Sierra Pacific Lincoln F	0	111,760	WDS	1	Y	CA	19	0.66	WECC	N
10156	Y	Fresno Cogen Partners	31,490	62,294	NG	1	Y	CA	83	0.09	WECC	N
10162	N	Whitewater Hydro Plan	0	480	WAT	1	Y	CA	1	0.04	WECC	N
10168	Y	Cardinal Cogen	236,769	410,277	NG	1	Y	CA	53	0.89	WECC	N
10169	Y	Carson Cogeneration	189,878	411,544	NG	1	Y	CA	56	0.84	WECC	N
10175	Y	Childrens Hospital	11,343	17,557	NG	1	Y	CA	6	0.36	WECC	N
10180	Y	Metro Wastewater Rec	0	31,105	OBG	1	N	CO	15	0.24	WECC	N
10191	N	Tehachapi Wind Resou	0	16,600	WND	1	Y	CA	9	0.22	WECC	N
10199	N	West Ford Flat Power I	0	206,224	GEO	1	Y	CA	38	0.62	WECC	N
10206	Y	Loma Linda University	42,322	44,294	NG	1	Y	CA	13	0.38	WECC	N
10213	Y	El Segundo Cogen	243,251	1,031,754	NG	1	Y	CA	137	0.86	WECC	N
10215	Y	Snowbird Power Plant	3,822	14,738	NG	1	Y	UT	2	0.93	WECC	N
10222	N	Tulare Success Power	0	163	WAT	1	Y	CA	1	0.01	WECC	N
10253	N	Haypress Hydroelectric	0	10,788	WAT	1	Y	CA	10	0.12	WECC	N
10262	Y	California Institute of T	30,417	78,315	NG	1	Y	CA	13	0.69	WECC	N
10282	N	Big Creek Water Work	0	0	WAT	1	Y	CA	5	0.00	WECC	N
10287	N	Beowawe Power	0	102,669	GEO	1	N	NV	17	0.69	WECC	N
10294	Y	King City Power Plant	180,497	396,520	NG	1	Y	CA	133	0.34	WECC	N
10296	N	South Forks Hydro	0	25,900	WAT	1	N	ID	8	0.37	WECC	N
10300	N	Mecca Plant	78,176	365,331	WDS	1	Y	CA	56	0.75	WECC	N
10323	N	Copper Dam Plant	0	14,133	WAT	1	Y	OR	3	0.54	WECC	N
10324	N	Peters Drive Plant	0	1,087	WAT	1	Y	OR	2	0.07	WECC	N
10325	N	Mink Creek Hydro	0	8,112	WAT	1	N	ID	3	0.30	WECC	N
10339	Y	Southside Water Recla	2,262	21,996	OBG	1	Y	NM	7	0.38	WECC	N
10342	Y	Foster Wheeler Martine	351,209	791,121	NG	1	Y	CA	114	0.80	WECC	N
10349	Y	Greenleaf 2 Power Plai	104,645	248,964	NG	1	Y	CA	50	0.57	WECC	N
10350	Y	Greenleaf 1 Power Plai	94,037	286,730	NG	1	Y	CA	66	0.50	WECC	N
10367	N	East Third Street Powe	191,951	166,105	PC	2	Y	CA	21	0.92	WECC	N
10368	N	Loveridge Road Power	183,934	156,728	PC	2	Y	CA	21	0.87	WECC	N
10369	N	Wilbur West Power Pla	181,612	156,402	PC	2	Y	CA	21	0.87	WECC	N
10370	N	Wilbur East Power Plai	186,431	160,681	PC	2	Y	CA	21	0.89	WECC	N
10371	N	Nichols Road Power Pl	184,878	160,069	PC	2	Y	CA	21	0.89	WECC	N
10373	N	Hanford	281,730	214,399	PC	2	Y	CA	27	0.91	WECC	N
10386	N	San Marcos	0	9,292	LFG	1	Y	CA	2	0.59	WECC	N
10387	N	Sycamore San Diego	0	20,704	LFG	1	Y	CA	5	0.49	WECC	N
10388	N	Newby Island I	0	14,492	LFG	1	Y	CA	2	0.83	WECC	N
10389	N	Newby Island II	0	17,342	LFG	1	Y	CA	3	0.60	WECC	N
10390	N	Guadalupe Power Plan	0	18,551	LFG	1	Y	CA	3	0.81	WECC	N
10391	N	Marsh Road Power Pla	0	11,172	LFG	1	Y	CA	2	0.64	WECC	N
10392	N	American Canyon Pow	0	8,308	LFG	1	Y	CA	2	0.59	WECC	N
10395	N	Coyote Canyon Steam	0	17,091	LFG	1	Y	CA	20	0.10	WECC	N
10405	Y	Kingsburg Cogen	50,526	95,353	NG	1	Y	CA	36	0.30	WECC	N
10421	N	Dillon Hydro Plant	0	12,376	WAT	1	N	CO	2	0.78	WECC	N
10422	N	Williams Fork Hydro Pl	0	9,516	WAT	1	N	CO	3	0.36	WECC	N
10423	N	North Fork Hydro Plant	0	5,084	WAT	1	N	CO	6	0.11	WECC	N
10424	N	Gross Hydro Plant	0	227	WAT	1	N	CO	8	0.00	WECC	N
10427	Y	Inland Ontario Mill	23,569	284,366	NG	1	Y	CA	34	0.95	WECC	N
10437	N	SEGS I	2,261	8,641	NG	2	Y	CA	14	0.07	WECC	Y
10438	N	SEGS II	9,828	29,148	NG	2	Y	CA	30	0.11	WECC	Y
10439	N	SEGS III	4,674	65,366	SUN	1	Y	CA	34	0.22	WECC	N
10440	N	SEGS IV	4,987	65,712	SUN	1	Y	CA	34	0.22	WECC	N
10441	N	SEGS V	5,016	65,973	SUN	1	Y	CA	34	0.22	WECC	N
10442	N	SEGS VI	4,782	71,049	SUN	1	Y	CA	35	0.23	WECC	N

10443	N	SEGS VII	5,419	66,207	SUN	1	Y	CA	35	0.22	WECC	N
10444	N	SEGS VIII	18,553	146,536	SUN	1	Y	CA	92	0.18	WECC	N
10446	N	SEGS IX	17,545	147,071	SUN	1	Y	CA	92	0.18	WECC	N
10458	N	Muck Valley Hydroelec	0	22,345	WAT	1	Y	CA	30	0.09	WECC	N
10469	N	Bear Canyon Power Pl	0	114,597	GEO	1	Y	CA	24	0.54	WECC	N
10471	N	Spadra Landfill Gas to	0	53,712	LFG	1	Y	CA	11	0.58	WECC	N
10472	N	Puente Hills Energy Re	0	406,990	LFG	1	Y	CA	63	0.74	WECC	N
10473	N	Palos Verdes Gas to E	3,516	28,824	LFG	1	Y	CA	13	0.25	WECC	N
10478	Y	Pitchess Cogen Station	70,683	198,562	NG	1	Y	CA	28	0.80	WECC	N
10479	N	Ples I	0	98,045	GEO	1	Y	CA	15	0.75	WECC	N
10480	N	Mammoth Pacific I	0	39,012	GEO	1	Y	CA	10	0.45	WECC	N
10481	N	Mammoth Pacific II	0	82,206	GEO	1	Y	CA	30	0.31	WECC	N
10496	Y	Kern River Cogeneratio	310,925	1,256,634	NG	1	Y	CA	300	0.48	WECC	N
10501	Y	Mid-Set Cogeneration	80,675	298,578	NG	1	Y	CA	39	0.87	WECC	N
10502	N	Thermal Energy Dev P	832	122,104	WDS	1	Y	CA	23	0.61	WECC	N
10504	Y	Amalgamated Sugar T	20,269	48,006	BIT	1	N	ID	10	0.54	WECC	N
10548	Y	San Jose Cogeneration	12,262	37,160	NG	1	Y	CA	6	0.71	WECC	N
10586	N	Cameron Ridge LLC	0	186,504	WND	1	Y	CA	60	0.36	WECC	N
10597	N	Ridgetop Energy LLC	0	71,192	WND	1	Y	CA	31	0.26	WECC	N
10600	Y	Union Tribune Publishi	140	144	NG	1	Y	CA	3	0.01	WECC	N
10601	Y	BP Wilmington Calcine	263,689	261,774	PC	1	Y	CA	34	0.88	WECC	N
10602	N	Centaur Generator Fac	17,288	29,498	NG	2	Y	CA	4	0.96	WECC	N
10623	Y	Civic Center	68,621	145,071	NG	1	Y	CA	35	0.48	WECC	N
10631	N	J M Leathers	0	349,044	GEO	1	Y	CA	36	1.11	WECC	N
10632	N	A W Hoch	0	328,732	GEO	1	Y	CA	36	1.05	WECC	N
10634	N	J J Elmore	0	313,310	GEO	1	Y	CA	36	1.00	WECC	N
10635	Y	Corona Cogen	121,690	307,181	NG	1	Y	CA	47	0.75	WECC	N
10640	Y	Stockton Cogen	242,114	370,703	BIT	1	Y	CA	60	0.71	WECC	N
10648	N	Olinda Landfill Gas Re	0	36,296	LFG	1	Y	CA	5	0.77	WECC	N
10649	Y	Bear Mountain Cogen	148,624	381,138	NG	1	Y	CA	46	0.95	WECC	N
10650	Y	Badger Creek Cogen	136,873	363,756	NG	1	Y	CA	46	0.90	WECC	N
10652	Y	Burney Forest Products	2,040	216,702	WDS	1	Y	CA	31	0.80	WECC	N
10661	Y	Collins Pine Project	0	42,231	WDS	1	Y	CA	12	0.40	WECC	N
10677	N	AES Placerita	6,259	11,607	NG	2	Y	CA	150	0.01	WECC	Y
10682	N	Colorado Power Partne	27,392	39,086	NG	2	N	CO	88	0.05	WECC	Y
10683	Y	BCP	97,410	210,361	NG	1	N	CO	74	0.32	WECC	N
10684	Y	Argus Cogen Plant	159,502	374,337	BIT	1	Y	CA	55	0.78	WECC	N
10685	Y	Westend Facility	32,698	110,094	NG	1	Y	CA	20	0.63	WECC	N
10706	N	Burney Creek	0	2,451	WAT	1	Y	CA	3	0.09	WECC	N
10707	N	Cove Hydroelectric	0	10,012	WAT	1	Y	CA	5	0.23	WECC	N
10708	N	Lost Creek I	0	6,358	WAT	1	Y	CA	1	0.66	WECC	N
10709	N	Ponderosa Bailey Cree	0	826	WAT	1	Y	CA	1	0.09	WECC	N
10718	N	Karen Avenue Windfar	0	34,195	WND	1	Y	CA	12	0.33	WECC	N
10720	Y	Kyocera America Proje	7,428	20,000	NG	1	Y	CA	3	0.71	WECC	N
10733	Y	Santa Maria Cogen Pla	580	987	NG	1	Y	CA	9	0.01	WECC	N
10735	N	Barber Dam	0	10,434	WAT	1	N	ID	4	0.29	WECC	N
10737	N	North Fork Hydro	0	2,256	WAT	1	Y	OR	1	0.21	WECC	N
10738	N	Northwind Energy	0	18,082	WND	1	Y	CA	13	0.16	WECC	N
10740	N	Magic Dam Hydroelect	0	10,351	WAT	1	N	ID	9	0.13	WECC	N
10748	N	Marina Landfill Gas	0	27,507	LFG	1	Y	CA	4	0.71	WECC	N
10755	N	Rifle Generating Statio	47,330	101,908	NG	2	N	CO	108	0.11	WECC	Y
10759	N	Salton Sea Unit 3	0	379,893	GEO	1	Y	CA	54	0.80	WECC	N
10761	Y	Las Vegas Cogen LP	86,716	197,496	NG	1	N	NV	61	0.37	WECC	N
10763	N	Geo East Mesa III	0	97,699	GEO	1	Y	CA	28	0.40	WECC	N
10767	N	Rio Bravo Fresno	5,555	147,846	WDS	1	Y	CA	28	0.60	WECC	N
10768	Y	Rio Bravo Jasmin	283,967	271,872	PC	1	Y	CA	38	0.81	WECC	N
10769	Y	Rio Bravo Poso	299,528	281,141	PC	1	Y	CA	38	0.84	WECC	N
10772	N	Rio Bravo Rocklin	1,274	137,371	WDS	1	Y	CA	28	0.56	WECC	N
10776	Y	E F Oxnard Energy Fac	70,219	168,965	NG	1	Y	CA	49	0.40	WECC	N
10777	N	HL Power	0	136,854	WDS	1	Y	CA	36	0.43	WECC	N
10781	N	Koyle Ranch Hydroelec	0	2,446	WAT	1	N	ID	1	0.21	WECC	N
10784	N	Colstrip Energy LP	428,538	303,650	WC	1	Y	MT	42	0.84	WECC	N
10806	N	Crystal Springs	0	6,996	WAT	1	N	ID	2	0.35	WECC	N
10807	N	Dietrich Drop	0	12,672	WAT	1	N	ID	5	0.30	WECC	N
10808	N	Low Line Rapids	0	9,245	WAT	1	N	ID	3	0.38	WECC	N
10809	N	Rock Creek II	0	5,479	WAT	1	N	ID	2	0.33	WECC	N
10810	Y	NTC/MCRD Energy Fa	82,767	202,743	NG	1	Y	CA	26	0.90	WECC	N
10811	Y	Naval Station Energy F	156,230	370,046	NG	1	Y	CA	55	0.77	WECC	N
10812	Y	North Island Energy Fa	101,346	281,674	NG	1	Y	CA	39	0.84	WECC	N
10815	N	Difwind Farms Ltd VII	0	51,507	WND	1	Y	CA	24	0.24	WECC	N
10820	Y	Aliso Water Manageme	452	6,446	OBG	1	Y	CA	1	0.61	WECC	N
10836	N	Woodland Biomass Po	2,084	148,224	WDS	1	Y	CA	28	0.60	WECC	N
10837	N	Covanta Mendota	0	166,000	WDS	1	Y	CA	28	0.68	WECC	N
10840	N	Delano Energy	0	217,980	WDS	1	Y	CA	57	0.44	WECC	N
10850	Y	Mojave Cogen	153,778	368,244	NG	1	Y	CA	57	0.74	WECC	N
10869	Y	Biomass One LP	0	140,910	WDS	1	Y	OR	25	0.64	WECC	N
10873	N	Coso Finance Partners	0	631,038	GEO	1	Y	CA	92	0.78	WECC	N
10874	N	Coso Power Developer	0	586,613	GEO	1	Y	CA	90	0.74	WECC	N
10875	N	Coso Energy Develope	0	494,325	GEO	1	Y	CA	90	0.63	WECC	N
10878	N	Salton Sea Unit 1	0	78,400	GEO	1	Y	CA	10	0.89	WECC	N
10879	N	Salton Sea Unit 2	0	128,000	GEO	1	Y	CA	20	0.73	WECC	N
10880	N	Bidwell Ditch Project	0	12,799	WAT	1	Y	CA	2	0.81	WECC	N
10881	N	Roaring Creek Water F	0	3,911	WAT	1	Y	CA	2	0.22	WECC	N
10882	N	Hatchet Creek Project	0	12,439	WAT	1	Y	CA	7	0.21	WECC	N
10884	Y	Olive View Medical Cer	8,621	14,242	NG	1	Y	CA	6	0.29	WECC	N
50001	N	Altamont Midway Ltd	0	16,665	WND	1	Y	CA	11	0.17	WECC	N
50003	Y	Chalk Cliff Cogen	151,878	388,143	NG	1	Y	CA	46	0.96	WECC	N
50024	N	HGST San Jose Stand	0	0	DFO	2	Y	CA	55	0.00	WECC	Y
50037	N	Rio Bravo Hydro Projec	0	22,439	WAT	1	Y	CA	14	0.18	WECC	N
50049	Y	Pacific Lumber	0	163,478	WDS	1	Y	CA	33	0.57	WECC	N
50061	Y	San Diego State Unive	21,689	76,227	NG	1	Y	CA	14	0.61	WECC	N
50062	N	San Joaquin Cogen	3,913	7,247	NG	2	Y	CA	46	0.02	WECC	Y
50064	Y	Univ of Calif Santa Cru	4,017	13,861	NG	1	Y	CA	3	0.57	WECC	N
50066	N	Calistoga Power Plant	0	581,899	GEO	1	Y	CA	176	0.38	WECC	N
50068	Y	Sierra Power	0	52,147	WDS	1	Y	CA	8	0.79	WECC	N
50076	N	Santa Felicia Dam	0	1,411	WAT	1	Y	CA	1	0.12	WECC	N
50089	Y	Univ of San Francisco	2,492	7,636	NG	1	Y	CA	2	0.58	WECC	N
50091	N	Sheep Creek Hydro	0	5,985	WAT	1	Y	WA	2	0.43	WECC	N
50099	Y	Tamarack Energy Part	0	38,169	WDS	1	N	ID	6	0.70	WECC	N
50104	Y	United Cogen	112,177	211,313	NG	1	Y	CA	31	0.78	WECC	N
50110	Y	Sierra Pacific Burney F	0	117,412	WDS	1	Y	CA	20	0.67	WECC	N
50111	N	Sierra Pacific Loyalton	0	90,765	WDS	1	Y	CA	20	0.52	WECC	N
50112	Y	Sierra Pacific Quincy F	0	186,919	WDS	1	Y	CA	28	0.78	WECC	N
50115	Y	US Borax	100,784	337,086	NG	1	Y	CA	48	0.80	WECC	N
50119	Y	ConocoPhillips Rodeo	55,273	398,887	NG	1	Y	CA	55	0.83	WECC	N
50129	N	Indian Valley Dam Hyd	0	9,792	WAT	1	Y	CA	4	0.30	WECC	N

50131	Y	Coalinga Cogeneration	86,429	322,660	NG	1	Y	CA	38	0.96	WECC	N
50134	Y	Sycamore Cogeneratio	663,930	2,670,618	NG	1	Y	CA	300	1.02	WECC	N
50147	N	R E Badger Filtration P	0	1,035	WAT	1	Y	CA	1	0.08	WECC	N
50148	Y	Linde Wilmington	0	0	NG	1	Y	CA	31	0.00	WECC	N
50156	N	Bear Creek	0	2,437	WAT	1	Y	CA	3	0.09	WECC	N
50170	Y	Berry Cogen	83,498	304,359	NG	1	Y	CA	39	0.90	WECC	N
50179	N	Box Canyon	0	11,755	WAT	1	Y	CA	5	0.27	WECC	N
50180	N	Olsen	0	4,652	WAT	1	Y	CA	5	0.11	WECC	N
50187	Y	Weyerhaeuser Longvie	25,544	346,128	BLQ	1	Y	WA	59	0.67	WECC	N
50191	Y	Weyerhaeuser Springfi	12,775	167,964	BLQ	1	Y	OR	65	0.29	WECC	N
50200	Y	B Braun Medical	10,987	38,157	NG	1	Y	CA	6	0.71	WECC	N
50205	Y	Williams Ignacio Gasol	0	41,190	WH	1	N	CO	6	0.77	WECC	N
50206	N	Vallecito Hydroelectric	0	24	WAT	1	N	CO	6	0.00	WECC	N
50210	N	Vulcan	0	283,636	GEO	1	Y	CA	40	0.82	WECC	N
50216	Y	Watson Cogeneration	689,137	3,027,826	NG	1	Y	CA	405	0.85	WECC	N
50218	N	Woodward Power Plan	0	5,543	WAT	1	Y	CA	3	0.23	WECC	N
50219	N	Frankenheimer Power	0	15,422	WAT	1	Y	CA	5	0.33	WECC	N
50223	N	Nelson Creek	0	1,647	WAT	1	Y	CA	1	0.16	WECC	N
50224	Y	Oxnard Wastewater Tr	393	6,194	OBG	1	Y	CA	2	0.47	WECC	N
50228	N	Rocky Brook Hydroelec	0	1,432	WAT	1	Y	WA	2	0.10	WECC	N
50231	Y	SDS Lumber Gorge Er	0	16,625	WDS	1	Y	WA	10	0.19	WECC	N
50233	N	San Dimas Wash Gen	0	0	WAT	1	Y	CA	1	0.00	WECC	N
50234	Y	San Antonio Communit	9,824	18,563	NG	1	Y	CA	3	0.78	WECC	N
50267	N	Redlands Water & Pow	0	9	WAT	1	N	CO	1	0.00	WECC	N
50270	Y	ExxonMobil Santa Yne	120,993	368,629	NG	1	Y	CA	49	0.85	WECC	N
50274	Y	Simplot Leasing Don P	0	68,599	OTH	1	N	ID	16	0.49	WECC	N
50276	N	Wintec Energy Ltd	0	19,053	WND	1	Y	CA	8	0.29	WECC	N
50281	N	San Gorgonio Farms V	0	69,992	WND	1	Y	CA	28	0.29	WECC	N
50293	N	Wadham Energy LP	1	129,283	AB	1	Y	CA	29	0.52	WECC	N
50298	N	Wheelabrator Lassen	62,862	120,567	NG	2	Y	CA	39	0.35	WECC	Y
50299	Y	Ripon Mill	116,406	272,687	NG	1	Y	CA	50	0.63	WECC	N
50300	Y	San Gabriel Facility	59,666	137,430	NG	1	Y	CA	46	0.34	WECC	N
50322	N	Site 980 65	0	2,754	WAT	1	Y	CA	2	0.15	WECC	N
50323	N	Power Investments	0	1,986	WAT	1	N	ID	1	0.19	WECC	N
50329	Y	West Point Treatment	0	1	OBG	1	Y	WA	1	0.00	WECC	N
50350	N	Forks of Butte Hydro P	0	19,663	WAT	1	Y	CA	15	0.15	WECC	N
50352	N	Nacimiento Hydro Proj	0	14,792	WAT	1	Y	CA	4	0.40	WECC	N
50360	N	Michell Butte Power Pr	0	5,906	WAT	1	Y	OR	2	0.37	WECC	N
50361	N	Owyhee Dam Power P	0	23,855	WAT	1	Y	OR	4	0.63	WECC	N
50362	N	Tunnel 1 Power Projec	0	12,560	WAT	1	Y	OR	7	0.20	WECC	N
50375	N	East Portal Generator	0	6,826	WAT	1	Y	CA	1	0.65	WECC	N
50380	N	Upriver Dam Hydro Pla	0	45,378	WAT	1	Y	WA	18	0.29	WECC	N
50382	N	Twin Reservoirs	0	12,386	WAT	1	Y	WA	2	0.64	WECC	N
50386	N	Windland	0	31,046	WND	1	Y	CA	16	0.22	WECC	N
50388	Y	Phillips 66 Carbon Plar	246,122	127,164	PC	1	Y	CA	27	0.53	WECC	N
50393	N	Friant Hydro Facility	0	34,425	WAT	1	Y	CA	31	0.13	WECC	N
50396	Y	Dillard Complex	284	188,422	WDS	1	Y	OR	52	0.42	WECC	N
50400	N	Sand Bar Power Plant	0	57,452	WAT	1	Y	CA	16	0.40	WECC	N
50421	N	Orchard Avenue 1	0	3,424	WAT	1	Y	WA	2	0.24	WECC	N
50423	N	Cowiche	0	3,458	WAT	1	Y	WA	2	0.23	WECC	N
50426	N	Warm Springs Forest F	0	13,428	WDS	1	Y	OR	9	0.17	WECC	N
50428	Y	Paper Pak Industries	0	0	NG	1	Y	CA	0	0.00	WECC	N
50435	N	Sugarloaf Hydro Plant	0	6,844	WAT	1	N	CO	3	0.31	WECC	N
50464	Y	Oxnard	139,796	508,374	NG	1	Y	CA	69	0.84	WECC	N
50485	N	Altech III	0	49,380	WND	1	Y	CA	25	0.22	WECC	N
50492	Y	Gas Utilization Facility	0	39,894	OBG	1	Y	CA	6	0.75	WECC	N
50493	Y	Double C	109,770	318,485	NG	1	Y	CA	50	0.73	WECC	N
50494	Y	Kern Front	105,491	312,423	NG	1	Y	CA	50	0.72	WECC	N
50495	Y	High Sierra	108,352	307,363	NG	1	Y	CA	50	0.70	WECC	N
50530	Y	Equilon Los Angeles R	115,522	417,744	NG	1	Y	CA	83	0.57	WECC	N
50532	N	Victory Garden (Tehac	0	32,086	WND	1	Y	CA	18	0.21	WECC	N
50533	N	Painted Hills	0	37,056	WND	1	Y	CA	19	0.22	WECC	N
50534	N	Santa Clara (85C)	0	31,795	WND	1	Y	CA	18	0.20	WECC	N
50535	N	Mesa Wind Power Cor	0	58,596	WND	1	Y	CA	30	0.22	WECC	N
50536	N	Sky River Partnership	0	193,931	WND	1	Y	CA	77	0.29	WECC	N
50537	Y	SRI International Coge	9,851	31,720	NG	1	Y	CA	6	0.60	WECC	N
50538	Y	Black Hills Ontario Fac	12,149	26,527	NG	1	Y	CA	12	0.25	WECC	N
50540	Y	BP Carson Refinery	0	0	NG	1	Y	CA	14	0.00	WECC	N
50541	N	Harbor Cogen	51,185	91,854	NG	2	Y	CA	107	0.10	WECC	Y
50544	Y	Port Townsend Paper	4,065	49,815	BLQ	1	Y	WA	14	0.41	WECC	N
50546	N	Bowman	0	8,334	WAT	1	Y	CA	4	0.26	WECC	N
50552	N	Cabazon Wind Farm	0	54,134	WND	1	Y	CA	40	0.16	WECC	N
50553	N	Edom Hills Project 1 LL	0	3,396	WND	1	Y	CA	11	0.04	WECC	N
50557	Y	TXI Riverside Cement	59,770	139,851	BIT	1	Y	CA	24	0.67	WECC	N
50560	N	Pacific-Ultrapower Chir	0	123,220	WDS	1	Y	CA	25	0.56	WECC	N
50571	N	Altamont Gas Recover	0	48,729	LFG	1	Y	CA	9	0.65	WECC	N
50602	N	Hershey Chocolate Co	554	833	NG	2	Y	CA	6	0.02	WECC	Y
50612	Y	McKittrick Cogen	148,251	373,985	NG	1	Y	CA	46	0.93	WECC	N
50622	Y	Berry Cogen Tanne Hil	31,965	120,290	NG	1	Y	CA	18	0.78	WECC	N
50623	Y	Gaviota Oil Plant	5,451	13,192	NG	1	Y	CA	14	0.11	WECC	N
50624	Y	ExxonMobil Oil Torranc	41,724	81,823	NG	1	Y	CA	49	0.19	WECC	N
50630	Y	Covanta Marion Inc	0	87,463	MSB	1	Y	OR	13	0.76	WECC	N
50632	N	Covanta Stanislaus En	0	131,904	MSB	1	Y	CA	24	0.63	WECC	N
50637	Y	Potlatch Idaho Pulp Pa	19,930	434,374	BLQ	1	N	ID	114	0.44	WECC	N
50654	N	Steamboat Hills, L.P.	0	28,998	GEO	1	N	NV	20	0.17	WECC	N
50674	Y	Municipal Cogen Plant	5,892	10,098	NG	1	Y	CA	1	0.96	WECC	N
50676	Y	Thermo Power & Electi	39,624	119,663	NG	1	N	CO	111	0.12	WECC	N
50690	N	San Gorgonio Westwin	0	133,253	WND	1	Y	CA	43	0.35	WECC	N
50696	Y	Plant No 1	467	33,994	OBG	1	Y	CA	8	0.52	WECC	N
50707	Y	TCP 272	480,575	1,003,125	NG	1	N	CO	387	0.30	WECC	N
50709	Y	Thermo Greeley	59,690	196,403	NG	1	N	CO	37	0.61	WECC	N
50712	N	Altamont Pass Windpla	0	682,450	WND	1	Y	CA	333	0.23	WECC	N
50718	N	Notch Butte Hydro	0	3,018	WAT	1	N	ID	1	0.34	WECC	N
50748	Y	Agnews Power Plant	99,469	223,986	NG	1	Y	CA	32	0.80	WECC	N
50750	Y	Coalinga Cogeneration	12,821	55,057	NG	1	Y	CA	7	0.92	WECC	N
50751	N	Southeast Kern River C	139,942	213,564	NG	2	Y	CA	31	0.79	WECC	N
50752	Y	South Belridge Cogene	123,425	434,849	NG	1	Y	CA	94	0.53	WECC	N
50754	N	Oak Creek Energy Sys	0	105,224	WND	1	Y	CA	35	0.35	WECC	N
50755	N	New Hogan Power Plai	0	7,947	WAT	1	Y	CA	3	0.32	WECC	N
50760	N	Empire	0	19,824	GEO	1	N	NV	5	0.47	WECC	N
50762	N	Ormesa IH	0	52,632	GEO	1	Y	CA	14	0.42	WECC	N
50763	N	Steamboat 1	0	4,570	GEO	1	N	NV	8	0.06	WECC	N
50764	N	Ormesa IE	0	45,578	GEO	1	Y	CA	14	0.36	WECC	N
50765	N	Stillwater Facility	0	49,525	GEO	1	N	NV	21	0.27	WECC	N
50766	N	Ormesa I	0	131,410	GEO	1	Y	CA	31	0.48	WECC	N
50805	Y	Catalyst Paper Inc. - Sı	208,004	381,154	SUB	1	Y	AZ	71	0.62	WECC	N

50814	Y	Stone Container Misso	2,365	120,823	WDS	1	Y	MT	17	0.80	WECC	N
50818	N	Altech	0	13,700	WND	1	Y	CA	6	0.27	WECC	N
50820	N	East Winds Project	0	7,733	WND	1	Y	CA	4	0.21	WECC	N
50821	N	Mojave 16	0	53,539	WND	1	Y	CA	30	0.20	WECC	N
50822	N	Mojave 17	0	47,188	WND	1	Y	CA	25	0.22	WECC	N
50823	N	Mojave 18	0	75,187	WND	1	Y	CA	30	0.29	WECC	N
50826	N	Tres Vaqueros Wind F	0	29,945	WND	1	Y	CA	28	0.12	WECC	N
50827	N	Twin Falls Hydro	0	72,935	WAT	1	Y	WA	24	0.35	WECC	N
50831	N	Nove Power Plant	0	15,291	LFG	1	Y	CA	3	0.58	WECC	N
50837	Y	Southeast Resource R	5,358	222,174	MSB	1	Y	CA	36	0.71	WECC	N
50849	Y	PE Berkeley	51,543	194,890	NG	1	Y	CA	29	0.78	WECC	N
50850	Y	OLS Energy Chino	85,911	227,395	NG	1	Y	CA	31	0.84	WECC	N
50851	Y	OLS Energy Camarillo	95,598	235,212	NG	1	Y	CA	31	0.86	WECC	N
50864	Y	Sargent Canyon Coger	68,852	275,264	NG	1	Y	CA	38	0.82	WECC	N
50865	Y	Salinas River Cogenera	72,077	295,572	NG	1	Y	CA	39	0.87	WECC	N
50876	Y	Wheelabrator Norwalk	38,507	92,392	NG	1	Y	CA	31	0.34	WECC	N
50881	N	Wheelabrator Shasta	0	401,359	WDS	1	Y	CA	63	0.73	WECC	N
50886	N	Wheelabrator Spokane	0	141,748	MSB	1	Y	WA	26	0.62	WECC	N
50891	N	El Dorado Hydro Elk Cr	0	3,446	WAT	1	N	ID	3	0.15	WECC	N
50892	N	Rock Creek LP	0	909	WAT	1	Y	CA	3	0.03	WECC	N
50895	N	Bypass	0	27,887	WAT	1	N	ID	10	0.32	WECC	N
50896	N	S E Hazelton A	0	24,007	WAT	1	N	ID	8	0.33	WECC	N
50905	Y	Univ New Mexico Coge	0	0	NG	1	Y	NM	3	0.00	WECC	N
50906	Y	Ford Utilities Center	6,979	22,349	NG	1	Y	NM	7	0.36	WECC	N
50917	N	Middle Fork Irrigation D	0	25,245	WAT	1	Y	OR	3	0.87	WECC	N
50921	Y	Co-Gen LLC	0	35,568	WDS	1	Y	OR	8	0.54	WECC	N
50931	Y	Yellowstone Energy LP	464,495	481,724	PC	1	Y	MT	65	0.85	WECC	N
50938	N	Galesville Project	0	4,878	WAT	1	Y	OR	2	0.35	WECC	N
50951	N	Sunnyside Cogen Assc	483,250	404,184	WC	1	Y	UT	58	0.79	WECC	N
50961	N	Slate Creek	0	5,421	WAT	1	Y	CA	4	0.15	WECC	N
50963	Y	Naval Hospital Medical	19,262	48,459	NG	1	Y	CA	5	1.20	WECC	N
50964	N	Amedee Geothermal V	0	4,877	GEO	1	Y	CA	3	0.19	WECC	N
50968	Y	Watsonville Power Plar	66,615	163,579	NG	1	Y	CA	35	0.54	WECC	N
50972	N	Marsh Valley Developn	0	4,934	WAT	1	N	ID	2	0.35	WECC	N
50980	N	Siphon Power Project	0	25	WAT	1	Y	OR	5	0.00	WECC	N
50985	Y	Solano County Cogen I	6,187	9,532	NG	1	Y	CA	3	0.39	WECC	N
50987	N	Rock Creek I	0	7,308	WAT	1	N	ID	2	0.40	WECC	N
50993	Y	Co-Gen II LLC	0	65,539	WDS	1	Y	OR	8	1.00	WECC	N
50997	Y	Gallup Refinery	488	1,700	NG	1	Y	NM	6	0.03	WECC	N
52015	N	Caithness Dixie Valley	0	491,494	GEO	1	N	NV	61	0.93	WECC	N
52039	N	Quail Creek Hydro Plar	0	5,761	WAT	1	Y	UT	2	0.29	WECC	N
52063	Y	Martinez Sulfuric Acid I	1,382	14,502	OTH	1	Y	CA	4	0.41	WECC	N
52064	Y	Rhodia Dominguez Pla	2,987	22,029	NG	1	Y	CA	5	0.50	WECC	N
52073	Y	UCLA So Campus Cer	54,941	195,331	NG	1	Y	CA	43	0.52	WECC	N
52076	N	McKittrick Cogen	53,749	59,760	NG	2	Y	CA	10	0.71	WECC	N
52077	Y	Lost Hills Cogeneratior	13,899	58,534	NG	1	Y	CA	11	0.64	WECC	N
52078	N	North Midway Cogen	42,134	47,530	NG	2	Y	CA	11	0.52	WECC	Y
52080	Y	Concord Cogen	8,220	14,804	NG	1	Y	CA	3	0.56	WECC	N
52081	N	Cymric 31X Cogen	53,324	48,737	NG	2	Y	CA	7	0.82	WECC	N
52082	N	Cymric 6Z Cogen	53,675	49,732	NG	2	Y	CA	7	0.83	WECC	N
52083	N	Coalinga 6C Cogen	53,026	47,704	NG	2	Y	CA	7	0.80	WECC	N
52085	N	Taft 26C Cogen	117,078	90,315	NG	2	Y	CA	12	0.83	WECC	N
52086	N	Coalinga 25D Cogen	104,777	98,196	NG	2	Y	CA	14	0.82	WECC	N
52094	N	Kern River Fee A Coge	39,331	51,869	NG	2	Y	CA	7	0.80	WECC	N
52095	N	Kern River Fee C Coge	35,028	46,784	NG	2	Y	CA	8	0.68	WECC	N
52096	Y	Berry Placerita Cogen	87,226	339,971	NG	1	Y	CA	43	0.91	WECC	N
52099	Y	Plant No 2	6,374	57,424	OBG	1	Y	CA	16	0.41	WECC	N
52104	N	Cymric 36W Cogen	105,637	91,194	NG	2	Y	CA	12	0.84	WECC	N
52105	N	Richmond Refinery TG	0	124,710	OG	1	Y	CA	30	0.47	WECC	N
52107	N	Kern River Eastridge C	211,558	346,032	NG	2	Y	CA	49	0.81	WECC	N
52109	Y	Richmond Cogen	172,572	788,185	NG	1	Y	CA	125	0.72	WECC	N
52115	Y	Corn Products Stockto	7,088	24,783	NG	1	Y	CA	3	1.01	WECC	N
52119	Y	Primary Childrens Med	1,517	5,197	NG	1	Y	UT	2	0.33	WECC	N
52127	N	Elk Basin Gasoline Pla	0	13,032	OG	1	N	WY	2	0.70	WECC	N
52138	N	Steamboat 1A Power F	0	6,535	GEO	1	N	NV	3	0.29	WECC	N
52142	N	Mojave 4	0	86,843	WND	1	Y	CA	29	0.34	WECC	N
52143	N	Mojave 3	0	74,015	WND	1	Y	CA	24	0.36	WECC	N
52144	N	Mojave 5	0	72,647	WND	1	Y	CA	23	0.37	WECC	N
52147	Y	C P Kelco San Diego F	41,252	146,729	NG	1	Y	CA	28	0.60	WECC	N
52155	N	Lacomb Irrigation Distr	0	4,803	WAT	1	Y	OR	1	0.55	WECC	N
52158	N	Aidlin Geothermal Pow	0	146,205	GEO	1	Y	CA	25	0.67	WECC	N
52160	N	Victory Garden Phase I	0	43,626	WND	1	Y	CA	22	0.23	WECC	N
52161	N	Terra-Gen 251 Wind LI	0	31,540	WND	1	Y	CA	18	0.20	WECC	N
52162	N	85 A	0	16,263	WND	1	Y	CA	14	0.13	WECC	N
52163	N	85 B	0	23,345	WND	1	Y	CA	21	0.13	WECC	N
52165	N	Helzel and Schwarzhof	0	1,148	WND	1	Y	CA	2	0.07	WECC	N
52169	Y	Midway Sunset Cogen	469,721	1,867,337	NG	1	Y	CA	234	0.91	WECC	N
52174	N	Soda Lake Geotherma	0	64,406	GEO	1	N	NV	26	0.28	WECC	N
52186	Y	Yuba City Cogen Partn	54,473	131,427	NG	1	Y	CA	49	0.31	WECC	N
52187	N	Falls Creek	0	14,909	WAT	1	Y	OR	4	0.42	WECC	N
52198	Y	JRW Associates LP	4,015	11,603	NG	1	Y	CA	10	0.13	WECC	N
52199	Y	Ridgewood/Byron Pow	7,006	9,353	NG	1	Y	CA	7	0.16	WECC	N
52201	Y	Sunnyside Cogen Partı	0	0	NG	1	Y	CA	7	0.00	WECC	N
52204	N	Otay	0	46,759	LFG	1	Y	CA	7	0.77	WECC	N
52205	N	Salinas	0	9,687	LFG	1	Y	CA	1	0.79	WECC	N
52206	N	Oxnard	0	15,983	LFG	1	Y	CA	5	0.34	WECC	N
54001	Y	Pittsburg Power Plant	44,111	147,010	NG	1	Y	CA	74	0.23	WECC	N
54006	N	Broadwater Power Proj	0	44,977	WAT	1	Y	MT	10	0.53	WECC	N
54015	N	BKK Landfill	0	57,925	LFG	1	Y	CA	12	0.57	WECC	N
54017	N	San Gabriel Hydro Proj	0	0	WAT	1	Y	CA	5	0.00	WECC	N
54038	N	Geo East Mesa II	0	81,988	GEO	1	Y	CA	20	0.47	WECC	N
54050	N	Glines Hydroelectric Pr	0	98,078	WAT	1	Y	WA	16	0.69	WECC	N
54051	N	Elwha Hydroelectric Pr	0	58,379	WAT	1	Y	WA	13	0.53	WECC	N
54111	N	Second Imperial Geoth	0	317,047	GEO	1	Y	CA	64	0.57	WECC	N
54142	N	Hillcrest Pump Station	0	9,155	WAT	1	N	CO	2	0.52	WECC	N
54219	N	Burney Mountain Powe	0	72,850	WDS	1	Y	CA	11	0.73	WECC	N
54238	Y	Port of Stockton Distric	305,718	284,891	BIT	1	Y	CA	54	0.60	WECC	N
54245	Y	Nelson Plant Generato	937	1,211	DFO	1	Y	AZ	2	0.06	WECC	N
54249	N	Smith Falls Hydro Proje	0	86,785	WAT	1	N	ID	38	0.26	WECC	N
54251	N	Opal Springs Hydro	0	26,806	WAT	1	Y	OR	4	0.71	WECC	N
54258	N	Westwind Trust	0	31,911	WND	1	Y	CA	16	0.23	WECC	N
54261	N	Warm Springs Hydro F	0	11,793	WAT	1	Y	CA	3	0.50	WECC	N
54267	N	Koma Kulshan Associa	0	43,743	WAT	1	Y	WA	12	0.42	WECC	N
54268	Y	March Point Cogenerat	221,033	1,004,423	NG	1	Y	WA	167	0.69	WECC	N
54271	Y	Saguaro Power	313,917	632,904	NG	1	N	NV	127	0.57	WECC	N
54296	Y	Biola University	6,203	11,231	NG	1	Y	CA	2	0.58	WECC	N

54298	N	Coram Energy LLC (E(	0	28,421	WND	1	Y	CA	8	0.43	WECC	N
54299	N	Coram Energy LLC	0	11,863	WND	1	Y	CA	3	0.45	WECC	N
54300	N	CTV Power Purchase (	0	15,037	WND	1	Y	CA	5	0.37	WECC	N
54306	N	Wilson Lake Hydroelec	0	27,171	WAT	1	N	ID	8	0.37	WECC	N
54308	N	Three Forks Water Po\	0	6,007	WAT	1	Y	CA	1	0.53	WECC	N
54318	Y	General Chemical	104,387	233,075	BIT	1	N	WY	30	0.89	WECC	N
54326	N	Penrose Power Station	1,828	38,235	LFG	1	Y	CA	9	0.48	WECC	N
54327	N	Toyon Power Station	819	15,660	LFG	1	Y	CA	9	0.20	WECC	N
54343	N	Terminus Hydroelectric	0	15,971	WAT	1	Y	CA	20	0.09	WECC	N
54349	Y	Nevada Cogen Associa	254,030	724,599	NG	1	N	NV	96	0.86	WECC	N
54350	Y	Nevada Cogen Assoc#	271,855	701,641	NG	1	N	NV	96	0.83	WECC	N
54371	Y	Oildale Cogen	138,669	314,767	NG	1	Y	CA	42	0.85	WECC	N
54372	Y	University of Colorado	10,543	27,769	NG	1	N	CO	33	0.10	WECC	N
54374	Y	Sinclair Oil Refinery	1,777	3,372	NG	1	N	WY	3	0.12	WECC	N
54386	N	Little Wood Hydro Proj	0	3,024	WAT	1	N	ID	3	0.12	WECC	N
54387	N	Weeks Falls	0	13,390	WAT	1	Y	WA	4	0.36	WECC	N
54394	N	Dry Creek Project	0	12,038	WAT	1	N	ID	4	0.38	WECC	N
54410	Y	DAI Oildale	97,367	214,860	NG	1	Y	CA	36	0.68	WECC	N
54447	Y	Welport Lease Project	17,111	39,567	NG	1	Y	CA	5	0.90	WECC	N
54449	Y	Dome Project	19,078	46,366	NG	1	Y	CA	6	0.88	WECC	N
54451	Y	Los Angeles Refinery V	19,857	388,917	OG	1	Y	CA	69	0.65	WECC	N
54453	N	ENXCO Wind Farm V	0	151,832	WND	1	Y	CA	60	0.29	WECC	N
54454	N	San Gorgonio Windpla	0	41,973	WND	1	Y	CA	35	0.14	WECC	N
54468	N	Mt Lassen Power	0	67,063	WDS	1	Y	CA	11	0.67	WECC	N
54469	N	Pacific Oroville Power I	0	118,928	WDS	1	Y	CA	18	0.75	WECC	N
54472	Y	Simplot Phosphates	5,123	78,699	OTH	1	N	WY	12	0.78	WECC	N
54476	Y	Sumas Power Plant	88,104	228,922	NG	1	Y	WA	126	0.21	WECC	N
54477	Y	Oroville Cogeneration I	8,491	11,066	NG	1	Y	CA	8	0.16	WECC	N
54514	N	Blind Canyon Hydro	0	4,468	WAT	1	N	ID	1	0.39	WECC	N
54517	Y	Sierra Pacific Sonora	0	31,663	WDS	1	Y	CA	8	0.48	WECC	N
54524	N	Horseshoe Bend Hydro	0	46,122	WAT	1	N	ID	9	0.56	WECC	N
54537	Y	Tenaska Ferndale Cog	286,917	714,610	NG	1	Y	WA	253	0.32	WECC	N
54554	N	Spicer Meadow Project	0	269,970	WAT	1	Y	CA	6	5.22	WECC	N
54555	N	Collierville Powerhouse	0	268,523	WAT	1	Y	CA	253	0.12	WECC	N
54558	N	Hazelton B Hydro	0	24,002	WAT	1	N	ID	8	0.36	WECC	N
54561	Y	Jefferson Smurfit Santa	68,345	223,837	NG	1	Y	CA	27	0.95	WECC	N
54562	Y	Longview Fibre	5,932	137,543	BLQ	1	Y	WA	127	0.12	WECC	N
54567	N	MM Yolo Power LLC Fa	0	17,701	LFG	1	Y	CA	3	0.72	WECC	N
54578	Y	Glenns Ferry Cogen Fa	16,059	54,144	NG	1	N	ID	10	0.59	WECC	N
54579	Y	Rupert Cogen Project	17,095	47,903	NG	1	N	ID	10	0.53	WECC	N
54594	N	Biosphere 2 Center	256	151	DFO	2	Y	AZ	3	0.01	WECC	Y
54626	Y	Mt Poso Cogeneration	403,956	416,731	BIT	1	Y	CA	62	0.77	WECC	N
54628	Y	Phelps Dodge Refining	15,297	45,418	NG	1	N	TX	20	0.26	WECC	N
54630	Y	American Gypsum Cog	17,703	22,999	NG	1	N	CO	10	0.27	WECC	N
54647	N	TPC Windfarms LLC	0	70,102	WND	1	Y	CA	29	0.28	WECC	N
54650	N	Swanmill Windfarm I	0	41,809	WND	1	Y	CA	19	0.26	WECC	N
54653	N	Kanaka	0	651	WAT	1	Y	CA	1	0.07	WECC	N
54654	N	Kekawaka Power Hous	0	5,384	WAT	1	Y	CA	5	0.13	WECC	N
54665	N	Steamboat II	0	47,572	GEO	1	N	NV	23	0.24	WECC	N
54666	N	Steamboat III	0	66,210	GEO	1	N	NV	23	0.33	WECC	N
54667	N	Chino Mines	3,643	5,113	NG	2	Y	NM	54	0.01	WECC	Y
54668	N	Falls River Hydro	0	42,358	WAT	1	N	ID	9	0.54	WECC	N
54674	N	Ford Hydro LP	0	2,874	WAT	1	N	ID	1	0.27	WECC	N
54679	N	Boulder City Lakewood	0	7,575	WAT	1	N	CO	4	0.25	WECC	N
54680	N	Boulder City Betasso H	0	7,575	WAT	1	N	CO	3	0.29	WECC	N
54681	N	Difwind Farms Ltd I	0	16,107	WND	1	Y	CA	7	0.25	WECC	N
54682	N	Difwind Farms Ltd II	0	8,317	WND	1	Y	CA	6	0.17	WECC	N
54685	N	Difwind Farms Ltd V	0	21,418	WND	1	Y	CA	12	0.21	WECC	N
54686	N	Difwind Farms Ltd VI	0	59,210	WND	1	Y	CA	27	0.25	WECC	N
54687	N	Difwind Farms Ltd VIII	0	25,442	WND	1	Y	CA	15	0.19	WECC	N
54689	N	Heber Geothermal	0	344,678	GEO	1	Y	CA	63	0.63	WECC	N
54690	Y	Amalgamated Sugar LI	20,559	45,401	BIT	1	N	ID	9	0.60	WECC	N
54694	Y	Yuma Cogeneration As	136,135	337,796	NG	1	Y	AZ	63	0.62	WECC	N
54721	N	Warm Springs Power E	0	83,659	WAT	1	Y	OR	20	0.49	WECC	N
54724	N	Ormesa II	0	145,582	GEO	1	Y	CA	23	0.72	WECC	N
54729	N	Taylor Draw Hydroelec	0	11,819	WAT	1	N	CO	2	0.59	WECC	N
54734	N	Phelps Dodge Tyrone	48	63	DFO	2	Y	NM	45	0.00	WECC	Y
54749	Y	Goal Line LP	126,029	305,655	NG	1	Y	CA	51	0.68	WECC	N
54750	N	Coram Tehachapi	0	17,693	WND	1	Y	CA	7	0.29	WECC	N
54753	N	Lateral 10 Ventures	0	5,429	WAT	1	N	ID	2	0.26	WECC	N
54761	Y	Hermiston Generating	1,379,050	3,417,904	NG	1	Y	OR	621	0.63	WECC	N
54768	Y	Live Oak Cogen	150,661	384,881	NG	1	Y	CA	46	0.96	WECC	N
54800	Y	Saint Agnes Medical C	8,145	28,181	NG	1	Y	CA	7	0.46	WECC	N
54809	Y	University of Washingto	2,272	9,434	NG	1	Y	WA	5	0.22	WECC	N
54812	N	Mile 28 Water Power P	0	3,676	WAT	1	N	ID	1	0.30	WECC	N
54814	Y	Milagro Cogeneration F	116,013	450,201	NG	1	Y	NM	122	0.42	WECC	N
54854	N	Sun Peak Project	13,770	21,921	NG	2	N	NV	222	0.01	WECC	Y
54860	N	Black Creek	0	2,777	WAT	1	Y	WA	4	0.09	WECC	N
54909	N	Tehachapi Wind Resou	0	55,312	WND	1	Y	CA	22	0.28	WECC	N
54912	Y	Martinez Refining	222,252	769,339	NG	1	Y	CA	100	0.88	WECC	N
54931	N	Ridgetop	0	160,150	WND	1	Y	CA	47	0.39	WECC	N
54936	Y	Richard J Donovan Co	0	0	NG	1	Y	CA	3	0.00	WECC	N
54944	Y	Albany Paper Mill	114,153	390,686	BLQ	1	Y	OR	96	0.46	WECC	N
54950	Y	Univ of Oregon Central	1,540	5,134	NG	1	Y	OR	4	0.15	WECC	N
54951	Y	Monterey Regional Wa	0	8,799	OBG	1	Y	CA	2	0.67	WECC	N
54975	Y	New Mexico State Univ	23,432	36,066	NG	1	Y	NM	5	0.88	WECC	N
54996	N	Salton Sea Unit 4	0	334,143	GEO	1	Y	CA	51	0.75	WECC	N
55007	N	K W Company	0	3,751	WAT	1	N	ID	1	0.31	WECC	N
55009	N	Montgomery Creek Hyd	0	5,854	WAT	1	Y	CA	3	0.26	WECC	N
55039	N	Delta Person LLC	6,159	10,508	NG	2	Y	NM	150	0.01	WECC	Y
55049	Y	Sierra Pacific Andersor	0	30,719	WDS	1	Y	CA	4	0.88	WECC	N
55077	N	El Dorado Energy	968,911	2,501,889	NG	2	N	NV	598	0.48	WECC	Y
55084	Y	Crockett Cogen Projec	217,963	689,796	NG	1	Y	CA	247	0.32	WECC	N
55090	Y	Plummer Cogen	0	37,116	WDS	1	N	ID	6	0.68	WECC	N
55094	Y	Miramar Landfill Metro	0	46,783	LFG	1	Y	CA	6	0.83	WECC	N
55103	Y	Klamath Cogeneration	890,773	2,433,973	NG	1	Y	OR	502	0.55	WECC	N
55112	N	Sutter Energy Center	1,040,608	2,668,953	NG	2	Y	CA	636	0.48	WECC	Y
55124	N	Griffith Energy LLC	768,471	1,967,892	NG	2	Y	AZ	654	0.34	WECC	Y
55125	N	Vansycle	0	70,486	WND	1	Y	OR	25	0.32	WECC	N
55127	N	Manchief Electric Gene	193,119	339,650	NG	2	N	CO	300	0.13	WECC	Y
55129	N	Desert Basin	651,806	1,643,070	NG	2	Y	AZ	646	0.29	WECC	Y
55151	N	La Paloma Generating	2,340,096	5,970,006	NG	2	Y	CA	1,200	0.57	WECC	Y
55160	N	Visalia Landfill Gas Util	0	10,692	LFG	1	Y	CA	2	0.68	WECC	N
55161	N	Lopez Landfill Gas Utili	0	48,610	LFG	1	Y	CA	6	0.92	WECC	N
55177	N	South Point Energy Ce	829,480	2,115,788	NG	2	Y	AZ	708	0.34	WECC	Y
55179	N	Rathdrum Power LLC	470,115	1,275,784	NG	2	N	ID	302	0.48	WECC	Y

55182	N	Sunrise Power LLC	1,429,483	3,661,797	NG	2	Y	CA	605	0.69	WECC	N
55184	Y	Aera San Ardo Cogen	11,960	46,833	NG	1	Y	CA	6	0.86	WECC	N
55185	Y	Aera South Belridge Co	0	0	NG	1	Y	CA	9	0.00	WECC	N
55200	N	Arapahoe Combustion	122,738	269,760	NG	2	N	CO	194	0.16	WECC	Y
55203	N	Ponnequin Phase 1	0	7,918	WND	1	N	CO	5	0.17	WECC	N
55207	N	Valmont Combustion T	9,825	17,232	NG	2	N	CO	142	0.01	WECC	Y
55209	N	Brush IV	78,280	130,826	NG	2	N	CO	138	0.11	WECC	Y
55210	N	Afton Generating Static	42,905	80,960	NG	2	Y	NM	287	0.03	WECC	Y
55217	Y	Los Medanos Energy C	1,226,447	3,476,895	NG	1	Y	CA	678	0.59	WECC	N
55257	Y	Ina Road Water Polluti	3,053	16,366	NG	1	Y	AZ	4	0.44	WECC	N
55278	Y	Beaver Creek Gas Plai	7,613	26,516	NG	1	N	WY	5	0.61	WECC	N
55282	Y	Dynergy Arlington Valle	562,957	1,515,271	NG	1	Y	AZ	713	0.24	WECC	N
55283	N	Front Range Power Pro	1,128,215	2,757,249	NG	2	N	CO	541	0.58	WECC	Y
55295	N	Blythe Energy LLC	500,078	1,245,528	NG	2	Y	CA	591	0.24	WECC	Y
55302	Y	Wasatch Energy Syste	0	10,633	MSB	1	Y	UT	2	0.76	WECC	N
55306	N	Gila River Power Static	2,683,509	7,251,234	NG	2	Y	AZ	2,476	0.33	WECC	Y
55312	N	Phelps Dodge Cobre M	0	0	DFO	2	Y	NM	2	0.00	WECC	Y
55322	N	Chuck Lenzie Generati	2,563,006	6,765,375	NG	2	N	NV	1,466	0.53	WECC	Y
55328	N	Hermiston Power Partr	1,177,199	3,078,085	NG	2	Y	OR	689	0.51	WECC	Y
55333	N	Delta Energy Center	1,994,677	5,086,194	NG	2	Y	CA	944	0.62	WECC	N
55339	N	Phoenix Wind Power L	0	6,322	WND	1	Y	CA	2	0.34	WECC	N
55343	N	Luna Energy Facility	983,831	2,630,709	NG	2	Y	NM	650	0.46	WECC	Y
55372	N	Harquahala Generating	1,006,918	3,007,705	NG	2	Y	AZ	1,325	0.26	WECC	Y
55393	N	Metcalf Energy Center	1,103,753	2,935,887	NG	2	Y	CA	635	0.53	WECC	Y
55396	N	Green Power I	0	28,043	WND	1	Y	CA	17	0.19	WECC	N
55400	N	Elk Hills Power LLC	1,396,638	3,731,938	NG	2	Y	CA	623	0.68	WECC	N
55453	N	Fountain Valley Power	255,411	449,520	NG	2	N	CO	228	0.23	WECC	Y
55455	N	Red Hawk	1,672,283	4,201,845	NG	2	Y	AZ	1,136	0.42	WECC	Y
55477	N	Neil Simpson Gas Turb	11,142	21,627	NG	2	N	WY	40	0.06	WECC	Y
55478	N	Lange Gas Turbines	17,942	32,121	NG	2	N	SD	#N/A	#N/A	WECC	#N/A
55479	N	Wygen 1	800,734	705,444	SUB	2	N	WY	88	0.92	WECC	N
55481	N	Mesquite Generating S	2,997,329	7,866,746	NG	2	Y	AZ	1,383	0.65	WECC	N
55482	N	Goldendale Generating	272,254	718,654	NG	2	Y	WA	280	0.29	WECC	Y
55494	N	Tri Center Naniwa Ene	39,153	46,918	NG	2	N	NV	380	0.01	WECC	Y
55499	N	CalPeak Power Vaca D	6,737	12,070	NG	2	Y	CA	50	0.03	WECC	Y
55504	N	Limon Generating Stati	90,222	140,947	NG	2	N	CO	154	0.10	WECC	Y
55505	N	Frank Knutson	151,225	238,047	NG	2	N	CO	154	0.18	WECC	Y
55508	N	CalPeak Power Panocl	6,550	11,729	NG	2	Y	CA	50	0.03	WECC	Y
55510	N	CalPeak Power Border	14,638	25,370	NG	2	Y	CA	50	0.06	WECC	Y
55512	N	CalPeak Power El Cajo	17,693	30,168	NG	2	Y	CA	49	0.07	WECC	Y
55513	N	CalPeak Power Enterp	14,238	24,963	NG	2	Y	CA	49	0.06	WECC	Y
55514	N	Apex Generating Static	701,246	1,678,527	NG	2	N	NV	601	0.32	WECC	Y
55518	N	High Desert Power Pla	1,697,183	4,518,068	NG	2	Y	CA	852	0.61	WECC	N
55522	N	Sundance	73,150	137,652	NG	2	Y	AZ	450	0.03	WECC	Y
55536	N	Hoover Company	56	97	DFO	2	N	TX	7	0.00	WECC	Y
55538	N	Escondido Power Plant	2,816	2,897	NG	2	Y	CA	44	0.01	WECC	Y
55540	N	Chula Vista I	1,724	1,842	NG	2	Y	CA	44	0.00	WECC	Y
55541	N	Indigo Energy Facility	48,804	81,172	NG	2	Y	CA	150	0.06	WECC	Y
55542	N	Larkspur Energy Facilit	27,844	47,271	NG	2	Y	CA	100	0.05	WECC	Y
55544	N	Klamath Expansion Pro	14,882	25,543	NG	2	Y	OR	118	0.02	WECC	Y
55557	Y	Wilmington Hydrogen F	0	186,377	WH	1	Y	CA	32	0.67	WECC	N
55560	N	FPL Energy Vansycle L	0	418,313	WND	1	Y	WA	177	0.27	WECC	N
55578	N	Hueco Mountain Wind	0	736	WND	1	N	TX	1	0.06	WECC	N
55601	N	Prima Desheha Landfil	0	24,004	LFG	1	Y	CA	6	0.46	WECC	N
55602	N	North City Cogen Facili	0	28,752	LFG	1	Y	CA	4	0.91	WECC	N
55603	N	Tajiguas Landfill	0	19,794	LFG	1	Y	CA	3	0.75	WECC	N
55607	N	Foote Creek I	0	121,227	WND	1	N	WY	41	0.33	WECC	N
55608	N	Foote Creek II	0	4,976	WND	1	N	WY	2	0.32	WECC	N
55609	N	Foote Creek III	0	71,170	WND	1	N	WY	25	0.33	WECC	N
55610	N	Foote Creek IV	0	51,159	WND	1	N	WY	17	0.35	WECC	N
55622	N	West Valley Generation	386,738	667,264	NG	2	Y	UT	217	0.35	WECC	Y
55625	N	Creed Energy Center	6,966	12,873	NG	2	Y	CA	47	0.03	WECC	Y
55626	N	Lambie Energy Center	7,836	14,617	NG	2	Y	CA	47	0.04	WECC	Y
55627	N	Goose Haven Energy C	7,875	14,643	NG	2	Y	CA	47	0.04	WECC	Y
55637	Y	Leviton Manufacturing	0	0	DFO	1	N	TX	2	0.00	WECC	N
55645	N	Blue Spruce Energy Ce	299,535	496,782	NG	2	N	CO	468	0.12	WECC	Y
55650	N	Plains End	57,489	114,113	NG	2	N	CO	114	0.11	WECC	Y
55656	N	Pastoria Energy Facility	1,867,329	4,843,618	NG	2	Y	CA	779	0.71	WECC	N
55662	N	Chehalis Generating Fa	714,998	1,887,450	NG	2	Y	WA	593	0.36	WECC	Y
55687	N	Bighorn Electric Genera	558,160	1,434,855	NG	2	N	NV	688	0.24	WECC	Y
55698	N	Hanford Energy Park P	21,005	35,714	NG	2	Y	CA	92	0.04	WECC	Y
55719	N	Mountain View I	0	129,134	WND	1	Y	CA	44	0.33	WECC	N
55720	N	Mountain View II	0	71,865	WND	1	Y	CA	22	0.37	WECC	N
55733	N	Bennett Mountain	104,568	183,930	NG	2	N	ID	173	0.12	WECC	Y
55739	N	Condon Windpower LL	0	83,829	WND	1	Y	OR	50	0.19	WECC	N
55740	N	Rock River I LLC	0	140,904	WND	1	N	WY	50	0.32	WECC	N
55741	N	Ridge Crest Wind Partı	0	76,890	WND	1	N	CO	30	0.30	WECC	N
55748	N	Los Esteros Critical En	35,617	65,704	NG	2	Y	CA	180	0.04	WECC	Y
55749	N	Hardin Generator Proje	899,220	728,486	SUB	2	Y	MT	116	0.72	WECC	N
55752	N	Sonoma Central Landfi	0	26,132	LFG	1	Y	CA	3	0.93	WECC	N
55753	N	Sonoma Central Landfi	0	25,899	LFG	1	Y	CA	3	0.92	WECC	N
55766	N	Kiefer Landfill	0	53,775	LFG	1	Y	CA	9	0.68	WECC	N
55772	N	P.E.R.C.	0	2,491	LFG	1	Y	WA	3	0.11	WECC	N
55807	N	Henrietta Peaker	11,831	21,012	NG	2	Y	CA	98	0.02	WECC	Y
55810	N	Gilroy Peaking Energy	47,796	86,459	NG	2	Y	CA	135	0.07	WECC	Y
55811	N	King City Peaking	11,608	22,503	NG	2	Y	CA	47	0.05	WECC	Y
55813	N	Yuba City Energy Cent	13,546	25,033	NG	2	Y	CA	47	0.06	WECC	Y
55818	N	Frederickson Power LP	337,543	899,228	NG	2	Y	WA	318	0.32	WECC	Y
55820	N	RCWMD Badlands Lar	0	3,246	LFG	1	Y	CA	1	0.29	WECC	N
55835	N	Rocky Mountain Energ	1,310,607	3,220,560	NG	2	N	CO	705	0.52	WECC	Y
55841	N	Silverhawk	1,143,729	2,889,329	NG	2	N	NV	665	0.50	WECC	Y
55847	N	Feather River Energy C	13,644	25,533	NG	2	Y	CA	47	0.06	WECC	Y
55851	Y	Valero Refinery Cogen	62,365	365,279	NG	1	Y	CA	51	0.82	WECC	N
55855	N	Wolfskill Energy Cente	11,148	20,517	NG	2	Y	CA	47	0.05	WECC	Y
55858	Y	Desert Power LP	0	0	NG	1	Y	UT	135	0.00	WECC	N
55866	N	Basin Creek Plant	41,580	80,267	NG	2	Y	MT	55	0.17	WECC	Y
55871	N	Klondike Wind Power	0	56,169	WND	1	Y	OR	25	0.26	WECC	N
55874	N	Panoche Peaker	506	9,096	NG	2	Y	CA	50	0.02	WECC	Y
55875	N	Gates Peaker	5,158	4,444	NG	2	Y	CA	47	0.01	WECC	Y
55880	N	Sonoma Central Landfi	0	11,880	LFG	1	Y	CA	2	0.85	WECC	N
55882	Y	Sierra Pacific Aberdeer	0	111,324	WDS	1	Y	WA	18	0.71	WECC	N
55931	N	Boulder City Silver Lak	0	11,919	WAT	1	N	CO	3	0.41	WECC	N
55933	N	Tracy Peaker	9,091	13,708	NG	2	Y	CA	169	0.01	WECC	Y
55934	N	Century Generating Fa	1,724	1,681	NG	2	Y	CA	45	0.00	WECC	Y
55935	N	Drews Generating Faci	1,716	1,669	NG	2	Y	CA	45	0.00	WECC	Y
55950	Y	Elk Hills Cogen	86,450	322,404	NG	1	Y	CA	47	0.79	WECC	N

55951	N	Agua Mansa Power Pla	27,401	48,774	NG	2	Y	CA	61	0.09	WECC	Y	
55952	N	Las Vegas Cogeneratio	295,108	642,500	NG	2	N	NV	298	0.25	WECC	Y	
55963	N	Riverview Energy Cent	14,085	26,403	NG	2	Y	CA	47	0.06	WECC	Y	
55970	N	Cosumnes	1,454,287	3,731,659	NG	2	Y	CA	530	0.80	WECC	N	
55977	N	Bluffview	180,381	424,772	NG	2	Y	NM	67	0.72	WECC	N	
55983	N	Salton Sea Unit 5	0	351,962	GEO	1	Y	CA	50	0.81	WECC	N	
55984	N	CE Turbo	0	71,000	GEO	1	Y	CA	12	0.70	WECC	N	
55985	N	Palomar Energy	1,251,230	3,352,807	NG	2	Y	CA	559	0.68	WECC	N	
55988	N	Wabuska	0	6,211	GEO	1	N	NV	2	0.32	WECC	N	
55989	N	FPL Energy Vansycle L	0	288,177	WND	1	Y	OR	123	0.27	WECC	N	
55991	N	Brady	0	91,375	GEO	1	N	NV	33	0.32	WECC	N	
56011	N	Cabazon Wind Partner	0	120,655	WND	1	Y	CA	41	0.34	WECC	N	
56012	N	Whitewater Hill Wind P	0	178,716	WND	1	Y	CA	62	0.33	WECC	N	
56016	N	Grimes Way	232	-2,556	NG	2	Y	WA	4	-0.07	WECC	Y	
56017	N	Franklin/Grays	1,138	643	NG	2	Y	WA	46	0.00	WECC	Y	
56026	N	Donald Von Raesfeld F	271,404	236,866	NG	2	Y	CA	154	0.18	WECC	Y	
56036	N	WWTP Power Generat	319	35,395	OBG	1	Y	CA	7	0.61	WECC	N	
56039	N	H. Gonzales	149	233	NG	2	Y	CA	12	0.00	WECC	Y	
56041	N	Malburg	302	712	NG	2	Y	CA	159	0.00	WECC	Y	
56046	N	Magnolia Power Projec	560,501	1,418,905	NG	2	Y	CA	388	0.42	WECC	Y	
56051	N	THUMS	183,961	382,687	NG	2	Y	CA	57	0.76	WECC	N	
56075	N	High Winds LLC	0	449,162	WND	1	Y	CA	162	0.32	WECC	N	
56078	N	Walnut Energy Center	567,210	1,356,665	NG	2	Y	CA	301	0.52	WECC	Y	
56080	Y	SJ/SC WPCP	11,908	50,244	NG	1	Y	CA	14	0.40	WECC	N	
56090	N	Blacksand Generating	0	23,659	OG	1	Y	CA	8	0.35	WECC	N	
56093	N	Wyoming Wind Energy	0	348,565	WND	1	N	WY	144	0.28	WECC	N	
56097	N	New Mexico Wind Ene	0	461,043	WND	1	Y	NM	204	0.26	WECC	N	
56102	N	Currant Creek	1,380,292	3,606,157	NG	2	Y	UT	567	0.73	WECC	N	
56112	N	Mountain View III	0	75,702	WND	1	Y	CA	22	0.39	WECC	N	
56124	Y	SP Newsprint- Newber	87,322	469,924	WDS	1	Y	OR	132	0.41	WECC	N	
56125	N	Springville Hydroelectri	0	2,571	WAT	1	Y	CA	1	0.29	WECC	N	
56134	Y	Regional Wastewater (	469	9,470	OBG	1	Y	CA	5	0.23	WECC	N	
56135	N	Ripon Generation Stati	17,941	27,094	NG	2	Y	CA	121	0.03	WECC	Y	
56143	N	Riverside Energy Reso	19,967	39,592	NG	2	Y	CA	100	0.05	WECC	Y	
56144	N	Springs Generating Sta	1,499	2,238	NG	2	Y	CA	40	0.01	WECC	Y	
56163	N	KUCC	990,942	860,031	BIT	2	Y	UT	214	0.46	WECC	Y	
56167	N	Colton Landfill	0	3,616	LFG	1	Y	CA	1	0.32	WECC	N	
56170	N	Mid Valley Landfill	0	11,772	LFG	1	Y	CA	3	0.52	WECC	N	
56171	N	Milliken Landfill	0	9,290	LFG	1	Y	CA	2	0.48	WECC	N	
56173	N	Colorado Green Holdin	0	342,746	WND	1	N	CO	162	0.24	WECC	N	
56175	N	Phoenix Wind Power L	0	6,652	WND	1	Y	CA	#N/A	#N/A	WECC		#N/A
56177	N	Nebo Power Station	275,767	681,389	NG	2	Y	UT	140	0.56	WECC	Y	
56184	N	Red Bluff	5,801	12,353	NG	2	Y	CA	46	0.03	WECC	Y	
56185	N	Chowchilla II	7,986	17,431	NG	2	Y	CA	50	0.04	WECC	Y	
56192	Y	Wauna Mill	25,511	169,779	NG	1	Y	OR	36	0.54	WECC	N	
56193	Y	Medford Operation	0	1,018	WDS	1	Y	OR	9	0.01	WECC	N	
56195	N	Combine Hills I	0	117,081	WND	1	Y	OR	41	0.33	WECC	N	
56213	N	Patterson Pass	0	44,536	WND	1	Y	CA	22	0.23	WECC	N	
56214	N	Aeroturbine	0	7,057	WND	1	Y	CA	5	0.17	WECC	N	
56223	N	Alden Bailey Power Pla	398	549	NG	2	Y	OR	11	0.01	WECC	Y	
56227	N	Port Westward	652,038	1,722,070	NG	2	Y	OR	483	0.41	WECC	Y	
56228	N	Prescott Airport	0	6,701	SUN	1	Y	AZ	2	0.36	WECC	N	
56229	Y	Cogeneration 1	28,808	54,083	NG	1	Y	AZ	9	0.69	WECC	N	
56232	N	Miramar	4,117	7,837	NG	2	Y	CA	53	0.02	WECC	Y	
56237	N	Lake Side Power Plant	435,899	1,619,621	NG	2	Y	UT	568	0.33	WECC	Y	
56239	N	Kings River	69,022	133,319	NG	2	Y	CA	121	0.13	WECC	Y	
56253	N	Millcreek Power Gener	22,376	42,980	NG	2	Y	UT	40	0.12	WECC	Y	
56255	N	Hopkins Ridge Wind	0	402,465	WND	1	Y	WA	150	0.31	WECC	N	
56271	N	Diablo Wind LLC	0	64,756	WND	1	Y	CA	18	0.41	WECC	N	
56275	N	Helzel & Schwarzhoff 8	0	487	WND	1	Y	CA	2	0.02	WECC	N	
56276	N	ZCO	0	7,436	WND	1	Y	CA	2	0.53	WECC	N	
56284	N	Santa Maria EPG	276	29,333	OG	1	Y	CA	6	0.58	WECC	N	
56293	N	Caprock Wind Farm	0	305,560	WND	1	Y	NM	80	0.44	WECC	N	
56295	N	Kumeyaay Wind	0	148,009	WND	1	Y	CA	50	0.34	WECC	N	
56298	N	Roseville Energy Park	58,658	86,750	NG	2	Y	CA	164	0.06	WECC	Y	
56301	N	Wolverine Creek	0	148,933	WND	1	N	ID	65	0.26	WECC	N	
56302	N	Oasis Wind	0	208,083	WND	1	Y	CA	60	0.40	WECC	N	
56308	N	Fossil Gulch	0	23,334	WND	1	N	ID	11	0.25	WECC	N	
56312	Y	Shute Creek Facility	106,743	669,003	NG	1	N	WY	108	0.71	WECC	N	
56320	N	Spring Canyon	0	216,640	WND	1	N	CO	60	0.41	WECC	N	
56321	N	Richard Burdette Geotl	0	151,915	GEO	1	N	NV	30	0.58	WECC	N	
56322	N	Wild Horse	0	612,859	WND	1	Y	WA	229	0.31	WECC	N	
56336	N	Aragonne Wind LLC	0	239,761	WND	1	Y	NM	90	0.30	WECC	N	
56356	N	Clearwater Power Plan	895	1,350	NG	2	Y	CA	49	0.00	WECC	Y	
56359	N	Klondike Windpower II	0	223,339	WND	1	Y	OR	75	0.34	WECC	N	
56360	N	Leaning Juniper	0	290,452	WND	1	Y	OR	101	0.33	WECC	N	
56361	N	Big Horn Wind Project	0	550,365	WND	1	Y	WA	199	0.32	WECC	N	
56362	N	Shiloh I Wind Project	0	499,618	WND	1	Y	CA	150	0.38	WECC	N	
56371	N	Cedar Creek Wind	0	106,803	WND	1	N	CO	301	0.04	WECC	N	
56377	N	Judith Gap Wind Energ	0	471,279	WND	1	Y	MT	135	0.40	WECC	N	
56405	N	Nevada Solar One	373	41,592	SUN	1	N	NV	64	0.07	WECC	N	
56406	N	Sierra Pacific Burlingto	0	126,299	WDS	1	Y	WA	28	0.51	WECC	N	
56428	N	AMERESCO Santa Cru	0	20,277	LFG	1	Y	CA	3	0.77	WECC	N	
56445	N	Spindle Hill Energy Cer	300,010	506,487	NG	2	N	CO	394	0.15	WECC	Y	
56446	N	Buena Vista Energy LL	0	106,888	WND	1	Y	CA	38	0.32	WECC	N	
56460	N	Twin Buttes Wind Proje	0	128,688	WND	1	N	CO	75	0.20	WECC	N	
56461	N	Dry Creek Landfill Gas	0	12,026	LFG	1	Y	OR	3	0.43	WECC	N	
56466	N	Marengo Wind Plant	0	160,636	WND	1	Y	WA	140	0.13	WECC	N	
56468	N	Klondike Windpower III	0	89,171	WND	1	Y	OR	221	0.05	WECC	N	
56472	N	Grapeland	3,930	6,890	NG	2	Y	CA	50	0.02	WECC	Y	
56473	N	Mira Loma Substation	4,362	7,388	NG	2	Y	CA	50	0.02	WECC	Y	
56474	N	Barre Substation	5,705	9,165	NG	2	Y	CA	50	0.02	WECC	Y	
56475	N	Center Substation	4,589	8,141	NG	2	Y	CA	50	0.02	WECC	Y	
56481	N	SunE Alamosa	0	2,208	SUN	1	N	CO	8	0.03	WECC	N	
56485	N	Biglow Canyon Wind F	0	11,400	WND	1	Y	OR	125	0.01	WECC	N	
56487	N	White Creek Wind Farı	0	130,469	WND	1	Y	WA	204	0.07	WECC	N	
56496	Y	ConocoPhillips Billings	33	223	OG	1	Y	MT	2	0.02	WECC	N	
56498	N	Mora Drop Hydroelectr	0	3,557	WAT	1	N	ID	2	0.24	WECC	N	
56499	N	Tiber	0	38,901	WAT	1	Y	MT	8	0.59	WECC	N	
56500	N	Western 102 Power Pla	194,743	412,459	NG	2	N	NV	119	0.40	WECC	Y	
56508	N	MMC Midsun LLC	873	1,077	NG	2	Y	CA	#N/A	#N/A	WECC		#N/A
56509	Y	Tesoro SLC Cogenerat	54,837	40,986	NG	1	Y	UT	25	0.19	WECC	N	
56533	N	Bradley Gas Recovery	0	11,817	LFG	1	Y	CA	7	0.21	WECC	N	
56534	N	El Sobrante Gas Reco\	0	12,355	LFG	1	Y	CA	4	0.36	WECC	N	
56535	N	Simi Valley	0	9,895	LFG	1	Y	CA	3	0.43	WECC	N	
56540	N	Galena 2	0	36,889	GEO	1	N	NV	13	0.32	WECC	N	

56554	N	Salt Lake Energy Syste	0	25,076	LFG	1	Y	UT	3	0.89	WECC	N
56563	N	Peetz Table Wind Ener	0	220,714	WND	1	N	CO	200	0.13	WECC	N
56568	N	Nellis Solar	0	2,755	SUN	1	N	NV	14	0.02	WECC	N
56570	N	Caithness VG Wind	0	17,470	WND	1	Y	CA	7	0.27	WECC	N
56574	N	G M Corp Distr Ctr - Ra	0	1,135	SUN	1	Y	CA	1	0.13	WECC	N
56591	N	Horseshoe Bend Wind	0	24,481	WND	1	Y	MT	10	0.28	WECC	N
56613	N	Logan Wind Energy	0	132,286	WND	1	N	CO	201	0.08	WECC	N
56615	N	Rancho Penasquitos	0	17,517	WAT	1	Y	CA	5	0.43	WECC	N
56623	N	Elkhorn Valley Wind Fa	0	16,890	WND	1	Y	OR	101	0.02	WECC	N
56694	N	Russell D Smith	0	15,240	WAT	1	Y	WA	6	0.29	WECC	N
56695	N	Summer Falls Power P	0	380,483	WAT	1	Y	WA	92	0.47	WECC	N
56696	N	Eltopia Branch Canal 4	0	7,747	WAT	1	Y	WA	2	0.40	WECC	N
56697	N	Potholes East Canal 66	0	6,933	WAT	1	Y	WA	2	0.34	WECC	N
56698	N	Main Canal Headworks	0	100,204	WAT	1	Y	WA	27	0.43	WECC	N
56781	N	Evergreen BioPower LI	0	6,648	WDS	1	Y	OR	21	0.04	WECC	N

Carbon Leakage Provisions in US Climate Policy

November, 2009

Washington, DC

W R I

James Bradbury
Senior Associate
Climate and Energy Program
World Resources Institute
jbradbury@wri.org
http://www.wri.org

Overview

Policies for addressing carbon/ jobs leakage from energy-intensive and trade-exposed (EITE) industries

- Background on the issue
  - Political history on Capitol Hill
- Active Legislation
  - Waxman-Markey (HR 2454) and Kerry-Boxer (S1733)
  - Output-based rebates (OBR)
  - Border measures; International Reserve Allowances (IRA)

Carbon and Jobs Leakage: US Political History

- July **1997**, Byrd-Hagel Resolution passed the Senate (95-0)
- Early **2007**, AEP-IBEW proposed border measures; widely incorporated into House and Senate climate policy proposals
- June **2008**, letter from 10 Senate Democrats opposing Lieberman-Warner ("Gang of 10")
- September **2008**, Inslee-Doyle H.R. 7146
- June **2009**, Waxman Markey passed the House (219-212)

How Congress Proposes to Address Emissions and Jobs Leakage?

Two Integrated Provisions:

1) ***Allowance Rebate Program*:** Temporary rebates (guaranteed thru 2025 & phased out by 2035) for energy-intensive, trade-exposed industries on an output basis.
2) ***International Reserve Allowance Program*:** Border adjustment measures (border taxes) starting in 2020 on imports if international negotiations and actions are not sufficient and allowance rebates do not fully compensate affected industries.

OBR Issue #1: Why Allowance Allocation?

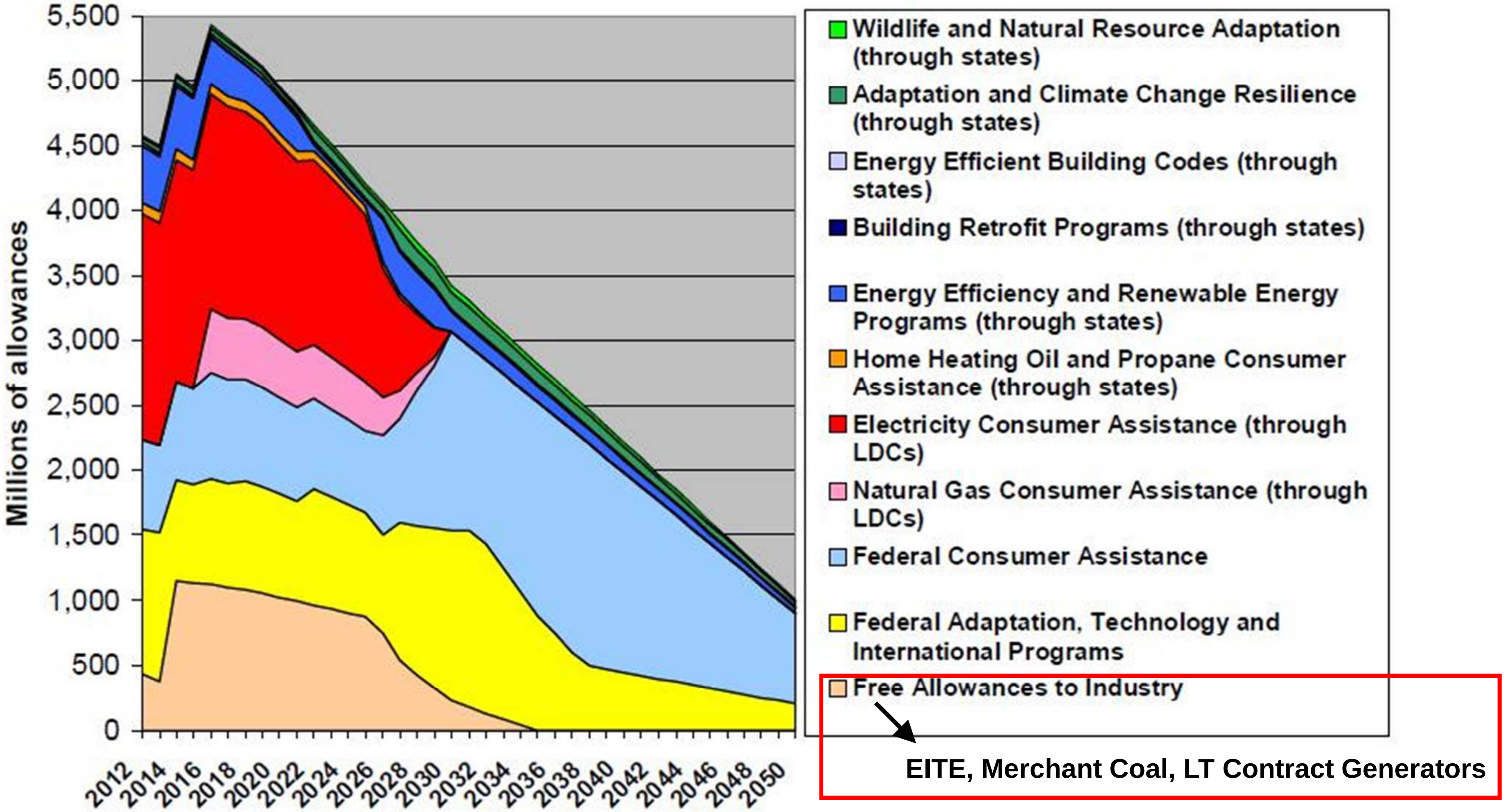
<u>Two distinct reasons - Two different policies</u>

1) Protect shareholders from stock losses
   - Studies find <15% of total allowance value

2) Prevent carbon leakage**
   - For EITE industries
     - Iron and Steel, Aluminum, Cement, etc.
   - Examples:
     - EU ETS phase III; phased out over time
     - Proposed Australia ETS takes similar route
     - Lieberman-Warner; phased out by 2031

Allowances are directed to states and LDCs for clean technology, adaptation, and energy consumer assistance.

ACESA Allowance Distribution, 2012-2050



As assistance through LDCs phases out, additional federal consumer assistance programs phase in.

OBR Issue #2: Eligibility

- Which industrial sectors should be eligible for compensation?
  - Lieberman-Warner (Boxer substitute):
    - *Specified* broad sectors:
      - “Iron, steel, pulp, paper, cement, rubber, chemicals, glass, ceramics, SF_6 and aluminum and other non-ferrous metals.”
  - Inslee-Doyle (HR 1759)
    - Narrowly target recipients based on need, using objective criteria
    - Goals: minimize over allocation; preserve policy integrity

EITE - Eligibility for rebates

EPA Administrator determines eligibility on the basis of whether or not a NAICS code sector (6-digit level) meet certain key criteria:

1) Energy intensity (or Carbon Intensity) > 5 percent

AND

Trade Intensity > 15 percent

OR

3) Energy intensity (or carbon intensity) > 20 percent

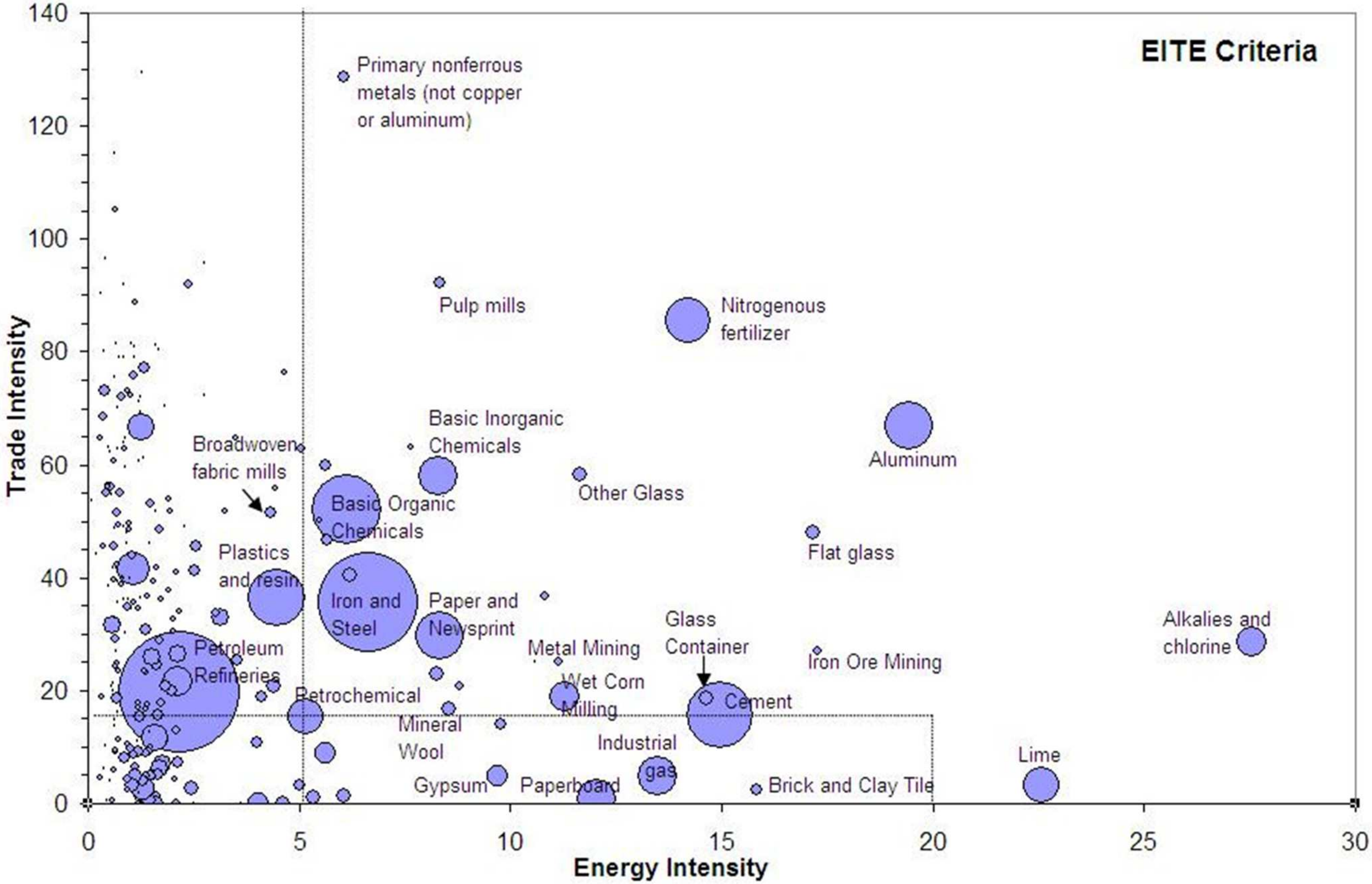
OR

4) Groups of facilities can make an “individual showing” that their subsector is eligible, based on the above criteria

Energy-Intensity = (Energy & Fuel Costs + Generation) / Value of Shipments

Trade-Intensity = (Imports+Exports) / (Value of Shipments+Imports)

OBR Eligibility; Sectors by NAICS Code (6-digit level)



Energy-Intensity = (Energy & Fuel Costs + Generation) / Value of Shipments

Trade-Intensity = (Imports+Exports) / (Value of Shipments+Imports)

OBR Issue #3: Allocation Methodology

- On <u>what basis</u> should allowances be allocated to industry?
  - *Past Emissions*
    - Rewards least efficient plants
    - Creates incentive to collect allowances while relocating production overseas
      - Does not effectively address leakage
  - *Output of Production*
    - Rewards most efficient plants
    - Effectively addresses leakage
    - Implementation is complex and political
    - Reduces downstream price signal
      - Hampers demand reduction (and possibly innovation)

W-M: OBR for Direct Carbon Costs

For onsite combustion or process emissions

$$\text{Facility Output (production)} \times \frac{\text{Sector average emissions}}{\text{Unit of Output}} = \text{Allowance Rebate}$$

Notes:

- Accommodates new market entrants
- Creates incentive to:
  - Invest in efficiency improvements
  - Maintain domestic production

W-M: OBR for Indirect Carbon Costs

For upstream emissions/ electricity use

Facility Output (production) X Sector avg. energy intensity of production X Emissions intensity of local utility = Allowance Rebate

$$\left[\ \text{Facility output (production)} \times \frac{\text{sector avg. kWh electricity use}}{\text{Unit of output}} \times \frac{\text{Utility ton CO2}}{\text{kWh elec. sold}} = \text{Allowance Rebate}\ \right]$$

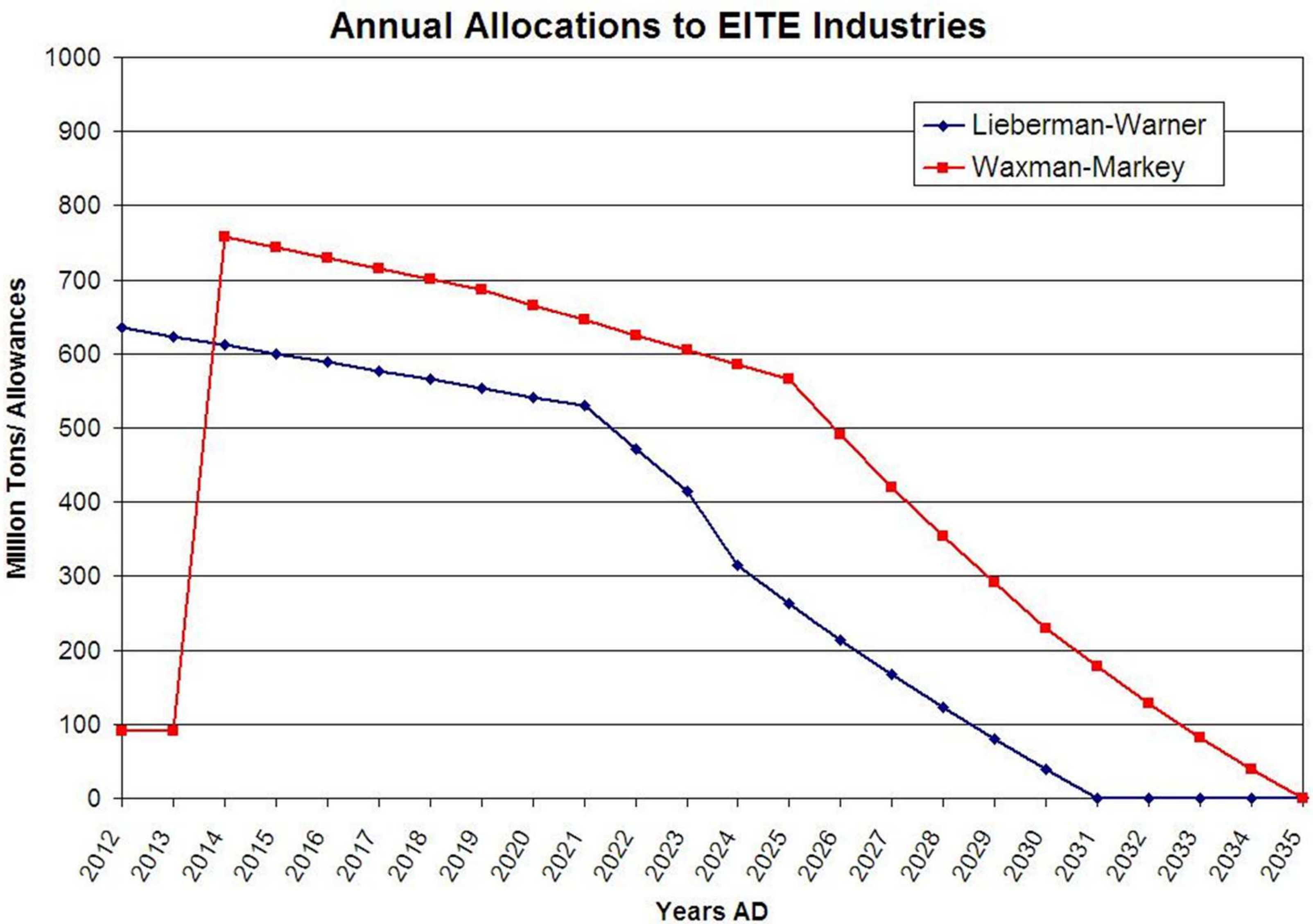
Note: To account for allowance distribution to utilities, OBR is reduced by value of free allowances passed on by utilities

Issue #4: Phase down

- At what point should allowance allocation be phased down or replaced with an alternative policy mechanism?
  - When the carbon price disparity is reduced or eliminated
  - *Best addressed through international trade and climate agreements*

  - Waxman-Markey (ACESA)
    - Allowance pool reduces with the cap
    - After 2025, allowances phase-down for all sectors, unless exposure to leakage persists

WRI



Annual Allocations to EITE Industries
Million Tons/ Allowances
1000
900
800
700
600
500
400
300
200
100
0
Lieberman-Warner
Waxman-Markey
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
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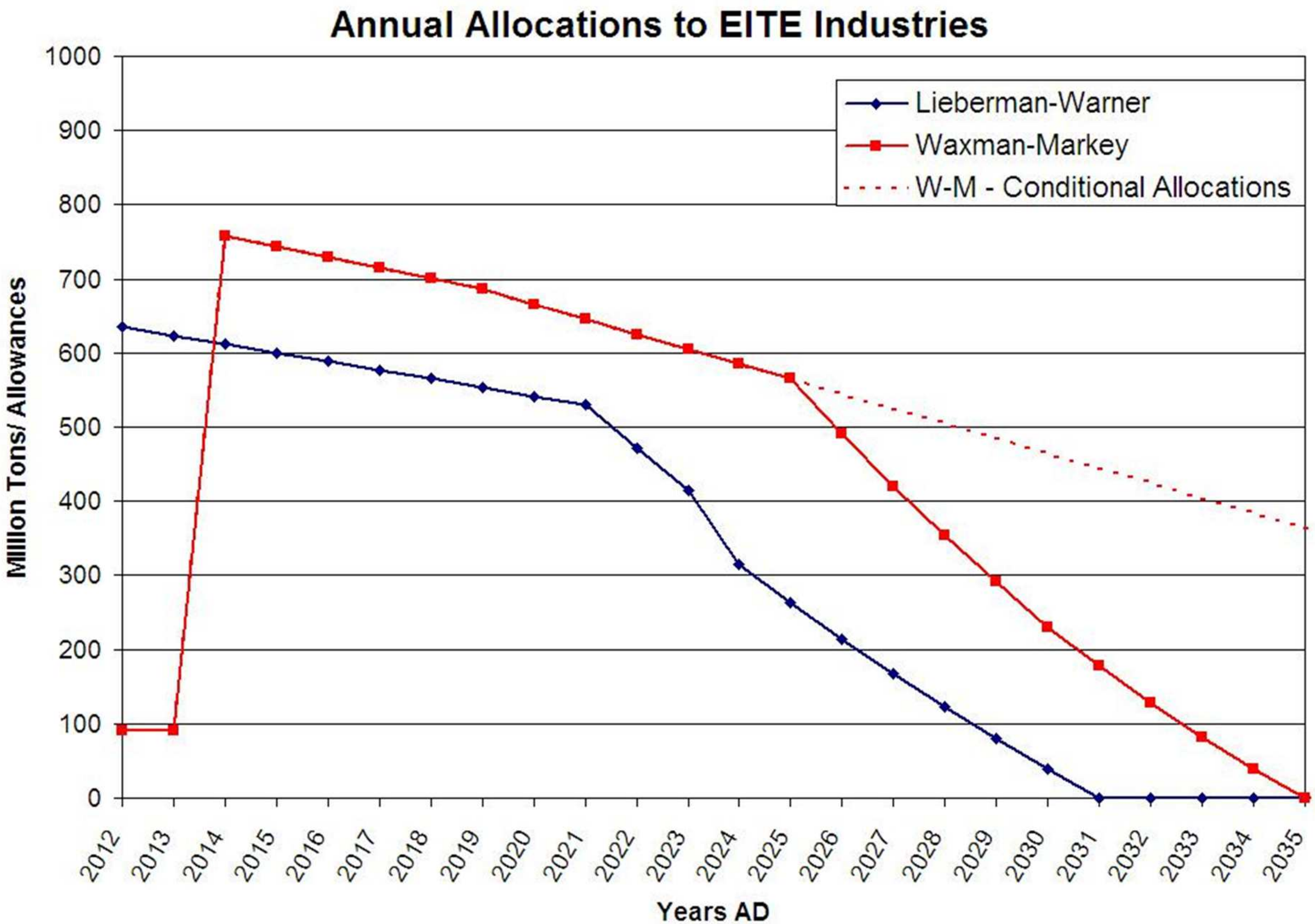
2033
2034
2035
Years AD


Annual Allocations to EITE Industries
Lieberman-Warner
Waxman-Markey
W-M - Conditional Allocations
Million Tons/ Allowances
Years AD
1000
900
800
700
600
500
400
300
200
100
0
2012
2013
2014
2015
2016
2017
2018
2019
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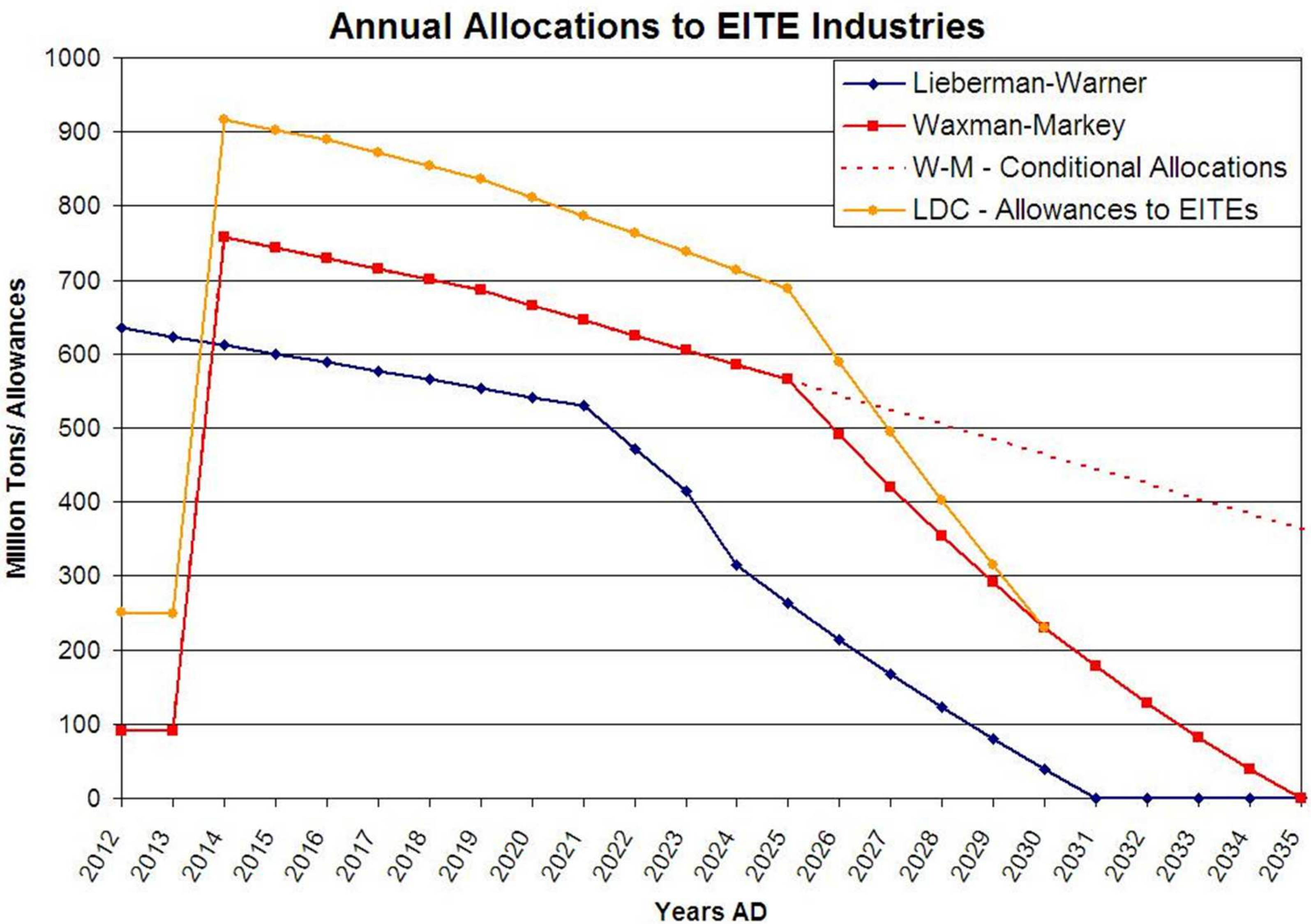
Annual Allocations to EITE Industries
1000
900
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Million Tons/ Allowances
2012
2013
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2016
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2031
2032
2033
2034
2035
Years AD
Lieberman-Warner
Waxman-Markey
W-M - Conditional Allocations
LDC - Allowances to EITEs

International Reserve Allowance (IRA) Program (with off-ramps)

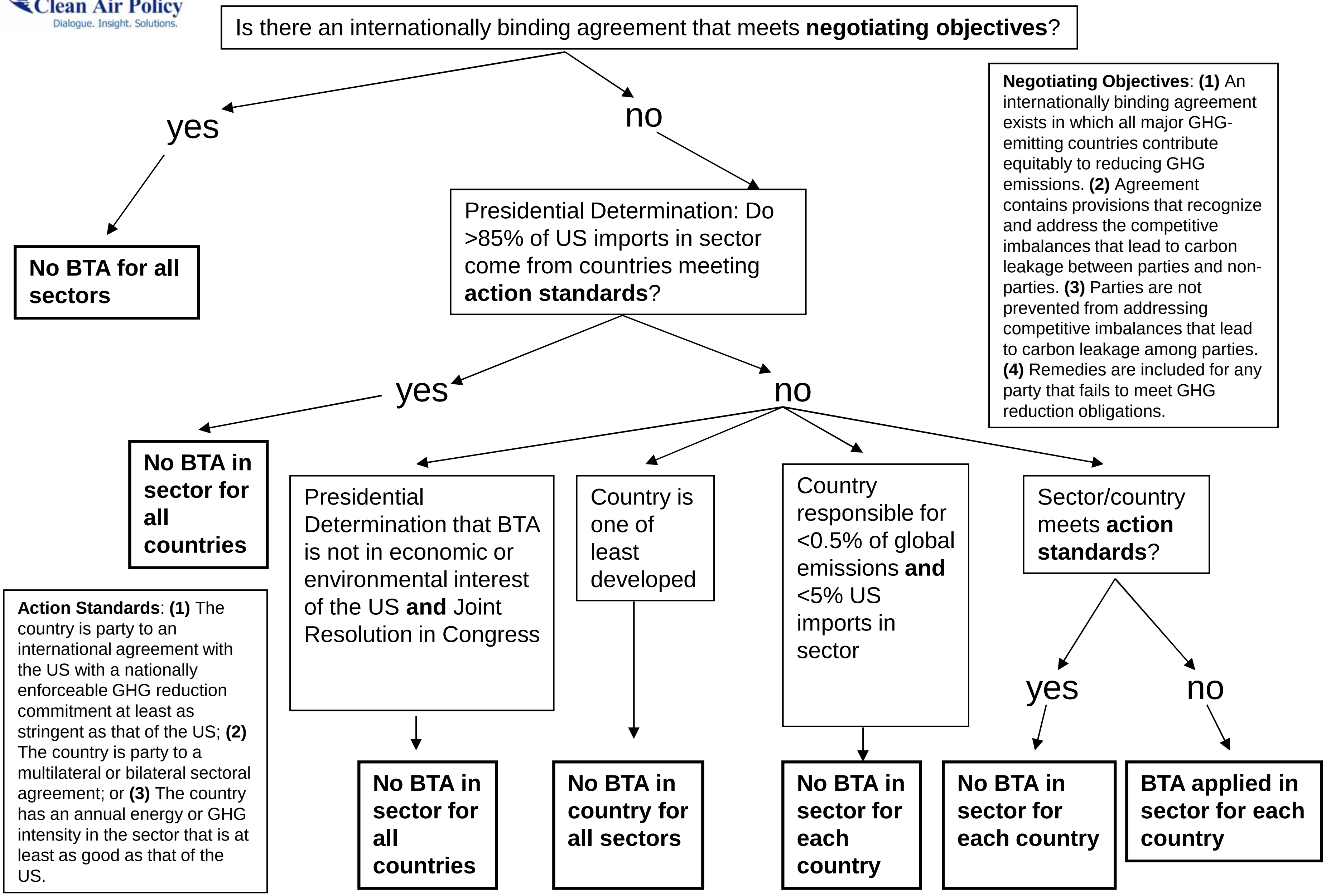
- A required purchase of a IRA credits would apply to **imports of primary products** from EITE industries starting in 2020, unless an international agreement is in place that meets the "*negotiating objectives*".
  - May also apply to imports of "covered goods"
- If negotiating objectives are not met, then imports of products from some sectors and/or countries would be subject to IRA, unless certain conditions are met:
  - Ex: sector is exempt if 85% of US imports within that sector are from countries that have met certain *"Action Standards"*

    OR
  - A country has met the Action Standards, with respect to a sector
  - A country is one of the least developed
  - A country is responsible for <0.5% of global emissions and <5% of US imports for a sector

When are Border Tax Adjustments Applied to Imports of Primary Products?

American Clean Energy and Security Act as passed in US House of Representatives

Center for Clean Air Policy
Dialogue. Insight. Solutions.



For Example:
Border Measures *on Canada?*

- If an internationally binding post-Kyoto agreement is not reached: Like all countries, Canada would have to meet our GHG standards:
  - party to an international agreement with the US with a nationally enforceable GHG reduction commitment at least as stringent as the US *(exempts country)*
  - party to a multilateral or bilateral sectoral agreement with the US* *(exempts sector)*; **or**
  - have an annual energy or GHG intensity, in each sector, that is at least as good as the US *(exempts sector)*

** A NAFTA-like agreement for EITEs?*

Take Away Messages

- Carbon Leakage is a key policy issue of environmental, economic and political significance
- The leakage problem appears to be real, but manageable
- International approach is best option; interim measures needed
  - Best if these are similar (among developed nations)
- *Targeted* allowance allocation provides effective protection for domestic industries
- Border measures may help, but they have substantial limitations

Thank you!

James Bradbury

Climate and Energy Program

World Resources Institute

jbradbury@wri.org

http://www.wri.org

W R I

EU ETS and competitiveness: dealing with carbon leakage

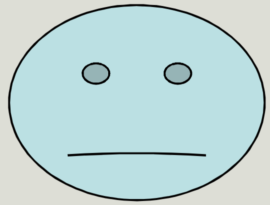
Webinar about Addressing Leakage & Competitiveness in the EU and US

Thursday 12 November 2009

I.Juergens
J. Barreiro-Hurle – J. Bemelmans –
M. Przeor – A. Vasa

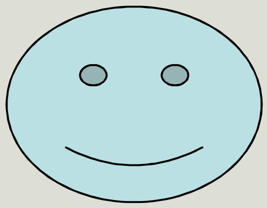
European Commission
Enterprise and Industry

Border Measures



- Considerable administrative cost
- Ensure conformity with WTO and UNFCCC principles
- Avoid retaliation
- Negative effect on Copenhagen negotiations
- Welfare effects?

Co-operative sectoral approaches



- Focus on the development, application and diffusion, including transfer of technologies, best practices and processes that control, reduce or prevent GHG emissions;
- Foster initiatives in R&D, capacity building and technology cooperation (covering) all phases of the technology cycle;
- Include measures to overcome barriers to development, transfer and deployment of technology;

3 Studies

1. “Proof of concept”: assess merits of SA as a tool to engage business to act
2. “Governance” – stakeholders involvement
3. “Efforts and costs to industry in different sectors and world regions”

European Commission’s carbon leakage assessment: Background

- ETS Directive (Dec. 2008): Sectors at risk of carbon leakage will receive ***100% free allocations based on (AMBITIOUS!!!) benchmarks***.

- EC undertook comprehensive assessment of 258 NACE 4-digit sectors covering Mining and Manufacturing activities and specific subsectors where needed.

How have industrial sectors been assessed ?

- **Quantitative evaluation of indicators** (*Article 10a Paragraphs 14-15-16):*
  - Intensity of trade with third countries.
  - Direct and indirect additional costs induced by the implementation of the directive as proportion of gross value added.

- **Qualitative assessment** (*Article 10a Paragraph 17*) **taking into account :**
  - Extent to which it is possible to reduce emission levels
  - Current and projected market characteristics
  - Profit margins

When is a sector deemed at risk ?

- Quantitative assessment
  - Trade Intensity over 30% OR
  - CO_2 cost over 30% of GVA OR
  - Trade Intensity over 10% AND CO_2 cost over 5% of GVA
- Qualitative assessment at NACE 4-digit level
  - No threshold, expert judgement based on economic and technological assessment

What was the reference period ?

- Trade: 2005-2007 / 2004-2006 / 2006-2007

	2004	2005	2006	2007
Turnover	SBS COMEXT	SBS COMEXT	SBS COMEXT	COMEXT
Exports	COMEXT	COMEXT	COMEXT	COMEXT
Imports	COMEXT	COMEXT	COMEXT	COMEXT

- Cost increase: 2005-2006

	2004	2005	2006	2007
GVA	SBS	SBS	SBS	
Direct CO2	MS	CITL MS	CITL MS	CITL MS
Indirect CO2	MS	MS	MS	MS

How has Trade Intensity been measured

- Directive defines trade intensity as:

  "*ratio between the total value of exports and imports to third countries and the total market size for the community (annual turnover plus total imports from third countries)*"

- Data sources: EUROSTAT COMEXT and structural business statistics (SBS) databases

- Key issue:
  - Import and export data needed to be compatible with turnover data
    → annual production sold (not straight forward – different data domains!)
    → Fallback: turnover from SBS

How have CO2 costs been measured?

- Direct emissions:
  - process emissions
  - combustion installation related emissions
- Indirect emissions: cost increase due to CO2 cost pass-through by power sector
- … compared to gross value added at factor cost (GVA)

Direct Emissions in CITL
(Community Independent transaction log)

- CO2 emissions for each current ETS installation
- Matching of installations with NACE sector (AMADEUS, Dan&Bradstreet, Kompass; MS; Industry; …)
- Emissions and GVA of an installation have been allocated to the same NACE sector
- Results of the matching process >95% complete.
  - Emissions not matched do not impact on the position of any given sector relative to thresholds

- Key issues with CITL:
  - No emission data for new (“2013”) ETS sectors and gases
  - Sectors with a substantial number of small installations that are not included in the scope of the EU-ETS
  - Sectors with "opt-outs" or temporary exclusions.

Data Sources other than CITL

- Process emissions data from the European Community' s greenhouse gas inventory.
  - matching of activities with NACE sectors

- Direct CO2 emissions, fuel consumption, (limited) process emissions data by Member States

- Issue with indirect cost: Data on electricity not available

- Response: Electricity consumption reported by MS

Indirect CO_2 Cost

- Primary data source: MS data on net electricity consumption in volume (MWh)

- Calculation of corresponding emissions: Average CO2 content of the EU-27 electricity mix (0.465 CO2 tons per MWh) used to estimate cost increase due to purchasing of allowances by power sector.

- Not all MS reported data but ratios calculated for reporting MS assumed to be representative of EU27 as a whole

- Key issues with indirect emissions:
  - Relevant emission factor
  - NET electricity consumption: auto-generation & double counting
  - Data coverage & representativity

Gross value added (GVA)

- Data sources: EUROSTAT SBS database
- Key issues:
  - Ensure consistency with emissions data
  - Not readily available at company level (for assessment at higher disaggregation)
- Response:
  - Ad-hoc aggregates of GVA estimates < EU-27
  - Business consultants reviewing company data under confidentiality agreements

Quantitative assessment results

- Out of 258 sectors, 146 meet the criteria at NACE 4-digit level
  - Most (117) sectors show a high trade intensity (>30%)
  - Others (27) have both significant CO_2 cost and trade intensity
  - Two sectors qualify through significant CO_2 cost alone (>30%)

Sectors quantitatively assessed at a higher level of disaggregation

- **WHY:** Assessment at NACE 4-digit can be missing specific products or groups of products which would meet the thresholds for the quantitative criteria laid down in the Directive.

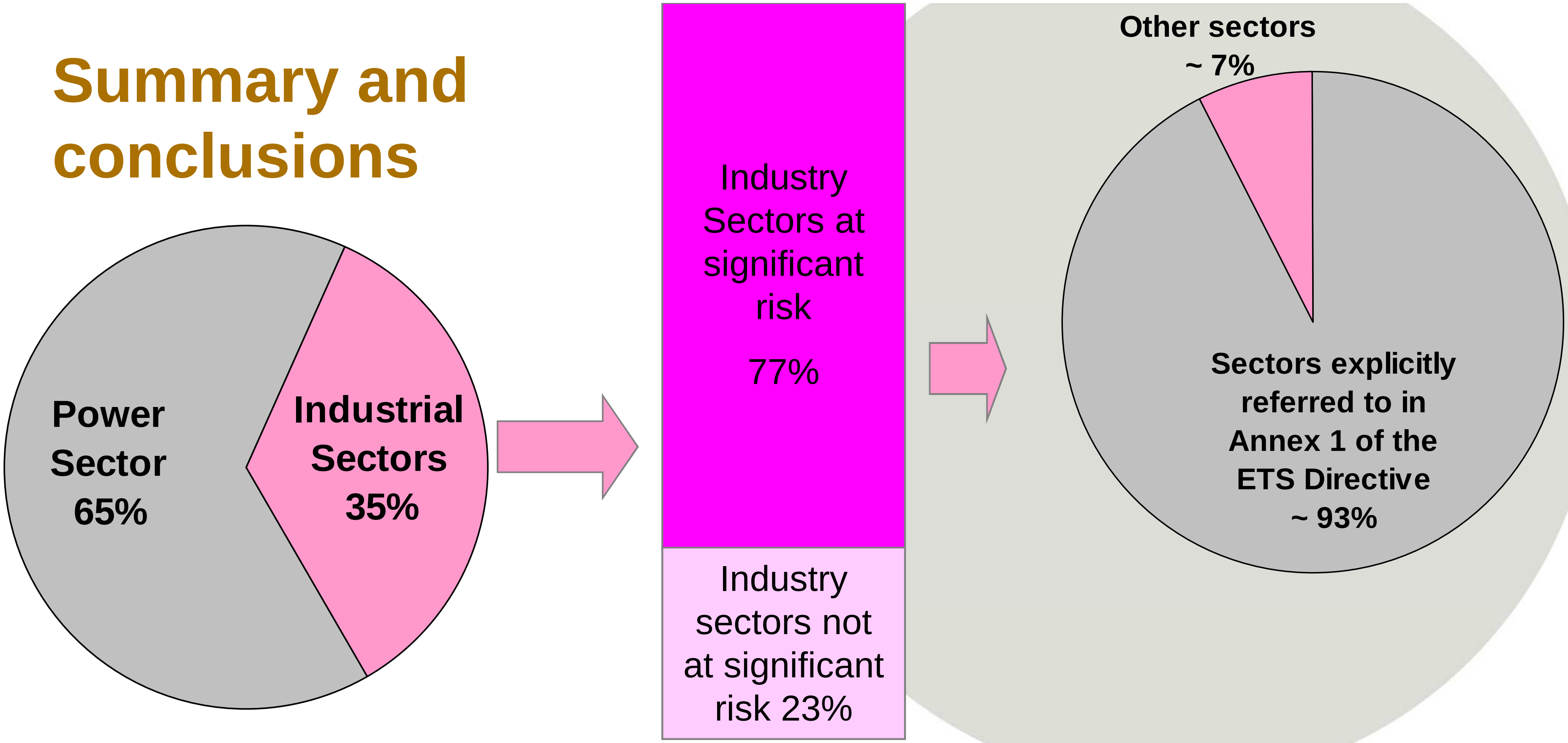
- **HOW:** Same Trade Intensity and CO_2 Cost indicators and thresholds as for NACE 4-digit sectors.

- 9 product groups deemed at risk of carbon leakage, including: Reinforced Glass Fibres; Hydrogen, Nitrogen and Oxygen

Qualitative assessment results

- **What triggered a qualitative assessment**
  - sectors close to the thresholds,
  - absence of data for one of the indicators (ex.: casting sectors → no trade data),
  - doubts about accuracy or coverage of quantitative data (Ex.: discrepancy GVA vs. emissions)
  - integrated production
- **Selective, clear EXCEPTION to the rule:** only 7 out of 94 sectors that did not meet the thresholds were assessed.
- 5 sectors deemed at risk of carbon leakage, including plastics in primary forms and casting of light metals

Summary and conclusions



- A majority of emissions in ETS will be auctioned
- Free allowances focused on sectors explicitly referred to in Annex 1
- The environmental objectives not compromised at all, as cap is not influenced; only distributional effects
- Emission reductions are autonomous and non-conditional, unlike under border measures!

Thank you!

EU ETS and competitiveness: dealing with carbon leakage

I.Juergens
J. Barreiro-Hurle – J. Bemelmans – M. Przeor – A. Vasa

European Commission
Enterprise and Industry

Western Climate Initiative

Market Oversight White Paper

November 18, 2009

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1. Introduction

The Western Climate Initiative (WCI) is a cooperative effort of seven U.S. states and four Canadian provinces that are collaborating to identify, evaluate, and implement policies to reduce greenhouse gas (GHG) emissions, including the design and implementation of a regional cap-and-trade program. The WCI began in February 2007 with the governors of Arizona, California, New Mexico, Oregon, and Washington, who have since been joined by the premiers of British Columbia, Manitoba, Ontario, and Quebec, and the governors of Montana and Utah. Participation in the WCI reflects each Partner jurisdiction's strong commitment to identifying, evaluating, and implementing collective and cooperative actions to address climate change.

In September 2008, the Partner jurisdictions released the final "Design Recommendations for the WCI Regional Cap-and-Trade Program."[1] The first compliance period for the cap-and-trade program will begin January 1, 2012, covering GHG emissions from electricity generation (including emissions associated with imported electricity), combustion at large industrial and commercial facilities, and industrial process emissions for which adequate measurement methods exist. Starting in 2015, the program's coverage expands to include transportation fuels in addition to residential, commercial, and small industrial combustion. Thus, by 2015 the cap-and-trade program will cover almost 90% of GHG emissions in the Partner jurisdictions.

In February 2009, the Partner jurisdictions released the WCI 2009 – 2010 Work Plan, describing the approach to implementing the Design Recommendations.[2] The WCI is working through six committees: Offsets, Reporting, Electricity, Complementary Policies, Cap Setting and Allowance Distribution, and Markets. The Work Plan describes the tasks and deliverables for each committee. The purpose of one of the Markets Committee's tasks, "market oversight," is to recommend measures to ensure that the allowance and offset credit trading market is organized properly to operate reliably and prevent or minimize manipulation. This task was included in the work plan based on the consensus among WCI Partner jurisdictions on the need to provide effective oversight to assure an efficient and transparent carbon market.

This white paper reports on the information collected and reviewed by the Markets Committee on market oversight approaches and issues. The information was obtained through several means, including the following.

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[1] The Design Recommendations and accompanying Background Report can be found at http://westernclimateinitiative.org/the-wci-cap-and-trade-program/design-recommendations.
[2] The 2009 – 2010 Work Plan can be found at http://westernclimateinitiative.org/component/remository/general/workplans/2009-2010-WCI-Work-Plan/.

- The Markets Committee held a stakeholder workshop on market oversight in Seattle, Washington in April 2009. The Committee presented a draft set of principles of market oversight, and a list of questions for discussion with those who attended in person or online.[3] Stakeholders were invited to submit written comments.[4] Stakeholders' responses guided the Committee's consideration of issues and the Committee revised the principles of market oversight as set forth below. The principles guided the Committee's research, analysis, and deliberation, and will continue to do so as the Committee progresses towards draft and final recommendations.

- The Markets Committee held a webinar with the market monitor used by the Regional Greenhouse Gas Initiative (RGGI).

- The Markets Committee consulted with U.S., Canadian, state, and provincial regulatory authorities, and received input from European market regulators, potential market participants, trade associations, market infrastructure providers, and other stakeholders.

- The Markets Committee conducted a literature review with the assistance of our task advisor at the Nicholas Institute at Duke University.

Through this process, the Committee acquired substantial knowledge about the types of regulation in place in existing financial markets, the roles of regulators and exchanges, and the scope of existing carbon-related financial products. This information is presented in this paper as follows:

- Section 2 presents the revised principles being used to guide the development of the market oversight recommendations.

- Section 3 summarizes background information, including an overview of cap-and-trade, market architecture and oversight, and existing market models.

- Section 4 describes oversight of existing markets in the U.S., Canada, and Europe.

- Section 5 identifies recent U.S. federal proposals related to carbon market oversight.

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[3] The principles and questions can be found at http://westernclimateinitiative.org/component/remository/func-startdown/25/. Market oversight was one of three tasks for which the Committee developed draft principles for comment; the others were auction design and compliance verification and enforcement.
[4] Stakeholder comments were submitted to the WCI website, and can be found at http://westernclimateinitiative.org/documents/public-comments/document/2.

The paper concludes with a brief list of key decisions that are under consideration.

2. Principles

These principles serve as guidelines for developing oversight of the allowance, offset credit, and associated derivatives trading markets to assure maximum environmental and economic benefit to the public.

- **Fairness:** All market participants, especially covered entities, have fair and equal access to the market.

- **Efficiency:** The market is designed to operate efficiently so that greenhouse gas (GHG) emission reductions can be achieved at the least cost. An efficient market means that allowance and offset credit prices reflect supply and demand, and accurately reveal the value of allowances and offset credits.

- **Effective Oversight:** The design and oversight of the market is effective in preventing or minimizing fraud, manipulation, and speculative excess.

- **Transparency and the Reporting and Disclosure of Relevant Information:** Transparency in the design and the operation of the allowance and offset credit market builds and retains public confidence.

    - Reporting of relevant information to regulatory authorities and public disclosure of information has important benefits. It enables regulatory authorities to conduct effective oversight and ensure compliance. It also helps to ensure market efficiency, effective oversight, and compliance and enforcement. The release of information can change the decisions of market participants, which impacts the prices of allowances and offset credits. Timely, accurate, coordinated and consistent release of market-relevant information allows all market participants to have equal access to public information.
    - The reporting and disclosure requirements for compliance verification and enforcement balance these benefits against the need for entities to protect certain sensitive information. The potential to disclose certain information that could be used to manipulate the market is also considered. This balancing is consistent with applicable law relating to the disclosure of information.

- **Administrative Simplicity and Cost:** Proposed rules are designed to be understood and enable entities to have a clear compliance path. Administrative costs and transaction costs are minimized for all parties, consistent with the need to provide effective oversight.

- **Accountability:** All entities involved in the allowance and offset credit market, as either regulators or market participants, are accountable for their actions. The responsibility, authority, and capacity to conduct the necessary oversight and take appropriate action are fully defined for all agencies charged with compliance verification and enforcement.

- **Conflicts of Interest:** Conflicts of interest between market participants, monitors, and regulators are prevented.

The principles were revised as a result of further review after the Markets Committee stakeholder workshop and submitted comments. First, "maximum environmental and economic benefit for the public" was explicitly confirmed as the purpose of the principles. A sentence was added to the principle of "Transparency and the Reporting and Disclosure of Relevant Information" to acknowledge that the release of information can change the decisions of market participants. Timely and accurate release of market-relevant information has been more explicitly noted. These additions are in line with the Markets Committee's intent and highlight concepts that stakeholders were interested in seeing expressed explicitly.

3. Background

In 2008, the value of global carbon market was estimated at €92.4 billion. Though trade volumes were expected to continue growing, anticipated lower prices led to a forecast of €62.6 billion in 2009[5,6]. The volume of transactions is growing each year and further growth is expected as cap-and-trade programs are likely to be launched in North America and elsewhere. Numerous financial products are now available to the firms that face a regulatory obligation under the European Union Emissions Trading Scheme (EU ETS) or the Regional Greenhouse Gas Initiative (RGGI) as well as to investors and intermediaries that participate in the trading of carbon allowance-based financial products. It is likely that the WCI regional cap-and-trade program will generate a substantial volume of transactions and the creation of a number of new financial products based on allowances issued by WCI Partner jurisdictions. The recent financial crisis and market turmoil has further highlighted the potential for disruptions to markets and need to properly address market architecture and oversight to ensure that the carbon market works efficiently and effectively in support of the program's environmental and economic goals.

This background section provides an overview of the financial markets that may develop along with the establishment of a cap-and-trade program. It will help explain the role of the different

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[5] "Carbon Market Analyst: Outlook for 2009," PointCarbon Research, February 19, 2009.
[6] At October 8, 2009 exchange rates, these values would be $U.S. 136.7 billion and $CAN 144.2 billion in 2008, and $U.S. 92.6 billion and $CAN 97.7 billion in 2009.

participants and institutions in the carbon market and how they might influence the future WCI market. The outline of the section is as follows: Section 3.1 summarizes the foundations of a cap-and-trade program. Section 3.2 defines and describes market architecture and oversight. Section 3.3 outlines oversight of existing financial markets.

3.1 Overview of a cap-and-trade program

In a GHG cap-and-trade program, an emitter must turn in one "allowance" for every metric ton of carbon dioxide equivalent[7] (CO_2e) it emits. An allowance may be a limited authorization to emit GHGs. The regulator(s) implementing the cap-and-trade program issues a limited number of allowances, thus creating a "cap" on emissions. The number of issued allowances can decline over time, resulting in further emissions reductions toward a predetermined goal.

Market participants can buy and sell (i.e., trade) allowances, and the allowances commonly are fungible across the emitters and jurisdictions participating in a cap-and-trade program. The market price for allowances is derived from supply and demand. Supply is determined through establishment of the cap and subsequent issuance of allowances. Allowance demand depends on energy demand and the cost of technologies and strategies that reduce emissions. Emitters will choose whether and how much to invest in allowances, offsets, or reductions of their own emissions based in part on current and projected prices of allowances, offsets, and emission abatement costs. In a well-functioning market, the allowance price will adjust in response to clearly communicated and accurate information aggregated from the broad market. Accurate and timely information about allowance price, trade volume, and current bids and offers helps market participants and observers minimize transaction costs and uncertainty about market activity.

Existing GHG emissions cap-and-trade programs include the EU ETS and the Regional Greenhouse Gas Initiative (RGGI), a collaboration of 10 U.S. states.

3.2 Market architecture and oversight

"Market architecture," for WCI purposes, refers to: 1) the market participants (those who buy, sell, and hold allowances) and institutions that make up a market; and 2) the systems, infrastructure, processes, and tools used by the participants and institutions. "Market oversight" refers to a broad range of activities that ensures allowance and offset credit markets serve the environmental and economic goals of a cap-and-trade program. Oversight includes choices regarding the establishment of a market, the rules governing market participants, and

---

[7] Some GHGs have a greater climate effect than carbon dioxide (CO_2); for example, methane is about 25 times as potent (Intergovernmental Panel on Climate Change Fourth Assessment Report, 2007, Working Group I Report, p. 212). To treat emissions uniformly, GHGs are referenced to their carbon dioxide equivalent, CO_2e.

monitoring of market activity. The WCI Partner jurisdictions intend to consider these choices in accordance with the principles in section 2 of this white paper.

The central purpose of a market mechanism is to aggregate and transmit price information. Market participants require complete, accurate, and unambiguous disclosure of price information on a regular and timely basis to make informed decisions about investments and transactions. In the case of a cap-and-trade program, emitters will use the current and expected price of allowances to assess whether to spend money to reduce emissions or to purchase additional allowances. The carbon market is used to determine the price of allowances, reflecting underlying supply and demand.

A lack of information or inaccurate information in the marketplace can lead to prices that do not accurately reflect the real marginal cost of reducing emissions. Such misinformation would distort emitters' investment decisions, which could raise the overall costs to regulated entities and the public. Market transparency and effective oversight helps ensure an efficient market with prices that more accurately reflect the marginal cost of emissions abatement, as well as preventing distortion of the price through, for example, attempts to manipulate the market.

Given the importance of information in determining prices in markets, market oversight typically includes requirements for disclosure of certain market-relevant information in a systematic and transparent manner. For example, in a carbon market, the accurate and timely disclosure of emissions data can be of particular importance. In addition to the disclosure of information publicly, regulators will want to collect information needed to analyze the market and to ensure that market participants are following the rules and laws that govern a market. This commonly includes collecting data regarding:

- the types of instruments being traded;
- bid, offer, and settlement prices;
- trade volumes and net changes for each contract type;
- the location of trades;
- the number and value of open positions held by market participants;
- price movements;
- changes in price relationships among futures in different delivery months, on different trading facilities (e.g., exchanges), and between futures and the cash markets;
- trade liquidity and severity of price changes; and
- market news and rumors.

Regulators can require that information be provided by market participants to support this analysis. This information can be supplemented with publically or commercially available information. While transparency is important for efficient market operation, some information may reveal competitive positions that would do more to assist manipulation than prevent it. Consequently, care must be exercised in determining which information will be disclosed publicly. Information reporting and disclosure will be at the heart of many decisions to be made on market oversight.

Regulatory authorities may allow one or more exchanges or other commercial marketplaces to offer trading services. In that circumstance, the regulatory authorities may gather and distribute information so that market participants can have good information on which to base their trading decisions. The regulatory authorities also monitor the potential risks of these marketplaces that may affect the securities marketplace operations. Prior to operation and then typically on an ongoing basis, the regulatory authorities assess a marketplace against core operating criteria and evaluate risk to the public and market participants, market integrity, and market efficiency. Examples of core operating criteria include public interest mandates, good corporate governance requirements, conflict management mechanisms, rule-making, -monitoring and -enforcement, clearance and settlement, fair access and fees, and information sharing and cooperation with regulators. Market regulation tools may also include software systems that allow surveillance to determine breaches in market integrity rules, identify suspicious trading patterns, and accurately identify who is trading and when.

3.3 Existing markets as models

There are a variety of market structures that can serve as useful models for the WCI Partner jurisdictions as they create a regional cap-and-trade system. Given the newness of allowance and offset credit markets, the committee examined longstanding markets in securities and commodities for examples of what a fully developed carbon market might look like. For the purposes of this paper only, we use "allowances" to mean both allowances and offset credits, and collectively refer to trading of allowances, offset credits, and their derivatives as a "carbon market."

Securities include stocks and bonds, and represent part ownership of a corporation or debt. Like allowances, they are issued in limited numbers and have serial numbers that allow tracking of ownership of a particular unit.

Commodities are goods that are interchangeable with other goods of the same type.[8] For example, as long as a bushel of grain meets certain standards, the purchaser is indifferent to its source. In contrast to fixed issues of securities, commodity supplies may fluctuate over time depending on economic conditions and production factors—for example, grain supplies depend

[8] "Commodity," Investopedia, retrieved August 3, 2009. http://www.investopedia.com/terms/c/commodity.asp

on the weather in producing regions. Because most are not financial instruments but goods, commodities usually have non-negligible storage costs. “Energy commodities” refers to commodities like oil and natural gas.

There are significant differences between allowances and traditional securities and commodities. First, because allowances may be limited authorizations to emit GHGs, their possession may not imply ownership of property. Second, covered entities must submit allowances for compliance with regulations on GHG emissions.

Participants trading allowances in existing carbon markets have generally treated them as commodities. Many firms that are covered in existing cap-and-trade programs require energy commodities as inputs. As with commodities, allowance prices reflect global economic conditions and demand more than the decisions made at an individual corporation, which affect the value of that corporation’s stock.

Despite differences with commodities and securities markets, there are important lessons from these that can guide the development of the WCI’s carbon market. By examining the regulations that have proven to be effective, as well as the types of market problems that occurred in the past and the proposed solutions, the WCI Partners are identifying best practices in market regulation that can ensure a transparent, efficient carbon market.

3.3.1 Types of markets

If the market for allowances were to resemble those for securities and commodities, it would have several interrelated facets:

- The distribution of allowances by WCI Partner jurisdictions, such as through auctions, would comprise the primary market.
- Trading of allowances after the initial distribution would comprise the secondary market.
- A part of the secondary market important and distinct enough to be treated separately in this paper is the derivatives market. Derivatives are instruments whose value is derived from an underlying instrument—in this case, allowances.

In this white paper, references to the “secondary,” “spot,” or “cash” markets mean the approximately instant trading of allowances themselves, while derivatives markets will be treated separately.

Examples of derivatives include:

- Futures: Standardized contracts (i.e., contracts that are fungible with one another) to deliver something (e.g., allowances) at a certain price on a certain date in the future.

- Forwards: Non-standardized contracts to deliver something at a future date. The price may be fixed when the contract is executed, or may be determined at a time in the future.

- Options: A contract that gives the purchaser the right to buy or sell something at a certain price before a certain date.

- Swaps: A contract to exchange one thing for another.

Derivatives products are generally either "physically settled" or "cash settled," meaning the transaction involves an exchange of goods or solely of money.

Derivatives can be used to manage the risks inherent in fluctuating prices. This is often referred to as "hedging." For example, a natural gas-fired power plant may prefer to hedge against the possibility of an increase in natural gas prices by buying a future. A natural gas producer may similarly want to guarantee a price for some part of its production, and consequently may sell a future. Other firms may be willing to accept some risk of price volatility for the possibility of a higher return, or are confident of their analysis of whether prices will rise or fall. They trade derivatives even though they are not producers or consumers of a good. This motive for trading is commonly called "investing" or "speculating."

Derivative products may serve an important function in a carbon market. The WCI cap-and-trade system, for example, will create a long-term obligation for covered entities. Some of those entities may find it necessary or desirable to lock in future prices to provide certainty to customers, investors, or regulators. Because many of the allowances issued during a compliance period will likely be submitted for compliance, derivative products may provide one of the few options for managing this long-term risk. In addition, derivatives markets may give emitters a sense of the long-term trends in allowance prices, allowing emitters to justify and finance investment in reducing their emissions. Moreover, derivatives may reduce volatility in commodities markets, by accelerating the incorporation of new information into asset prices[9,10].

[9] E.g., "Populists and Theorists: Futures Markets and the Volatility of Prices," David S. Jacks, Explorations in Economic History 44, p. 342 – 362, 2007, http://www.sfu.ca/~djacks/papers/publications/populists.pdf (Accessed October 8, 2009).

3.3.2 Market participants

A WCI carbon market could involve diverse participants who may trade to satisfy a compliance obligation, purchase for resale to emitters, speculate on the price of allowances, or diversify an investment portfolio. Entities that could participate in the carbon market may include compliance entities, investors, brokers and other intermediaries. Each entity would play a different role in the market.

Even if compliance entities receive allowances without charge from a government, the number may not be equal to their obligation, perhaps due to growth or contraction in their emissions or policy decisions on the quantity or formula for distribution. These entities may then choose to purchase additional allowances from the primary or secondary market, or sell allowances they will not require for compliance or for other reasons. In early 2009, industrial facilities in the EU ETS sold allowances, many freely allocated, to raise cash when other finance avenues became more difficult.[11]

Many compliance entities may desire to use allowance derivatives to limit the risks inherent to them in higher or lower prices. Allowance prices will likely rise and fall as new information is incorporated by market participants. Information that may influence prices includes weather data and forecasts, emissions data, economic data and forecasts, and policy choices by governments.

Though they would not be required to hold allowances for compliance, other categories of participants could play market roles. Brokers and other intermediaries may, for a fee, arrange trades of allowances or derivatives between parties, or provide advice or other services. Investors may desire to be market participants to profit from trading.

The WCI Partner jurisdictions have received oral and written comments from stakeholders suggesting that market participation be limited to compliance entities. Many of these comments referred specifically to auctions, which are the subject of a separate WCI white paper, but may also be addressed in the context of secondary and derivatives markets. The concerns expressed can be summarized as:

1) That participation by non-compliance entities will increase the price of allowances.
2) That participation by non-compliance entities increases the chances of market manipulation.

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[10] "The Impact of Energy Derivatives on the Crude Oil Market," Jeff Fleming and Barbara Ostdiek, http://www.rice.edu/energy/publications/docs/Flemming_ImpactEnergyDerivativesCrudeOilMarket.pdf (Accessed October 8, 2009).

[11] E.g., "Carbon Markets 2009," IFSL Research, July 2009, http://www.ifsl.org.uk/upload/Carbon_Markets_2009.pdf (accessed October 1, 2009).

3) That participation by non-compliance entities will limit access to allowances.

The first concern may be related to questions regarding the role of speculation in markets: particularly speculation in energy markets as the price of oil rose rapidly in late 2007 and 2008 to a peak of $147 per barrel on July 11, 2008. Whether oil prices during this period reflected an understanding of underlying supply and demand, or may have been driven by "excessive" speculation, is a question that will not soon be resolved. Investors *can* play important roles in competitive markets by increasing liquidity and accepting risk. A healthy market is "liquid," meaning there is a sufficient number of buyers and sellers in the marketplace to allow trading to take place. Larger numbers of market participants make it more likely that there will be counterparty (i.e., another party willing to participate in a trade). Derivatives transactions are often described as a transfer of risk from one entity to another. Investors are often willing to act as counterparties and accept the risk. A market with less liquidity may be subject to more price volatility and it may be more difficult for entities needing to buy allowances to locate willing sellers. Consequently, concerns about potential "excess" speculation by investors must be weighed against these benefits of allowing investors access to the carbon market.

The second concern implies either that more market participants increases the ease or risk of manipulation, or that non-compliance entities might attempt market manipulation while compliance entities would not. However, a larger number of market participants would most likely make manipulation more difficult, not less, by increasing liquidity and making control of a significant proportion of allowances by one or a few persons harder. Moreover, there is no assurance that a non-compliance entity is more likely to attempt market manipulation than a non-compliance entity, or that no compliance entity would attempt market manipulation. Limiting market participation to compliance entities would exclude some number of potentially beneficial participants, with no certainty that the risk of market manipulation would decrease.

The third concern is that non-compliance entities may hold allowances for some period of time, making them unavailable to compliance entities who may need them for compliance. There are many possible reasons for holding allowances; the auction design recommendation report commissioned by RGGI identifies five:[12] speculation; allowance market manipulation; electricity market interference; competitive advantage; and external compliance. In none of these cases would market risks be reduced by restricting the market to compliance entities, save potentially external compliance. When restricting a market reduces liquidity, in fact, the risks are increased. "External compliance" is the possibility of another cap-and-trade program accepting WCI allowances in lieu of its own, without any reciprocal acceptance of the program's

[12] "Auction Design for Selling CO2 Emission Allowances Under the Regional Greenhouse Gas Initiative," Charles Holt, William Shobe, Dallas Burtraw, Karen Palmer, Jacob Goeree, October, 2007, section 9, "Hoarding of Allowances," http://www.rggi.org/docs/rggi_auction_final.pdf (Accessed October 6, 2009).

allowances by WCI jurisdictions. Though this risk might be enhanced by allowing non-compliance entities to participate, it is nevertheless very small, as it has not been proposed by the existing GHG cap-and-trade programs, RGGI and the EU ETS.

In addition to considering whether participation limits are desirable, WCI Partner jurisdictions will consider whether they are practical.

One consideration is how to determine who has a compliance obligation, including when that determination is made. The determination could be made the moment a facility emits beyond the cap-and-trade emission threshold of 25,000 metric tons in a calendar year; when it submits its verified emissions report showing emissions in excess of the threshold; at the “compliance event” after the end of a three-year compliance period when it must submit allowances to cover its emissions; or perhaps other choices. Each of these approaches may have different implications for who would be considered to have a compliance obligation for purposes of participation in the market. For example, if a smaller entity will not cross the emissions threshold until November in a given year, would it be forbidden to obtain allowances earlier? This implies that larger entities would be able to start trading earlier than smaller ones. To prevent this, the WCI Partner jurisdictions could allow an entity to participate in the market in anticipation of having a compliance obligation. However, if “anticipation” of an obligation is sufficient, then there would have to be procedures for who determines whether that anticipation is adequately grounded, and when, as well as any the penalties and recourse if the estimates used to anticipate an obligation are incorrect or fraudulent.

Another practical consideration for participation limits is to evaluate whether such limits are enforceable. One example is a person otherwise excluded by participation rules purchasing some fractional interest in a facility that was a compliance entity, with an agreement that the person could trade as a representative of the entity. A second example from derivatives trading is that the Chicago Climate Futures Exchange (CCFE) has been the most active platform for derivative trading of RGGI allowances. The CCFE determines its own membership. WCI states and provinces may not have jurisdiction over either the exchange or traders, so rules about allowable participation may be impossible to enforce.

The Markets Committee continues to evaluate arguments for and against limiting participation by the type of entity, and is investigating markets beyond the financial markets for examples of participation limits and their effects.

3.3.3 Exchanges and OTC transactions

Securities and commodities trading encompass a variety of markets, physical and electronic, where buyers and sellers meet to trade. The U.S. Commodity Futures Trading Commission (CFTC), for example, oversees at least four kinds of markets for trading commodity derivatives.

The markets vary in their restrictions on participation (e.g., some are limited to large investors, assumed to be sophisticated in their evaluation of risks) and contracts offered. The type of market is often defined by a regulator's choices about transparency, participation, and other requirements.

Here two particular kinds of markets are highlighted: exchanges and over-the-counter (OTC) markets, which represent ends of a spectrum in regulation. Exchanges are associated with a higher degree of oversight and transparency. They are centralized marketplaces that offer standardized contracts that are fungible with one another and generally require "clearance." Federal law in the United States and provincial law in Canada generally require exchanges to set rules implementing governance principles on market manipulation, publication of trading information, fair and equitable trading, emergency authority, and more.[13]

In "clearing," a central organization becomes the buyer to the seller and the seller to the buyer—that is, it becomes the counterparty to both sides. The clearing organization, therefore, assumes the obligation to complete the transaction even if one party is unable to perform its part. Most clearing organizations associated with exchanges perform clearing only for members, who set the clearing organization's rules and collectively shoulder the risk of default of any one party. This diffusion of risk facilitates trading by reducing counterparty credit risk to a single entity, the clearing organization; the clearing members have a financial incentive to set their rules to keep the risk of default low. Clearing organizations typically require members to post "margin," liquid collateral (such as cash or government bonds) against the risk of default on a contract.

OTC transactions are executed directly between private parties. There is typically little public disclosure of the contract terms for OTC trades. Some of the contracts are less standardized, and the counterparty credit risks are associated with the specific parties to the transaction. OTC trades are generally subject to less regulatory oversight than exchanges, although both U.S. and Canadian lawmakers are considering proposals to increase regulation of OTC instruments. At the same time, OTC contracts may help to develop new types of standardized contracts, especially in new markets. OTC instruments may provide initial products that evolve into standardized contracts.

4. Oversight in existing markets

Market oversight activities include:

[13] E.g., "Designation of boards of trade as contract markets," 7 U.S.C. §7.

- Establishment of rules for market participants, including standing rules for participants and rules for trades;

- Information collection and analysis to track market activity and verify compliance with market rules and laws (market monitoring);

- Information release to the public; and,

- Enforcement actions in response to suspected violations of rules or laws.

As stated above, there could be many participants in the Western Climate Initiative—compliance entities, exchanges, clearing organizations, investors, brokers, etc.—each of which play different roles in the marketplace. Current practices in market regulation provide useful models for policymakers designing cap-and-trade systems to limit greenhouse gas emissions.

4.1 U.S. market oversight

In the United States, there are four federal agencies whose current experience regulating markets and/or emissions provide useful lessons for the WCI carbon market: the CFTC, the Securities and Exchange Commission (SEC), the Federal Energy Regulatory Commission (FERC), and the Environmental Protection Agency (EPA).

In the federal U.S. climate debate, it appears that allowances and offsets will be treated as a commodity. Futures contracts linked to allowances issued by RGGI states are already trading on CFTC-regulated exchanges. Further, several bills pending in Congress would clarify the definition of a commodity to specifically include allowances and offsets.

The U.S. Commodity Exchange Act (CEA) directs the CFTC and/or self-regulatory organizations (SROs) comprised of industry participants to establish restrictions for regulated transactions[14] that include: (i) trading limits, (ii) position limits, (iii) prohibition of fraud, false reporting and deception, (iv) prohibition of meretricious transactions, (v) registration requirements for market professionals, (vi) reporting and recordkeeping requirements, and (vii) prohibition against falsely holding oneself out as a market professional.

The CFTC has created different regulatory regimes for the following market participants:

- Boards of Trade: The CEA defines at least four categories of boards of trade, each with a different level of CFTC regulation and oversight and a different level of required self-

[14] The CEA exempts certain transactions from regulation. See 7 U.S.C. §§7a, 6 for more detail. These exemptions are a significant part of the definition of OTC markets.

regulation.[15] Designated contract markets (DCMs) are the most closely regulated category. In order to qualify as a DCM, the board of trade must meet designation criteria set out in 7 U.S.C §§ 7, 7a. Examples of designation criteria include the ability to prevent market manipulation by enforcing rules with respect to the "financial integrity of transactions," proper activity by members, public access to contract specifications, and access to information required to carry out its operations. The Food, Conservation and Energy Act of 2008 requires the CFTC to regulate electronic commodities markets in the same manner as DCMs in order to detect and prevent manipulation and to limit speculation in U.S. electronic energy markets.[16]

- Clearing houses: Clearing houses must register with the CFTC and be designated a derivatives clearing organization (DCO) before providing clearing services for regulated commodities.[17] Clearing organizations that only clear exempt contracts are not required to register with the CFTC. Clearing houses are discussed in further detail below.
- Intermediaries: Agents trading on behalf of a principal must register with the CFTC. In addition, they are often subject to "various financial, disclosure, reporting, and recordkeeping requirements."[18] Types of intermediaries include futures commissions merchants, introducing brokers, commodity pool operators, and commodity trading advisors. Any individual or firm wanting to "conduct futures-related business with the public" must register with the National Futures Association, an independent organization authorized to process intermediary registration with the CFTC.[19]

4.2 Canadian provincial market oversight

Regulation of Canadian securities and commodities markets is performed by a combination of provincial regulatory authorities and SROs. SROs exercise authority derived from a range of sources, including provincial legislation, delegation of authority from securities regulators and

[15] We say "at least four categories" because the statute is unclear in a number of areas. For example, 17 U.S.C. § 1a, defines something called an "alternative trading system" that appears to be highly unregulated. It is difficult to determine the scope or breadth of such alternative trading systems from the rest of the statute.
[16] The CFTC also regulates other categories of trading facilities, including derivatives transaction execution facilities, exempt board of trade, exempt commercial markets. Each category is subject to different levels of regulatory oversight.
[17] "Derivatives Clearing Organizations," 7 USC § 7a-1; Commodity Futures Trading Commission, http://www.cftc.gov/industryoversight/clearingorganizations/index.htm (Accessed May 28, 2009).
[18] "Intermediaries," Commodity Futures Trading Commission, http://www.cftc.gov/industryoversight/intermediaries/index.htm (Accessed May 28, 2009).
[19] "Registration of Intermediaries," Commodity Futures Trading Commission, http://www.cftc.gov/industryoversight/intermediaries/registration.html (Accessed May 28, 2009); "Who Has to Register," National Futures Association, http://www.nfa.futures.org/registration/who_has_to_register.asp (Accessed May 28, 2009).

agreement by members to follow rules established by their respective SRO. A more detailed description of Canadian capital markets oversight is presented below:[20]

- Provincial Market Regulatory Authorities: Provinces differ in regulation requirements for exchange and OTC derivatives. In Ontario, OTC derivatives and exchange-traded derivatives are administered by the Ontario Securities Commission (OSC) and are regulated under the Securities Act (Ontario) ("OSA")—if OTC derivatives qualify as securities under the OSA—and the Commodity Futures Act (Ontario) (CFA), respectively. The CFA defines "commodities" to include emissions and emission credits.[21] Like Ontario, Manitoba has commodity futures legislation that specifically regulates exchange-traded futures and options on futures. Other derivative products (generally OTC derivatives) are regulated under the Securities Act (Manitoba). In Quebec, the Quebec Derivatives Act (QDA) applies to both exchange-traded and OTC derivatives. British Columbia, as with several other provinces, regulates exchange-traded derivatives. It regulates OTC derivatives as "securities" under its securities legislation but effectively exempts them from many aspects of its securities regulations.

- Exchanges: There are currently three commodity futures exchanges located in Canada: Bourse de Montréal (the "Bourse") in Quebec, ICE Futures Canada in Manitoba, and the Natural Gas Exchange ("NGX") in Alberta. All of these exchanges are recognized (or authorized) by the provincial securities regulatory authority in their home jurisdiction, and are recognized or exempted from recognition in other provinces where they carry on business. Exemptions are granted on the basis of reliance on the regulation of the exchange by its home jurisdiction regulator (the "lead regulator" model).

- Clearing Houses: Regulation of clearing houses also varies by province. For example, Quebec is the only jurisdiction to require mandatory recognition of clearing houses. The Canadian Derivatives Clearing Corporation (CDCC)—the clearing house for contracts traded on the Bourse—is recognized as a SRO in Quebec and is under the oversight of the Autorité des marchés, financiers (AMF).[22] In Ontario, clearing houses can apply to the Ontario Securities Commission (OSC) for recognition under the CFA. Recognized clearing houses would file their rules and regulations with the OSC and be subject to rules regarding governance, access, fees, risk controls, financial viability, and

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[20] Provincial governments are currently considering proposals to reform market regulation, including a role for the federal government. It should however be noted the federal initiative is currently the subject of a constitutional challenge.

[21] Under OSC Rule 14-502 – Designation of Additional Commodities

[22] "CDCC (Mx)," Canadian Derivatives Clearing Corporation, http://www.cdcc.ca/accueil_en.php (Accessed October 28, 2009).

information sharing. The OSC has authority to make any decision with respect to those rules. However, no clearing houses are currently recognized under the CFA. British Columbia legislation does not require a clearing agency to be recognized but permits its BC Securities Commission to recognize them. Manitoba has the ability to designate a clearing agency as recognized, and has issued a recognition order for ICE Clear Canada, the clearing house of ICE Futures Canada.

- Intermediaries: Ontario's CFA requires registration of advisers (including commodity trading advisers, commodity trading counsels or commodity trading managers) and dealers (referred to as futures commission merchants or FCMs). Registrants are subject to various requirements imposed by regulation, for example requirements relating to capital, record-keeping, and proficiency. Registrants are also subject to the general record-keeping and compliance review provisions of the CFA. FCMs are required to be members of the Investment Industry Regulatory Organization of Canada (IIROC), a recognized SRO, and to participate in the Canadian Investor Protection Fund, an approved compensation fund. British Columbia requires registration in order to trade in a security or exchange contract. In Manitoba, trading under CFA requires registration as a FCM and the firm must be a member of IIROC. Quebec's QDA, in addition to requiring registration of advisers and dealers, also requires that any person other than a "recognized regulated entity" that seeks to "create or market" a retail off-exchange derivative must be qualified by the AMF and that the derivative must also be approved by the AMF.

The IIROC is a national SRO responsible for overseeing trading activity in the Canadian equity markets. The organization monitors regulated firms and their registered employees to ensure compliance with market integrity rules, including post-trade reviews of trading data to identify any manipulative trading patterns that violate the Universal Market Integrity Rules (UMIR).[23] The IIROC prosecutes violations of UMIRs and refers other violations to the appropriate securities regulatory authority.

The oversight of trading in commodity futures contracts is conducted by the commodity futures exchanges themselves. The Bourse and ICE Futures Canada are recognized as SROs by their respective lead regulators and are required to maintain a separate regulatory division with defined regulatory, compliance, market surveillance and disciplinary responsibilities. They are also required to establish rules to govern and regulate all aspects of their business and internal affairs and to prevent fraudulent and manipulative acts and practices by participants. Regulatory divisions of these exchanges perform real-time monitoring of trading activity to detect trading infractions and market manipulation, conduct investigations and discipline

[23] "Market Integrity Rules – UMIR," Investment Industry Regulatory Organization of Canada, http://www.iiroc.ca/English/ComplianceSurveillance/RuleBook/Pages/UMIR.aspx (Accessed October 8, 2009).

exchange participants. The exchanges also impose and monitor position limits for each of their listed contracts.

All futures contracts traded on the three Canadian futures exchanges are cleared by their respective designated clearing house. Each of these clearinghouses acts as central counterparty to each transaction, manages the financial risk and oversees the final settlement of contracts. Clearing houses impose margin requirements, monitor the financial risk of their members in real time and may issue intra-day margin calls when needed.

4.3 European Union Emissions Trading Scheme market oversight

As part of its efforts to fight against climate change, the European Community ratified the Kyoto Protocol on April 25, 2002, establishing a goal of reduction in greenhouse gas emissions from all 15 Member States of 8% below 1990 levels for the period 2008 – 2012.

The establishment of a cap for a category of GHG emitters was designed to assist Member States and the European Union to meet their commitments to the Kyoto Protocol, while allowing companies to comply at the lowest cost by participating in the purchase and sale of emission allowances. The EU ETS covers around 10,500 installations across the 27 Member States of the European Union plus three other States. The ETS is designed to work in successive and independent phases. The first phase took place from January 2005 to December 2007. The second runs from January 2008 to December 2012 and corresponds to the compliance period of the Kyoto Protocol. The third phase will run from 2013.[24]

The legal framework of the trading scheme does not regulate how and where allowance trading takes place. Companies with commitments may trade allowances directly with each other, or they may buy or sell via a broker, bank or other allowance market intermediary. The Community Independent Transaction Log (CITL) records the issuance, transfer, cancellation, retirement and banking of allowances that take place in the registry.

It is mandatory that each Member State have a national registry. These registries will ensure the accurate accounting of all units under the Kyoto Protocol plus the accurate accounting of allowances under the CITL scheme for greenhouse gas emission allowance trading.[25]

The London-based European Climate Exchange[26] (ECX) provides standardized futures contracts. The underlying unit of trading is EU allowances (EUAs) or certified emission reductions (CERs).

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[24] "Emission Trading System (EU ETS)," European Commission, http://ec.europa.eu/environment/climat/emission/index_en.htm (Accessed October 28, 2009).
[25] "Emission Trading System (EU ETS): Community Independent Transaction Log," European Commission, http://ec.europa.eu/environment/climat/emission/citl_en.htm (Accessed October 28, 2009).

ECX contracts are cleared through ICE Clear Europe. Margin requirements for ECX products are determined by ICE Clear Europe and rates are reviewed on a quarterly basis based on historic price fluctuations of the contract.

In 2007, the traded volume of EUAs totaled 1,443 million, a daily average traded volume of 5.6 million tons (Mt). Around 70% was traded in the brokered over-the-counter market and the rest was traded on exchanges. The ECX accounted for 87% of exchange traded derivatives by volume in 2007, 92% in 2008, and 99% in the first half of 2009.[27,11]

The Financial Services Authority (FSA) regulates providers of financial securities in United Kingdom, including the ECX. The following is a summary of the FSA's scope of regulation:

- The FSA regulates exchanges and clearing houses, under UK Financial Services and Markets Act.
- The FSA does not have any responsibilities specifically relating to the underlying emission markets. Activities conducted by participants in relation to derivative instruments based on emissions allowances fall within its regulatory perimeter.
- The FSA regulates commodities derivatives that are traded for investment purposes.
- The fact that emissions allowances are a dematerialized allowance certificate, as opposed to a physical commodity does not distinguish this market from other commodities markets. The FSA does not consider that a different approach is required regarding the allowance market.
- The FSA does not regulate spot trading of emission allowances.
- The FSA could investigate behavior on the spot trading market if it appears it has an impact on derivatives listed on a regulated exchange.

5. U.S. Federal Proposals

The U.S. executive and legislative branches have presented various proposals for broad reform of financial markets, reform of energy commodity trading, and regulation of carbon markets that would be created by a federal cap-and-trade program.

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[26] "What Are Futures?" European Climate Exchange, http://www.ecx.eu/ECX-EUA-Futures-What-are-Futures (Accessed October 28, 2009).
[27] "Carbon 2008," PointCarbon, http://www.pointcarbon.com/polopoly_fs/1.912721!Carbon_2008_dfgrt.pdf (Accessed October 28, 2009).

The U.S. House of Representatives approved comprehensive climate and energy legislation (HR 2454) in June, 2009 that would create a federal GHG cap-and-trade system.[28] The bill would require:

- Creating a separate regulatory frameworks for the trading of allowances and allowance derivative instruments;
- Including verified offset credits in the definition of "allowances" for the purpose of the market oversight provisions;
- Choosing not to restrict who may trade in the carbon market; and
- Allowing multiple registered exchanges to trade allowance-based instruments rather than requiring that all instruments trade on a single platform.

Rather than specifying all of the rules to govern the markets, the HR 2454 articulates a series of general standards for oversight of the allowance market. The regulator of the allowance market must promulgate regulations that:

- Prohibit fraud, manipulation, excessive speculation;
- Facilitate compliance with emissions limits;
- Ensure transparency;
- Set position limits and margin requirements, as necessary;
- Create a national market system;
- Limit or eliminate counterparty risks, market power concentration risks, and other risks associated with OTC trading;
- Create standards for trading facilities (i.e., exchanges) and clearing organizations; and
- Other requirements necessary to preserve market integrity and compliance.[29]

The bill would amend the Commodity Exchange Act to include allowance-based derivative instruments, thereby treating derivatives in a manner similar to agriculture commodities. In addition to the list of market elements that regulations must address, the legislation also includes detailed enforcement provisions.[30]

Senators Diane Feinstein (CA) and Olympia Snowe (ME) introduced a bill (S 1399) in June, 2009 to regulate a federal cap-and-trade system.[31] The bill includes more specific regulatory provisions for both the allowance and derivative markets and would create a new branch at the CFTC specifically to regulate the carbon market. For example, the legislation would require all allowance trading to occur on a registered carbon trading facility and to be cleared through a single Carbon Clearing Organization. Virtually all allowance-based derivative instruments would have to trade on a designated carbon derivative trading facility. The bill technically permits OTC

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[28] American Clean Energy and Security Act, HR 2454, 111th Cong.
[29] HR 2454, § 341(b)(2)&(c)(2).
[30] HR 2454, § 341(b)(3)&(f).
[31] Carbon Market Oversight Act of 2009, S.1399, 111th Cong.

transactions but it defines "private bilateral contract" very narrowly, effectively requiring most, if not all, derivative transactions to occur on registered derivatives trading facilities.

In October, 2009, Senators John Kerry (MA) and Barbara Boxer (CA) introduced a new cap-and-trade bill (S.1733) in the U.S. Senate.[32] Rather than set forth specific statutory requirements for oversight of the carbon market, the Kerry-Boxer bill includes a nonbinding "sense of the Senate" provision that calls for:

> "a single, integrated carbon market oversight program--
>
> > "(1) to provide for effective and comprehensive market oversight and enforcement;
> > "(2) to lower systemic risk and protect consumers;
> > "(3) to ensure market liquidity and allowance availability;
> > "(4) to enhance the price discovery function of such markets, ensuring that the price for emission allowances and offset credits reflects the marginal cost of abatement;
> > "(5) to prevent excessive speculation that contributes to price volatility, including the establishment of robust aggregate position limits and margin requirements;
> > "(6) to ensure that market mechanisms and associated oversight support the environmental integrity of the program established under title VII of the Clean Air Act ...;
> > "(7) to establish provisions for market transparency that provide authority, resources, and information needed to prevent fraud and manipulation in such markets;
> > "(8) to establish standards for trading as, and operation of, trading facilities;
> > "(9) to ensure a well-functioning, well-regulated market, including a futures market, designed to manage risk and facilitate investment in emission reductions;
> > "(10) to establish clear, professional standards for dealers, traders, and other market participants;
> > "(11) to provide for appropriate criminal and civil penalties; and
> > "(12) to prevent any excessive leverage by market participants that creates risk to the economy."[33]

In addition to legislation specifically aimed at governing a new federal carbon market, the U.S. Congress is also considering broader market reform proposals that may impact carbon markets. Both the House of Representatives' Financial Services Committee and Agriculture Committee

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[32] Clean Energy Jobs and American Power Act, S 1733, 111th Cong.
[33] S 1733 Title VII, Subtitle D.

have approved legislation to regulate swap markets.[34] Under both bills, standardized swap transactions between dealers and large market participants would be required to be traded on an exchange or electronic platform and cleared through a clearing organization registered by the CFTC or the Securities and Exchange Commission (SEC). The bills would grant new authority to the CFTC and SEC to define the term "standardized," and any swap accepted for clearing by a clearing organization would be presumed to be standardized. The clearing requirement would not apply to transactions intended to hedge a commercial risk (e.g., end users of a commodity). Non-cleared transactions would have to be reported to a trade repository or, if a trade repository is not available for the particular transaction, reported directly to the CFTC or the SEC. The bills include new reporting and recordkeeping requirements for any person who enters into a swap that is not cleared or reported to a repository.

On August 11, 2009, the Obama Administration forwarded a proposal to Congress to bring OTC derivatives markets for all types of commodities under regulatory oversight of a combination of banking regulators, the CFTC and/or the Securities and Exchange Commission (SEC).[35] On October 26, 2009, the U.S. Treasury Department and the House Financial Services Committee released a draft bill to address "systemic risk and 'too big to fail' banks."[36] The draft bill would:

- "Create a mechanism for monitoring and reducing the threats that systemically risky firms pose to the financial system.
- "Establish a process for winding down large, financially-troubled non-bank financial institutions in a way that protects American taxpayers and minimizes the impact on the financial system."[37]

6. Conclusion

There are a variety of market structures that can serve as useful models as the WCI Partners create a regional cap-and-trade system. The Markets Committee is considering a number of key issues, including:

- Whether current U.S. and Canadian regulation of commodity markets is appropriate. Allowance-based derivative instruments in the EU ETS and RGGI markets are regulated like commodities, and the U.S. CFTC has jurisdiction over RGGI-based derivative

[34] Over-the-Counter Derivatives Markets Act of 2009, HR 3795, 111th Cong. Reported by the Committee on Financial Services on Oct. 15, 2009. Over-the-Counter Derivatives Markets Act of 2009, HR 3795, 111th Cong. Reported by the Committee on Agriculture on Oct. 21, 2009.

[35] See http://www.treas.gov/press/releases/tg261.htm.

[36] House Committee on Financial Services, Press Release: Financial Services Committee and Treasury Department Release Draft Legislation to Address Systemic Risk, "Too Big to Fail" Institutions, October 26, 2009, http://www.house.gov/apps/list/press/financialsvcs_dem/presstitleone_102709.shtml.

[37] *Id.* The draft legislation is available at http://www.house.gov/apps/list/press/financialsvcs_dem/title_i_discussion_draft_final.pdf (Accessed October 28, 2009).

instruments that trade on exchanges. Based on opinions from outside experts, it may be challenging to structure a derivatives market that does not fall under U.S. CEA. Should the WCI Partners decide to follow existing U.S. and Canadian approaches to commodity market regulation, they may consider establishing relationships with the appropriate market regulators to ensure a properly functioning regional carbon market.

- <u>Whether to place restrictions on OTC instruments.</u> The question of whether to allow OTC trading has received significant attention in the U.S. federal debate regarding the design and regulation of a carbon market. WCI Partners will need to evaluate the potential benefits of and risks posed by OTC instruments, in both secondary and derivatives markets.

- <u>The appropriate transparency and disclosure requirements.</u> There is broad agreement that transparency is a critical element to a well-functioning market. Access to accurate and timely market data helps regulators monitor trading activity, maintains the public's confidence in market fairness and integrity, and allows market participants to make informed investment decisions. Market participants will have access to different types of information and the WCI Partners will need to balance the transparency requirements with the need for confidentiality and the reporting burdens placed on individual market participants. The balance may vary for secondary and derivatives markets.

The WCI's initial market design choices will have a significant influence on overall market activity. By making careful decisions at the outset, the WCI Partners can help ensure a stable, transparent, efficient marketplace that minimize risks of fraud and manipulation

November 18, 2009 Market Oversight White Paper

List of Commenters

Carbon Markets & Investors Association

Monitoring Analytics

Morgan Stanley Capital Group, Inc.

Pacific Gas and Electric Company

PacifiCorp

Power Workers' Union

Southern California Edison Company

Southern California Public Power Authority

Washington Public Utility Districts Association

Western Climate Advocates Network

Zini, Gian P.

Western Climate Initiative

Market Oversight White Paper

Stakeholder Conference Call

11:00 a.m. PST, December 2, 2009

Western Climate Initiative

- A collaboration of seven U.S. states and four Canadian provinces to reduce greenhouse gas emissions
- Signature effort to date has been design of cap-and-trade program; now in implementation phase
- 2009 – 2010 work plan: “Essential elements” by June, 2010
- Markets Committee includes market oversight task

Objectives

- "The recommended design will provide opportunities to obtain low-cost emission reductions through emission trading, allowance banking, and inclusion of an offsets component."

WCI Design Recommendations, September 23, 2008

- "The WCI Partner jurisdictions and stakeholders want appropriate safeguards and oversight of the allowance and offset credit trading markets and want them to function efficiently."

Materials for Markets Workshop, April 9, 2009

Market Oversight Stakeholder Engagement

- Apr. 9, 2009 workshop
  - Principles
  - Questions for stakeholders
- White paper released to public Nov. 18, 2009
- Today's stakeholder call
- Written comment requested by Dec. 18, 2009
- Consideration of stakeholder comments
- Draft recommendations

Market Oversight White Paper

- Purpose is to provide foundation for recommendations
- Background on market oversight, including existing markets, especially environmental trading programs
- Roles of existing market oversight agencies in the U.S. and Canada
- Forum for stakeholder interaction

Principles

These principles serve as guidelines for developing oversight of the allowance, offset credit, and associated derivatives trading markets to assure maximum environmental and economic benefit to the public.

- Fairness
- Efficiency
- Effective oversight
- Transparency and the reporting and disclosure of relevant information
- Administrative simplicity and cost
- Accountability
- Conflicts of interest

Architecture and Oversight

- "Market Architecture:" Market participants and institutions, and the connections between them
- "Market Oversight:" The regulators' relationship with the market

Types of Markets: A Convenient Taxonomy

- Primary: Initial distribution of allowances issued by governments (auction, sale, or allocation).
- Secondary: Trading of allowances by participants for immediate delivery
- Derivatives: Value based on another instrument (e.g., a contract based on the price of allowances)

Secondary Markets

- Immediate delivery
- WCI tracking system
  - Major part of architecture of market
  - Rules for system a significant part of oversight choices
  - Important resource for monitoring
- Unlike traditional commodities markets, supply is fixed and known

Derivatives

- Allowance market expected to have some volatility
- Derivatives can be used for risk management
  - E.g., electricity generators may lock in power prices and fuel prices for a period of time, and ensure an operating margin
- OTC and exchange structures similar
- Derivatives markets can be larger and more active than spot markets

Ways to Trade Allowances

- “Over the Counter” (OTC) transactions
  - Between two (or more) parties
- Exchanges
  - Standardized terms
  - Clearing
    - Centralized counterparty
    - Margin requirements
  - Data recording and disclosure requirements
  - Position limits

Market Participants

- Could be a wide variety: Compliance entities, brokers, investors
- Have heard calls to limit access to markets to compliance entities
  - Could be difficult to implement
  - Counterarguments are that broad participation can add liquidity, reduce opportunities for exercise of market power
  - Requires assumption that compliance entities form an exclusive class that is somehow different from class of all participants

Oversight in Existing Markets

- Existing commodity regulation in U.S. and Canada
- Existing greenhouse gas trading programs:
  - Regional Greenhouse Gas Initiative
  - European Union Emissions Trading Scheme
- Proposals to reform market oversight

Particular Requests for Stakeholder Feedback

- Whether it is appropriate to consider allowances to be commodities for market oversight purposes
- Whether the WCI jurisdictions should favor or require exchange transactions over over-the-counter transactions
- The appropriate requirements for data collection, filing with regulators, and disclosure to the public

Questions?

WCI Markets Committee

Co-Chair Jim Whitestone, Ontario

Jim.Whitestone@Ontario.ca

Co-Chair Michael Gibbs, California

MGibbs@calepa.ca.gov

White paper and comment submission at:

http://westernclimateinitiative.org/public-comments/document/13

Western Climate Initiative

La Posada de Santa Fe
330 East Palace Avenue
Santa Fe, NM 87501

For remote access, call ***1-800-868-1837*** *toll free in the U.S. and Canada (1-404-920-6440 for outside the U.S. and Canada),* ***participant code 659 537#***

Wednesday, November 18, 2009

9:00 am	**Convene (Montana Ballroom)** Welcome and Introductions Agenda Review
9:15 am	**Offset Compliance Limit** Purpose: Review and approve final recommended design for implementing the offset limit (as updated based on stakeholder comments).
9:45 am	**Reporting Harmonization** Purpose: Review and approve plan, timeframe and budget for harmonizing reporting requirements. Discuss status of state and provincial reporting rules.
10:30 am	**Break**
10:45 am	**Complementary Policies White Paper** Purpose: Review and approve the complementary policies white paper.
11:30 am	**Competitiveness Analysis** Purpose: Review and approve final statement of principles on competitiveness, the proposed process for addressing competitiveness, and an outline of the industry guidance document for emitters.
12:30 pm	**Lunch** *(attendees are on their own for lunch)*
1:30 pm	**Market Oversight Options** Purpose: Discuss market oversight issues in the context of the regional program. Partner direction to Committee on next steps.
2:45 pm	**Break**
3:00 pm	**Next Steps** Purpose: Discuss plans for upcoming WCI Partner meetings and collaborative
3:30 pm	**Open Comment Period**
4:00 pm	**Adjourn**

Western Climate Initiative

Market Architecture and Oversight

Partner Meeting, Santa Fe, New Mexico

November 18, 2009

Oversight Task

- Purpose of Market Architecture and Oversight task is "to provide recommendations that are designed to ensure that the allowance and offset credit trading market is organized properly to operate reliably and prevent or minimize manipulation."
- White paper
- Stakeholder conference call
- Written comments
- Next step: incorporate comments; write draft recommendations

"Clay Man"

- Aid to focus discussion internally, and list options
- Intended to be malleable
- Will never be final but will be replaced by draft recommendations
- Draft discussed today includes some "proposed" (pre-draft) recommendations and some areas for further exploration

Risks to Markets

- Manipulation
- Fraud
- Excessive speculation
- Systemic problems due to counterparty risk
- Lack of effective price discovery

Tools to Address Market Risks

- Tracking system
- Limits on market participation
- Favoring exchange transactions
- Data & records filing and disclosure
- Position limits
- Cost-containment measures
- Collaboration with other regulators
- Market monitoring

Types of Markets: A Convenient Taxonomy

- Primary: Initial distribution of allowances issued by governments (auction, sale, or allocation).
- Secondary: Trading of allowances by participants for immediate delivery
- Derivatives: Value based on another instrument (e.g., a contract based on the price of allowances)

Tracking System

- WCI tracking system
  - Major part of architecture of market
  - Rules for system a significant part of oversight choices
  - Important resource for monitoring
- Can impose conditions for account holders and allowance transfers

Market Participation

- Limits by type of entity—e.g., has compliance obligation
- Limits by qualifications of person trading—e.g., registration with regulators

Compliance entities

- Benefits to having broad participation
  - Increased liquidity
  - Makes concentration (and therefore manipulation) more difficult
  - More information and analysis may improve price discovery
- Arguments against non-compliance entities
  - Artificial increase in allowance prices
  - Increase chances of manipulation
  - Limit access to allowances

Practical considerations for limiting market participation

- Determining who has compliance obligation
- Ownership or fractional ownership of compliance entity
- First jurisdictional deliverer
- Derivatives challenges—e.g., CCFE is busiest exchange for RGGI

Qualifications for participants

- In general, registration required to trade commodities derivatives on behalf of another person in US and Canada—but not for own trades
- Requirements vary, but may include
  - Passing a proficiency exam
  - Maintaining minimum capital
  - Rules for treatment of customer funds
  - Disclosures to customers
  - Filings to regulators

Ways to Trade Allowances

- "Over the Counter" (OTC) transactions
  - Between two (or more) parties
- Exchanges
  - Standardized terms
  - Clearing
    - Centralized counterparty
    - Margin requirements
  - Data recording and disclosure requirements
  - Position limits

Derivatives

- Allowance market expected to have some volatility
- Derivatives can be used for risk management
  - E.g., electricity generators may lock in power prices and fuel prices for a period of time, and ensure an operating margin
- Derivatives markets can be larger and more active than spot markets

Records and Disclosure

- Transparency key to markets
- Recommend requiring ultimate beneficial ownership of allowances in tracking system
- Recommend immediate recording of transfers with tracking system
- Considering requirements on derivatives records for account holders

Position limits

- Limits on number of allowances or derivative contracts that can be held by an entity
- Need more information on levels
- Potential exceptions or higher limits for compliance entities

Cost-containment measures

- Minimum or maximum prices for allowances (e.g., “safety valve”)
- Strategic reserve
- Price triggers for offsets quantity

Excessive speculation

- “In theory, the price of futures and derivatives should be a reflection of physical market pricing. That is, the price of consumable, commercial goods should be set by the consumers and users of such commodities….A good definition of ‘excessive speculation’ is the market condition where non-commercial interests set the price.”

“Defining Excessive Speculation,” Jeff Korzenik, http://inefficientfrontiers.wordpress.com/2009/07/14/defining-excessive-speculation/ (Accessed Nov. 3, 2009).

Relationships with US and Canadian provincial regulators

- Canadian provinces will coordinate with provincial securities commissions
- US regulators:
  - Commodity Futures Trading Commission
  - Federal Energy Regulatory Commission
  - Securities and Exchange Commission
  - Environmental Protection Agency

Monitoring

- In addition to jurisdictions' own monitoring:
  - Develop WCI in-house capacity
  - Rely on existing regulators (US Commodity Futures Trading Commission, provincial Securities Commissions)
  - Contract with independent monitor
- Role of public information

Offset Credits

- Need to be distinguishable in tracking system to enforce a quantitative limit
- Potential for “reversal”
- Issuance follows different path than for allowances

Next Steps

- Current thinking
- Lines of continued inquiry
- Timing and resource commitment

Questions?

WCI Markets Committee

Co-Chair Jim Whitestone, Ontario

Jim.Whitestone@Ontario.ca

Co-Chair Michael Gibbs, California

MGibbs@calepa.ca.gov

April 9, 2009 Stakeholder consultation documents and comments available at http://westernclimateinitiative.org/public-comments/document/2

Western Climate Initiative

Reporting Committee
WCI ER/EPA Reporting Rule Harmonization Workplan
November 10, 2009

Task #	Description	Responsibility	Deadline
1	Review EPA General Provisions and identify changes needed for WCI program: • additional elements needed for cap and trade program • change threshold from 25,000 MT/yr to 10,000 MT/yr; • gases covered (e.g. NF3); • addition of verification requirements; • treatment of biomass emissions; • addition of provisions from current WCI general provisions that reflect Canadian regulatory traditions (e.g. operator's representative)	Reporting Committee	12/16/2009
2	Compare EPA quantification methodologies to final and near final Essential Requirements (ERs) and identify significant differences between the two.	Reporting Committee ERG	12/16/2009
3	Analyze differences identified as part of Task 2 for compatibility with a cap-and-trade program and identify necessary modifications to EPA Rule. Consider: • Method accuracy; • Potential for bias. • Choices allowed in the EPA program Sources of information: • EPA Technical Support Documents; • EPA Responses to Comments; • Reports submitted under existing programs for source category.	Reporting Committee ERG	1/13/2010

Task #	Description	Responsibility	Deadline
4	Where EPA has developed a method for a source category that is not covered by a final or near final ER: • Evaluate the EPA method for compatibility with a cap-and-trade program considering the same criteria and sources as in task 3; • If the method is not compatible with a cap-and-trade program, decide whether (1) the method can be modified to make it compatible, (2) the method should be excluded from the WCI ERs or (3) the method should be included in the WCI ERs for informational purposes. Note: The EPA reporting requirements for fuel producers, importers and exporters will not work for a regional, as opposed to a national, program. The Reporting Committee will develop separate fuel supplier reporting requirements in accordance with the current schedule.	Reporting Committee ERG	1/13/2010
5	Draft model incorporation by reference rule for U.S. jurisdictions.	Reporting Committee ERG	3/4/2010
6	Where WCI has developed a draft ER that is not covered by a method included in the final or proposed EPA Rule, proceed to develop a final ER. Note: Where WCI has developed a draft ER that is covered by a proposed EPA method, the Reporting Committee will defer work on the ER until the EPA method is final, unless a Canadian jurisdiction needs to adopt the method by reference for the 2011 reporting year.	Reporting Committee ERG	3/18/2010
7	Align the third party verification rule with the structure and language of the EPA rule (keeping the rigour and principles the same).	Reporting Committee ERG	3/18/2010

Task #	Description	Responsibility	Deadline
8	Modify the EPA rule to serve as new ERs for Canadian jurisdictions by substituting metric units and conforming to Canadian regulatory norms. Alternatively (if regulatory traditions allow and such a decision is made by the Canadian jurisdictions) draft model incorporation by reference rule for Canadian jurisdictions noting changes required for Canadian circumstances and exceptions to the EPA rule. Submit work product for tasks 5 to 8 to Partners for approval.	Reporting Committee ERG	3/18/2010
9	Partner review and approval of proposed model incorporation by reference rule and new ERs. Publication for stakeholder review.	Partners	4/1/2010
10	Stakeholder review and comment on proposed model incorporation by reference rule and new ERs.	Reporting Committee	5/4/2010
11	Publication of final model incorporation by reference rule and new ERs and response to stakeholder comments.	Reporting Committee Partners	6/1/2010

Western Climate Initiative

Oil and Gas Collaborative

November 19, 2009

Montana Ballroom - La Posada de Santa Fe
330 East Palace Avenue, Santa Fe, NM
Call in: 1-800-868-1837 (toll free in the U.S. and Canada), code 659537#

Meeting Objectives:

1) Increase understanding of the oil and gas sector with an emphasis on exploration and production and natural gas processing;
2) Increase understanding of the oil and gas sector's GHG emission pathways and reduction opportunities;
3) Discuss and receive input on critical outstanding issues in the sector including emissions reporting;
4) Determine next steps for continued oil and gas sector engagement in the WCI.

Attendees:

1) Oil and Gas Reporting Protocol Technical Working Group (TWG) Members (http://www.wrapair.org/ClimateChange/GHGProtocol/twg-members.html)
2) The Public will be invited to observe and provide comments during the meeting.

Facilitation: The meeting will be facilitated by Rob Greenwood with Ross and Associates.

		Lead Presenters
8:30 – 8:45	1. Call to Order: Opening Remarks • Introductions • Review Purpose and Agenda	WCI US and Canadian Leads
8:45 – 10:15	2. North American Oil and Gas Industry and Climate Change • Introduction and Overview ○ Defining the Sector (Upstream and Midstream) ○ Major Sources of Emissions ○ Emission Controls ○ Canadian and U.S. similarities and differences • Challenges of addressing upstream Oil and Gas emissions • Industrial achievements in emission reductions and measurements	Tom Moore, Western Governors' Association Krista Phillips Canadian Association of Petroleum Producers Ramon Alvarez, Environmental Defense Fund Reid Smith, BP

10:15 – 10:30	Break	
10:30-11:00	3. Update on key industry issues: • Low Carbon Fuel Standard • U.S. Legislation (How it proposes to regulate oil and gas) • Geologic Sequestration (pore space ownership, surface rights, accounting for CO2 transfers and leakage)	Byard Mosher, CARB Paula Fields, ERG Mark Fesmire, NM Oil Conservation Division
11:00-11:30	4. Status of the WCI Reporting Requirements: • General Reporting Principles • Essential Requirements of Mandatory Reporting • Information on harmonization of WCI and future EPA mandatory reporting (including reflection of Canadian data streams and circumstances) for the Upstream O&G Sector • Developing Mandatory Oil and Gas Protocols	Jim Norton
11:30 – 12:15	5. TWG Discussion on Draft WCI Issues Paper: • Defining the Reporting Entity and Threshold	All
12:15 – 1:15	Lunch	

1:15 – 3:00	6. Cont. TWG Discussion on Draft WCI Issues Paper:
	• Contractor Emissions
	• Quantification Issues
	    • Stationary Combustion and Field Gas
	    • Instrument Gas and Vented Methane Emissions
	    • Storage Tanks
		All

3:00-3:30	7. Public Comment	
3:30-3:45	Break	
3:45-4:15	8. Collaborative Discussion • Comments from group on what was presented. • Summary of what was heard during the day.	All
4:15– 4:45	9. Next Steps	Jim Norton

CAPP CANADIAN ASSOCIATION OF PETROLEUM PRODUCERS

Canada’s Upstream Oil & Gas Industry

Krista Phillips
Policy Analyst, Air Quality & Climate Change

WCI Oil & Gas Collaborative
November 19, 2009

- Large and small producer member companies
- Explore for, develop and produce natural gas, natural gas liquids, crude oil, and oil sands throughout Canada
- Members produce about 90 per cent of Canada's natural gas and crude oil
- Associate members provide a wide range of services that support the upstream crude oil and natural gas industry

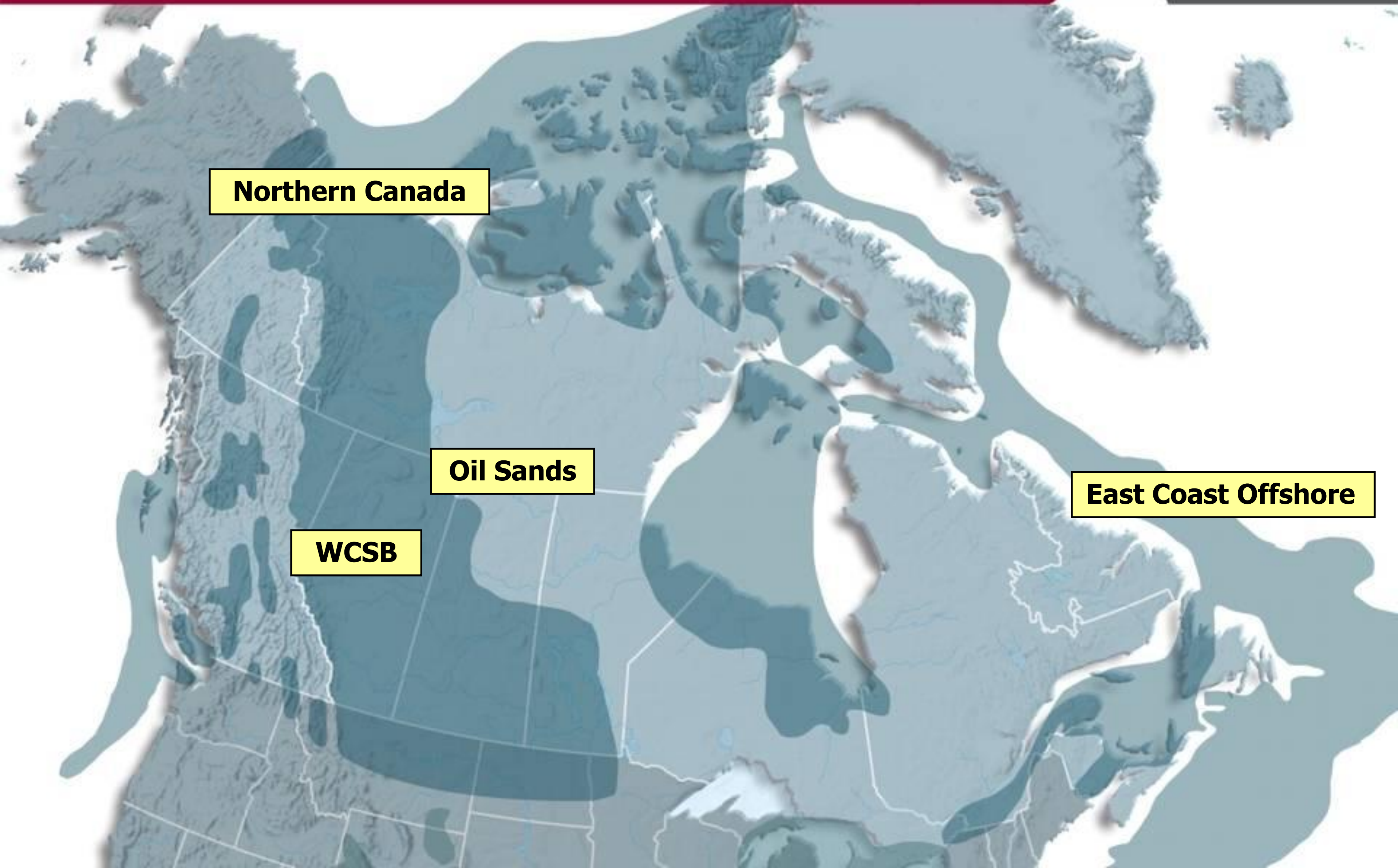
Canada’s Crude Oil and Natural Gas Industry

CAPP

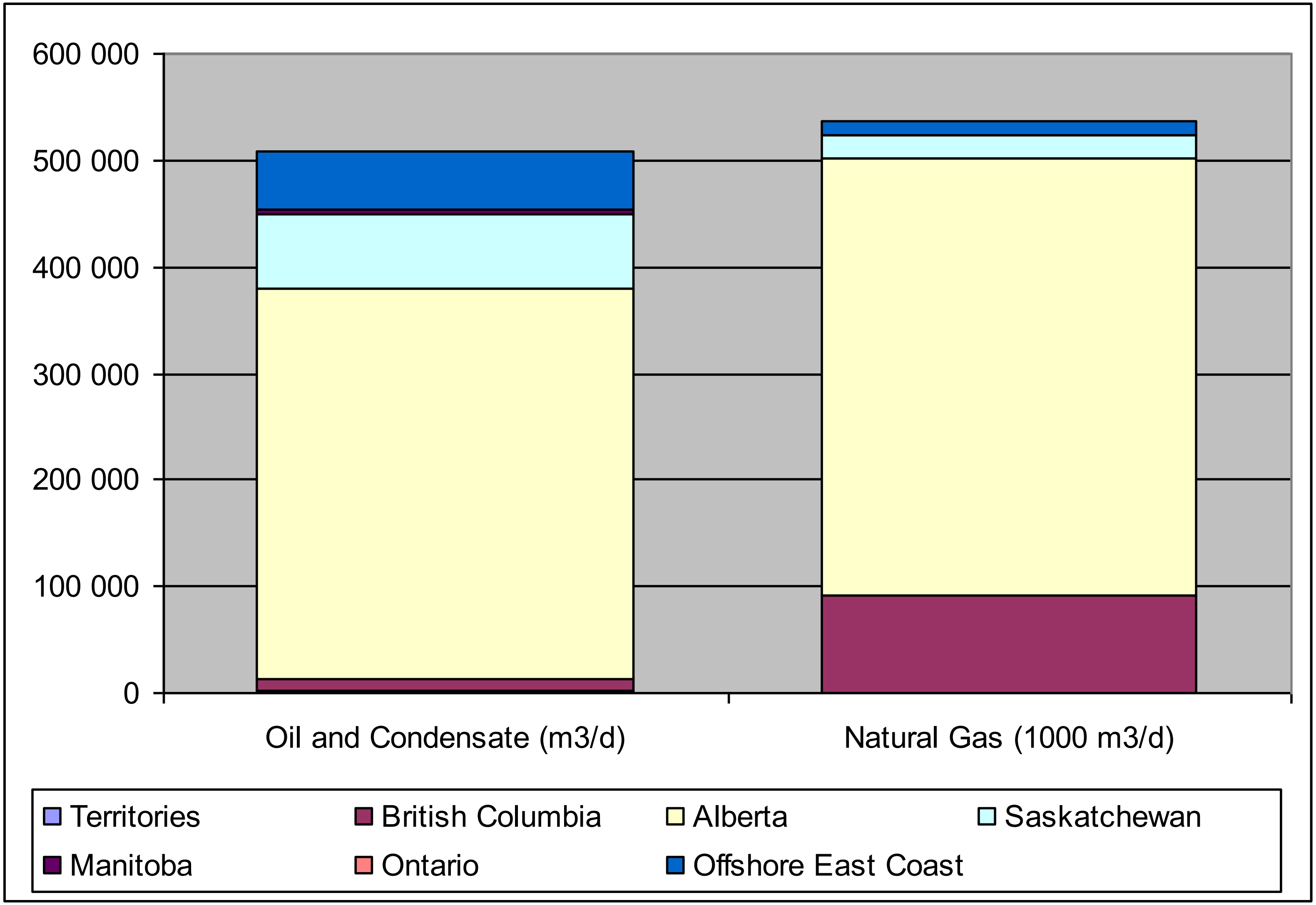
- **World’s 3rd largest natural gas producer**
- **World’s 7th largest crude oil producer**
- **Canada is the 5th largest energy producer in the world**
- **Employment near 500,000 in Canada**
- **Invested $50 billion in 2008**
  - Largest single private sector investor in Canada
- **Canada is the largest supplier of energy to the United States**

2008	Canadian Natural Gas	Canadian Petroleum
Share of U.S. consumption	15%	12%
Share of U.S. imports	90%	19%

Canada's Oil and Gas Basins

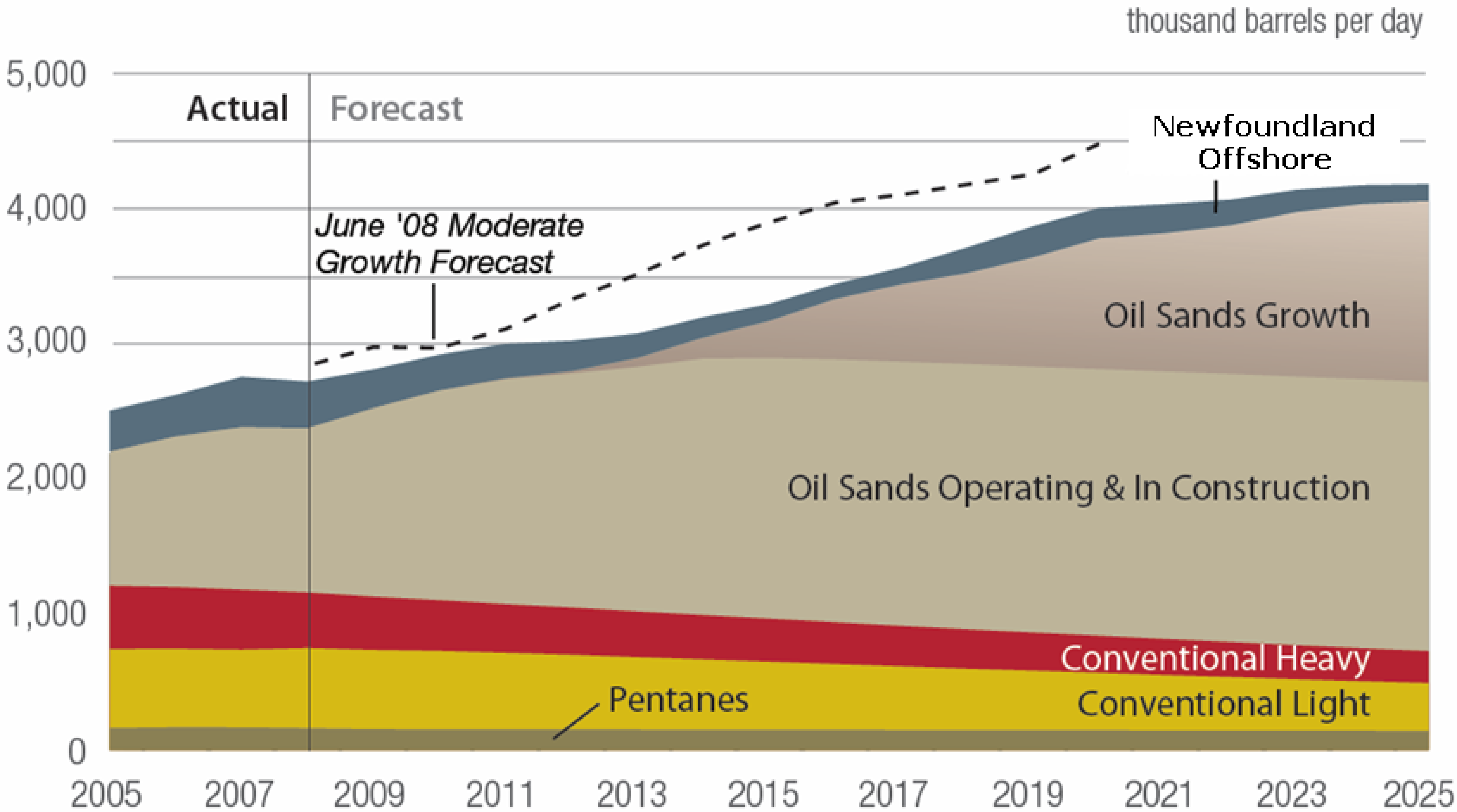


Canadian Oil and Gas Production

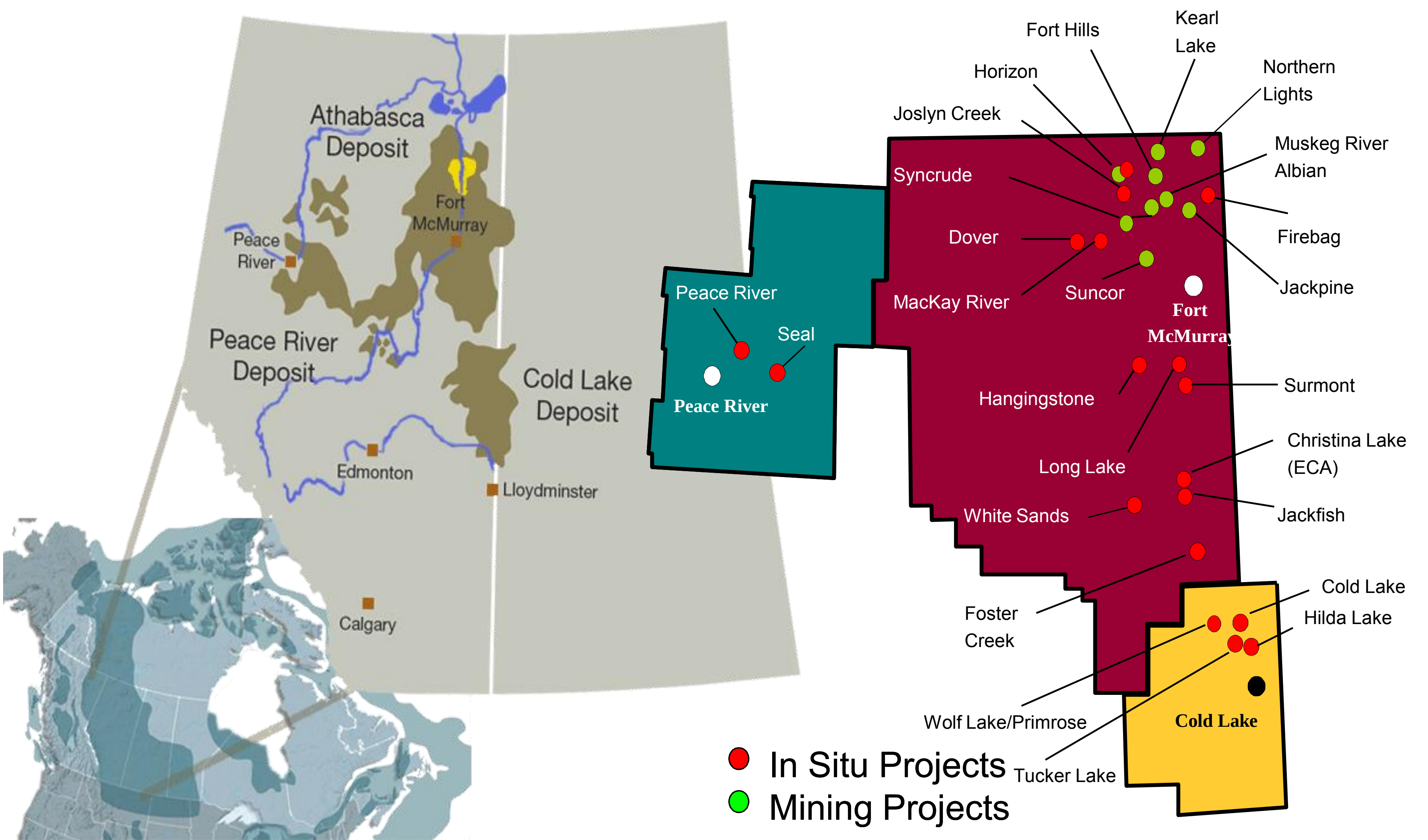


Source: CAPP Statistical Handbook 2009

Total Canadian Oil Production



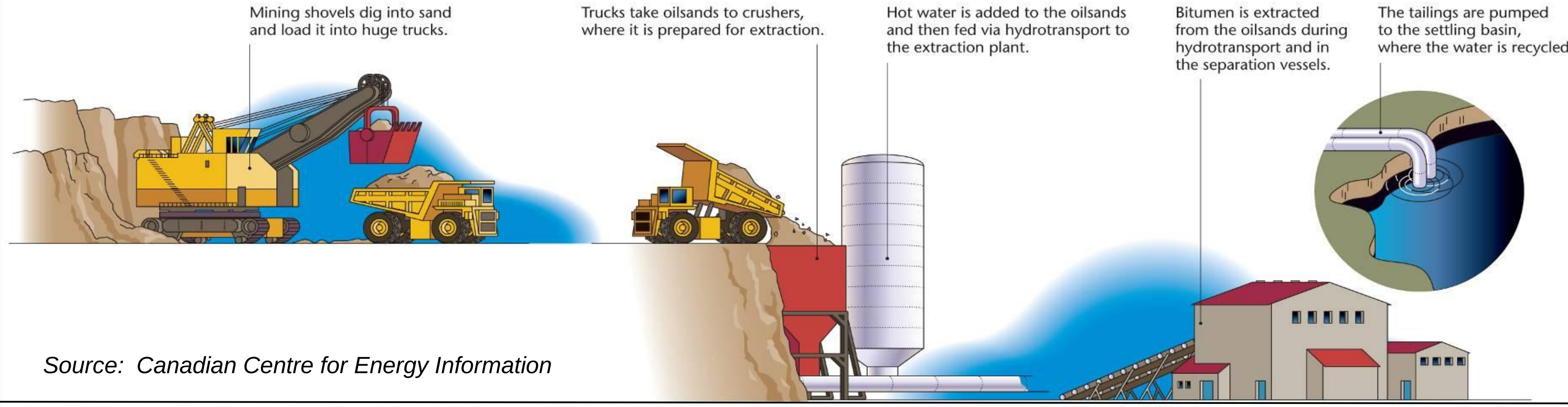
Oil Sands Projects in Three Deposits



Oil Sands Production Technologies

CAPP

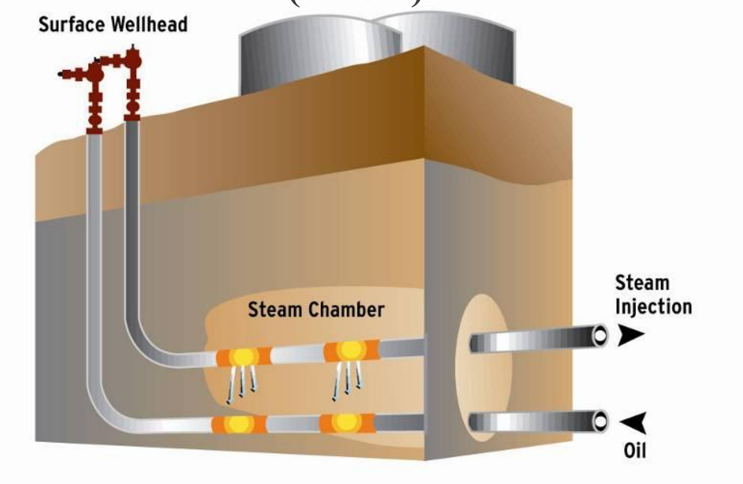
Mining – oil sands less than 200 feet deep



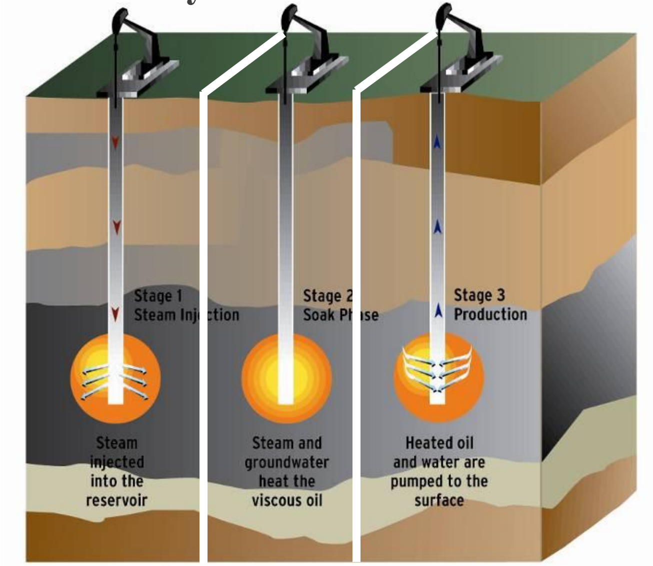
Source: *Canadian Centre for Energy Information*

In situ – oil sands more than 200 feet deep

Steam Assisted Gravity Drainage (SAGD)



Cyclic Steam Process



Oil Sands Mining – Truck and Shovel

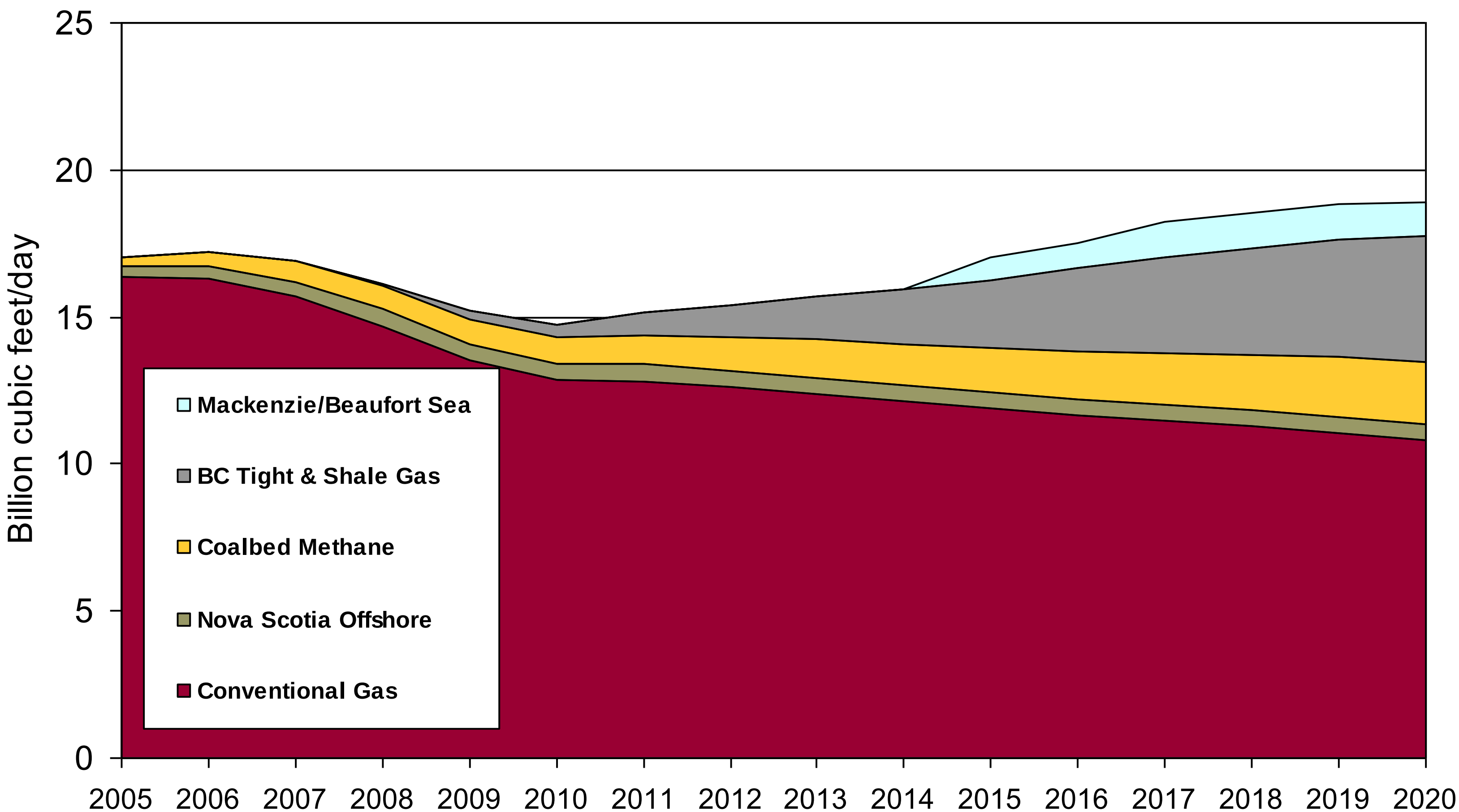
CAPP

- 20% reserves will be produced with mining

In-Situ Oil Sands Production

- **80% of the oil sands will be developed in situ which accounts for 97.5 per cent of the total surface area of the oil sands region in Alberta.**

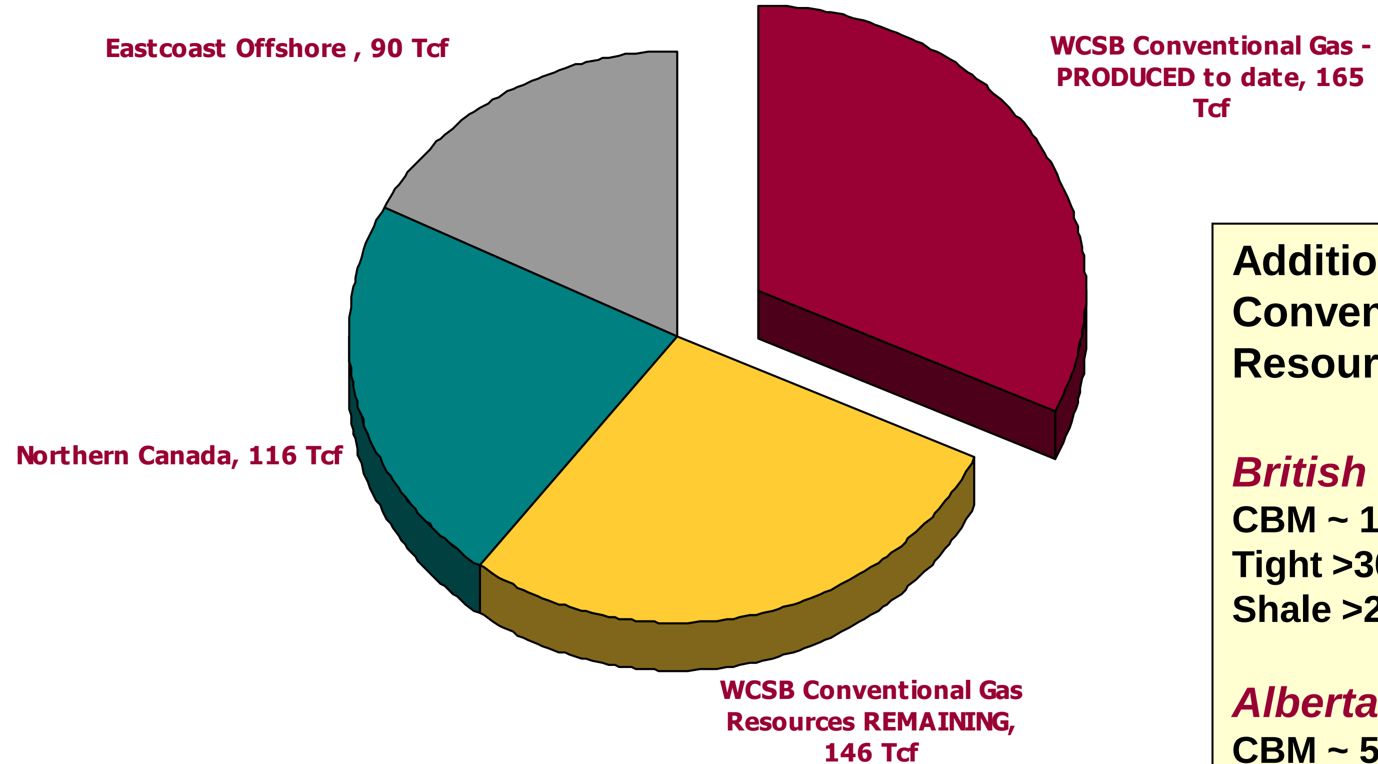
Canadian Natural Gas Production Forecast



Sources: CAPP

Canadian Natural Gas Resources - Conventional and Non-Conventional

RECOVERABLE RESOURCES (Conventional)



Additional Non-Conventional Natural Gas Resources (in place)

British Columbia

CBM ~ 100 tcf
Tight >300 tcf
Shale >250 tcf

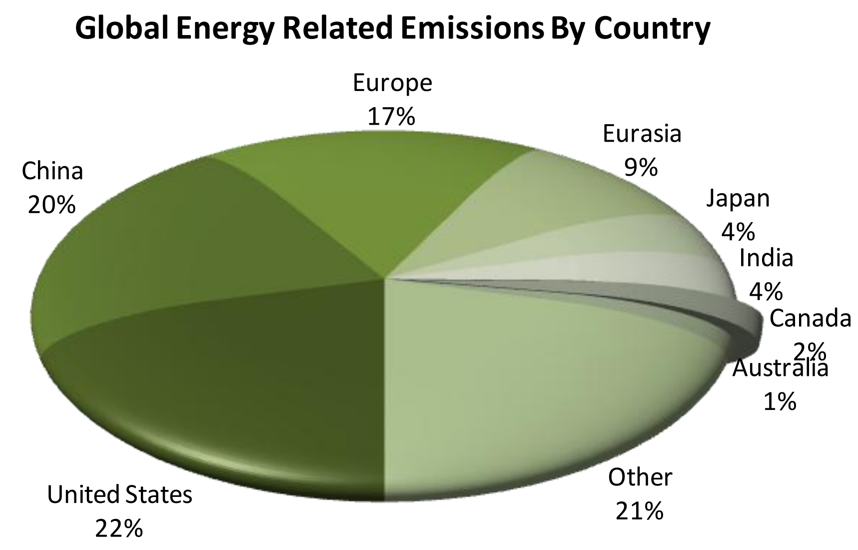
Alberta

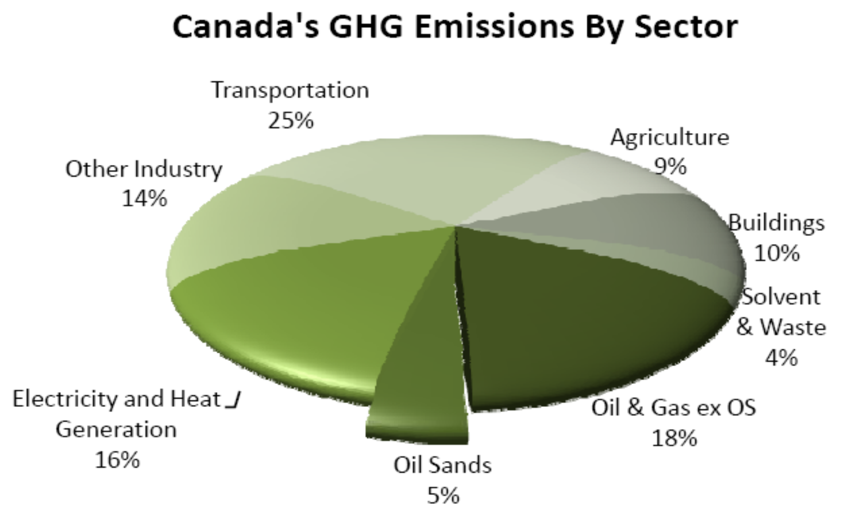
CBM ~ 500 tcf

Source: National Energy Board
British Columbia Ministry of Energy, Mines & Petroleum Resources
Alberta Geological Survey

Greenhouse Gas Emissions

- **All of Canada accounts for 2% of global energy related GHG emissions**
- **Oil Sands is continuing to reduce GHG emissions**
  - Some projects have reduced their GHG intensity by 38% since 1990
  - Increasing energy efficiency
  - Starting CO_2 capture, sequestration and EOR
- **Oil Sands accounts for:**
  - 5% of GHG emissions in Canada
  - 0.1% of global energy related GHG





Canada’s Greenhouse Gas Policies & Programs – British Columbia

- **GHG Emission Reduction Targets**
  - 33% below 2007 by 2020
  - 80% below 2007 by 2050
- **Oil And Gas Flaring Targets**
  - 50% reduction in flaring by 2011
  - Elimination of routine flaring by 2016
- **Carbon Tax**
  - In effect July 1, 2008, starting at $10/t
  - Currently $15/t (rising to $30/t by 2012)
  - Applied to all fuel use (industrial/commercial/domestic)
  - Revenue neutral – reduced taxes for individuals and businesses
- **Reporting Regulation in force January 1, 2010**
  - Verification Required: > 25,000 kt/year
  - Reporting for Oil & Gas: > 10,000 kt/year

Canada's Greenhouse Gas Policies & Programs – Alberta

- **GHG Targets**
  - By 2020: reduce emissions by 50 megatonnes
  - By 2050: reduce emissions by 200 megatonnes, or 14% below 2005 levels
- **Specified Gas Emitters Regulation**
  - Legislation passed, July 2007
  - Requires immediate 12% reduction in emission intensity for large emitters
  - Applies to large emitters >= 100kt
    - ~100 facilities
    - Covers 70% of AB's industrial GHG emissions and 50% total
  - Compliance mechanisms:
    - Direct reductions
    - \$15/tonne CO_2 levy into Technology Fund
    - Alberta-based Offsets
  - Independent verification for baseline report and each annual compliance report
    - Verified to a "Limited Level" of assurance (moderate risk level)
- **Reporting in 2009 > 50kt**

Canada's Greenhouse Gas Policies & Programs – Saskatchewan

- **GHG Reduction Target**
  - Stabilize emissions by 2010
  - 20% reduction from 2006 levels by 2020
- **Regulations expected in 2010**
  - Intensity-based system similar to AB
  - Reduction targets similar to AB
  - Compliance by emissions reductions, offsets or technology fund (100% access)
- **Reduction Plan**
  - Conservation and energy efficiency
  - CCS for oil and gas and power generation
  - Renewable energy
  - Reductions in methane emissions from oil & gas
  - Carbon sinks in soils and forests

Challenges with UOG – GHG Reporting

- **Number of facilities**
  - 200,000 Wells
  - 20,000 Batteries
  - 12,500 Gas Gathering Systems
  - 3,000 Injection Facilities
  - 700 Gas Processing Plants
- **Size ranges (emissions)**
  - Average Well ~20 t/y CO_2e (equipment leaks, venting, pumpjack, dehydrator/line heater)
  - Average Gas Plant ~31,000 t/y CO_2e (separation, sweetening, compression, dew point control, fractionation, sulphur recovery, formation CO_2)

Challenges with UOG – GHG Reporting

- **No CEMS requirements**
- **Measurement challenges**
  - Facilities have total fuel measurement (fuel meter)
    - Fuel is not usually metered at the equipment level
    - Well sites often do not meter fuel use (it is estimated and reported)
  - Production Accounting – reporting measured value or defensible estimate
    - All gas volumes (fuel, flare, vent) > 0.1×10^3 m^3/month must be reported
    - Volumes > 0.5×10^3 m^3/d must be metered
    - Volumes < 0.5×10^3 m^3/d can be estimated
  - Casing gas venting – based on GOR values
    - 24 h GOR tests required annually for venting wells
  - Instrument venting & pneumatic devices
    - Gas volume is required to be reported in the fuel volume
    - Potential to over-report emissions if vented gas is not backed out of fuel
  - Fugitive equipment leaks based on emission factors – OK for large population but may not accurately characterize facility emissions
  - Sampling of fuel streams limited – leads to emission factor uncertainty

Western Climate Initiative

Defining the Reporting Entity and Threshold

Reporting Committee
Dennis Paradine, British Columbia

Defining the Reporting Entity

- Oil and gas industry emission sources are often small and distributed over a large geographic area
- Together these emissions can contribute significantly to total GHG emissions
- To ensure WCI captures 90% of emissions from oil and gas as it does with other sectors, individual oil and gas sources may need to be aggregated into reporting entities

Oil and Gas Reporting Entity Options

A – do not aggregate emissions, apply existing facility definition

B – aggregate emissions to the field level

C – aggregate emissions to the basin level

D – aggregate emissions to the jurisdiction level

- WCI (or EPA) facility definition clause “are under common control of the same owner(s) or operator(s)” would be used in defining the reporting entity, with the adjacency clause discarded

- WCI Oil and Gas ERMR would include not only oil and gas sources in draft EPA Subpart W, but also additional sources that the WCI intends to capture

Defining Oil and Gas Thresholds

- 10,000 tonne reporting and 25,000 tonne verification threshold applies to all other source categories

- There is a direct interaction between how the oil and gas entity is defined and the appropriate threshold level
  - Basin level coverage may allow for higher reporting entity thresholds compared to field level coverage
  - Higher thresholds would lower the number of reporters and lower emissions coverage

- Barrel of oil equivalent thresholds have also been suggested

Feedback – Reporting Entity and Threshold

- Is the basin the appropriate level at which to define a reporting entity for the WCI mandatory reporting program?
- Would a 10,000 tonne reporting (and a 25,000 tonne verification) threshold for an oil and gas reporting entity capture 90% of emissions from the sector?
- Would an analogous barrel of oil equivalent threshold be better to use?

Western Climate Initiative

Contractor Emissions

Reporting Committee

Dennis Paradine, British Columbia

Contractor Emissions

- Oil and gas installation operation varies between producers and contracted service providers
  - With multiple owners, one company can be assigned operational control and perform the work or contract it out.
- Excluding contractor emissions could lead firms to contract out operations to avoid reporting or cap and trade obligations
- The above two points raise issues of equitable coverage
- Concerns have been noted about potential burdens in reporting contractor emissions
  - Are sufficient contracts in place to ensure GHG data is reported?

Contractor Emissions Options

A – Not require reporting of contractor emissions.

- Neither the oil and gas producer nor the contractor report emissions

B – Require contractors to report if aggregated emissions exceed threshold.

- Contractors report all emissions associated with the operations they are contracted for (if > threshold.)

C – Include venting, fugitive and flaring emissions from a contractor in the emissions of the owner/operator.

- The producer reports all emissions (excluding combustion) from contractor operations

D – Include all emissions in C and combustion emissions from contractors, other than portable combustion emissions.

- The producer reports all emissions associated with contractor operations including combustion emissions, other than portable combustion emissions.

E - Include all emissions in D and portable combustion emissions from contractors .

- The producer reports all emissions associated with contractor operations including portable combustion emissions occurring on-site

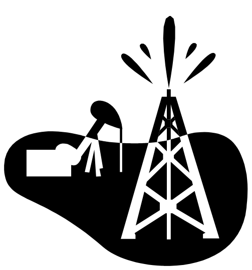
Feedback – Contractor Emissions

- How to minimize inequitable coverage and potential facility splitting?
- What is the appropriate boundary for reporting oil and gas emissions from contractors?
    - WRAP / TCR uses Option C (above). Is it appropriate to extend to include combustion emissions from a contractor for a mandatory reporting program?
- Would phasing in types of reporting of contractor emissions help to reduce burden?

Defining the Upstream Oil and Gas Sector: Exploration, Production, and Natural Gas Gathering and Processing

Western Climate Initiative – Oil & Gas Collaborative
Santa Fe, NM
November 19, 2009

Tom Moore
Air Quality Program Manager, Western Governors' Association



Acknowledgements for those supporting the Upstream O&G Protocol work to date

- Project Sponsors – NM, CARB, TCR
- Project additional funding support (Chevron, BP, Alberta Environment Ministry, API)
- Lee Gribovicz, WRAP staff
- SAIC and ENVIRON for technical support
- Ross & Associates for facilitation
- Technical WorkGroup members for expert review & frank advice

- O&G GHG Reporting Protocol project webpage

Oil and Gas “Upstream” sources & activities

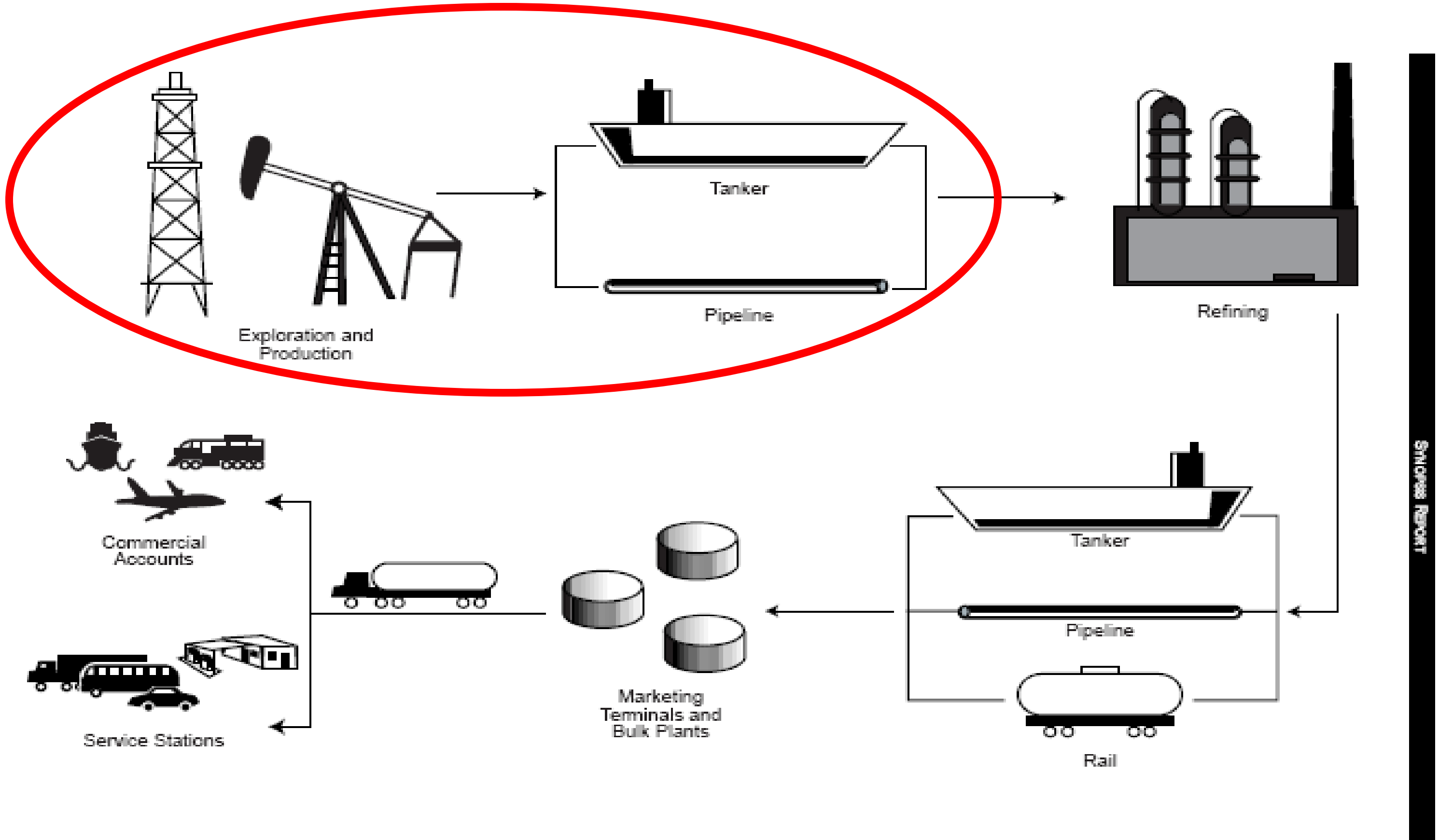


Figure 1—Major Emission Sources for an Integrated Oil Company

Figure 1—Oil and Gas Industry Schematic of GHG Emissions

Source: American Petroleum Institute: Toward a Consistent Methodology for Estimating Greenhouse Gas Emissions from Oil and Natural Gas Industry Operations. Page 4.

Geographic Scope and Source Types addressed in developing work on Upstream Reporting Protocols to date

- North America
- All O&G source activities upstream of:
  - Oil refineries (GHG reporting covered by ARB regulation)
  - Gas sale pipeline transfer points (CCAR/WRI/TCR protocol)
- Types of O&G E&P
  - Conventional Oil & Gas
  - Unconventional Gas
    - Tight Sands Gas
    - Gas Shale
    - Coalbed Methane Gas
    - Oil Sands
  - Oil
    - Offshore
    - Enhanced Oil Recovery
    - Oil Sands

Emissions Inventory Sources addressed in Protocol work to date

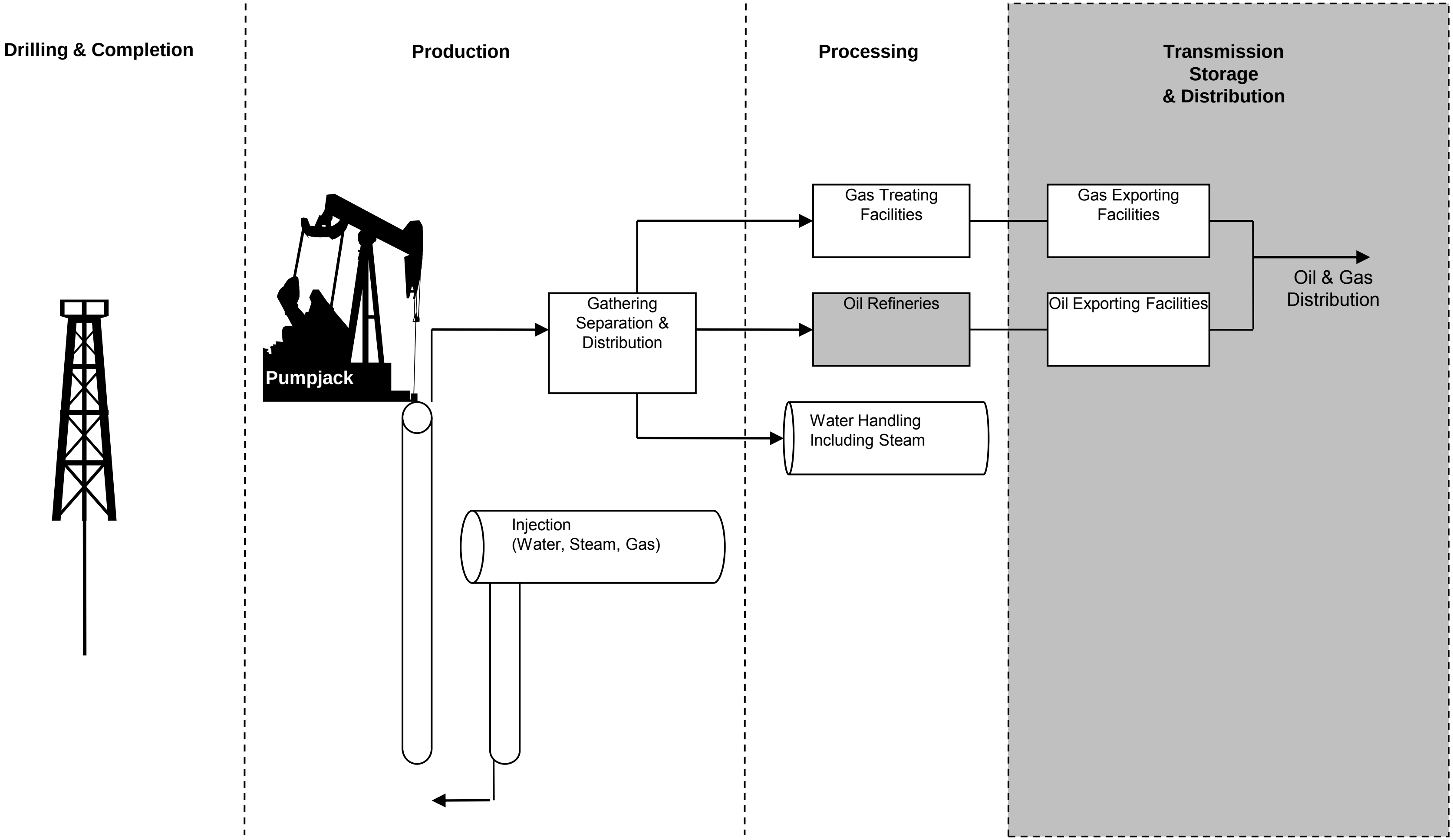
- Gas Processing Plants
- Compressor Stations
- Wellhead Compressor Engines
- CBM Pump Engines
- Miscellaneous/Exempt Engines
- Drilling/Workover Rigs
- Salt-water Disposal Engines
- Artificial Lift Engines (Pumpjacks)
- Vapor Recovery Units (VRUs)
- Oil/Gas Well Heaters
- Hydrocarbon Liquid Storage Tanks

- Well Completions
- Fugitive Emissions
- Completion Venting
- Well Blowdowns
- Dehydration Units
- Amine Units
- Hydrocarbon Liquid Loading
- Landfarms
- Water Treatment/Injection
- Flaring
- Pneumatic Devices
- Produced Water Tanks
- Crude Oil Transportation

Sources included/not included in the Upstream O&G sector

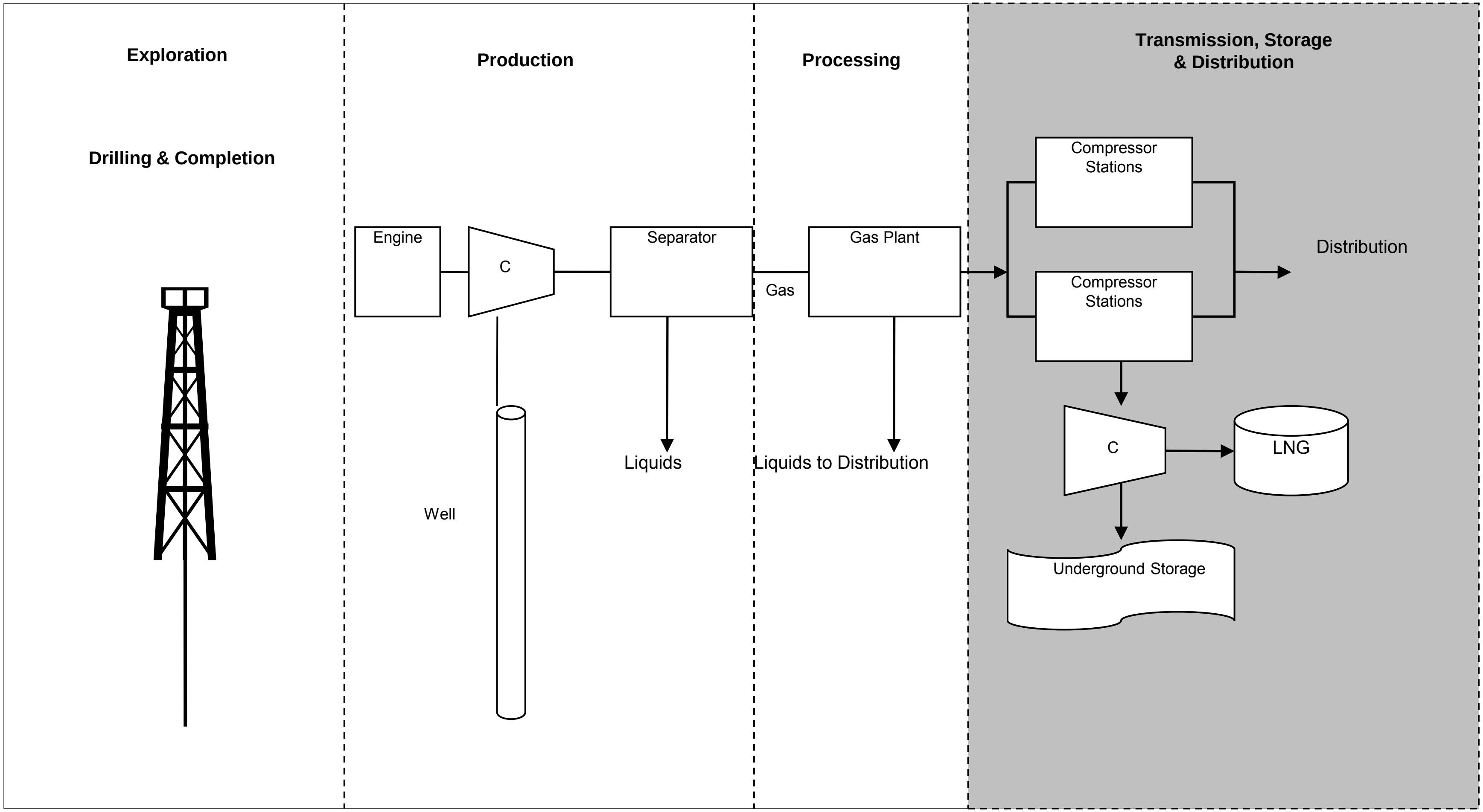
- Includes all emissions sources in the:
  - **Exploration and production** (E&P) sector of **oil** & **natural gas, as well as:**
    - **Gas gathering, collection, and processing** - through to the "tailgate" of Natural Gas Processing Plants
    - **Crude Oil Transportation** (including pipelines, trains, trucks, and marine vessels) to the "entry gate" of Oil Refineries
- ***Does not include***:
  - Oil refining and downstream distribution of petroleum products
  - Transmission, storage and distribution of natural gas downstream of the processing plant
- Includes ***all*** companies involved in any way in E&P, natural gas processing, and/or crude oil transportation, including:
  - Oil and Gas leaseholders
  - Support services contractors (e.g., drilling contractors)

Oil Industry Sector



Upstream O&G Protocols do not address oil operations shown in the shaded area.

Natural Gas Industry Sector



Upstream O&G Protocols do not address natural gas operations shown in the shaded area.

Facility Issue Addressed in Protocol work to date

- Definition of a facility/Aggregation of emissions:
  - **Proposed Solution:** Dispersed emission sources to be aggregated, at a minimum, to "production field" level:
    - *Production field is a well understood, broadly accepted concept within the industry*
    - *Production fields are precisely defined by state, province, or country*
  - Reporters are given the option of aggregating multiple fields together (particularly useful, e.g., for infrastructure common to more than one field)
  - Emissions from sources corresponding to standard definition of a facility (e.g., natural gas processing plants) must be reported by facility

Questions -

Western Climate Initiative

Federal GHG Legislation

Potentially Affecting the Upstream Oil and Gas Industry

Summarized by Paula Fields, ERG

for the Oil and Gas Collaborative

Santa Fe, New Mexico

November 19, 2009

Federal GHG Legislation

- Proposed "Endangerment and Cause or Contribute Findings for Greenhouse Gases under the Clean Air Act" – April 24, 2009
- Promulgation of final Mandatory Reporting Rule (MRR) for Greenhouse Gases – September 22, 2009
- Proposed PSD and Title V Greenhouse Gas Tailoring Rule (September 30, 2009)
- American Clean Energy and Security Act of 2009 (ACES) (Waxman-Markey Climate Change Bill, HR2454)
- Clean Energy Jobs and American Power Act (CEJAPA) (Introduced to Senate on September 30, 2009)

Proposed PSD and Title V Greenhouse Gas Tailoring Rule

- "Tailors" NSR requirements to limit the number of facilities required to obtain NSR permits
- Applicability:
  - Title V major source threshold: 25,000 tons CO_2e
  - PSD permit applicability thresholds:
    - New sources or existing source making major modifications: 25,000 tons CO_2e
    - Significance level for major source modification increase: 10,000 to 25,000 tons CO_2e (single value to be selected)
- Covers ~70% of the national GHG emissions from stationary sources
  - 14,000 large sources will require Title V permits (3,000 new)
  - 400 new/modifications will require PSD review (100 new)

The American Clean Energy and Security Act of 2009 (ACES), H.R. 2454

- Targets
  - Economy-wide reductions from 2005 levels
  - Interim reductions; 17% by 2020
  - 83% by 2050
- Allowance Allocations
  - 85% distributed (incl. 9% to NG distributors; 2% to refineries)
  - 15% for auction in 2012
- Cost Containment
  - Via offsets
  - Sets price, adjusts for inflation
- Offsets
  - 2 billion credit ceiling
  - 1 billion each domestic, international
  - Special provisions for domestic agriculture and forestry sources
- Technology
  - Renewable electricity standard
- Technology (cont.)
  - Electric vehicles and infrastructure development
  - New performance standards for sources individually emitting <10,000 tons CO_2e
- Competitiveness
  - Rebates (allocations) to energy-intensive, trade-sensitive industries, oil refineries, etc.
  - May require border tariffs in 2020
- CAA and Regulatory Authority
  - Establishes GHG registry with 10,000/ 25,000 tons CO_2e thresholds (entities/vehicle fleets)
  - Removes EPA authority to further regulate GHGs from large sources
  - Puts state trading programs on hold from 2012-2017
  - Eliminates NSR applicability to GHGs

Clean Energy Jobs and American Power Act (CEJAPA)

- Targets:
  - Economy-wide reductions from 2005 levels
  - Interim reductions; 20% by 2020
  - 83% by 2050
- Allowance Allocations
  - 78% distributed (incl. 9% to NG distributors; 2.25% to refineries; 30% to LDCs)
  - 22% for auction in 2012
- Cost Containment
  - Via offsets
  - Sets price, adjusts for inflation
- Offsets
  - 2 billion credit ceiling
  - 1 billion each domestic, international
  - (No special provisions for domestic agriculture and forestry sources)
- Technology
  - National strategy, early deployment of CCS program
  - (No renewable standard)
  - Transportation efficiency standards
  - Removes barriers for nuclear
- Competitiveness
  - Rebates (allocations) to energy-intensive, trade-sensitive industries, oil refineries, etc.
  - Will contain border measures
- CAA and Regulatory Authority
  - Maintains EPA authority to further regulate GHGs from large sources
  - Does not put state trading programs on hold
  - Does not eliminate NSR applicability to GHGs

Resources

- http://www.epa.gov/climatechange/index.html
- http://www.epa.gov/nsr
- http://www.house.gov/
  - http://energycommerce.house.gov/Press_111/20090602/hr2454_reported_summary.pdf
- http://www.senate.gov/
  - http://kerry.senate.gov/cleanenergyjobsandamericanpower/pdf/SectionbySectionSummary.pdf
- http://www.rff.org/wv/Documents/Major_domestic_bill_comparison_091027.pdf
- http://www.pewclimate.org/docUploads/waxman-markey-detailed-summary-july2009.pdf

E&P GHG Inventory

A Daunting Challenge

The Challenge

- Size of Industry – **Its Big**
- Complexity
  - Operating Environments
  - Types of Operations
  - Ages of Operations
  - Business Arrangements
  - Number, Size, and Capabilities of Operators
- Dispersed Nature
- Multiple Regulatory Schemes and Agencies
- Technically Difficult Sources

Arctic to Sub-Tropical

Onshore and Offshore

Deep Water and Shallow Water

Heavy Oil to Dry Gas

Old to New

High Tech to Low Tech

Giant Companies to Tiny Companies

Remote Locations

Technically Difficult Sources

Operating Environments and Complexity

United States & Canada
Distribution of Wells by Production Rate Bracket

	United States						Canada						Combined	
	Oil Wells			Gas Wells										
Prod. Rate Bracket (BOE/Day)	# of Oil Wells	% of Oil Wells	% of Oil Prod.	# of Gas Wells	% of Gas Wells	% of Gas Prod.	# of Oil Wells	% of Oil Wells	% of Oil Prod.	# of Gas Wells	% of Gas Wells	% of Gas Prod.	# of Wells	% of Wells
0 - 1	125,933	35.4	1	83,132	19.9	0.3	4,382	7.0	0.1	4,500	6.2	0.1	217,947	24%
Subtotal <=10	***275,362***	***77.4***	***13.3***	***271,109***	***64.7***	***7.9***	***26,935***	***43.1***	***7.3***	***39,453***	***53.9***	***5.5***	612,859	67%
Subtotal <=15	***302,220***	***85***	***19.9***	***309,340***	***73.9***	***12.3***	***34,632***	***55.5***	***13.2***	***46,087***	***63.0***	***8.1***	692,279	76%
15 - 20	13,589	3.8	4.8	22,948	5.5	3.7	5,362	8.6	5.8	3,619	4.9	2.0	45,518	5%
20 - 25	8,670	2.4	3.9	14,741	3.5	3	3,781	6.1	5.3	2,500	3.4	1.8	29,692	3%
25 - 30	5,710	1.6	3.1	10,403	2.5	2.6	2,899	4.6	4.8	2,053	2.8	1.8	21,065	2%
30 - 40	7,352	2.1	5	13,526	3.2	4.3	4,099	6.6	8.7	3,095	4.2	3.4	28,072	3%
40 - 50	4,799	1.3	4.1	8,660	2.1	3.5	2,772	4.4	7.6	2,352	3.2	3.3	18,583	2%
50 - 100	7,703	2.2	9.9	19,038	4.5	11.6	5,806	9.3	24.4	6,600	9.0	14.1	39,147	4%
100 - 200	3,009	0.8	7.4	11,517	2.8	12.9	2,193	3.5	16.8	4,097	5.6	17.8	20,816	2%
200 - 400	1,311	0.4	6.4	5,173	1.2	10.8	619	1.0	7.8	1,810	2.5	15.8	8,913	1%
400 - 800	606	0.2	5.8	1,852	0.4	7.3	222	0.4	3.9	590	0.8	10.3	3,270	0%
800 - 1600	253	0.1	4.8	814	0.2	6.7	52	0.1	1.1	228	0.3	8.2	1,347	0%
1600 - 3200	160	0	6.3	450	0.1	8.1	4	0.0	0.4	77	0.1	5.4	691	0%
3200 - 6400	95	0	7.3	233	0.1	8.5	1	0.0	0.2	40	0.1	5.7	369	0%
6400 - 12800	47	0	7.1	57	0	3.9	0	0.0	0.0	8	0.0	2.3	112	0%
> 12800	13	0	4.3	6	0	0.8	0	0.0	0.0	0	0.0	0.0	19	0%
Remainder	53,317	15	80	109,418	26	88	27,810	45	87	27,069	37	92	217,614	24%
Total	***355,537***	***100***	***100***	***418,758***	***100***	***100***	***62,442***	***100.0***	***100.0***	***73,156***	***100.0***	***100.0***	909,893	100%

Then there is the collection, compression, treating, and processing

WRAP and TWG Significant Sources

- **Task to categorize significant sources by basin for the 6 member states/provinces in the WCI**
  - **Includes New Mexico, California, Utah, Montana, British Columbia and Manitoba**
  - **Significance = sources contributing to the top 95% of GHG emissions in a basin**
  - **Basins defined using USGS basin boundary definitions**
- **Screening-level inventories vs. reporting**
  - **Screening-level inventories developed at the basin level - attempt to account for regional variations in the significant sources**
  - **This is only for purposes of determining significant sources – not reporting**

Basin Examples

San Juan (South Basin)[1]	Uinta Basin[2]
Permitted Compressor Engines (24.5%)	Heaters/Boilers (21.9%)
Permitted Heaters/Boilers (13.9%)	Unpermitted Compressor Engines (6.3%)
Unpermitted Compressor Engines (13.0%)	Permitted Compressor Engines (5.9%)
Permitted NG Turbines (7.4%)	Artificial Lift Engines (5.6%)
Unpermitted Heaters/Boilers (6.8%)	Drill Rigs (3.8%)
Workover Rigs (1.6%)	
Artificial Lift Engines (1.2%)	

San Juan (South Basin)[1]	Uinta Basin[2]
Well Completion Venting (17.8%)	Pneumatic Devices (32.2%)
Well Blowdowns (7.2%)	Pneumatic Pumps (15.6%)
Flaring (1.2%)	Wellhead Fugitives (4.1%)
Wellhead Fugitives (1.1%)	

Type of Production Example

California Offshore	Tight Sands Gas	CBM Gas
Gas Turbines (57.7%)	Compressor Engines (33.0%)	Compressor Engines (46.0%)
Supply Boats (2.2%)	Heaters/Boilers (17.5%)	Heaters/Boilers (25.4%)
	Drill Rigs (3.9%)	
	Workover Rigs (1.8%)	
	Turbines (1.6%)	
Flaring (20.1%)	Pneumatic Devices (14.3%)	Well Blowdowns (15.3%)
Fugitives (16.1%)	Fugitives (10.9%)	Fugitives (4.7%)
	Flaring (7.6%)	Pneumatic Devices (3.5%)
	Condensate Tanks (2.7%)	Flaring (2.6%)
	Well Blowdowns (2.2%)	

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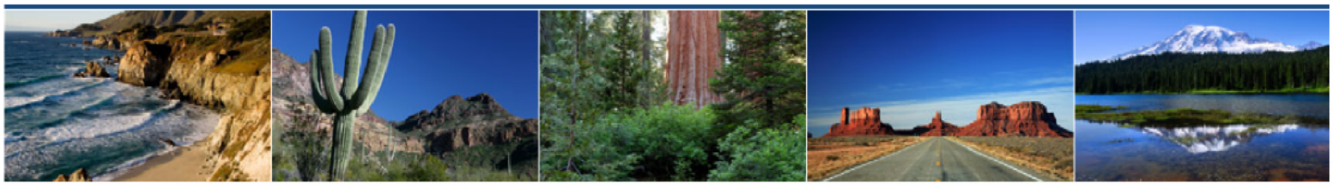

Issue Paper -- Defining the Reporting Entity and Threshold

Issue:

Greenhouse gas emission sources in the oil and gas industry often consist of small sources distributed over a broad geographic area that, when taken together, can contribute significantly to total GHG emissions in their regions. Large numbers of these emissions sources are typically owned and/or operated by the same company, although ownership (and operation) is not necessarily determined exclusively on the basis of geographic proximity. While many of the oil and gas emission sources in the oil and gas sector are small, some individual oil and gas facilities are large enough to be captured under the current reporting and verification thresholds. To ensure that a comparable portion of emissions is captured in the oil and gas sector as in other sectors, individual small oil and gas sources may need to be aggregated into oil and gas reporting entities for the purposes of reporting GHG emissions to WCI jurisdictions.

In discussions of this issue, it should be noted that the oil and gas industry in Canada can be vertically integrated (i.e. the producing company can also own the natural gas plant and/or the transmission company), while in the United States such vertical integration is prohibited by FERC regulations.

WRAP/TCR Approach:

Aggregate and report emissions from small individual oil and gas sources which are owned and/or operated by a company at the field level. Large sources that meet the traditional definition of a standalone facility must be reported separately to maintain transparency. Reporting thresholds would be established at the field level for small sources and at the facility level for sources meeting the traditional definition of a facility. Companies have the option to aggregate multiple fields together up to the state-level for reporting convenience.

EPA Approach:

Not applicable – deferred to final Subpart W.

WCI Options:

The basic option would be to follow the general WRAP/TCR approach (defining the reporting entity as outlined in the first option table below), adding the following detail needed for a mandatory reporting program:

1. Use the WCI.9 (or EPA) facility definition part c clause: 'are under common control of the same owner(s) or operator(s)' for aggregation purposes. Discard part b of the same definition for aggregation purposes.

2. Apply thresholds (as outlined in the second option table below) to the aggregated emissions to create an 'Oil and Gas Installation'
3. Allow jurisdictions flexibility to aggregate emissions to a higher level than the WCI determines.
4. Apply to all oil and gas emissions sources covered under EPA Subpart W and those emissions sources not included in Subpart W but to be included in the WCI Oil and Gas Essential Requirement. Apply similarly to all emission sources involved in carbon transfer.

Defining the Reporting Entity

Option	Pros	Cons
A. Do not aggregate emissions. Apply existing facility definition to oil and gas installations	Simple, follows current WCI facility definition.	Due to disaggregated sources, may not meet WCI principle of covering a significant portion of emissions
B. Aggregate emissions to the field level	WRAP approach Emission factors likely similar at a field level	May not meet WCI principle of covering a significant portion of emissions unless lower thresholds are used. Fields vary in size, potentially creating inequity between leaseholders in different fields
C. Aggregate emissions to the basin level	Extends WRAP field approach to a scale potentially more suitable for a mandatory program. With appropriate thresholds would likely meet WCI design principle of covering a significant portion of emissions with as few facilities and reporting entities as possible.	Appropriate thresholds would need to be determined. Variable emission factors may need to be used in different fields.

D. Aggregate emissions to the jurisdiction level	Extends WRAP approach to a scale potentially more suitable for a mandatory program. With appropriate thresholds would likely meet WCI design principle of covering a significant portion of emissions with as few facilities and reporting entities as possible.	Appropriate thresholds would need to be determined. Variable emission factors may need to be used in different fields.

Reporting Thresholds

Option	**Pros**	**Cons**
A. Existing WCI thresholds: 10,000 tonnes reporting, 25,000 tonnes verification	Follows current WCI standards. Easy to communicate	May not meet WCI principle of covering a significant portion of emissions. May need more detailed reports from a reporting entity to understand the distribution of emission sources.
B. Lower thresholds	Would capture a higher portion of emissions and may meet the WCI principle of covering a significant portion of emissions. May not require more detailed reports from a reporting entity to understand the distribution of emission sources.	May or may not meet WCI principle of covering a significant portion of emissionswith as few facilities and reporting entities as possible. May increase reporting burden for small companies.

C.	**Higher thresholds**	May reduce reporting burden for small companies. Potentially could meet WCI principle of covering a significant portion of emissions with as few facilities and reporting entities as possible.	May not meet WCI principle of covering a significant portion of emissions May need more detailed reports from a reporting entity to understand the distribution of emission sources.
D.	**Base thresholds of a similar amount of barrels of oil equivalent**	May be easier to determine obligations for the oil and gas industry.	Deviates from WCI emissions thresholds approach for reporting and verification

Note: there is a relationship between how the reporting entity is defined and the appropriate thresholds to use. A broader reporting entity may mean a higher threshold could be used. A smaller reporting entity may mean a lower threshold is needed. The optimum combination of reporting entity definition and threshold to meet the design principle may not be known until one or more years of reported data is available at a finer scale than that ultimately required for the long-term.

Possible Quantification Methodology:

'Oil and Gas Installation' emissions could be calculated using the following general approach:

i. Include all oil and gas installations covered by EPA Subpart W, those other installations deemed appropriate and included in the WCI Oil and Gas Essential Requirement and all WCI and/or EPA source categories (e.g. stationary combustion).

ii. Include, exclude, or extend applicability for contractor emissions as determined by the WCI through this process.

iii. Apply emission factors to installations at the well, gathering location or field level (as appropriate in the jurisdiction) for true upstream sources. Apply emission factors as otherwise used in EPA Subpart W or the WCI metric ERMR (for use in Canada).

iv. Sum all oil and gas installations under common control of the same owner(s) or operator(s) to the field, basin or jurisdiction (as determined by the WCI) level

v. To provide sufficient information to understand distribution of emission sources, to determine potential facility splitting and to determine whether equitable coverage is occurring, provide at a minimum disaggregated reporting for each individual installation within the aggregated 'Oil and Gas Reporting Entity'. Determination of reporting and verification thresholds would be from the aggregated 'Oil and Gas Facility' total, including the installations reported individually.

vi. Some emission sources that are required to be reported may be determined not appropriate for market trading in combination with the WCI Cap Setting and Allowance Distribution work.

Attention will need to be paid in the compliance and policies of jurisdictions to change of ownership/leasehold, possible facility splitting and/or outsourcing of emissions to contractors.

Stakeholder Input:

To be completed (Santa Fe Collaborative).

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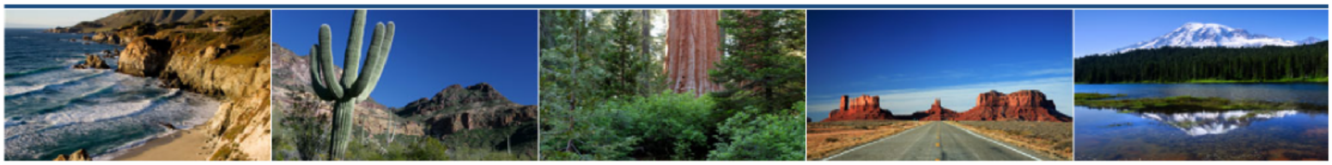


Issue Paper -- Contractor Emissions

Issue:

Oil and gas installation operation varies – often between adjacent installations that are otherwise similar - between owners/leaseholders and service providers who act as contractors. In some cases there are multiple fractional owners of wells, each owner having a slightly different ownership group. One company will often be assigned operational control and either perform the exploration and extraction operations themselves, or contract them to a service provider.

There is concern from installation owners/leaseholders that reporting contractor emissions could cause significant burden as such emissions are not currently reported in any form and new contractual obligations may be required.

A significant issue could arise in firms contracting out oil and gas installation operation to avoid both greenhouse gas reporting and a future cap and trade system. Equally significant is the WCI's goal of capturing 90% of emissions from each source category. Without capture of contractor emissions it is doubtful that 90% of oil and gas production installation emissions will be captured.

WRAP/TCR Approach:

This issue was discussed in depth in the WRAP/TCR process, and TCR decided that contractor emissions should be considered Scope 3 indirect emissions which are not required to be reported under a voluntary program. The WRAP process did identify that emissions such as venting are in general considered to be the responsibility of the leaseholder to report and are therefore not contractor emissions. That left contractor emissions as primarily the combustion that contractors use to do their work (portable, such as a mobile drilling rig, or stationary). There were various opinions about whether these remaining contractor emissions should or should not be covered by the reporting system.

The importance of including contractor emissions under a mandatory reporting program was not addressed.

EPA Approach:

EPA's definition of facility would not preclude contractor equipment at an installation from being considered a separate facility subject to the MRR and reportable by the owner or operator, or as part of the larger facility. The EPA definition would include in the facility all equipment under "common ownership or *common control*" [emphasis added]; therefore, specifics of the contractual arrangement might determine whether contracted equipment was under the control of the party contracting to purchase services. However, EPA excludes portable equipment from coverage under MRR Subpart C (General Stationary Combustion), and defines portable equipment to exclude equipment which is easily transportable and located at a given site for less than twelve months. Portable contractor equipment is often located at a site for periods less than a year, and therefore much of contractor combustions emissions would thereby be excluded from reporting under Subpart C. EPA deferred on the issues of defining the reporting entity for oil and gas production sources and of reporting vented and fugitive emissions from oil and gas sources.

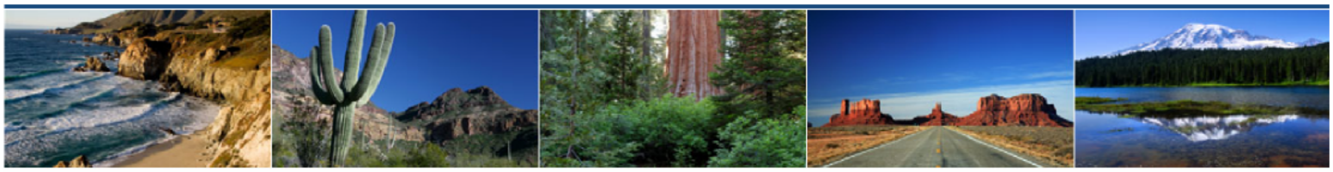
WCI Options:

Option	Pros	Cons
A. Not require reporting of contractor emissions. Neither the oil and gas producer nor the contractor report emissions.	Simple	Facility splitting could be a problem Would capture the lowest amount of emissions Does not match WRAP/TCR approach to leaseholder emissions Inequitable coverage: creates a two-tier system of facilities with and without contractors Could result in under reporting contrary to WCI design principle (See BM Comment 2)
B. Require contractors to report if aggregated emissions exceed threshold. Require contractors to report all emissions associated with the operations they are contracted to perform (if in total they exceed the threshold.	Creates responsibility for contractors to report emissions Would be simplest scenario for combustion and portable emissions	Emission sources could be covered by several operators at a single installation Does not match WRAP/TCR approach to leaseholder emissions Facility splitting could create administrative difficulties Would create a new class of ‘facility’

C. Include venting, fugitive and flaring emissions from a contractor in the emissions of the owner or operator. The oil and gas producer reports all emissions associated with the contractor operations excluding combustion emissions.	Would cover a significant portion of emission sources Reduces facility-splitting potential through intentional use of contractors All emissions are generally considered part of a typical oil and gas installation WRAP/TCR approach identified that these emissions are the responsibility of the leaseholder	Does not include what could be substantial combustion emissions if from a contractor Inequitable coverage: potentially creates a two tier system of facilities with and without contractors (for other emission sources)
D. Include all emissions in Option C (above) and combustion emissions from contractors, other than portable combustion emissions. The oil and gas producer reports all emissions associated with contractor operations including combustion emissions, other than portable combustion emissions.	Creates equitable coverage. Would cover all emission sources that are typically considered as part of an oil and gas installation. Producer consumption is a significant emission source Reduces facility-splitting potential through intentional use of contractors Requirements to track combustion emissions from contractors could be included within contracts	May require phasing in due to contractual issues. (could require owners/leaseholders to estimate combustion emissions in the first years to allow importance to be established) More rigorous than WRAP/TCR approach to leaseholder emissions
E. Include all emissions in D and portable combustion emissions from contractors. The oil and gas producer reports all emissions associated with contractor operations including portable combustion emissions occurring on-site.	Would cover the largest portion of emission sources	Portable combustion emissions (e.g., onsite emissions from a mobile drilling rig) in the oil and gas industry likely would prove hard to track, creating an administratively burdensome system More rigorous than WRAP approach to leaseholder emissions

Stakeholder Input:

To be completed (Santa Fe Collaborative).



Issue Paper -- Stationary Combustion of Field Gas

Issue:

Gas (field or associated gas) of varying composition recovered from oil and gas wells is combusted in the field. Field gas is consumed as a fuel at the well head in devices such as compressors, dehydrators and heaters.

The volume of field gas produced in association with oil production that is not marketed is typically estimated by periodic sampling to determine the gas to oil ratio (GOR) at a particular well. The total volume of gas produced at the well is then calculated by multiplying the oil production by the GOR. Most of the produced gas is marketed; however some of this gas is combusted as a fuel at the site, while other portions may be vented, flared or released to the atmosphere as fugitive emissions. The disposition of the produced gas in terms of use in equipment, flaring and venting is not routinely metered. Existing Oil and Gas regulations, which vary by jurisdiction, typically rely on engineering calculations to estimate the use of field gas in production equipment and estimate volumes flared or vented as the difference between field gas produced and the volume of field gas used by equipment at the production facility.

Field gas CO_2 combustion emissions may represent a significant GHG emissions source. Field gas metering requirements appear to be quite variable across WCI partner jurisdictions.

Accurate estimation of field gas combustion GHG emissions requires an accurate estimate of the volume of fuel gas combusted and gas composition (carbon content or HHV).

Improvements in measurement accuracy for greenhouse gas emission from field gas can be achieved by better measurement of volumes of gas produced and by including metering where expected rates of greenhouse gas emission may differ between different areas of disposition of field gas. For example, it is useful to determine the volumes of field gas consumed in combustion processes versus field gas which is vented to the atmosphere.

WRAP/TCR Approach:

In cases where meter data is not available, TCR recommends the use of an engineering approach where equipment specific data such as device horse power, heat rate, and loaded factor are used to calculate fuel consumption.

EPA Approach:

EPA has not published an emissions calculation methodology specific to field gas. Subpart W – Oil and Natural Gas Systems (which was not included in the final reporting rule) required reporters to use methods in Subpart C- General Stationary Combustion Sources to calculate the CO_2, CH_4, and N_2O emissions for stationary combustion sources.

WCI Options:

.

Option	Pros	Cons
Option A 1. Determine fuel consumption using either installed gas meters (where available) or engineering calculation where metered data is not available. 2. Measure field gas composition periodically 3. Calculate emissions	Simplest approach requiring no installation of meters. Engine run- time meters may be required	Data quality and consistency will vary within a reporting entity and across reporters US data may not be as high quality as Canadian data where there are regulatory requirements to quantify lease gas consumption

Option	Pros	Cons
Option B 1. Meter a significant fraction of field gas consumption 2. Estimate remaining field or lease gas consumption using an engineering method 3. Determine lease gas composition periodically 4. Calculate emissions	More accurate method which would generate more consistent data both for individual reporters and for all reporters. Would provide more consistent data quality between jurisdictions (US and Canada) WCI could require determination of fuel flow for a subset of metered engines using the engineering approach. This would allow evaluation of the engineering approach to fuel consumption determination	Would require the upfront installation of meters on the larger engines. Prior to the beginning of reporting period it may be difficult to determine which engines require metering. Engines changes during the reporting period would also complicate this approach.

Option B is discussed in more detail below. Two engineering methods for the calculation of field gas consumption are discussed.

1. Meter a significant fraction of field gas consumption.

a. Tabulate the annual horse power – hours (hp-hr) for each unit combusting field gas. For example, a 450hp compressor running continuously would annually generate

3.942×10^6 hp-hr (450hp x 8,760 hrs/yr).

b. Sort the resulting list of combustion units by hp-hr generated annually (highest to lowest).

c. Require metering of field fuel consumption for the units which cumulatively (highest to lowest) represent 75% of total annual hp-hr.

2. Estimate remaining field gas consumption (engineering approach).

a. Apply an engineering approach (see below) for the remaining 25% of combustion emissions.

b. For a sub-section of the metered combustion units, use the engineering approach as well. This would allow WCI to compare methodologies (metered field gas consumption versus the engineering calculation).

Engineering Options for Determination of Unmetered Fuel Flow:

API method

See the API Compendium of Greenhouse Gas Emission Methodologies for the Oil and Natural Gas Industry (2009) for specifics (page 4-5, 4.1 Estimating Fuel Consumption Data from Energy Output or Volumetric Flow).

$$FC = ER \times LF \times OT \times ETT \times 1/HHV$$

Where:

FC = annual fuel consumed (volume/yr)

ER = equipment rating (hp, kW, or J)

LF = equipment load factor (fraction)

OT = annual operating time (hr/yr)

ETT = equipment thermal efficiency ($Btu_{input}/hp\text{-}hr_{output}$ etc)

HV = fuel heating value (energy/volume)

This is inherently a less accurate method of determining fuel consumption due to a number of issues (e.g. the estimation of unit load factor).

Fuel Consumption Method Based on Gas Produced and Pressure

A relatively accurate means of estimating the fuel consumption for field gas consumption in well head compressors is to base it on the quantity of gas produced and the pressures the compressor must overcome. The following equation can be offered as an alternative to the equation in the current issue paper on field gas consumption:

$$FC = EE \times V \times 1/HHV$$

Where:

FC = annual fuel consumed (volume/yr)

EE = equipment efficiency (Btu/mscf)*

V = volume of gas produced in the time period (mscf)

HV = fuel heating value (Btu/volume)*

*Note that the EE and HV must be provided on either a HHV or LHV basis, but not a mixed basis.

Manufacturers have tables for their compressor skids which provide the unit's efficiency (EE) based on the model of engine driving the compressor and the inlet and outlet pressures. The inlet pressure is essentially the average well pressure for the year and the outlet pressure is essentially the gathering line operating pressure.

3. **Determine field gas carbon content (quarterly?).**

4. **Calculate CO_2 stationary combustion emissions.**

$$E_{CO2} = \sum_{n=1}^{n} Fuel_n \times CC_n \times MW_n / MVC \times 3.664 \times 0.001$$

Where:

E_{co2} = CO_2 emissions (metric tonnes/yr)

$Fuel_n$ = volume of field gas combusted in quarter n

CC_n = carbon content of field gas in quarter n

MW_n = molecular weight of field gas (from quarterly gas analysis)

MVC = molar volume conversion factor

3.664 = conversion factor (C to CO_2)

0.001 = conversion factor (kg to metric tonnes)

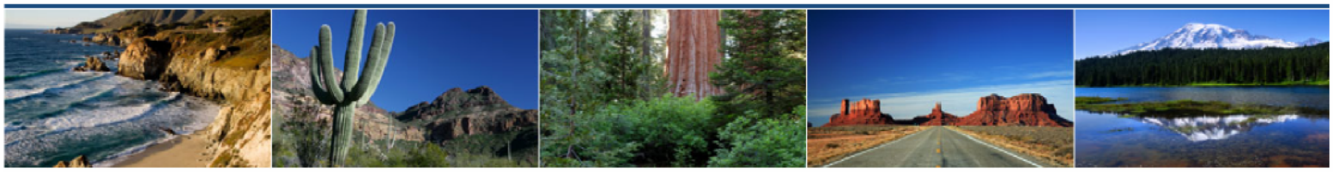
5. **Calculate CH_4 and N_2O stationary combustion emissions**

Use default emission factors.

Stakeholder Input:

To be determined (Santa Fe Collaborative).

Western Climate Initiative



Issue Paper – Instrument Gas and Vented Methane Emissions

Issue:

Pneumatic control devices employing pressurized natural gas or field gas are commonly used in the natural gas industry. In the production sector these devices perform tasks such as the control and monitoring of gas and liquid flows and levels in dehydrators and separators, temperature in dehydrator regenerators, and pressure in flash tanks. In the processing sector high and low bleed pneumatic devices are used for compressor and glycol dehydration control in gas gathering and booster stations and isolation valves in processing plants. In the transmission sector these devices actuate isolation valves and regulate gas flow and pressure at compressor stations, pipelines, and storage facilities.

Pressurized natural gas or field gas is used as the motive agent and is routinely vented, either continuously or periodically. Many factors influence pneumatic device venting rates and volumes. Important variables are: the gas supply pressure, actuation frequency, and the age, condition and maintenance history of the equipment.

Consequently, these pneumatic devices are a major source of methane emissions from the natural gas industry. In most cases instrument gas is not routinely metered.

WRAP/TCR Approach:

TCR recommends that oil and gas producers who voluntarily report GHG emissions use the method and emissions factors found in the API Compendium .

EPA Approach:

EPA has not published an emissions calculation methodology specific this vented source.

WCI Options:

Option	**Pros**	**Cons**
A. Use Original Equipment Manufactures (OEM) information	Easiest of the methods	Data consistency and reliability questionable
B. API Compendium (2009) – use available emission factors	Simple methodology	Large uncertainty for emission factors

Option	Pros	Cons
C. Measure individual device emissions	Accurate methodology	Labor intensive and expensive Instrument modification and changes in operating conditions may require additional measurements
D. Meter instrument gas	Most accurate method	Requires installation of piping and meters. Does not provide consumption information for individual devices.

Background on available methodologies:
The options are discussed below.

A. Use of OEM data.

In many cases manufacturers' data for equipment bleed rates is available. There are several issues which suggest that significant errors in estimated emissions may result when one uses OEM data. First, there is no industry standard concerning the reporting of instrument bleed rates and thus manufacturers report information in a wide range of units and under varying operating conditions. In addition the data reported by manufacturers has not been independently verified. USEPA has found large discrepancies between OEM bleed rate data and actual field data. As stated above, factors not reflected in available OEM data, such as gas pressure and maintenance history, significantly influence emissions rates. While API (2009) states that the use of manufactures' data is "the most rigorous approach" the Compendium also acknowledges that manufactures emission rates "tend to be lower than emissions observed."

B. API Methods:

API offers several approachs for the calculation of "emissions from a high or continuous bleed device" based on an equation from a Gas Processors Suppliers Association 1987 publication (see API Compendium, Section 5.6 Other Venting Sources, page 5-66). However, this equation is applicable only to high or continuous bleed devices and does not consider factors such as device maintenance history. Emission factors for pneumatic devices have been developed. Many of these EFs were published in the 1997 GRI/EPA Report, Methane Emissions from the Natural Gas Industry. The API Compendium compiles these and other EFs (see Table 5-15, pages 5-68 and 5-69) and estimates uncertainties in some cases. Where specified, reported uncertainties range from ±33% to ±407%. This indicates that use of EFs would result in very unreliable estimates of vented methane emissions. In general, the use of EFs may result in relatively accurate emission estimates on a large scale (e.g. for an annual national inventory) but at the facility level EFs which are not site or equipment specific can introduce significant error.

C. Use of site specific measurements.

Actual site specific measurement of vented emissions from low and high bleed pneumatic control devices is accepted to be the most accurate method to quantify methane (and CO_2 if present in the gas) emissions. There are two approaches one may take when conducting site specific measurements.

One may characterize emissions from each pneumatic device at a facility using a bagging technique (or other method) where emissions from the device are captured and the volume of released gas is measured. Gas analysis then allows one to calculate actual CH_4 and CO_2 emissions. This technique is time consuming, labor intensive and expensive. In addition emissions may subsequently change as the result of factors such as maintenance activities and gas pressure changes.

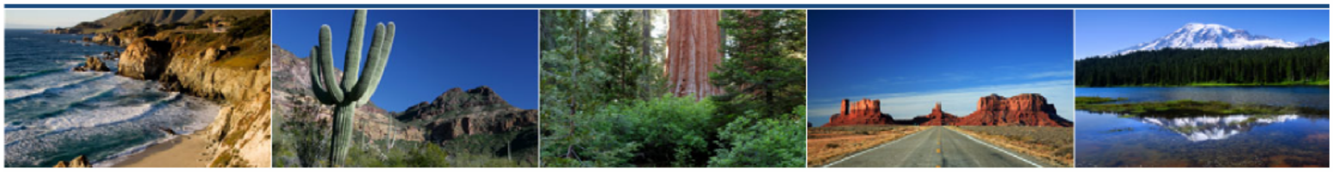
D. Meter Instrument Gas Consumption:

Actual metering of instrument gas consumption and periodic measurement of gas composition will provide a much more accurate determination of GHG emissions. Changes in instrument gas plumbing and installation of one or more gas meters may be required initially and this will result in upfront material and labor costs. However, reporting in subsequent years will be very simple and easy, especially given the fact that periodic gas analysis will be required for other GHG emission calculations (e.g. stationary combustion emissions). In addition, changes in system operating conditions (e.g. line pressure, maintenance activities, instrument modifications) designed to reduce emissions would be reflected in the volume of instrument gas consumed and thus would be easily quantified. Facility operators receive immediate feedback on their efforts to reduce emissions and can also monitor instrument gas consumption in real time.

Stakeholder Input:

To be determined (Santa Fe Collaborative).

Western Climate Initiative



Issue Paper -- Storage Tanks

Issue:

Storage tanks provide temporary storage of liquids prior to the point when produced liquids are moved off site in a pipeline or mobile tanker for processing. Emissions of methane (and CO_2 if present in significant quantities in produced liquids) occur through several mechanisms.

Flashing losses occur when the produced liquid experiences a change in pressure. For instance as produced oil is pumped from the well it experiences a pressure drop as it exits the pipe and enters the tank. Dissolved gases such as methane and carbon dioxide may flash off as the pressure is reduced.

Working losses occur as a result of the filling and emptying of the storage tank. Tank headspace gases containing methane and carbon dioxide are emitted from the tank as the tank fills. As the tank is emptied the reverse process occurs, outside air is drawn into the tank. The liquid in the tank then re-equilibrates with this introduced air. Finally, breathing losses of headspace air containing methane and carbon dioxide occur as the tank gas volume expands and contracts in response to environmental conditions such as ambient temperature, solar insulation, and atmospheric pressure.

Flashing, breathing and working losses must all be characterized to insure an accurate estimation of storage tank GHG emissions.

Storage tank emissions occur when produced liquids are sent to atmospheric storage at the following locations:

1. wellhead sites
2. tank batteries
3. compressor stations
4. gas plants
5. where liquids in a gas line are "pigged"

WRAP/TCR Approach:

WRAP has not specifically addressed the issue of accurately determining GHG (CH_4 and CO_2) emissions from storage tanks in the up-stream oil and gas sector. A method using the EPA TANKS Model was included in the Essential Requirements for the Refinery sector.

EPA Approach:

EPA has not officially published an emissions calculation methodology specific for this source. A method was published in Subpart W of the Draft Reporting Rule (see §98.233(d)(8) – page 1167). Subpart W was subsequently withdrawn prior to release of the EPA Final Rule.

Briefly, the EPA Subpart W method requires that reporters:

a) Measure the volume of vapor escaping each storage tank over a representative period of operation,

b) Determine the vapor composition by chemical analysis,

c) Calculate fugitive emissions using this data.

The details of this method are shown below:

1. Calculate the total annual hydrocarbon vapor fugitive emissions using Equation W-7

$$E_{a,h} = Q \times ER \qquad \text{(Eq. W-7)}$$

   Where:

   $E_{a,h}$ = hydrocarbon vapor fugitive emissions at actual conditions

   Q = storage tank total annual throughput

   ER = measured hydrocarbon vapor emissions rate per throughput (e.g. cubic feet/barrel) determined from §98.234(j)(2) (page 1181).

   ER is measured using a flow meter described in paragraph (h) for a test period that is representative of the normal operating conditions of the storage tank throughout the year and which includes a complete cycle of accumulation of hydrocarbon liquids and pumping out of hydrocarbon liquids from the storage tank.

2. Estimate hydrocarbon vapor volumetric fugitive emissions at standard conditions using calculations in paragraph (e).

3. Estimate CH_4 and CO_2 volumetric fugitive emissions from volumetric hydrocarbon emissions using Equation W-8 (page 1168).

$$E_{s,i} = E_{s,h} \times M_i \qquad \text{(Eq.W-8)}$$

   Where:

   $E_{s,i}$ = GHG i (CH_4 and CO_2) volumetric fugitive emissions at STP

   $E_{s,h}$ = hydrocarbon vapor volumetric fugitive emissions at standard conditions

   M_i = mole percent of GHG i in the hydrocarbon vapors; the hydrocarbon analysis shall be conducted using ASTM D1945-03

4. Estimate CH_4 and CO_2 mass fugitive emissions from GHG volumetric emissions using the calculations in paragraph (g)

$$Mass_{s,i} = E_{s,i} \times \rho_i \qquad \text{(Eq. W-11)}$$

   Where:

   $Mass_{s,i}$ = GHG i (CH_4 or CO_2) mass fugitive emissions at STP

   $E_{s,i}$ = GHG i volumetric fugitive emissions at STP

P_i = density of GHG i; 1.87 kg/m^3 for CO_2 and 0.68 kg/m^3 for CH_4

Background on Available Methodologies:

A recent study commissioned by the Texas Commission on Environmental Quality (TCEQ) provides an in-depth analysis of available methods for the determination of storage tank emissions. The following modeling methods were compared with actual measurements of storage tank emissions which were conducted in a manner very similar to the EPA Subpart W method detailed above.

1. TANKS 4.09 (EPA model)
2. Vasquez-Beggs + TANKS 4.09
3. GOR + TANKS 4.09
4. Valko-McGagn + TANKS 4.09
5. Hysis VOCs
6. E&P Tank – RVP VOCs
7. E&P Tank – GEO/RVP VOCs
8. AP-42 LPO VOCS
9. GRI-HAPCalc VOCs

The final report concluded that "each model reviewed has limitations and shortcomings. No one model resulted in the extremely strong correlation to measured data." Measurements were made at thirty six production sites. The models also required measurement of input variables such as GOR (gas oil ratio). This is a difficult measurement given that the recovered liquid/gas mixture from a well must be collected and maintained at pressure prior to analysis. The report states that the TCEQ considers direct measurement the most accurate method to quantify storage tank fugitive emissions. A copy of this report, Upstream Oil and Gas Storage Tank Project Flash Emissions Models Evaluation Final Report, July 16, 2009 is available on the WCI RC Sharepoint website.

The API Compendium (2009) also contains a discussion of several of the models available (see Section 5.4 Storage Tank Emissions, page 5-40). API states that direct measurement provides accurate emissions estimates but "*this approach is generally expensive and time consuming for large numbers of tanks."*

WCI Options:

WCI is considering using the method contained in Subpart W – Oil and Natural Gas Systems of the EPA Draft Mandatory Reporting of Greenhouse Gases. It is recognized that direct measurement of the volume and composition of fugitive emissions emitted from storage tanks is the most accurate quantification method. Volumetric emissions at a storage tank can be completed in as little as 24 hours. In addition, the determination of the CH_4 and CO_2 concentration in storage tank fugitive emissions is straightforward and relatively inexpensive.

Other modeling approaches require input data (such as GOR, API, separator pressure, stock tank gas molecular weight and specific gravity, oil gravity, etc.) which may require extensive gas and oil analysis. These models do not provide the level of accuracy that direct measurement does.

Stakeholder Input:

To be determined (Santa Fe Collaborative).

Western Climate Initiative

Western Climate Initiative
Oil and Gas Collaborative

Issue Papers

Santa Fe, New Mexico

November 19, 2009

Issue Papers

- Stationary Combustion of Field Gas
  - CO_2, CH_4, N_2O
- Venting – Pneumatic Pumps and Control Devices
  - CH_4, CO_2
- Venting – Storage Tanks
  - CH_4, CO_2

Stationary Combustion –Field Gas

- Combustion of field gas represents a significant GHG source (CO_2, CH_4, and N_2O)
- Field gas consumption quantification requirements vary across the WCI jurisdictions
- Accurate quantification of emissions requires accurate and consistent methodology

Quantification Options

Option A	Pros	Cons
1. Determine fuel consumption w/ meters where available or engineering calculation 2. Measure field gas composition 3. Calculate emissions	Simplest approach requiring no installation of meters.	Data quality and consistency will vary within a reporting entity and across WCI jurisdictions Potential for US and Canadian data inconsistencies Installation of engine runtime meters may be required

Quantification Options – con't

Option B	Pros	Cons
1. Meter a significant fraction of field gas consumption 2. Estimate remaining field gas consumption –engineering approach 3. Determine field gas composition 4. Calculate emissions	More accurate method, w/ consistent data Use of meter and engineering calculation on a subset would allow evaluation of engineering approach	Requires installation of meters on larger engines Potential difficulties determining which engines require metering

Option B - details

- Metered data
  - Tabulate annual horse power-hours for each engine
  - Sort list
  - Meter cumulative percentage of largest units
- Engineering estimation of fuel consumption
  - API method
    - Engine hp, load factor, operating time, thermal eff, HHV
  - Method based on gas produced and operation pressures
    - Engine efficiency, volume produced gas, HHV

Questions for the TWG

- Which engineering approach is more accurate?
- Are US and Canadian lease fuel consumption data consistent?
- Are there difficulties determining which engines require metering?
- Is data available which is useful in determining how many meters are required?
- Do you use another approach for quantification of lease fuel consumption?

Venting – Pneumatic Control Devices

- Pneumatic pumps and control devices are important sources of venting (CH_4 and CO_2) in the NG production, processing and transportation sectors
- Instrument gas is not routinely metered and quality of available EFs varies widely

Quantification Options

Option	Pros	Cons
A. Use OEM info	Easiest of methods	Data consistency and reliability are questionable
B. Use available EFs	Simple methodology	Large uncertainty for EFs
C. Measure individual device emissions	Accurate methodology	Labor intensive, expensive. Device modification requires additional measurements
D. Meter instrument gas consumption	Most accurate method	Requires installation of piping and meters. Does not provide info for individual devices.

Questions for the TWG

- Is OEM data available for all pumps and devices?
- Are there additional methods that should be considered?
- Should we consider requiring metering of instrument gas only about a threshold?
- How would we define a threshold for metering?

Venting - Storage Tanks

- Uncontrolled release of CH_4 (and CO_2) from storage tanks – flashing, working and breathing losses
- Many quantification models are available – none appears to be ideal

Quantification Options

Option	Pros	Cons
A. Direct measurement of storage tank emissions – determine volume and composition of gas emitted	Accurate method if measurements are taken under normal operating conditions	Expensive and time consuming for large number of tanks. Require only for tank batteries above production threshold (bbl/d)?
B. Use one of nine models	Easier approach	Models require measurement of variables (e.g. GOR, pressure, temperature). Each model has limitations.

Questions for the TWG

- What is your experience with available models?
- Should measurement be required for a tank battery only above a production threshold?
- If both measurement and modeling approaches are used, which model is most appropriate?

Western Climate Initiative
Oil & Gas Collaborative

California

Low Carbon Fuel Standard

(LCFS)

November 18th, 2009
Santa Fe, New Mexico

California Environmental Protection Agency
AIR RESOURCES BOARD

Background

- Transportation sector represents approximately 40% of GHG emissions in California

- A number of legislative and policy directives support the development of a LCFS
  - AB 32 – reduce GHG emissions to 1990 levels by 2020
  - EO S-06-06 – increase production and use of bioenergy
  - EO S-01-7 –develop a LCFS to reduce carbon intensity of transportation fuels

California Transportation Related Initiatives

- Low Carbon Fuel Standard
- Tailpipe CO_2 emissions standards – Pavley standards for new passenger vehicles
- Tire Pressure Strategy
- Reduction in refrigerant loss
- Cool Car Standards

LCFS Goals

- Reduce the carbon intensity of transportation fuels 10% by the year 2020 (same as EU). Equivalent to about 10% of total reduction need to reduce to 1990 levels by 2020
- Establish a durable carbon regulatory template that can be exported to other jurisdictions (no fuel-shifting)
- Complement Federal renewable fuel standards (RFS and RFS2)
- Spur the introduction of lower carbon fuels
- Create a market for clean transportation technology

LCFS – approach and structure

- Two performance standards established
  - Gasoline and alternatives
  - Diesel and alternatives
- Standards based on the premise that each fuel has a "lifecycle" GHG emission value (g CO_{2e}/MJ)
- Fuel suppliers and importers meet standards starting in 2011 to reach 10% goal by 2020
- Standards "back-loaded" – more reductions required in the last 5 years than in first 5 years
- LCFS requirements met with combination of strategies – lower carbon fuels and advanced technology vehicles

Developing Fuel Carbon Intensity Standards

- Fuel based “lifecycle” GHG emission values
  - Updated California-GREET Model Version 1.8b
- Land Use Change Assessment
  - GTAP Model version 6 – Perdue University

LCFS Compliance Schedule

Year	CI – gasoline ($g\ CO_{2e}/MJ$)	CI- diesel ($g\ CO_{2e}/MJ$)	% reduction
2010	Reporting Only		
2011	95.61	94.47	0.25
2012	95.37	94.24	0.5
2013	94.89	93.76	1.0
2014	94.41	93.29	1.5
2015	93.45	92.34	2.5
2016	92.50	91.40	3.5
2017	91.06	89.97	5.0
2018	89.62	88.55	6.5
2019	88.18	87.13	8.0
2020	86.27	85.24	10.0

LCFS – 2009 and Beyond

- 2010 -Reporting only
- 2011 -First compliance year
- 2010- Expert Workgroup will evaluate the Land Use Change component of LCFS
- 2011 –Sustainability of LCFS examined

Program Reviews

Two Programs Reviews are mandated in the LCFS Regulation

In 2011 and 2014 the LCFS Program will be reviewed: new pathways considered, adjustments made to existing pathways, examine economics

California LCFS –
Additional Information

Low Carbon Fuel Standard web-site

www.arb.ca.gov/fuels/lcfs/lcfs.htm

climate CHANGE

California Environmental Protection Agency
AIR RESOURCES BOARD

North America E&P – Methane/GHG Reductions

November 2009

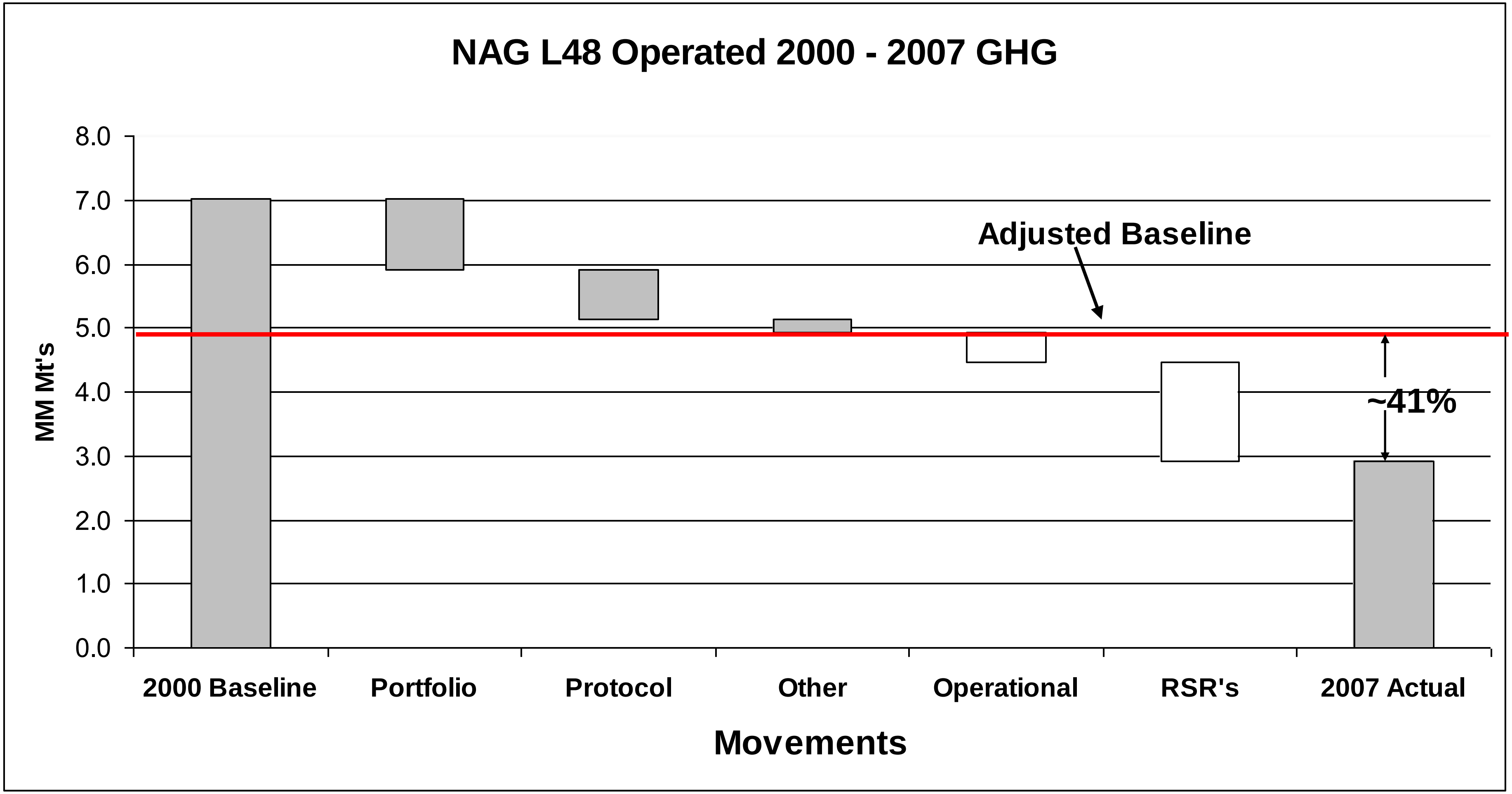
Operational GHG Management

- Inventory and Understand Energy Use and Emissions from Our Operations
  - Global Inventory of GHG's (CO_2 and CH_4) Since 1999
- Identify and Execute Opportunities to Increase Efficiency and Decrease Emissions From Existing Operations
  - Technical, Operational, Reliability, and Economic Evaluations
- Purposefully Design and Construct New Facilities and Projects to be Inherently Energy and Emissions Efficient
  - Include "Carbon Cost" and Fuel Value in Economic Evaluations and Design Choices
  - E&P 2007 Intensity - Ton CO2e per mboe
    - Existing Profit Centers 31.2
    - New Profit Centers 14.9
- Stay Abreast of New Technology and Work to Broaden Application of Existing Technology

Accounting Principles

Greenhouse Gas		2007	2008 Actual/Forecast				2008
All emissions in tonnes		Year	1Q	2Q	3Q	4Q	Year
Greenhouse Gas (100%)		123,965	29,573	29,959	29,950	30,655	120,137
Equity Share Direct Greenhouse Gas		73,763	17,592	17,824	17,823	18,247	71,486
Difference from Previous Year		0					-2,277
MOVEMENTS	Transfer of sources between RUs (+/-)	0	0	0	0	0	0
	Acquisition / divestment / equity change (+/-)	0	0	0	0	0	0
	Outsourcing / insourcing (+/-)	0	0	0	0	0	0
	Protocol / methodology changes (+/-)	0	0	0	0	0	0
	Real Sustainable Reductions (-)	0	0	0	0	0	0
	Permanent operational increase (+)	0	0	0	0	0	0
	Temporary operational / production variation (+/-)	4,192	-596	-864	-1,215	398	-2,277
	Permanent production / throughput variation (+/-)	0	0	0	0	0	0
Sum of Movements		4,192					-2,277
Check Sum (Should be zero)							0

Accounting



NAG L48 Operated 2000 - 2007 GHG
8.0
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
MM Mt's
Adjusted Baseline
~41%
2000 Baseline
Portfolio
Protocol
Other
Operational
RSR's
2007 Actual
Movements

North America Gas and GHG Management

- North America Gas
  - Full inventory of GHG's since 1999
  - Reduced our emissions ~41% from a year 2000 baseline (corrected for A&D and Protocol Changes)
    - Focused on reducing methane emissions and flaring
    - Less Emissions = More Production/Sales
      - >48 BCF Reduction; > 17MM Metric Tonnes Gross CO_2e's
  - Active Partners in EPA's Natural Gas Star Program Since Inception
- Major Contributors to Reductions
  - Well Venting Reduction via Advanced Automation Control
  - Pneumatic Controller Replacement
  - Green Completions
  - A Host of Smaller Projects and Efforts

GHG Efficiency = Cost Reduction/ Product Sales

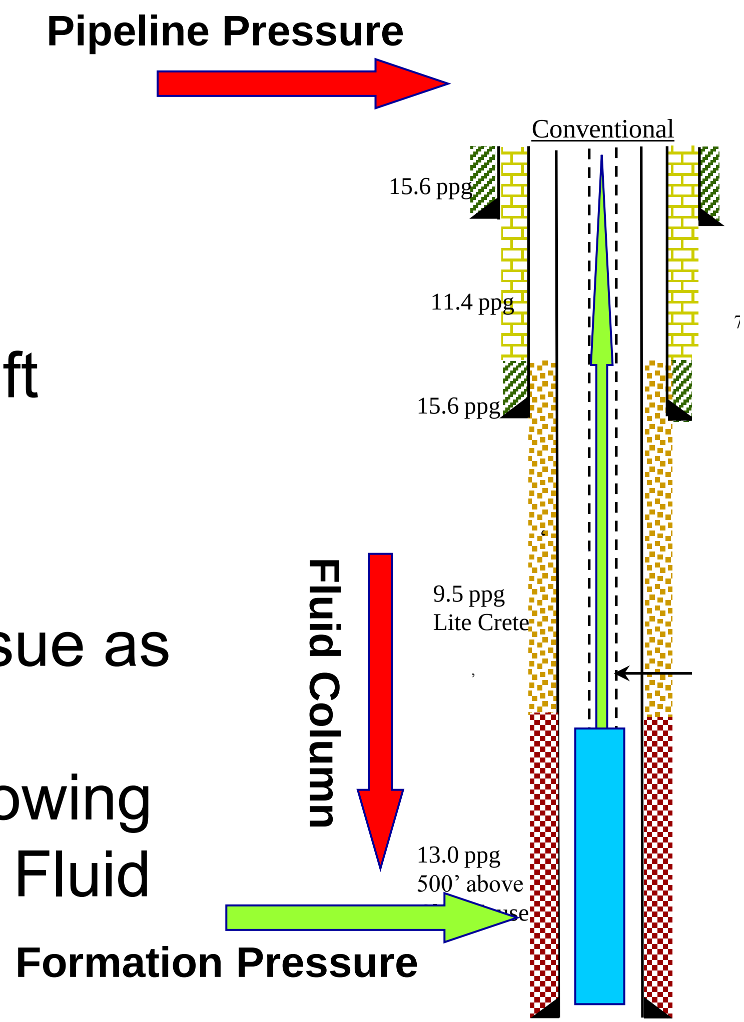
Well Venting – What and Why

Well Flow:

- Depends on Delta P
- Flow Rate is a f of Delta P
- Rate Determines Velocity
- Velocity Determines Fluid Lift

Formations:

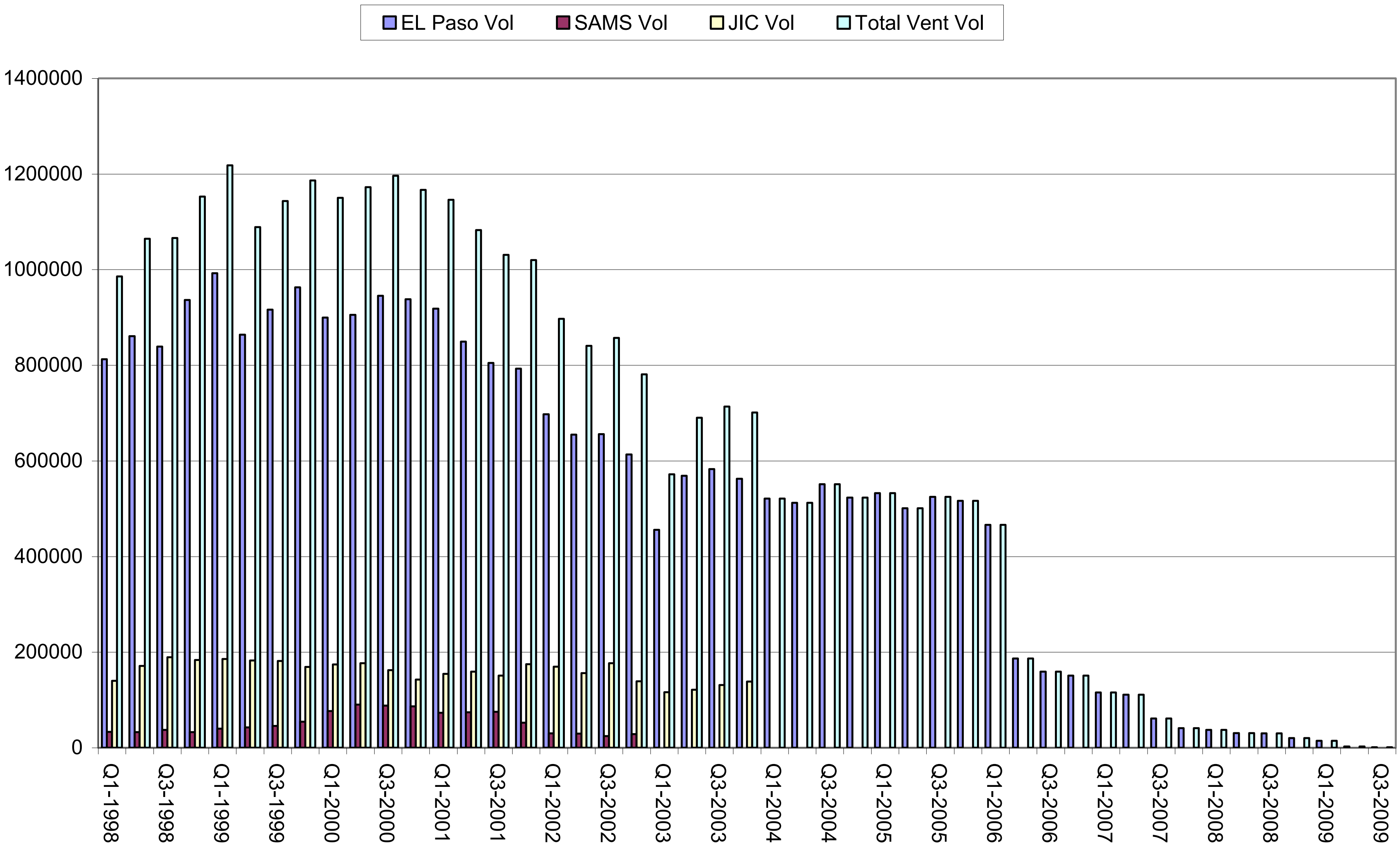
- Deplete over Time
- Liquid Loading Becomes Issue as Depletion Occurs
- Build P While Well is Not Flowing
- Shut-in Time is Important to Fluid Unloading



Low Energy Reservoir Vent Control

- "Smart" Automation"
- Both Plunger Equipped and No Plunger
- On-site PLC Based
- Custom Control Code – Based on "Turner" Lift
- RTU Transmission to Host
- ~2300 Wells Under Control – Beginning in 2001
- Venting Reduced >98% – Positive Production Response

“Smart” Automation Results

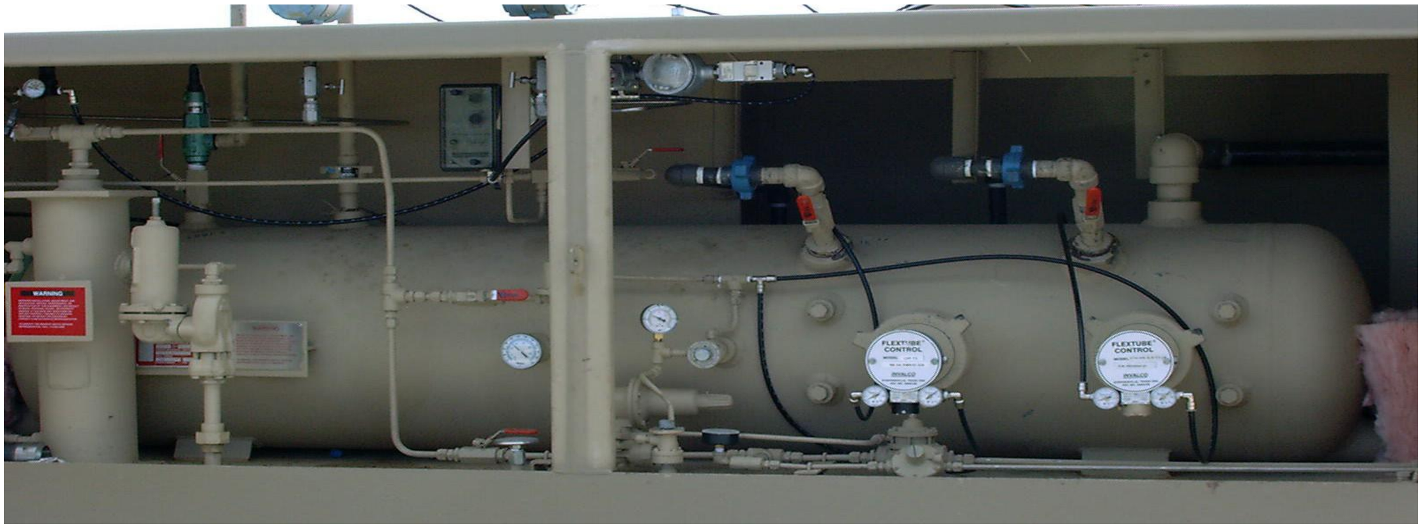


Summary

- Great success >4 bcf/yr to <0.01 bcf/yr
- Technology is only a piece of the solution - most significant recent reductions are due to revised operational beliefs and practices.
- Requires constant focus – Teams deliver on current goals.
- Operational beliefs have shifted from “we must vent to produce” to **“Venting is one of our last options.”**

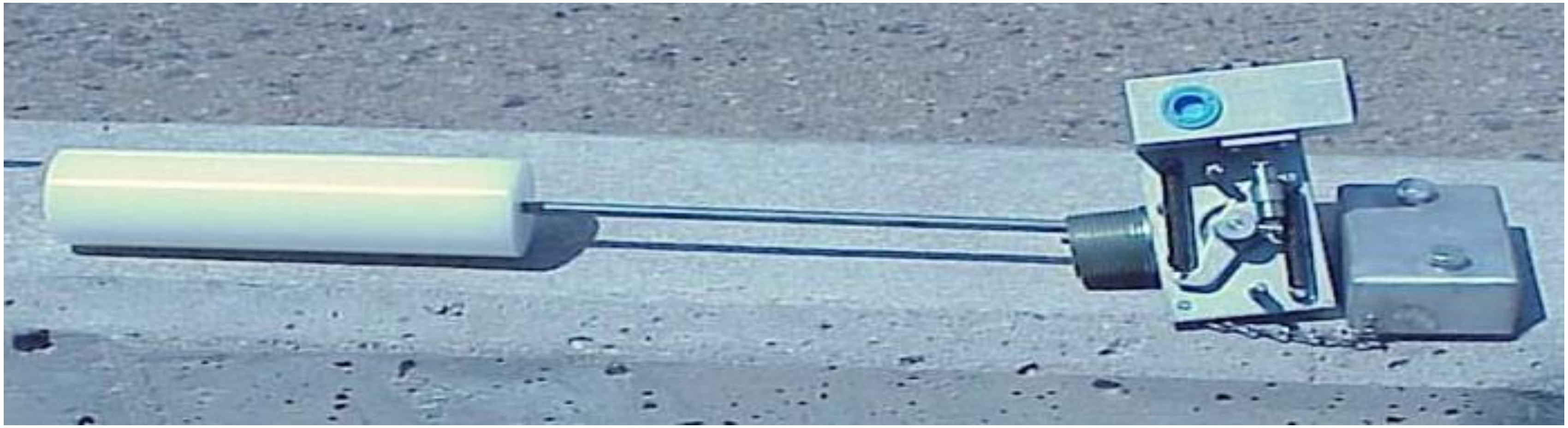
Pneumatic Controller Replacement

- Replacement of “High Bleed” Pneumatic Instruments With “Low or No Bleed” Instruments
- ~11,500 Level Controllers Replaced in 6 States
- Began in 1999 and Complete in 2002



Pneumatic Controller Results

- ~3.4 BCF of Gas/Yr Sold
- Capital Investment ~$4,071,000
- ~ 60,700 Metric Tonnes of Methane Not Emitted Annually
- Reduction of ~ 1,275,000 Metric Tonnes of CO_2 E's Annually
- Does not include effect of low bleed on new wells/facilities (BAU)



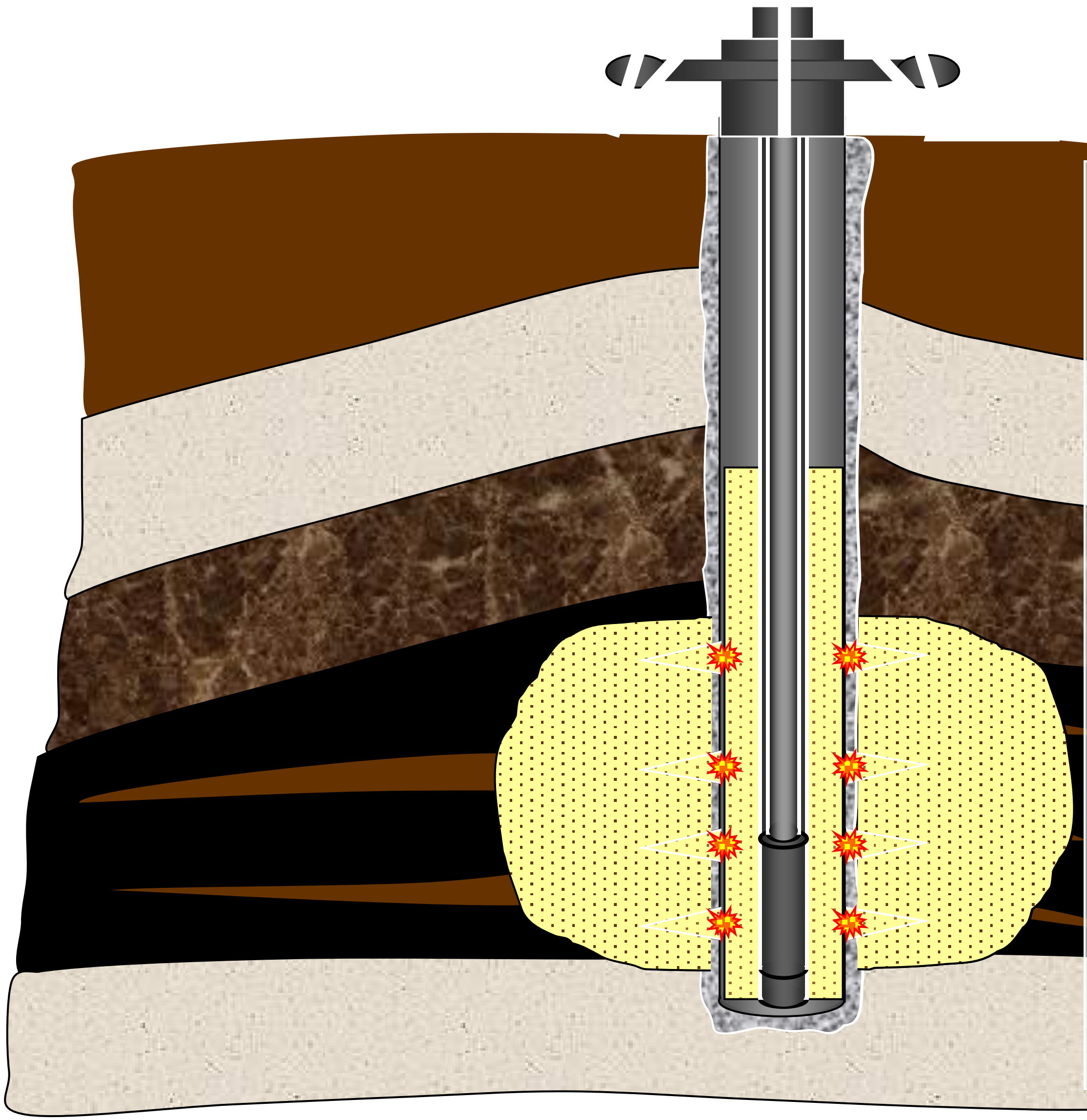
Green Completions

- What are well completions and why do emissions result
- What is different about “Green Completions”
- Enabling Criteria
  - Must have a sales pipeline
  - Must have “salable” gas
  - Must be able to adequately clean-up well and avoid reservoir damage
- Cases
  - “High Energy” Reservoirs – Wyoming Example
  - “Low Energy” Underbalanced
  - “Low Energy” Overbalanced

The Basics of Post-frac Cleanout and "Green" Completions

bp

◆ Drilling and Completing a Typical CBM Well

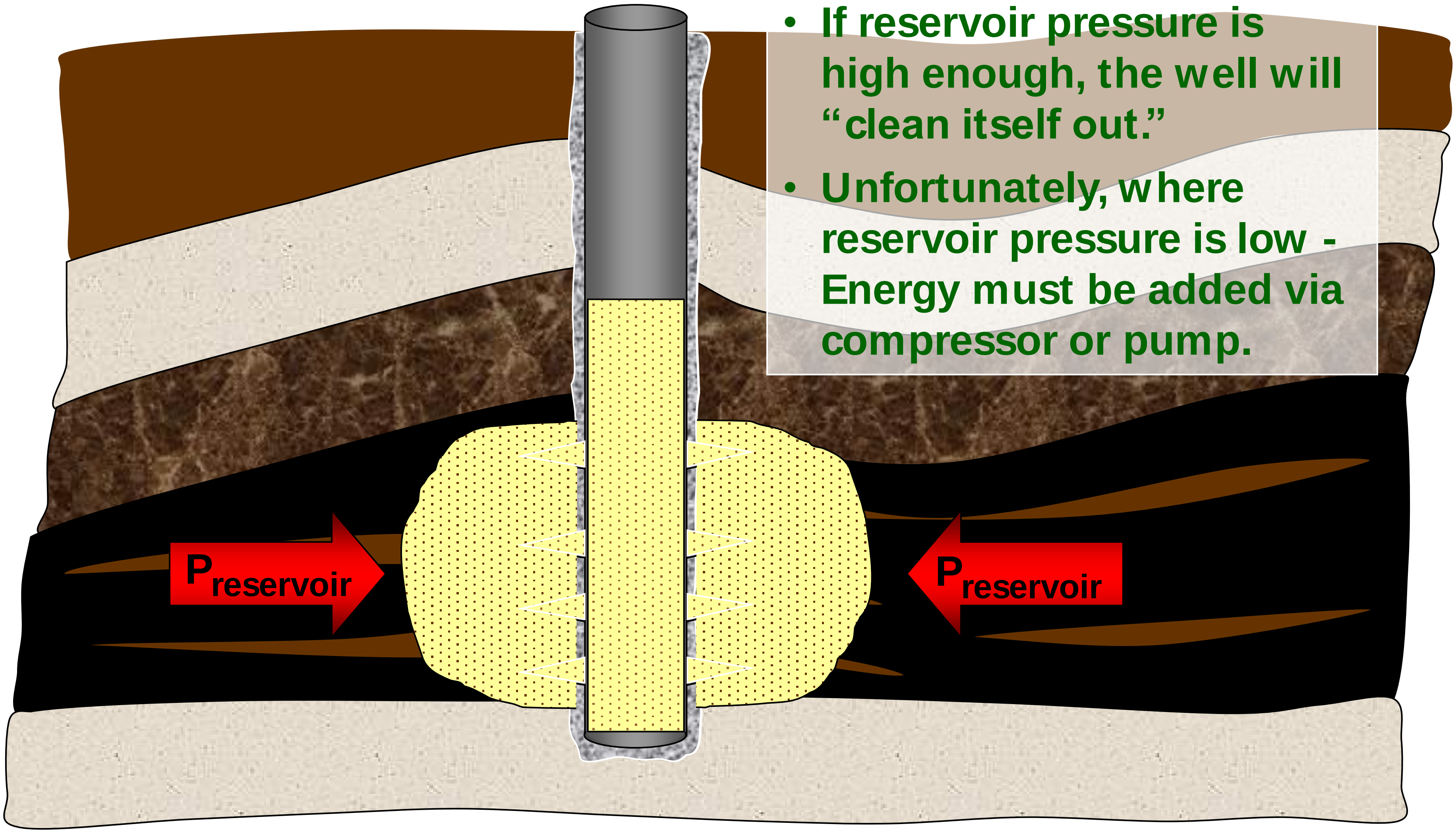


- Move in, rig up drilling rig
- Drill well
- Run casing
- Cement casing
- Perforate casing
- Frac coal
- Cleanout wellbore
- Run pump and tubing
- Rig down, move off drilling rig
- Install wellhead
- Install pump jack

The Basics of Post-frac Cleanouts and "Green" Completions

◆ The Role of Reservoir Pressure in Post-frac Cleanouts

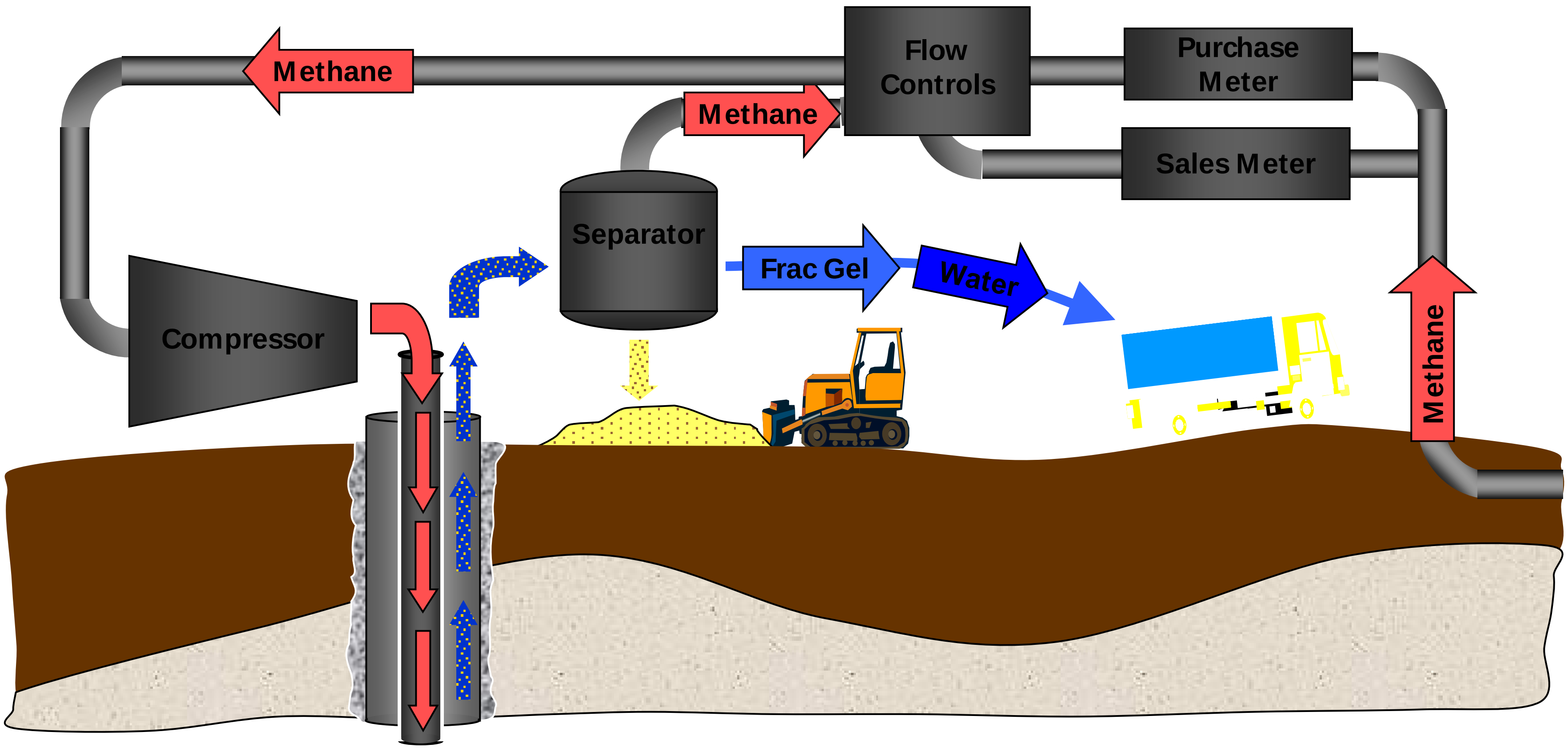
- If reservoir pressure is high enough, the well will "clean itself out."
- Unfortunately, where reservoir pressure is low - Energy must be added via compressor or pump.



◆ "Green" Cleanouts

Q: So, what do you need to make this work?

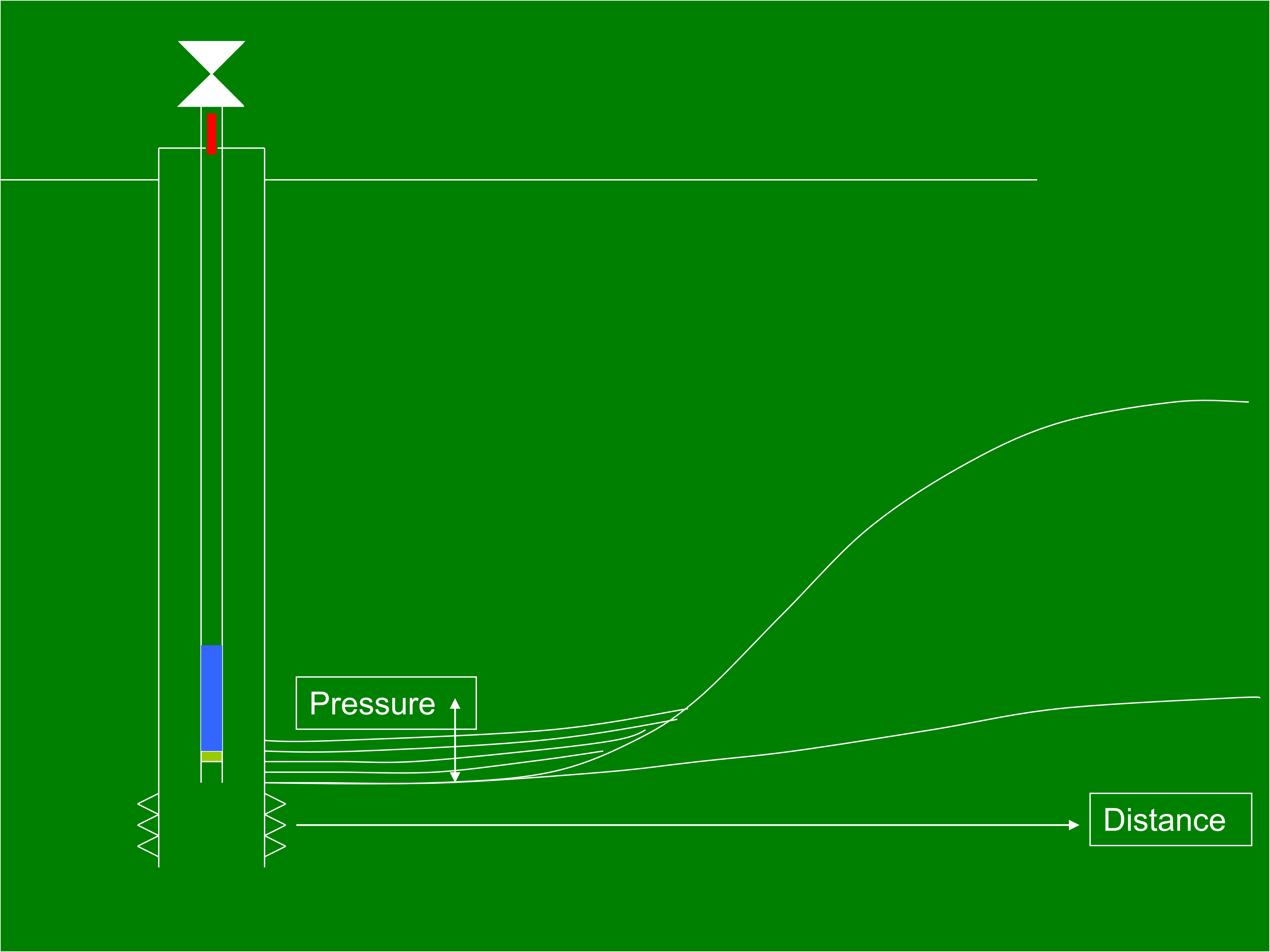
A: An operational gas pipeline and a great deal of specialized equipment.

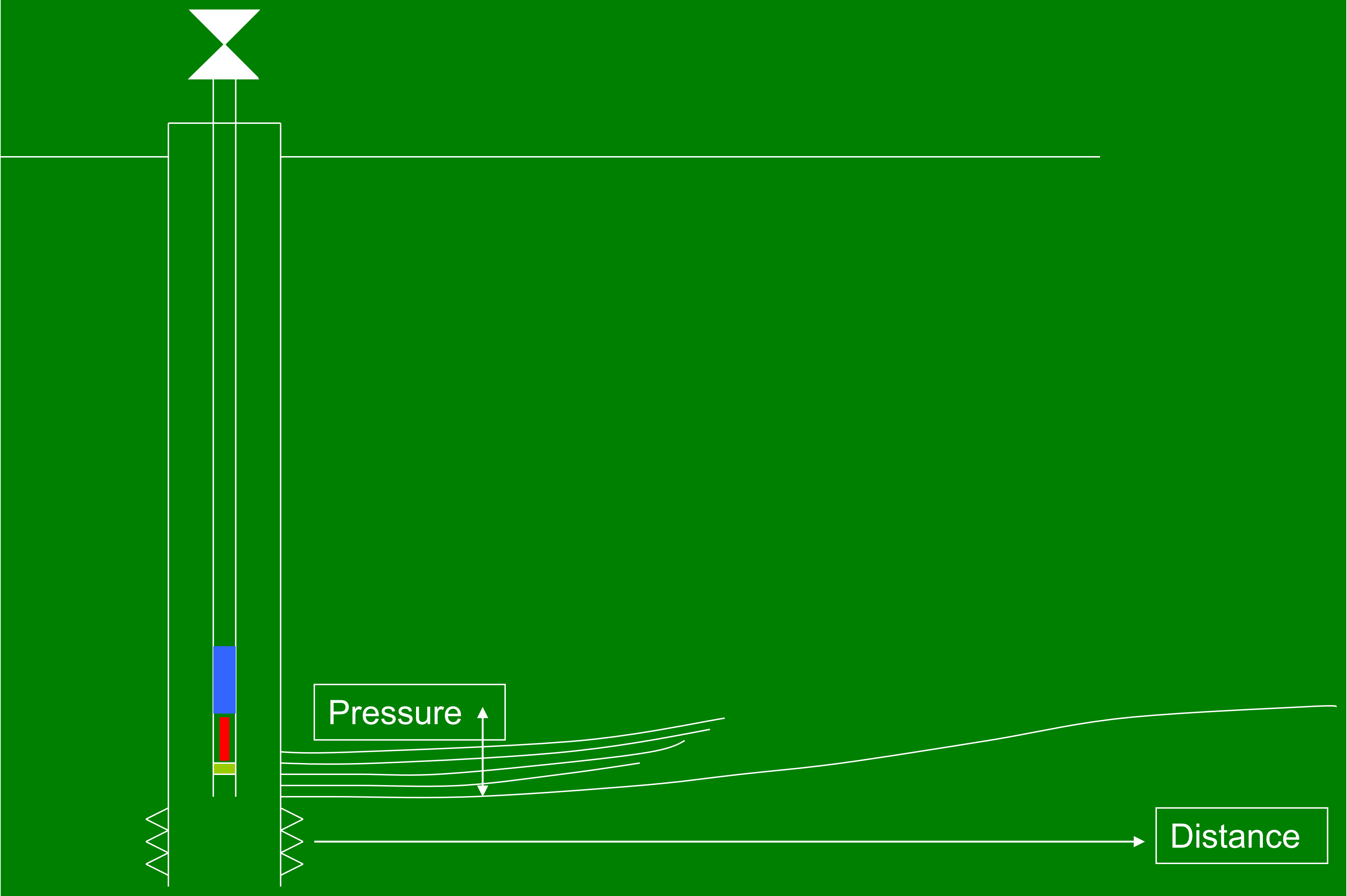


Wyoming Green Completions Results

- Piloted in 2000; Operational 2001 Forward
- Higher Energy Reservoirs Without the Need for Supplemental Energy Input
- Cumulative Recovery Since 2001
  – More than 8.7 Billion Cubic Feet of Natural Gas
  – More than 500,000 metric tonnes of CO2 Equivalent Reduction
- Has Spread Widely Through Industry

Backup Slides


Pressure
Distance

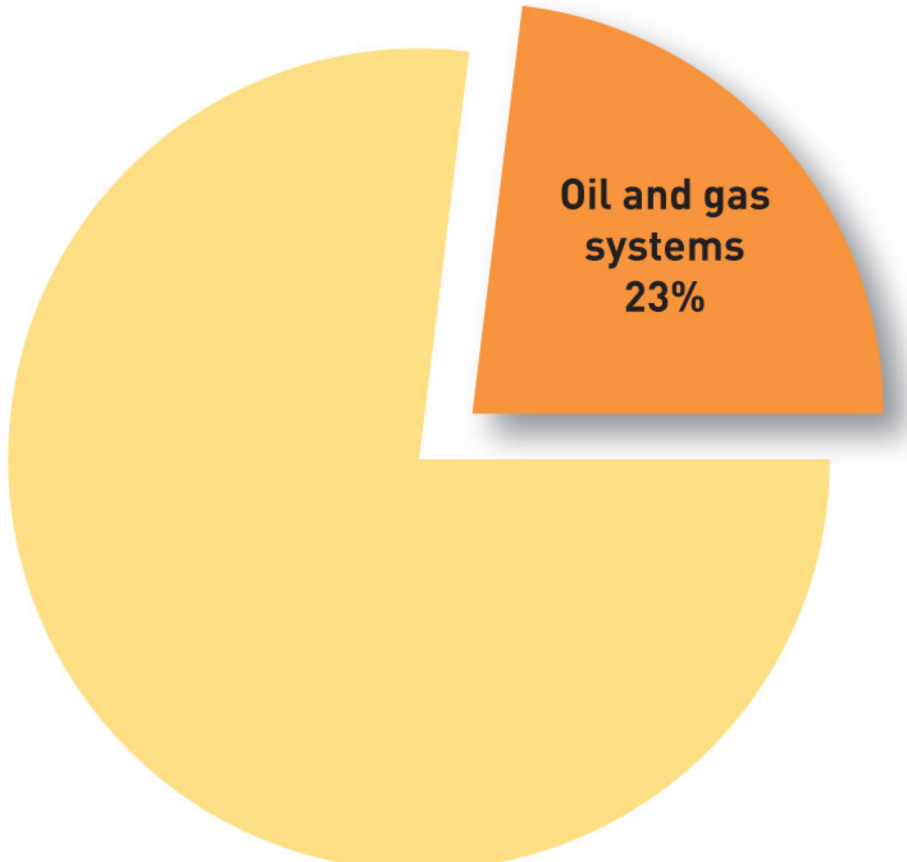

Pressure
Distance

Consider the Shale Gas

WCI Oil and Gas Collaborative
November 19, 2009

ENVIRONMENTAL DEFENSE FUND™
Finding the ways that work

2007 U.S. methane emissions



~2% of total U.S. CO_2 Eq.

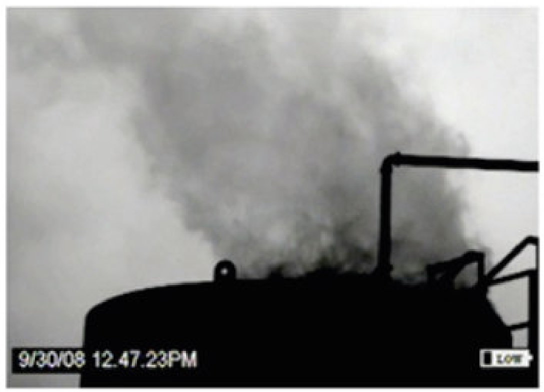
In 2007, methane emissions from oil and gas systems were equivalent to 133.5 million metric tons of CO_2. Total U.S. methane emissions for the same year equaled 585.3 million metric tons of CO_2. Source: EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2007* ES-5 (draft 2009), available at http://epa.gov/climatechange/emissions/usinventoryreport.html.

The New York Times

Energy & Environment

BY DEGREES

Curbing Emissions by Sealing Gas Leaks



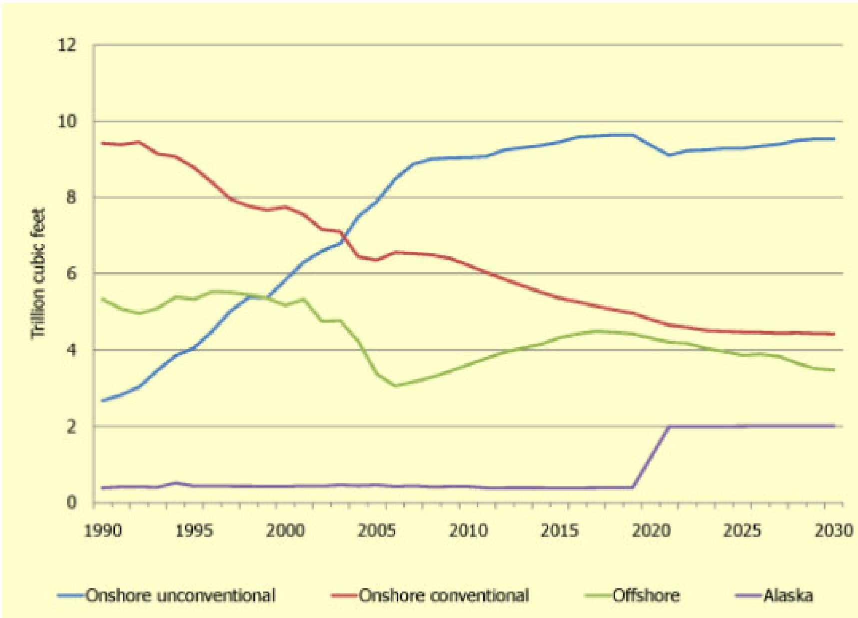
Photographs by the U.S. Environmental Protection Agency

To the naked eye, no emissions from an oil storage tank are visible. But viewed with an infrared lens, escaping methane is evident.

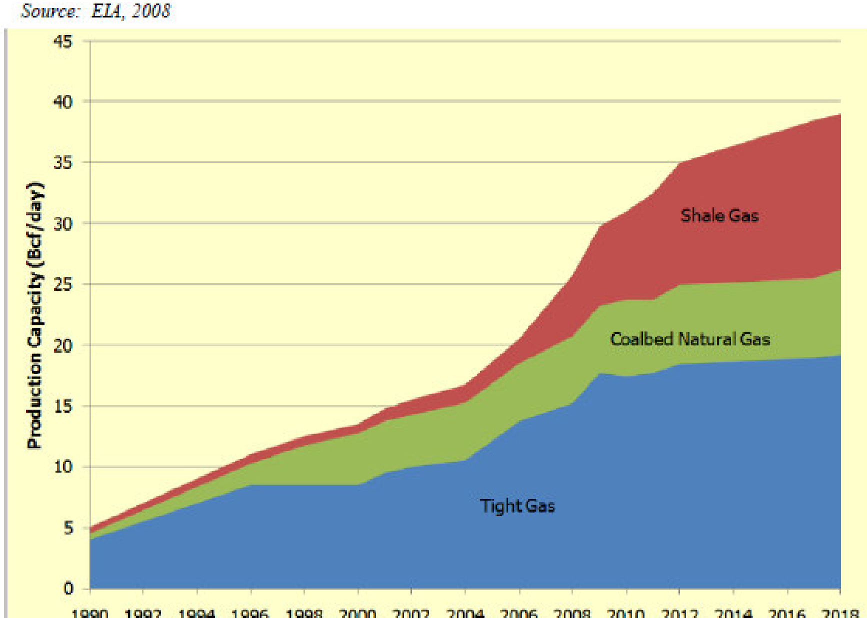
By ANDREW C. REVKIN and CLIFFORD KRAUSS
Published: October 14, 2009

To the naked eye, there was nothing to be seen at a natural gas well in eastern Texas but beige pipes and tanks baking in the sun.

U.S. Natural Gas Production



Source: EIA, 2008



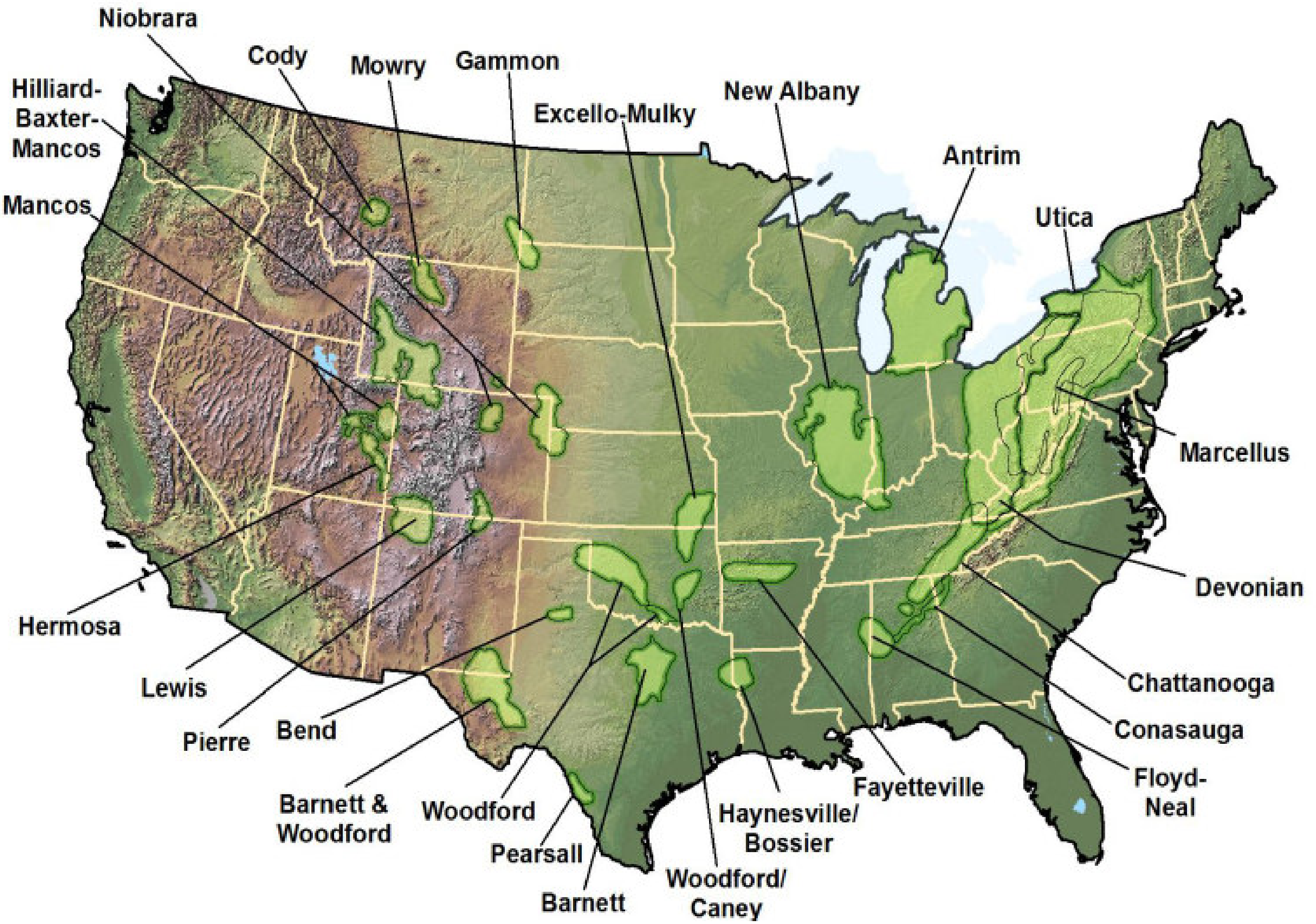
Source: Modified from American Clean Skies, Summer 2008

- Unconventional production now accounts for 46% of total U.S. production

- In 2007, Texas, Wyoming, and Colorado were the states with the greatest additions to proved gas reserves for the year; these additions were from shale gas, tight sands, and coalbed methane, all of which are unconventional gas plays

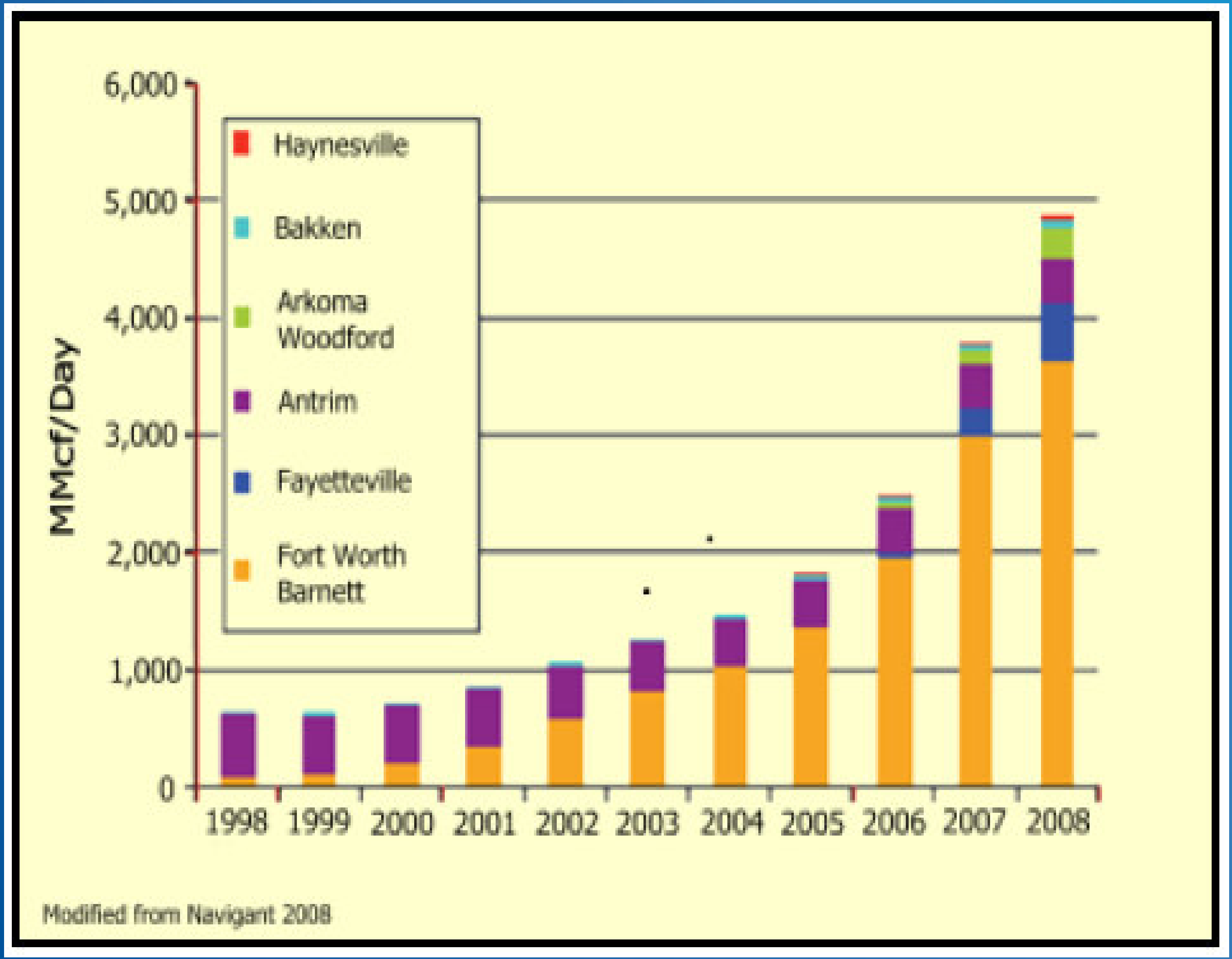
- Source: DOE, “Shale Gas Primer”

U.S. Shale Gas Basins



Source: Ground Water Protection Council and ALL Consulting, "Modern Shale Gas Development in the United States: A Primer" Prepared for U.S. Department of Energy Office of Fossil Energy and National Energy Technology Laboratory April 2009.

Most Active Shale Plays



Source: DOE, “Shale Gas Primer”

Importance of WRAP and WCI work

- Leveling the playing field
  - Requiring E&P to meet minimum monitoring and reporting standards (should bring all producers up to the same minimum level of emissions estimation competency)

- Capturing potentially undercounted emissions
  - NYT article, Shale Gas example, WRAP Task 1 inventory (showing uncertainty in current emissions estimates)

- Informing the national conversation
  - Assisting the development of a national O&G reporting standard by US EPA

Relevance of Shale Gas Example to WCI O&G Protocol Development

- Supports findings of WRAP Task 1 & 2 reports
  - Although there exists differences between fields and production types, there are significant similarities between the types of equipment used, emissions sources and extraction processes
- Supports the speed of WCI protocol development and need for comprehensive emissions coverage
  - Based on need to capture increasingly emissive and innovative extraction processes

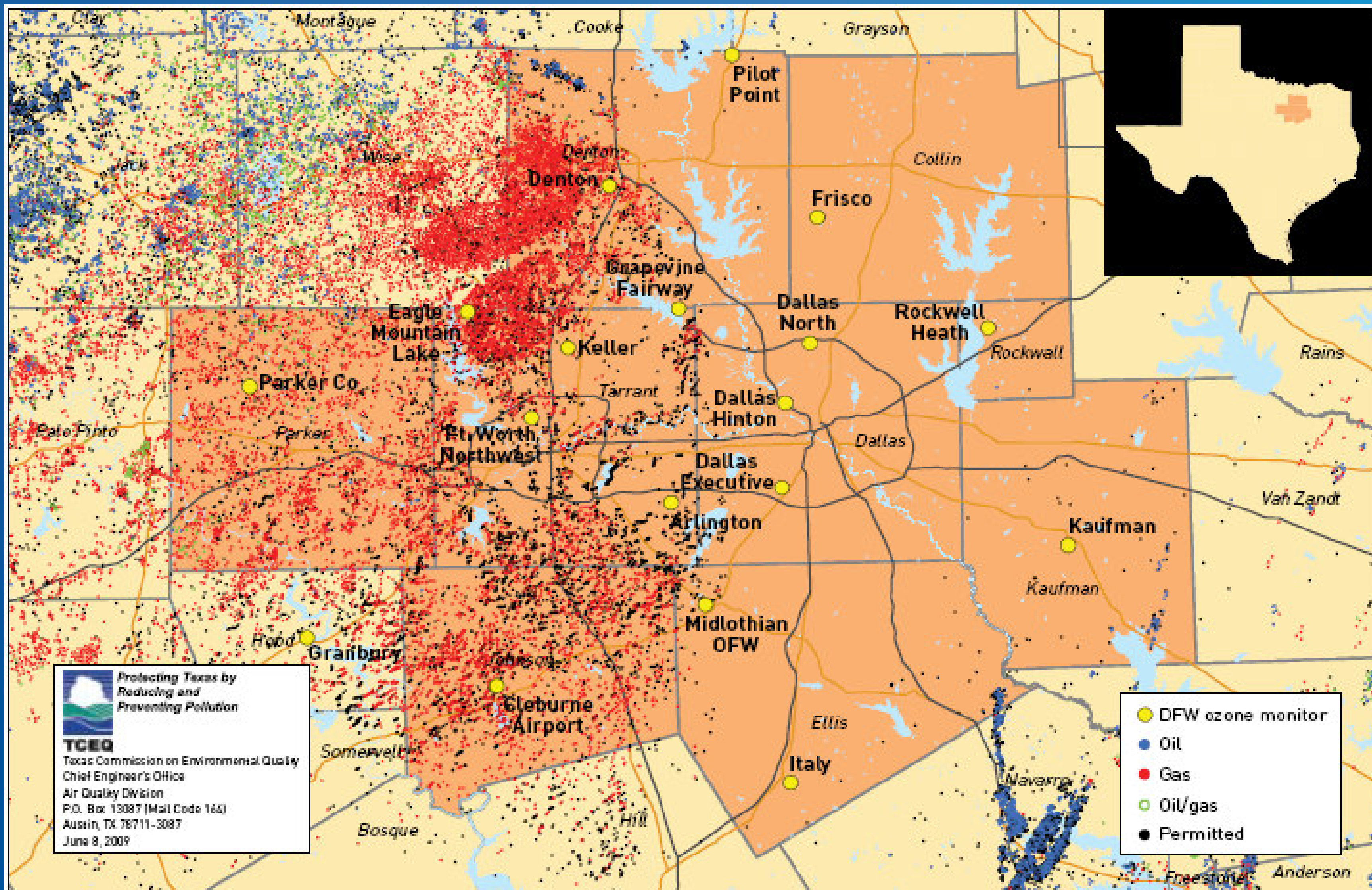
Relevance of Shale Gas Example to WCI O&G Protocol Development

- Significance for protocol development at WCI
  - An expansive protocol that accurately covers as many sources as possible at Oil and Gas E&P sites in the WCI region and uses field level data (metered - rather than default values) will be adaptable to multiple production types and useful outside the WCI region

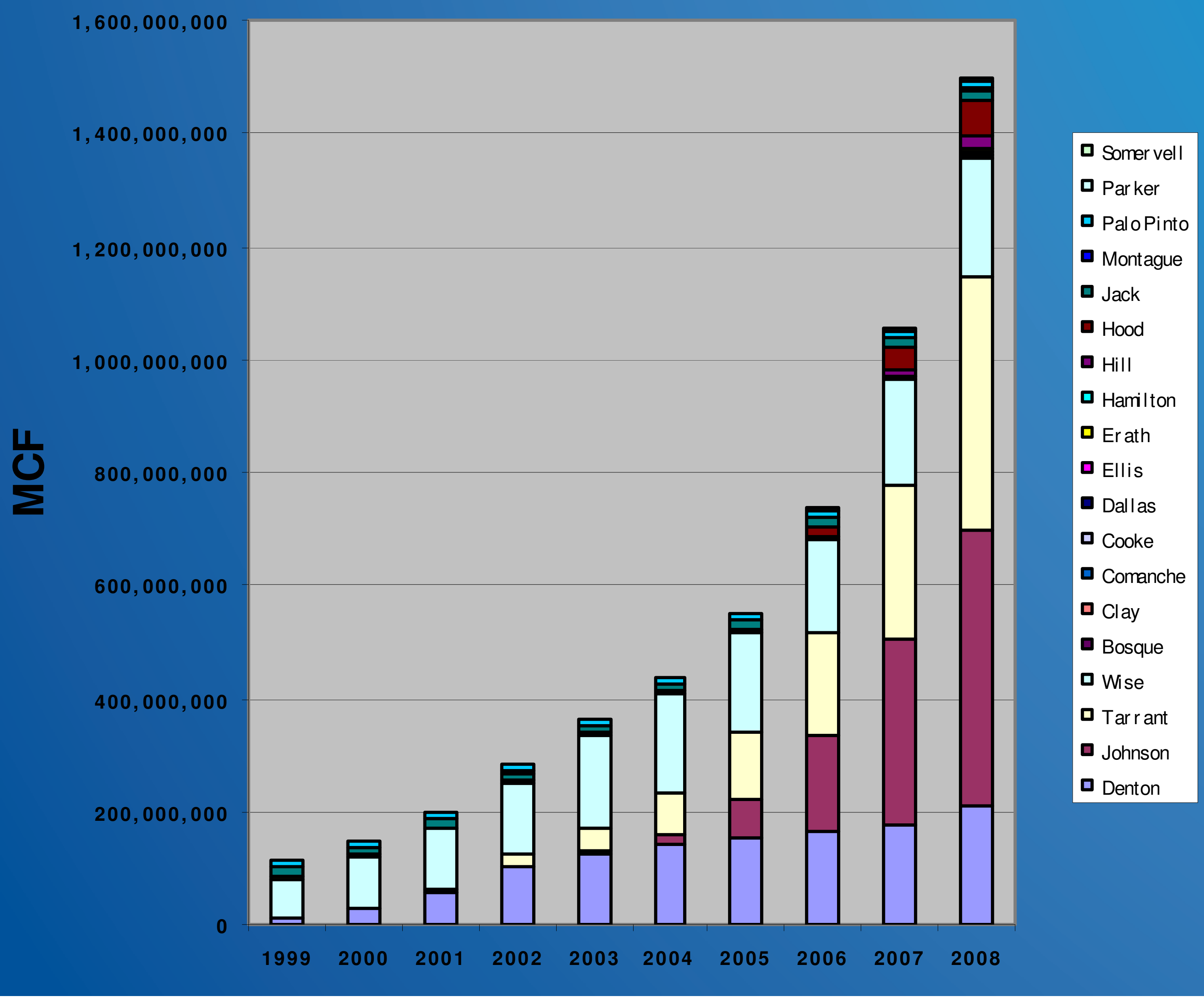
Relevance of Shale Gas Example to WCI O&G Protocol Development

- Highlights future needs
  - Increased use of fracturing linked to emissions of traditional pollutants and GHGs.
  - Some aspects of E&P may have greater emissions than otherwise expected
  - Comprehensive monitoring and reporting protocol needed at the regional and national level

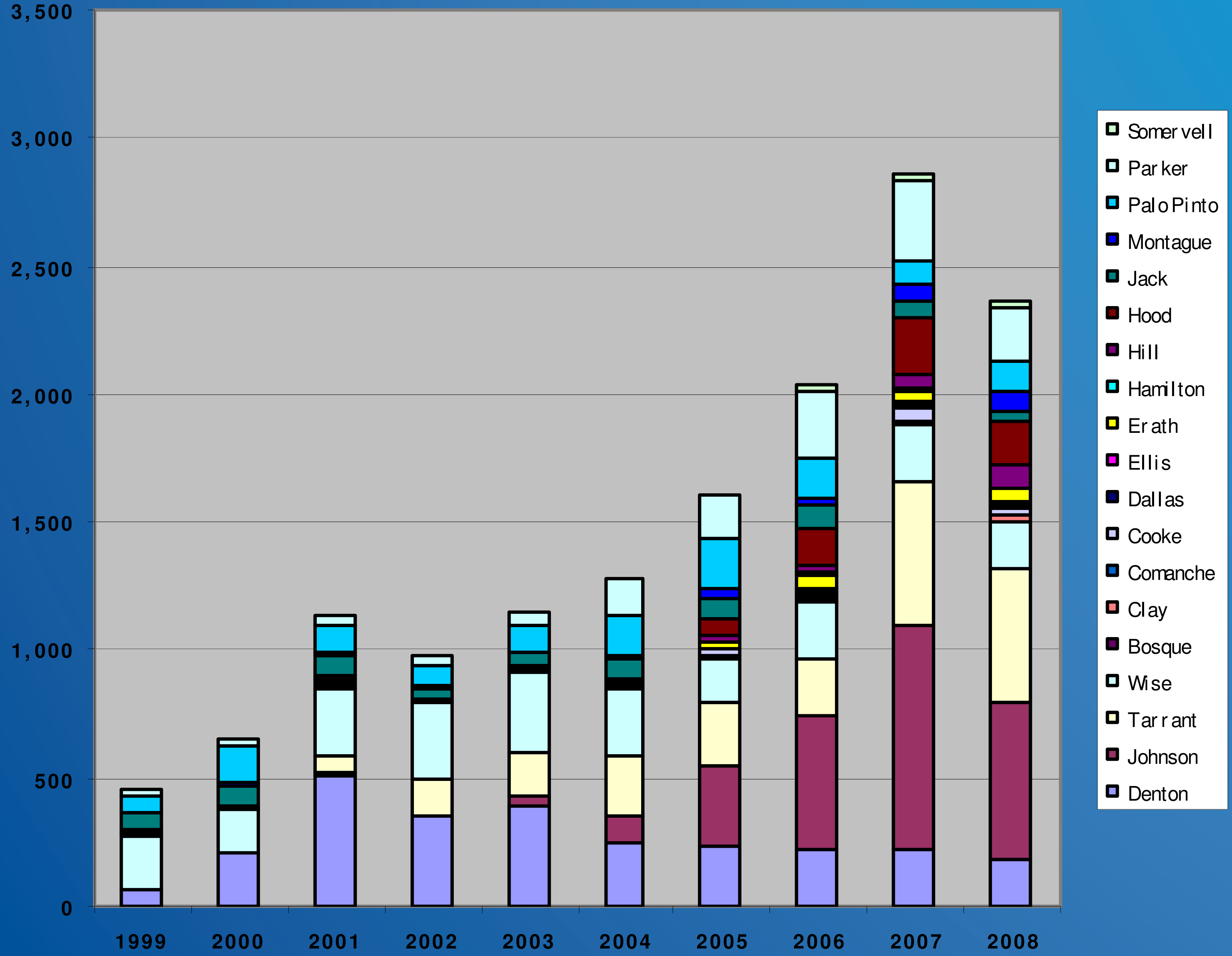
Barnett Shale Area Wells



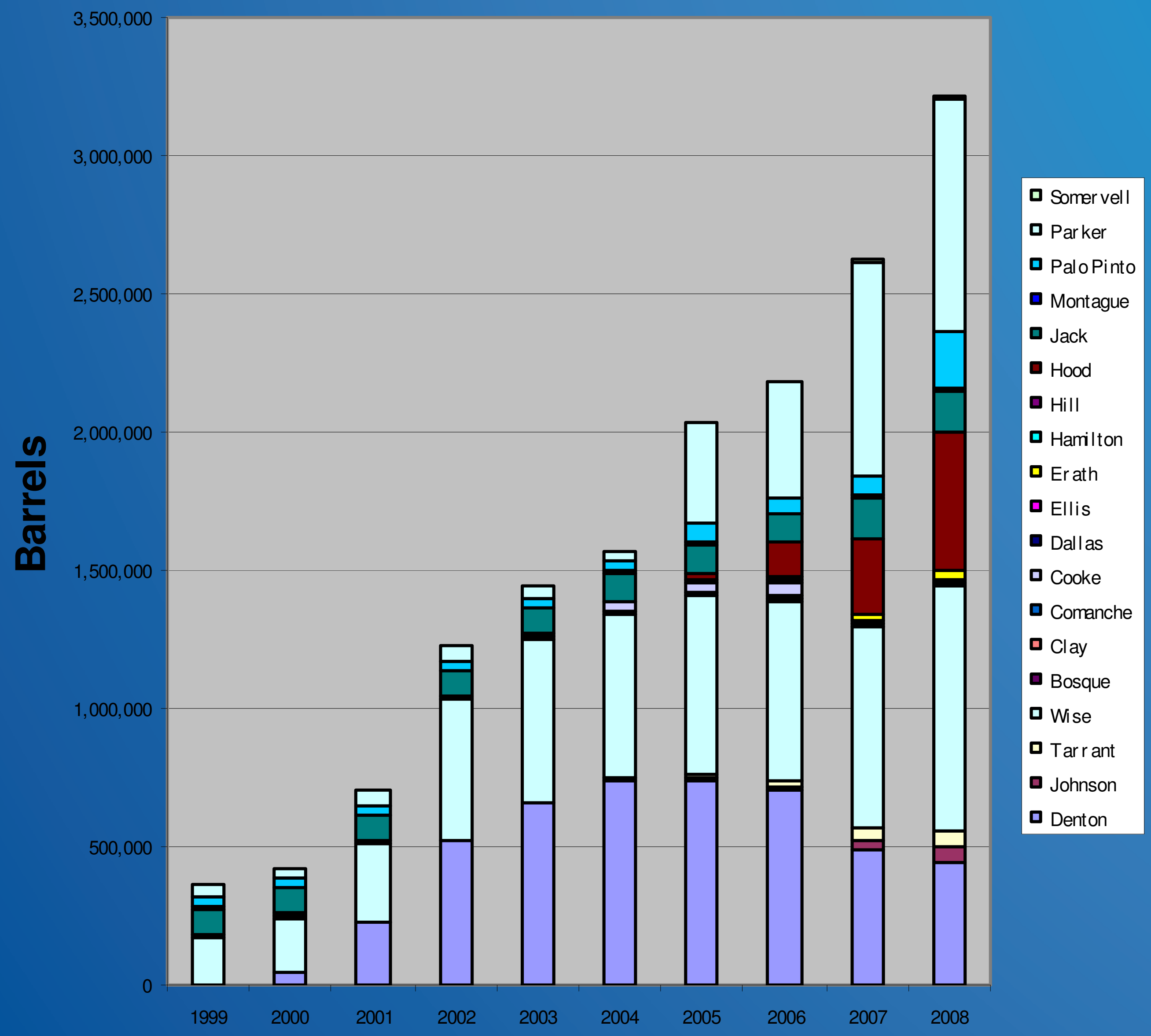
Natural Gas Production



Well Completions



Condensate Production



EDF's Barnett Shale Work

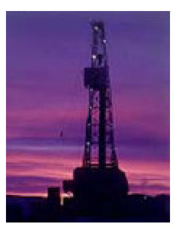
- Conduct emissions inventory
- Assess air quality impacts
  - Analyze state air pollution monitoring data
  - Compare to trends in county-level drilling and production activity
  - No one has looked at ozone effects yet
- Encourage the use of cost-effective emission controls

Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements

report by:
Al Armendariz, Ph.D.
Department of Environmental and Civil Engineering
Southern Methodist University
P.O. Box 750340
Dallas, Texas, 75275-0340

for:
Ramon Alvarez, Ph.D.
Environmental Defense Fund
44 East Avenue
Suite 304
Austin, Texas 78701

Version 1.1
January 26, 2009



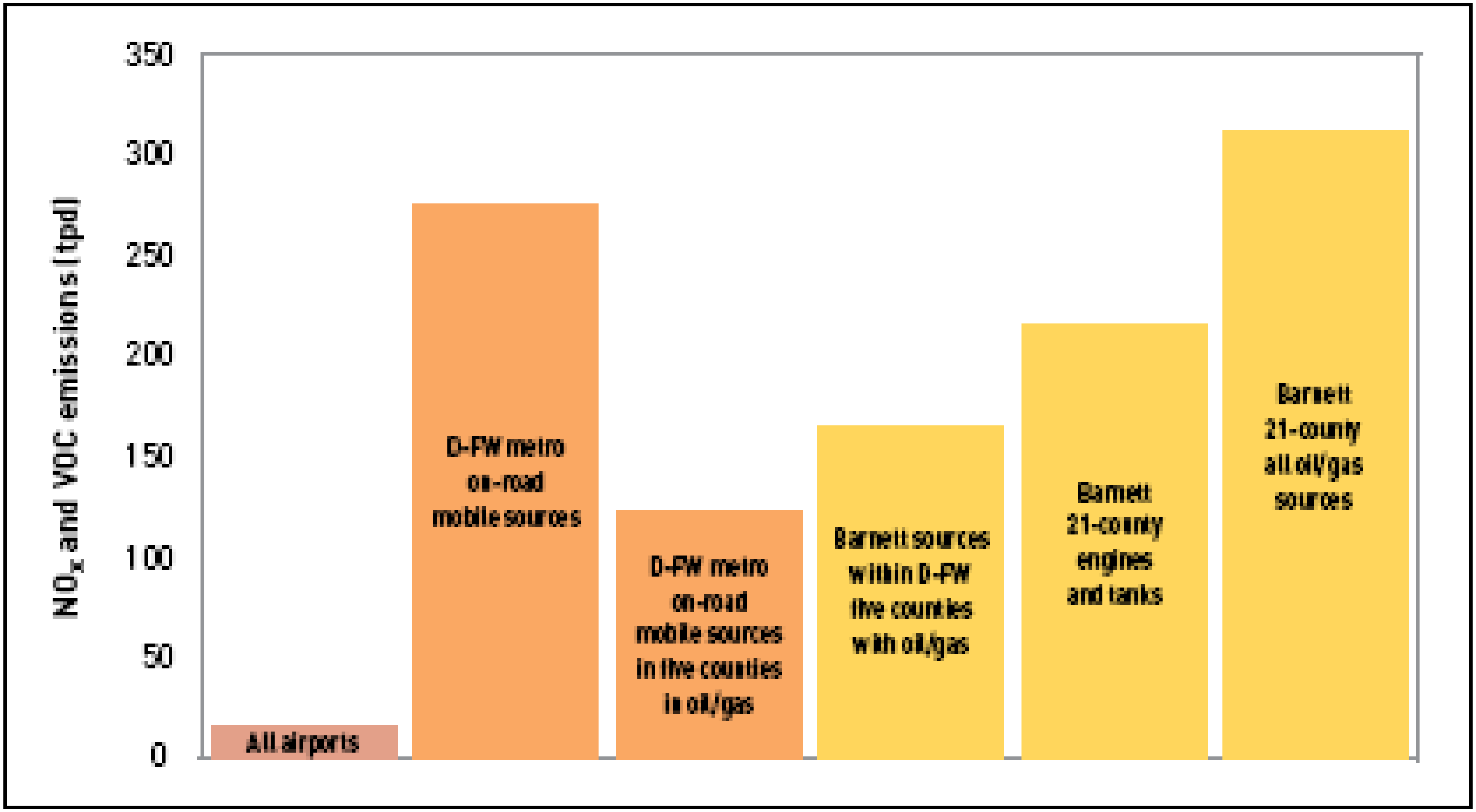
- Dr. Armendariz's report concluded that emissions from oil and gas activity in Barnett area are significant
- Despite industry criticism, estimated emissions found to be in line with TCEQ's own estimates

Peak summertime daily emissions (tons per day) from Barnett Shale area oil and gas production

	2009				
	Pollutant (tpd)				
	NO_x	VOC	HAPs	CH_4	CO_2e
Compressor engine exhausts	46	19	3.6	61	13877
Condensate and oil tanks	0	146	11	23	483
Production fugitives	0	26	0.62	232	4884
Well drilling and completions	5.5	21	0.49	183	4061
Gas processing	0	15	0.37	50	1056
Transmission fugitives	0	28	0.67	411	8643
Total daily emissions (tpd)	**51**	**255**	**17**	**961**	**33004**

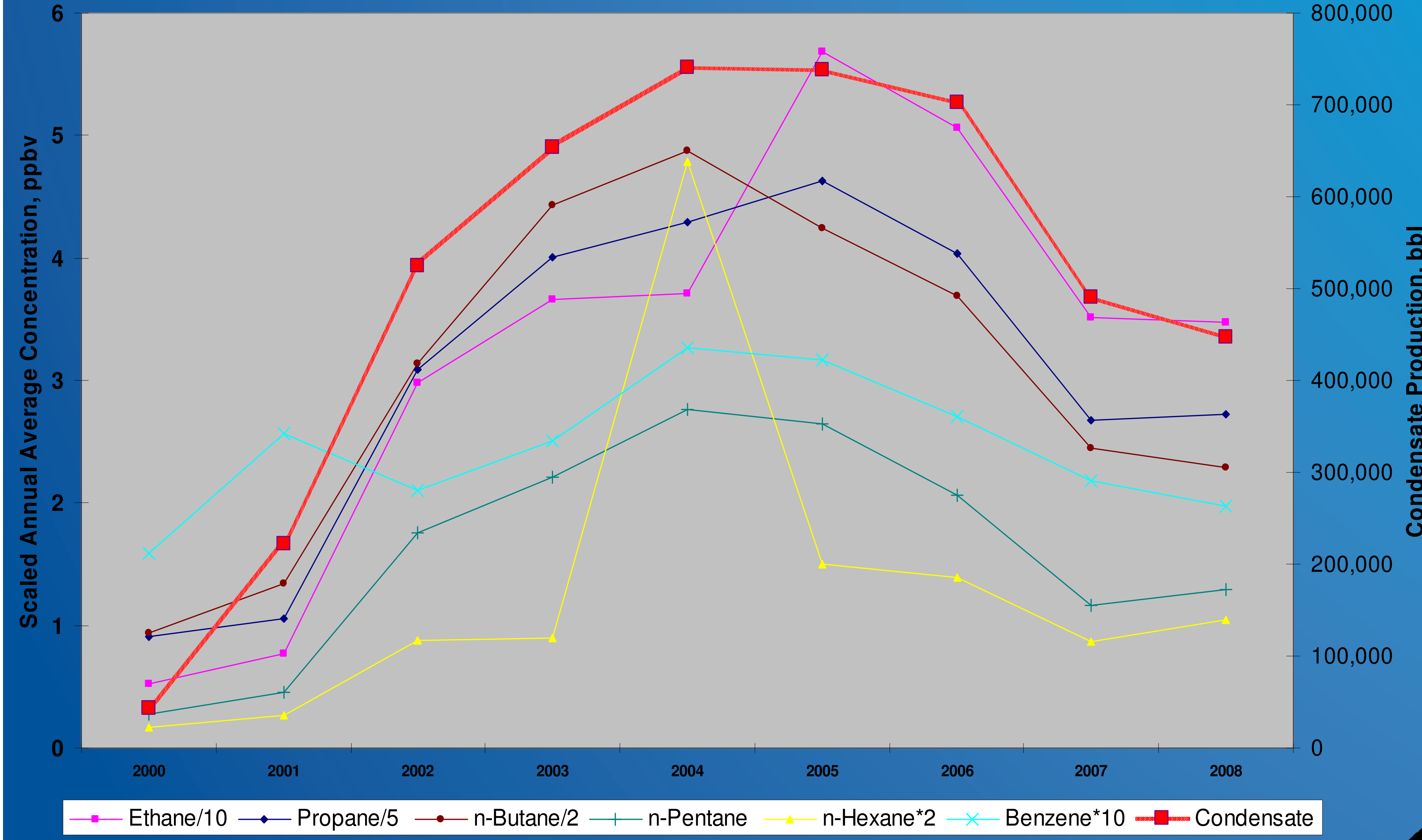
Source: Al Armendariz, Ph.D., Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements, 6, (January 26, 2009).

NO_X and VOC 2009 summer emissions



Emissions of NO_X and VOC in the summer of 2009 from all oil and gas sources in the Barnett Shale 20-county area will exceed emissions from on-road mobile sources in the D-FW metropolitan area by more than 30 tpd (307 vs. 273 tpd). Source: Al Armendariz, Ph.D., Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements, 6, (January 26, 2009).

Denton VOC vs. Condensate Production



Haynesville Shale

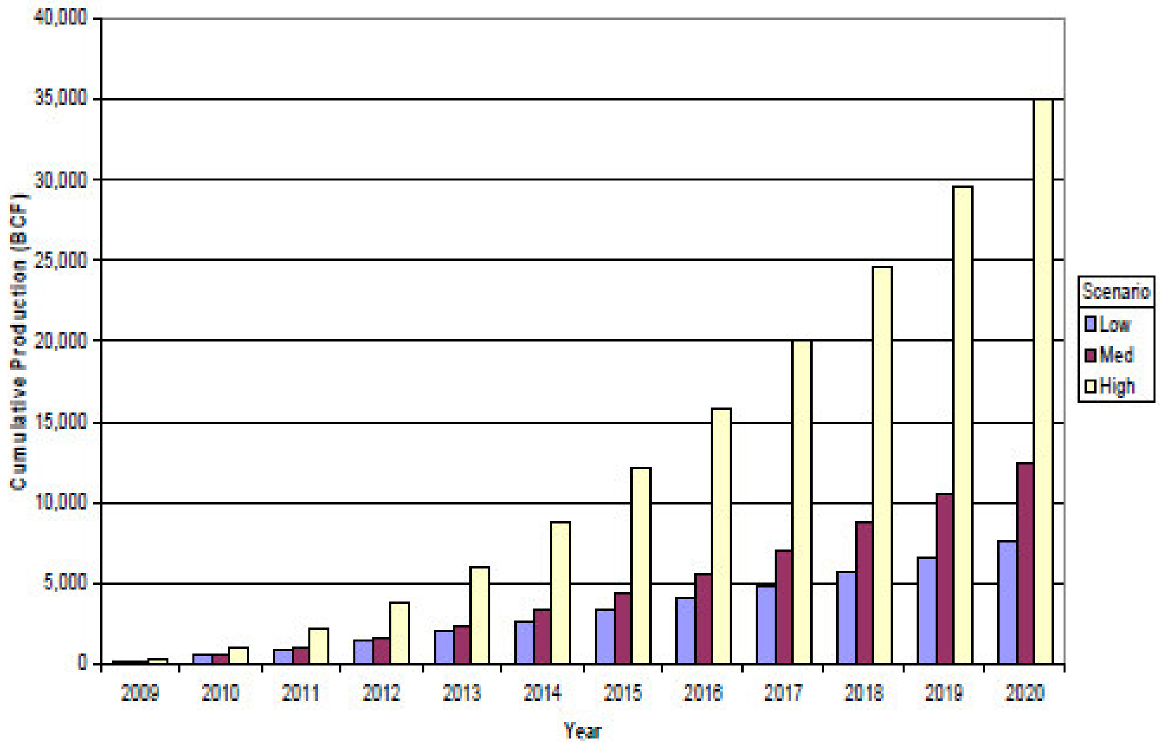
- Environ recently forecasted emissions in this developing play for NETAC
- Three slides borrowed from Environ follow for illustration purposes

Emission Inventory Scope

- Emission inventories developed for 2009-2020
  - Detailed inventory for 2012, the future year for NETAC ozone model
- Red counties define geographic extent of Haynesville for this study
  - Based on TRRC and LDNR well data as of March, 2009

ENVIRON

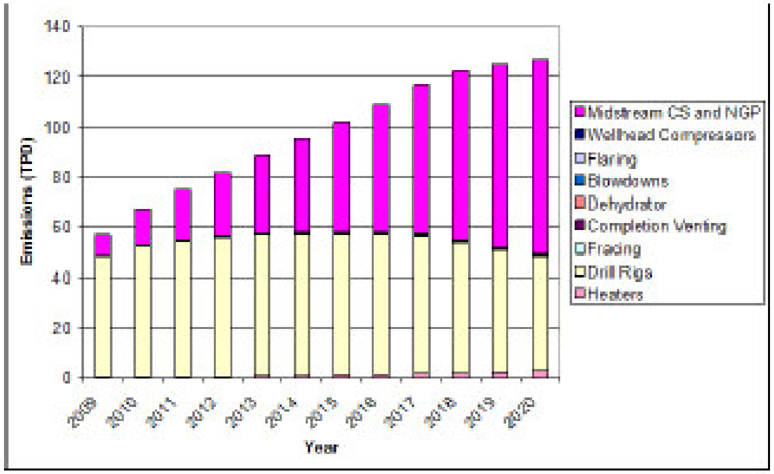
Projected Cumulative Gas Production in the Haynesville Shale: 2009-2020



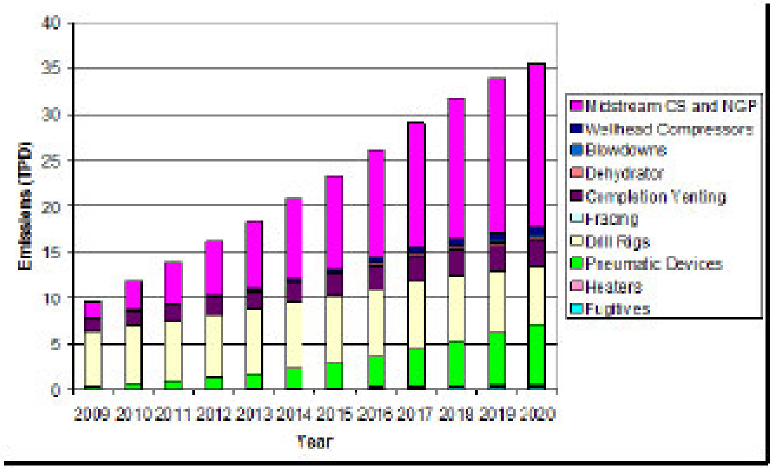
- 2020 production estimates range from 7.6-35 TCF
- Within range of published estimates of recoverable reserves (7-250 TCF)
- Barnett Shale reserves estimated to be 25-50 TCF
- All estimates highly uncertain-will be refined as Haynesville Shale is explored

Haynesville Emissions

NOx: Moderate Scenario



VOC: Moderate Scenario



- Largest NOx and VOC source categories are
  - midstream compression and natural gas processing (NGP)
  - drill rigs
- 2012 NOx emissions:
  - 61 tons/day, low scenario
  - 82 tons/day, moderate scenario
  - 140 tons/day, high scenario
- 2020 NOx emissions:
  - 64 tons/day, low scenario
  - 127 tons/day, moderate scenario
  - 267 tons/day, high scenario

Marcellus Shale

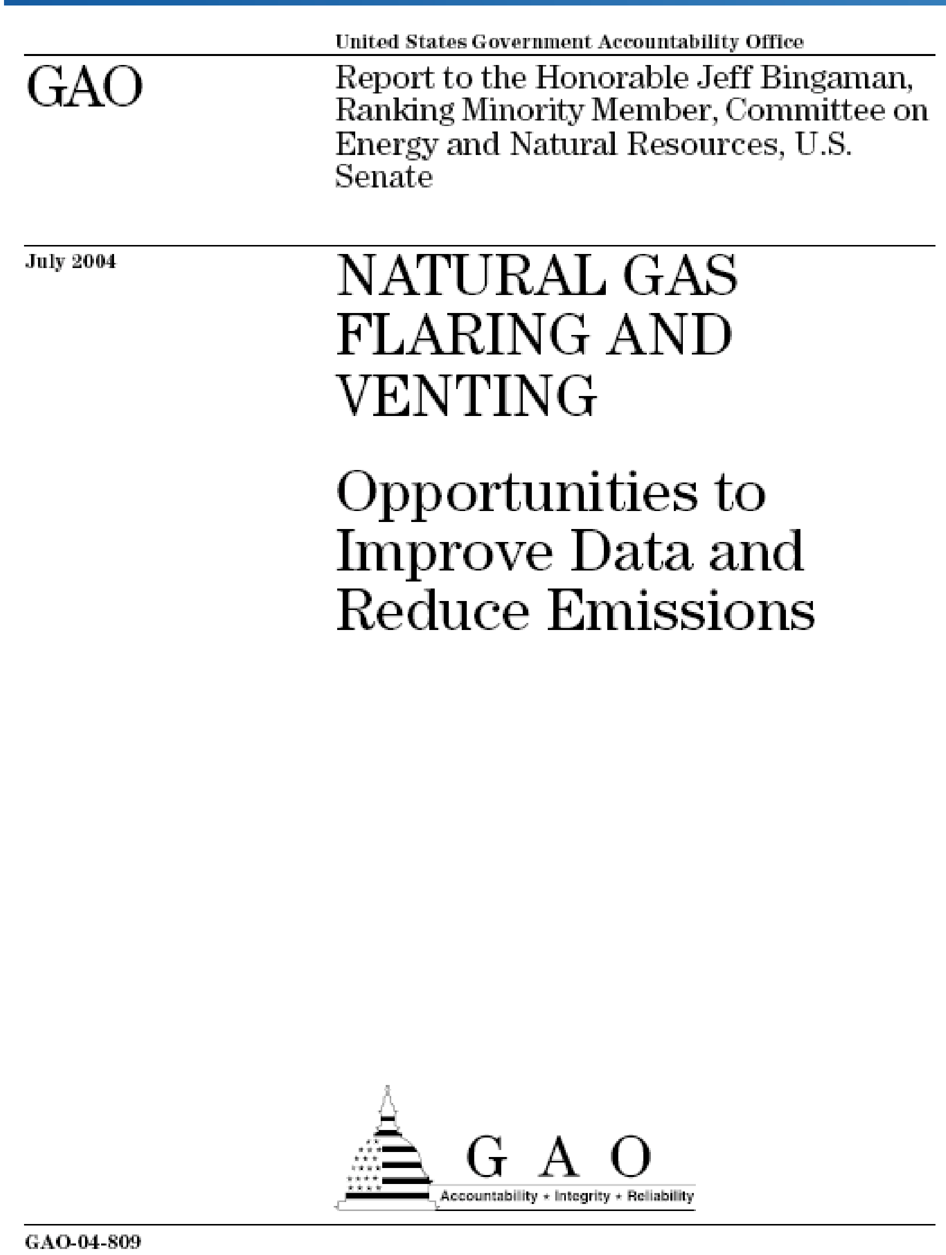
New York State Department of Environmental Conservation
Division of Mineral Resources

DRAFT

**Supplemental Generic Environmental Impact Statement
On The Oil, Gas and Solution Mining
Regulatory Program**

**Well Permit Issuance for Horizontal Drilling
And High-Volume Hydraulic Fracturing to
Develop the Marcellus Shale and Other
Low-Permeability Gas Reservoirs**

September 2009



United States Government Accountability Office

GAO

Report to the Honorable Jeff Bingaman, Ranking Minority Member, Committee on Energy and Natural Resources, U.S. Senate

July 2004

NATURAL GAS FLARING AND VENTING

Opportunities to Improve Data and Reduce Emissions

G A O

Accountability * Integrity * Reliability

GAO-04-809

This is not just an environmental issue

= Lost product

= Lost producer revenues

= Lost royalties and/or taxes

Methane losses in Barnett Shale alone represent about $46 million per year in lost revenues for producers and $3.2 million in lost severance tax payments to TX

~40% of NM general revenues are oil & gas royalty payments

Thank You

Ramon Alvarez, Ph.D.
Senior Scientist
ralvarez@edf.org
512-691-3408

EDF ENVIRONMENTAL DEFENSE FUND™

Finding the ways that work

DRAFT

Summary of Key Emission Source Types in the Oil and Gas Production and Gas Processing Industries

Emission Source	Pollutant			Sector			Source Type		
	CO_2	CH_4	N_2O	Exploration	Production	Processing	Fugitive	Process Vent	Combustion Stack
Flaring & Incineration	●	●	●	●	●	●			●
Drilling Fluid Degassing	●	●		●			●		
Drill Rig Combustion	●	●	●	●					●
Condensate Tanks	●	●			●			●	
Oil Tanks	●	●			●			●	
Pneumatic Control Devices	●	●			●	●		●	
Pneumatic Pumps	●	●			●	●		●	
Well Completion Venting	●	●			●			●	
Well Blowdowns & Maintenance	●	●			●			●	
Well Head & Casings	●	●					●		
Compressor Purge & Starts	●	●			●	●		●	
Equipment Purge / Blowdowns	●	●			●	●	●	●	
Dehydrator Vents	●	●			●	●		●	
Acid Gas Removal Vents	●	●			●	●		●	
Centrifugal Compressor Seals	●	●			●	●	●		
Compressor Seal Degassing Vents	●	●		●	●	●		●	
Open-Ended Lines	●	●			●	●		●	
Pump Seals	●	●			●	●	●		
Pressure Relief Valves	●	●			●	●	●		
Recip. Compressor Seals	●	●			●	●	●		
Valves – Flanges – Fittings	●	●			●	●	●		
Oil-Water Separators & Treatment	●	●			●	●	●		
Combustion of Lease Fuel Gas	●	●	●		●				●
Plunger Lift Systems	●	●			●			●	
Field Gathering Lines	●	●			●		●		
Gas Sampling and Analysis	●	●			●	●		●	

DRAFT Summary of Key Emission Source Types in the Oil and Gas Production and Gas Processing Industries (Notes)

- Purpose and Scope:
  - This source list identifies all GHG emission sources that exist within the oil and gas production and gas processing industries operating within the WCI jurisdictions (in the U.S. and Canada).
  - The list will be used for development of essential requirements (ER) for mandatory reporting under the WCI cap-and-trade program.
  - For purposes of ER development, mobile transportation sources are not included, but mobile drilling rigs are included.

- References:
  - "Oil and Gas Exploration and Production Greenhouse Gas Protocol. Task 2 Report - Significant Source Categories and Technical Review of Estimation Methodologies." Prepared for Western Regional Air Partnership, Oil and Gas Greenhouse Gas Protocol Steering Committee by ENVIRON International Corporation and Science Applications International Corporation (SAIC). August 31, 2009.
  - "Background Paper - Fugitive Background_EPA Draft." Byard Mosher, California Air Resources Board. October 29, 2009.
  - "Draft EPA Mandatory Reporting of Greenhouse Gases Regulation - Subpart W - Oil and Natural Gas Systems."

Western Climate Initiative

Status of WCI Reporting Requirements

Reporting Committee

Jim Norton, Chair

November 19, 2009

Santa Fe, NM

WCI Cap and Trade Program Design Principles

The program should:

1. ***Be equitable, administratively simple for government and private participants, minimizes administrative costs, and have a clear compliance path;***
2. Maximize total benefits throughout the region, including reducing air pollutants, diversifying energy sources, and advancing economic, environmental, and public health objectives, while also avoiding localized or disproportionate environmental or economic impacts;
3. Require all [offset] reductions to be real, surplus/additional, verifiable, permanent, and enforceable;
4. Stimulate investment, especially in low carbon technologies, and reward innovations that will lead to long-term permanent greenhouse gas reductions;

WCI Cap and Trade Program Design Principles (cont.)

The program should:

5. ***Cover as many sources as is practical, while encouraging pollution reductions beyond the capped sources and sectors;***
6. ***Provide appropriate recognition and incentives for early emissions reductions;***
7. ***Assure a transparent and robust accounting system that will measure and report emissions rigorously and consistently across all sectors and throughout the region;***
8. Minimize the potential for leakage; and
9. ***Facilitate linkage to similarly rigorous regional and international greenhouse gas reduction markets and encourage other states, provinces, and countries to join the market.***

Some Key Design Recommendations
(Sept. 23, 2008)

EMISSIONS COVERED

- ***Combustion at industrial and commercial facilities***
- ***Industrial process (non-combustion) emission sources, including oil and gas process emissions***
- ***Transportation, residential, commercial, and (below-threshold) industrial fuel combustion, at distributor or supplier level***
- ***Adequate quantification methods will be established for emissions sources prior to including them in the program***

Some Key Design Recommendations (Sept. 23, 2008)

THRESHOLDS

- ***For cap-and-trade program: 25,000 metric tons CO2e per year, may adjust for specific industries***
- ***For emissions reporting: 10,000 metric tons CO2e per year; for some source categories, could be based on other parameters such as throughput or capacity***

REPORTING

- ***Third party verification will be required for sources included under the cap***
- ***Prior to start of mandatory reporting program, the WCI Partner jurisdictions will establish essential requirements for reporting***

Essential Requirements of Mandatory Reporting

- ***Developed Spring 2008 – July 2009***
- ***Stepwise development, multiple drafts for stakeholder review and comment***
- ***July 2009 Release - Final ERMR Sections***

  - General Provisions (Applicability, Schedule, General Contents of Reports, etc.)

  - Verification

  - General Stationary Combustion

  - Source Category Specific Sections (Refineries, Pulp and Paper, Lime, etc.)

  - Oil and Gas Production other than General Stationary Combustion not included
- ***September 2009: U.S. EPA finalizes rule for Mandatory Reporting of Greenhouse Gases***
- ***Need for harmonization***

Harmonizing WCI ERMRs with Federal Requirements

- ***Goal is to avoid imposing conflicting reporting obligations on facilities subject to both programs***
- ***Will amend WCI Essential Requirements to achieve harmonization with the U.S. EPA rule***
- ***Will make version of Essential Requirements suitable for use in Canada (regulatory structure, language, emissions factors, standard practices***
- ***Complete tasks in time for jurisdictional rulemaking to cover 2011 emissions***

WCI Principles for Harmonization

- ***A U.S. facility should be able to comply with both the EPA rule and a WCI jurisdiction's reporting requirements by following a single set of monitoring, recordkeeping and reporting requirements.***
- ***The quantification methods included in the amended ERs must be sufficiently reliable and accurate to be employed in a (GHG) cap-and-trade program. Because EPA has acknowledged that it did not develop the MRR with this goal in mind, the Reporting Committee must review each method included in the MRR to assure it meets this criterion. (e.g., WCI may allow only subset of quantification methods in EPA rule)***
- ***The amended ERs must remain suitable for use in Canadian WCI jurisdictions. For example, they must allow reporting in metric as well as English units and must where necessary include Canada-specific emission factors.***

Developing Mandatory Oil and Gas Reporting Requirements

- ***U.S. EPA proposed Subpart W (Oil and Natural Gas Systems) for non-combustion emissions, but deferred in September final rule***
- ***U.S. EPA will address oil and gas requirements in 2010 rulemaking***
- ***Development of WCI requirements will build on WRAP/TCR Protocol development process***
- ***Continue WRAP/TCR Technical Working Group, with some new members***
- ***Include U.S. EPA representation as they develop new proposal for oil and gas***
- ***New roles and responsibilities***

  - WCI Oil and Gas Subcommittee (of Reporting Committee) will assume Steering Committee role; ERG as technical contractor
- ***Completion first quarter 2010***
- ***Amend as needed for harmonization with final EPA rule anticipated in mid-2010***

Western Climate Initiative

Final Draft Complementary Policies White Paper

November 7, 2009

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1 Background and Purpose

The Western Climate Initiative (WCI) Partners have recommended a comprehensive regional effort to reduce emissions of global warming pollution, combining a broad cap-and-trade program with complementary policies to achieve the WCI 2020 regional emissions goal.[1] Complementary policies can address market barriers that would otherwise limit the use of low-cost GHG emission reduction options, and can reduce emissions from sources excluded from the cap-and-trade program. Thus, complementary policies can lower the overall cost of reducing GHG emissions. This view is supported by the 2008 economic analysis of WCI's cap-and-trade design that incorporated complementary policies related to energy efficiency and tailpipe emission standards, which found that the WCI 2020 reduction goals can be achieved with small overall net savings due to reduced energy expenditures exceeding the direct costs of greenhouse gas emission reductions.[2]

As part of the WCI 2009-2010 Workplan, the WCI Partner jurisdictions formed the Complementary Policies Committee. The charge of the Committee is to recommend to the WCI Partner jurisdictions those policies which, if harmonized across multiple states and provinces both within and outside the WCI Partner jurisdictions, would help achieve the regional emissions reduction goals and assist with the transition to a low-carbon economy. As a first step, the Committee has prepared this white paper to solicit input from stakeholders on:

- the policies it recommends for further evaluation as outlined in its workplan;
- the Committee's recommended evaluation criteria;
- key issues or barriers to harmonization; and
- benefits that could accrue to the Partner jurisdictions and businesses that operate in more than one jurisdiction if implementation is harmonized.

This paper also discusses why and when policies complementary to a cap-and-trade program are useful, how complementary policies help achieve the WCI GHG reduction goals, and which policies would affect emissions under the cap and which would affect emissions from sectors and sources outside the cap.

It is important to note that many important complementary policy initiatives are not proposed to be evaluated by the Committee because they are being fully examined and developed in other venues. These other important policies are described briefly at the end of this paper.

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[1] The WCI GHG reduction goals, established in 2007, call for an aggregate reduction in the region of 15 percent below 2005 levels by 2020 and, over the long term, a reduction that significantly lowers the risk of dangerous threats to the climate. *See* http://www.westernclimateinitiative.org/component/remository/general/Emission-Reduction-Goal-Aug-2007/.

[2] *See* WCI, Appendix B: Economic Modeling Results, Sept. 23, 2008, at: http://www.westernclimateinitiative.org/component/remository/Economic-Modeling-Team-Documents/.

Forthcoming reports from the Committee will address two additional policy areas: 1) workforce transition, job creation, job retention, and mitigation of community impacts associated with climate-related policies; and 2) climate change adaptation.

1.1 The Role of Complementary Policies

The WCI Partner jurisdictions have designed an economy-wide cap-and-trade program to reduce emissions in accordance with the WCI GHG reduction goals while maximizing market efficiency in achieving those reductions. Putting a price on GHG emissions will result in investments in technologies and other actions that will reduce emissions. However,some activities that reduce emissions cost effectively do not respond to this price signal: so-called market barriers prevent or impede the diffusion of cost-effective technologies and practices that could mitigate GHG emissions. The distribution of the costs and benefits of improving a building's energy performance is an instructive example of a market barrier. In commercial buildings, the cost of building improvements is typically borne by the building owner but the benefits are enjoyed by the tenants through lower energy bills. Because the building owner does not realize directly the financial benefit from the efficiency investment, s/he is less likely to make that investment. A well designed energy efficiency program can provide the needed incentive to make that investment.

Complementary policies achieve a variety of objectives in addition to reducing GHG emissions and removing market barriers. They can:[3]

- Achieve reductions outside (or below) the cap
- Encourage investments in low-carbon technologies
- Lower the cost per metric ton of reductions in GHG emissions covered by the cap-and-trade program
- Lower the cost of transitioning to a low carbon economy
- Prevent emissions and economic leakage
- Create and retain clean energy jobs

Given the role complementary policies play in the transition to a low-carbon economy, a comprehensive program that combines a cap-and-trade program with targeted complementary policies will deliver emissions reductions at a lower cost to consumers, measured as cost per ton of avoided GHG emissions.[4] The WCI Partners would also like to consider the potential benefits of harmonizing complementary programs among not only WCI jurisdictions but among states and provinces that are not part of the WCI. This will require other states and provinces that are not currently part of WCI to participate with the organization as it moves forward in its evaluation of selected complementary policies.

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[3] Western Climate Initiative 2009-10 Workplan, updated June 23, 2009, at 36.

[4] *See* Testimony of Richard Cowart, Regulatory Assistance Project, Before the Committee on Energy and Commerce Subcommittee on Energy and Environment, U.S. House of Representatives, April 23, 2009, "The Consumer Allocation for Efficiency: How Allowance Allocations Can Protect Consumers, Mobilize Efficiency, and Contain the Costs of GHG Reduction," at http://energycommerce.house.gov/Press_111/20090423/testimony_cowart.pdf.

1.2 Evaluation Criteria

The next step for the Committee will be to more fully evaluate the selected policies based on the following criteria as they may be amended based on stakeholder review:[5]

- The policy will reduce GHG emissions.
- The policy is expected to reduce costs associated with achieving the WCI goals for covered facilities.
- Administrative costs are expected to be manageable.
- Impacts on low-income communities or small businesses can be mitigated.
- Meaningful benefits to harmonizing have been identified.
- Identified barriers to harmonizing implementation can be overcome.
- An opportunity to achieve collateral benefits (e.g., conserving water) has been identified.
- No collateral detriments (e.g., increased use of electricity,[6] increased fine particulates or air toxics pollution) have been identified.
- The policy does not encourage leakage outside the cap.
- The policy has the potential to create or retain clean energy jobs or otherwise transition to a low-carbon economy.

These criteria are intended to help the Committee determine whether and how each policy should be harmonized and how each policy will help achieve WCI's emissions reduction goal. Stakeholders are asked to specifically comment on the criteria and suggest qualitative indicators for determining if a given criterion has been met. Not all of the policies will meet all of the criteria, and some policies under initial consideration will not be recommended for harmonization.

1.3 Policies Recommended for Evaluation

Each of the WCI Partner jurisdictions has a climate action plan that delineates various policy instruments needed to achieve the jurisdiction's own emissions reduction goals or targets. The Committee used these plans to identify policies for consideration in this white paper. Listed below are the policies the Committee is recommending for further evaluation. The policies are grouped into three tiers to assist with scheduling the Committee's work. Policies in the highest tier (Tier 1) will be evaluated first. Stakeholders are asked to specifically provide feedback to the Committee on how it has proposed to tier the policies, the key issues that should be addressed and potential benefits of harmonizing them.

Energy Production

- Small-scale renewable energy resources (Tier 1)
- Emissions performance standards for electric generating units (Tier 1)
- Carbon capture and sequestration (Tier 2)

[5] Refinement of criteria in Western Climate Initiative 2009-2010 Workplan, at p. 38.
[6] Where electricity substitutes for higher GHG-emitting transportation fuels its increased use would be a benefit.

Energy Efficiency

- Energy efficiency targets (Tier 1)
- Energy efficiency programs and incentives (Tier 1)

Transportation

- Low-carbon fuel standard (Tier 1)
- Freight transportation infrastructure (Tier 1)
- Development of algae and ligno-cellulosic biofuels (Tier 1)
- Heavy-duty vehicle equipment (Tier 2)
- Electric and alternative fuel vehicle infrastructure (Tier 2)
- Vehicle emissions labeling (Tier 3)
- Medium and heavy-duty vehicle hybridization (Tier 3)
- Transport refrigeration units (Tier 3)

Industrial Sector

- Emissions performance standards for major industrial sources (Tier 3)

High-Global Warming Potential Gases

- Regulatory measures for high-global warming potential gases (Tier 1)

Agriculture

- Agricultural anaerobic digesters (Tier 2)

Waste Management

- Measures for landfill methane reduction (Tier 2)

Appendix A shows which of these complementary policies, if implemented, would reduce emissions from capped sources and sectors, and which policies would reduce emissions from uncapped sources and sectors.

1.4 Next Steps

This paper will be finalized after stakeholder review and comment. At that time, the Committee will begin to evaluate the policies that are included in the final paper. The key issues and benefits will be more fully identified. The Committee will attempt to identify other related issues such as needed jobs or skill sets to effectuate the policies. The outcome of the evaluation process will be design recommendations to facilitate regional harmonization of the specific policies. Stakeholders are asked to specifically comment on how the Committee can best engage with them as the evaluation process evolves—for example, opportunities for written comments on draft documents, Webinars, phone conferences, WCI's on-line newsletter, or a blog or other electronic discussion board.

2 Tier 1 Policies

2.1 Energy Production

- Small-scale renewable energy resources.
- Emissions performance standards for electric generating units.

2.1.1 Small-Scale Renewable Energy Resources

Small-scale renewable resources include solar photovoltaic systems, solar water heating systems, community-scale wind turbines, geothermal systems, biomass digesters, micro-hydro systems, and generating systems that run on wood waste, agricultural waste, or waste gas from landfills or water treatment plants. These systems can help meet power and thermal energy needs and reduce GHG emissions. They can be installed at homes and businesses to supply on-site energy needs. In addition, utilities and third parties can build small-scale generating facilities as system resources for all customers.

Potential Policies. State/provincial policy options to address the barriers to small-scale renewable energy sources – many of which have been adopted in one or more WCI Partner jurisdictions – include the following:

Workforce Training – Support for local and regional training programs may help ensure sufficient numbers of trained installers. Equipment and installer certification programs and random inspection of installations promote quality workmanship.

Public outreach and education – Public information can help consumers understand the benefits of small-scale renewable energy resources, how to undertake a project, and available assistance and funding options.

Uniform interconnection processes - Uniform technical standards, procedures and agreements can remove barriers and simplify the interconnection of small generators with utility systems, where appropriate. For projects with complex interconnection needs, reasonable timelines, fees and other requirements can be put in place for additional technical review and equipment that may be needed.

Power arrangements with the utility – Among the options:

- "Net metering" is a billing arrangement where the utility bills the customer only for the difference between the energy consumed at the premises and the energy produced by a qualifying system at the site. Any excess energy produced flows onto the utility grid for use by other customers, eliminating the need for the customer to have on-site storage or to to arrange for power sales to a third parties. While net metering programs are widespread, many do not require all utilities in the state to participate or include all customer classes. Programs also may be constrained by low limits for individual project size and aggregate capacity, payment provisions for excess energy, insurance and equipment requirements, standby rates, and restrictions on third-party ownership of systems.[7]

- The Public Utility Regulatory Policies Act (PURPA)[8] requires utilities in the U.S. to interconnect with and purchase all capacity and energy from "Qualifying Facilities" up to 80 megawatts (MW) that use eligible renewable resources[9] at rates equal to the cost of the utility's avoided resource (for example, market purchases or a natural gas-fired power plant). States have broad discretion in implementing PURPA. Among the provisions for successful state programs are long-term contracts with fixed rates, standard avoided cost rates, Commission-approved standard contract forms for small-scale projects, and methods for determining avoided costs that fully account for the value of the renewable energy to the utility system.
- Feed-in tariffs (FITs), also known as Advanced Renewable Tariffs, can provide rates that make it attractive for electricity to be produced by third parties (non-utilities) using renewable resources. Rates may vary by technology, geographic location and project size. FITs can encourage development of a variety of renewable energy projects. Like PURPA, FITs guarantee the right to interconnect and a buyer for the electricity, and payment is based on actual production. However, FIT rates are based on the cost of renewable energy generation, not the utility's avoided resource. Typically included in FIT rates is a return on investment sufficient to make the project worthwhile for investors.
- Targeted procurement of small-scale renewable energy resources that recognizes their unique benefits can incorporate many of the same features as a FIT, such as a must-take obligation and standard contract terms, but allow for market-based pricing through a reverse auction or similar mechanism.

Standby rates –Practices include cost-based rates, providing customer-generators choices for firm and non-firm service, including daily rates, allowing them to self-supply reserves and assure instantaneous load reductions to avoid standby charges, and providing supplemental power and maintenance service – with appropriate advance notice – at the customer's otherwise applicable tariff rate.

Utility resource planning and procurement – Utility resource planning and procurement often does not evaluate and include small-scale renewable resources for meeting generation and transmission needs. Similarly, the value of distributed generation typically is not considered in distribution system planning. Including distributed generation in utility planning and acquisition processes helps states and provinces examine whether and how to use these resources to meet energy, capacity, distribution and transmission system needs.

[7] A third party pays the upfront cost of the system; builds, installs and owns it for a specified term; takes advantage of tax, depreciation and other financial incentives; and sells the energy to the consumer hosting the system. The consumer reduces its bills through a net metering agreement with the utility. This financing model is especially important to local governments, schools, churches and others that can't raise the capital for the project or take advantage of some government incentives.
[8] U.S. Public Utility Regulatory Policies Act, 16 U.S.C. § 824a-3.
[9] And qualifying cogeneration facilities of any size.

Decouple utility sales from utility profits - "Decoupling" removes the link between utility sales and revenue so that the utility is indifferent to, rather than financially harmed by, customer-side distributed generation and efficiency measures.[10] Under decoupling, retail customer rates established to recover fixed utility costs are adjusted periodically to keep utility revenue at the level allowed by regulators.

Key issues to consider in developing small-scale renewable energy resources include:

- **Interconnection** – In the U.S., states generally have jurisdiction over interconnection (and sales) between customer-sited generation and retail electric utilities.[11] Utility interconnection processes may result in undue delays in gaining approval of applications as well as undue costs associated with insurance and equipment which, upon closer examination, regulators may find unnecessary.

- **Power sales** – Utility procurement generally does not adequately consider small-scale distributed systems, despite their potential advantages such as more rapid deployment and lower development risk compared to large projects. Small systems may not meet the minimum bid size for utility competitive bidding processes and wholesale markets, and the market for aggregation of small systems is immature. In addition, the prices utilities pay for renewable energy may be too low to drive significant development of small-scale systems.

- **Standby rates** – Unless prohibited by regulation, utilities may charge customer-generators special rates for back-up power when their on-site generator isn't running and for supplemental power to meet the customer's energy needs beyond the generator's capacity. Unless properly designed, standby rates can render a project uneconomic.

- **Utility planning** – Utility resource planning typically does not adequately evaluate and include small-scale renewable resources for meeting generation and transmission needs. Nor is the value of distributed generation typically considered in distribution system planning, where it could have especially high value in deferring costly upgrades to meet capacity needs in specific locations. Further, those locations are not revealed to consumers or the marketplace.

- **Utility disincentives** – Utilities recover a large amount of their fixed costs through volumetric rates. When customers develop on-site generation, utility revenue declines. Because so many of the costs of providing utility service do not change in the short run,

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[10] *See* National Action Plan for Energy Efficiency, *Aligning Utility Incentives With Investment in Energy Efficiency*, November 2007, at http://www.epa.gov/cleanenergy/energyprograms/napee/resources/guides.html; Regulatory Assistance Project, *Revenue Decoupling Standards and Criteria: A Report to the Minnesota Public Utilities Commission*, June 2008, at http://www.raponline.org/Pubs/MN-RAP_Decoupling_Rpt_6-2008.pdf.

[11] The Federal Energy Regulatory Commission has jurisdiction over interconnection of generating facilities for wholesale sales.

a small reduction in sales due to customer-side resources can result in a disproportionately large reduction in utility earnings. Also, utilities typically do not earn a return on non-utility resources, nor can they make profits on them through operational efficiencies.

- **Cost** – Homeowners, businesses, local governments and others may have difficulty securing financing at favorable terms. And without subsidies, it may take too long for the investment to pay back.

- **Trained workforce** – Successful programs require a trained workforce to properly size, select and install equipment. If installers are in short supply, the consumer's interest in developing a project may pass.

- **Consumer awareness** – Most consumers are not aware of the benefits of small-scale renewable energy resources, how to undertake a project, and available assistance and funding options.

Benefits to harmonizing. Harmonizing these policies could build a larger market for small-scale renewable energy resources. It also would allow manufacturers to build equipment to meet a uniform set of standards accepted across a large region, make it easier for installers operating in multiple jurisdictions to understand interconnection and program requirements, and facilitate regional marketing of renewable energy systems.

2.1.2 Emissions Performance Standards for Electric Generating Units

An emissions performance standard (EPS) sets a maximum level of GHG emissions per unit of output. An EPS for electric generating units is designed to "raise the bar" for the emissions performance of each power plant, analogous to efficiency standards for appliances. Through the use of an EPS requirement, the construction of high-emitting generating resources with long expected useful lifetimes may be avoided. Similarly, new long-term contracts with existing high-emitting generating resources may be prevented. As a consequence, an EPS may reduce ratepayers' financial and reliability risks associated with plant retirements, retrofits, and emission allowance and offset costs under future emission control regulations. An EPS can also promote technological innovation to advance new power generation systems and to modify existing facilities in order to meet the standard.

An EPS should be considered in conjunction with a cap-and-trade program if:

1. Market prices for electricity would need to increase to an unacceptable level to change the generation dispatch order or to induce new investments and technological advancements in clean generation at a sufficient rate or magnitude to meet GHG emissions reduction goals
2. The level of carbon "leakage" outside the cap-and-trade region is unacceptable.

Key issues to consider in designing an EPS for electric generating units include:

- Establishing the appropriate EPS performance level (emissions rate)
- Determining the point of regulation (Who must comply – for example, generators or distribution companies that serve load?)
- How broadly the EPS should be applied. (Only electricity produced within the jurisdiction or imported power as well?)
- What type of facility or commitment should be subject to the EPS
- New construction only? Also new investments in existing facilities that expand rated capacity, effective useful life, or both?
- Facilities underlying long-term contracts only? Short-term contracts, too?
- Determining the facility threshold (MW size or capacity factor)
- The state of technology and the degree to which it can be pushed
- Start date and implications of building current-technology power plants that will not qualify under the EPS
- Calculation of net emissions for combined heat and power and biomass facilities
- Potential for carbon capture and storage

Benefits to harmonizing. Harmonized EPS policies and standards design would promote consistent signals to the market across a broad geographic region concerning GHG emissions performance for generating units. This would drive technological advancement in low-carbon solutions within a specific timetable linked directly to the carbon reduction goals for the electricity sector.

This policy has already seen a great deal of harmonization in the Western jurisdictions of the WCI. The states of California, Oregon and Washington have enacted similar EPS laws.[12] In addition, Montana has adopted a law imposing restraints on emissions from coal plants.[13] British Columbia requires carbon capture and storage for any new coal-based generating facility.[14]

2.2 Energy Efficiency and Conservation

- Energy efficiency targets
- Energy efficiency programs and incentives

2.2.1 Energy Efficiency Targets

Energy efficiency targets are used by policy makers to set performance goals – binding or voluntary – for energy efficiency investments and savings. The targets may apply to states or provinces, utility companies or third-party administrators of programs.

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[12] California SB 1368: http://www.energy.ca.gov/emission_standards/documents/sb_1368_bill_20060929_chaptered.pdf; Oregon SB 101: http://www.leg.state.or.us/09reg/measpdf/sb0100.dir/sb0101.en.pdf; and Washington SB 6001: http://apps.leg.wa.gov/billinfo/summary.aspx?year=2007&bill=6001.
[13] HB 25 (2007): http://data.opi.mt.gov/bills/2007/billpdf/HB0025.pdf.
[14] Bill 31: http://www.leg.bc.ca/38th4th/3rd_read/gov31-3.htm.

Energy efficiency targets take various forms. Energy Efficiency Resource Standards (EERS) establish long-term efficiency targets that are typically expressed as a percentage reduction compared to retail energy sales over a baseline period. Both annual and cumulative energy savings targets may be included. Standards may apply to both electricity and natural gas, and they may target reductions in peak electricity demand as well as energy usage overall. EERS are already in place in many states and federal standards have been proposed.[15]

Energy savings generally are achieved through end-use efficiency programs. In some states, savings from building codes, appliance efficiency standards, combined heat and power facilities, and distribution system efficiency improvements also may count toward meeting the standard.

Instead of expressing savings targets as percentages or absolute (e.g., megawatt-hour) savings figures, some states and provinces have made a commitment to acquire all cost-effective energy efficiency or achieve zero load growth through energy efficiency programs. Such efficiency targets can be articulated as part of a utility's integrated resource planning process and incorporated into applicable regulations. The suitability of subsequent utility acquisitions would be measured against that goal.

Energy efficiency targets also can be articulated in contracts or informal proceedings between the jurisdiction and a third-party efficiency provider. In some cases, the third-party provider is remunerated, in part, for achieving savings above the specified targets.

Key issues to consider in setting and achieving energy efficiency targets include:

- Savings potential (as assessed by a resource potential study)[16]
- Performance levels (e.g., percentage rate of savings)
- Baseline measurement (i.e., the starting point)
- Cost-effectiveness tests in screening individual efficiency programs or a portfolio of programs
- Utility disincentives to achieving stated goals[17]

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[15] In the U.S., for example, the American Council for an Energy-Efficient Economy (ACEEE) reports that 19 states have adopted an EERS requiring achievement of specified energy savings targets. In addition to strict EERS requirements, ACEEE includes states with Commission-ordered efficiency targets, states that allow efficiency to count toward renewable energy standards, and states with a rate cap triggering a relaxation of EERS requirements. *See* Laura A. Furrey, Steven Nadel, and John A. "Skip" Laitner, ACEEE, *Laying the Foundation for Implementing a Federal Energy Efficiency Resource Standard*, March 2009, at http://aceee.org/pubs/e091.htm. Bills pending in the 111th U.S. Congress would establish a national EERS. The United Kingdom and several Australian states are among jurisdictions outside the U.S. that have mechanisms similar to an EERS.

[16] A resource potential study assesses the technical and market potential for energy efficiency efforts and lays the foundation for developing appropriate savings targets. Results generally show achievable potential far in excess of current program scope.

[17] *See* decoupling discussion on page 7 and Regulatory Assistance Project, "The Role of Decoupling Where Energy Efficiency Is Required by Law," September 2009, at http://www.raponline.org/Pubs/RAP_Schwartz_IssuesletterSept09_2009_08_25.pdf.

Benefits to harmonizing energy efficiency targets include helping promote consistent signals to a broader market. Standardized requirements could be expected to reduce implementation barriers and costs for companies operating in multiple states.

2.2.2 Energy Efficiency Programs and Incentives

Energy efficiency programs are business plans or market mechanisms that address barriers to cost-effective investments. Programs can be run by the utility, the state or province, or a third-party administrator. Program costs can be integrated into the utility's cost of service, like other resources, or be paid for through a separate charge on customer bills. The goal of a well-designed program is to motivate action by the targeted decision-makers – consumers, suppliers, stores or contractors – while minimizing program costs. Market mechanisms include tradable Energy Efficiency Credits ("white certificates" or "white tags") that certify specified reductions in energy consumption. In most cases, certificate schemes are combined with an obligation to achieve energy savings targets.

Energy efficiency investments can reduce total utility system costs[18] and avoid the use of fossil fuels and associated GHG emissions. Studies continue to find a vast potential of cost-effective efficiency remaining to be tapped.[19] Securing this potential could dramatically reduce electricity demand and significantly reduce the cost of meeting emissions reduction goals.

Policies include providing programs that offer the following types of assistance:[20]

- **Information, education, marketing and technical assistance** – Information on-line and at point of sale, branding (e.g., Energy Star), phone hotlines, workshops, multi-media advertising, on-site audits, field visits, training, certification and inspections are among the ways programs can increase awareness, knowledge and confidence among consumers, vendors and contractors.
- **Grants and rebates** – Financial incentives can reduce the cost to the consumer of investing in energy efficiency products and services. The incentive amounts are justified by a benefit-cost analysis and can be linked to the desired effect – for example, the number of targeted products installed by a certain date.

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[18] Preliminary research by ACEEE indicates average program costs of about 3 cents per kilowatt-hour saved and 29 cents per therm saved. (*See* Steven Nadel, ACEEE, Replies to Questions at the April 22, 2009, Hearing on Energy Efficiency Resource Standards, May 12, 2009, at http://aceee.org/tstimony/NadelQuestions04.22.09.pdf.) That's far less than the cost of new generating facilities. Efficiency investments also can avoid expensive upgrades to transmission and distribution systems.

[19] For example, the recent McKinsey study found the U.S. has the potential to cost-effectively reduce non-transportation energy consumption roughly 23 percent by 2020. *See* www.mckinsey.com/USenergyefficiency. The Northwest Power and Conservation Council recently estimated achievable, cost-effective conservation in the four-state region (Idaho, Montana, Oregon and Washington) at 21percent of 20-year forecasted (medium-case) electric load – an amount that would meet about 85 percent of load growth in the region while significantly reducing both system cost and risk. *See* http://www.nwcouncil.org/energy/crac/Default.htm.

[20] Building codes, appliance standards, and new energy efficiency technologies are addressed briefly at the end of this paper.

- **Financing** – Long-term financing of energy efficiency investments can provide consumers with positive cash flow. Financing strategies may focus on "lost opportunities," such as new buildings and new equipment, or they may provide consumers with the means to retrofit buildings or replace inefficient equipment. For example, some programs allow homeowners to add the cost of certain efficiency improvements to their mortgage, extending the repayment period.

Energy efficiency programs can include some form of "market transformation" – changing the way people make energy-related decisions or making efficient products and services widely available. Some programs are devoted exclusively to these purposes. Other programs focus on hard-to-reach sectors, such as multi-family housing and low-income households.

Programs to reduce energy consumption may be more compatible with a utility business structure that decouples utility sales from utility profits and includes performance incentives. Decoupling removes a utility's inherent *disincentive* to sell less of its product. Decoupling does not provide an *incentive* for the utility to acquire energy efficiency in lieu of supply-side alternatives that earn a return on investment. Where aggressive energy efficiency goals are in place, regulators may consider providing financial incentives to utilities for exceptional performance. Many utility commissions have adopted decoupling, incentive mechanisms, or both for electric and natural gas utilities.[21]

Key issues to consider in developing these policies include:
- High upfront cost, long payback on investment, and limited financing options
- Short windows of investment decision-making opportunity are easy to miss
- Trained workforce may be in short supply
- Limited public awareness, information and knowledge
- "Split incentives" between builders/building owners and tenants who pay the utility bills
- Resource planning and acquisition processes that don't evaluate energy efficiency on a par with supply-side alternatives
- Utility disincentives to encouraging energy efficiency

Benefits of harmonizing energy efficiency programs among the WCI jurisdictions and other states and provinces include reducing costs, helping to transform markets for energy efficiency products, technologies and practices, and achieving greater energy savings and GHG reductions. Regional programs can achieve economies of scale that are not possible with isolated programs. Working together, utilities and other program administrators can leverage personnel and funds for resource potential studies, regional marketing and training, developing a broad supply chain of products and services, robust evaluation of programs, and verification

[21] For maps showing status of decoupling in the U.S., *see* http://www.raponline.org/docs/NRDC_Decoupling%20Maps%20US_2009_08.pdf . For examples of incentive mechanisms and modeled results, *see* Chuck Goldman, Peter Cappers, Michele Chait, George Edgar, Jeff Schlegel and Wayne Shirley, "Financial Analysis of Incentive Mechanisms to Promote Energy Efficiency: Case Study of a Prototypical Southwest Utility," report to the Ernest Orlando Lawrence Berkeley National Laboratory, March 2009, at http://eetd.lbl.gov/EA/EMP/ee-pubs.html.

of estimated energy savings. Consistent program features and requirements also make it easier for vendors and contractors to participate.

Many programs rely on a common set of product and service specifications developed by the ENERGY STAR program. Some states already coordinate on energy efficiency assessments, strategy, model standards, programs, and common protocols for evaluating, measuring and verifying program results through such organizations as the Northwest Power and Conservation Council[22] and Northwest Energy Efficiency Alliance[23]. These efforts could be expanded to include a broader set of jurisdictions. Multi-state utilities offer similar programs throughout their service areas.

2.3 Transportation

- Low-carbon fuel standard
- Freight transportation infrastructure
- Development of algae and ligno-cellulosic biofuels

2.3.1 Low-Carbon Fuel Standard

A Low Carbon Fuel Standard (LCFS) is a GHG emissions standard for transportation fuels. An LCFS provides a method for calculating the carbon intensity of fuels and requires fuel providers to reduce over time the carbon intensity of the fuels they sell. The carbon intensity calculation is typically based on *life-cycle carbon emissions* for each fuel type. An LCFS is designed to be technology-neutral across alternative transportation fuels including electricity, biofuels and hydrogen. Fuel providers have the flexibility to provide the lowest priced mix of low-carbon fuels that achieves the intensity standard. This approach differs from a renewable fuel standard, which mandates certain volumes of biofuels.

The state of California has adopted an LCFS program. Oregon recently passed legislation directing the Department of Environmental Quality to develop an LCFS. British Columbia's Greenhouse Gas Reductions (Renewable and Low Carbon Fuel Requirements) Act will be implemented through two regulations: 1) the Renewable Fuel Requirement Regulation, which requires fuel suppliers to meet an annual, provincial average of 5 percent renewable content for gasoline and diesel fuels and 2) the proposed Low Carbon Fuel Requirement Regulation (LCFRR), which would require that the carbon intensity of transportation fuel sold in the province be reduced 10 percent by 2020. The LCFRR would require suppliers to provide transportation fuels with average carbon intensity less than or equal to annual target values beginning in 2010. The state of Washington is evaluating whether a LCFS should be adopted there.

Key issues to consider in designing an LCFS include:

- Carbon intensity reduction goals and schedule

[22] http://www.nwcouncil.org/Default.htm
[23] http://www.nwalliance.org/

- Interaction of an LCFS with the regional cap-and-trade system, including issues such as consistency of signals to industry under the two systems, potential for double counting of emissions reductions, and within-region vs. outside-region emissions reductions;
- Point of regulation (for example, should fuel companies be held responsible for increasing use of electric vehicles?)
- Cost to the public and businesses
- Current and expected regional capacity to produce sufficient low-carbon alternative fuels and opportunities for increasing capacity[24]
- Assessment of current and future technological feasibility
- Requirements for capital investment in low carbon fuels production
- Potential for commercialization of vehicles that can use low- or no-carbon fuels
- Development of a regional low-carbon fuel credit program
- Consistency in estimating carbon intensities, considering fuel mixes, land use issues and other factors
- Options for minimizing the cost of compliance
- Potential use of compliance deferrals to address issues such as fuel shortages, fuel quality problems and significant spikes in fuel costs
- Potential for exemptions
- Refueling infrastructure to support an LCFS
- Environmental and health impacts beyond GHG reductions
- Local needs and conditions

Benefits of harmonized LCFS policies and program design include consistent requirements among states and provinces that participate in the same fuel markets. Looking at the future needs for regional low-carbon fuel capacity may promote coordinated investment and economic opportunities. Regional harmonization could also provide a useful model for any national LCFS program.

2.3.2 Freight Transportation Infrastructure

West Coast ports are North America's links to the rapidly growing Asian economies. The amount of goods imported and exported through these ports will continue to grow. Similarly, as the populations of the WCI states and provinces grow, trade within the region and with the rest of North America also will increase. This continued growth in marine, air, rail and road transport activity poses a challenge to policy makers seeking to reduce GHG emissions. In addition, overlapping jurisdictions among many levels of government results in regulatory challenges for operators.

Many transport sectors have agreed that the solution lies in coordinating, rather than competing, on environmental issues. This is particularly relevant for areas such as the West Coast, where shippers have a choice among numerous air and marine ports of entry and land-based carriers. Through coordinated improvements and standards, states, provinces, port

[24] Regional capacity may be important from an economic impact perspective.

authorities and private carriers can justify investment in environmental improvements, without the fear that business will be lost to a higher-emitting, but lower cost competitor.

Examples of potential regional coordination on freight transportation include the following:

- Jurisdictions could adopt requirements such as the U.S. Environmental Protection Agency (EPA) model rule to reduce heavy-duty truck idling during rest stops to facilitate a uniform approach. Outreach and financial assistance programs could promote energy-efficient and cost-effective alternatives such as auxiliary power units and truck stop electrification. A viable electrification network requires action by multiple jurisdictions to be effective.
- Ocean- and river-going vessels at dock usually run onboard diesel generators for “hotel” power. Using power from the electric utility grid is less expensive, but it may be necessary for multiple ports to provide connection facilities on-shore to make it cost-effective for vessels to install capability to connect to those facilities. WCI members California, Washington and British Columbia have installed on-shore power facilities using the best available and most compatible technology. A regional approach also could help eliminate competitiveness concerns among ports providing on-shore power.
- Smaller engines to provide hotel power, new engine technologies, and electronic start/stop controls are available to reduce pollution from locomotives, which often idle for extended periods of time. A regional approach could coordinate incentives and address jurisdictional issues for cleaning up switchyards and long haul locomotives.
- Regional approaches to increasing the fuel efficiency of heavy duty trucks could be explored, such as lower speed limits and improvements in aerodynamics.

Key issues to consider for freight transportation infrastructure include:

- Competitiveness among ports for docking of ocean and river-going vessels
- Lack of consistent regulations, penalties and funding programs among states and provinces with respect to anti-idling to encourage investment while avoiding impacts on trade competitiveness
- Standards for port electrification under development by the International Maritime Organization and their broader use with increasing certainty regarding the final standards
- High upfront cost, long payback on investment, and limited financial resources and incentives to fund research, development and implementation of new technologies
- Need for public-private partnerships and investments to develop a network of truck stop electrification locations
- Programs developed by the American Trucking Association to reduce GHG emissions from freight movement, which can be implemented and enhanced through coordinated action by states and provinces

Benefits to harmonizing policies include improving uniformity of regulatory and incentive programs, reducing competitiveness issues among states and provinces, leveraging incentives, and addressing jurisdictional issues with interstate freight movement. Because many trucking companies, trains and marine vessels operate between WCI Partner jurisdictions, regional coordination could also help identify or prevent instances where one jurisdiction's compliance mechanism may cause emissions increases in other jurisdictions. A regional approach to on-shore power would allow for pricing strategies to encourage its use, without affecting the competitive balance. Regional strategies to reduce GHG emissions from the freight transportation sector would produce multi-pollutant benefits, reducing toxins, sulfur dioxide, nitrogen oxides and fine particulates.

2.3.3 Development of Algae and Ligno-Cellulosic Biofuels

Research is rapidly advancing into the selective breeding of algae for production of biomass that turns into oil at an extremely rapid rate. Algae grow much faster than other plants used for fuel, including corn and soybeans, and can produce many more gallons of oil per acre of land. There also are significant greenhouse gas emission reduction benefits to this technology. Through a process known as hydrogasification, whereby coal is made into synthetic natural gas (SNG), a portion of the process carbon emissions is used to nourish the growing algae. Algae can then be used as an additional fuel source or as a feedstock for biodiesel fuel production. The result is a cleaner, more efficient use of coal for energy production, and a beneficial use of carbon emissions that adds to fuel production while displacing need for fossil fuels.

Research on algae biofuels is underway in WCI Partner jurisdictions (including Arizona, California, Montana and New Mexico), in some cases with corporate support. Research also is progressing on the production of fuel-grade ethanol and other biochemical co-products from cellulosic biomass feedstocks, and WCI Partner jurisdictions (including British Columbia, Ontario and California) have commercialization efforts underway. By working together, WCI and other jurisdictions may be able to help move the fuel from research to the marketplace.

The Committee is not aware of any policies that act as a barrier to using algae or ligno-cellulosic biomass for transportation fuel. It recommends each WCI Partner jurisdiction conduct an evaluation to determine if such policies exist, and if so, to determine the rationale for that policy. The Committee might then evaluate policies to eliminate barriers and develop recommendations for further consideration.

2.4 High-Global Warming Potential (GWP) Gases

2.4.1 Regulatory Measures for High-GWP Gases

High-GWP gases are of growing concern due to their increasing rate of emissions and persistence in the atmosphere. These gases, from anthropogenic sources, are released as byproducts of industrial operations, primary from electric power transmission and distribution, aluminum smelters, semiconductor manufacturing, production of insulating foam, and magnesium smelters and die-casters. High-GWP chemicals also are used in many applications such as refrigeration, air conditioning and fire suppression. Typically, emissions of high-GWP gases from processes and products are individually too small to be covered by the WCI cap-and-trade program. Nevertheless, just a few pounds of these materials can have the equivalent effect on global warming as several *tons* of CO_2.

Voluntary partnerships between EPA and industry are substantially reducing emissions of high-GWP gases. For example, 81 utilities are participating in a voluntary program to reduce emissions from SF_6 used for insulation of electric transmission and distribution equipment. EPA publishes lists of acceptable substitutes for high-GWP gases.

Key issues to consider for reducing emissions of high-GWP gases include:

- Long timeframe for transitioning to safe and acceptable substitutes that offer lower overall risks to the environment and human health
- Removal and disposal of high-GWP gases
- Voluntary nature of existing programs
- Sizable expansion that is occurring in many industries that emit high-GWP gases

Benefits to harmonizing measures to reduce high-GWP gases include reducing burdens on consumers and manufacturers while encouraging a broader market for lower-emitting substitutes. Regional programs can achieve economies of scale that are not possible with isolated programs. Regional harmonization may promote coordinated investments for research and development of alternatives. Harmonized policies could include design and funding of programs for capturing and disposing of high-GWP gases, incentives for upgrading to newer products in order to more rapidly remove products with high-GWP gases from circulation, and establishing specifications for the use of high-GWP gases in newly manufactured products.

3 Tier 2 Policies

3.1 Energy Production

3.1.1 Carbon Capture and Sequestration

Carbon capture and sequestration (CCS) is a key technology for sustained emissions reductions in the electricity sector. It involves four steps: 1) separating CO_2 before or after combustion of fossil fuels; 2) compressing the CO_2 stream; 3) transporting it to an injection site; and 4) pumping it into underground geologic formations in a manner that prevents its release into the atmosphere.

Given the technical, institutional, and legal risks, solely putting a price on CO_2 emissions may be insufficient to advance CCS deployment. Additional policies for the capture, transport, injection, monitoring and liability of the sequestered CO_2 are needed. Utility resource policies that mandate or promote CCS may be appropriate – such as emissions performance standards[25] – as well as innovative policies for siting and permitting, financing and rate-making.[26] State and provincial policy options to advance CCS include the following:[27]

Managing transport and sequestration – Current rules for transport and injection of CO_2 are for enhanced oil recovery and CCS pilot projects, not large-scale CCS deployment. Existing pipeline laws must be adapted for CO_2 transport. A standard template such as the one produced by the Interstate Oil and Gas Compact Commission[28] may be useful for the development of rules for geologic sequestration of CO_2. Further options can accelerate CCS deployment, such as pre-screening and pre-qualifying the best CO_2 pipeline and injection sites and simultaneous review of permit applications for the power plant, CO_2 pipeline and injection infrastructure.

Limiting liability for CO_2 releases – Large-scale CCS may not be deployed unless companies are able to manage liability associated with the escape or migration of CO_2 from pipelines and storage sites following permanent capping of the site and decommissioning of the injection facilities.[29] Policies designed to address liability must balance the goals of shielding companies from excessive liability while maintaining a strong incentive for companies to minimize the chances of CO_2 release after decommissioning. In the absence of national legislation, states and provinces are beginning to address this issue on their own.

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[25] See pages 9-10.
[26] Jurisdictions also should consider whether any waivers may be warranted for power plant need determinations and competitive bidding requirements.
[27] For a complete discussion, see Richard Cowart and Shanna Vale, Regulatory Assistance Project, and Joshua Bushinsky and Pat Hogan, Pew Center on Global Climate Change, "Coal Initiative Reports: State Options for Low-Carbon Coal Policy," February 2008, at: http://www.pewclimate.org/docUploads/StateOptions-02-20-08.pdf.
[28] *See* http://iogcc.publishpath.com/Websites/iogcc/pdfs/Road-to-a-Greener-Energy-Future.pdf.
[29] Where those actions were taken in conformance with an approved plan for the cessation of operations.

Liability for releases during transport and injection (prior to decommissioning) also is an important issue. Insurance may adequately address liability during the operational period of a sequestration project, but clarifying legislation also could be beneficial. Other measures might be needed to compel the surrender of allowances for any CO_2 release.

Subsidies for CCS projects at fossil-fuel[30] plants – Among the options for funding are:

- A fee levied on generators or utilities on a per-megawatt-hour basis, or just on the portion attributable to fossil fuels
- A "feebate" system that charges fossil-fuel plants without CCS technology a per-megawatt-hour fee and distributes the funds collected for CCS equipment
- Direct expenditures or tax credits for CCS investments

Other financial incentives – Utilities could potentially receive higher rates of return or accelerated depreciation for CCS investments. Regulatory commissions or legislatures could grant bonding authority for CCS projects. Besides simply providing access to funds, such bonds could provide a lower interest rate.

Cost recovery support – Most regulatory commissions do not pre-approve power plants. Instead, they determine what costs may be included in a utility's retail rates only after the plant has reached commercial operation. Regulators can provide some type of cost recovery assurance for CCS projects even before construction begins, employing such strategies as:[31]

- Preapproval of CCS projects;
- Guaranteed buyer or must-take requirements for CCS-generated power;
- Cost recovery for power supply during unplanned outages of the CCS plant;
- Cost recovery even if the CCS plant is cancelled;
- Cost recovery for early retirement of existing coal plants if replaced with a CCS substitute.

Key issues to consider for CCS policies include the following:[32]

- *Acceleration:* Will it produce investment in CCS that would not otherwise occur?
- *Deterrence:* Will it deter investment in high-emitting technology options?
- *Prudence and accountability:* Will it promote prudent project management? Will those with responsibility be held accountable for performance?
- *Power supply costs:* Does it help to lower the cost premium for CCS power?
- *Administrative costs:* Does it help to lower administrative and regulatory costs for developers, government and other parties?
- *Risk and cost balance:* How well does it balance the interests of ratepayers and investors?

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[30] Coal, natural gas, biomass, petroleum coke and other fossil fuel plants are candidates for CCS.
[31] State "used and useful" requirements (mandating that a plant be functioning and necessary to be included in the utility's revenue requirement) may need to be modified by statute to implement the last three options in this list.
[32] *See* Cowart, *et al.*

- *Innovation:* Will it promote further CCS research and technical innovation?
- *Standardization:* Will it promote CCS projects that could be replicated elsewhere?
- *Performance:* Does it secure significant carbon reductions? Are any incentives scaled to real-world performance, measured in tons of CO_2 permanently sequestered?

Benefits to harmonizing. Harmonizing CCS policies across jurisdictions might make sense for a number of reasons. First, successful CCS efforts require significant research, development, and demonstration funding that is best spent in a coordinated manner. For example, coordinated mapping of potential sequestration sites and pipeline locations may reduce the need for redundant studies. Second, CCS projects may be developed by multi-state utilities, or developed jointly by utilities in multiple states and provinces, in order to achieve economies of scale and spread the costs and risks. Third, long-distance transmission lines for coal plants with CCS, as well as pipeline transport of CO_2 for sequestration at a remote location, may require cooperation among states and provinces.

In addition, consistent CCS policies could promote replicable CCS projects and reduce administrative costs for utilities and other project developers as well as stakeholders participating in regulatory processes. Further, absent a national policy, consistent policies across the region to address liability risks associated with potential CO_2 leakage could facilitate CCS projects where participating utilities, CO_2 pipeline transport, and sequestration sites involve multiple jurisdictions.

3.2 Transportation

3.2.1 Heavy-Duty Vehicle Equipment

Transborder freight transportation is a significant component of the economies of the WCI jurisdictions. U.S.-Canada surface transportation trade totalled $29.2 billion in May 2009. GHG emissions from heavy-duty trucks are increasing, along with emissions of carbon monoxide, nitrogen oxides and hydrofluorocarbons. Adopting regulations across jurisdictions will facilitate GHG reductions while transborder trading increases. Most trucks built during the last decade are equipped with a speed limiter – an integrated circuit that allows for regulating maximum vehicle speed. Policies could include the mandatory use of speed-limiting devices, equipment for aerodynamic efficiency, supporting the introduction of new energy-efficient and GHG-reducing technologies, and instituting an inspection and maintenance program for heavy-duty trucks in jurisdictions throughout the WCI jurisdictions and in other states and provinces.

Key issues to consider include the following:

- The burden posed by differing requirements on the majority of heavy-duty vehicles, which travel between states and provinces
- Trucks that do not operate in multiple jurisdictions
- Cost impacts of potential policies on individuals and small companies that own heavy-duty vehicles

Benefits to harmonizing. Harmonized policies would mitigate the challenges posed when emissions reduction measures for heavy-duty vehicles differ among states and provinces.

3.2.2 Electric and Alternative Fuel Vehicle Infrastructure

Development of electric and alternative fuel vehicle infrastructure can take a variety of forms including:

- Consumer outreach and education
- Direct purchases of charging stations and alternative-fuel refueling stations by businesses and local, state/provincial or regional governments
- Addressing utility system impacts
- Development and implementation of policies that streamline the permitting and installation of alternative fuel vehicle infrastructure
- Creation of grant, loan or loan guarantee programs to help finance infrastructure
- Enactment of tax incentives to reduce the cost to developers of installing infrastructure

Key issues to consider in developing programs to accelerate the deployment of alternative fuel vehicle infrastructure include:

- How to pay for infrastructure, including revenue-positive public and commercial cost models
- Electric system impacts
- Removing service provider disincentives to supplying additional electric load and alternative fuels through such means as providing additional emissions allowances
- Policies to ensure interoperability of refueling across utility service territories and jurisdictions
- Coordination of these programs with a regional low-carbon fuel standard, if implemented
- Whether public agencies should provide free electric vehicle charging
- Public and private partnerships
- Deployment simultaneously with (or in advance of) alternative-fuel vehicle sales
- Distance between stations for charging/fueling

Benefits to harmonizing. By coordinating the development of electric and alternative fuel vehicle infrastructure, the WCI jurisdictions could foster sufficient market penetration of electric and alternative fuel vehicles to attain significant reductions in GHG emissions, create jobs, foster economic growth, reduce reliance on foreign fuels and reduce air pollution.

3.3 Agriculture

3.3.1 Agricultural Anaerobic Digesters

Anaerobic digesters capture the gases created as agricultural waste materials break down into methane and CO_2. Anaerobic digesters:

- Capture methane, a potent GHG that would otherwise be released into the atmosphere
- Displace CO_2 emissions by producing carbon-neutral electricity, pipeline-quality natural gas, transportation and boiler fuels, feedstocks for commercial chemicals (such as ammonia and methanol), and digested fiber that can be used as a substitute for mined peat moss
- Provide a valuable economic resource to farmers through renewable energy production and cogeneration

Key issues to consider in harmonizing policies to facilitate on-farm anaerobic digesters are:

- The level of necessary capital investment and ongoing transaction costs as well as payback periods, which depend in part on:
    - The amount of financial assistance available
    - The rates available from electric and natural gas utilities for sale of digester-produced power and gas
- The ease with which small independent power producers are able to meet the interconnection requirements of electric and natural gas utilities
- The proportion of agricultural and non-agricultural wastes allowed on-farm by government agencies for the purpose of anaerobic digestion
- Environmental regulation by state and local governments
- Local government requirements on the movement of agricultural and non-agricultural waste
- The degree to which energy production is accepted as a normal farming practice by the public and relevant government agencies, including:
    - Whether there are special rules about what activities can take place on farmland
    - Whether energy production will remain ancillary to other types of agricultural production

Benefits to harmonizing. Anaerobic digestion offers significant potential for permanent, real, additional and verifiable GHG emissions reductions. Harmonizing anaerobic digestion policies by removing regulatory barriers and providing clarity and consistency in implementation of anaerobic digestion regulations would help states and provinces realize these reduction opportunities.

3.4 Waste

3.4.1 Landfill Methane Reduction

Methane gas from landfills is a significant source of GHG emissions due to its high global warming potential and the sheer number of landfills. According to Environment Canada, landfill emissions account for more than a quarter of the anthropogenic methane in the atmosphere.[33] Landfills generate methane as the anaerobic bacteria break down organic waste, a process that usually begins within the first year of landfill operation and can continue for 50 years after landfill closure.

The U.S. EPA defines "large" municipal solid waste landfills and requires that they collect landfill gas and combust it.[34] The regulations do not mandate secondary energy recovery processes. The B.C. Government passed a Landfill Gas Regulation under the Greenhouse Gas Reduction Statutes Amendment Act, which requires that by Jan. 1, 2016, all landfills that are above a certain size and methane threshold must install (and properly operate) landfill gas management facilities.[35]

Collected landfill gas can be used for electricity, heat production and other applications. Beneficial use of collected landfill gas offers potentially significant benefits including further reductions of GHG emissions by offsetting fossil fuels and producing energy from a renewable source. The EPA estimates that more than 450 municipal solid waste landfills in the U.S. operate landfill gas-to-energy programs, and approximately 520 more landfills could effectively do so, providing enough electricity to power 700,000 homes.[36] Environment Canada estimates that 600,000 homes could be powered by electricity generated from Canadian landfill gas sources.

The EPA operates a voluntary Landfill Methane Outreach Program (LMOP) to facilitate and provide assistance for landfill methane capture and conversion to energy. Canada and the U.S. participate in the Methane to Markets partnership with 28 other countries that have interest or expertise in developing methane projects.

Key issues to consider in developing programs to capture landfill methane include:

- Identifying the entire inventory of potential methane-generating landfills
- Closed landfills may be difficult to identify, but still have emissions
- The type of outreach and targeting needed to successfully maximize program participation and how to coordinate that effort regionally

[33] *See* "Harnessing the Power of Landfill Gas" at http://www.ec.gc.ca/Science/sandemay99/article1_e.html.
[34] *See* 2006 Standards of Performance for New Stationary Sources and Guidelines for Control of Existing Sources, and 2003 National Emission Standards for Hazardous Air Pollutants.
[35] *See* http://www.bclaws.ca/Recon/document/freeside/--%20e%20--/environmental%20management%20act%20%20sbc%202003%20%20c.%2053/05_regulations/28_391_2008.xml.
[36] *See Landfill Methane Outreach Program: Benefits of LFG Energy* at http://www.epa.gov/lmop/benefits.htm.

    - Targeting larger landfills that may qualify to participate in the LMOP but aren't yet taking action
    - Targeting a different population of landfills than federal programs
    - Quantifying the amount of methane produced to select target landfills using consistent procedures
- Funding of methane recovery projects, particularly for closed landfills or small municipal landfills
- Availability of electrical infrastructure and proximity of landfills to transmission lines
- Establishing effective and timely monitoring of landfill gas to identify problems or potential problems, including in the area between waste disposal sites and neighboring properties
- Difficulty of determining the percentage of landfill gas captured through a collection of wells and headers, with many uncertainties and variables
- Additional considerations that may explicitly address:
    - Organic waste diversion programs
    - Emission credits
    - Non-methane organic compounds (odors and air quality)

Benefits to harmonization. Reaching out to landfills not subject to U.S. or Canadian regulations could further reduce landfill methane emissions and encourage energy recovery. Guidance for outreach at the regional level – possibly modeled after EPA's Landfill Methane Outreach Program – would reduce the level of jurisdictional effort necessary and provide a consistent message for the goals, benefits and procedures for a program that reduces landfill methane emissions reduction and promotes electricity production from landfill gas.

4 Tier 3 Policies

4.1 Transportation

4.1.1 Vehicle Emissions Labeling

Emissions labels provide consumers with information on GHG emissions from vehicles. This approach has the potential to influence vehicle market decisions by providing information for consumers who might have a preference for purchasing vehicles with lower GHG emissions. Harmonizing the content of emissions labels would provide standardized information for consumers while reducing burdens for manufacturers and regulators.

4.1.2 Medium- and Heavy-Duty Vehicle Hybridization

Medium- and heavy-duty vehicles account for a significant portion of GHG emissions from the transportation sector. Hybridization reduces GHG and other emissions from these vehicles through greater fuel efficiency. Hybrid trucks and buses would likely achieve the greatest benefits in urban, stop-and-go applications, such as parcel delivery, transit and other short-range travel. A harmonized program of standards and incentives could help encourage a broader market for medium- and heavy-duty vehicle technology.

4.1.3 Transport Refrigeration Units

Transport Refrigeration Units (TRUs) are gasoline- or diesel-powered cooling units that are installed on containers used to transport produce, meat, dairy and other perishable goods. TRUs are capable of both cooling and heating and are found on refrigerated vans, trucks, trailers, railcars and shipping containers. Although TRU engines are relatively small, ranging from 9 horsepower to 36 horsepower, significant numbers of these engines congregate at distribution centers, truck stops and other facilities. Some companies use TRUs for extended cold storage and store overflow goods in TRU-equipped trucks and trailers for several weeks before holiday periods, or for more than a 24-hour period throughout the year. Harmonized policies and standards design would encourage more energy-efficient operations that reduce GHG emissions from systems using internal combustion engines. Harmonization also would encourage advancements in electrically-driven refrigeration systems and cryogenic systems.

4.2 Industrial Sector

4.2.1 Emissions Performance Standards for Major Industrial Sources

Emissions performance standards for industrial facilities would set a maximum level of GHG emissions per unit of product produced.[37] These standards would be established by sector, by product, or in some cases by industrial process within a sector.

[37] For example, tons of CO_2 equivalent emitted per unit of product produced at the facility. For energy-related emissions, both direct use of fossil fuels on-site as well as off-site production of electricity consumed at the plant would be included.

5 Important Policies Addressed in Other Venues

A comprehensive program to achieve significant GHG emissions reductions and transition to a low-carbon economy will require a broad range of actions and investments by business, consumers and all levels of government. In addition to the three tiers of policies discussed above, other important initiatives are being examined and developed in other venues. These policies are expected to make critical contributions to achieving the WCI Partner jurisdictions greenhouse gas reduction goals. These other polcies, not being evaluated by the Complementary Policies Committee, include the following:

- **Renewable portfolio standards in the electricity sector.** Already adopted by each of the WCI Partner jurisdictions, renewable portfolio standards direct retail electricity providers to generate or purchase a portion of their power from renewable sources. These requirements promote multiple objectives, including diversifying electricity supply and encouraging deployment of low-carbon technology in the electricity sector.

- **Energy efficiency standards for new buildings and appliances.** State and provincial building and appliance standards ensure that manufacturers and builders bring energy-saving products to market. These standards have proven to be highly effective for reducing energy consumption and GHG emissions. Moreover, their implementation in a similar manner across jurisdictions is key to building larger markets for energy-saving products and green building techniques. States and provinces regularly update building standards. Most of the WCI Partner jurisdictions have adopted residential and commercial building codes consistent with the 2006 model International Energy Conservation Code, which itself provides a degree of harmonization. Most appliance standards in the U.S. are set by the federal government, including recent updates under the Energy Independence and Security Act of 2007.

- **Smart grid infrastructure.** Smart grid infrastructure is under development in several of the WCI Partner jurisdictions in order to facilitate the dynamic transfer of information and electricity between the electric grid and retail customers. The smart grid will enable greater integration of intermittent renewable generation, demand-side resources and energy efficiency into the grid while improving reliability. This work is proceeding in the U.S. with assistance from the federal Department of Energy and funding from the American Recovery and Reinvestment Act of 2009. The National Institute for Standards and Technology is developing smart grid communication standards. The Western Electricity Coordinating Council is likely to have a role in developing harmonized standards for the western states and provinces.

- **Light-duty vehicle emissions standards.** In June 2009, EPA granted a waiver to California to proceed with implementation of its GHG emission reduction standards for new passenger cars, pickup trucks and sport utility vehicles beginning with the 2009 model year. This opened the way for the other 13 states and the District of Columbia that have adopted those standards to also proceed. Shortly thereafter, the Obama Administration announced its intent to adopt these emission standards at the national level.

- **Vehicle miles traveled reductions.** Several WCI Partner jurisdictions have undertaken initiatives to encourage reductions in vehicle miles traveled (VMT) by fostering transit-oriented development or integrating climate change into transportation and land use planning. VMT reductions can be an effective strategy to enhance mobility efficiency while reducing GHG emissions from the transportation sector.

- **Government leading by example.** Each WCI Partner jurisdiction has adopted goals or policies to save energy and reduce GHG emissions in its own operations. These policies build markets for low-GHG materials and equipment and set an important example for the private sector. By demonstrating exceptional emissions reductions in various areas, WCI Partner jurisdictions provide a laboratory for the development of innovative approaches.

- **Assistance for low-income households.** Results from the WCI economic analysis released in September 2008 indicate that the WCI emissions targets can be met through a broad-based cap-and-trade program and complementary policies with a net savings to the economy. However, the WCI Partner jurisdictions are committed to understanding and addressing potential impacts on low-income households that, for example, spend a relatively high portion of their income on energy. Each WCI Partner jurisdiction is examining how best to address this issue, relying on the programs and approaches most suitable to each Partner's circumstances.

Appendix 1: Complementary Policies: Capped vs. Uncapped Sources and Sectors

Table 1. Complementary Policies: Capped vs. Uncapped Sources and Sectors[38]

Policies to Reduce Emissions From Sources and Sectors Capped in 2012 *Energy Production* • Small-scale renewable energy resources (Tier 1) • Emissions performance standards for electric generating units (Tier 1) • Carbon capture and sequestration (Tier 2)
Energy Efficiency • Energy efficiency targets (Tier 1) • Energy efficiency programs and incentives (Tier 1)
Industrial Sector • Emissions performance standards for major industrial sources (Tier 3)
Policies to Reduce Emissions From Sources and Sectors Capped in 2015 *Transportation* • Low-carbon fuel standard (Tier 1) • Freight transportation infrastructure (Tier 1) • Development of algae and cellulosic biofuels (Tier 1) • Heavy-duty vehicle equipment (Tier 2) • Electric and alternative fuel vehicle infrastructure (Tier 2) • Vehicle emissions labeling (Tier 3) • Medium and heavy-duty vehicle hybridization (Tier 3) • Transport refrigeration units (Tier 3)
Policies to Reduce Emissions From *Uncapped* Sources and Sectors *High-Global Warming Potential Gases* • Regulatory measures for high-global warming potential gases (Tier 1)
Agriculture • Agricultural anaerobic digesters (Tier 2)
Waste Management • Measures for landfill methane reduction (Tier 2)
Policies adopted by jurisdictions outside the WCI region

[38]This table only includes policies the Committee will evaluate for further consideration; it does not include policy initiatives underway in other venues.

November 30, 2009 Final Draft Complementary Policies White Paper

List of Commenters

Arizona Public Service Company

BP America, Inc.

Energy Producers & Users Coalition and Cogeneration Association of California

EOS Climate

Hoyos, Lisa

National Hydropower Association

Pacific Carbon Exchange

Power Workers' Union

Public Utility District No. 1 of Chelan County

Sempra Energy

Southern California Public Power Authority

Southwest Energy Efficiency Project

US Department of Energy Intermountain Clean Energy Application Center

WEST Associates

Western Climate Advocates Network

Western Environmental Law Center

Western States Petroleum Association

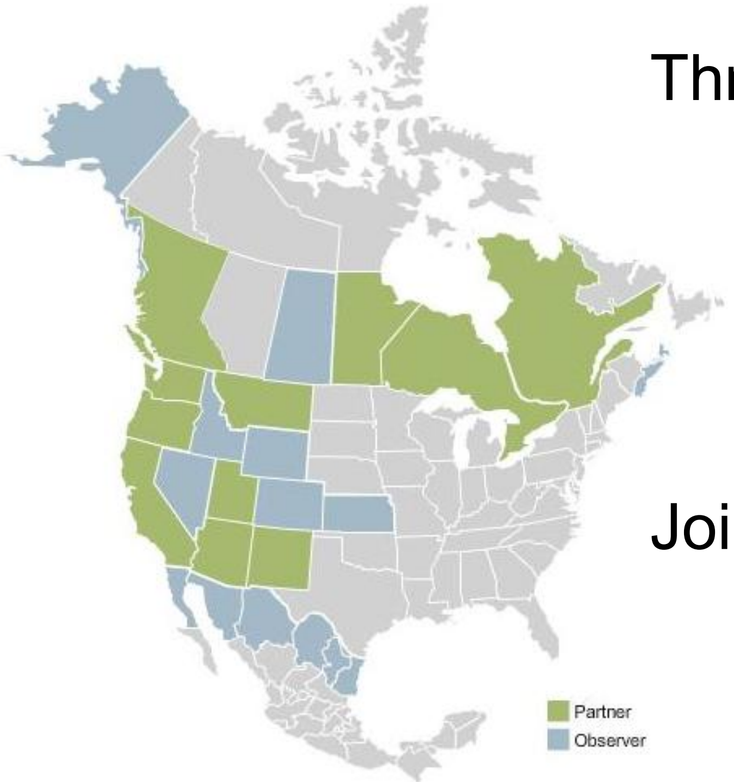
Western Climate Initiative

Complementary Policies Committee Draft White Paper

Stakeholder Presentation

December 7, 2009

Western Climate Initiative



Three specific directives:

- Set a regional emissions reduction goal
- Join a multi-state registry to track, manage and credit reductions
- Design a regional multi-sector market-based mechanism

Joint work to:

- Promote clean and renewable energy in the region
- Increase energy efficiency
- Advocate for regional and national climate policies that are in the interest of western states
- Identify measures to adapt to climate change impact

WCI Complementary Policies Committee

-Overview

Charged to recommend policies that:

- Would help achieve the regional emissions reduction goals and assist with the transition to a low-carbon economy if harmonized across multiple jurisdictions.
- Address market barriers to encourage low-cost GHG emission reduction options
- Reduce emissions from sources excluded from the cap-and-trade program.

WCI Complementary Policies Committee
-Overview

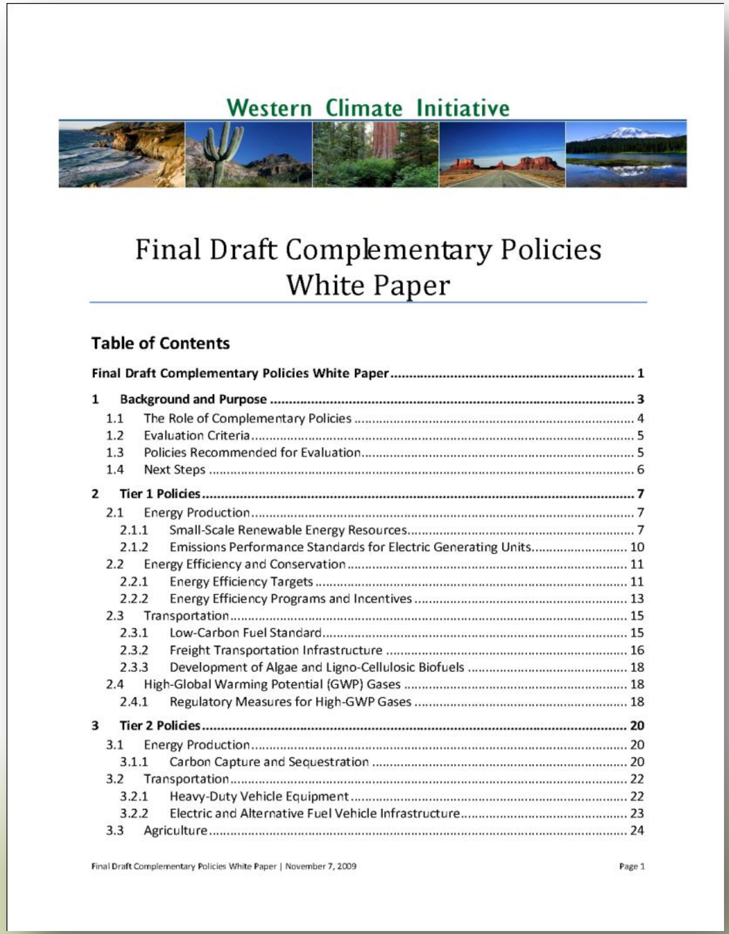
Complementary policies are designed to:

- Achieve reductions outside (or below) the cap
- Encourage investments in low-carbon technologies
- Lower the cost per metric ton of reductions in GHG emissions covered by the cap-and-trade program
- Lower the cost of transitioning to a low carbon economy
- Prevent emissions and economic leakage
- Create and retain clean energy jobs

WCI Complementary Policies Committee
-Draft White Paper

- Draft Report Released for 60-day public comment period on Dec. 1, 2009

- Comments can be submitted via the WCI website: www.westernclimateinitiative.org



Western Climate Initiative

Final Draft Complementary Policies White Paper

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How Complementary Policies Were Identified

- WCI Partner jurisdictions climate action plans
- The policies are grouped into three tiers to assist with scheduling the Committee's work.

WCI Complementary Policies Committee

-Draft White Paper

Policies were selected based on their ability to:

- Reduce GHG emissions
- Reduce costs associated with achieving the WCI goals for covered facilities
- Provide manageable administrative costs
- Mitigate impacts on low-income communities or small businesses
- Provide meaningful benefits from harmonization where there are not insurmountable barriers
- Achieve collateral benefits (e.g., conserving water)
- Avoid collateral detriments (e.g., increased use of electricity, increased fine particulates or air toxics pollution).
- Not encourage leakage outside the cap.
- Create or retain clean energy jobs or otherwise transition to a low-carbon economy.
- Provide electricity substitutes for higher GHG-emitting transportation fuels.

Tier 1 Policies

- Energy Production
  - Small-Scale Renewable Energy Resources
  - Emissions Performance Standards for Electric Generating Units
- Energy Efficiency and Conservation
  - Energy Efficiency Targets
  - Energy Efficiency Programs and Incentives

Tier 1 Policies

- Transportation
  - Low-Carbon Fuel Standard
  - Freight Transportation Infrastructure
  - Development of Algae and Ligno-Cellulosic Biofuels
- High-Global Warming Potential (GWP) Gases
  - Regulatory Measures for High-GWP Gases

Tier 2 Policies

- Energy Production
  - Carbon Capture and Sequestration
- Transportation
  - Heavy-Duty Vehicle Equipment
  - Electric and Alternative Fuel Vehicle Infrastructure
- Agriculture
  - Agricultural Anaerobic Digesters
- Waste
  - Landfill Methane Reduction

Tier 3 Policies

- Transportation
  - Vehicle Emissions Labeling
  - Medium- and Heavy-Duty Vehicle Hybridization
  - Transport Refrigeration Units
- Industrial Sector
  - Emissions Performance Standards for Major Industrial Sources

Important Policies Addressed in Other Venues

- Renewable portfolio standards in the electricity sector.
- Energy efficiency standards for new buildings and appliances.
- Smart grid infrastructure
- Light-duty vehicle emissions standards.
- Vehicle miles traveled reductions.
- Government leading by example.
- Assistance for low-income households.

WCI Complementary Policies Committee
-Draft White Paper

Feedback is sought on:

- The recommended evaluation criteria for complementary policies;
- The policies recommended for further evaluation;
- Key issues or barriers to harmonization; and
- The benefits that may accrue to jurisdictions and businesses that operate in more than one jurisdiction if implementation is harmonized.
- Input in how to engage stakeholders as evaluation process evolves

Additional policies for consideration:

- A description of the policy;
- The key issues to address or evaluate; and
- The potential benefits to harmonizing the policy across jurisdictions.

Western Climate Initiative

Questions?

www.westernclimateinitiative.org

Western Climate Initiative

Draft Guidance for Developing WCI Partner Jurisdiction Allowance Budgets

November 25, 2009

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1 Purpose And Summary

The purpose of this document is to provide guidance for calculating, establishing, and reviewing annual allowance budgets for the WCI Partner jurisdictions, the sum of which is the regional cap. The *Design Recommendations for the WCI regional Cap-and-Trade Program* describe conceptually how these budgets should be developed.[1] Recognizing, however, that further technical analysis and regional coordination would be needed to develop the budgets properly and consistently across jurisdictions, the *WCI 2009-10 Work Plan* established the Cap Setting and Allowance Distribution (CSAD) Committee and charged the Committee with, among other things, proposing a methodology and/or guidelines for establishing and periodically reviewing Partner allowance budgets.[2]

The WCI Partner jurisdictions believe there is great value in developing a budget-setting process in advance of when budgets must be established and with public knowledge of how the process will be conducted. For this reason, the CSAD Committee is releasing this draft guidance well ahead of when allowance budgets must be established, recognizing that changes to the method or process described within this guidance may be necessary in response to federal developments, state and provincial implementation schedules, availability and results of mandatory reporting data, and updated emission inventories and forecasts.

The objectives of this guidance are to:

- Describe the responsibilities of WCI Partner jurisdictions, the CSAD Committee, and WCI contractors in the process of developing allowance budgets;
- Promote consistency across WCI Partner jurisdictions in establishing allowance budgets;
- Provide transparency to the budget-setting process such that WCI Partner jurisdictions and the public can be confident that budgets were determined correctly and fairly; and
- Establish a timeframe for the budget-setting process to work in concert with the development of jurisdictional regulations and the emergence of an allowance market.

The guidance is organized into three major sections, as follows:

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[1] See http://www.westernclimateinitiative.org/the-wci-cap-and-trade-program/design-recommendations
[2] See http://www.westernclimateinitiative.org/component/remository/general/workplans/, CSAD Tasks 2.2 – 2.4.

Section 1

- Summarizes the proposed major activities, outcomes, and milestones for developing and reviewing allowance budgets, beginning with the calculation of preliminary allowance budgets by each Partner jurisdiction (Table 1);
- Shows how those budgets are calculated (Figure 1); and
- Provides a hypothetical illustration of a WCI Partner jurisdiction allowance budget (Figure 2).

Section 2

- Recommends the method for each WCI Partner jurisdiction to calculate preliminary allowance budgets.

Section 3

- Recommends an approach for establishing allowance budgets from the preliminary budgets; and
- Describes a process to finalize Partner budgets prior to the start each compliance period.

The guidance recognize the major factors in, and the procedures for, developing allowance budgets. They do not address how allowances within the budget may be distributed – for example, to address competitiveness and leakage issues – or seek to resolve all outstanding technical issues or policy decisions likely to have an effect on the allowance budgets, such as the best estimate of capped-source emissions in 2012 and 2015 or the results of the one-percent budget adjustment for 2012. The guidance identifies where such data and policy decisions would be incorporated into the calculation of allowance budgets and provides a roadmap for coordinating regional efforts over the course of the program.

Finally, the role of the CSAD Committee in the process of developing, reviewing, and finalizing allowance budgets is noted in several places in this guidance. Since the process would extend over several years, it is possible that the Committee's role may be filled by another regional committee or forum (e.g., a regional administrative organization) rather than the CSAD Committee in its current form.

The Committee will host a stakeholder conference call on this guidance on Tuesday, December 15 at 10:30 a.m. Pacific Standard Time (800-868-1837, participant code 659537#). Written comments can also be provided via the WCI website. Comments should be provided by Wednesday, January 13, 2010.

Table 1. Summary Of Budget Development And Review Process.

	Activity	Completion	Outcome	Purpose
Section 2	• Each Partner calculates a preliminary allowance budget, based in part on emission forecast methods developed by CSAD contractor. (See Figure 1.)	Q1 2010	Preliminary budgets	Form a consistent starting point to develop budgets that meet Partner and regional goals.
Section 3.1	• Partners present preliminary budgets and supporting information. • CSAD conducts a first review of budgets/info for consistent application of guidance and makes recommendations to improve. • Partners review recommendations and incorporate as appropriate. • CSAD conducts a second review of budgets/info and makes final recommendations. • Partner jurisdictions establish budgets, including any potential adjustments to address electricity generated in one jurisdiction but consumed in another.	Summer 2010	Established budgets	Basis for developing jurisdictional rules. Provide early and reliable market signal. Support any pre-2012 auctioning.
Section 3.2	• Partners inform CSAD of any adjustments to established budgets. • CSAD reviews emissions reporting and other data and makes recommendations for Partners' consideration. • Partner jurisdictions finalize budgets.	Q4 2011	Final budgets	Account for final program rules and available emissions and market data. Increase allowance market certainty, enable full distribution of allowances.
Section 3.3	• Similar process to above, but include assessment of the program's progress.	Summer 2014	Revised final budgets	Account for new data, program changes, and program performance.
	• Same process as in 2014.	Summer 2017	Revised final budgets	Account for new data, program changes, and program performance.

Figure 1. Calculation Of A Preliminary Allowance Budget.

2012 = 2012 emissions forecast for Phase I sources, determined with CSAD contract support to account for:

- Population growth*
- Economic growth*
- Mandatory emissions reductions*

"Best Estimate"

\+ 2012 forecast adjustments, determined by Partner jurisdictions to account for:

- Voluntary emissions reductions*
- Shut-down sources
- New sources

\+ 1 percent, 1 time adjustment

\+ Early Reduction Allowances to be awarded to emitters in accordance with Section 8.11 of the *Design Recommendations*

2013 = 2012 best estimate + 1 time adjustment - ROD_1

2014 = 2013 preliminary budget - ROD_1

2015 = 2014 preliminary budget - ROD_1 + 2015 best estimate of Phase II sources

2016 = 2015 - ROD_2

2017 = 2016 - ROD_2

2018 = 2017 - ROD_2

2019 = 2018 - ROD_2

2020 = 2019 - ROD_2

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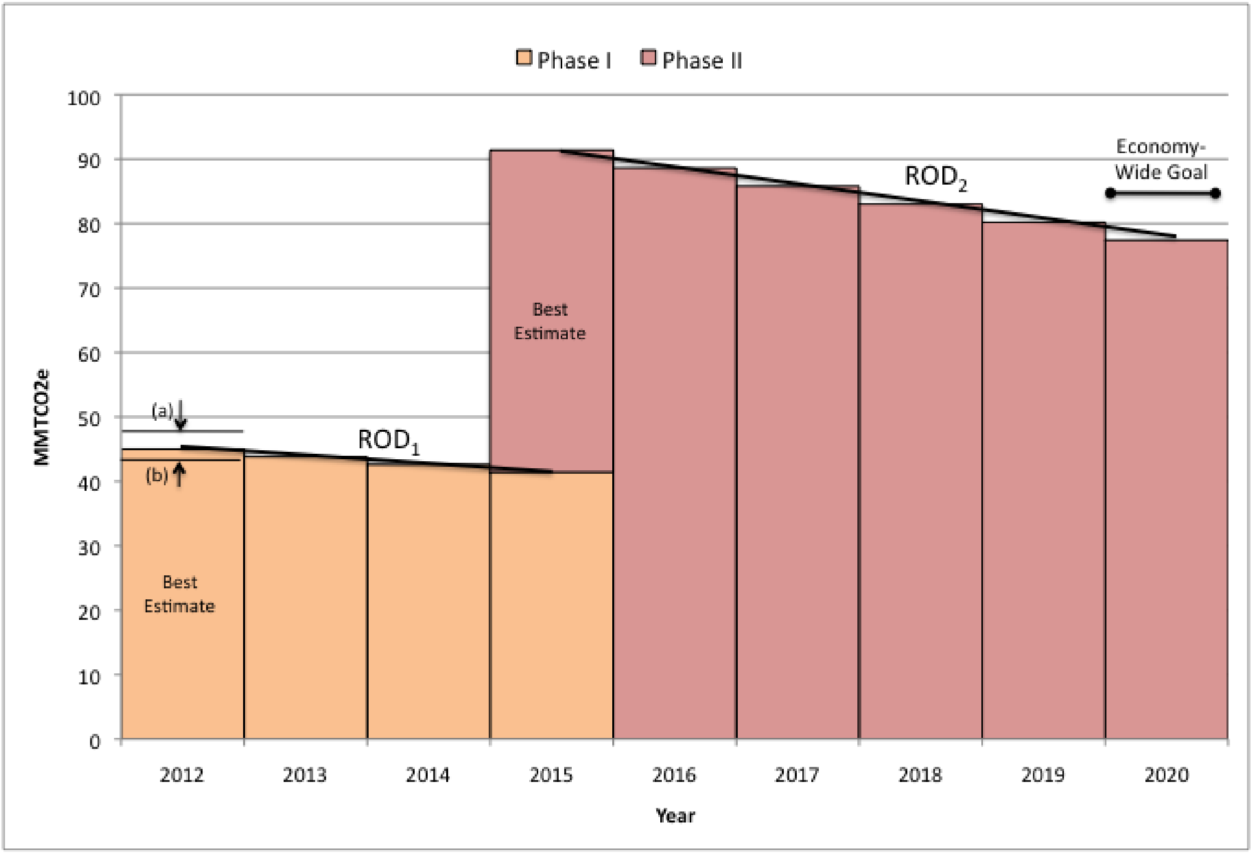
* = Factors also used to determine the 2015 best estimate for Phase II sources

ROD_1 = Rate of decline (in $MMTCO_2e$ per year) during Phase I

ROD_2 = Rate of decline during Phase II

Figure 2. Hypothetical Illustration Of A WCI Partner Jurisdiction Allowance Budget.



2 Methodology For Calculating Preliminary Allowance Budgets

2.1 Preliminary Allowance Budget For 2012

1. The Partner jurisdiction will calculate the best estimate of expected emissions for sources covered in the cap-and-trade program in the Partner's jurisdiction in 2012, accounting for population growth, economic growth (including new and shut-down sources), and voluntary and mandatory emission reductions through 2012. The best estimate will be an outcome of each Partner's application of the forecast methods developed by the CSAD Committee and contractor and is shown as the first colored bar in Figure 2. For the purpose of determining the best estimate of 2012 emissions:

    a. New sources are sources which are not included in the Partner jurisdiction's emission inventory but are expected to be emitting covered GHGs prior to January 1, 2013. The Partner jurisdiction will estimate, using any methods developed by the Committee to promote consistency, covered emissions from new sources and include these emissions in its 2012 best estimate.

    b. Shut-down sources are sources which are included in the Partner jurisdiction's emission inventory but are expected to be permanently shut down prior to January 1, 2012. The Partner jurisdiction will remove covered emissions from shut-down sources from its 2012 best estimate.

    c. Voluntary emission reductions are the emissions avoided in 2012 as a result of consumers or sources taking action which reduces GHG emissions and is not required by law or regulation. Such action must occur prior to 2012 and should have permanent emission benefits (e.g., persisting until 2020).[3] Voluntary emission reductions must include any reductions at sources which may be awarded with Early Reduction Allowances (ERAs) in accordance with Section 8.11 of the *Design Recommendations*.

2. The Partner jurisdiction will calculate the one-time, one-percent budget adjustment for 2012. This adjustment is the subject of Task 4 of the CSAD Committee and will be

[3] Actions first taken in 2012 can not necessarily be considered voluntary when Phase I producers are subject to the cap and when consumers face the cap's consequent price increase.

determined separately. If the one-time adjustment results in a greater amount of allowances for the Partner jurisdiction, then the 2012 preliminary budget will increase towards line (a) in Figure 2. If the one-time adjustment results in a lesser amount of allowances, then the 2012 preliminary budget will decrease towards line (b) in Figure 2.

3. The Partner jurisdiction will calculate the quantity of ERAs to be distributed to sources in accordance with Section 8.11 of the *Design Recommendations*. This quantity will increase the 2012 preliminary allowance budget towards line (a) in Figure 2.[4]

4. The Partner jurisdiction will calculate its 2012 preliminary allowance budget as the 2012 best estimate, plus (or minus) the one-time budget adjustment, plus the ERAs to be distributed to sources.

2.2 Preliminary Allowance Budgets For 2013 And 2014

1. The Partner jurisdiction will determine a rate of decline for the first phase of the cap-and-trade program (ROD_1). ROD_1 shall be expressed in units of million metric tons of CO_2 equivalents ($MMTCO_2e$) per year and shall be greater than zero.[5]

2. The Partner jurisdiction will calculate its 2013 preliminary allowance budget as the 2012 best estimate minus ROD_1.

3. The Partner jurisdiction will calculate its 2014 preliminary allowance budget as the 2013 preliminary allowance budget minus ROD_1.

2.3 Preliminary Allowance Budget For 2015

1. The Partner jurisdiction will calculate its 2015 preliminary allowance budget as the sum of the 2014 preliminary allowance budget minus ROD_1 plus the 2015 best estimate of expected emissions for sources first covered in the cap-and-trade program in the

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[4] Early reductions are voluntary and, as such, should be included in, and therefore reduce, the 2012 and 2015 best estimates. This is important to assure that the distribution of ERAs does not create a surplus in the allowance market.

[5] The purpose of ROD_1 (and ROD_2 below) is to ensure, as stated in the Design Recommendations, that the trajectory for each WCI Partner jurisdiction's annual allowance budget for covered sectors will be a straight line from the year of initial coverage to 2020. This is the only way to ensure for planning purposes that the 2020 reduction goal is met. However, the actual annual trajectories of jurisdictional emissions and allowance distribution to specific sources will not necessarily follow a straight line reduction trajectory. For instance, any given Partner jurisdiction's emission reduction trajectory will depend on regional trading and the use of offsets by covered sources. In addition, the three-year compliance periods will allow covered sources to reduce emissions at various rates across the three-year period.

Partner's jurisdiction in 2015, accounting for population growth, economic growth, and voluntary and mandatory emission reductions. The best estimate of 2015 emissions will be an outcome of each Partner's application of the forecast methods developed by the CSAD Committee and contractor and is shown as the top half of the 2015 bar in Figure 2. For the purpose of determining the best estimate of 2015 emissions:

a. Voluntary emission reductions are the emissions avoided in 2015 as a result of consumers or sources taking action which reduces GHG emissions and is not required by law or regulation. Such action must occur prior to 2015 and should have permanent emission benefits (e.g., persisting until 2020). Voluntary emission reductions must include any reductions which may be awarded with Early Reduction Allowances (ERAs) in accordance with Section 8.11 of the *Design Recommendations*.

2.4 Preliminary Allowance Budgets For 2016 Through 2020

1. The Partner jurisdiction will determine a rate of decline for the second phase of the cap-and-trade program (ROD_2). ROD_2 shall be expressed in units of $MMTCO_2e$ per year. ROD_2, in conjunction with any reductions in non-covered emissions in the Partner's jurisdiction, shall be sufficient to achieve the Partner jurisdiction's 2020 economy-wide goal.

2. The Partner jurisdiction will calculate its preliminary allowance budgets for 2016 through 2020 by subtracting its ROD_2 from the prior year's preliminary allowance budget, starting with 2016 and continuing to 2020.

3 Process For Reviewing, Finalizing, And Adjusting Allowance Budgets

3.1 Establishing Annual Budgets In 2010

The purpose of this process is to compile and harmonize preliminary allowance budgets as much as possible for Partner consideration, revision, and agreement. The outcome of this process will be an "established budget" for each Partner jurisdiction in the summer of 2010.

The established budgets are intended to (a) provide a basis for each Partner jurisdiction in developing its regulations implementing the regional cap-and-trade program and (b) provide an early and reliable indication of the supply of allowances in the regional marketplace. Although established budgets may be revised when finalized prior to the start of the first compliance period (see Section 3.2), the limited and specific conditions under which such revisions would occur should preserve the value of established budgets as an early and reliable market signal.

1. The Partner jurisdiction will provide to the CSAD Committee:

    a. A preliminary allowance budget for each year in the period 2012-2020.
    b. A ROD for each phase of the cap-and-trade program.
    c. An explanation of how the RODs were determined.
    d. A presumptive ROD_1, determined as the product of:
        i. the ROD resulting from a straight-line reduction from the 2012 best estimate of Phase I and Phase II source emissions to the 2020 preliminary budget, and
        ii. the ratio of the best estimate of Phase I source emissions to the best estimate of Phase I and II source emissions in 2012.
    e. A best estimate of economy-wide emissions in 2005 and 2020, assuming emissions from capped sources in 2020 are equivalent to the preliminary budget for 2020.[6]

2. The Committee will compile and review the jurisdictional preliminary budgets and recommend changes for maintaining a regionally-consistent approach to achieving the regional goal.

3. The Partner jurisdiction will review recommendations and incorporate as appropriate, informing the Committee of any changes to its preliminary budget.

4. The Committee shall compile and review the jurisdictional preliminary budgets, including any revised preliminary budgets provided under 3 above, and recommend changes which may be important for maintaining a regionally-consistent and approach to achieving the regional goal.

5. Each Partner representative will seek the appropriate approvals from their respective jurisdictional authorities for a Partner's established budget after considering the compiled preliminary budgets and any changes recommended by the Committee. The established budget shall include any potential adjustments which are part of an equitable solution to electricity generated in one Partner jurisdiction but consumed in another.

[6] In British Columbia, the emissions from transportation and residential, commercial, and industrial fuels will be covered by a carbon tax in lieu of a cap. The carbon tax will be integrated with the cap-and-trade program.

3.2 Finalizing Annual Budgets Prior To The Start Of The First Compliance Period

The purpose of this process is to adjust, where necessary and according to Section 7.4 of the *Design Recommendations*, the established budgets from 2010. The outcome of this process will be a "final budget" for each Partner jurisdiction in autumn of 2011.[7]

1. The Partner jurisdiction will identify and inform the Committee of any potential changes to its established budget resulting from each of the following conditions:

    a. Changes in WCI membership.
    b. Changes in scope or threshold of the WCI regional program design.
    c. Differences in scope or threshold between the jurisdiction's final regulations and the sources included in the 2012 and 2015 best estimates.
    d. Incorrect or inaccurate data that were used to determine the established budgets of 2010, including new and permanently shut down sources not identified in Section 2.1.

2. The Committee will obtain from the WCI Regional Emissions Database the 2010 mandatory reporting data for capped sources in each Partner jurisdiction. The Committee will compare these data to the 2012 and 2015 best estimates of Phase I and Phase II sources and Partner allowance budgets, evaluate the necessity of any changes to the established budgets (taking into consideration the information identified in Section 3.2.1), and provide the Partner representatives with a summary of this evaluation.

3. Each Partner representatives will seek the appropriate approvals from their respective jurisdictional authorities for a Partner's final budget after considering the Committee's evaluation.

3.3 Adjusting Annual Budgets Prior To The Start Of The Second And Third Compliance Periods

The purpose of this process is to adjust, where necessary and according to Section 7.4 of the *Design Recommendations*, the budgets for Phase II of the program finalized in 2011. The

[7] This date would allow time for submittal and review of the mandatory reporting data collected according to the WCI essential requirements, which would first be submitted to the Partner jurisdictions by April 1, 2011 and verified by September 1, 2011.

potential outcome of this process would be a “revised final budget” for one or more Partner jurisdiction in the summers of 2014 and 2017.[8]

1. The Partner jurisdiction will identify and inform the Committee of any potential changes to its final budget resulting from each of the following conditions:

    a. Changes in WCI membership.
    b. Changes in scope or threshold of the WCI regional program design.
    c. Changes in scope or threshold of the jurisdiction’s regulations.
    d. Incorrect or inaccurate data that were used to determine the final budgets of 2011.

2. The Committee will obtain from the WCI Regional Emissions Database all available mandatory reporting data for capped sources in each Partner jurisdiction. The Committee will use these (and potentially other) data to assess the progress of the regional cap-and-trade program, the necessity of any changes to budgets in Phase II of the program (taking into consideration the information identified in Section 3.3.1), and provide the Partner representatives with a summary of this evaluation.

3. Each Partner representatives will seek the appropriate approvals from their respective jurisdictional authorities for a Partner’s budget after considering the Committee’s evaluation.

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[8] Adjustments for Phase II budgets can occur earlier in the year than adjustments for Phase I budgets because verified data may be submitted earlier than September 1 for reporting years 2012 and later and because more mandatory data will be available in 2014 and 2017 than in 2011.

December 6, 2009 Draft Guidance for Developing WCI Partner Jurisdiction Allowance Budgets

List of Commenters

Arizona Public Service Company

BC Forestry Climate Change Working Group

Pacific Gas and Electric Company

Power Workers' Union

Puget Sound Energy

Southern California Edison Company

Southern California Public Power Authority

Utah Business Climate Change Coalition

WEST Associates

Western Climate Advocates Network

Western Climate Initiative

Draft Guidance for Developing WCI Partner Jurisdiction Allowance Budgets

An overview presented to stakeholders on December 15, 2009

Purpose of Document

- Provide guidance for calculating, establishing, and reviewing annual allowance budgets for the WCI Partner jurisdictions, the sum of which is the regional cap

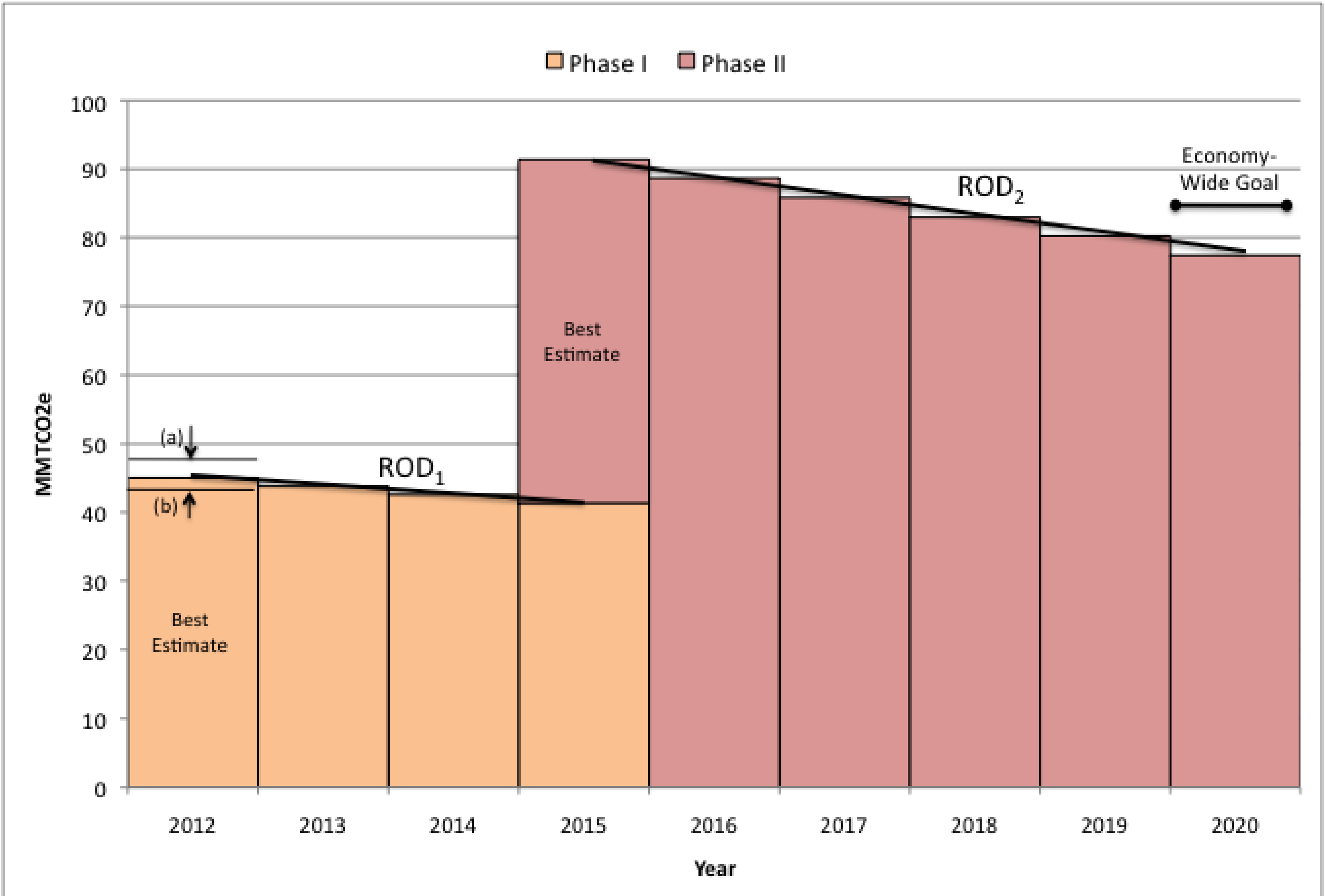
Objectives of the Guidance

- Describe roles and responsibilities of parties
- Promote consistency in establishing budgets across Partner jurisdictions
- Provide transparency to the budget-setting process
- Establish a timeframe for the process

Section 2 of the Guidance

- Methodology for calculating preliminary budgets
  - Consistent starting points for developing budgets that meet Partner and regional goals
- Best estimate of actual emissions from covered sources in 2012 and 2015 form the starting points of the annual budgets
- Rate of decline (ROD) forms the basis of subsequent year budgets
  - Determined individually by Partners to meet jurisdictional GHG reduction goals

Hypothetical Illustration of a WCI Partner Jurisdiction Allowance Budget



Section 3 of the Guidance

- Process for reviewing, finalizing, and adjusting budgets over time
- Budgets "established" in summer of 2010
- Budgets reviewed and finalized in fall of 2011
  - Adjusted as necessary to account for changes in WCI membership, changes in scope or threshold, or incorrect or inaccurate data used to establish budgets in 2010
- Budgets reviewed and revised as necessary in summers of 2014 and 2017 (essentially same criteria as above)

The Guidance Does Not …

- Specify numeric budgets or require Partner jurisdictions to follow a specific procedure in establishing them
  - But it does provide a coordinated, transparent path
- Indicate how allowances should be distributed to emitters (or others) from within a jurisdiction’s budget
  - But it does allow for harmonized methods among jurisdictions to address regional competitiveness, etc.

Next Steps

- Written comments should be provided via the WCI website by January 13, 2010
- CSAD Committee will continue collecting emissions data and developing forecast methods to support the best estimates of 2012 and 2015

Western Climate Initiative News

December 7, 2009

Upcoming Events

December 15: Stakeholder Call on WCI Draft Guidance for Developing Partner Allowance Budgets

A webinar to review and discuss the draft guidance document will be hosted by the CSAD Committee on December 15 at 10:30 a.m. Pacific. To join the call, dial 1-800-868-1837 (toll free) or 1-404-920-6440 (direct dial) and enter participant code 659537#.

January 20, 2010: WCI Partners Meeting in Phoenix, AZ

The next WCI Partner meeting will be on January 20 in Phoenix, Arizona, at the Mission Palms Hotel. Stakeholders are invited to attend in-person or via teleconference. To join by teleconference, dial 1-800-868-1837 (toll free), participant code 659537#. The agenda will be posted to the website and distributed via the WCI list server when available.

January 21, 2010: Electricity Collaborative in Phoenix, AZ

The WCI is sponsoring an electricity industry collaborative in Phoenix, Arizona, at the Mission Palms Hotel. The purpose

This status report is issued monthly from WCI Partner jurisdictions to all interested stakeholders via the WCI list server and website.

In This Issue

California ARB Issues Preliminary Draft Cap and Trade Regulation

Québec Sets Ambitious Greenhouse Gas Emissions Reduction Target

British Columbia Take Further Steps Towards Cap and Trade

Ontario Paves the Way for Cap and Trade System

Market Oversight White Paper Available

Complementary Policies White Paper Available

Draft Guidance for Allowance Budgets Available

Harmonization of Reporting Program with U.S. EPA Mandatory Rule

Electricity Team Takes Steps to Improve Quantification of Imported Power

Regional GHG Initiatives Hold Second Meeting

November Meeting Presentations Available

Competitiveness Presentations Available

California Air Resources Board Issues Preliminary Draft Cap and Trade Regulation

On November 24, 2009, the California Air Resources Board released a preliminary draft version of its greenhouse gas cap-and-trade regulation. This marks the beginning of the next phase of cap and trade rulemaking under AB32, the California Global Warming Solutions Act of 2006, which establishes a comprehensive program to achieve real, quantifiable, and cost-effect reductions of greenhouse gas emissions.

California collaborated with the other Partner jurisdictions in the Western Climate Initiative and solicited diverse stakeholder input to create a program with broad appeal. The program is designed to drive innovation and use market forces to find least-cost solutions to reducing greenhouse gas emissions. The proposed cap and trade program would cover 85 percent of California's emissions, including electricity generation, large industrial sources, transportation fuels, and residential and commercial use of natural gas and propane.

Once adopted, California's cap and trade program will link with of the collaborative is to expand discussion beyond the first jurisdictional approach to include how the industry may be affected by federal policy and other state/regional actions. Stakeholders are invited to attend in-person or via teleconference. To join by teleconference, dial 1-800-868-1837 (toll free), participant code 659537#. The agenda will be posted to the website and distributed via the WCI list server when available.

February 4, 2010: Stakeholder Update Call

The next WCI update call will be on February 4 at 12:30 p.m. Pacific. To join by teleconference, dial 1-800-868-1837 (toll free), participant code 659537#.

similarly rigorous programs implemented by partners of the Western Climate Initiative and include a stringent declining emissions cap along with trading and the limited use of offsets to provide flexibility for covered entities to comply. For more information, click here.

Québec Sets Ambitious Greenhouse Gas Emissions Reduction Target

On November 23, 2009 Premier Jean Charest and Minister of Sustainable Development, Environment and Parks, Line Beauchamp, unveiled a target to reduce GHG emissions by 20% below 1990 levels by 2020, a goal similar to the target established by the European Union. Nearly half of Québec's energy comes from renewable resources, and its industrial sector has already reduced emissions 7% below 1990 levels despite a 41% increase in GPD over the same period. At 11 tonnes per capita, Québec 's energy intensity is half the Canadian average. Québec 's energy intensity will become the lowest in North America under its new target. As part of its reduction strategy, the Québec government will soon be introducing light-duty vehicle emission standards equivalent to those in California. For more information, click here.

British Columbia Take Further Steps Towards Cap and Trade

On November 25, 2009, Environment Minister Barry Penner announced a new provincial regulation effective January 1, 2010 that will require all facilities in BC that emit over 10,000 tonnes of CO2e annually to publically report their emissions. It is expected that approximately 200 facilities will be required to report annually under this regulation. The regulation has been designed to allow for a single reporting window with Environment Canada and for reporting simplicity for the regulated entities. The regulation is also consistent with the WCI Essential Requirements for Mandatory Reporting and will facilitate the participation of BC in the regional cap-and-trade program. For more information click here.

Ontario Paves the Way for Cap and Trade System

Ontario's enabling legislation on cap and trade, the Environmental Protection Amendment Act (Greenhouse Gas Emissions Trading), was passed by the Ontario Legislature on December 3, 2009. The legislation, introduced by Ontario Environment Minister John Gerretsen earlier this year, provides the foundation to implement a cap and trade program in Ontario that can link to other jurisdictions and help industry reduce greenhouse gas (GHG) emissions at lowest cost.

The Ontario government also released a new reporting regulation and guideline on December 1, 2009 - another critical element to support the implementation of cap and trade and Ontario's participation in the Western Climate Initiative. The regulation comes into force on January 1, 2010 and specifies requirements for industry to report their GHG emission data to the government and public. The government anticipates that between 200 to 300 facilities will be affected. They will start reporting their 2010 emissions in 2011.

Ontario also released its second annual report which provides a comprehensive update on all the activities which Ontario has taken and the progress which has been made in 2008-09 towards achieving its GHG reduction targets.

For more information on these announcements, click the links below:

- McGuinty Government Paves The Way For Future Cap-And-Trade System
- McGuinty Government Sets Down Rules For Reporting Greenhouse Gas Emissions
- Ontario Releases Second Climate Change Annual Report

WCI Markets Committee Issues Market Oversight White Paper

WCI's Market Oversight White Paper is the next step in developing recommendations for the architecture and oversight of its allowance and offset credit markets. It defines market architecture and oversight, and describes existing financial markets. It discusses market participation and types of transactions. It also briefly reviews market oversight in the U.S. and Canada, and oversight of the European Union's Emissions Trading Scheme, as well as proposals for carbon market oversight and financial market reform in the U.S. federal government. A stakeholder call was hosted by the Committee on December 2 to discuss the white paper. Written comments may be provided through December 18 via the WCI website.

WCI Complementary Policies Committee Issues White Paper

WCI's Complementary Policies Committee has begun to identify and evaluate policies that may address market barriers that can limit the use of low-cost GHG emission reduction options and examine opportunities to reduce emissions from a variety of sources, including from sources not covered by the cap-and-trade program. The Committee will recommend to the WCI Partner jurisdictions those policies which, if harmonized across multiple states and provinces - both within and outside the WCI Partner jurisdictions, would help achieve the regional emissions reduction goal and assist with the transition to a low-carbon economy. Stakeholder input on the white paper is sought on:

- The recommended evaluation criteria for complementary policies;
- The policies recommended for further evaluation;
- Key issues or barriers to harmonization; and
- The benefits that may accrue to jurisdictions and businesses that operate in more than one jurisdiction if implementation is harmonized.

A webinar to review and discuss the white paper was hosted by the Committee on December 7. Written comments can be submitted via the WCI website through January 29, 2010.

WCI Cap Setting & Allowance Distribution Committee Issues Draft Guidance for WCI Partner Jurisdiction Allowance Budgets

The WCI Partners believe there is value in developing a budget-setting process prior to establishing budgets. For this reason, the CSAD Committee is releasing this document to provide guidance for calculating, establishing, and reviewing annual allowance budgets for the WCI Partner jurisdictions ahead of when allowance budgets must be established, recognizing that changes to the method or process described within the guidance may be necessary in response to federal developments, results of mandatory reporting requirements, etc. A webinar to review and discuss the draft guidance will be hosted by the Committee on December 15 at 10:30 a.m. Pacific. Written comments can be submitted via the WCI website through January 13, 2010.

Harmonization of WCI Reporting Program with EPA Mandatory Reporting Rule

WCI Partner jurisdictions are currently in the process of adopting rules to implement the WCI's final Essential Requirements for Mandatory Reporting (ERs), which were issued on July 16, 2009. On September 22, 2009, U.S. EPA adopted its final Mandatory Reporting Rule (MRR) for greenhouse gas (GHG) emissions. Both programs require the filing of initial reports in 2011 for the 2010 reporting year. Many U.S. facilities in the WCI region will be subject to both reporting programs.

In order to avoid the imposition of duplicative or conflicting reporting obligations on facilities subject to both programs, the WCI Partners have directed the Reporting Committee to amend WCI's ERs to achieve harmonization with the EPA MRR. The harmonization effort will be guided by the following principles:

- A U.S. facility should be able to comply with both the MRR

and a WCI jurisdiction's reporting requirements by following a single set of monitoring, recordkeeping and reporting requirements.
- The quantification methods included in the amended ERs must be sufficiently reliable and accurate to be employed in a (GHG) cap and trade program. Because EPA has acknowledged that it did not develop the MRR with this goal in mind, the Reporting Committee must review each method included in the MRR to assure it meets this criterion.
- The amended ERs must remain suitable for use in Canadian WCI jurisdictions. For example, they must allow reporting in metric as well as English units and must where necessary include Canada-specific emission factors.

The WCI Partners recognize that the detailed analysis, redrafting and stakeholder review required to harmonize the existing WCI ERs with EPA's MRR cannot be accomplished in time for the 2010 reporting year. As an interim measure, the U.S. WCI Partner jurisdictions intend to include in their rules a provision that will allow facilities to comply with the jurisdiction's reporting rules for the 2010 reporting year by submitting a copy of the reports they file with EPA under the MRR. Although this approach may result in some inconsistencies in the data submitted for 2010, the Partners believe that is preferable to the potential imposition of duplicative or conflicting reporting obligations.

The WCI is also engaging with Environment Canada to harmonize reporting requirements.

The WCI's goal is to adopt ER amendments that achieve consistency across the region and with the MRR in time for the 2011 reporting year. Further details on the Reporting Committee's workplan to harmonize reporting requirements is available here.

Electricity Team Takes Steps to Improve Quantification of Imported Power

Through a contract with Open Access Technology International (OATI), the WCI Electricity Team has initiated an effort to collect and analyze data on power imports into each western WCI Partner jurisdiction during the period 2005-2008. When coupled with emission factors currently under development by the Electricity Team, these data will lead to quantitative estimates of emissions from historical electricity imports. Quantifying these emissions is an important step in establishing a cap which includes these emissions starting in 2012, as called for by the *Design Recommendations for the WCI Regional Cap-and-Trade Program*. The Electricity Team is receiving technical support from OATI to quantify power imports into WCI Partner jurisdictions in the Western Interconnection. Options to quantify power imports into Manitoba, Ontario, and Québec are currently under consideration.

Regional GHG Initiatives Hold Second Meeting

State and Provincial representatives of the three regional GHG initiatives met for the second time on November 9 in Washington, D.C. to continue sharing information on the status of their initiatives. Representatives of the Western Climate Initiative, Midwestern Greenhouse Gas Reduction Accord, and the Regional Greenhouse Gas Initiative discussed plans to collaborate in three specific areas - offsets, complementary policies, and identifying issues that would have to be addressed if the regions were to link their programs.

The group also discussed state roles under various federal action scenarios. This included meeting with EPA officials to discuss a plan for ongoing interaction with states as federal climate change programs are designed and implemented.

In a briefing hosted by the Senate Energy and Energy Resources Committee that afternoon, the three regional groups reiterated their support for federal action to implement comprehensive and rigorous programs to reduce greenhouse gases. The groups stated their intention to continue moving ahead with the development and implementation of their programs while working with Congress, EPA, and other federal agencies to ensure appropriate and effective state roles in the implementation of emerging federal programs and regulations. A video of the Senate Energy and Natural Resources Committee briefing is available here.

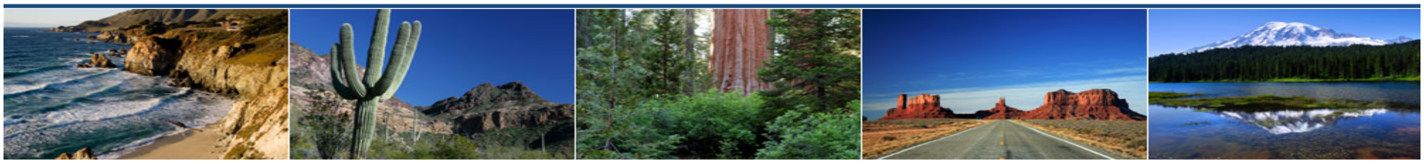
Presentations Available from November Partner Meeting and Oil & Gas Industry Collaborative

Material from the November 18 Partner meeting and November 19 oil and gas industry collaborative are available on the WCI website.

Presentations Available from Competitiveness Webinar

On November 12, the WCI Cap Setting & Allowance Distribution Committee hosted a webinar on competitiveness. Representatives from the European Commission and World Resources Institute presented the policies being developed for addressing competitiveness concerns of energy-intensive, trade-exposed industries, as well as the process for engaging industry in climate policy developments under the EU-ETS and proposed U.S. legislation. Their presentations are available on the WCI website.

Western Climate Initiative



Voluntary Renewable Energy Market: Issues and Draft Recommendations

January 14, 2010

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1 Executive Summary

Voluntary purchases of renewable energy products have played an important role in expanding the renewable energy market in many WCI jurisdictions. However, the voluntary renewable energy (VRE) market may be impacted by the implementation of a greenhouse gas cap-and-trade program. The impact on the VRE market depends in part on expectations that VRE consumers may have about the emission reduction benefits associated with their purchases. Renewable generators located in capped jurisdictions no longer contribute to greenhouse gas emission reductions once a cap is in effect because the level of allowable emissions is determined by the cap. In light of this, consumers motivated primarily by the desire to reduce greenhouse gases may choose to opt out of the VRE market or direct their purchases to uncapped jurisdictions. WCI Partner jurisdictions that wish to address potential impacts on the VRE market from the cap-and-trade program have the option to adjust their baseline allowance budget to reserve (or "set aside") a pool of allowances for retirement that ensures that emission reductions occur for VRE market purchases. This type of VRE policy (a "VRE set aside") has been implemented in the cap-and-trade system in the US Northeast (the Regional Greenhouse Gas Initiative, or RGGI), and has been proposed in Australia. Conversely, no such program exists in the European cap-and-trade system or proposed federal US programs.

The WCI Design Recommendations provide that WCI Partner jurisdictions have broad discretion in determining whether to reserve their allowances for designated purposes. In accordance with these recommendations, no program-wide recommendation is made as to whether all Partner jurisdictions should implement a VRE set aside. While it is important, if not necessary, for linked cap and trade programs to harmonize on certain elements, it is not important for all Partner jurisdictions to harmonize on the choice of whether to implement a VRE set aside.

This paper focuses on discussing the key design elements of VRE set asides and provides recommendations to those WCI Partner jurisdictions that do choose to implement a VRE set aside. Elements on which it is important for the WCI Partner jurisdictions to harmonize are highlighted. These draft recommendations are summarized below in Table 1.

Table 1: Summary of Draft Recommendations on VRE Set Aside Design Elements

Design Element	WCI Partner jurisdictions that choose to implement a VRE set aside should:	Importance of Harmonization
Accounting Mechanism for VRE Set Aside Program	Include a requirement that the measurement of voluntary renewable energy purchases that form the basis of any allowance retirement be based, first and foremost, on transactions verified through established REC tracking systems that span some or all of the WCI region (e.g., WREGIS). In addition, to account for those purchases that are not tracked through an established system (or for regions without such a system) provision should be made to accept transactions that are certified through a third-party verification system for voluntary renewable energy that includes, at a minimum, a requirement that the seller must attest to not having previously sold or otherwise transferred the greenhouse gas benefits of the renewable energy product.	High
Defining Eligible Renewable Energy Project Types	Define their own eligibility requirements for their VRE set aside programs. They may choose to mirror existing RPS or other statutory definitions or to define a separate list of qualifying project types.	Low
Jurisdictional Retirement Responsibility	Retire allowances using a generator-based approach in which allowances are retired whenever RECs from a facility in that WCI Partner jurisdiction's territory are purchased and retired by a customer in the VRE market with no limitation on the customer's location. Alternatively, the retirement should be based on VRE sales if RECs are not used.	High
Upper Limit on Retirement Amount	Choose whatever upper limit (if any) that is found appropriate for that jurisdiction. Partner jurisdictions must determine if they will cover shortfalls by either borrowing allowances from a future year or lowering the per MWh retirement rate.	Low
Time Limit on VRE Set Aside Program	Choose whatever time limit (if any) that is found appropriate for that jurisdiction. Partner jurisdictions may choose to base time limits on periodic reviews of the cost-competitiveness of the technologies supported by the set aside program.	Low
Emission Attribution for VRE Purchases	Work together to develop a rate based on a marginal dispatch analysis, such as the WCI Default Emission Factor Calculator, for each major grid region. However, use of this rate should be optional and specific assignment of emissions left to jurisdictional discretion.	Medium

2 Background

The WCI Partner jurisdictions committed to a set of principles when designing the WCI Regional Cap-and-Trade Program. A theme in those principles is the support of renewable energy by "diversifying energy sources" and "stimulating investment … in low carbon technologies"[1]. Therefore, increasing the amount of energy generated by renewable energy sources in the WCI region is a key goal of the WCI Partners. Much of the growth in renewable energy in the WCI region will happen through the economic incentives created by cap-and-trade, government mandates on load-serving entities to obtain renewable energy, and other complementary policies such as direct procurement or feed-in tariffs. Additional growth may come from energy consumers that make individual, voluntary decisions to purchase renewable energy in the voluntary renewable energy (VRE) market.

At present individual decisions to purchase renewable energy in the WCI region can potentially lead to reductions in greenhouse gas emissions.[2] Implementing a cap-and-trade program changes that dynamic because under a cap-and-trade program the amount of greenhouse gas emissions allowed in the region are pre-established by the cap level. As a result, decisions to purchase renewable energy – beyond what is cost-effective after imposition of a carbon price – free up emission allowances that would have been needed to generate electricity from fossil fuels, allowing other regulated entities to emit more than they could have otherwise. In essence, the voluntary purchase of renewable energy lessens the regulatory burden on greenhouse gas emitters. A large number of such VRE purchases has the potential to marginally decrease the cost of the program by eliminating the need for what may have otherwise been the most expensive[3] mitigation measure necessary to meet the cap. Therefore, in order for VRE purchases from facilities in the WCI region to deliver climate benefits beyond those achieved by the cap, those purchases must either lead to a reduction in the total number of allowances in the system or the emissions value of the allowances in the WCI system must be reduced.[4]

VRE consumers may be motivated to support renewable energy due to any one of various benefits renewable energy provides. These benefits include economic development ("green jobs"), reduced dependence on fossil fuels ("energy independence"), reduced use of nuclear

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[1] Western Climate Initiative, "Design Recommendations for the WCI Regional Cap-and-Trade Program", September 23, 2008.

[2] This assumes that those decisions happen in the context of a program structure that can guarantee incremental increases in renewable energy generation. Without a firm program structure the same generation mix may simply be allocated differently; zero-carbon electricity may get diverted to interested customers while the energy mix to indifferent customers may become slightly more carbon intensive as zero-emission sources are stripped out.

[3] And therefore likely the price setting mitigation measure.

[4] For example, starting in 2010 the SO_2 allowances, which were allocated in perpetuity by the Acid Rain program, are worth less than a ton under EPA's more recent Clean Air Interstate Rule in order to reduce emissions more rapidly than envisioned when the Acid Rain program was established.

power, and numerous environmental benefits, including reduced (or avoided) greenhouse gas emissions.[5] If it is believed that a significant proportion of consumers in the VRE market are largely motivated by the desire to reduce greenhouse gas emissions, and they are aware that the presence of a cap and trade system will undermine those emissions benefits, then those participants may either stop purchasing VRE products or direct their purchases to sources in uncapped areas. As a result, the VRE market in the WCI region may be significantly impacted by the introduction of cap-and-trade. The extent of impact on the VRE market is difficult to predict. Central to this question is the degree to which consumers are primarily motivated by the desire to reduce greenhouse gas emissions when they purchase VRE products. If VRE consumers do not strongly prioritize reducing greenhouse gas emissions, then it is possible that the introduction of a cap-and-trade program may not have much impact on the VRE market.

If there is a strong relationship between consumer expectations of greenhouse gas reductions and voluntary purchases of renewable energy, support of the VRE market through a policy mechanism may be necessary if there is a desire to support a robust VRE market. This paper focuses on the key issues in deciding whether the VRE market should be actively supported by jurisdictions in the WCI cap-and-trade program and if so, how a policy mechanism that supports the VRE market should be designed and implemented.

3 Current Status of the Voluntary Renewable Energy Market

The VRE market started when some utilities began offering green power programs to their customers. These programs enabled their customers to support the development of "green power"—wind and other renewable energy generation—by paying the incremental cost of renewable energy above the cost of the conventional generation sources the utility would otherwise build. The utility in turn used the revenue to purchase electricity from renewable generators or to build renewable resources of its own. The introduction of renewable energy credits (RECs) which allowed the renewable attributes to be sold separately from the power enabled other players besides utility customers to participate by allowing buyers to pay for renewable energy generated anywhere in the United States. Renewable developers and utilities could sell RECs to anyone who wanted to be able to claim that in principle, large percentages of their electricity came from green resources.

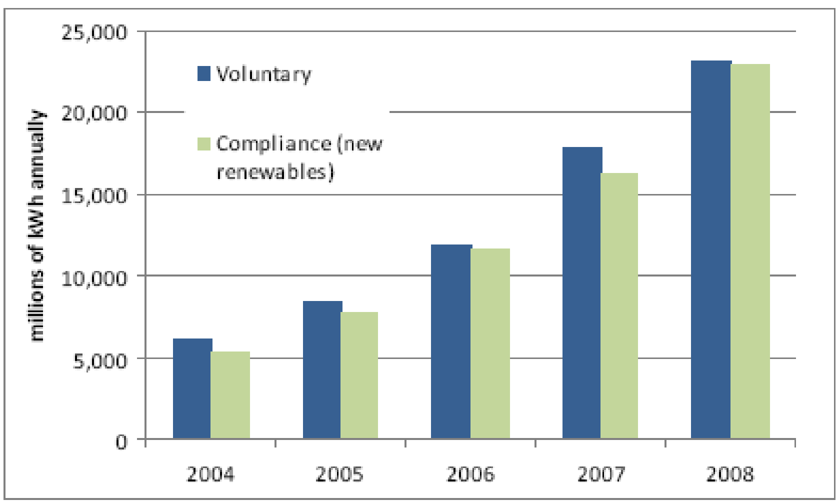
As climate change has become more salient as both a political and "values" issue, a voluntary carbon offset market has emerged in which carbon offset certificates denominating a unit of CO2 reduction are registered on an exchange (e.g. Chicago Climate Exchange) and issued by, among others, generators of renewable energy who can show that their increment of

[5] Another factor driving VRE purchase decisions is whether they are perceived as producing incremental growth to the renewable energy market. For purposes of this paper, it is assumed that the VRE market provides enough value to the renewable energy market to produce additional renewable capacity beyond business-as-usual levels.

renewable energy reduced greenhouse gases from the generation their energy replaced. In 2008, carbon offsets were sold from about 350 thousand Megawatt-hours (MWh) of electricity, a small fraction of the 25 million MWh VRE market.[6]

Today, green power programs are flourishing in the United States. More than 750 utilities offer them nationwide and 13 states mandate that their utilities offer them to customers, including Washington, Oregon, Montana, and New Mexico.[7] The average rate of participation in 2008 among eligible customers was 2.2% with the top ten programs reaching from 5% of customers up to a high of 21%. Actual energy sales amounted to almost 5 million MWh in regulated energy markets. In restructured markets, sales of green power tend to be in the form of RECs, which accounted for over 80% of VRE sales. Direct renewable energy sales in restructured markets and voluntary RECs combined amounted to almost 20 million MWh in 2008. Total VRE direct sales and RECs accounted for 0.7% of electricity sales nationally.[8] Residential customers dominated the markets for sales of energy while commercial customers dominated the REC markets, which have been growing much faster than the market for green energy products.

Figure 1: Comparison of Voluntary and Compliance Markets for Renewable Energy in the United States (Source: NREL)[1]



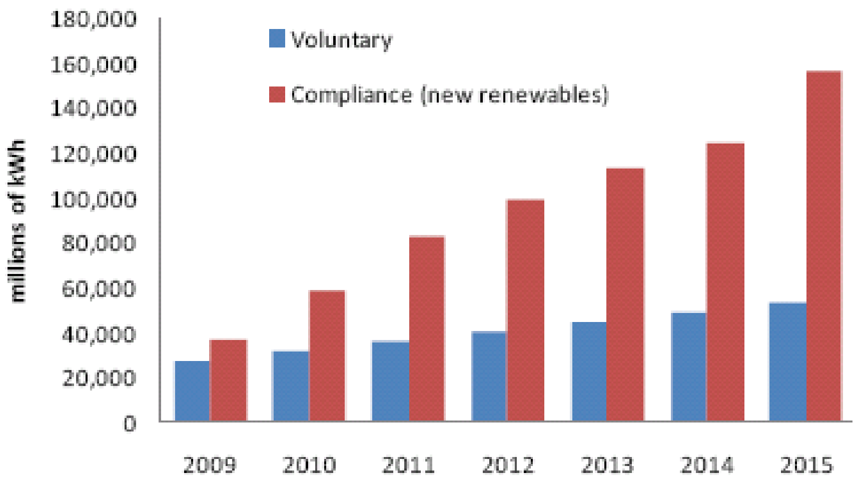
Note: Compliance market data sourced from Lawrence Berkeley National Laboratory (LBNL) (Barbose 2009)

Although green power programs have grown rapidly over the last ten years, renewable portfolio standards (RPS) in many states have served to drive a comparable amount of new renewable generation capacity (See Figure 1).

[6] Lori Bird, Claire Kreycik, and Barry Friedman, 2009. Green Power Marketing in the United States: A Status Report (11th Edition). National Renewable Energy Laboratory. http://www.nrel.gov/docs/fy09osti/44094.pdf
[7] See http://apps3.eere.energy.gov/greenpower/markets/state_policies.shtml.
[8] US. DOE/EIA, 2009. Electric Power Monthly – Retail Sales of Electricity to Ultimate Customers: Total by End-Use Sector. http://www.eia.doe.gov/cneaf/electricity/epm/table5_1.html

Twenty nine states plus the District of Columbia now have legislation requiring load serving entities to supply increasing percentages of their resource portfolios with renewable energy with targets ranging from 10-25% by the 2020s. It is projected that these amounts will soon overtake the voluntary market (See Figure 2).

Figure 2: Projected Voluntary Renewable Energy Market Relative to Compliance Market to 2015 in the United States (Source: NREL[1])



The voluntary market in Canada is relatively small compared to the US. A minority of provinces have utility green pricing programs or private green marketing programs. This reflects the fact that electricity generation already incorporates a large renewables component in most provinces. In addition, most provinces have adopted renewables procurement programs through government-owned utilities, with results similar to an RPS but without RECs, leaving limited opportunity for voluntary renewables. The degree of government ownership may also pose a barrier, in that private sector investment opportunities are limited in many provinces. Nonetheless a small number of retailers have been successful in establishing a voluntary market for renewable energy in some provinces. Voluntary renewables marketing has been most prevalent in the provinces with greater private ownership, including Ontario. The voluntary market for renewables in Canada today is estimated to be around 500,000 MWh/year[9].

4 Overview of VRE Support Policies under Cap-and-Trade

WCI Partner jurisdictions must decide whether to support the VRE market to ensure that it is not disadvantaged by the adoption of a cap-and-trade program or to put the burden on VRE

[9] Commission for Environmental Cooperation, *Fostering Electricity Markets in North America,* April 2007, http://www.cec.org/files/pdf/ECONOMY/Fostering-RE-MarketsinNA_en.pdf

market participants to ensure that some customers adapt to cap-and-trade programs. These two approaches are described and discussed in detail below.

4.1 Allowance Budget Adjustment Approach ("VRE Set Aside")

One possible policy response to support a VRE market would be to implement a VRE budget adjustment mechanism to allow the desired emission reductions to occur when VRE products are purchased from facilities subject to the cap. This is achieved by carving out a number of allowances from the Partner's base budget and setting those allowances aside to potentially be retired based on the estimated amount of voluntary renewable energy expected to either come on line in that Partner's state or province, or the amount of VRE products purchased by consumers in that state or province. Once the expected energy sales (in terms of MWhs) have been verified, allowances could be permanently retired. If there is a balance, those allowances could be released, or rolled over to the set aside for the following time period. The term used to describe this process is called an "off the top" approach to implementing this type of allowance budget adjustment to account for the sales of renewable energy in the VRE market.

Historically programs that reserve a portion of an overall budget of allowances for a certain purpose within a cap-and-trade system have been called a "set aside", referring to the fact that this portion of the allowances are reserved and literally set aside for the designated purpose. Once allowances are set aside they can be held, recycled for other uses, transferred, sold, or retired depending on how the program is designed. In the case of implementing a VRE budget adjustment mechanism for the purposes of ensuring that emission reductions accompany the VRE products in the marketplace, it is necessary that the allowances be retired, either immediately when the VRE products are consumed, or banked for future retirement at the appropriate time. Following this tradition, most of the literature on addressing the VRE market focuses on "VRE set asides" to describe the VRE budget adjustment mechanism described here. This paper will continue this tradition and refer to the policy option described in this section as a "VRE set aside". It is important to understand that the VRE set aside referred to in this paper is what is known as an "unallocated set aside" because the allowances are specifically intended to be retired (and not allocated to a programmatic use). Using the allowances set aside from the jurisdiction's overall budget for other purposes, such as selling them and using the revenue (except for any unused balance), would defeat the purpose of the VRE set aside program.

In order to implement a VRE set aside program market data and tracking systems can be used to estimate, track and verify voluntary renewable energy expected to come on line and enter the VRE marketplace. These estimates can assist WCI Partner jurisdictions in establishing the number of allowances to set aside for a given year. For example, the National Renewable

Energy Lab publishes a status report[10] that describes the status of the voluntary market in the US as compared to the compliance market. In addition, WCI Partner jurisdictions could also use data from their perspective energy agencies or organizations such as the Center for Resource Solutions[11]. The estimated generation should be verified before allowances are retired.

Verification of the estimated energy sales could be accomplished via tracking systems such as the Western Renewable Energy Generation Information System (WREGIS). WREGIS covers the Western Electricity Coordinating Council region (the western grid) and generates a REC for every MWh of renewable energy generation that is verified. In order to calculate the appropriate number of allowances, an emission factor is needed to represent the emissions of the electrical generation plant that would have operated if not for the additional renewable energy. The US EPA publishes these emission factors[12] for the US.

Table 2: Example of Voluntary Renewable Energy Set Aside Mechanism

Estimated VRE MWh sold in 2012	**Example Set Aside Emission Rate**	**Allowances in 2012 Reserve**	**Actual VRE MWh sold in 2012**	**2012 Allowances Retired by Jurisdiction**	**2012 Allowances Unused (and available for set aside in 2013)**
1,000,000	0.40 tCO2e	400,000	900,000	360,000	40,000

Table 2 provides an example of how a voluntary renewable energy set aside mechanism could work. Based on information provided by VRE vendors, the state or province estimates approximately 1,000,000 MWh of electricity (or a combination of direct energy sales and RECs) will be sold into the voluntary renewable energy market in 2012. The jurisdiction has determined that 0.40 metric tons CO_2e per MWh will be the emission rate used to retire allowances from the set aside for every MWh of voluntary renewable energy generated annually. Thus, the jurisdiction sets 400,000 allowances aside in the VRE reserve account. At the end of the year, the jurisdiction certifies that only 900,000 MWh of VRE were sold in 2012. In this case, only 360,000 allowances will be retired and the remainder is released or rolled over to 2013.

If a set aside is created for the VRE market, it may set an interesting precedent. Assuming that most VRE buyers are primarily motivated by a desire to reduce greenhouse gas emissions, the rationale for creating a VRE set aside could apply equally to other products and actions that reduce emissions. For example, many households and firms undertake measures to reduce their energy consumption. Without a set aside for energy efficiency, it could be argued that

[10] Lori Bird, Claire Kreycik, and Barry Friedman. Green Power Marketing in the United States: A Status Report (2008 Data). National Renewable Energy Laboratory; September 2009. http://www.nrel.gov/docs/fy09osti/46581.pdf
[11] Center for Resource Solutions; 2008 Green E Verification Report; http://www.green-e.org/docs/2008%20Green-e%20Verification%20Report.pdf
[12] http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html

some of these households and firms may no longer implement efficiency measures knowing that if they do, total greenhouse gas emissions will not change.

A counterargument to this example is that energy efficiency is generally cost-effective, and those who implement efficiency measures benefit from their actions. Purchasers of VRE products, on the other hand, pay a premium for the superior environmental attributes of renewable energy, in effect providing a public good at their own expense. This difference may justify the creation of a set aside for VRE but not energy efficiency. However, there are other examples where consumers pay a premium for environmental attributes that are not cost-effective. Presumably, purchasers of hybrid vehicles do so largely for the environmental advantages that such vehicles provide because in most cases, these vehicles only recoup their price premiums over long time horizons (if ever). If a VRE set aside is established, vendors of hybrid vehicles may also ask for a hybrid-vehicle set aside using similar logic.

For these reasons, WCI jurisdictions that choose to implement a VRE set aside may need to provide some rationale for limiting such a set aside mechanism only to VRE products. Otherwise additional set asides for different classes of products may require tracking the sales of a wide variety of products and leading to an unacceptably large pool of unallocated allowances dedicated to set asides. Alternatively, a broader-based set aside that accommodates all of the types of greenhouse gas reduction products or actions discussed above (including the VRE market) may be established by the jurisdiction.

4.2 No Intervention Approach

If it is believed that most participants in the VRE market are not motivated primarily by the desire to reduce greenhouse gas emissions in their jurisdiction or region, or that no public policy is served by VRE once a cap and trade program is implemented, then an argument can be made that the VRE market does not need policy support, and no intervention in the VRE market is necessary. Some buyers may value other environmental or socioeconomic benefits more than greenhouse gas reductions and would continue to buy VRE from jurisdictions participating in a cap-and-trade system even if greenhouse gas reductions are not ensured. Other buyers may be more concerned with their personal “carbon footprints” than with the impacts that their purchase decision have on total greenhouse gas emissions. This is because buying VRE still reduces the carbon footprint of the individual buyer even if total emissions (at the jurisdictional or regional level) do not fall[13]. In short, the VRE market may continue to be viable for a number of reasons regardless of whether total greenhouse gas emissions reductions can be guaranteed to take place when purchases of renewable energy occur.

[13] This assumes the purchase is from a jurisdiction participating in the cap-and-trade program.

If most purchasers of VRE are not primarily motivated by total greenhouse gas reductions implementation of a VRE set aside may pull more allowances out of circulation than is necessary to ensure the continued viability of the VRE market. If jurisdictions auction allowances as part of their cap-and-trade program, a VRE set aside may also reduce the volume of allowances auctioned, and therefore total auction revenue. These allowances could be used for other purposes, including using the value of those allowances for other types of support programs for renewable energy (e.g., increased funds for existing public purpose funds supporting renewable energy projects). Even if permits are allocated for free, rather than auctioned, a VRE set aside reduces total permitted emissions and thus may raise the permit price while limiting the opportunity for firms that reduce their emissions to sell excess credits and offset compliance costs.

If WCI jurisdictions decide not to implement VRE set asides, VRE certifiers face the option of either de-certifying renewable generators from eligibility in their programs or changing the way they market VRE from capped jurisdictions. For example, generators or marketers of VRE products can obtain and retire a sufficient number of emission allowances within the cap-and-trade system to provide the emissions reduction advertised or otherwise conveyed to the buyer of those renewable energy products. It would be up to each seller in the VRE market to decide whether or not they want to package a given amount of greenhouse gas emission reductions with their renewable energy products, and they would purchase the appropriate amount of allowances and bundle or retire them to meet that claim.

If there is concern that some sellers of VRE products may claim emission reductions for which they have no basis, government intervention in the form of a requirement to obtain allowances before making those claims may be an option. Since it is likely that the provisions for this type of government-backed guarantee would happen in a legal or regulatory framework outside of the cap-and-trade system (e.g., consumer fraud rules) this approach would likely not involve including a program element specific to the VRE market in the cap-and-trade program. Moreover, it may not be necessary for the government to take any action in order for such a guarantee to exist based on existing consumer protection law at the state or provincial level.

It is important to note that an approach of requiring that allowances be obtained (either explicitly or implicitly through existing law) for VRE products sold to consumers would increase the price premium for VRE products and disadvantage renewable facilities in capped jurisdictions that seek to compete in the VRE market. Even if not required it is possible that many VRE sellers would include allowances as part of their VRE offering. As a result, the VRE market in the WCI region would be impacted, although it is difficult to predict the extent to which the overall market would be reduced.

5 Status of VRE Approaches in Other Trading Schemes and Proposed Federal Legislation

The following existing or proposed cap-and-trade programs were reviewed to identify how they address the VRE market prior to the development of the recommendations in this paper.

- Regional Greenhouse Gas Initiative (RGGI), the greenhouse gas emissions cap-and-trade program currently in place in the Northeastern United States.
- European Union Emissions Trading Scheme.
- American Clean Energy and Security Act of 2009 (H.R.2454), commonly referred to as Waxman-Markey, which was passed by the U.S. House of Representatives.
- Kerry-Boxer, the U.S. Senate version of American Clean Energy and Security Act of 2009 that is still undergoing debate and revision in the US Senate as this paper is written.
- The proposed Australian Carbon Pollution Reduction Scheme.

Table 3 below summarizes how these proposals or programs address the VRE market:

Table 3: Summary of Treatment of Voluntary Renewable Energy in Cap-and-Trade Systems and Proposals

Cap-and-trade program or proposed legislation	Voluntary Renewable Energy Market Directly Addressed?	Policy Mechanism Used to Address VRE Market	Potential Indirect Means of Addressing VRE Market
US Regional			
Regional GHG Initiative (RGGI)	Yes	Set aside as optional element of RGGI Model Rule.	Not necessary
European Union			
EU Emissions Trading System (EU ETS)	No	None	Unclear
US National Legislation and Proposals			
American Clean Energy And Security Act of 2009 (Waxman-Markey)	No	None	Allowances are distributed to states for renewable energy. States may use those allowances to implement a program like a VRE set aside at a state-by-state level.
Kerry-Boxer (Senate version of ACES)	No	None	Still in development, presumably similar to Waxman-Markey
Australia National Legislation			
Carbon Pollution Reduction Scheme (proposed for 2011)	Yes	By taking GreenPower (official VRE program) purchases above 2009 levels into account when setting program's emission caps.	Not necessary

5.1 Overview of the Australian VRE Market Approach

Australia's proposed GHG emission trading scheme is referred to as the Carbon Pollution Reduction Scheme (CPRS). This trading scheme would potentially reduce emissions from approximately 5 to 25 percent of 2000 levels by 2020, depending on the status of international treaty negotiations on a new binding global emissions reduction treaty.

The framework contains a provision for tightening the cap to recognize the contribution of additional renewable energy purchases[14,15]. The scheme sets a baseline for renewable energy purchases at the 2009 levels and factors renewable energy into setting the cap. If purchases go over that baseline the cap will be adjusted to recognize these contributions. If purchases fall below the baseline there will not be an adjustment of the cap.

On August 13, 2009 the Australian Senate voted against the set of bills that were to establish the program. On December 2, 2009 a renegotiated set of bills failed to pass the Australian Senate again by a vote of 41-33, and the scheme's future is currently uncertain.

5.2 Overview of the RGGI Model of a VRE Set Aside

The RGGI Model Rule contains a provision for a VRE set aside program. In RGGI the number of allowances retired is pegged to the CO_2 emissions that would have been avoided in the absence of the cap. This is calculated using two types of data:

- The amount of voluntary renewable energy purchased (typically in megawatt-hours, or MWh); and,
- The emissions rate of the electric generating source that would have run had the renewable energy not been purchased (expressed in tons CO_2/MWh).

Because the number of allowances reserved for the set aside is based on ex ante estimates of VRE sales, it is possible that the number may be too high or too low in any given year. The Model Rule contains provisions to adjust the size of the VRE set aside in subsequent years accordingly.

These set aside provisions are an optional part of the RGGI Model Rule, and therefore participating jurisdictions are not obligated to adopt them. However, at this time 9 of the 10 RGGI states have adopted them.

[14] http://www.climatechange.gov.au/government/initiatives/cprs/voluntary-action.aspx
[15] http://whitepaper.climatechange.gov.au/emissionstrading/householdassistance/pubs/fs_GreenPower.pdf

6 Implementation of VRE Set Asides in WCI Jurisdictions

A key decision made by the WCI Partner jurisdictions in the "Design Recommendations for the WCI Regional Cap-and-Trade Program" is that each jurisdiction has discretion over how the allowances apportioned to that jurisdiction are to be used. Other than agreeing that "some portion" of the apportioned allowances will be used for purposes like supporting renewable energy, which a VRE set aside would fit under, there is currently no common agreement among the Partner jurisdictions to require a VRE set aside in the design of each jurisdiction's cap and trade program. In keeping with the WCI design recommendations, it is therefore up to each individual WCI jurisdiction whether or not to implement a VRE set aside program in their jurisdiction. For those jurisdictions that do choose to put in place a VRE set aside program there are a number of design issues associated with implementing a VRE set aside program. The remainder of this paper focuses on those key design issues that will need to be examined by any of the WCI jurisdictions that choose to implement a VRE set aside program.

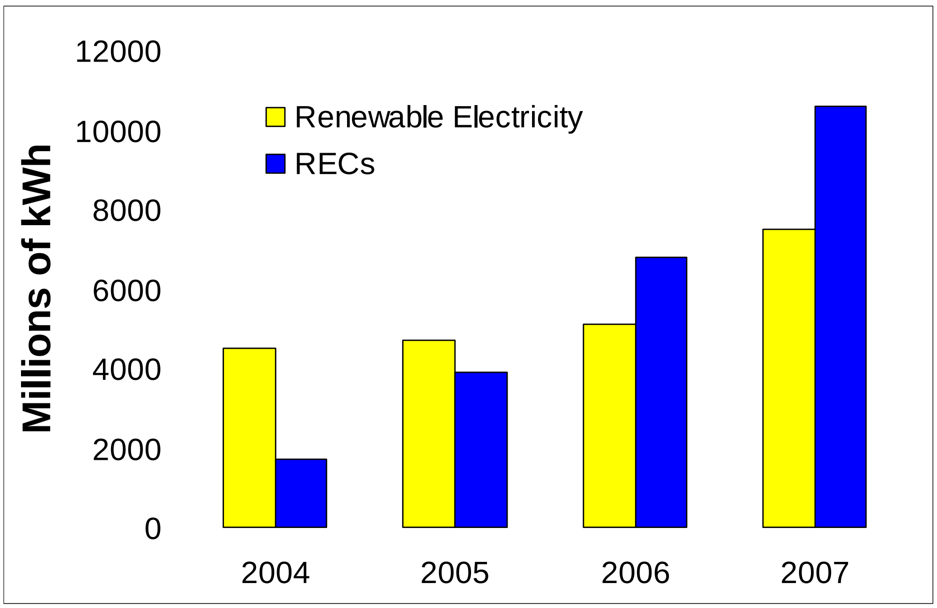
An important consideration in examining the design elements of a VRE set aside program is the extent to which certain elements need to be harmonized across participating jurisdictions. In other words, for each of the design elements examined below can each jurisdiction make its own policy choice without impacting the effectiveness of a VRE set aside program in either another WCI jurisdiction or the WCI region as a whole? Particular attention to this question is given as each design issue is addressed below. For comparison, the approach that RGGI took for each of these points of implementation is also summarized. Finally, a draft recommendation to WCI Partner jurisdictions for each design question is given.

6.1 Accounting Mechanism for the VRE Set Aside

There are two broad classes of products in the voluntary renewable electricity market: renewable electricity and renewable energy credits (RECs). RECs are the renewable attributes created by the generation of electricity from a renewable source and serve as proof of generation of (typically) one MWh of renewable energy generation. They can be sold bundled with the electricity underlying the REC or unbundled and bought and sold independently of the electricity produced. Unbundled RECs are often re-bundled with generic electricity to rebrand the generic electricity as green electricity. RECs may be defined solely by their primary attribute (i.e., that a MWh of renewable electricity was generated) or they may include reference to secondary attributes such as the greenhouse gas emissions avoided by displacing conventional generation. The inclusion of secondary attributes varies across states with respect to RECs used for compliance with renewable portfolio standards, but RECs used in the secondary market generally include reference to the secondary attributes.

When implementing a VRE set aside program, a decision has to be made as to what "currency" the program should use. One option is to base the program on actual renewable energy sales, and typically the basis for measuring VRE transactions are documents such as the sales receipt, sales contract, or other similar proof of the transaction. Another option is to use RECs as the currency to serve as the proof of renewable generation. This is convenient since the primary purpose of a REC is to serve as an easily transferable and trackable proxy for other legal documents (such as sales contracts) which provide the legal basis for ownership of the renewable energy in the voluntary renewable energy market. For this reason, renewable energy programs of all types (voluntary and mandatory) are increasingly using RECs.

Figure 3: Estimated Annual Green Power Sales 2004-2007[16,17]



RGGI Model Rule

The RGGI Model Rule only retires allowances for purchases of renewable electricity[18], and therefore does not accommodate sales of unbundled RECs. According to the National Renewable Energy Laboratory[19], about 95 percent of residential consumers purchased renewable electricity (typically through green power utility programs) instead of unbundled RECs in 2007. However, nonresidential customers clearly prefer unbundled RECs, which amount to over 90 percent of sales for these customers. This suggests that while the RGGI model is responsive to residential consumer demand, it does not match the purchase decisions

[16] Ibid.
[17] 2006 sale figures for renewable electricity may be underestimated because of data gaps (Ibid).
[18] Note that this means both renewable electricity purchased directly and bundled RECs (REC + electricity).
[19] Lori Bird, Claire Kreycik, and Barry Friedman. Green Power Marketing in the United States: A Status Report (11th Edition). National Renewable Energy Laboratory. http://www.nrel.gov/docs/fy09osti/44094.pdf

of nonresidential consumers. This is notable because REC sales (99% of which are to nonresidential consumers) account for nearly three-quarters of all voluntary renewable product sales in 2007. Therefore, the RGGI model may not be optimal for stimulating new renewable development.

Draft Recommendation

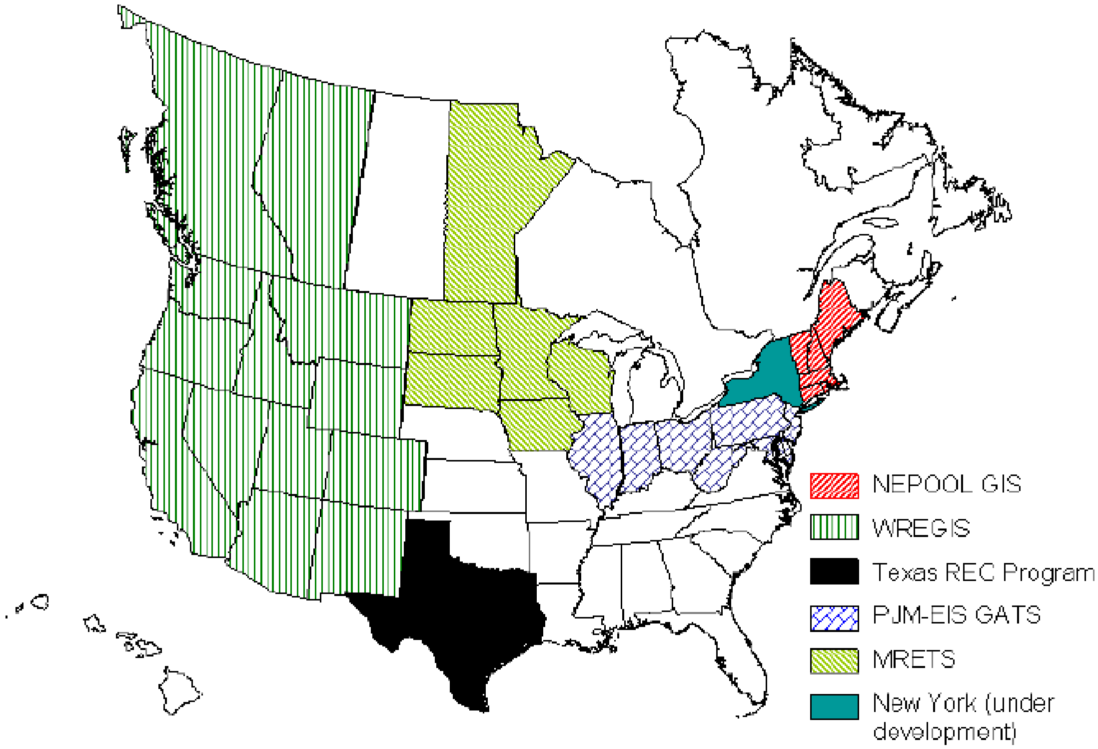
> *WCI Partner jurisdictions that choose to implement a VRE set aside should include a requirement that the measurement of voluntary renewable energy purchases that form the basis of any allowance distribution be based, first and foremost, on transactions verified through established REC tracking systems that span some or all of the WCI region (e.g., WREGIS). In addition, to account for those purchases that are not tracked through an established system (or for regions without such a system) provision should be made to accept transactions that are certified through a third-party verification system for voluntary renewable energy that includes, at a minimum, a requirement that the seller must attest to not having previously sold or otherwise transferred the greenhouse gas benefits of the renewable energy product.*

The decision as to whether to use RECs or the renewable electricity (i.e., using contracts as the proof of generation) as the principal mechanism for tracking the quantity of VRE applicable to the set aside is one design feature where harmonization across WCI jurisdictions is critical. Non-harmonization raises the potential for double-counting the renewable attribute because one jurisdiction may retire allowances for the electricity generated while another retires allowances for the RECs purchased for the same electricity. Harmonization ensures that each MWh of renewable energy in the voluntary market is claimed only once by a final user.

6.2 Defining Eligible Renewable Energy Project Types

WCI jurisdictions will need to decide which types of voluntary renewable energy projects should be encouraged through a VRE set aside. Establishing common criteria is challenging as jurisdictional RPS criteria vary, suggesting disparity about the types of renewable energy that each region wants to encourage.   Requiring that renewable projects meet RPS criteria where applicable may provide additional assurance that allowances are only retired for desired projects so long as those RECs can be retired in a regional tracking system (see Figure 4).

Figure 4 -- Map of Regional Tracking Systems (Source: NREL)[20]



In addition, VRE certifying organizations (typically independent non-profit organizations or government agencies) have their own eligibility criteria that they are likely to overlay on any state or jurisdictional eligibility criteria.[21,22] In both cases, the eligibility criteria are likely to address not only the types of eligible renewable energy, but also provide some assurances that the renewable projects used for voluntary program purposes are authentic and also meet additional criteria which consumers may find desirable. For example, both the Canadian EcoLogo and the Green-E certification program for VRE certify that the projects that meet their requirements are "additional", i.e., that those projects were not required by government mandate and that the VRE purchase is helping to advance the renewable energy market above and beyond what would be happening without the purchase.

One issue worth noting, which is an ongoing concern with tracking and verification systems used in both the mandatory and voluntary renewable energy markets, is some of the market barriers that small-scale "behind the meter" renewable energy systems (typically residential

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[20] Lori Bird and Elizabeth Lokey. Interaction of Compliance and Voluntary Renewable Energy Markets. National Renewable Energy Laboratory. October 2007. http://apps3.eere.energy.gov/greenpower/pdfs/42096.pdf

[21] Green-e certification criteria can be found at http://www.green-e.org/docs/energy/Appendix%20D_Green-e%20Energy%20National%20Standard.pdf

[22] An example of this can be found in Green-e's RGGI update http://www.resource-solutions.org/pressreleases/2008/120508-2.htm.

solar photovoltaic systems) have encountered in entering the VRE marketplace. In some cases the additional administrative costs or process issues associated with either (or both) the REC tracking systems used for the mandatory renewable market or the certification programs in the voluntary market have prevented the owners of these installations from becoming VRE market participants. If the VRE set aside policy option is focused solely on addressing the traditional VRE market, which is focused on VRE products, than the VRE set aside option may not be of direct assistance to all entities that voluntarily produce renewable energy. Nonetheless, the decisions to install these smaller systems may be driven by similar motivations as in the VRE product market (i.e., ghg emission reductions). Therefore it may be worth including behind the meter distributed resources, such as residential systems, in the list of eligible resources for the VRE set aside to further encourage their growth. Since these systems are generally not registered with generation information systems like WREGIS and may not be configured to report output data at all, quantifying these systems for inclusion in the VRE set aside can be a challenge. WCI Partner jurisdictions that include small-scale solar or wind systems among their VRE set aside eligible resources will have to determine whether to limit eligibility to systems with metered output or whether to accept generation estimates for unmetered systems.

RGGI Model Rule

The RGGI Model Rule limits eligibility for retirement from the VRE set aside to electricity generated from biomass, wind, solar thermal, photovoltaic, geothermal, hydroelectric facilities certified by the Low Impact Hydropower Institute, wave and tidal action, and fuel cells powered by renewable fuels. However, this particular definition was intended to be optional. Several states have adopted it, while others have limited eligibility to renewables that meet their own RPS standards.

Draft Recommendation

> *WCI Partner jurisdictions that choose to implement a VRE set aside should define their own eligibility requirements for their VRE set aside programs. They may choose to mirror existing RPS or other statutory definitions or to define a separate list of qualifying project types.*

Unlike the choice of accounting mechanism, jurisdictional consistency on eligibility criteria is less important. Marketers of VRE products will adapt to whatever eligibility criteria jurisdictions adopt. If a facility is eligible for set aside retirements, marketers will know that emission reduction claims are supported and can market energy or RECs from the facility accordingly. A modest advantage to harmonization is that potential project developers would not have to keep track of eleven different sets of eligibility criteria when financing and developing projects in WCI jurisdictions.

6.3 Jurisdictional Retirement Responsibility

Another variable to consider when designing a VRE set aside is whether the jurisdiction responsible for retiring allowances is determined by the location of the purchaser or the generator. For example, when a renewable facility in a WCI jurisdiction produces RECs that are used in the VRE market and then retired by an entity in another WCI jurisdiction, which jurisdiction bears the responsibility for retiring allowances? Either approach is feasible, but the underlying rationale and effect differ. The purchaser-based approach serves to assure consumers in the jurisdiction where the VRE set aside is based that emission reductions occur regardless of the location of the renewable electricity facility. The generator-based approach supports renewable energy development in the jurisdiction where the VRE set aside is based by allowing emission reduction claims in the marketing of the VRE product to customers.

RGGI Model Rule

The RGGI Model Rule uses a purchaser-based responsibility in which each state retires allowances for VRE purchases occurring in the state. The RGGI Model Rule provides for the retirement of allowances for in-state sales regardless of where the REC is generated. Because these RECs may come from uncapped states, the RGGI Model Rule may be retiring too many allowances for in-region purchases. However, some RGGI states have adopted VRE set aside provisions that only retire allowances for in-region generation, which avoids this problem.[23]

6.3.1 Purchaser-Based Responsibility

Under the purchaser-based approach, a WCI jurisdiction retires allowances whenever a retail customer, utility, or VRE aggregator serving customers in the jurisdiction retires RECs[24] from the VRE market from a facility in a capped jurisdiction. The application of the set aside could be limited by various geographic criteria. If the goal is to both protect in-jurisdiction consumers and promote renewable development in the jurisdiction, the set aside could be limited to purchases from in-jurisdiction generators. If adoption of the set asides is widespread in the WCI, Partner jurisdictions may opt to apply the set aside to purchases from sources in any WCI jurisdiction. Alternatively, this reciprocity could extend further to apply the set aside to purchases from any capped source (assuming that the capped source selling RECs in the VRE market is not already supported by a generator-based set aside).

[23] RGGI State Set-Aside Provisions for Voluntary Renewable Energy (VRE). Draft October 25, 2008. Ed Holt & Associates, Inc. http://www.epa.gov/greenpower/documents/events/rggi_status_table.pdf

[24] Or otherwise documents a VRE purchase if the accounting mechanism is not based on RECs.

This system is relatively simple where there is a direct connection between the in-jurisdiction person or entity retiring the RECs (or purchasing the electricity) and the facility. However, the fact that some VRE products consist of RECs purchased from a large number of facilities by VRE marketers complicates matters. If, for example, a REC retailer buys 5,000 RECs from capped jurisdictions and 5,000 RECs from uncapped jurisdictions, and then sells 5,000 RECs to customers in uncapped jurisdictions and 5,000 RECs to customers in a capped jurisdiction with a purchaser-based set aside, how many RECs should the set aside jurisdiction count when it retires allowances?

One option would be to assume that all customers receive the same share of RECs from each facility, that is, that all of the RECs are thoroughly mixed and then sold to customers. If the set aside jurisdiction assumes that all customers receive the same mix of renewables, then the jurisdiction would apply 2,500 RECs toward its set aside on the basis that half of the 5,000 RECs used by customers in the jurisdiction came from capped areas and half came from uncapped areas. However, that would entail that 2,500 RECs from a capped area were sold to customers in uncapped jurisdictions, necessitating that those RECs could not be associated with claims of emission reductions.

Another option would be to allow REC marketers to specify the renewable generators used to supply RECs to their various customers. Under this approach, REC marketers in a purchaser-based model are likely to direct the maximum amount of RECs from capped areas to those jurisdictions that implement a set aside to ensure that no RECs are left without credible emission reduction claims.

The participation of large organizations with locations in multiple jurisdictions may add further complication to accounting under the purchaser-based approach. For example, if the headquarters of a large corporation is located in a set aside jurisdiction, and the headquarters coordinates the purchase of several hundred thousand RECs for its facilities throughout North America, a VRE marketer might report all of those RECs as being consumed in the set aside jurisdiction. If the jurisdiction does not believe that it should have responsibility for retiring allowances for all of the RECs in this example, either the marketer or the customer could provide information on the customer organization's consumption within the jurisdiction.

If the rationale for the set aside is to protect consumers in WCI jurisdictions, WCI VRE consumers could simply buy RECs from uncapped jurisdictions. However, to the extent that demand for VRE is driven by customers primarily motivated by contributing to absolute GHG reductions, this "no action" solution to protecting consumers will push investment in renewable facilities serving the voluntary market toward uncapped jurisdictions. Purchaser-based retirement responsibility would not cover sales of RECs from facilities in the jurisdiction to VRE consumers in uncapped areas or capped areas without a set aside.

Because the RGGI Model Rule provisions do not retire allowances for exported renewable products, renewable energy generated inside the RGGI region will not have an emissions benefit when sold outside the RGGI region unless allowances are purchased and retired by the renewable energy marketers. This has led Green-e to announce that they are no longer certifying renewable energy generated inside the RGGI region and sold outside the RGGI region.[25] It is not clear whether this will have practical implications for the RGGI states in the short-term. High REC prices inside several RGGI states indicate that in-region supply of certain types of renewables is already struggling to meet demand. This may be an indicator that the RGGI states are not currently strongly situated as net exporters of renewable energy products.

Purchase and generation data for WCI partner states available from Green-e and the National Renewable Energy Laboratory suggest that WCI Partner US States on the whole appear to generate more renewable products for sale on the voluntary market than they purchase from it, meaning that they are a net exporter of voluntary renewable energy products. Constraining retirement to in-region purchases could disrupt the market for renewable generation in WCI Partner jurisdictions.

Unfortunately, comparable data does not appear to be available for the Canadian WCI Partner jurisdictions, making it challenging to determine whether constraining retirement to in-region purchases would disrupt the market for renewable generation.

6.3.2 Generator-Based Responsibility

Under the generator-based approach to retirement responsibility, a WCI jurisdiction would retire allowances whenever RECs from a facility in its territory were retired by customers in the voluntary market. Like the purchaser-based approach, the set aside could be limited to purchases by customers in the same jurisdiction, other WCI jurisdictions, other capped jurisdictions, or to apply regardless of the customer's location. One advantage to a generator-based approach with no limitation on the customer's location is that it enables renewable generators in the jurisdictions to be certified for the VRE market without any further need to track where VRE sales ultimately occur (i.e., where RECs are retired). If set aside jurisdictions impose a geographic limitation, then generators participating in the VRE market risk having some portion of their output being decertified (or marketed as a different "no avoided emissions" product) based on the purchaser's location. All other options introduce an additional complication of having to track either where the RECs used in each jurisdiction were generated or where the purchasers of RECs from generators in each jurisdiction are located[26].

[25] Green-e Energy Policy Update: RGGI State Set-Aside Provisions for Voluntary Renewable Energy Sales and Green-e Energy Eligibility. Green-e. December 5, 2008. http://www.resource-solutions.org/where/pressreleases/2008/120508-2.htm

[26] Or where the renewable energy is generated if the accounting system for the VRE set aside is not based on RECs.

Renewables from uncapped regions do not require allowance retirement because their generation does avoid additional fossil-based electric generation. Renewables from other capped regions present the same issue as RECs from within the capped WCI region. The only other capped region at this time is RGGI, which does not contain provisions to retire allowances for exports of renewables outside the RGGI region (i.e., to the WCI). However, given the current supply and demand balance in North America, failure to retire allowance for REC imports from the RGGI region may not have any practical implications for WCI. Voluntary renewable products imported from the Midwestern Greenhouse Gas Reduction Accord (Midwestern Accord) region[27] could be made whole through allowance retirement by the Midwestern Accord or the WCI. The question that remains is who should bear the financial costs of allowance retirement. Exporting states may wish to do so in order to encourage new renewable development within their borders, while importing states may wish to do so in order to encourage renewable development outside their borders in effort to make these products more affordable to their citizens.

Table 4: Comparison of Options for Geographic Treatment of Voluntary Renewable Energy

Limitation→ ↓ Responsibility	Purchased from/sold to own jurisdiction	Purchased from/sold to any WCI jurisdiction	Purchased from/sold to any capped jurisdiction	Purchased from/sold to any jurisdiction
Purchaser-Based	Equivalent to gen-based, need to account for number of RECs from in-jurisdiction sources	Need to account for number of RECs used from in-WCI sources	Need to account for number of RECs used from all capped (e.g. RGGI) sources	N/A (no need to have purchaser-based version because purchases from uncapped jurisdictions do not need set aside)
Generator-Based	Equivalent to purchaser-based, need to track where RECs are retired	Need to track where RECs are retired	Expands application to sales to entities in other capped jurisdiction such as RGGI or Midwestern Accord jurisdictions, need to track where RECs are retired	Generators receive one certification, good for sales to all jurisdictions, no need to track where RECs retired

6.3.3 Implications of Geographic Treatment Options

The options for treatment of VRE products are summarized above in Table 4. In short, in-region renewable development may be maximized under a purchase approach by retiring allowances only for renewable energy generated in the region, and under a generator approach by retiring

[27] Assuming the Midwestern Accord results in an active cap-and-trade regime.

allowances for all renewable generation including exports. Retirement for out-of-region generation is only necessary when renewables are located in a capped state, and then the question is which program should bear the responsibility for the retirement.

Draft Recommendation

> *WCI Partner jurisdictions that choose to implement a VRE set aside should retire allowances using a generator-based approach in which allowances are retired whenever RECs from a facility in that Partner jurisdiction's territory are purchased and retired by a customer in the VRE market with no limitation on the customer's location. Alternatively, the retirement should be based on VRE sales if RECs are not used.*

Harmonization on the jurisdictional responsibility is essential to avoid introducing considerable and unnecessary confusion into the VRE market. Consider two WCI states, one with a purchaser-based set aside (State A) and the other with a generator-based set aside (State B). If RECs from a generator in State B are retired by an entity in State A, then both states would retire allowances for the same MWhs. If RECs from a generator in State A are retired by an entity in State B, then neither state would retire allowances.

This draft recommendation has some interesting implications for both the WCI and RGGI. There is considerable variation among the RGGI states in how they treat voluntary purchases of renewable energy generated outside their borders. While some states only retire allowances for renewable energy generated within the RGGI states, others do not constrain geographic scope in this manner. The RGGI voluntary renewable energy program is purchaser-based. Therefore, no RGGI state retires allowances to account for in-state renewable generation that meets out of state voluntary renewable energy demand. As a result, the RGGI rule does not contemplate a scenario under which allowances have already been retired to account for renewable energy sold into the voluntary market. Therefore, it is not clear whether those states would retire allowances for WCI-based renewable energy sold into the RGGI market if a WCI jurisdiction has already retired allowances to account for that electricity. While there is an environmental benefit to retiring more allowances than is warranted for an individual purchase of voluntary renewable energy, the RGGI and WCI jurisdictions have a financial interest in not retiring more allowances than is warranted. Therefore, it could be advantageous for any WCI jurisdictions that plan on adopting a generation-based VRE program to work with the RGGI states that retire allowances for generation outside the RGGI region to collaboratively determine an appropriate path forward.

6.4 Retirement Limits

Because establishing a VRE set aside involves removing allowances that could be used for other purposes, such as funding energy efficiency or R&D, jurisdictions may wish to limit the amount of allowances placed in the VRE reserve. In addition, jurisdictions may consider limiting the number of compliance periods the program will remain in effect.

6.4.1 Upper Limit on Retirement Amount

As described in Section 4.1, a key component to establishing a VRE set aside is determining the total allowances that would be dedicated for retirement to support the VRE market. However, the need to access allowances for compliance purposes may lead covered entities to resist dedicating a large number of allowances to support one sector of the economy. For that reason WCI Partner jurisdictions may choose to limit the amount of allowances that are dedicated to supporting the VRE market.

Given the regional strength as an exporter of voluntary renewable products, if the WCI adopts VRE set aside provisions that acknowledge out-of-region purchases of in-region renewable generation, then a larger set aside might be appropriate (as a fraction of electricity emissions). However, it is important to note that WCI is an economy-wide program and therefore its base budget is much larger than electric sector emissions. This means that more VRE sales can be supported with 1% of the budget from the economy-wide WCI program than 1% of the budget from the RGGI program, which only covers the electric sector.

Establishing limits does provide planning certainty to regulated entities. However, while short-term predictions may be reasonably accurate, uncertainty increases substantially the further out in time predictions are made. Some RGGI states have dealt with this by establishing provisions that allow them to increase the size of the set aside over time. Rather than exclude some VRE transactions from set aside eligibility after the fact, a jurisdiction that does reach the retirement limit in a given year could borrow some allowances from a future period or avoid borrowing by pro-rating the reductions by lowering the per MWh rate at which allowances are retired. This would give the jurisdiction time to re-evaluate the retirement limits and avoid having some transactions disqualified from the set aside eligibility assumed by parties at the time those transactions were arranged. If a jurisdiction has hit its limit for several years and compensated by adjusting the de facto retirement rate downward, it is possible that VRE certifiers may respond by decertifying facilities located in or serving customers in that jurisdiction.

RGGI Model Rule

The VRE set aside provisions in the RGGI Model Rule provide for states to retire enough allowances to make all voluntary renewable energy purchases whole. However, all nine states that have adopted a VRE set aside have limited the total number of allowances that may be retired to around 1% to 2% of the state allowance budget. Most states adopted these limits expecting that this limit would be adequate to satisfy demand for the next several years.

Draft Recommendation

> *WCI Partner jurisdictions that choose to implement a VRE set aside should choose whatever upper limit (if any) that is found appropriate for that jurisdiction. Partner jurisdictions must determine if they will cover shortfalls by either borrowing allowances from a future year or lowering the per MWh retirement rate.*

It is not important for jurisdictions to harmonize on the issue of limits to allowances in the set aside. Because there is significant disparity in member jurisdictions' renewable capacity, then if retirement limits are pursued, each jurisdiction may wish to calculate its own.

6.4.2 Time Limit on VRE Set Aside Program

In determining whether or not a set aside is necessary, consideration may be given to how long a set aside for this purpose should be available. Stakeholders have expressed concern that a cap-and-trade program could dampen the dramatic increase in VRE sales in recent years. A justification for a set aside could be to initially provide a bridge for this market while they adjust their promotion message to reflect an economy that is now factoring in the cost of carbon. As technology improves, the cost of renewable energy goes down and allowance price stabilizes, Partners may want to be able to adjust a program accordingly.

If the price premium is the justification for a VRE set aside (or any other set aside), then it will face a problem in the longer-term. Cap and trade programs work by putting a price on the right to emit GHGs, thereby incentivizing conservation, efficiency, and alternative sources of energy. As a price signal propagates through the economy, additional investments in energy efficiency and alternative energy become cost-effective. Thus, over time there is greater prevalence of low-carbon investments and purchases because such decisions are economically beneficial, as well as environmentally beneficial. If the price of allowances is low and/or renewable energy technology has not progressed enough to make renewable energy cost-competitive, a VRE set aside could be justified to encourage those willing to pay a premium to cover the spread between conventional and renewable energy. But what happens when renewable energy technology advances and rising allowance prices make renewable energy cost-competitive? In other words, if the rationale used to justify a VRE set aside is that VRE consumers are willing to pay a premium to provide a public good, what happens when a premium is no longer needed?

If the public goods aspect of the VRE market serves as the primary justification of a set aside, then WCI jurisdictions that choose to implement them should consider making them contingent on a continued price premium for the technologies supported by the set aside. The set aside program should be re-evaluated periodically to determine whether the technologies supported by the set aside have attained price parity with conventional alternatives. Presumably, with the combination of rising costs for fossil fuels (as a result of the cap and trade price signal) and technological progress many sources of renewable energy will be cost-competitive in the next ten to fifteen years. As renewable technologies become cost-competitive, they would be removed from the list of eligible sources.

<u>RGGI Model Rule</u>

At present, there is no time limit on the VRE set aside program in any RGGI jurisdiction.

Draft Recommendation

> *WCI Partner jurisdictions that choose to implement a VRE set aside should choose whatever time limit (if any) that is found appropriate for that jurisdiction. Partner jurisdictions may choose to base time limits on periodic reviews of the cost-competitiveness of the technologies supported by the set aside program.*

This is not an area where harmonization among WCI jurisdictions is important.

6.5 Attributing Emissions to Voluntary Renewable Energy Purchases

A central feature of designing a VRE set aside is determining the rate at which allowances will be retired for every MWh of verified eligible VRE. If the goal of the VRE set aside is to preserve the right to make legitimate emission reduction claims comparable to the claims that could be made before implementation of a cap, that suggests basing the allowance retirement rate on the emissions that would have been avoided by VRE facilities in the absence of a cap. However, estimating the emissions avoided by renewable electricity requires a complex analysis of the resources serving the grid region where the facility is located.

Power from many generating units is dispatched to meet fluctuating demand, and the impact of a given renewable energy facility could cause any of a number of operating plants to curtail its generation, prevent a different plant from generating at all or some combination of the two. This effect is referred to as the “operating margin.” In the longer term, investment in renewable energy capacity could displace the construction of a new fossil-fired plant altogether. This effect is referred to as the "build margin."[28] With interconnected electricity markets, the problem becomes even more complex. A VRE purchase in one jurisdiction from another may then cause the second jurisdiction to import less fossil-fired generation from a third jurisdiction.

Since the exact units affected by the output from a renewable energy facility cannot be known at every moment, estimated avoided emissions rates are necessary. One method of estimating the emissions rate is to use the average emissions rate for the jurisdiction in which the VRE purchase is made or the jurisdiction where the renewable energy was generated. This calculation is straightforward, but it is unlikely to be very accurate.[29] Marginal emission factors better reflect the generation sources displaced by output from renewable energy facilities. Use of an emission factor for the region where the electricity was generated would be consistent with the generator-based responsibility recommended in section 6.3.

One option may be to use the Default Emissions Factor Calculator that the WCI Electricity Team is currently developing for the purpose of attributing emissions to electricity imported into the WCI region. The Calculator is designed to calculate marginal emission factors based on operating margins

RGGI Model Rule

The RGGI Model Rule defines the benefit of a voluntary renewable energy purchase as the marginal CO_2 emissions rate (lbs CO_2/MWh) in the control area where the generation occurred. However, if the data necessary to determine the marginal emissions rate is unavailable, then the average emissions rate should be used.

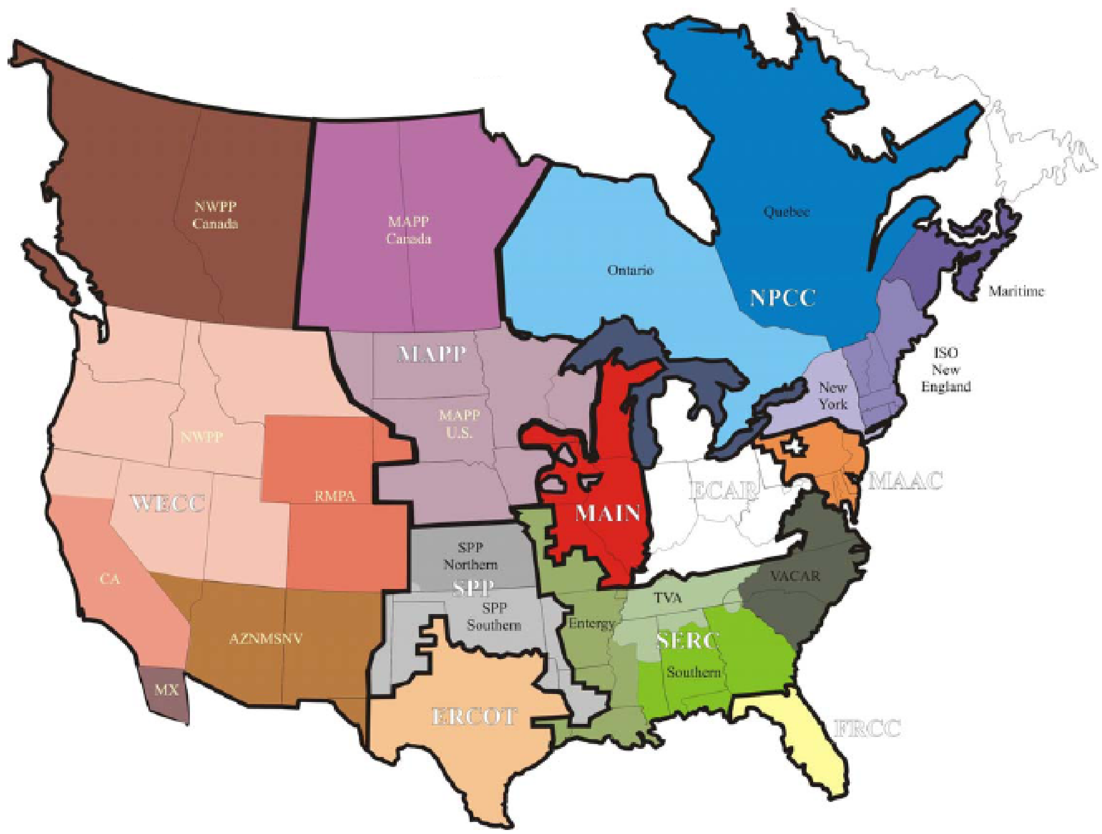
The RGGI Model Rule simply refers to a "control area." The interconnection of electric grids seems to make state and provincial borders less relevant than NERC regions (e.g., WECC) and NERC sub-regions (e.g., AZNMSNV) (See Figure 5). If allowance retirement is tied to use of renewable energy products, then a broader region may be desirable as RECs are likely to come from sub-regions different than where they are "used." However, if allowance retirement is tied to generation, than smaller sub-regions may be useful. At this time, it is not yet clear whether marginal emissions rates are calculated for each NERC region and sub-region.

Several of the RGGI states intend to use the marginal emissions rate calculated by their NERC Sub-region, ISO New England (ISO-NE). ISO New England (ISO-NE) began calculating marginal

[28] Derik Broekhoff, 2007. *Guidelines for Quantifying GHG Reductions from Grid-Connected Electricity Projects.* World Resources Institute/World Business Council for Sustainable Development. http://www.wri.org/publication/guidelines-quantifying-ghg-reductions-grid-connected-electricity-projects
[29] Ibid.

emissions rates in 1994 in order to analyze the impact of Demand Side Management programs. This analysis continues today, though the methodology has changed over time. Currently, ISO-NE calculates the marginal emissions rate using the actual hourly generation and monthly air emissions rate[30] of marginal fossil units, which are defined as all units whose primary fuel is oil or natural gas.

Figure 5: NERC Regions and Sub-Regions (Source: NERC)



Previously, the ISO-NE marginal emissions rate was based on the emissions rate of units that would have run had demand been higher. This employed a production simulation model developed to replicate system operations for the previous year. The marginal emissions rate was calculated as the difference between modeled historical emissions and modeled emissions when load was 500 MW higher in each hour. According to the 2006 Marginal Emissions Rate Analysis, ISO-NE moved away from the production simulation model because "the reference case never exactly matched the previous year's unit level energy production because of

[30] The emission rates are mainly based on actual emissions reported in the EPA Clean Air Markets database, along with some data from the NEPOOL Generation Information System (GIS), and some rates from EPA's eGRID.

numerous modeling reasons including market dynamics, specific outages and deratings." [31] Additional communications with ISO-NE indicate that prior to switching methods, a comparison of the two methods was performed and yielded "very similar" results, and therefore, they decided to go with the "more straightforward" approach of evaluating actual emissions from oil and gas fired units.[32]

Draft Recommendation

> *WCI Partner jurisdictions that choose to implement a VRE set aside should work together to develop a rate based on a marginal dispatch analysis, such as the WCI Default Emission Factor Calculator, for each major grid region. However, use of this rate should be optional and specific assignment of emissions left to jurisdictional discretion.*

Harmonization on the allowance retirement rate is not essential, and in the current market, avoided emissions rates are either not quantified or vary by location. It may be desirable, however, to use one rate across the WCI region to simplify transactions in the VRE market.

7 Stakeholder Involvement and Next Steps

The WCI Partner jurisdictions invite stakeholders to provide written comments on the discussion and analysis in this paper. We encourage stakeholders to structure their comments around the draft recommendations (summarized in Table 1 at the beginning of this paper) for those WCI Partner jurisdictions that do choose to implement a VRE budget adjustment program (VRE set aside) as part of their cap-and-trade program.

We invite stakeholders to discuss with us and provide their comments during the WCI Electricity Collaborative on January 21, 2010 in Phoenix, AZ. Details on the collaborative and stakeholder participation options will be distributed via the WCI list serve and posted on the Western Climate Initiative website (www.westernclimateinitiative.org).

Written comments on this paper can be submitted via the Western Climate Initiative website until February 19, 2010.

A paper with final recommendations which incorporates stakeholder comments on this paper will be produced and posted after the comment period closes.

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[31] 2006 New England Marginal Emission Rate Analysis. ISO New England. September 2008. http://www.iso-ne.com/genrtion_resrcs/reports/emission/2006_mea_report.pdf
[32] Email communication. Kurt Dahdah. Customer Service. ISO New England. 12/30/08.

Annex: Optional VRE Set aside Language in RGGI Model Rule[33]

Voluntary renewable energy purchase. A purchase of electricity from renewable energy generation or renewable energy attribute credits by a retail electricity customer on a voluntary basis. Renewable energy includes electricity generated from biomass, wind, solar thermal, photovoltaic, geothermal, hydroelectric facilities certified by the Low Impact Hydropower Institute, wave and tidal action, and fuel cells powered by renewable fuels. The renewable energy generation or renewable energy attribute credits related to such purchases may not be used by the generator or purchaser to meet any regulatory mandate, such as a renewable portfolio standard.

(d) Voluntary renewable energy market set-aside allocation. For each control period, the REGULATORY AGENCY shall allocate to the voluntary renewable energy market set-aside account a certain number of tons, calculated as set forth in this subdivision, from the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program base budget set forth in section XX5.1, as applicable. The REGULATORY AGENCY shall administer the voluntary renewable energy set-aside in accordance with this subdivision.

> (1) The REGULATORY AGENCY will open and manage a general account for the voluntary renewable energy market set-aside for each control period.
>
> (2) The number of tons that will be allocated to the voluntary renewable energy market set-aside account in a specific control period will be determined as set out in this paragraph.
>
>> (i) Any person may submit data to the REGULATORY AGENCY documenting purchases of voluntary renewable energy that meet the requirements of this subdivision by no later than the July 30 prior to the beginning of a control period. Such data must be from reputable sources, which may include retail electricity providers, organizations that certify renewable energy products, and other parties as determined by the REGULATORY AGENCY. To be considered, data must be verifiable and document the following for voluntary renewable energy purchases.
>>
>>> (a) Documentation of voluntary renewable energy or renewable energy attribute credit purchases by retail customers, by customer class, in the State during the most recent three-year period for which data are available.
>>>
>>> (b) Documentation that the renewable energy or renewable energy attributes related to voluntary renewable energy or renewable energy attribute credit sales was procured by the retail provider.
>>>
>>> (c) Time period when the retail purchase(s) was made.
>>>
>>> (d) State where the electricity was generated or the renewable energy attribute credit was created, including documentation of facility name, unique generator identification number, and fuel type.
>>>
>>> (e) Time period when the electricity was generated or the renewable energy attribute credit was created.
>>
>> (ii) Subject to the timely receipt of adequate data pursuant to subparagraph (i) of this paragraph, and based on such data, the REGULATORY AGENCY shall project the

[33] Regional Greenhouse Gas Initiative Model Rule. 1/5/07 Final with Corrections. http://rggi.org/docs/model_rule_corrected_1_5_07.pdf

voluntary renewable energy purchases in the State during a control period that represents renewable energy generation in one or more participating states. The megawatthours (MWh) of projected voluntary renewable energy purchases in a control period shall be multiplied by the marginal CO_2 emissions rate (lbs. CO_2/MWh) in the control area where the generation occurred, as determined by the REGULATORY AGENCY. If data to determine the marginal emissions rate is unavailable, the average emissions rate shall be used, as determined by the REGULATORY AGENCY.

(iii) The CO2 tons to be allocated to the voluntary renewable energy set-aside account shall be calculated as follows:

CO2 tons = MP x EF

where:

CO2 tons, rounded down to the nearest whole ton, is the number of allowances to be placed in the reserve account.

MP is the projected MWh of voluntary renewable energy purchases in the State during the future control period that meets the requirements of this subdivision.

EF is the CO2 emissions factor for the control area where the electricity represented by the sale was generated.

(iv) If following the end of a control period, the number of CO2 allowances allocated to the voluntary renewable energy set-aside account is less than the number of CO2 tons represented by the actual MWh of voluntary renewable energy purchases during the control period, the REGULATORY AGENCY will add the difference between CO2 tons represented by actual purchases, as calculated in accordance with subparagraph (iii) of this paragraph, and CO2 allowances held in the set-aside account to the projection for the following control period, pursuant to paragraph (2) of this subdivision. If following the end of a control period, the number of CO2 allowances allocated to the voluntary renewable energy set-aside account is greater than the number of CO2 tons represented by the actual MWh of voluntary renewable energy purchases during the control period, the REGULATORY AGENCY will subtract the difference between CO2 tons represented by actual purchases, as calculated in accordance with subparagraph (iii) of this paragraph, and CO2 allowances held in the set-aside account from the projection for the following control period, pursuant to paragraph (2) of this subdivision. In no event shall the size of the voluntary renewable set-aside exceed ___________ tons.

(3) As of the December 31 that is after the end of a control period for which an allocation has been made to the voluntary renewable energy set-aside account, the REGULATORY AGENCY shall determine the actual MWh of voluntary renewable energy purchases that occurred during the control period. The REGULATORY AGENCY shall retire CO2 allowances in the voluntary renewable energy set-aside account in an amount up to the number of tons of CO2 represented by actual voluntary renewable energy purchases, based on actual MWh purchases and the emissions factor determined pursuant to paragraph (2) of this subdivision.

January 14, 2010 Voluntary Renewable Energy Market, Issues and Draft Recommendations

List of Commenters

Center for Resource Solutions

Independent Energy Producers Association

NextEra Energy

Power Workers' Union

Renewable Energy Markets Association

Southern California Edison Company

Southern California Public Power Authority

Southwest Energy Efficiency Project

Waste Management

WEST Associates

Western Climate Advocates Network (WeCAN)

Western Climate Initiative

Tempe Mission Palms Hotel
60 East 5th Street
Tempe, AZ 85281

Remote access: Call **1-800-868-1837** toll free in the U.S. and Canada
(1-404-920-6440 for outside the U.S. and Canada), **participant code 659 537#**

<u>Wednesday, January 20, 2010</u>

8:30 am **Convene** (Abbey Meeting Room)
Welcome and Introductions
Agenda Review

8:45 am **Committee /Team Work Anticipated in 2010**
Purpose: Review and discuss anticipated tasks, work products, and resource needs in 2010 for each Committee and Team.

- **CSAD**
- **Markets**
- **Offsets**

10:30 am **Break**

10:45 am **Committee /Team Work Anticipated in 2010 (continued)**

- **Reporting**
- **Electricity Team**
- **Complementary Policies**

12:00 pm **Lunch Break**

1:00 pm **CSAD Committee**

a) Status of Partner data review and emission forecasts.
b) Review feedback from stakeholders on Draft Guidance for Developing Partner Jurisdiction Allowance Budgets.
c) Review progress on competitiveness analysis and next steps.

2:15 pm **Offsets Committee**
Purpose: Review Task 3 Report from DNV on Existing Protocols and provide direction on next steps.

3:15 pm **Break**

3:30 pm **Liaison Reports**
Update on activity at the federal level in U.S. and Canada. Identify opportunities for ongoing WCI involvement. Status of "Three Regions" collaboration.

4:00 pm **Open Comment Period**

4:30 pm **ASU Presentation:** Algal-Based Biofuels and Biomaterials
http://biofuels.asu.edu/biomaterials.shtml

5:15 pm **Adjourn**

Algae-Based Biofuels and Bioproducts

Brief Overview

Milton Sommerfeld and Qiang Hu

Laboratory for Algae Research and Biotechnology (LARB)

Department of Applied Sciences and Mathematics

ASU Polytechnic Campus, Mesa, AZ 85212

Western Climate Initiative

Tempe Mission Palms Hotel

Tempe, Arizona

January 20, 2010

Laboratory for Algae Research and Biotechnology

LARB's Mission:

To conduct fundamental and applied research on algae to accelerate the use of algae as a cost-affordable and sustainable source of fuels and chemicals and for improving the environment through algae-based bioremediation.

LARB provides innovative training for the next generation of scientists and engineers for the biotechnology workforce, collaborates with industry and research institutions, and develops international partnerships for research and education to promote algae-based opportunities and solutions.

LARB's Research Areas

Algae Biology

- Strain selection and characterization
- Lipid metabolism
- Carotenoid synthesis
- Carbon partitioning
- Oxidative stress and stress response

Biofuels

- Bioreactor
- Algal mass culture
- Downstream rocessing
- Oil production
- Fuel conversion
- Co-products recovery

Carbon Capture

- CO_2 removal from power plant gas emissions

Water/wastewater bioremediation

- Nutrient and heavy metal removal from water and wastewater

High-value products

- Omega-3 fatty acids
- Carotenoids and other pigments
- Polysaccharides and starch
- Biologically active substances

What are Algae?

- Photosynthetic organisms
- Range from giant seaweeds to microscopic unicellular organisms
- Lack specialization associated with typical terrestrial plant life
- Widely distributed

Macroalgae

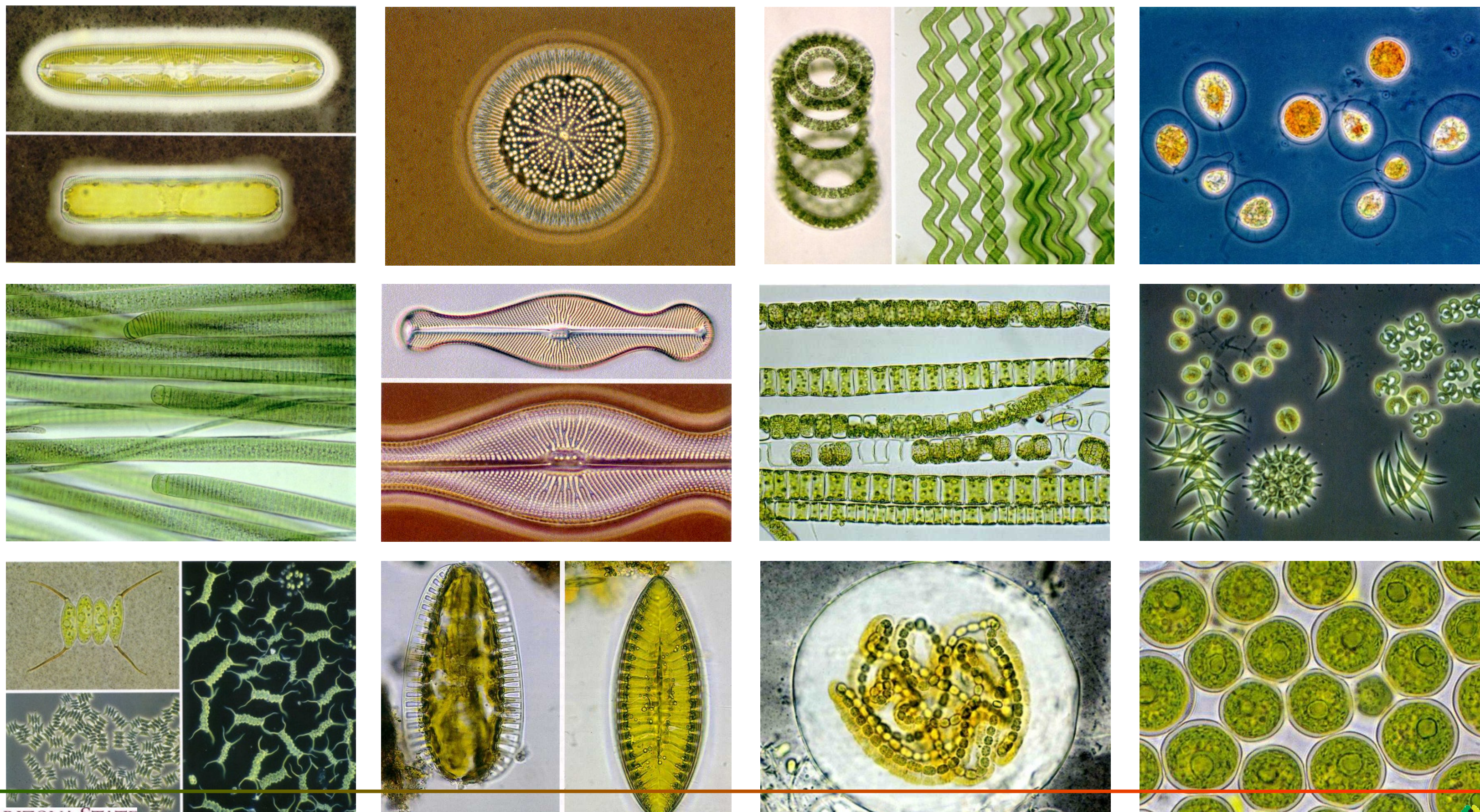


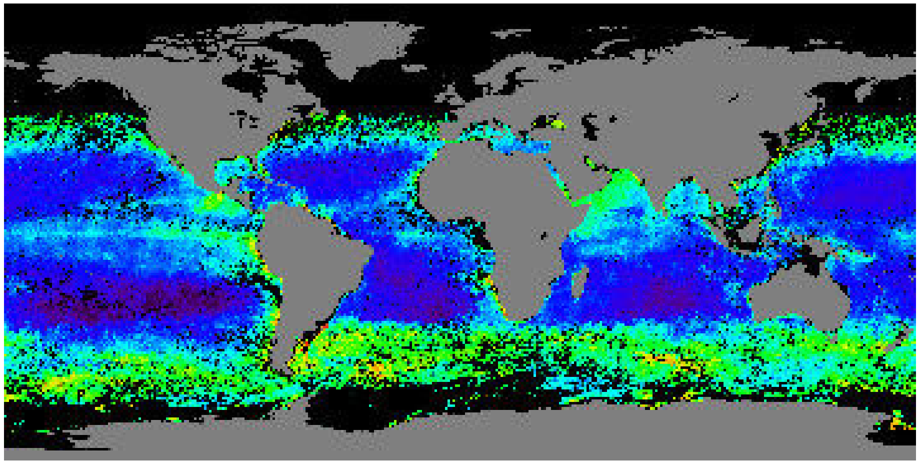


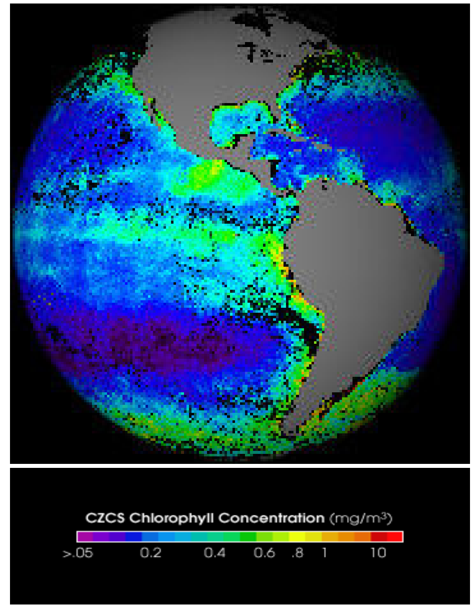



Microalgae

Prokaryotic: **cyanobacteria (blue-green algae)**
Eukaryotic: **diatoms, green algae, red algae, brown algae, golden algae, dinoflagellates, etc**



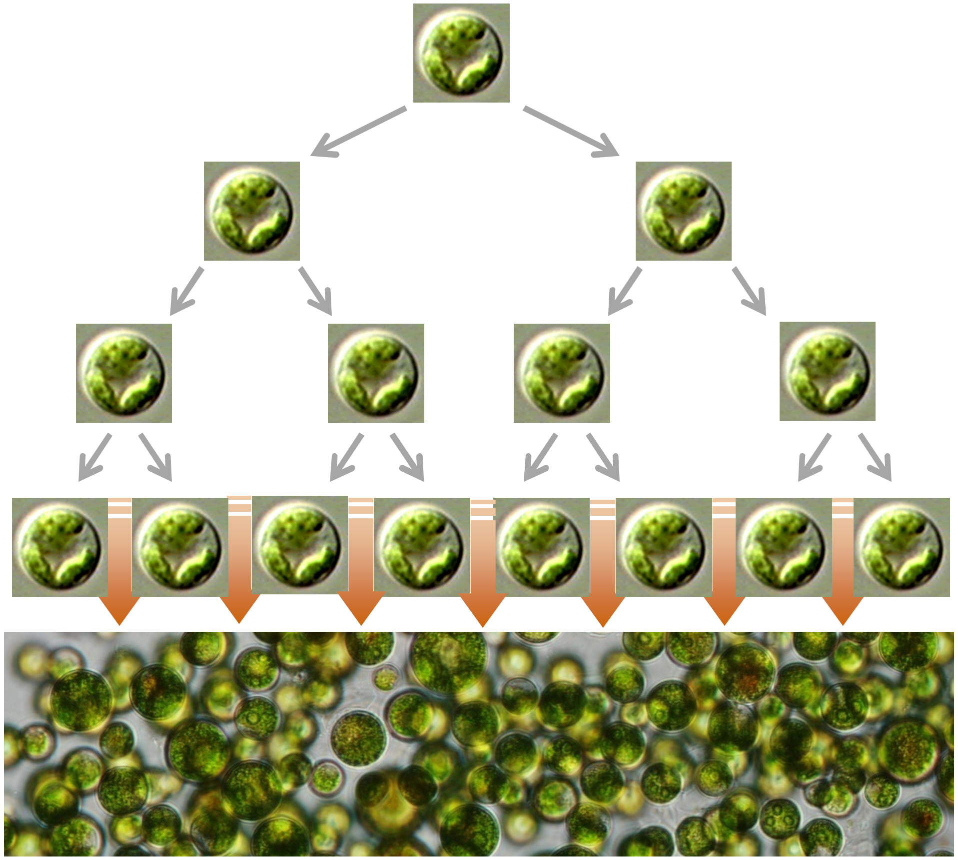




Some Facts about algae:

- > 40,000 described species
- ~ 1-2 % of the total global plant carbon
- Fix about 40 % the total carbon annually (30~50 billion metric tons of carbon/yr)
- Rapid biomass doubling time (1-6 days)

Growth Potential: Algae *vs* Plants



Biomass Yields of Algae *vs* Terrestrial Crops

Crops	Biomass yield (tons ha^{-1} y^{-1})
Sugar cane	54 - 125
Sweet sorghum	35 - 70
Soybean	1.1- 4.0
Sweet potato	10 - 40
Forest plants	20 - 50
Microalgae	100 - 300

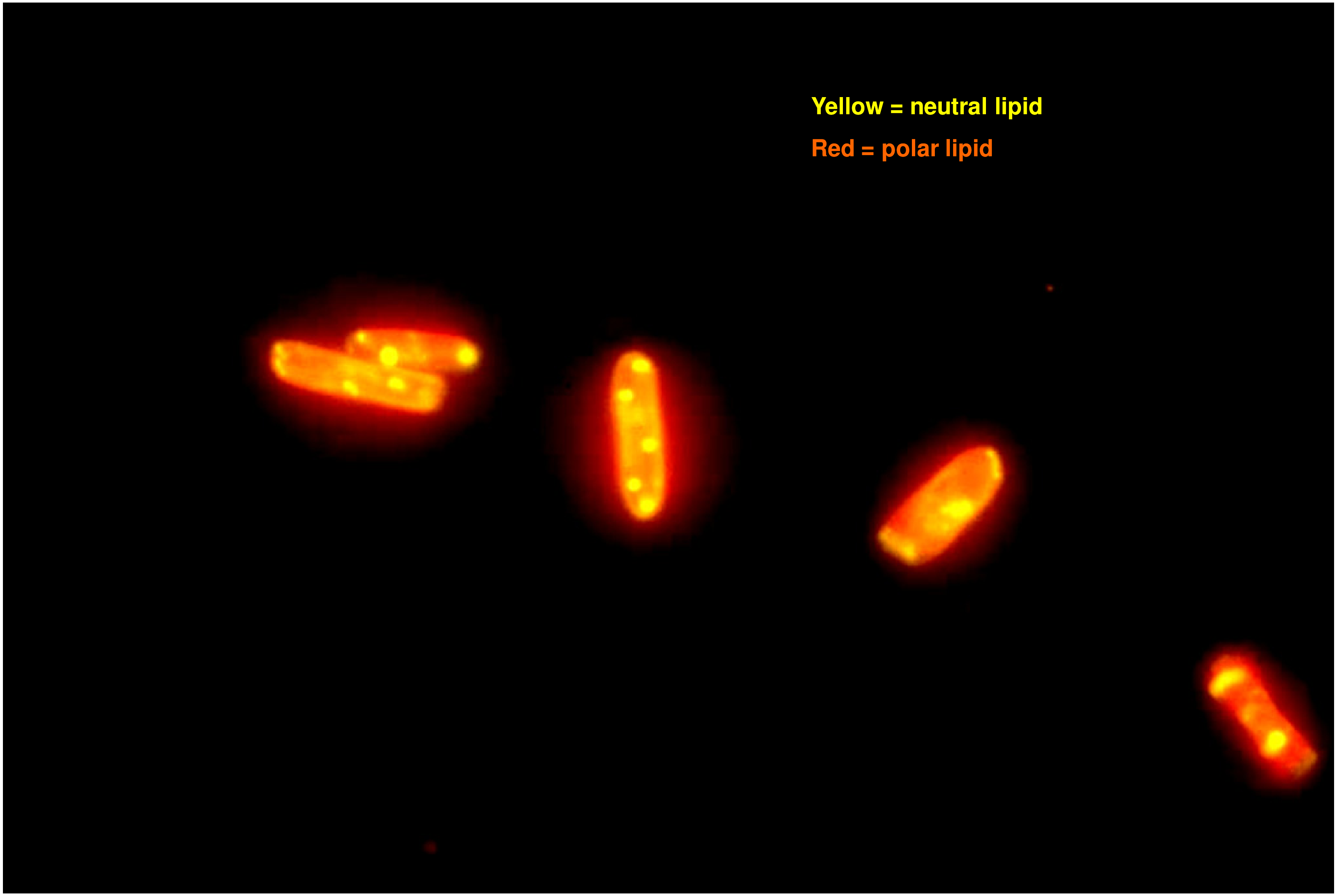
Algae for Fuel?

"The identification or development of microalgal strains that will meet the performance criteria of high productivity, high lipid content, and wide ranges of environmental tolerance is the single most critical research requirement for the economic viability of microalgal fuels technology."

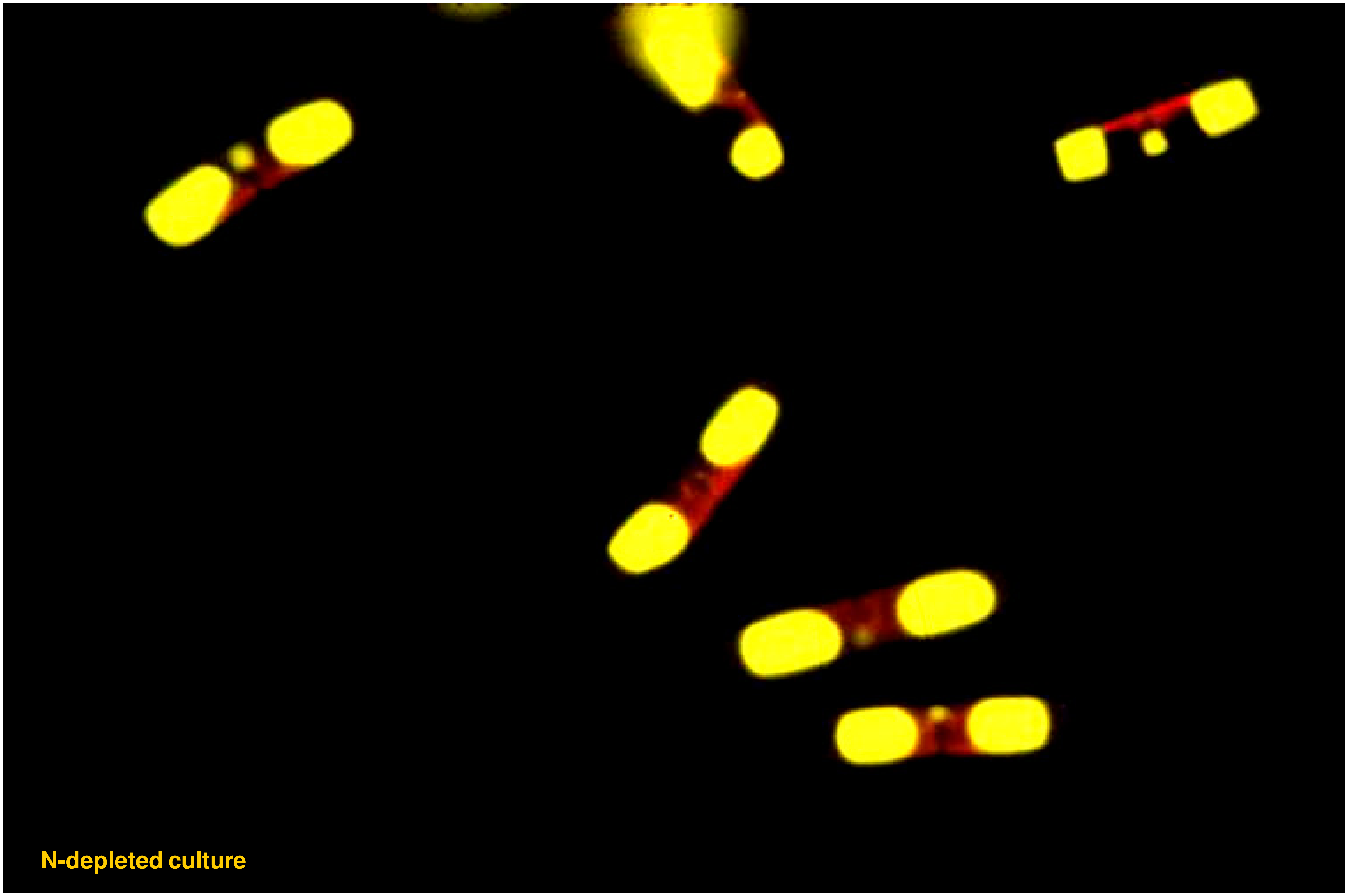
Fuels from Microalgae: Technology Status, Potential, and Research Requirements (Solar Energy Research Institute, U.S. Department of Energy, 1986)

Diatom - *Nitzschia communis*

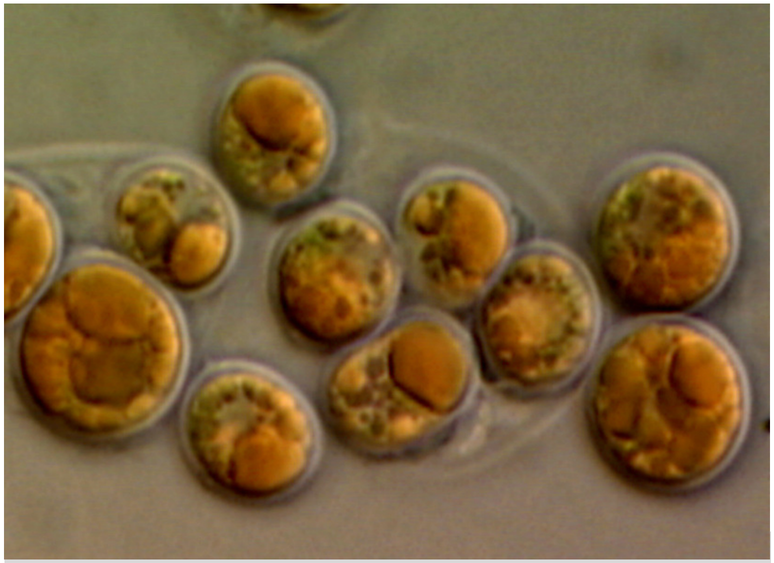
Nile Red Fluorescence-Based Lipid Detection



Lipid Accumulation in Stressed Cells

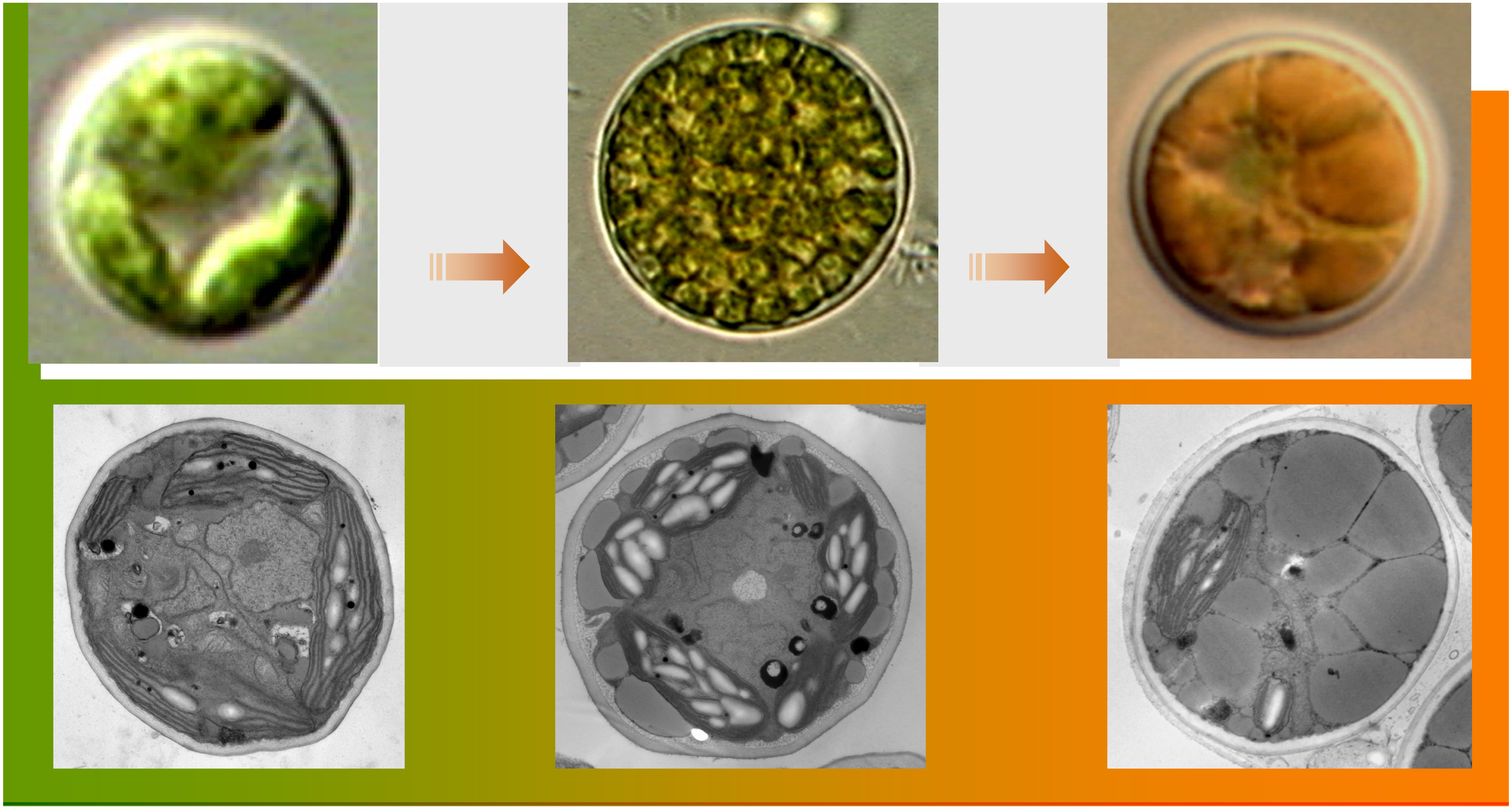


Oil Content: Crop Plants vs Algae

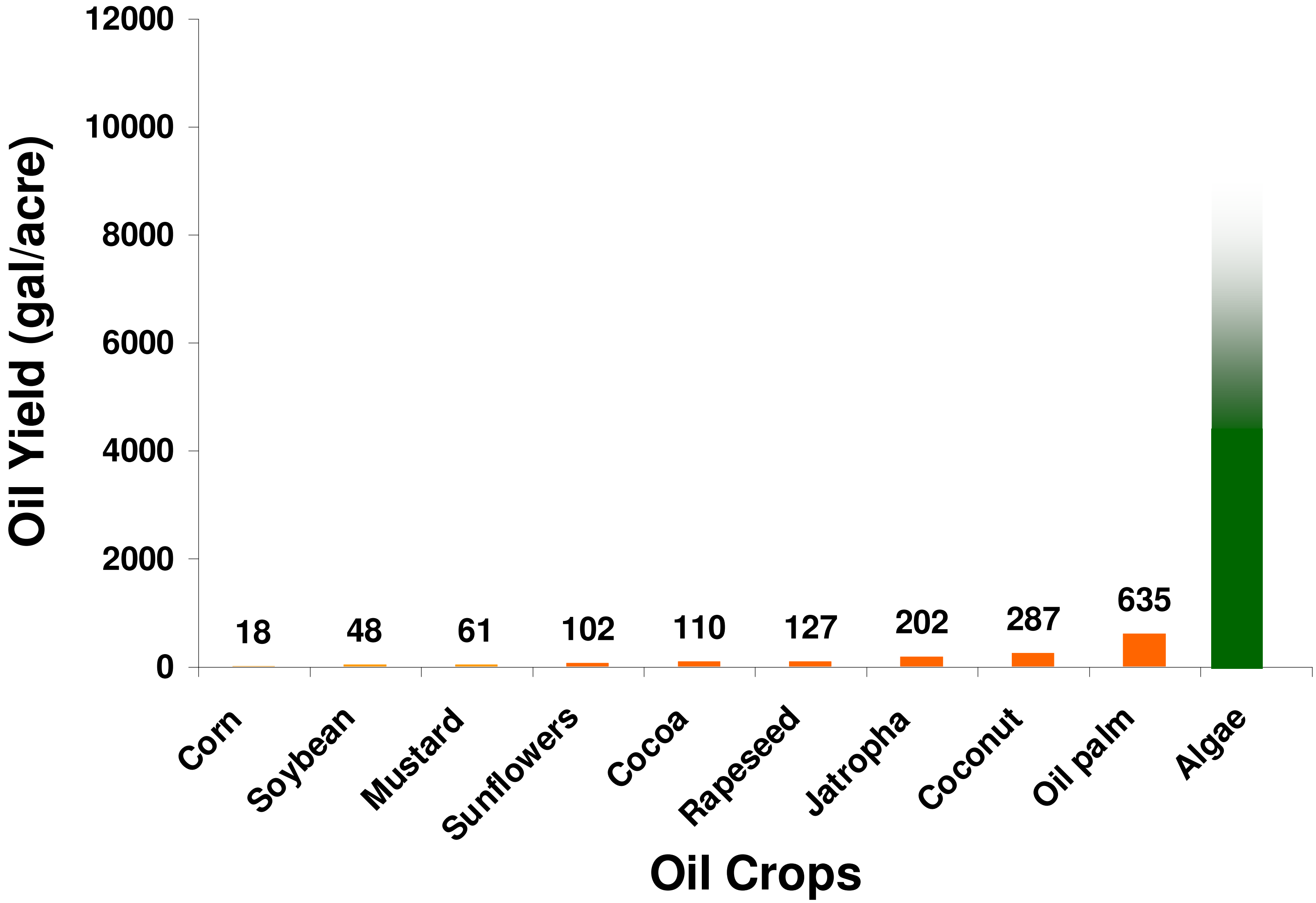


Changes in Cellular Constituents

protein- carbohydrate- lipid-rich

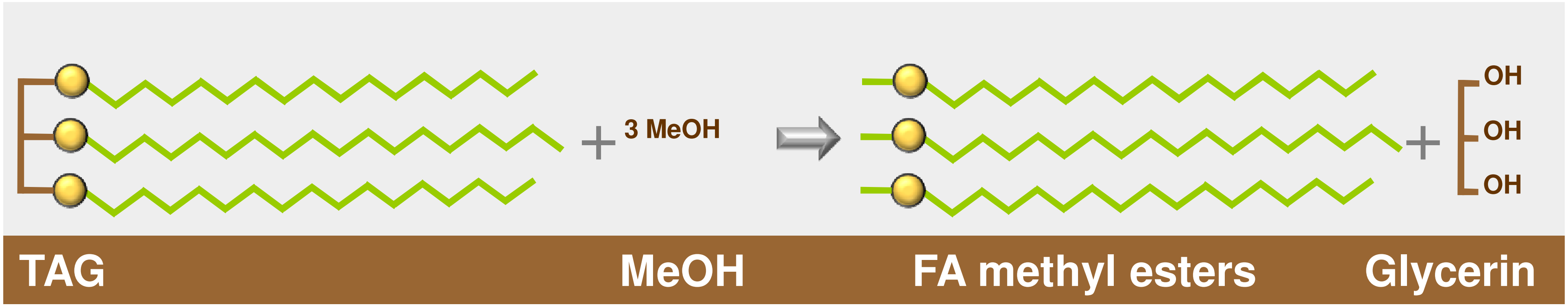


Crop Plant- and Algae-Based Oil Production Potential

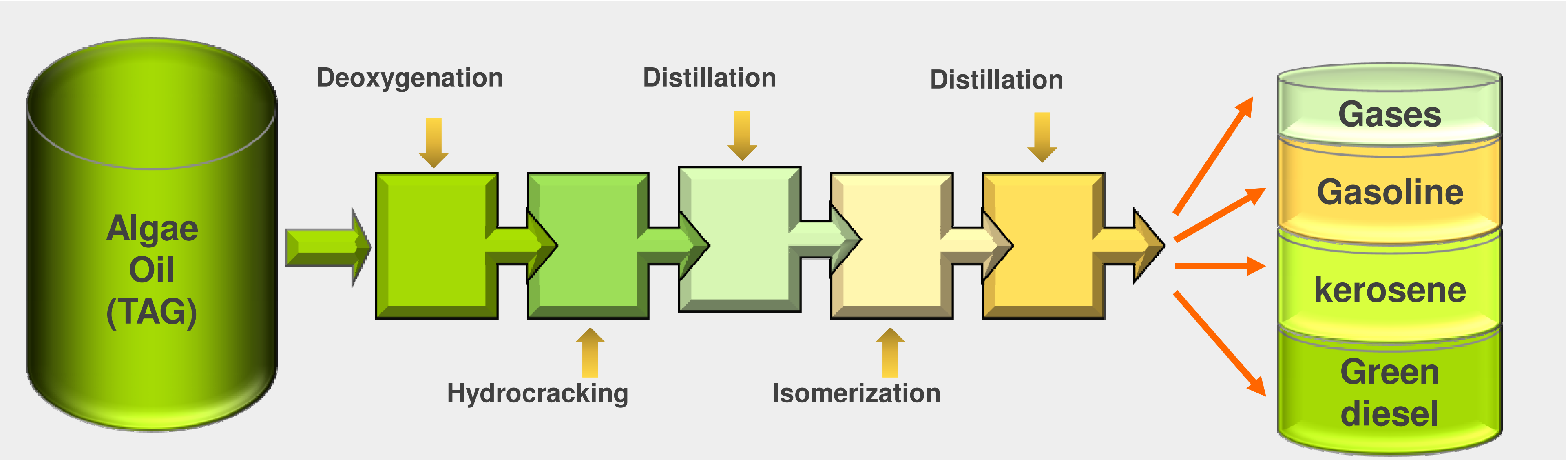


Refinement of Algae Oil to Fuels

Transesterification



Thermo/chemical cracking

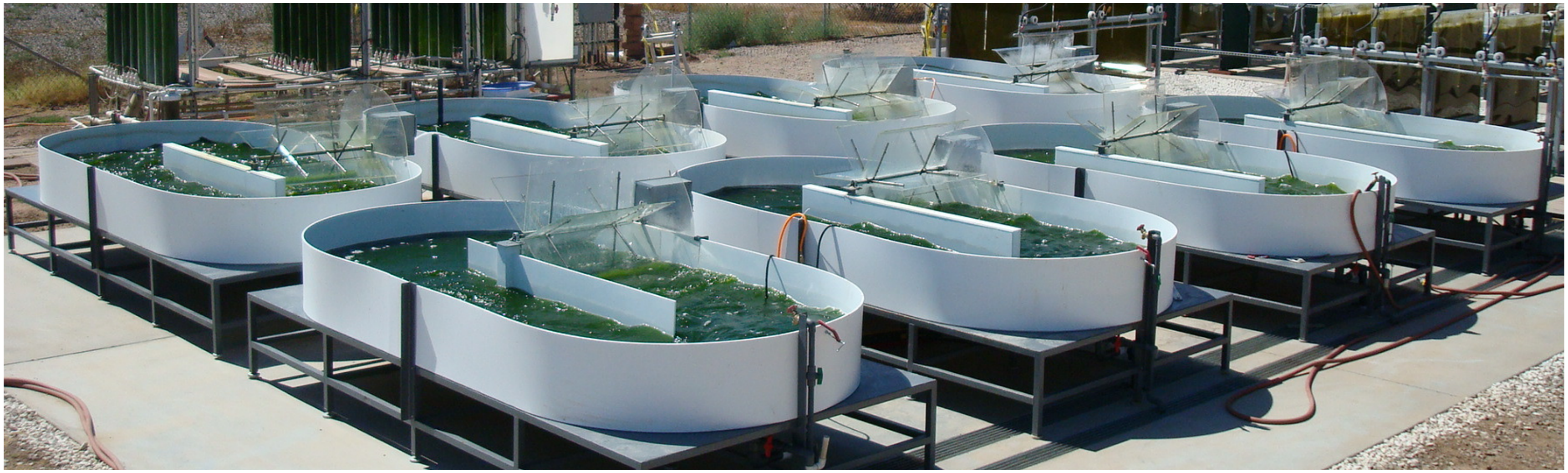


What do you Need to Make the Algae for Fuel System Work?

- Microalgae that grow rapidly and have high oil content
- Light
- Water
- Inexpensive land
- Favorable temperature
- Nutrients (N, P, CO_2)

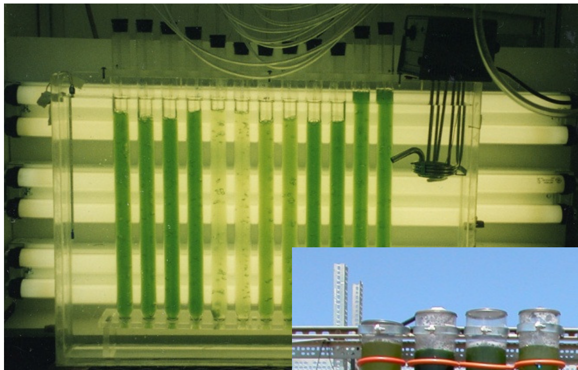
Lab Facility for Strain Selection & Characterization

Outdoor Test Facility for Strain Selection & Characterization

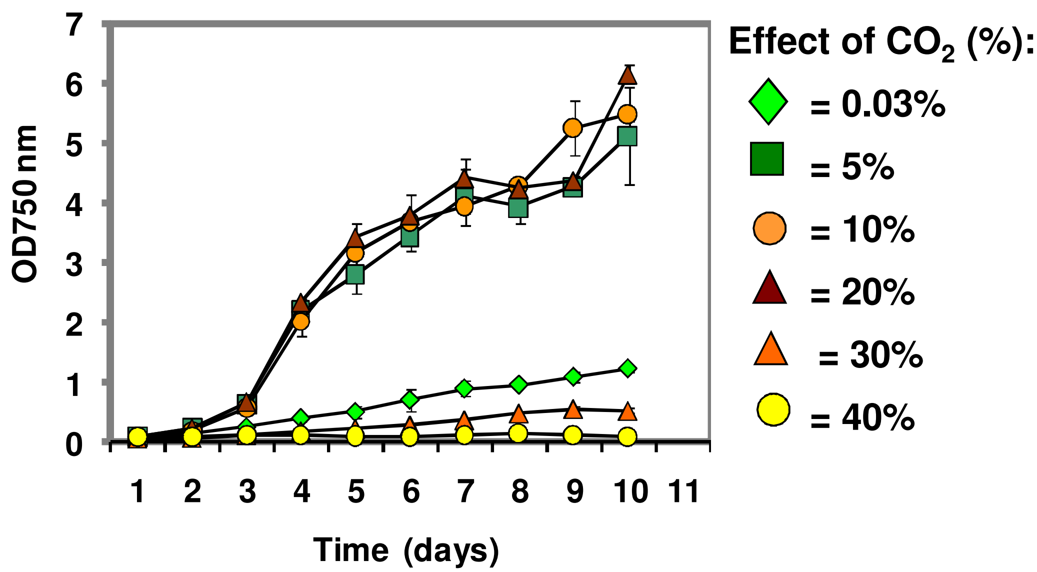


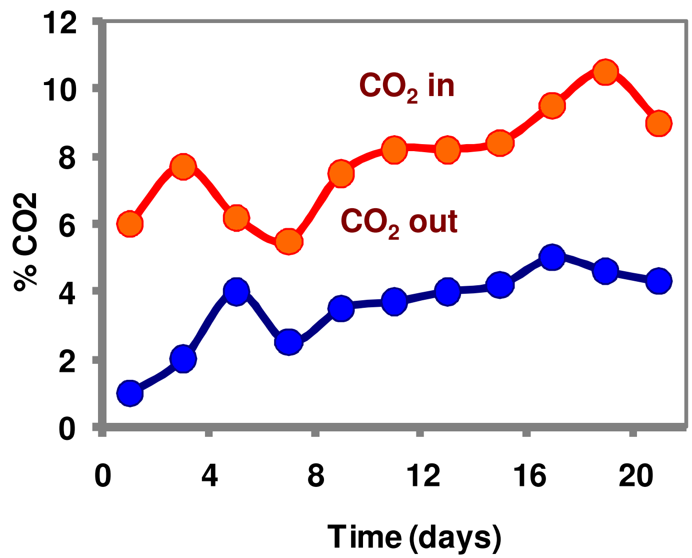
Nutrient Uptake by Microalgae

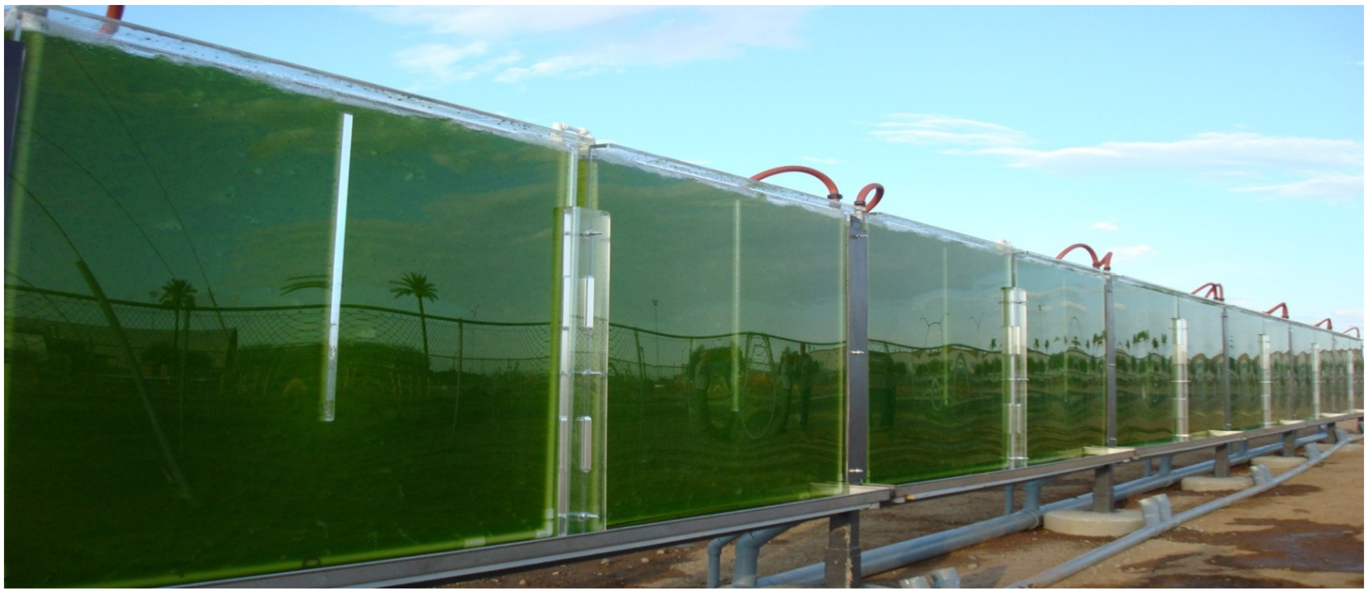
$$106\ CO_2 + 236\ H_2O + 16\ NO_3^{+} + HPO_4^{2-} \longrightarrow C_{106}H_{181}O_{45}N_{16}P + 118\ O_2 + 171\ H_2O + 14\ H^{+}$$



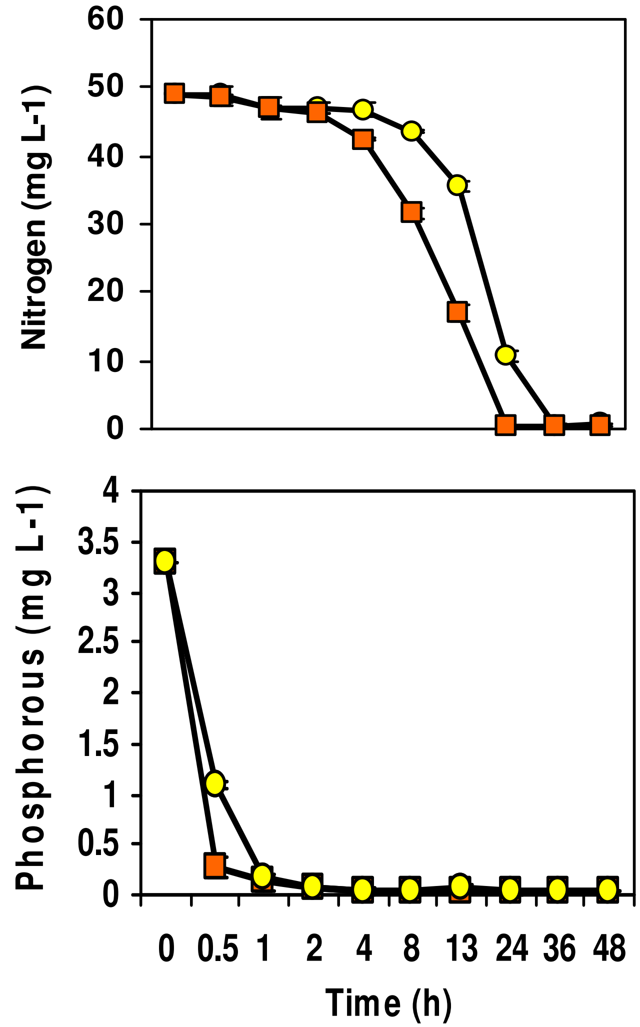
CO_2 Capture by Algae







Field Demonstration of Algae-Based Nutrient Removal from Wastewater

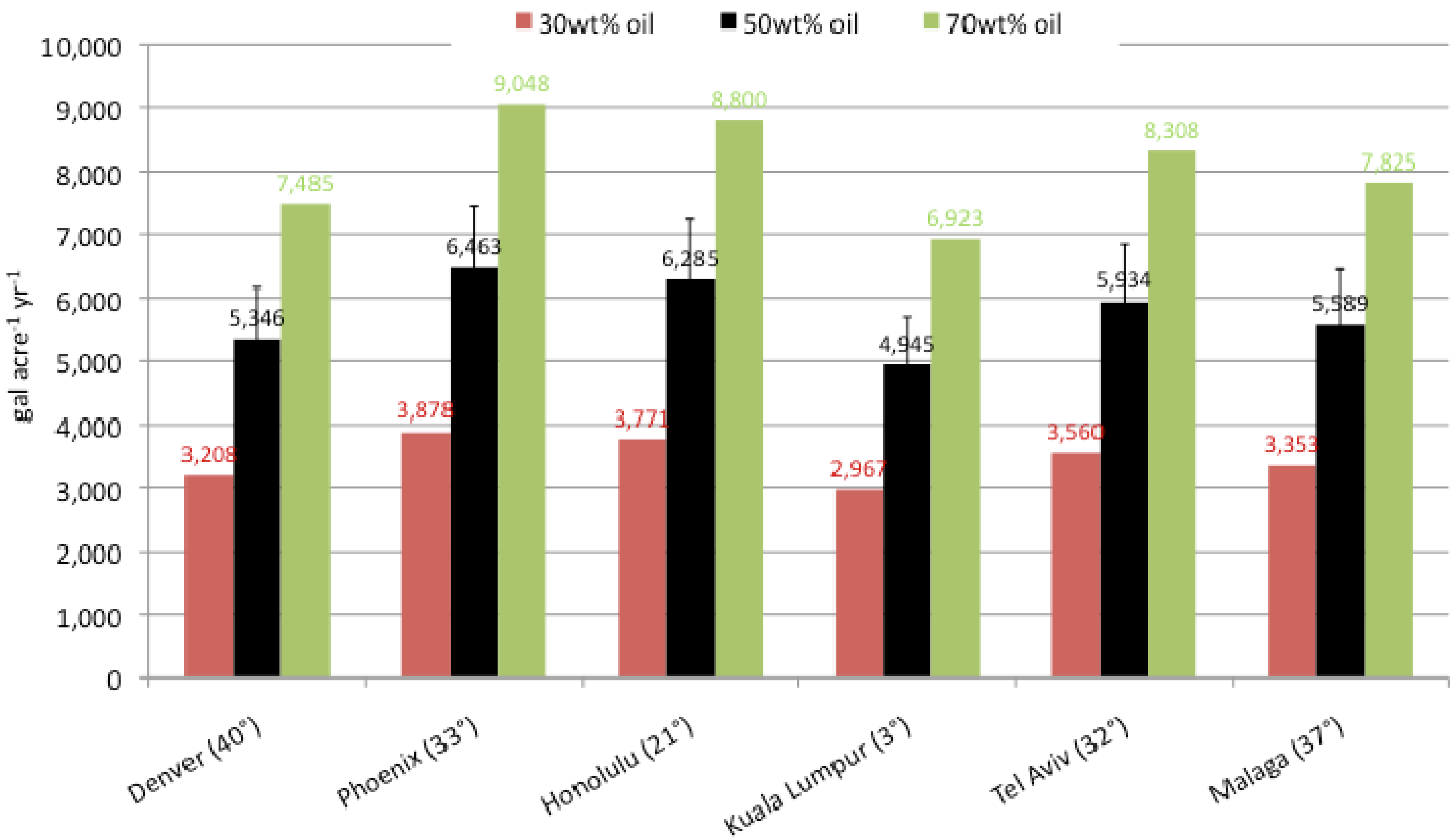


Where do you grow algae?

Locations with:

- High year-round levels of incident sunlight
- Warm/mild temperatures most of the year
- Large expanses of available flat land
- Large supply of water- can use waste water/saline/brackish water

Algae Oil Production Potential in Different Geological Locations



Data from NREL/Solix Biofuels Corp.

Resource Potential: Land
(Basis: algal oil needed for 5 billion gal/yr jet fuel)

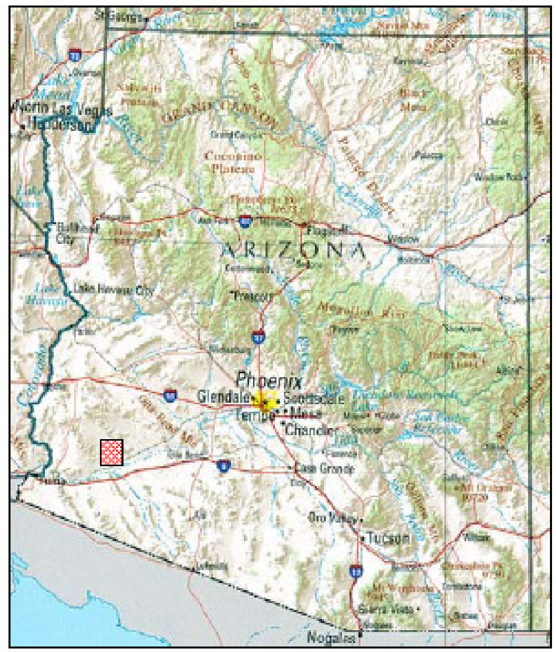
<u>Near Term (SOT)</u>
(~1,200 gal/acre-yr)

4,000,000 acres
(6,250 square miles)

- Compare to 2005 U.S. soybean acreage of 74 million acres
- Using otherwise unproductive land

<u>Longer Term</u>
(~10,000 gal/acre-yr)

530,000 acres
(830 square miles)



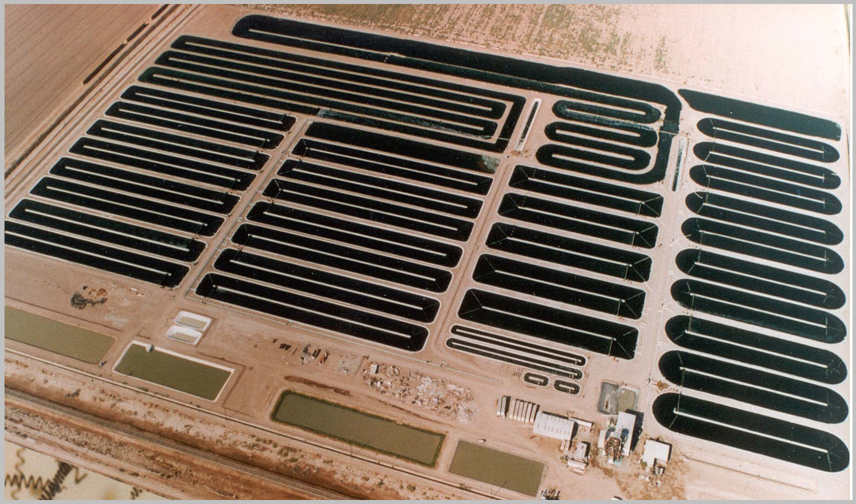
How do you grow algae?

- Open ponds
- Bioreactors
- Other

Open Ponds

NBT LTD, Israel

Taiwan Chlorella. Taiwan



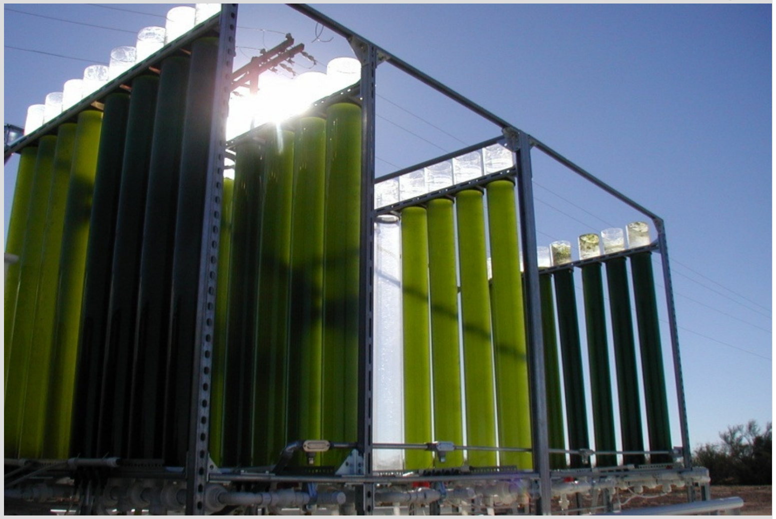
Earthrise Farm, USA

Yunnan Spirin Co. Ltd, China

Tubular Photobioreactors: Vertical or Inclined

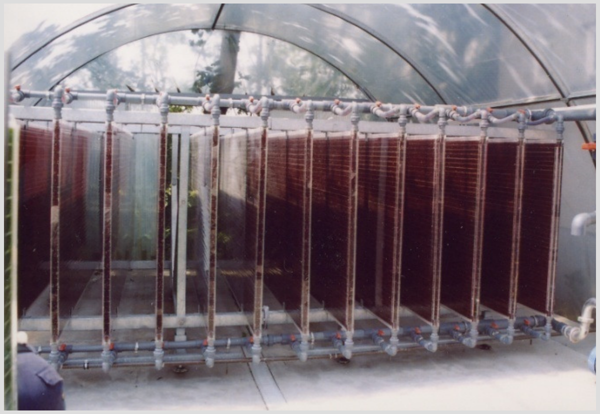
Univ. of Florence, Italy

Greenfuel Technol. Corp.



ASU Polytechnic

Flat-Panel Photobioreactors



ÖPA GmbH, Germany

Ben-Gurion Univ. Israel

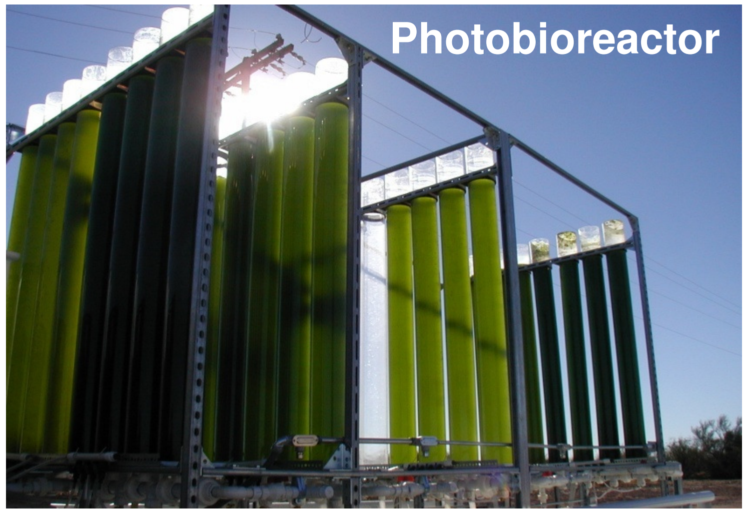
ASU Polytechnic

ASU Polytechnic

LARB's Integrated Solution
for Sustainable Energy and Environment

CO_2 from power plant flue gases

Nutrients (N, P) from wastewater



Treated gases

Treated water

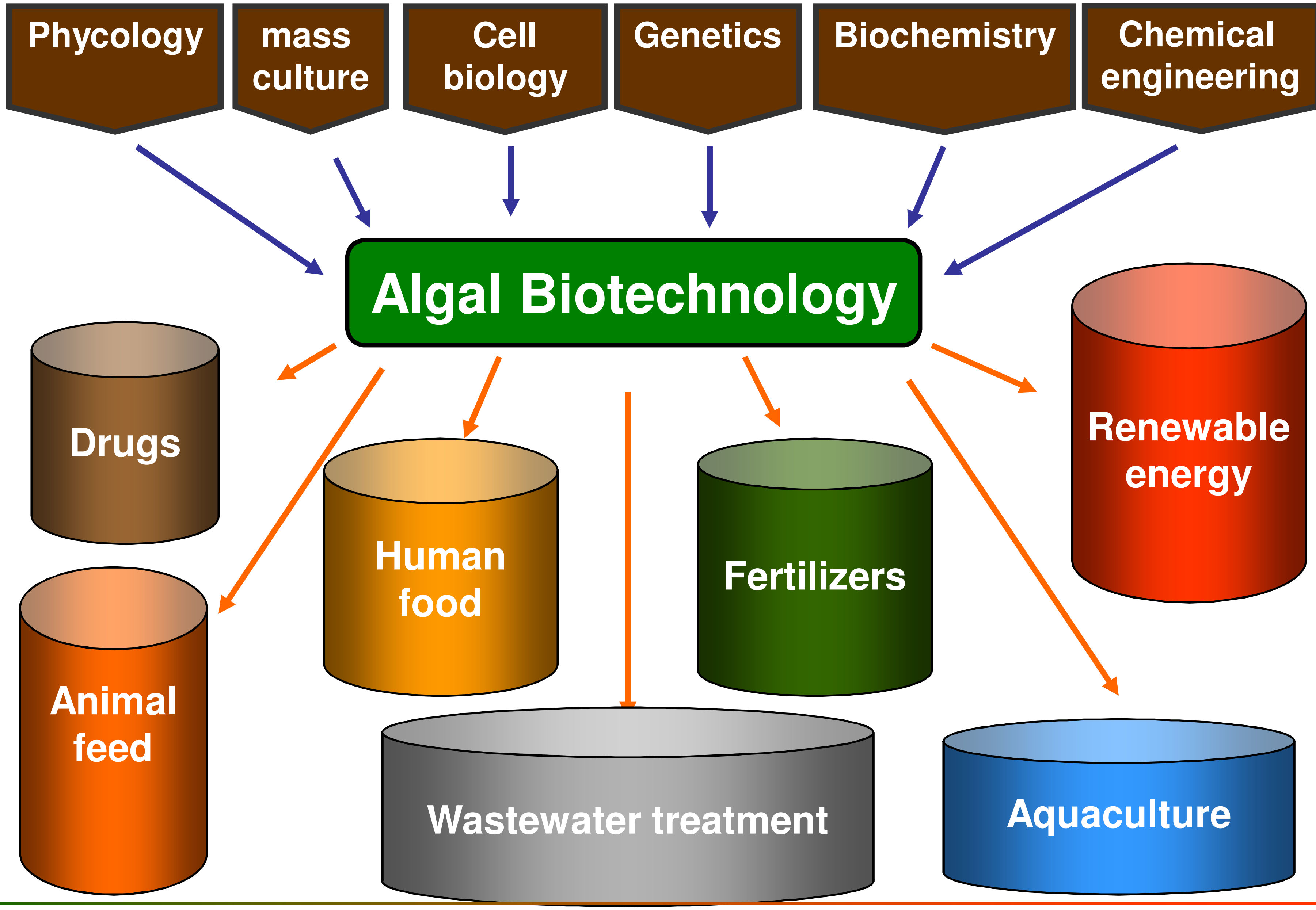
- Jet fuel
- Biodiesel
- Green diesel
- Biopolymers
- Petro-chemicals

Algal oil

Algae feedstock

Biomass residues

- Animal feed
- Fertilizer
- Starch/sugar
- Minerals


Phycology
mass culture
Cell biology
Genetics
Biochemistry
Chemical engineering
Algal Biotechnology
Drugs
Human food
Fertilizers
Renewable energy
Animal feed
Wastewater treatment
Aquaculture

Chemicals from Algae

Proteins
- enzymes
- antibodies
- vaccines

Vitamins
- vitamin B, C, D, E

Polysaccharides
- agarose
- agaropectin
- sodium alginates
- sulfated polysaccharides
- destrin
- carrageenans

Minerals
- zinc
- iron
- selenium
- calcium, boron

Polyunsaturated fatty acids
- eicosapentaenoic acid (EPA, 20:5ω3)
- docosahexaenoic acid (DHA, 22:6ω3)
- γ-linolenic acid (GLA, 18:3ω6)
- arachidonic acid (AA, 20:4ω6)

Pharmaceuticals
- antibiotics
- antitumour/cancer metabolites
- antineoplastic metabolites
- anti-HIV substances
- anti-viral compounds

Pigments
- lutein
- ß-carotene
- zeaxanthin
- astaxanthin
- phycobiliproteins

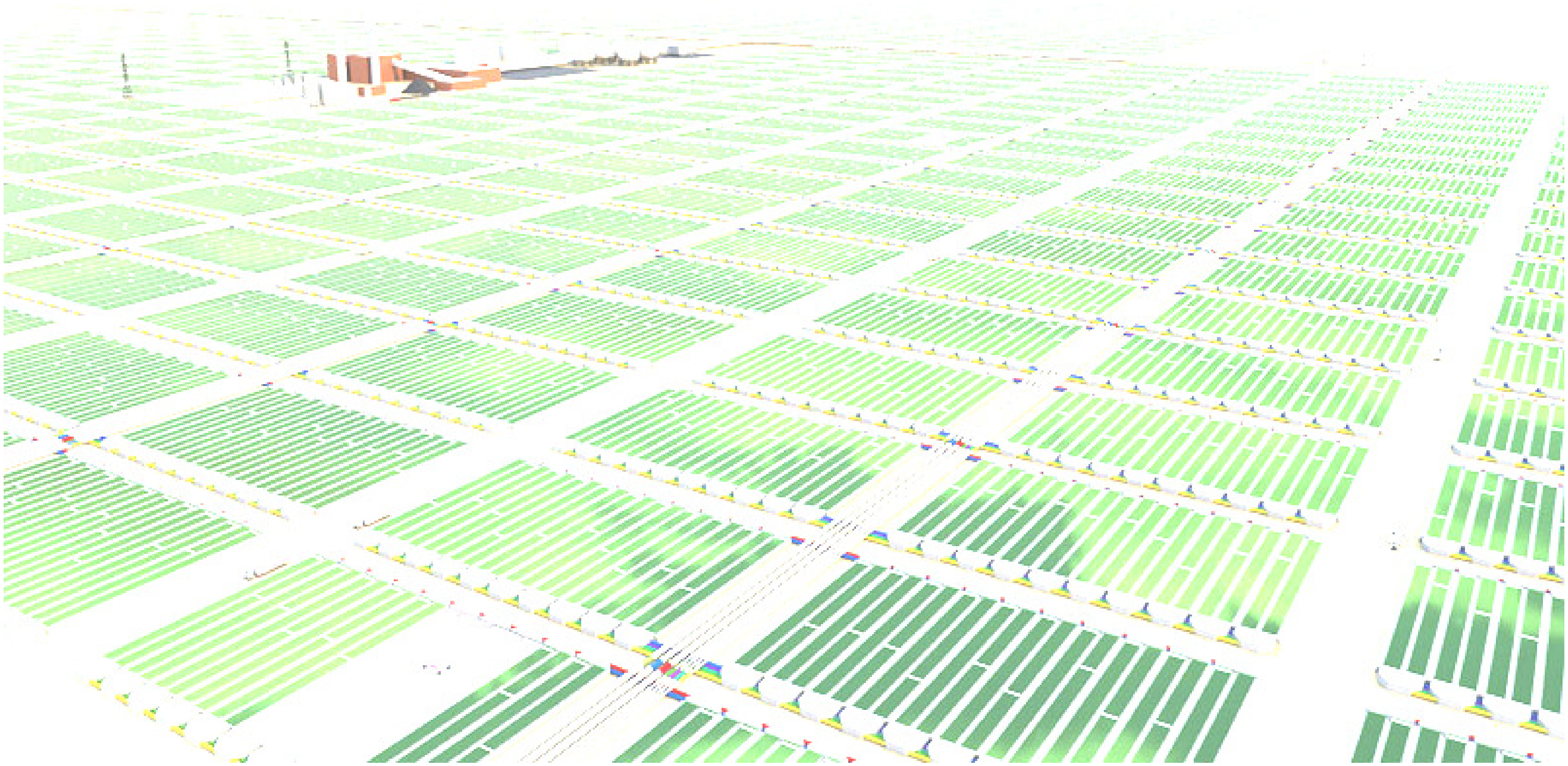
Advantages of Microalgal Feedstock Production

- High growth potential (>1 doubling time a day)
- High cellular oil content (20~60% of dry weight)
- 5~10-fold higher yield potential than oilseed plants
- Wealth of natural products and chemicals
- Thrive in saline/brackish (non-potable) water
- Couple with wastewater treatment
- Couple with carbon capture
- Flexibility in land requirement: desert and arid lands
- Opportunities for strain improvement
- Not a food crop

Producing Algae for Fuel: Then

Microalgae biodiesel production, Aquatic Species Program, DOE NREL 1987 Note Raceway and settling-harvesting ponds

Producing Algae for Fuel: Future



Western Climate Initiative

Summary of Comments on Draft Guidelines for Developing WCI Partner Allowance Budgets

www.westernclimateinitiative.org

Commenters

- Approximately 50 comments from 10 submitters / letters
  - Arizona Public Service
  - BC Forestry Climate Change Working Group
  - Pacific Gas & Electric
  - Puget Sound Energy
  - Southern California Edison
  - Southern California Public Power Authority
  - Power Workers' Union
  - WEST Associates
  - Utah Business Climate Change Coalition
  - Western Climate Advocates Network

Nature of Comments (1)

- Increase transparency and stakeholder input
  - Contractor methods / results regarding emissions forecast
  - Economic modeling results
  - Proposed budgets
- Provide greater explanation / detail
  - Relationship between capped emissions, uncapped emissions, and regional goal
  - Developing a rate of decline
  - Voluntary reductions and early reduction allowances
  - Accounting for recession / recovery
  - One percent 2012 adjustment

Nature of Comments (2)

- Maximize accuracy of 2012 / 2015 best estimates
  - Avoid use of economic/emissions forecast (too uncertain)
  - Consider using 2005-07 or 2009-2011 reported emissions
- Minimize risk of over /under allocation
  - Maintain flexibility in establishing / adjusting budgets
  - Consider mandatory reporting data
  - Develop criteria for when adjustments are warranted
  - Avoid overestimation of new source emissions (retire new source allowances if sources not built)

Nature of Comments (3)

- Consider improving budget-setting method by:
  - Setting a single rate of decline from 2012 to 2020
  - Assessing actual vs forecasted data in 2011
  - Improving 2005 emission inventory
  - Actively engaging industry to improve emissions/forecasts

Nature of Comments (4)

- Schedule / process
  - Establishing preliminary budgets this summer unrealistic, especially if public review / input is expected
  - What if a Partner jurisdiction rejects CSAD recommend-ations, or if program not fully implemented by 2012
- Other
  - Allocation methods should be developed as early as possible and more heavily centralized or harmonized
  - Economic/pop growth should not be factors in forecast
  - Economic/pop growth should not be underestimated due to current recession

Nature of Comments (5)

- Other (continued)
  - Budgets should be based on on electricity consumption
  - Linear decline could create high costs
  - All sectors should be included in 2012

Western Climate Initiative

An Update on CSAD Competitiveness Work (task 3)

WCI Partners Meeting
Phoenix, AZ
January 20, 2009

Background

WCI Design Recommendations (Section 8.5):

Analyze competitiveness for like facilities

- Sectors such as: aluminum, steel, cement, lime, paper and pulp, and oil refining. Other big sectors include iron, copper, glass, and basic chemicals*****
- Analysis of competitive factors in the electricity sector

*****Identified in *Leveling the Carbon Playing Field* (2008)

Milestones

- Stakeholder discussion in Seattle (May 2009)
- Release of principles (Aug 2009)
- Review of other programs (Aug 2009)
- Outlined process and guidance (Nov 2009)
- Provide first analysis and identify methods for further assessment (Mar 2010)
  - Guidance to partners by April 2010
- Evaluate mechanisms to address competitiveness (April 2010)

Number of facilities in WCI*

FOR DEMONSTRATION ONLY

Sector	Hypothetical Partner	WCI (most partners)	Nationally (U.S.)
Aluminum	4	~10	55
Cement	2	~50	300
Glass	2	~20	695
Lime	2	~20	80
Steel	2	~10	740

Obama Competitiveness Report

Dec 2, 2009: Obama Administration releases report on competitiveness provisions of HR 2454*

- **Without** output based rebates to identified manufacturing sectors and allocations to LDCs, total annual emissions leakage to countries without C&T in the order of ~10 million MTCO2e.
- **With** rebates to mfg sectors and allocations to LDCs, leakage of emissions from identified sectors estimated at ~1 million MTCO2e.

Next steps

- **Task 3.1:** Carry out the initial WCI competitiveness analysis and identify methods for additional assessment (April 2010)
- **Task 3.2:** Evaluate mechanisms to address competitiveness based on competitiveness principles (April 2010)
- **Task 3.3:** Sponsor a workshop on benchmarking of GHG emissions from industrial sectors (May 2010)

Western Climate Initiative

An Update on the CSAD Committee's Emissions Inventory and Forecast Work

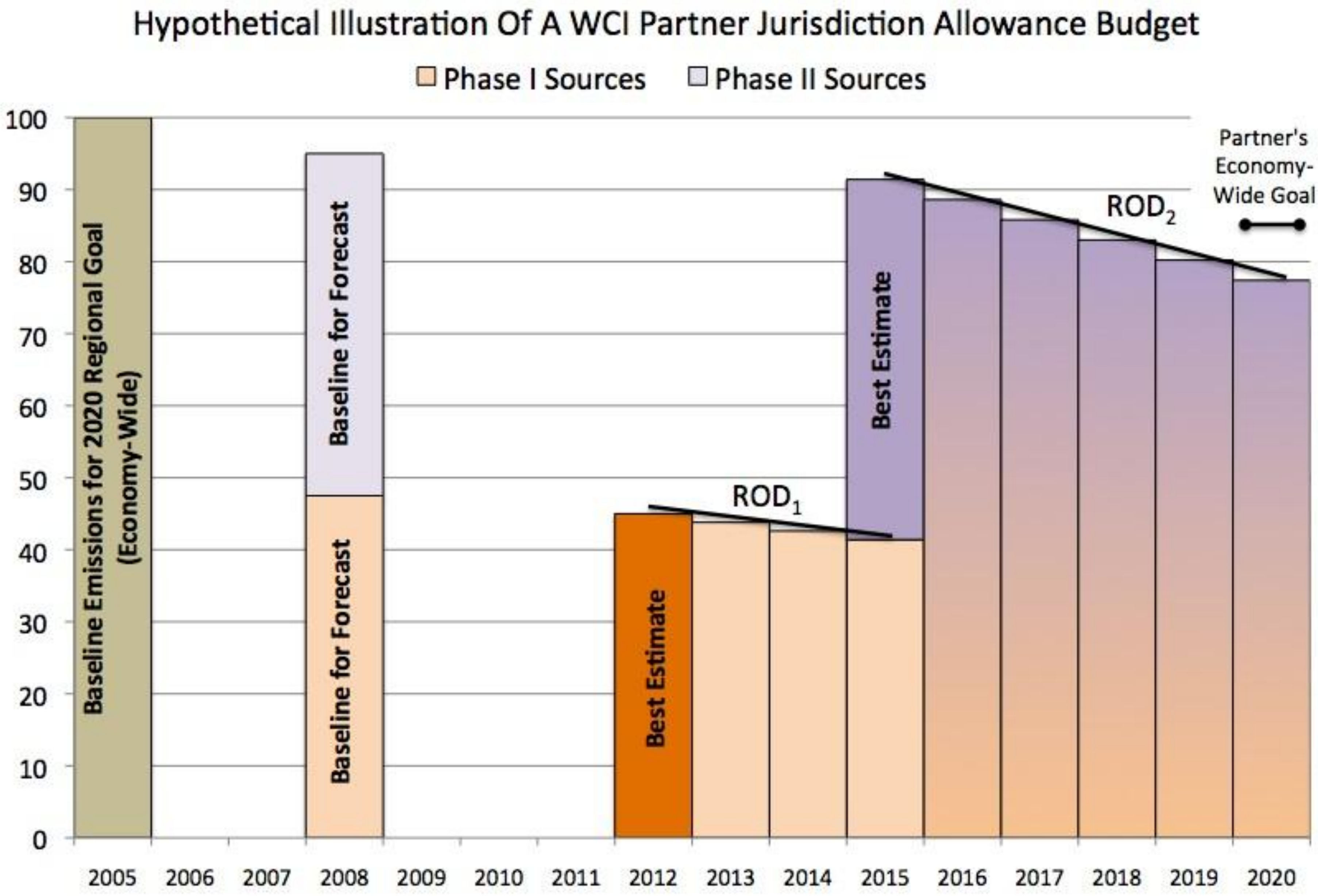
WCI Partners Meeting
Phoenix, AZ
January 20, 2009

Acknowledgements

- E. H. Pechan & Associates
  - Andy Bollman, Project Manager
  - Steve Roe, Brad Strode, and Viola Glenn
- Multiple jurisdictional staff
  - Collecting and submitting emissions data
  - Reviewing proposed forecast methods, preliminary results, and this presentation

Project Background

- WCI Design Recommendations
  - "For 2012, each Partner's allowance budget will be based on the best estimate of expected emissions for sources covered in the cap-and-trade program in the Partner's jurisdiction in 2012."
  - "For 2015 each Partner's allowance budget will be set by adding the best estimate of expected actual emissions in 2015 from transportation fuels and RCI fuels to the emissions trajectory for the sources first included in 2012."



Hypothetical Illustration Of A WCI Partner Jurisdiction Allowance Budget
Phase I Sources
Phase II Sources
100
90
80
70
60
50
40
30
20
10
0
Baseline Emissions for 2020 Regional Goal (Economy-Wide)
Baseline for Forecast
Baseline for Forecast
Best Estimate
Best Estimate
ROD$_1$
ROD$_2$
Partner's Economy-Wide Goal
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020

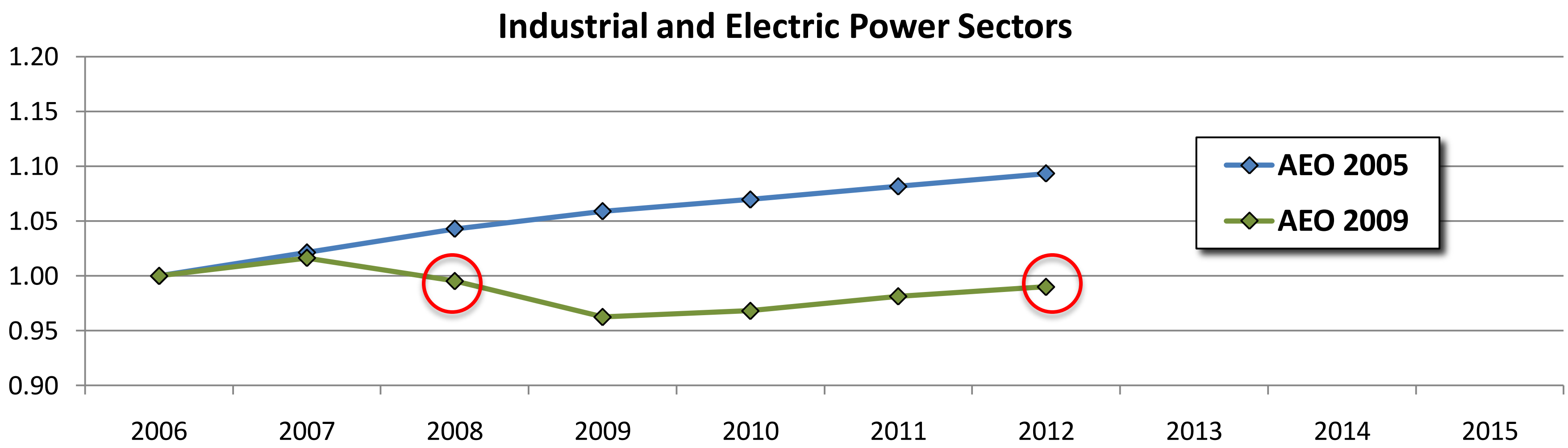
Project Background

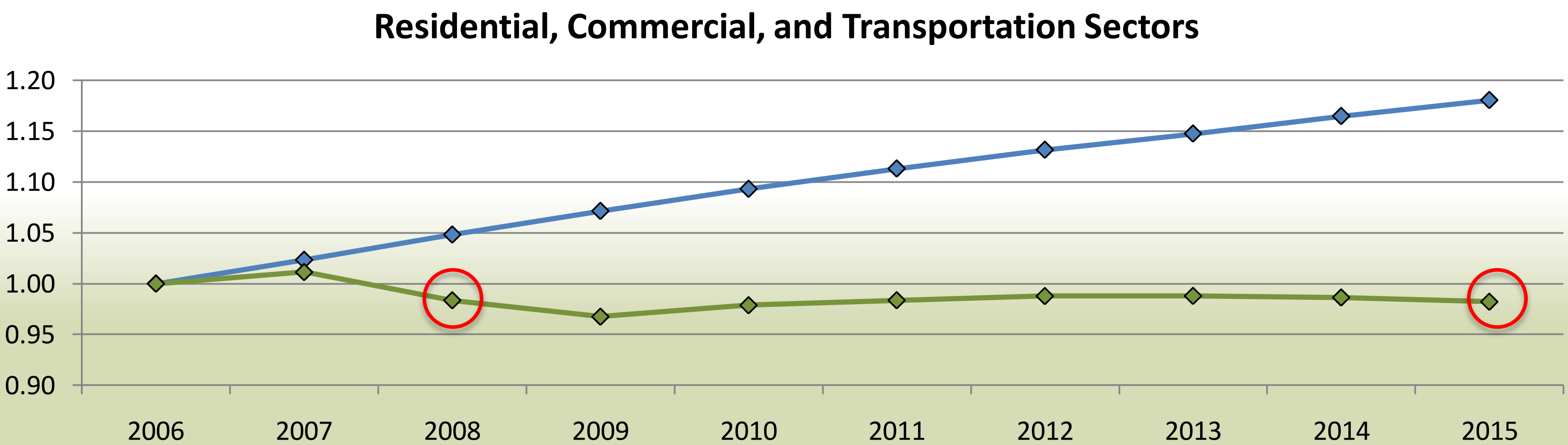
- Project objectives
  - Collect the most recent emissions data from Partners
  - Identify and compare forecast methods that can produce “best estimates” of 2012 and 2015 emissions consistently across Partner jurisdictions
  - Build a regional database that can be used by Partners throughout the budget setting process
- Project history
  - RFP released June 19, 2009
  - Pechan selected on July 29, 2009
  - Project funded at $50,000

Project Background

- Notes
  - This inventory necessarily differs from prior inventories (e.g., state action plans and the Task 0 data) in that it must include only those emissions which would be subject to the cap (e.g., facilities > 25,000 tpy for which sufficient monitoring protocols have been developed)
  - Emissions associated with electricity imports are not yet included in this analysis (the necessary data are being collected by the Electricity Team)
  - Accounting for the 2008-09 recession, recovery, energy efficiency improvements, and renewable energy standards is important for avoiding over allocation

Normalized Growth in CO_2e Emissions
U.S. DOE Annual Energy Outlook 2005 vs 2009





Basic Approach

1. Identify emission forecast methods
   - Appropriate for purpose of project
   - Provide growth factors at no additional cost
2. Collect "base year" emissions data from each Partner jurisdiction
   - As recent as possible
   - At a resolution that matches / takes advantage of the resolution in the forecast methods

Basic Approach

3. Apply emissions "growth factors" from each forecast method to the base year data and compare results

Example: WA Paper Manufacturing (NAICS 3221)								
	Base Emissions		ENERGY 2020			AEO		
Fuel/Process	Year	CO_2e	Surrogate	GF	2012	Surrogate	GF	2012
Natural Gas	2007	534,032	WA - EI Industry - Energy Use	0.85	453,927	National - Paper - NG Consumption	0.97	518,011
Waste Oil	2007	108,124	WA - EI Industry - Energy Use	0.85	91,905	National - Paper - Renewable Consumptior	0.95	102,718
Natural Gas	2008	98,886	WA - EI Industry - Energy Use	0.89	88,009	National - Paper - NG Consumption	0.99	97,897
Waste Oil	2008	73,539	WA - EI Industry - Energy Use	0.89	65,450	National - Paper - Renewable Consumptior	0.96	70,597

Emission Forecast Methods

Method Number	Energy		Industrial Processes	
	Canada	United States	Canada	United States
1	ENERGY 2020 energy use projections		ENERGY 2020 GHG emissions, fuel, and economic output projections	
2	*Canada's Energy Outlook* energy projections	*Annual Energy Outlook* energy projections	EPA non-CO_2 GHG projections and growth projected based on analysis of historical emission trends	
3	*Canada's Energy Outlook* socioeconomic projections	*Annual Energy Outlook* socioeconomic projections	*Canada's Energy Outlook* socioeconomic projections	*Annual Energy Outlook* socioeconomic projections

- Task 1a and Task 1b memos on SharePoint
  - Describe each method and compares them across five evaluation criteria
- The Task 2 memo on SharePoint
  - Describes a crosswalk linking growth factors from each method to base year emissions by jurisdiction, sector, and fuel/process

Method Comparison: Transparency

ENERGY 2020	AEO	CEO
• Major assumptions documented. • Extensive history of application/review by many clients. • Algorithms and functions deriving emission estimates are not identified in WCI documentation. • Calibration to historical emissions data not clear.	• Major assumptions very well documented. • Algorithms very well documented. • Undergone extensive review, including peer reviews.	• Much less well documented than AEO, however, CEO models are derived from AEO models.

Method Comparison: Scope

ENERGY 2020	AEO	CEO
• Comprehensive 2012 and 2015 emission forecasts provided for all Partner jurisdictions.	• Provides 2012 and 2015 energy sector and socioeconomic projections by regions. • Does not project industrial process activity/emissions.	• Provides 2010 and 2015 projections for energy sectors by province, and 2010/2015 national economic projections for a limited number of sectors. • Reports industrial sector projections by fuel type only for combustion sources. • Projects CO_2-equivalent total industrial sector "non-energy" emissions by province for 4 GHGs.

Regions Modeled by the AEO

Census Region

Electricity Market Module Regions

Method Comparison: Resolution

ENERGY 2020	AEO	CEO
• Primary fuel energy forecasts for each Partner jurisdiction. • Industrial processes not categorized at level of preferred detail. • U.S. power sector generation and emissions are modeled at the plant level, and by "model" plants in Canada. • US energy data are from 2004. The vintage of Canadian energy data is not documented.	• Primary fuel demand forecasts by region. • Power generation and emissions are forecast by NERC region, although modeled at plant-level. • RCI and transportation primary fuel use forecast at Census division level. • Incorporates data up through 2007	• Primary fuel demand forecasts for each sector reported by province. • Some growth factors available by province, others at national level. • Forecasts total CO_2e emissions by pollutant (no process-specific data are reported). • Does not specify the vintage of source data, however CEO projections were last published in 2006.

Method Comparison: Method Design and Foundation

ENERGY 2020	AEO	CEO
• Robustness of model difficult to assess (proprietary nature). • Does not explicitly assume learning curves over the period for most building end uses. • Price elasticities are modeled endogenously. • Electricity imports /exports between jurisdictions are simulated. • Impacts of numerous state/federal policies included.	• Built on a strong theoretical foundation and includes rich detail of energy technologies. • Develops 4 sets of alternative forecasts (low/high economic growth, and low/high oil prices). • Models learning-by-doing effect on tech costs. • Price elasticities, and their associated rebound effects, are modeled. • Impacts of numerous state/federal policies included.	• Provides cursory information on MAPLE-C model (derived from NEMS used in AEO) • Provides cursory information on the governmental policies for which impacts are estimated.

Method Comparison: Historical Performance

ENERGY 2020	AEO	CEO
• The range of differences between the 2006 model forecast and Partner base year emissions is generally modest, but some anomalies for a few jurisdictions. • Prediction of 2006-2007 growth in electricity sales and generation in Illinois was mixed.	• Provides historical performance evaluations in an annual Retrospective Report, indicating modest differences relative to actual EIA estimates.	• CEO does not document a retrospective comparison of its projections against historical estimates.

Base Year Emissions:
Two Major Types of Data

- “Bottom-up” data
  - Emissions reported for each facility based on emission measurements, fuel consumption, or other throughputs
  - Basis for 2012 forecast
- “Top-down” data
  - Emissions calculated for an entire sector and jurisdiction based on its fuel use or other activity data
  - Basis for 2015 forecast

Base Year Emissions: Data Collection Process

- In Aug-Sep, staff from each WCI jurisdiction were contacted to determine:
  - availability of bottom-up data
  - preferences for top-down data
  - estimates for voluntary reductions

See Task 3 memo on SharePoint

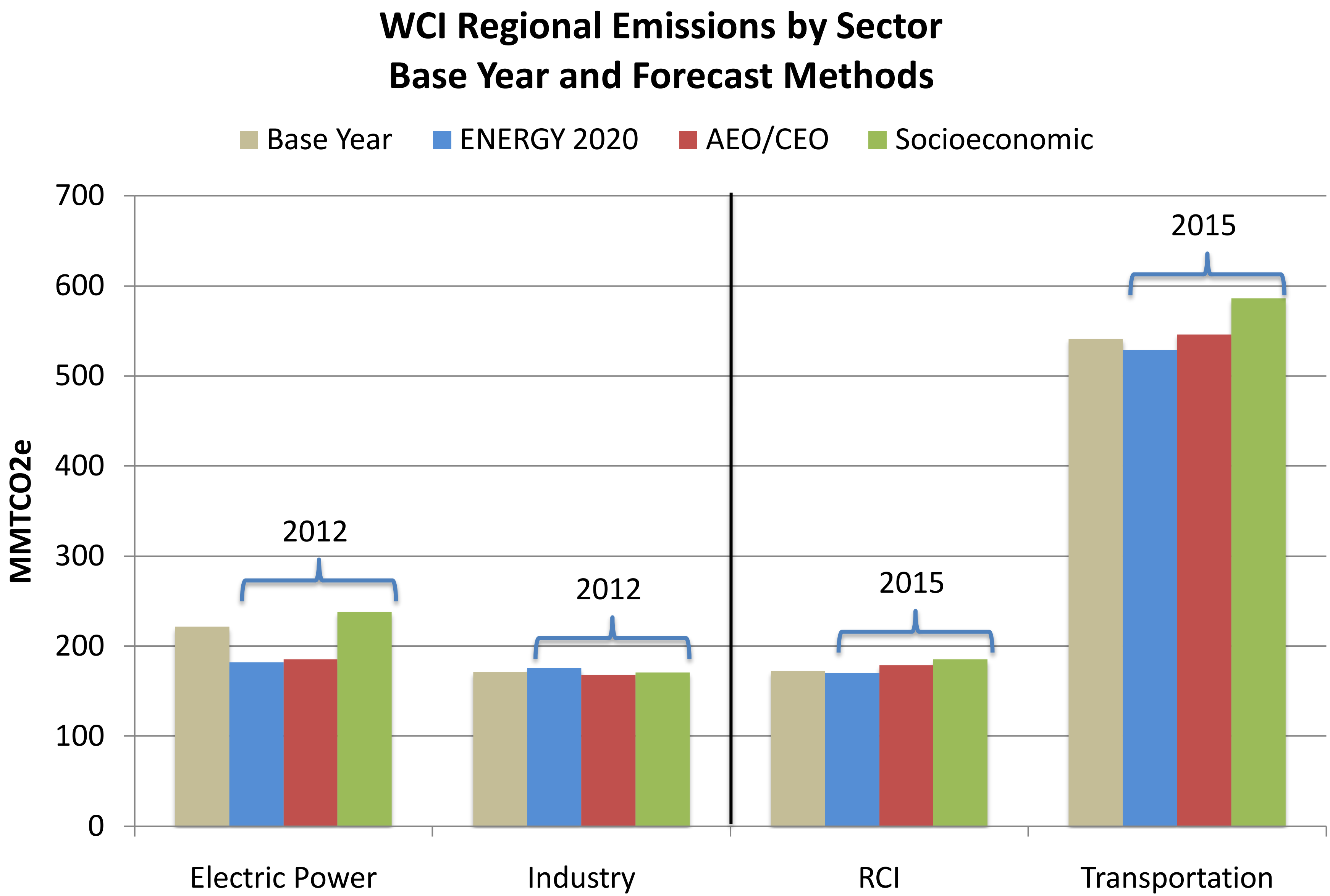
- In October, templates were sent to each jurisdiction to collect bottom-up data in a common format
- Sufficient data were collected for purposes of comparing forecast methods, but additional data will be needed for budget-setting purposes

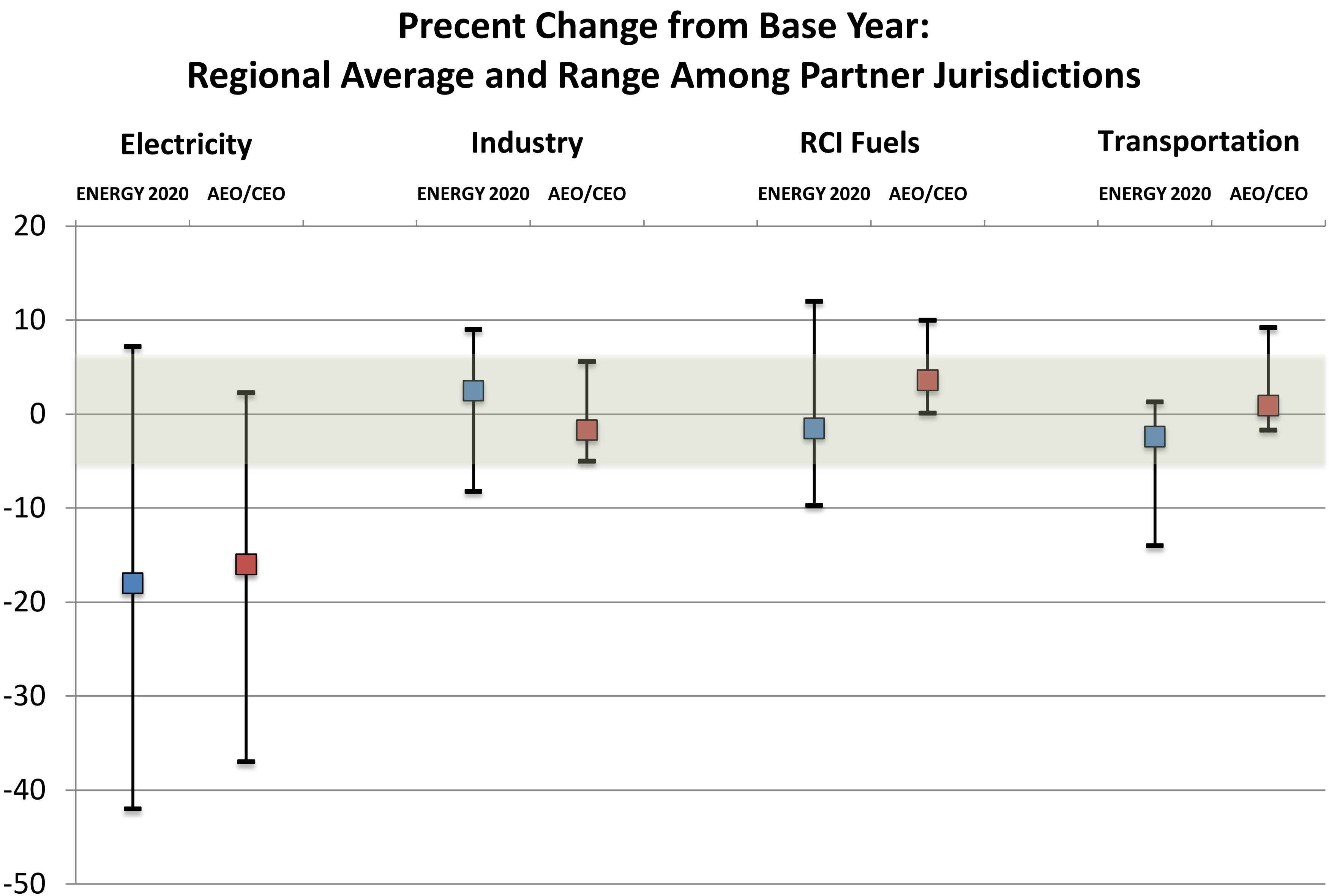
Base Year Emissions:
Data Sources

	Bottom-Up	Top-Down
BC, MB, ON	Federal Large Final Emitters Database (2008)	Federal National Inventory Report (2007)
QC	Provincial GHG reporting rule (2006)	
CA, NM	State GHG reporting rule (2008)	U.S. State Energy Data System (2007)
AZ, OR, WA	State/local air quality permits and some voluntary industry data in WA (2008 for AZ and 2007/2008 for WA)	
MT, UT	Mostly power plant data from EPA, with some industry data from MT (2008)	

Model Results

- Recently received, under review by staff
- Socioeconomic growth factors provide a useful reference but are not recommended as surrogates for forecasting GHG emissions
  - Do not account for significant changes in efficiency, renewable energy generation, demand response to price
  - Emissions growth surrogate not always appropriate (e.g., power sector employment)
- ENERGY 2020 generally predicts a wider range of changes than AEO/CEO


WCI Regional Emissions by Sector
Base Year and Forecast Methods
Base Year
ENERGY 2020
AEO/CEO
Socioeconomic
MMTCO2e
700
600
500
400
300
200
100
0
2012
2012
2015
2015
Electric Power
Industry
RCI
Transportation


Precent Change from Base Year:
Regional Average and Range Among Partner Jurisdictions
Electricity
Industry
RCI Fuels
Transportation
ENERGY 2020
AEO/CEO
ENERGY 2020
AEO/CEO
ENERGY 2020
AEO/CEO
ENERGY 2020
AEO/CEO
20
10
0
-10
-20
-30
-40
-50

Next Steps

- Partner review and feedback
- Additional data collection and analysis
  - Include electricity imports
  - Improve base year emissions data
- Decide on forecast approach
- Stakeholder review
- Additional funding required for all the above
- Prelim annual budgets from Partners by April?

Additional Data Collection/Analysis

- Top-down emissions data
  - Update data for U.S. and Canada from 2007 to 2008
- Bottom-up emissions data
  - Two states could not complete bottom-up inventory
  - Some states missing or have incomplete process emissions
  - Three provinces missing most sources in the 25-100kt range
  - Most U.S. power plant emissions for 2009 available by April
- Forecast data
  - New AEO and CEO expected this spring (last CEO was 2006)

Possible Forecast Approaches

1. All Partners use same method
2. Each Partner chooses most appropriate method or blend of methods
3. Investigate alternative methods
   - A third multi-sector equilibrium model
   - Single-sector method (electricity)
     - Partner-level data/knowledge (utility forecasts/IRPs)
     - Regional forecasts/model (NERC forecasts and utility production-cost modeling)

Possible Forecast Approaches

The following two approaches place a stronger emphasis on empirical data and Partner knowledge of local, near-term economic development and emission trends

4. Use methods above to portray the likely range of 2012 and 2015 best estimates while Committee continues improving inventory through 2011

   … as new data become available on economy, new sources, shutdowns, process emissions, and mandatory reporting.

5. Each Partner submits "best estimate"
   - Methodological results used as a check in this process

Western Climate Initiative

Next steps for WCI Offset Protocols

WCI Partners Meeting
Phoenix, AZ
January 20, 2009

Overview

Today, we are seeking Partner guidance on:

1. Completing the final DNV report
2. Options for adapting existing protocols to meet WCI's criteria
3. Options for stakeholder engagement on the DNV report and the adaptation of existing protocols

DNV Report

- DNV has completed the draft Report on Existing Offset Protocols.
- The Offsets Committee is awaiting Partner feedback prior to tasking DNV to complete the Report.
- On what timeline can we expect Partner feedback?

Options for adapting existing protocols to meet WCI criteria

We have discussed three different options for moving forward, which have different timing and cost implications.

1. **Staff complete required modifications for the existing protocols to meet WCI criteria**

   Time: Slow – high time commitment from WCI staff

   Cost: Low

   Considerations:

   - Do WCI Partner jurisdictions have the expertise and are they willing to dedicate staff time to this project?
   - Are there copyright issues with using existing protocols as the base?

Options for adapting existing protocols to meet WCI criteria, con't

2. WCI issues RFP to hire contractor(s) to complete the required modifications for the existing protocols to meet WCI criteria

Time: Fast

Cost: High

Considerations:

- Does WCI have the budget to complete this work via contractors?
- Are there copyright issues with using existing protocols as the base?

Options for adapting existing protocols to meet WCI criteria, con't

3. **WCI partners with the organizations that created the protocol to create a version that meets WCI criteria**

   Time: Fast

   Cost: Medium

   Considerations:

   - What if there are different organizations that are best for different project types?
   - Are the organizations willing to partner with WCI?
   - Are the organizations willing to put their resources into the partnership with WCI?
   - Should WCI select a single organization for all protocol adaptation work?
   - What financial contribution would WCI have to make?

Options for engaging the public

- Provide DNV's final report for public release to:
  1. provide public input on protocols evaluated by DNV;
  2. seek public comment on DNV's evaluation of the protocols;
  3. make suggestions on way forward.

Options for engaging the public, con't

- Involve public in protocol adaptation work:
  1. Involve experts in the protocol adaptation process;
  2. Involve the public directly in adaptation of protocols (subcommittee structure);
  3. Provide draft adapted protocols for public review and comment.

Options for engaging the public, con’t

- Seek public feedback on adapted protocols:
  1. Post final recommended protocols for comment;
  2. Hold stakeholder workshops/webinars for final protocols;
  3. Incorporate final protocols into Offset Essential Elements with final Committee recommendations.

Western Climate Initiative

Preliminary 2010 Work Plan Proposals

WCI Partners Meeting

Phoenix, AZ

January 20, 2009

Cap Setting and Allowance Distribution

- Task 1: Data Review and Collection
  - Assumes data collection by Committee will be used to assess issues, guide improvements, and promote transparency, but not as ***the*** data for setting budgets
  - Products and timing:
    - In process: Assemble regional emissions spreadsheet
    - In process: Draft recommendations for forecast methodologies
    - Ongoing: Spreadsheet revised every 3-6 months
    - March: Recommendations for harmonizing historic emissions data and applying forecast methodologies
    - April: Stakeholder call and comment on regional emissions data and projection methodologies
    - June – October: Compare and assess differences between inventory methodologies and reporting methodologies
  - Resources: Approximate budget is $95,000

Data Needed to Establish Annual Partner Allowance Budgets

Data sources in red to be provided by Partners
Data sources in blue to be provided by Partners and/or CSAD/contractors

+ New Sources
– Shut Downs
– Vol. Reductions ← **Forecasted Emissions** ← **Base Year Emissions (inc. electricity imports)**

CSAD Task 1

2001 – 2005 Econ-Wide GHG & **MWh Produced MWh Consumed** & **Population Growth**

CSAD Task 4

CSAD Task 2

2012 = **2012 B.E.** + **1% Adjustment** + **ERAs**

2013 = 2012 B.E. + 1% Adjustment - **ROD_1**

2014 = 2013 - ROD_1

2015 = 2014 - ROD_1 + **2015 B.E.**

2016 = 2015 - **ROD_2**

Etc

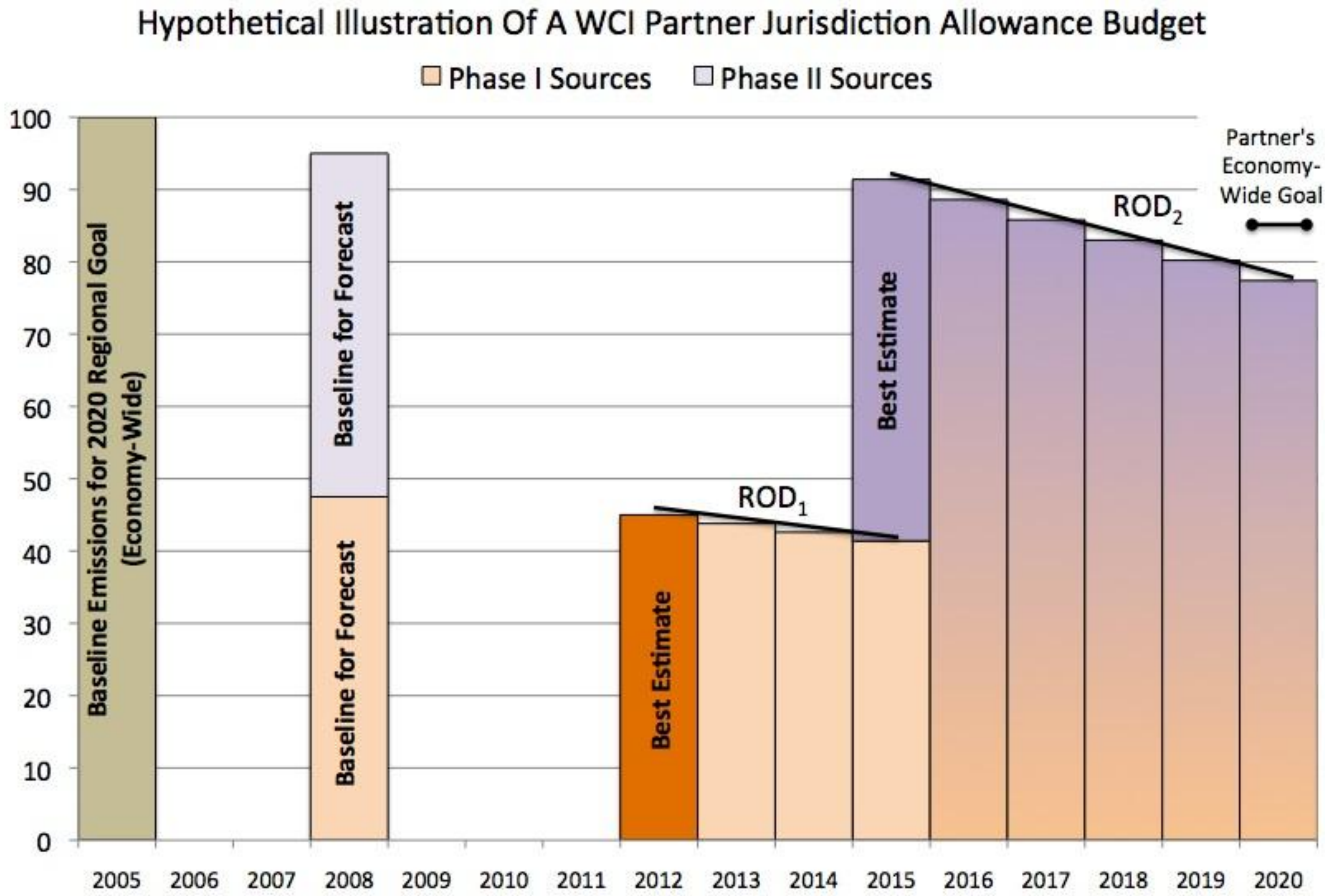
.

<u>Other factors potentially affecting budgets:</u>

- Results of mandatory reporting data in 2011
- Number of participants in C&T program in 2012
- Bilateral agreements on electricity generated in one Partner jurisdiction / consumed in another

Data Needed to Evaluate Reductions Against Regional Goal

- To determine if regional emissions are likely to be 15% lower in 2020 relative to 2005, the following data will be needed for each Partner jurisdiction:
- **2005 Economy-Wide GHG Emissions**
  - Could use the 2001-2005 data from the 1% adjustment
- **2020 Best Estimate of Uncapped Emissions**
  - Would be added to 2020 budget to determine economy-wide emissions
  - Waste, wastewater, non-combustion agriculture/forestry, and miscellaneous industrial process emissions
    - Process emissions without sufficient monitoring protocols
    - Process emissions with sufficient monitoring protocols but at facilities whose total emissions are less than 25,000 tpy CO_2e



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Baseline Emissions for 2020 Regional Goal (Economy-Wide)
Baseline for Forecast
Baseline for Forecast
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Best Estimate
ROD1
ROD2
Partner's Economy-Wide Goal
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020

CSAD *Cont.*

- Task 2: Cap and Budget Setting
  - Principal work involves potential revision to draft guidance document and implementation of guidance by Partners and Committee
  - Products and timing:
    - March: Approve any revisions to guidance document
    - April: Submit/review "preliminary" budgets
    - June: Partner jurisdictions agree to "established" budgets
    - October 2011: Partner jurisdictions agree to "final" budgets
  - Resources: No additional needs are currently identified

CSAD *Cont*

- Task 3: Competitiveness Analysis
  - CSAD will work closely with the Electricity Team to assess competitiveness issues in the electricity sector
  - Products and timing:
    - Jan – March: Data analysis for competitiveness impacts, and evaluate mechanisms to address
    - March: Stakeholder call and comment
    - April: Options papers - methods for additional assessment , and mechanisms to address competitiveness
    - TBD: Stakeholder workshop
  - Resources: No additional needs are currently identified

CSAD *Cont.*

- Task 4: 2012 One-time Budget Adjustment
  - Products and timing:
    - February: Draft criteria recommendations
    - March – April: Data set for the budget adjustment
    - May: Final adjustment recommendation
  - Resources: $10,000 for gathering data and initial calculation
- Task 5: Offset Compliance Limit
  - Products and timing:
    - February : Offset Compliance Limit Recommendations
    - March: Stakeholder call
  - Resources: No additional needs are currently identified

CSAD *Cont.*

- Task 6: Early Reduction Allowances (ERA)
  - Products and timing:
    - February: Draft recommendations on ERA criteria and process
    - March: Draft ERA design recommendations (with a background document)
    - April: Stakeholder call and comments
    - June: Final ERA design recommendations
  - Resources: No additional needs are currently identified

Markets Committee

- Task 1: Coordinate Development of Cap-and-Trade Essential Elements
  - 2009 Status: Moved out of Markets Committee to be under overall responsibility of Partners through Co-Chairs
- Task 2: Recommend Compliance Verification and Enforcement Requirements
  - 2009 Status: Work deferred as part of mid-year prioritization
  - Products: **Partner input requested on what specific products are needed from this task to support 2010 WCI priorities**
  - Timing: TBD based on guidance received
  - Resources: Partner staffing support needed

Markets Committee, *Cont.*

- Task 3: Recommend Market Oversight
  - 2009 Status: Objectives defined, white paper released, and stakeholder call and workshop held
  - Products, timing and resource needs:
    - March: Draft recommendations (budget TBD, no additional staffing needs)
    - March-June: Options paper on quantity limits ($25,000)
    - April: Stakeholder call and comments
    - May-June: Final recommendations

Markets Committee, *Cont.*

- Task 4: Recommend Tracking Systems and Related Infrastructure
  - 2009 Status: Work deferred as part of mid-year prioritization
  - The task group recommends two tracks for 2010:
    - Tracking system policy recommendations (to be completed in time to feed into the model rule)
    - Approach to tracking system procurement (timing TBD)
  - Resources: Budget TBD. Partner staffing support needed.

Markets Committee, *Cont.*

- Task 5: Design Regional Administrative Body
  - 2009 Status: Work deferred as part of mid-year prioritization
  - Products: **Partner input requested on whether interest in broadening RAO work beyond cap and trade to support complementary policies (e.g. LCFS)**
  - Resources: Budget TBD. Partner staffing support needed.
- Task 6: Recommend Auction Design for Allowances
  - 2009 Status: White paper drafted, circulated for peer review
  - Products and timing: White paper and draft/final recommendations (Feb-June 2010)
  - Resources: Budget TBD. Partner staffing support needed.

Offsets Committee

- Task 1: Recommendations for Offset System Essential Elements
  - Products and timing - Offsets Definition and Criteria
    - Jan : Draft recommendations, release for stakeholder comment
    - March – April: Draft Final recommendations, release for stakeholder comment
    - June: Final recommendations, release for stakeholder comment
  - Products and timing – Offsets Process
    - Feb: White paper, release for stakeholder comment
    - March-April: Draft recommendations, release for stakeholder comment
    - May: Draft Final recommendations, release for stakeholder comment
    - July: Final recommendations, release for stakeholder comment
  - Resources: No additional needs are currently identified

Offsets Committee, *Cont.*

- Task 2: Recommendations for accepting offsets credits and allowances from systems other than the WCI
  - On hold: Develop white paper and recommendations
  - Current work:
    - Monitor ongoing development of international offset mechanisms and the linking of emission trading systems on an ongoing basis.
    - Prepare comments for WCI as needed.
  - **Partner input requested: is specific work required on this task to support June WCI priorities.**

Offsets Committee, *Cont.*

- Task 3: Offset Protocols
  - Products and timing:
    - Feb: Evaluation Report on Existing Protocols, release for stakeholder comment
    - March – December: Adapt existing protocols (timing TBD based on resources – possible additional resources from 3 regional initiatives collaboration):
    - July onwards: Recommend protocols where no suitable protocol exists
    - October – December: Release final WCI protocols for WCI Partner jurisdiction adoption
  - Resources:
    - $50,000 per protocol for significant modifications of an existing protocol
    - $100,000 per protocol for new protocols where no suitable protocol exists

Reporting Committee

- Task 1: Harmonization of WCI Essential Requirements for Mandatory Reporting (ERs) with EPA Mandatory Reporting Rule (EPA Rule)
  - Products and timing
    - In process: Committee technical work to review EPA Rule and identify changes needed for:
      – WCI program
      – Conformance to Canadian regulatory norms
    - March-April: First present final recommendations, stakeholder call and comments
    - April: Final ERs
  - Resources: No additional needed

Reporting Committee, *Cont.*

- Task 2: Develop Essential Requirements for Mandatory Reporting for Oil and Gas Exploration and Production and Natural Gas Processing
  - Products and timing:
    - In process: Ongoing calls/workshops with stakeholder Technical Working Group
    - March: WCI comments to US EPA on re-proposed Subpart W of their mandatory reporting rule
    - December: First present harmonized ERs for Mandatory Reporting for Oil and Gas, stakeholder comment period
    - January 2011: Approve final ERs
  - Resources: No additional needed

Electricity Team

- Task 1: Attributing emissions for electricity imports
  - Products and timing
    - In progress: Default emissions calculator to determine emission factors for imports (tied to CSAD Task 1 & 2, will be discussed at Collaborative)
    - In progress: OATI report and analysis, and eastern provinces data collection, to quantify historical imports (tied to CSAD Task 1 & 2 and Reporting, will be discussed at Collaborative)
    - In progress: Recommendation on treatment of RECs
    - March – July : Recommendation on conditions for specified imports
  - Resources: No additional needed

Electricity Team, *Cont.*

- Task 2: Estimate Eastern Leakage potential
  - Products and timing
    - In progress: Contractor study to estimate Eastern Leakage potential
    - January: Initial results will be presented at Collaborative
    - March: Report complete, will be used as input for eastern Provinces decision on FJD
  - Resources: No additional needed

Electricity Team, *Cont.*

- Task 3: Recommend Administrative Option Design
  - Products and timing:
    - January – Feb: Issues will be discussed at Collaborative
    - March - June: Draft and final Administrative Option recommendations
  - Resources: Support staff assistance on analysis and drafting

Electricity Team, *Cont.*

- Task 4: Voluntary Renewable Energy
  - Products and timing:
    - January – Feb: Draft options and recommendations paper will be presented at Collaborative, released for stakeholder comment
    - April: Final recommendations
  - Resources: Support staff assistance
- Task 5: Competitiveness and Reliability Issues Related to Distribution of Allowance and Allowance Value
  - Support CSAD Task 3 on competitiveness issues associated with the electricity sector – Team will provide analysis and recommendations as required.
  - Resources: Possible support staff assistance

Complementary Policies

- Task 1: Selection of Complementary Policies for Preliminary Analysis
  - Almost complete:
    - Stakeholder comment period on Complementary Policies White Paper closes Jan 29, 2010.
    - Committee will then amend and finalize paper.
- Task 2: Stakeholder input and dialogue
  - The committee will continue to work to identify and pursue ways to obtain stakeholder views and engage additional partners
  - Additional resources not anticipated

Complementary Policies, *Cont.*

- Task 3: Analyze Workforce Issues and Develop Recommendations
  - Products and timing: To be developed based on Partner guidance
  - Resources: Additional needs will depend on approach developed and ability to access state/provincial experts

Complementary Policies, *Cont.*

- Task 4: Recommend Complementary Policies for Regional Harmonization
  - Products and timing:
    - June: Draft white paper on policies for regional harmonization
    - June: Stakeholder review and comment
    - July: Final recommendations for harmonized policies
  - Resources: Additional needs will depend on policies selected
- Task 5: Inventory of inter-jurisdictional adaptation work groups, committees and other collaborations
  - Work deferred in 2009 as part of mid-year prioritization
  - Partner input requested on priority of this task for 2010

Western Climate Initiative

Administrative approach to covering imported electricity in the WCI cap and trade system

Electricity Collaborative
Phoenix, Arizona

January 21, 2010

Background

- September 2008 Design Recommendations recommend First Jurisdictional Deliverer (FJD) as point of regulation for electricity sector including imported electricity
- July 2009 recommendation to use individual boundary approach
- September 2009: Electricity team asked to propose an administrative option

Rationale

- Some jurisdictions may import only small amounts of fossil-fuel-fired electricity and it may be more cost effective to take an administrative approach to those very small emissions
- The environmental integrity of the cap (total number of allowances in 2012 and declining amounts through 2020) should be considered in the alternative approach
- The effect of the price signal for buyers and consumers of imported electricity GHG emissions created by the cap should be considered in the alternative approach

Concept

Step 1: Jurisdiction determines 2012 forecast emissions for imported electricity

Step 2: Jurisdiction creates allowances equal to the forecast emissions and places them in a the jurisdiction’s reserve account

Step 3: Jurisdiction tracks emissions attributable to imported electricity consumed in the jurisdiction

Step 4: Jurisdiction retires allowances in an amount equal to emissions attributable to imported electricity

Possible Results

- FJD has no direct compliance obligation under jurisdiction’s cap and trade system
- Price advantage for importers of fossil-fuel-fired electricity may be contained if the amount of imports are small or if the type of imports is regulated by another regulator under an approach such as a Renewable Portfolio Standard
- Negative impacts on GHG and electricity markets could be mitigated if electricity is imported under a specified contract and generation information is tracked by the jurisdiction to calculate annual reserve pool amounts.

Challenges

1. Forecasting the reserve pool
   - What if the reserve pool is insufficient to cover emissions from imports?
     - Are allowances taken from other compliance entities?
     - Does the jurisdiction purchase allowances on the market?
   - What if the reserve pool contains more allowances than are needed to cover emissions from imported electricity?
     - Are excess allowances retired?
   - Reserve pool would not affect integrity of cap so long as 2010 baselines are not inflated.

Challenges

2. Creating a price signal for deliverers of power from outside the jurisdiction.
   – Administrative option may create incentive to shift emissions out of region (leakage).
   – Administrative option imposes no carbon price on electricity from outside jurisdiction, while putting a price on in-jurisdiction generation
3. Creating a price signal for purchasers and consumers of power from outside the jurisdiction.
   – Administrative option creates price differential for electricity suppliers (and their consumers) in same jurisdiction based on regulation coverage and not on emissions

Summary questions

- Can an administrative approach be designed to achieve the environmental objective while also sending a consistent price signal to deliverers, buyers and consumers of imported electricity?
  – How important is the price signal to importers/traders?
  – How can the design be modified to reduce or eliminate leakage?
  – How important is the price signal to consumers?
  – How can the design be modified to emulate the price signal of the cap and trade coverage

Western Climate Initiative

Electricity Collaborative

Tempe Mission Palms Hotel

60 East 5th Street
Tempe, AZ 85281

Remote access: Call 1-800-868-1837 toll free in the U.S. and Canada
(1-404-920-6440 for outside the U.S. and Canada)
Participant code 659 537#

Thursday, January 21, 2010

8:30 am Welcome and Introductions (Palm Conference Room)

8:40 am Status of WCI program development
Overview of WCI design as it relates to the electricity sector

9:00 am Industry and Environmental Perspectives on Status of Carbon Regulation

Panelists:

- Ed Fox, Vice Pres. & Chief Sustainability Officer, AZ Public Service Co.
- David Butters, President, Association of Power Producers of Ontario
- Steven Kelly, Dir. of Policy, Independent Energy Producers Assoc., CA (invited)
- Suzanne Leta Liou, Renewable Northwest Project

10:30 am Break

10:45 am Moderated discussion with panel and WCI Partners followed by audience Q&A

11:30 am Wrap-Up and Next Steps – Discuss opportunities for ongoing collaboration

12:00 pm Lunch

1:00 pm WCI Electricity Team

General introduction to the issue of addressing emissions from imported electricity, including status of OATI work on historical emissions

1:30 pm Default Emissions Calculator

- Electricity Team will present and discuss default emission rates suggested by their work on an updated calculator.

2:00 pm Eastern Leakage Study

- The WCI's contractor for the Eastern Leakage Study (Navigant Consulting) will provide an update on their analysis.

3:00 pm Break

3:15 pm Voluntary Renewable Energy Market

- The WCI Electricity Team will present its white paper on this topic, including recommendations.
- Response from environmental representative

4:15 pm Administrative Option

- The Electricity Team will present a description of the administrative option and call for comments.

5:00 pm Adjourn

WCI Greenhouse Gas Analysis for Ontario, Quebec and Manitoba
DRAFT

Prepared for

Western Climate Initiative

January 21, 2010

Disclaimer

Status of Report

The results summarized in this report are the results of Navigant's analysis and as such as are draft and are subject to review and acceptance by WCI

Copyright

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1 Introduction
2 Modeling Methodology
3 Modeling Results
4 Contract Shuffling
5 RGGI & MGGRA
6 Modeling Conclusions

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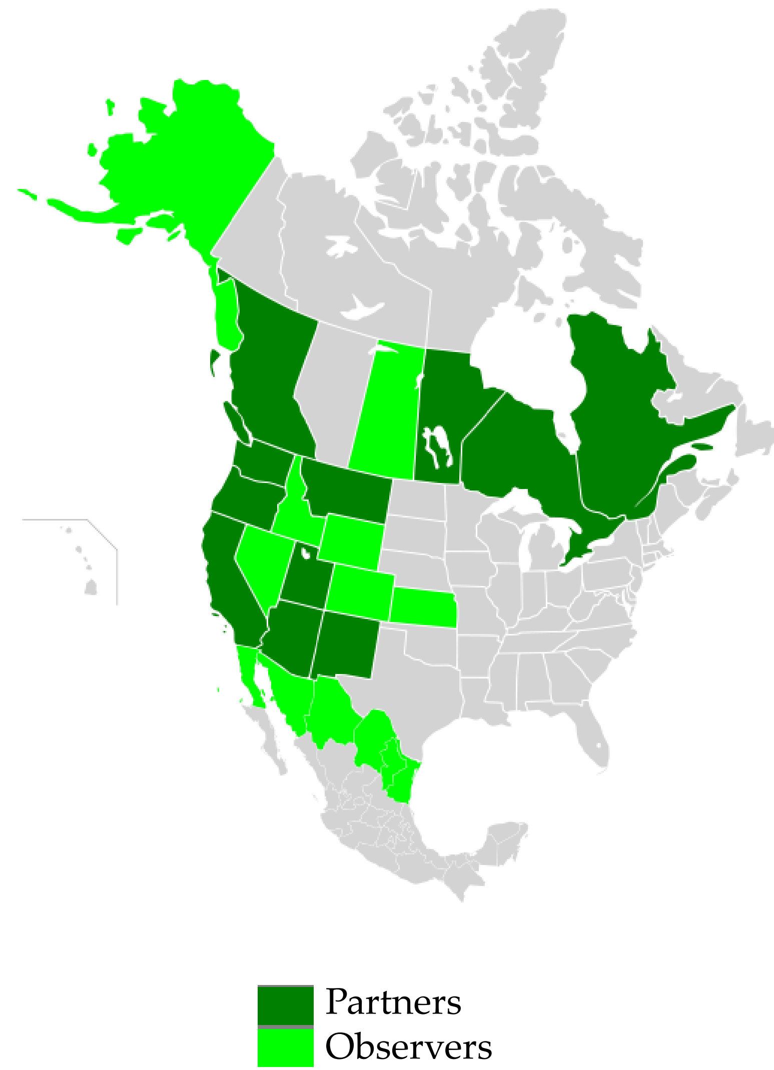
Study Scope

- WCI retained Navigant Consulting to analyze how electricity system operation would change if the Eastern Canadian WCI members (Manitoba, Ontario and Quebec) put a price on carbon
  - In particular, Navigant was to look at 'leakages' – whether reductions in WCI emissions would be offset by increases in non-WCI emissions
- The analysis was based on a series of hourly simulations of the electricity system in eastern Canada and the eastern U.S.
  - With and without carbon emission charges in Quebec, Ontario and Manitoba
  - With and without deemed charges on importing electricity into Quebec, Ontario and Manitoba

Western Climate Initiative Participants



Who We Are

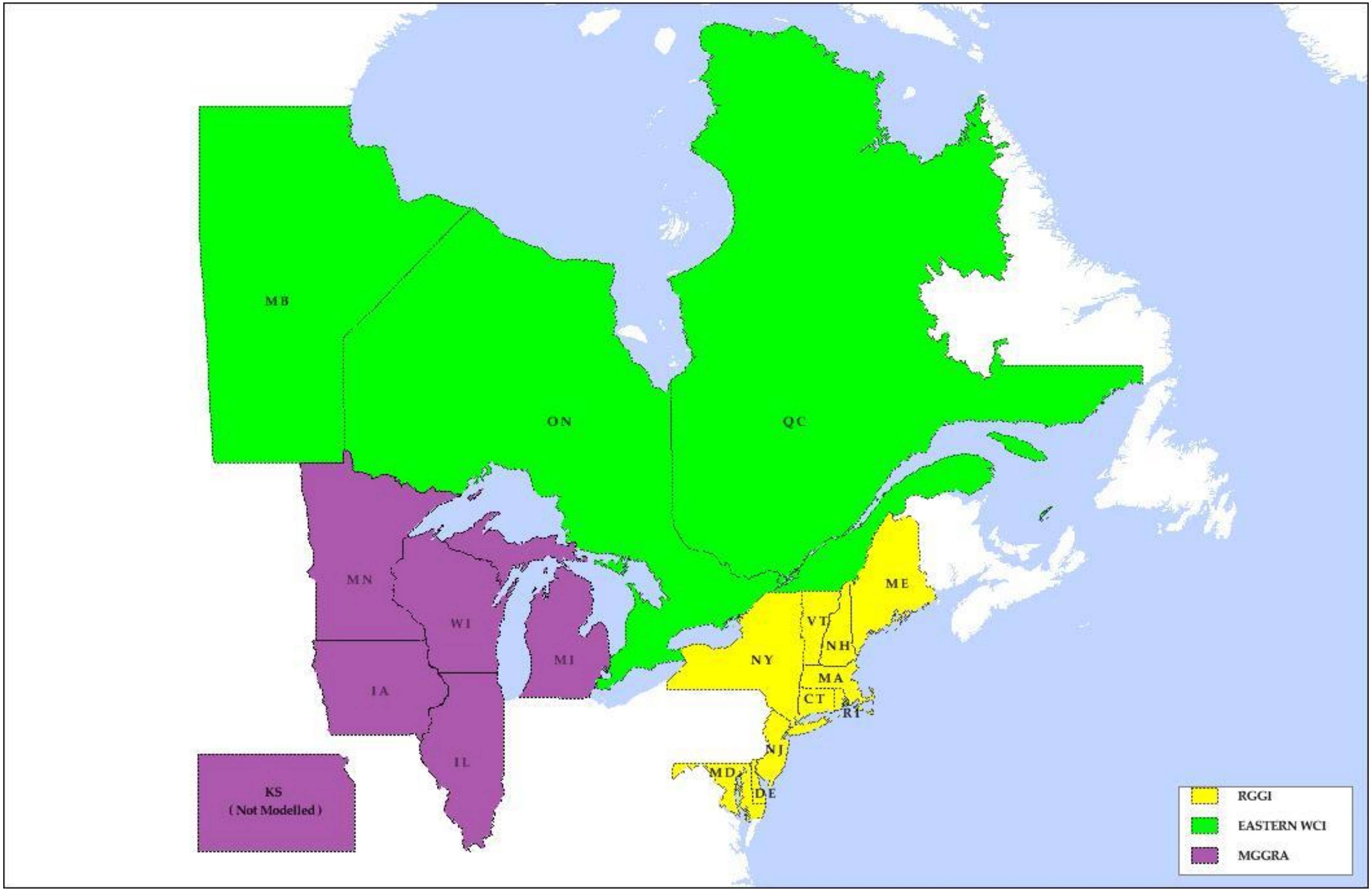
Navigant Consulting ("NCI") is a specialized independent consulting firm providing professional services to assist clients in identifying practical solutions to the challenges of uncertainty, risk and distress.

- NCI has over 1800 professionals in 30 cities
- The Energy Practice, hired by the WCI for this analysis, is 250 professionals and provides a full range of advisory services for energy sector clients
- Particular expertise in clean energy, renewables and greenhouse gas issues

Questions Addressed

- This study was intended to address the following questions:
  - Expected reduction in WCI emissions with various carbon and import charges
  - Offsetting increases in non-WCI emissions
  - Changes in generation and flows
  - Average carbon content of induced imports
  - Impact of exempting non-fossil generation outside WCI from import charges
  - Impact of aligning with RGGI (Regional Greenhouse Gas Initiative) and MGGRA (Midwestern Greenhouse Gas Reduction Accord)

WCI – MGGRA – RGGI Geography



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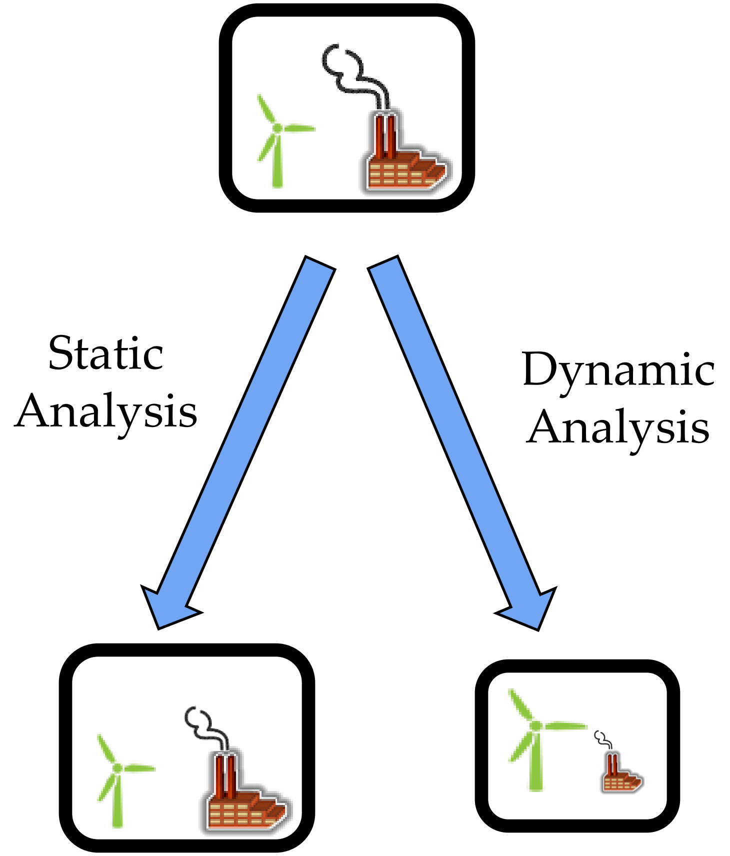
Static Analysis Only

- Important caveat: this is a STATIC analysis
  - Available power plants are fixed – the only change is how they operate
  - Demand is fixed – no change in total generation
  - Annual output of non-fossil plants is fixed – only fossil output can change
  - Carbon charges in WCI

    => less fossil generation in WCI

    => more fossil generation in non-WCI areas
  - Expect shifting of carbon emissions but no significant overall reduction
- Dynamic analysis (NOT considered here) would involve different expansion plans in each scenario.
  - Higher carbon prices would lead to less fossil and more non-fossil capacity
  - Potentially different demand
  - This was beyond the scope of this study



Assume no change in demand or generation *capacity*; expect less fossil generation *output*.

Expect lower demand due to higher prices, less fossil generation capacity, more non-fossil generation capacity.

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PROMOD IV

- PROMOD IV is a commercial software package that simulates the hourly operation of electricity markets:
  - Widely used in the U.S. by utilities, energy consulting firms and ISOs including WECC, PJM and MISO
  - PROMOD typically used to forecast future electricity prices and generation, revenue and costs for units
- PROMOD represents the US using three regional models:
  - WECC, the Western Electricity Coordinating Council, which covers the western U.S., Alberta and British Columbia
  - ERCOT, the Electricity Reliability Council of Texas, which covers most of Texas
  - Eastern Interconnect, the generation and transmission system that extends from Eastern Canada to Florida into the Midwest
- For the WCI analysis Navigant used the Eastern Interconnect model:
  - For Canada, this includes Quebec, Ontario, Manitoba, Saskatchewan and the Maritime provinces
  - For the US, this includes the ISO NE, NYISO, PJM, MISO markets and regulated areas in the Midwest/southeast U.S.

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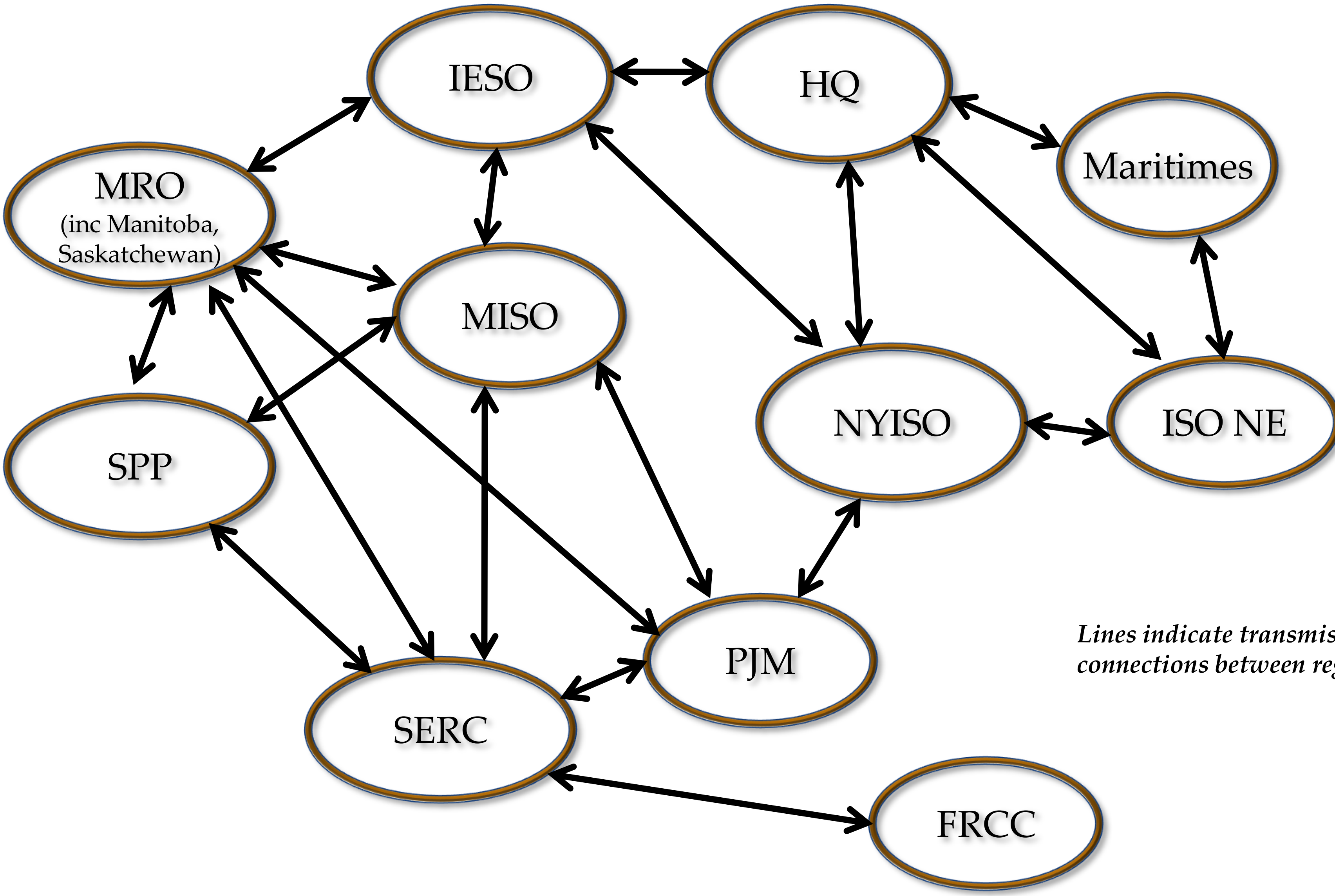
Eastern Interconnect Pool Structure



Lines indicate transmission connections between regions

PROMOD IV – Methodology

- PROMOD is a chronological optimization model that simulates the hourly operation of generation and transmission across the markets/regions included
- For each hour, PROMOD commits and dispatches units in order of increasing generation cost until hourly demand is met, while taking into account unit operating constraints and transmission limits:
  - The unit operating constraints represent real system parameters such as outages, unit minimum up and down times, ramp rates, heat rate structures
  - The transmission line limits and interface limits represent the operating restrictions that apply to the physical transmission system
- PROMOD's commitment and dispatch solution corresponds to least cost across the Eastern Interconnect, subject to the constraints defined by the user
- PROMOD output includes – hourly, monthly, annual, peak/off peak as necessary:
  - Prices at specific generators, load buses and zonal averages
  - Generation, cost and revenue data for units
  - Estimated emissions - SO_2, NO_X, CO_2 and Mercury if applicable - for units
  - Flows on transmission lines

PROMOD Assumptions

- To set up the Eastern Interconnect WCI runs for 2012 and 2020, Navigant provided assumptions for:
  - Existing and planned generation, based on published sources
  - Peak and annual energy forecasts, based on published ISO forecasts
  - Expected wind and hydro generation, based on published sources
  - Fuel prices – oil, gas, coal – based on the NCI Fall 2009 fuel forecasts
  - The likely transmission system in 2012 and 2020, based on FERC load flows and ISO transmission expansion plans
- These assumptions covered all regions in the Eastern Interconnect
  - Data assumptions for the WCI eastern Canadian provinces were reviewed by Manitoba, Ontario and Quebec

US – Canada Transmission Connections

- For the WCI analysis, PROMOD was run as a **nodal** model which includes a detailed representation of individual transmission lines in the Eastern Interconnect
- There are significant transmission interfaces that permit import and export of power into the eastern Canadian WCI provinces

  Quebec – New Brunswick [~1080 MW]

  Quebec – ISO NE [~1670 MW, expected to increase to ~2870 MW]

  Quebec – NYISO [~1625 MW]

  Ontario – NYISO [~1825 MW]

  Ontario – MISO [~2540 MW]

  Manitoba – MISO [~2175 MW]
- These transmission links create the possibility for leakage, where US generation and CO_2 emissions increase in response to WCI CO_2 regulation
- Quebec and Manitoba have substantial hydro generation and generation in excess of demand
  - Hydro Quebec has indicated intentions to increase exports to the northeast US to reach ~15-20 TWh annually
  - This assumes planned hydro and wind developments occur

WCI Modeling Methodology

- WCI Allowance Prices:
  - For some scenarios, PROMOD was set up to allow the inclusion of a CO_2 cost for carbon-emitting units in the WCI provinces, according to the proposed regulations
  - For some scenarios, a similar cost was added for thermal units in certain MGGRA states – Illinois, Wisconsin, Minnesota, Iowa, Michigan – based on that proposed legislation
- FJD Charges
  - WCI scenarios typically assumed that power imported from regions outside the WCI would attract a charge based on the assumed carbon content of the imported power
  - This is a mechanism to reduce 'leakage'
  - Referred to as FJD, First Jurisdictional Deliverer
  - Defined in PROMOD by setting tariffs between external pools to WCI provinces
- Key Assumptions:
  - Scenarios considered effects of WCI allowance and FJD charges assuming no change in demand and generating capacity from Base Case
  - Implies total generation across Eastern Interconnect is unchanged, ignoring slight difference in losses and pumped storage
  - Hydro and wind generation are unchanged as these are defined in PROMOD on the basis of annual expected generation
  - **Result is that in each scenario the balance of thermal generation changes in terms of coal/gas and US/Canadian share, taking into account transmission limits between the US and Canada**

Details of WCI Scenario Parameters - Regulatory

- Base Case
  - CAIR SO_2, NO_x in US
  - No national CO_2 in US but RGGI CO_2 in 10 north eastern US states
  - No mercury regulation
  - Ontario NO_X and SO_2
  - US regulations apply to units > 25 MW
- WCI allowance cases
  - Scenarios with $15, $30, $60 /metric tonne [US $]
  - Applied to carbon-generating units in Quebec, Ontario, Manitoba that generate more than 25,000 metric tons of CO_2 annually
  - Biomass units defined to be non-carbon generating
  - Nuclear units although thermal are non-carbon generating
- MGGRA
  - Similar legislation proposed for MGGRA
  - Five US states – Illinois, Wisconsin, Minnesota, Iowa, Michigan - plus Manitoba
  - For some scenarios, WCI and MGGRA allowance price aligned
- FJD charges
  - Defined on basis of assumed carbon content of imported power – 500 kg/MWh, 1000 kg/MWh
  - In terms of $/MWh adder, translates to 50% or 100% of WCI allowance price for each scenario
  - Depending on PROMOD setup, can be applied to all power imported into WCI provinces form non-WCI regions or can be applied to just imports from carbon-producing units

WCI Modeling - Simple Scenarios

First set of simulations considered scenarios with:

- CO_2 regulation for generating units in the eastern WCI provinces – Quebec, Ontario, Manitoba
- No corresponding CO_2 regulation in MGGRA states – Illinois, Wisconsin, Minnesota, Iowa, Michigan. [Kansas was not included in this analysis to reduce modeling complexity, and Manitoba is in the WCI]
- RGGI regulation in NE US **not** aligned with WCI regulation in terms of CO_2 allowance price
- FJD charges applied to all flows into Quebec, Ontario, Manitoba from other provinces/states – no distinction made on basis of carbon content of imported power

Scenario #	Years	WCI Allowance Price *$/tonne*	MGGRA Allowance Price *$/tonne*	RGGI Allowance Price *$/tonne*	FJD Charge *kg/MWh*	*$/MWh*
1 [Base Case]	2012, 2020	0	0	2.06	0	0
2	2012, 2020	30.00	0	2.06	0	0
3	2012, 2020	30.00	0	2.06	500	15
3a	2020	60.00	0	2.06	500	30
4	2012, 2020	30.00	0	2.06	1000	30
5	2012, 2020	15.00	0	2.06	0	0
6	2012, 2020	15.00	0	2.06	500	7.5
7	2012, 2020	15.00	0	2.06	1000	15
8	2012, 2020	15.00	0	15	500	7.5

Notes

1. In this table, RGGI allowance prices from the auction result - $1.87/short ton - have been converted to metric tonnes

2. In these scenarios the FJD charge applies only to imports from all units

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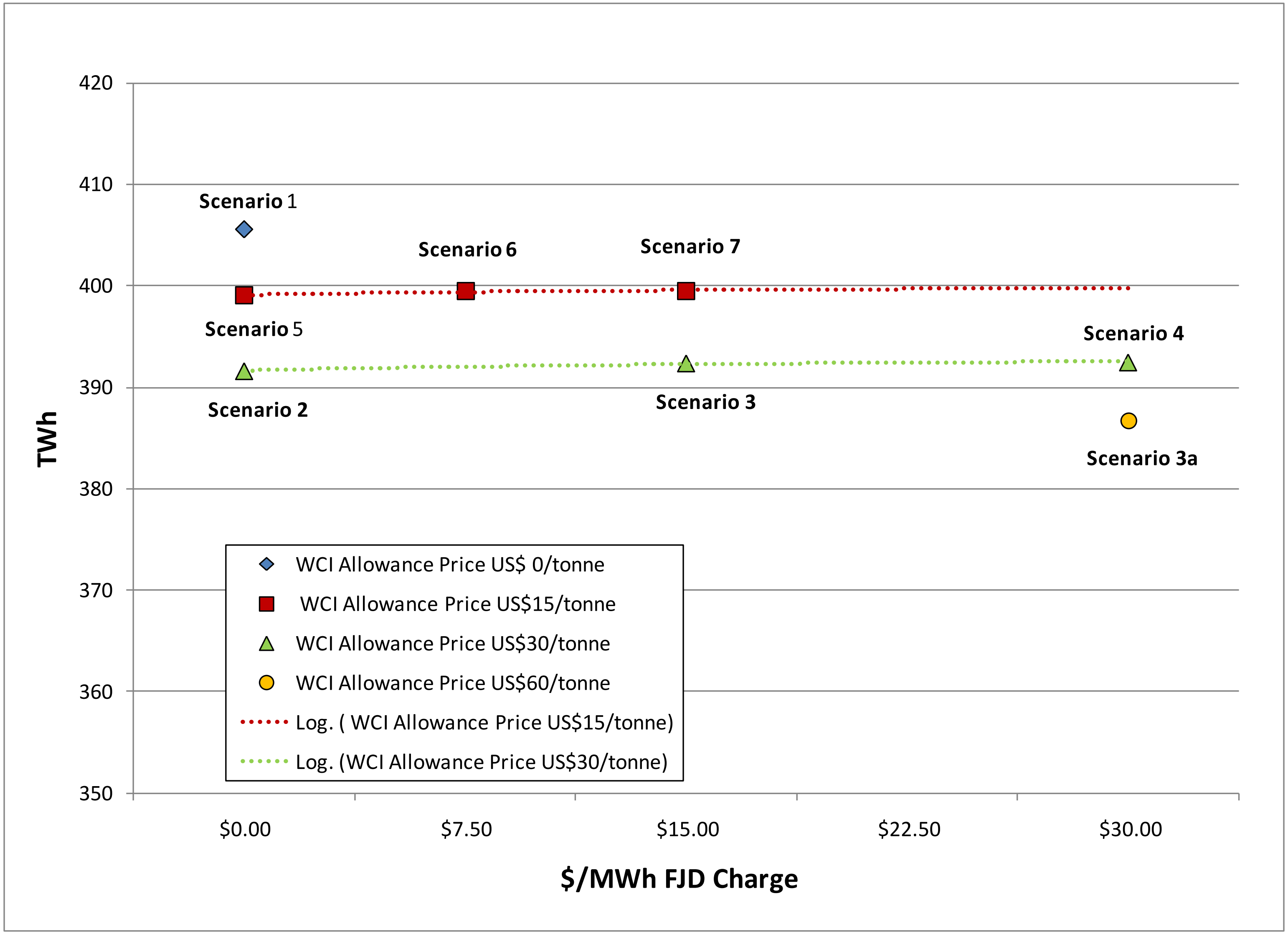
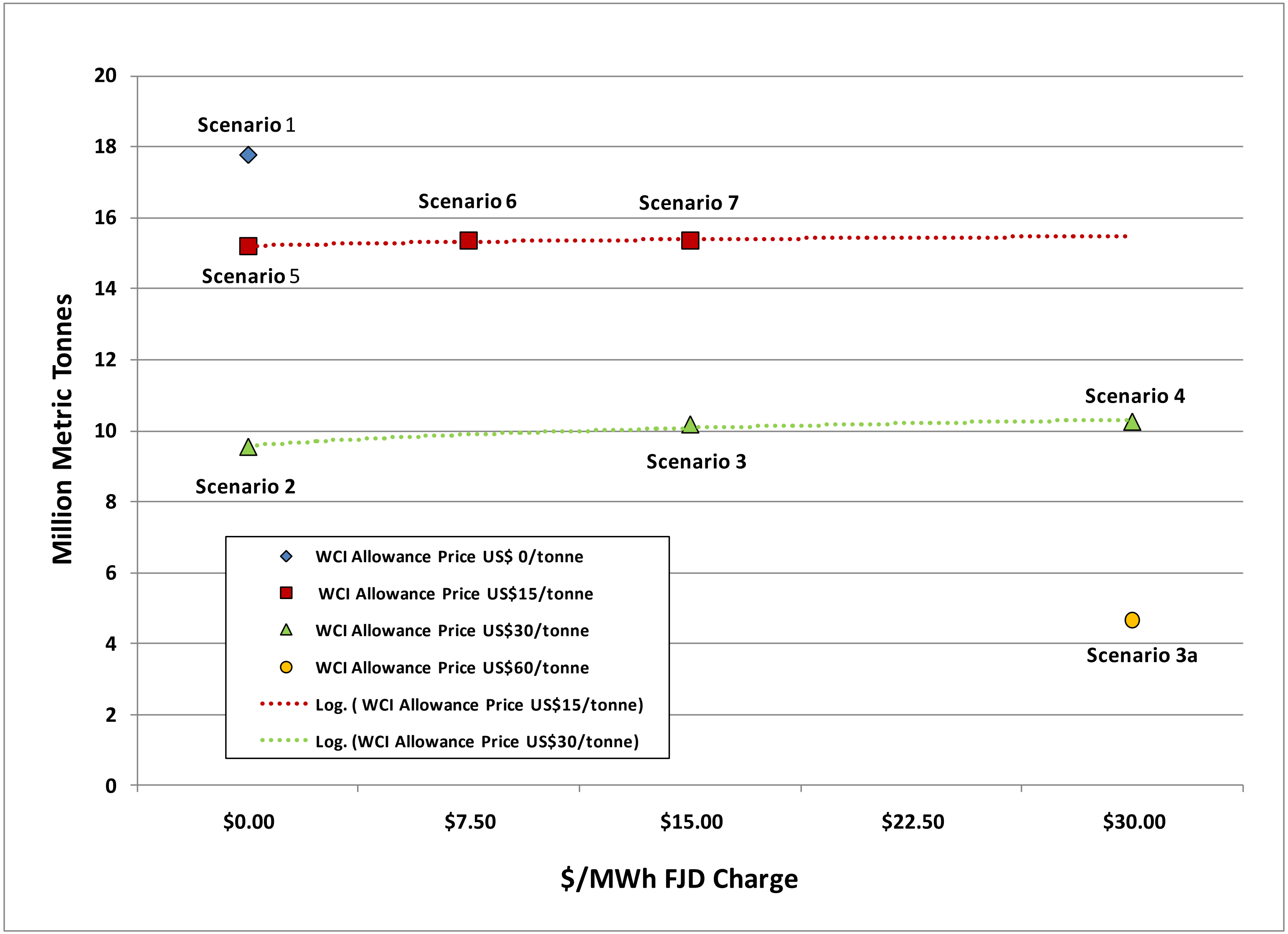
WCI Generation - 2012



Eastern WCI CO_2 Emissions - 2012



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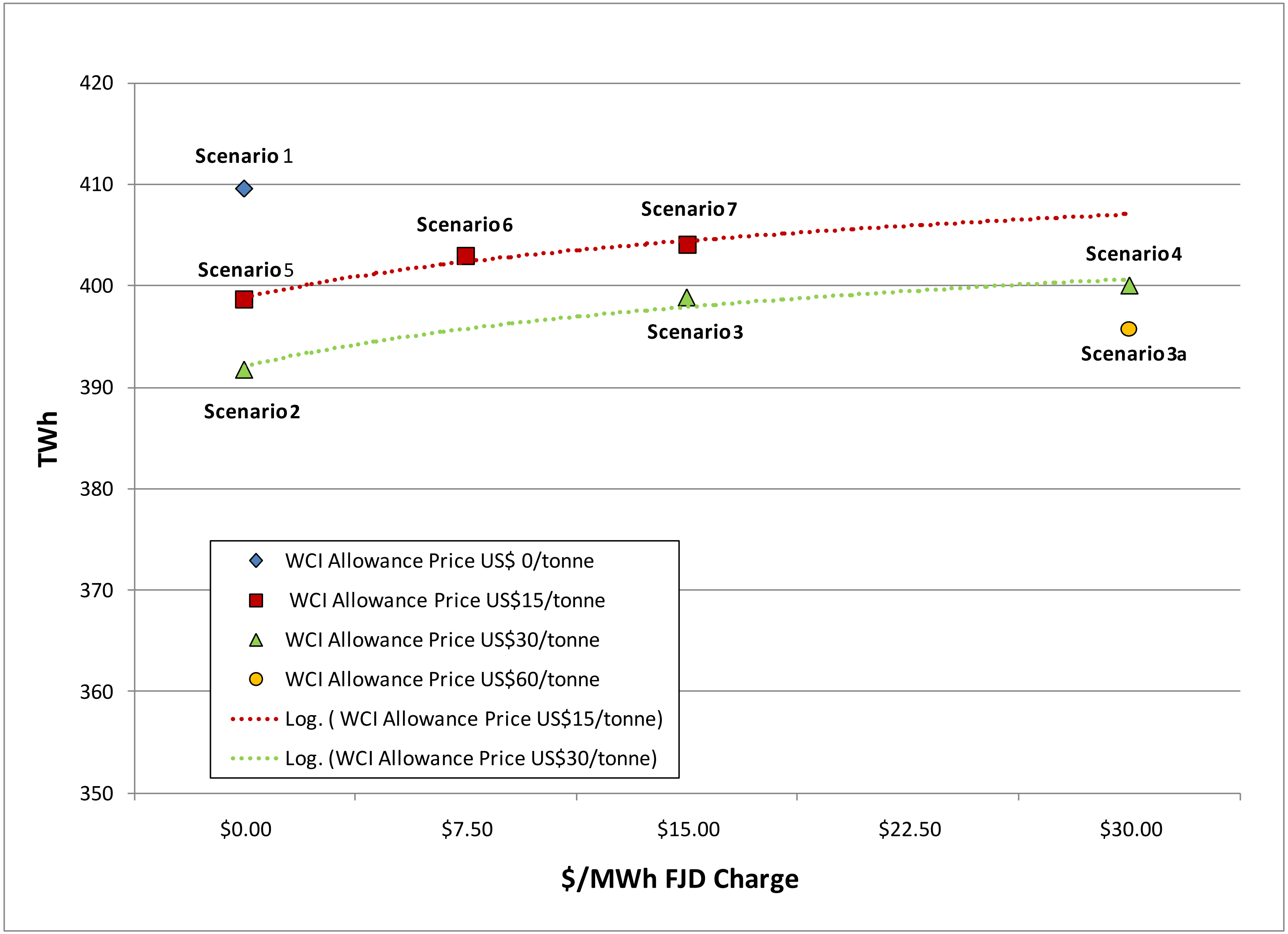
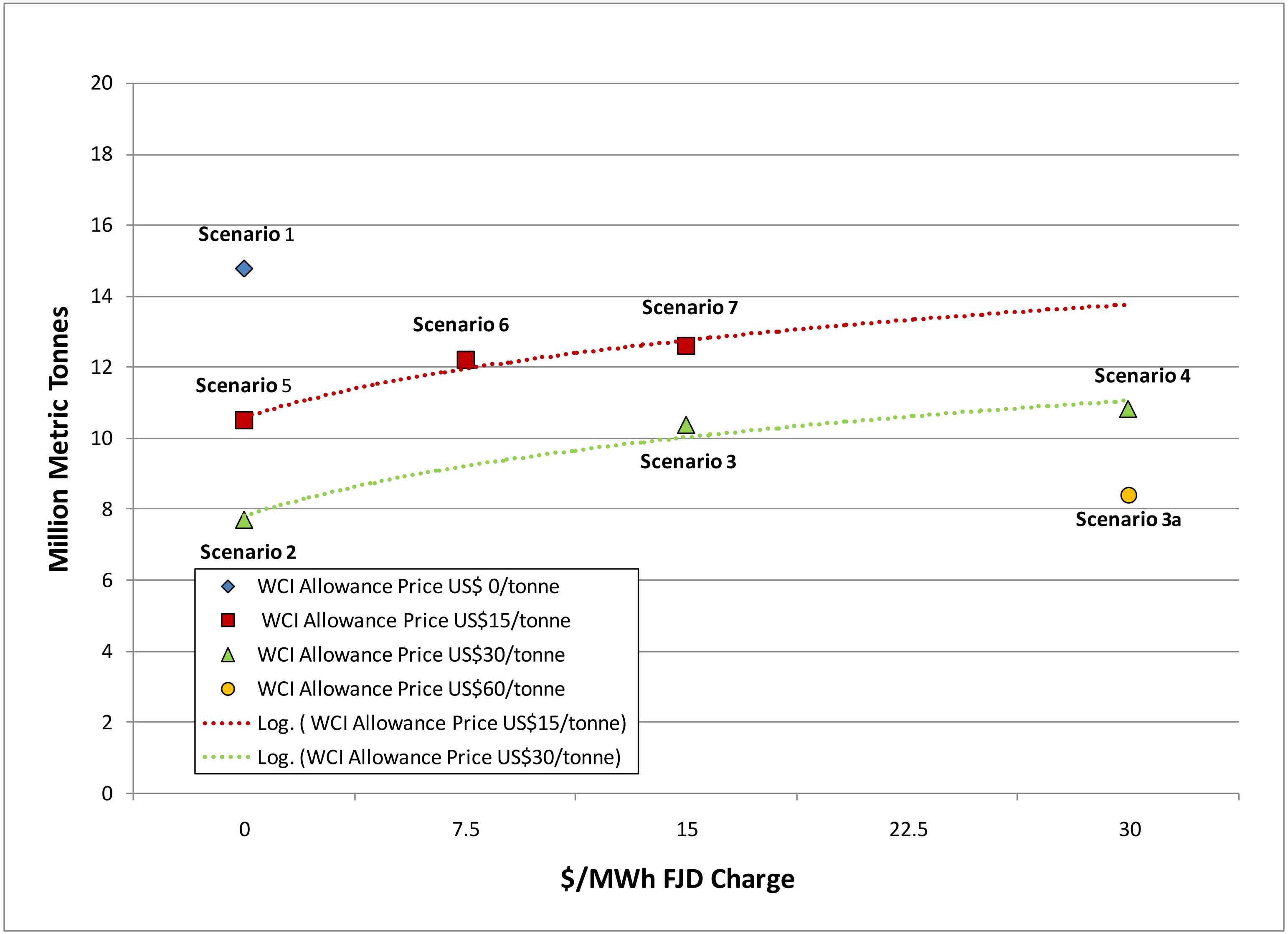
Eastern WCI Generation - 2020



Eastern WCI CO_2 Emissions - 2020



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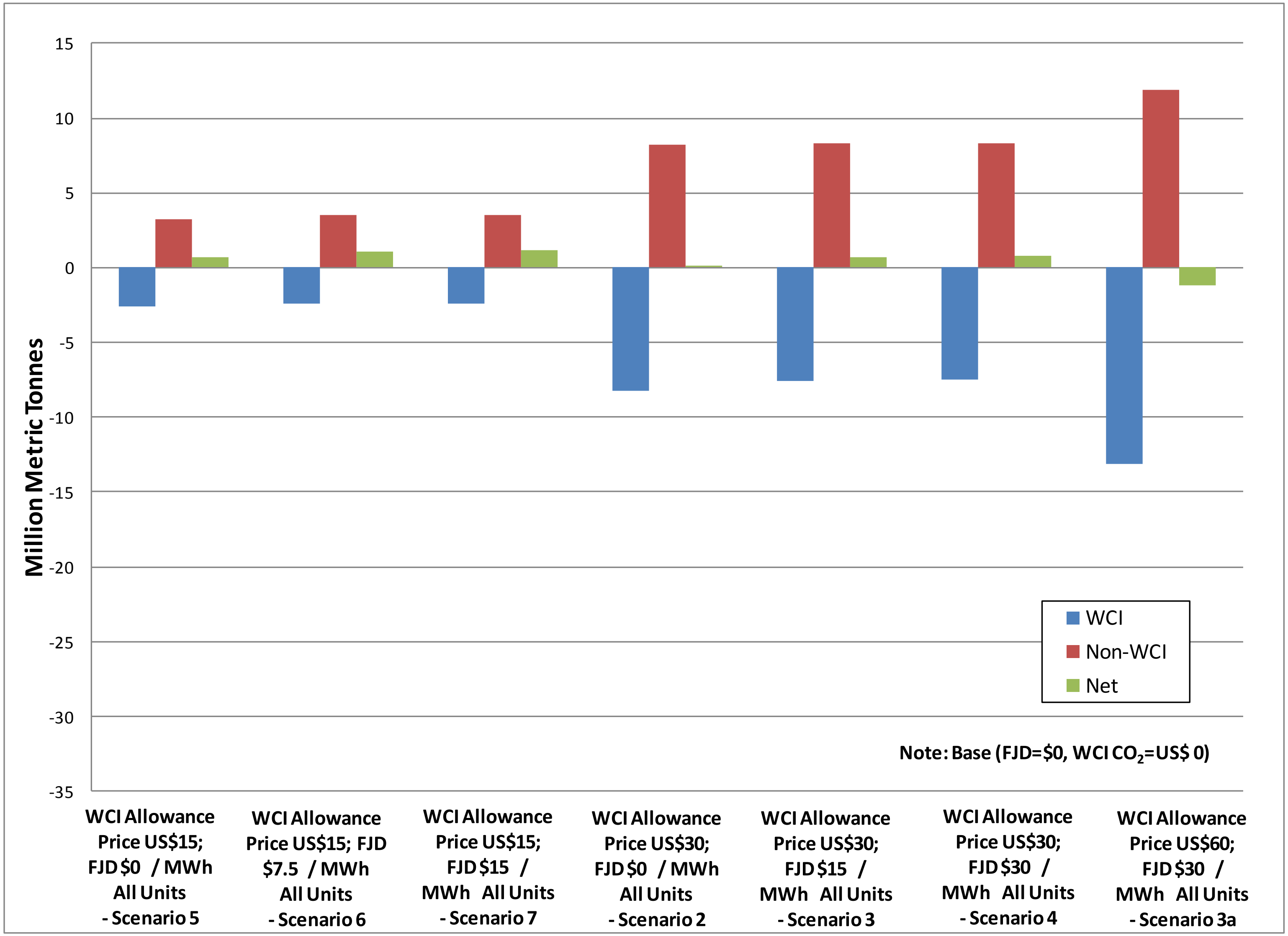
Change in Total Eastern Interconnect CO_2 Emissions - 2012



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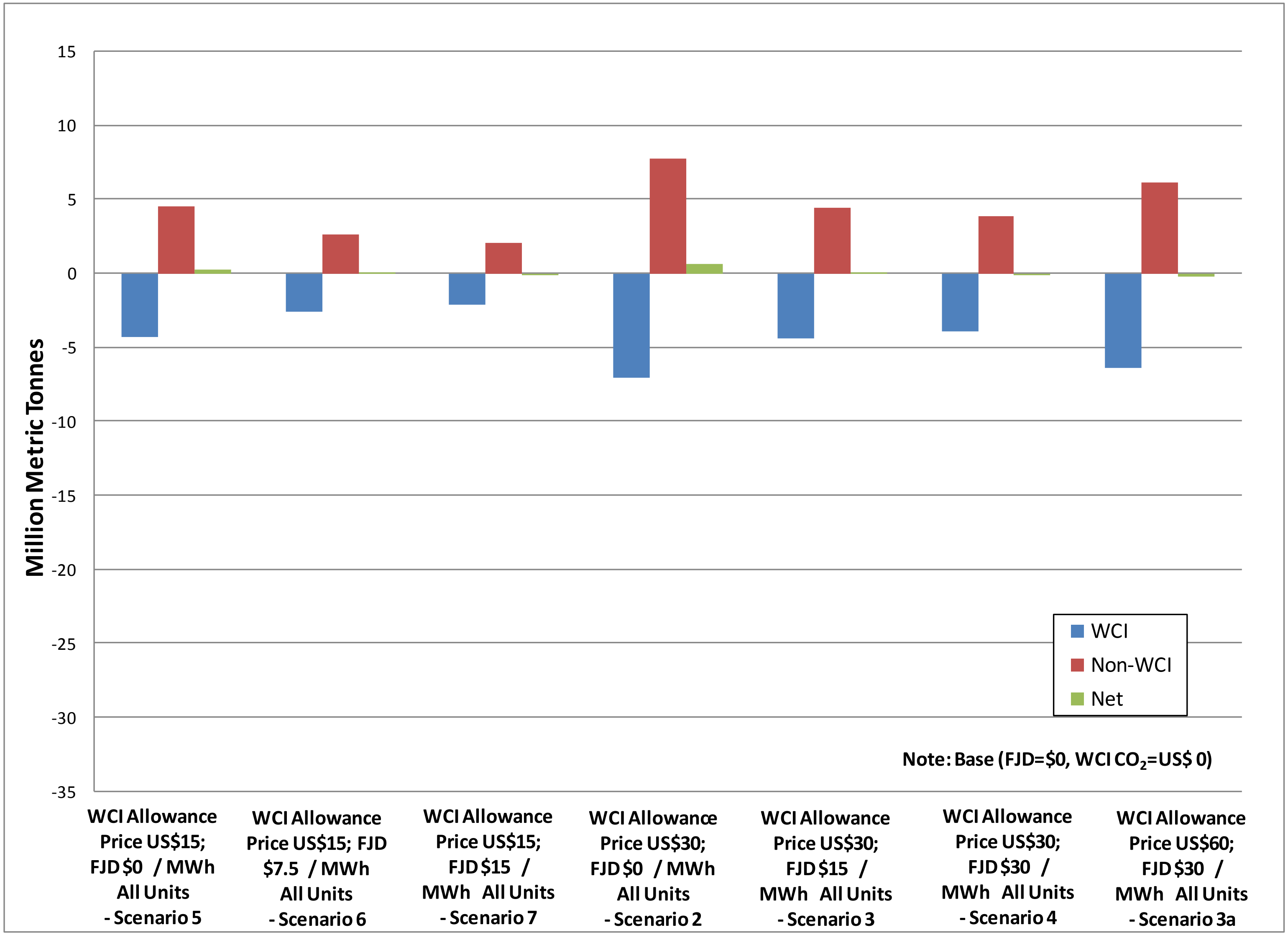
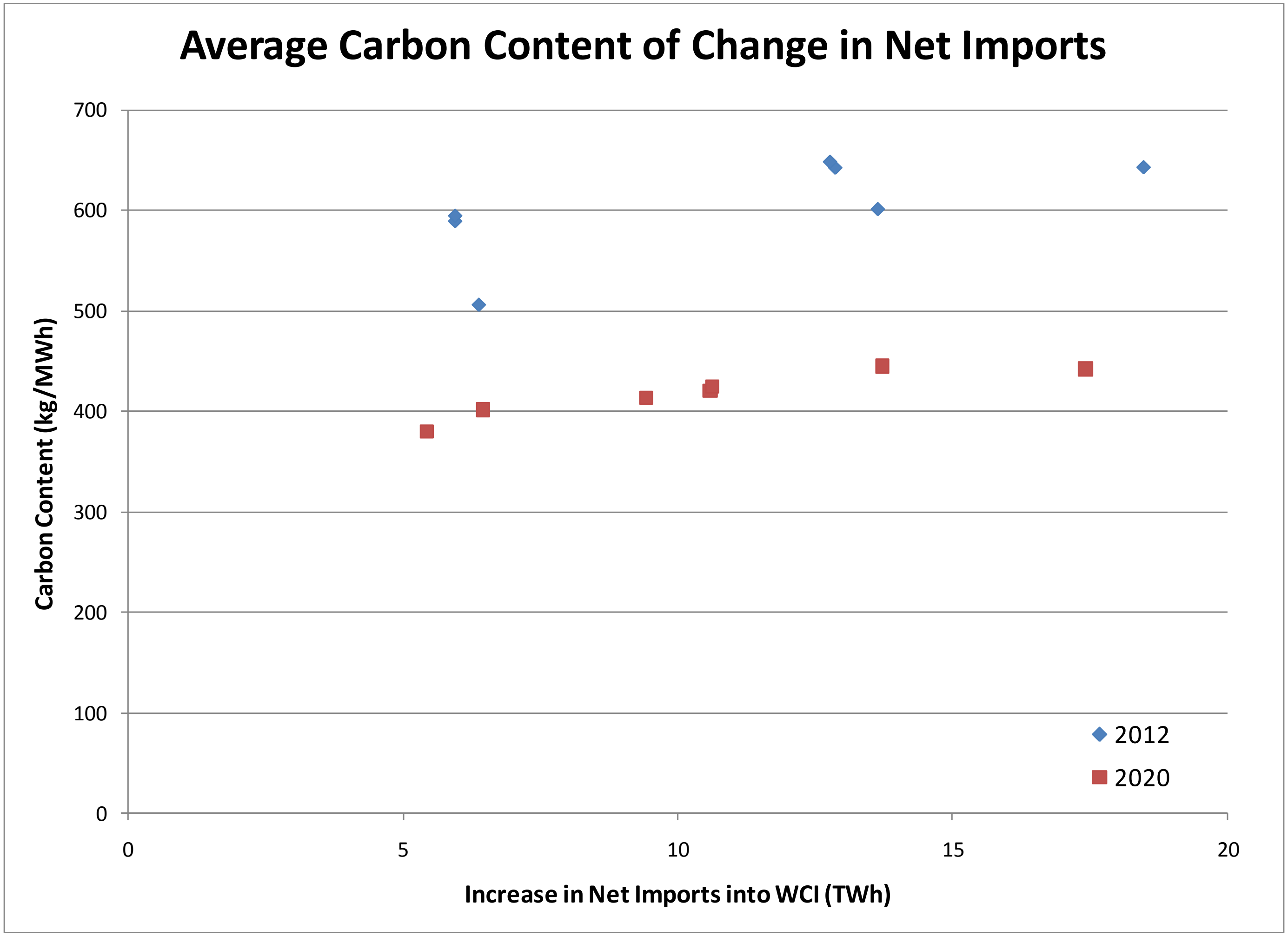
Change in Total Eastern Interconnect CO_2 Emissions - 2020



Carbon Content of Non-WCI Generation

- Carbon allowance costs in eastern WCI lead to
  - Reduction in Ontario fossil generation
    - Little change in Quebec and Manitoba generation because they do not have significant fossil capacity
  - More imports from Quebec, Manitoba and non-WCI regions into Ontario
  - Reduced exports from eastern WCI to non-WCI regions
  - More fossil generation in non-WCI regions
- For purposes of setting the FJD charge, it would be useful to know the average carbon content of imports from non-WCI regions
  - The best indicator is the CHANGE in non-WCI emissions divided by the CHANGE in NET flows (imports minus exports)
    - Looking only at imports misses most of the effect; the reduction in exports is much larger than the increase in imports

Carbon Content of Non-WCI Generation



- Average carbon content is around 600 kg/MWh in 2012 and around 400 kg/MWh in 2020. It increases slightly as the change in net imports increases (due to higher allowance costs and/or lower FJD charges).

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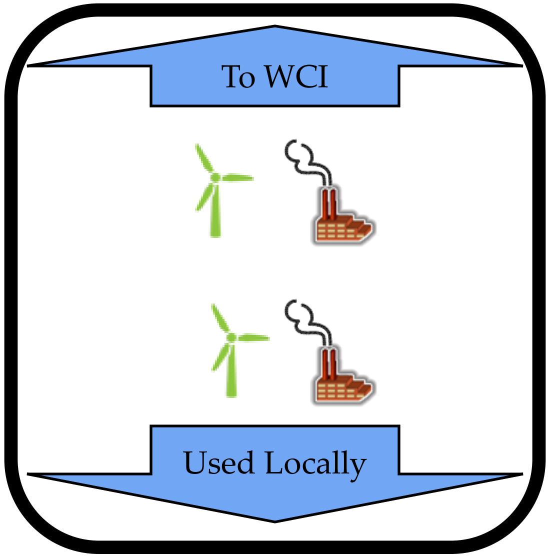
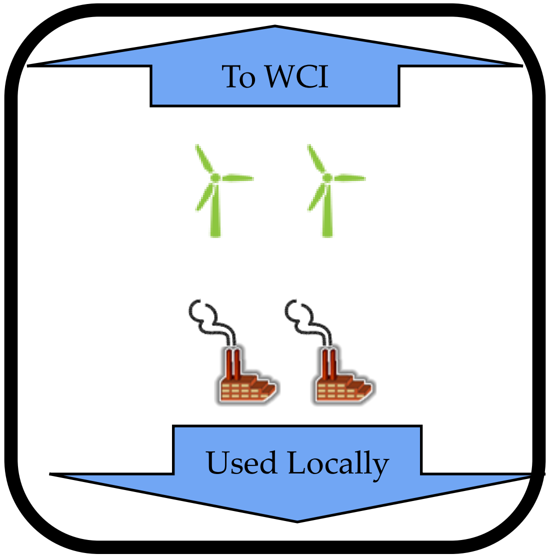
Contract Shuffling Defined

- Under WCI rules, non-fossil generation outside WCI can be exempt from import (FJD) charges if it is specified as no or low-carbon
  - This can lead to “contract shuffling”, as non-fossil generation is deemed to serve WCI load and fossil generation is deemed to serve local (non-WCI) load, with no change in total generation, fossil generation, flows, or emissions
- WCI rules regarding renewable attributes have not been finalized. For this analysis it was assumed that renewables can “double-dip”:
  - Sell renewable attributes to U.S. states – count toward meeting Renewable Portfolio Standards AND
  - Sell electricity to WCI provinces exempt from FJD charges
  - Impact of contract shuffling would be slightly less if renewables couldn’t double-dip, because most wind (but not nuclear or hydro) is tied to Renewable Portfolio Standards

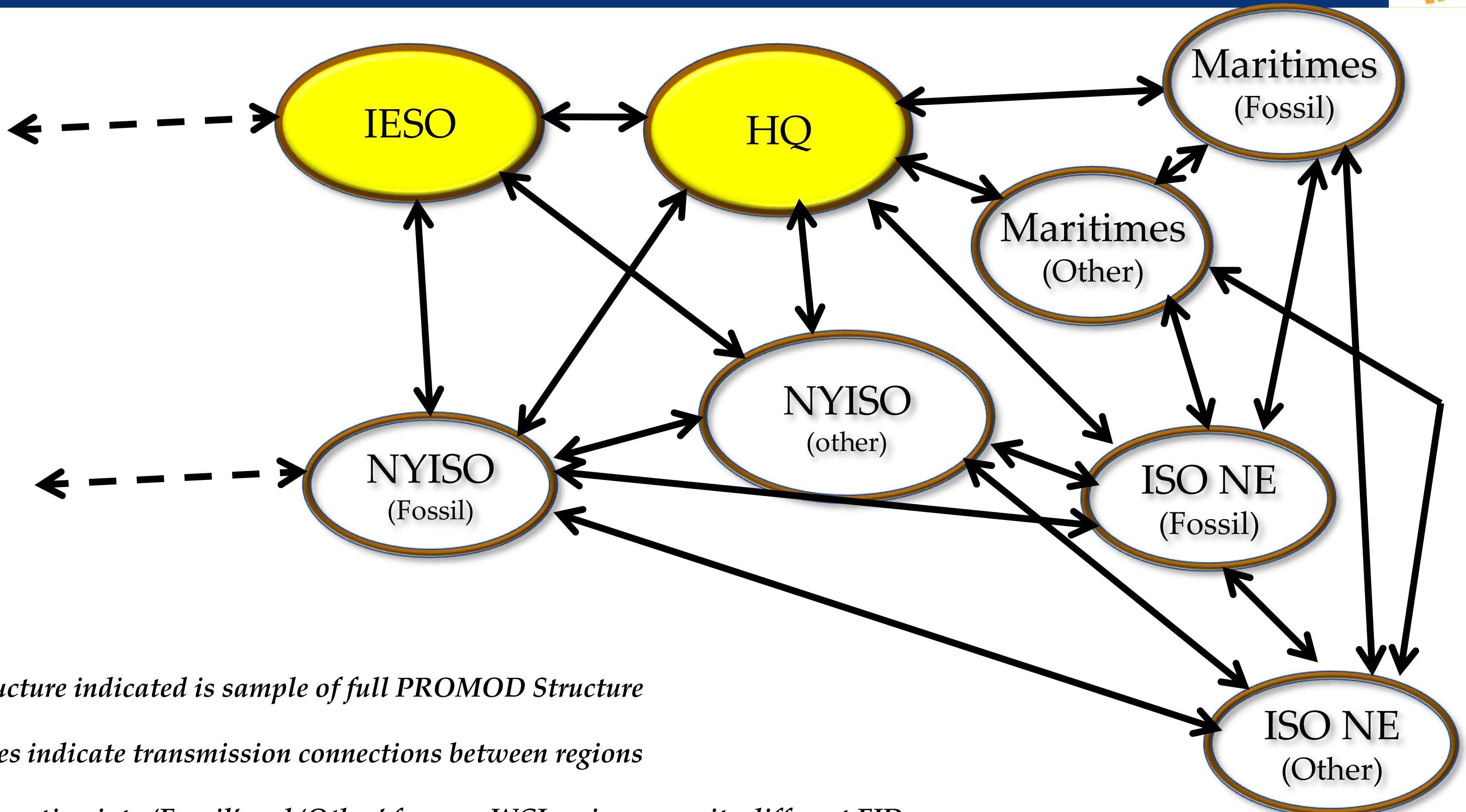
Non-WCI Generation Without Contract Shuffling



Non-WCI Generation With Contract Shuffling



Contract Shuffling – PROMOD Methodology



Structure indicated is sample of full PROMOD Structure

Lines indicate transmission connections between regions

Separation into 'Fossil' and 'Other' for non-WCI regions permits different FJD tariffs for different unit types based on carbon content

Contract Shuffling Methodology

- In PROMOD, transmission charges are based on pools not individual plants
- Generation in each non-WCI pool was divided into two pools: fossil and non-fossil
  - Demand was attached to non-fossil pool
  - FJD charge + transmission charge between fossil pool and eastern WCI pools
  - Zero FJD charge (normal transmission charge only) between non-fossil pools and eastern WCI pools
  - No charge between local fossil and non-fossil pools
- Significant increase in simulation time
  - Simple scenarios: each run took ~2 days elapsed time for one simulated year
  - Complex scenarios: each run took ~ two weeks elapsed time for one simulated year
  - The number of runs/scenarios was greatly reduced

Scenario #	Years	WCI Allowance Price	MGGRA Allowance Price	RGGI Allowance Price	FJD Charge	
		$/tonne	*$/tonne*	*$/tonne*	*kg/MWh*	*$/MWh*
9	2020	0	0.00	2.06	0	0
10	2020	30.00	0.00	2.06	1000	30.00
10a	2020	30.00	0.00	2.06	500	15.00
12	2020	30.00	30.00	30.00	1000	30.00

Notes

1. In this table, RGGI allowance prices from the auction result - $1.87/short ton - have been converted to metric tonnes

2. In these scenarios the FJD charge applies only to imports from carbon producing units

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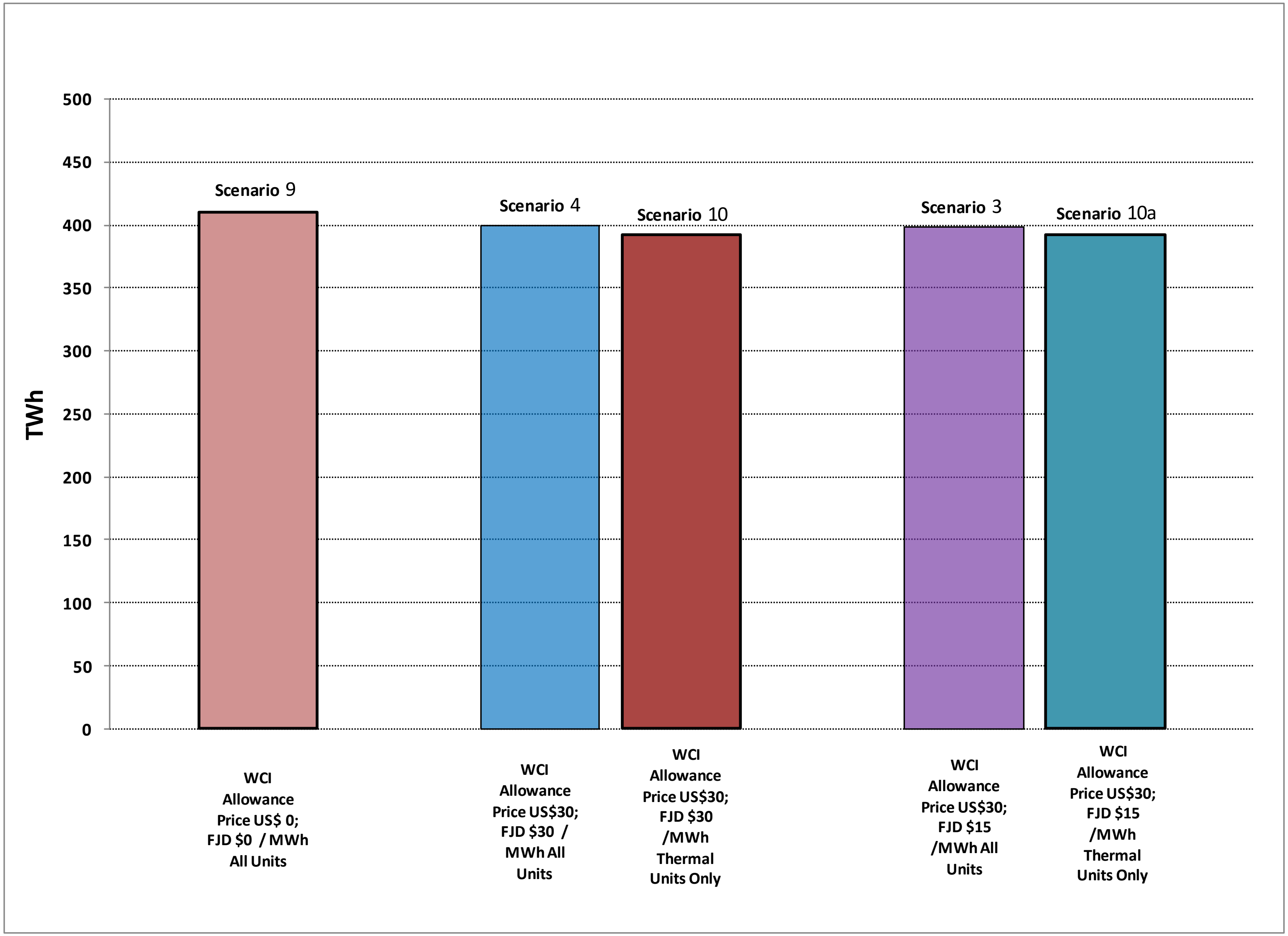
Eastern WCI Generation - 2020 – Complex Scenarios



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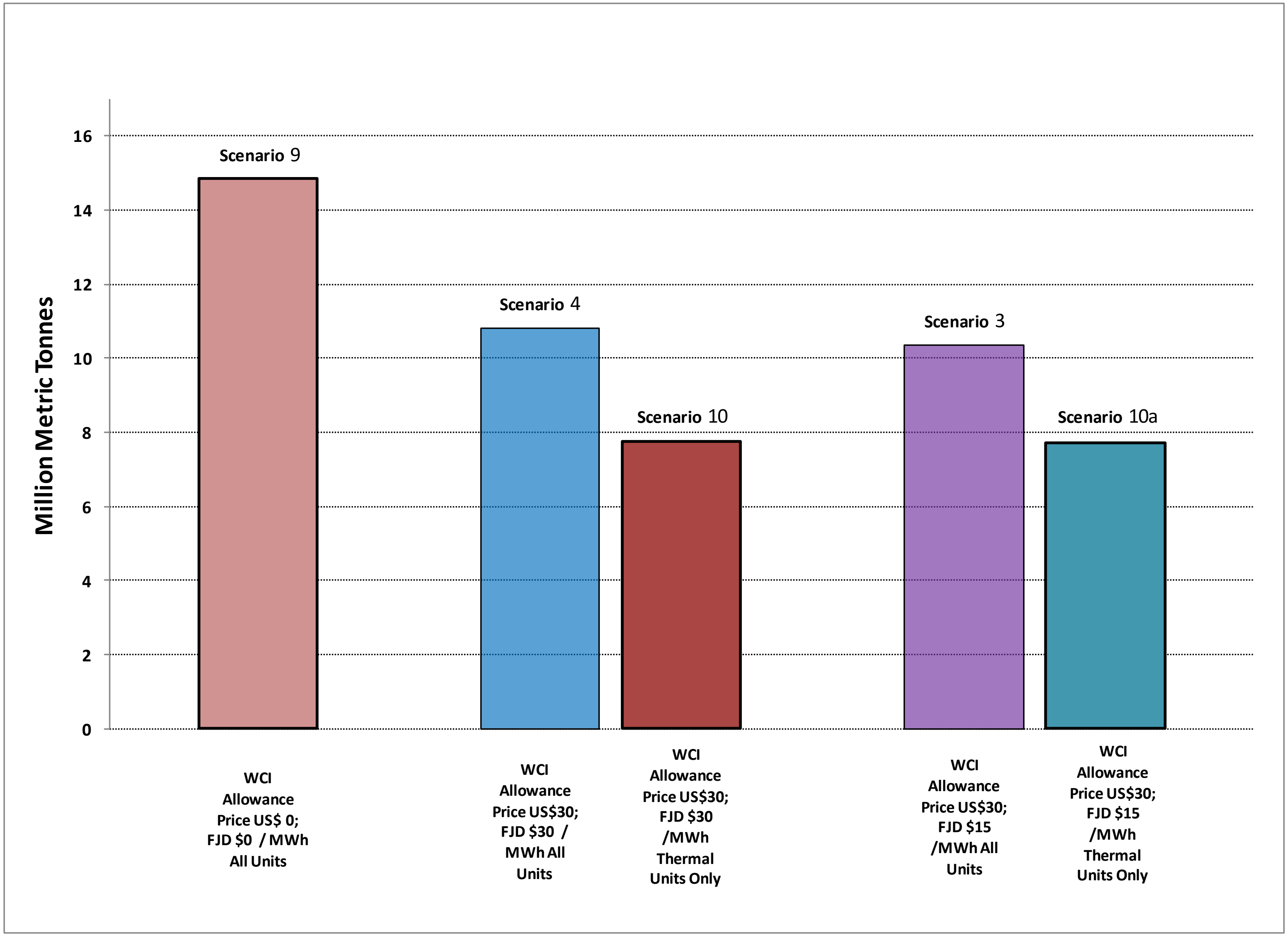
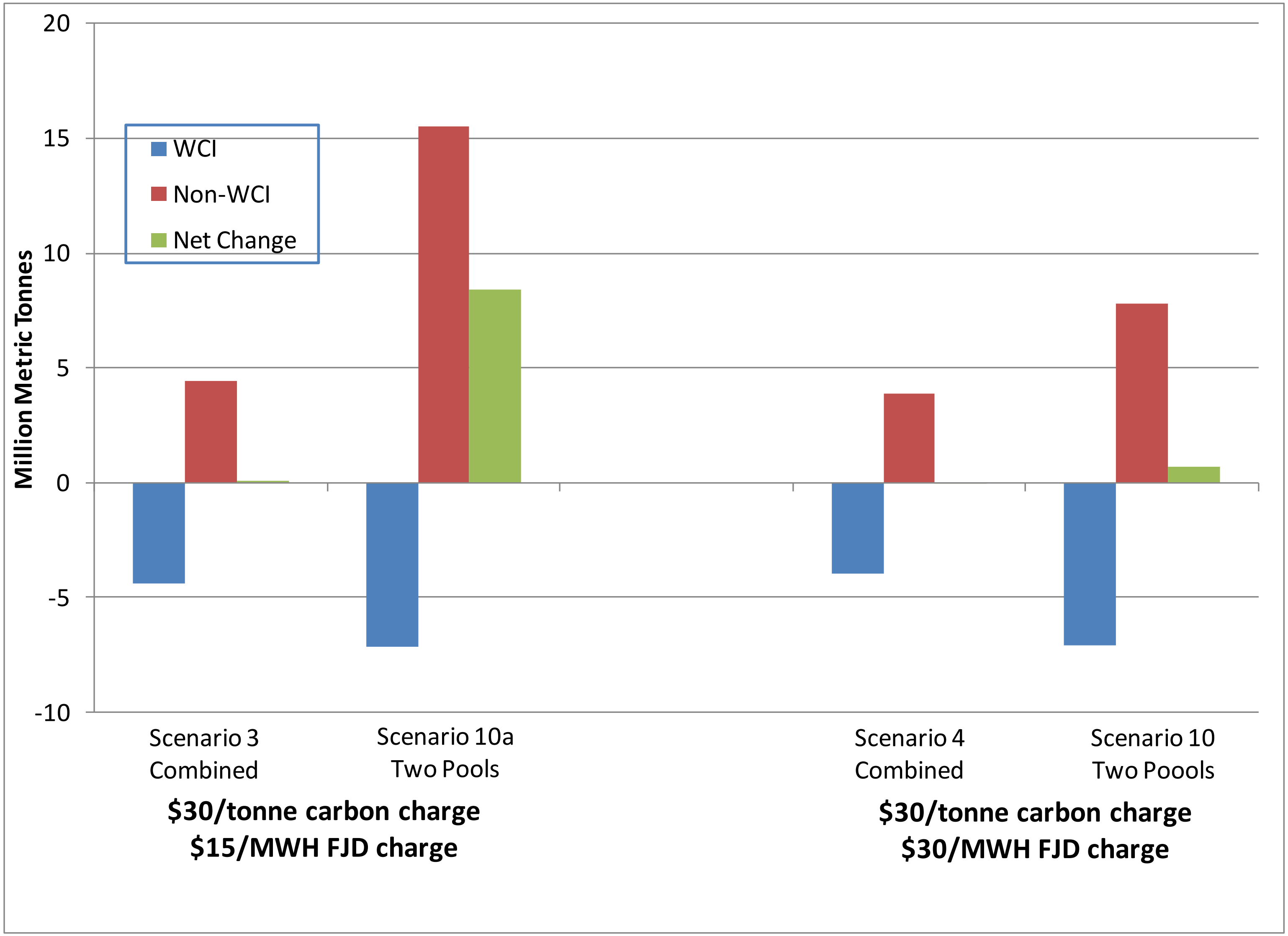
Eastern WCI CO_2 Emissions - 2020 – Complex Scenarios



Change in Total Eastern Interconnect CO_2 Emissions - 2020 - Complex Scenarios



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6 Modeling Conclusions

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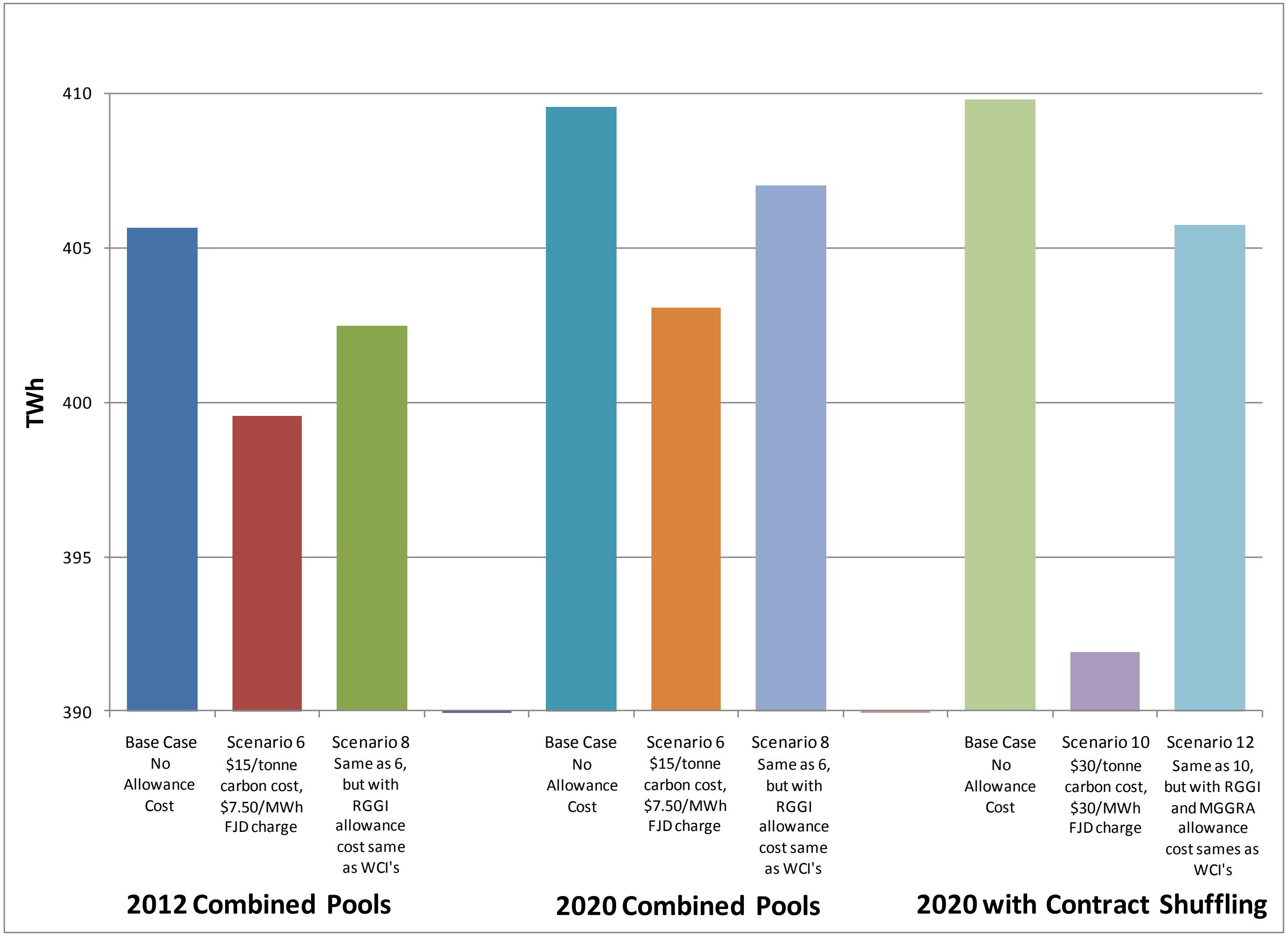
Coordination with RGGI and MGGRA

- In the base case, RGGI (New England, New York, New Jersey, Delaware, Maryland) was assumed to have a low ($2.06/metric ton) carbon price, and MGGRA (Illinois, Wisconsin, Minnesota, Iowa, Michigan) was assumed to have no carbon pricing. Both were subject to FJD charges where appropriate
- Several scenarios explored what would happen if eastern WCI, RGGI and/or MGGRA worked together to adopt similar carbon pricing regimes, and were therefore exempt from each other's FJD charges
  - For scenarios with RGGI and MGGRA allowance prices aligned with eastern WCI, FJD charges applied to flows into WCI and MGGRA rather than just into WCI

WCI Generation with RGGI and MGGRA Coordination



- Reduction in eastern WCI generation due to allowance costs is smaller if WCI coordinates with RGGI and/or MGGRA.

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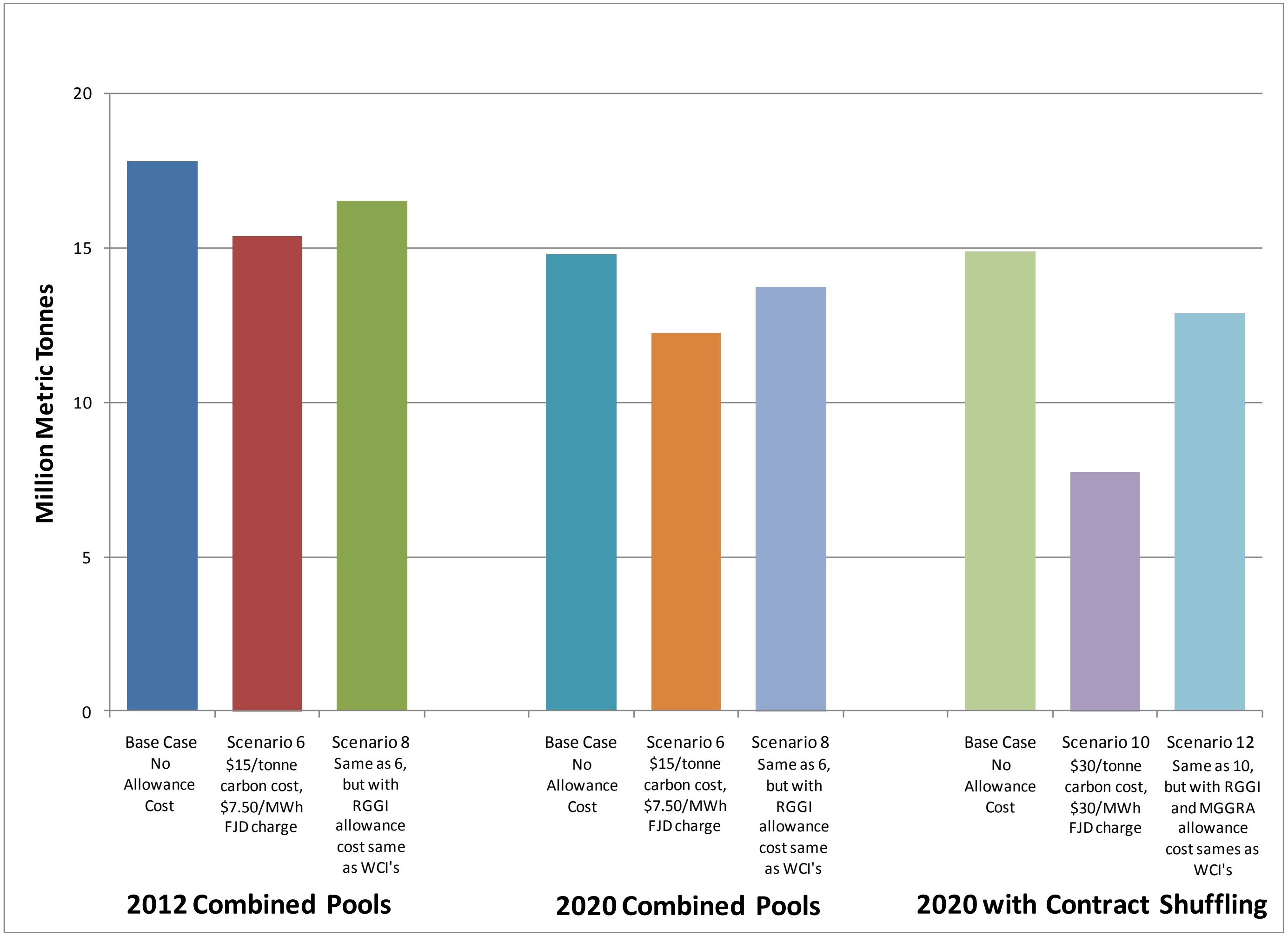
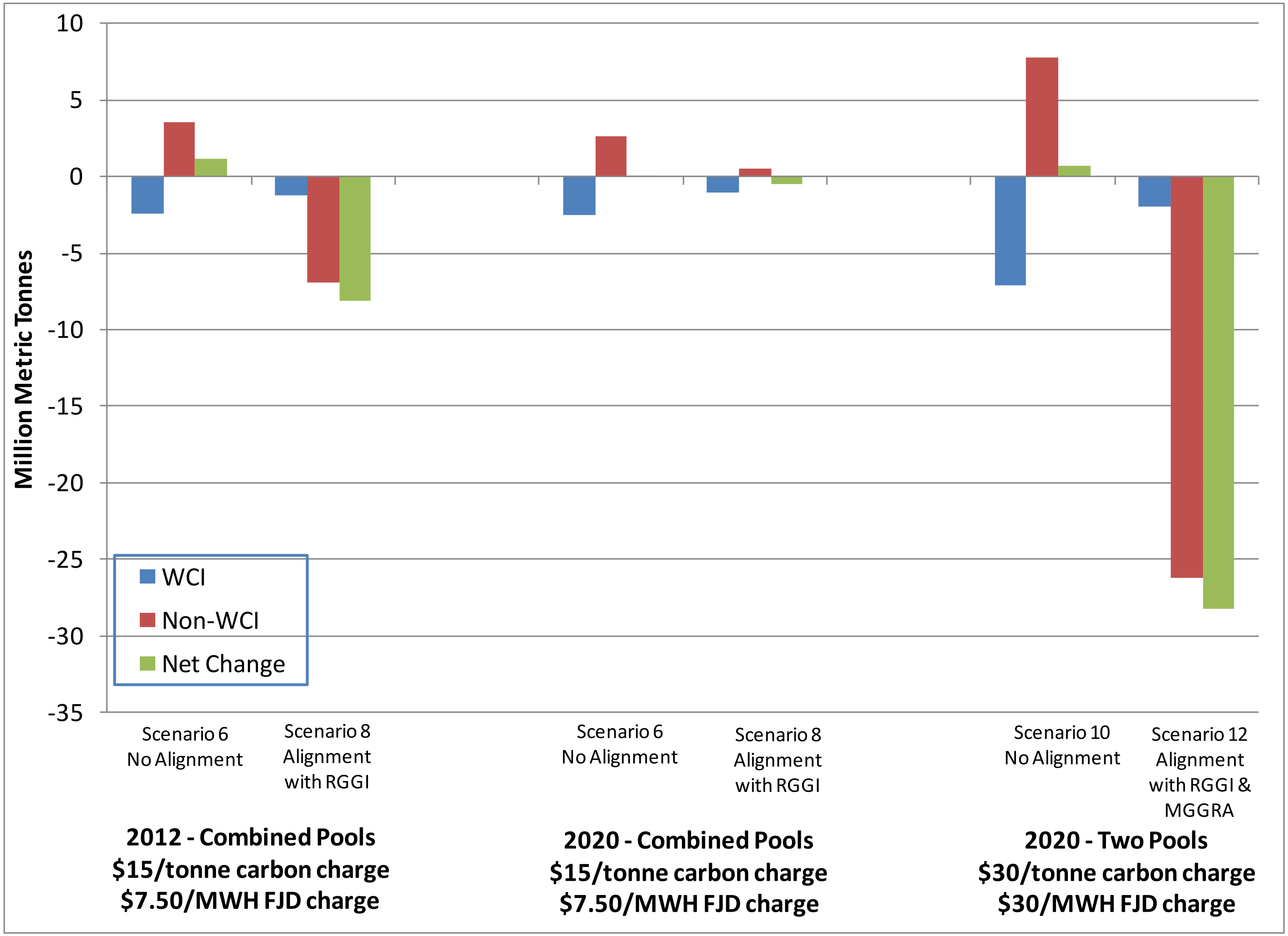
WCI Emissions with RGGI and MGGRA Coordination



- Higher allowance prices in RGGI and/or MGGRA mean less incentive for eastern WCI to use imports instead of their own generation.

Change in Total Eastern Interconnect Emissions with RGGI and MGGRA Alignment



1 Introduction

2 Modeling Methodology

3 Modeling Results

4 Contract Shuffling

5 RGGI and MGGRA

6 Modeling Conclusions

Modeling Conclusions - Summary

- As expected, given the static demand assumption, each scenario has almost the same total generation across the Eastern Interconnect. There are minor differences in total generation from the PROMOD loss calculations and the operation of pumped storage plants.
- However, the pattern of generation shifts between eastern WCI and non-WCI regions in response to the assumed eastern WCI allowance price and FJD charge
  - WCI emissions are reduced by between 13% and 50% depending on the scenario. Higher emission charges and lower FJD charges mean greater reductions.
  - This is almost exactly offset by increases in non-WCI emissions. The total level of CO_2 emissions across the Eastern Interconnect changes by less than 1% in most scenarios.
- These changes in CO_2 emissions from individual regions are the result of changes in the total generation from those regions interacting with the dispatch of different types of thermal units in the individual regions.
- The average carbon content of the increase in non-WCI generation is around 600 kg/MWh in 2012 and 400 kg/MWh in 2020.
  - This is calculated as the increase in non-WCI emissions divided by the change in net imports (imports minus exports) into WCI.

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Modeling Conclusions – Eastern WCI

- The changes in eastern WCI generation and eastern WCI CO_2 emissions levels are strongly affected by the eastern WCI CO_2 allowance price, with increases in non-WCI generation and in non-WCI CO_2 emissions as the WCI allowance price increases.
- For a given eastern WCI Allowance price, increasing the FJD charge on power imported from non-WCI regions lessens the reduction in WCI generation and CO_2 emissions.
- However, with the FJD charges used there is still a significant reduction in eastern WCI generation and CO_2 emissions regardless of the level of FJD charges.
- Although not reported in detail, most of the changes in eastern WCI emissions would occur in Ontario, the location of the majority of thermal generation in the eastern WCI.
- Overall, scenarios with non-zero eastern WCI allowance prices lead to leakage and this is not eliminated by imposing FJD charges.

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Modeling Conclusions – Contract Shuffling and Regulatory Structure

- Where contract shuffling was permitted, there was a further ~ 25% reduction in eastern WCI CO_2 emissions compared to the equivalent scenarios with no shuffling.
- Where similar allowance prices were assumed across eastern WCI, MGGRA and RGGI, the changes in eastern WCI generation and eastern WCI CO_2 emissions were much reduced.
- Effectively, a combined regulatory/allowance price structure across eastern WCI, MGGRA and RGGI would appear to reduce leakage potential.

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Western Climate Initiative

Western Climate Initiative: Electricity Sector Overview

WCI Electricity Collaborative
Phoenix. AZ
January 21, 2010

The Challenge

- WCI is a regional entity in an interconnected electricity market
  - Addressing electricity imports and exports
- WCI is inter-jurisdictional
  - Wide range of generation and emissions
  - Differing market structures
- WCI is international
  - Varying reporting conventions
  - Different legislative and legal frameworks

Cap-and-Trade:
What Has To Be the Same

- **Basic reporting requirements**
- *Sectors, gases and thresholds (generally)*
- **Points of regulation**
- *Quantification methods*
- *Setting regional caps*
- **Establishing partner budgets**
- *Compliance periods; banking; borrowing*

Items addressed by the Electricity Team

WCI Design: Electricity Imports

- Fundamental design decision: Jurisdictions to be responsible for emissions associated with electricity imports.
- Understanding the issues
  – Two studies to examine leakage potential
    - Electricity Leakage Study covering WECC presented October 16, 2008
    - Eastern Leakage study underway – discussion today

WCI Design: Electricity Imports

- Analysis and consultation on First Jurisdictional Deliverer design
  - Decision announced July 15, 2009
- Administrative Option
  - Analysis underway – discussion today

WCI Design: Reporting

- Essential Elements for Reporting for the Electricity Sector
  - Completed and released as part of the Final Essential Requirements for Mandatory Reporting
- Outstanding issues:
  - Assigning emissions to imports: Default Emissions Calculator – discussion today

WCI Design: Budgets

- Forecasting 2012 budgets requires data on base years.
- Outstanding items:
  - Establish baseline data for electricity imports
    - OATI analysis for WECC – discussion today
    - Default emissions calculator – discussion today
    - Specified imports
    - Eastern provinces data

WCI Design: Competitiveness

- Outstanding item: The Electricity Team will support the Competitiveness group on electricity issues

WCI Design: Special Items

- Voluntary Renewable Energy: how to accommodate the voluntary market under Cap and Trade
  - Draft recommendation paper released January 15, 2010 – discussion today
- Treatment of Renewable Energy Certificates under Cap and Trade
  - analysis underway

Western Climate Initiative

Emissions from Imported Electricity: Default Factors and Historical Imports

Presented at the Electricity Industry Collaborative

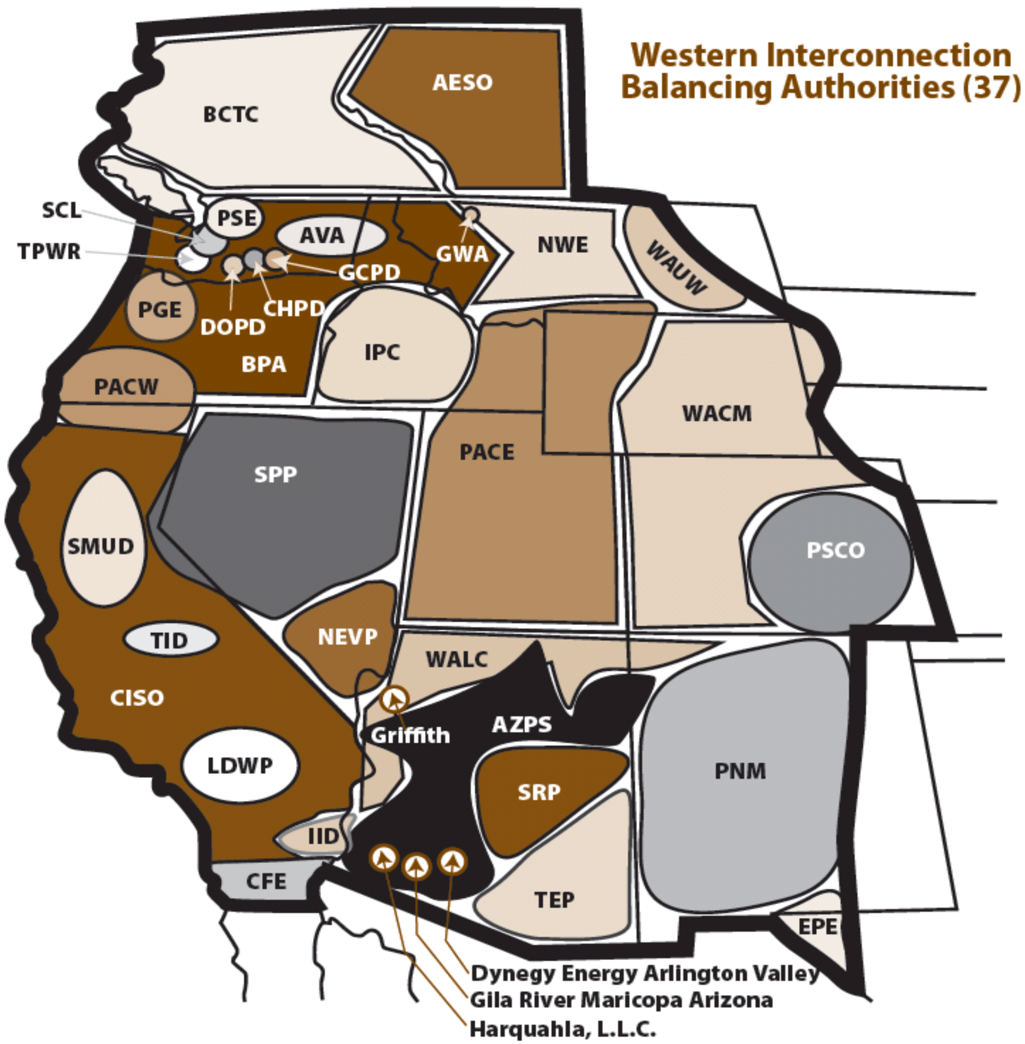
Phoenix

January 21, 2010

OATI Analysis of E-Tagged Transactions in WECC

- OATI, which manages the e-tag database for WECC, was hired to analyze inter-balancing authority transactions from 2005 to 2008
- This information will inform WCI's allowance budget setting process
- Balancing authorities in the eastern provinces are conducting their own analysis

WECC Balancing Authorities



Alberta Electric System Operator (AESO)
Arizona Public Service Company (APS)
Avista Corporation (AVA)
Bonneville Power Administration – Transmission (BPAT)
British Columbia Transmission Corporation (BCTC)
California Independent System Operator (CISO)
Comisión Federal de Electricidad (CFE)
Duke – Arlington Valley*
El Paso Electric Company (EPE)
Gila River Maricopa Arizona*
Harquahala Generator Maricopa Arizona*
Idaho Power Company (IPC)
Imperial Irrigation District (IID)
Los Angeles Department of Water and Power (LDWP)
NaturEner Glacier Wind Energy (GWA)*
Nevada Power Company (NEVP)
NorthWestern Energy (NWE)
PacifiCorp — East (PACE)
PacifiCorp — West (PACW)
Portland General Electric Company (PGE)

Public Service Company of Colorado (PSCO)
Public Service Company of New Mexico (PNM)
PUD No. 1 of Chelan County (CHPD)
PUD No. 1 of Douglas County (DOPD)
PUD No. 2 of Grant County (GCPD)
Puget Sound Energy (PSE)
Sacramento Municipal Utility District (SMUD)
Salt River Project (SRP)
Seattle Department of Lighting (SCL)
Sierra Pacific Power Company (SPP)
Tacoma Power (TPWR)
Tucson Electric Power Company (TEP)
Turlock Irrigation District (TID)
Western Area Power Administration, Colorado-Missouri Region (WACM)
Western Area Power Administration, Lower Colorado Region (WALC)
Western Area Power Administration, Upper Upper Great Plains West (WAUW)

E-Tag Modifications

- To aggregate results by state, three BAs were disaggregated using transmission point names
  - PacifiCorp East (PACE)
  - Bonneville Power Authority (BPAT)
  - WAPA Lower Colorado (WALC)
- Four plants (Colstrip, Boardman, San Juan & Springerville) were identified that can be sourced from multiple BAs; these were forced to appear in the BA where they are located

2005 Imports into WECC WCI Jurisdictions, MWh

Importing Jurisdictions	Exporting Jurisdictions							
	AB	CO-WY	non-WECC	ID	MX	NV	Tribal	Total
AZ	40	1,981,555	2,496	255,347	0	207,688	2,977,382	5,424,508
BC	885,536	158,493	29,556	83,280	0	25,089	110,495	1,292,449
BPA-SYS	20,417	13,738	12,065	663,660	0	475	93	710,448
CA	2,736	238,294	36,420	389,626	1,532,043	4,784,026	7,209,175	14,192,320
MT	195	583,034	558,715	409,484	0	1,177	2,439	1,555,044
NM	0	698,454	1,467,193	11,273	30	496	867,682	3,045,128
OR	23,813	307,933	23,018	399,275	0	1,776	1,924	757,739
UT	0	4,089,946	25	124,259	0	59,252	1,451,391	5,724,873
WA	60,505	119,020	122,494	350,348	0	12,296	1,791	666,454
Total	993,242	8,190,467	2,251,982	2,686,552	1,532,073	5,092,275	12,622,372	33,368,963

2008 Imports into WECC WCI Jurisdictions, MWh

Importing Jurisdictions	Exporting Jurisdictions: AB	CO-WY	non-WECC	ID	MX	NV	Tribal	Total
AZ	0	1,393,465	14,393	103,189	130	57,969	16,773,543	18,342,689
BC	314,587	78,579	45,778	83,732	0	86,794	85,822	695,292
BPA-SYS	51,237	14,672	20,139	113,096	612	15,973	4,467	220,196
CA	14,755	277,650	22,118	606,182	1,186,594	7,637,481	10,071,142	19,815,922
MT	571	786,111	482,613	136,110	0	1,577	3,710	1,410,692
NM	0	461,204	771,270	18,241	0	2,280	2,051,629	3,304,624
OR	21,424	1,057,078	74,613	348,121	124	12,647	9,973	1,523,980
UT	0	5,372,074	5,395	25,940	0	33,375	1,289,541	6,726,325
WA	91,290	63,688	149,095	792,269	732	21,813	8,871	1,127,758
Total	493,864	9,504,521	1,585,414	2,226,880	1,188,192	7,869,909	30,298,698	53,167,478

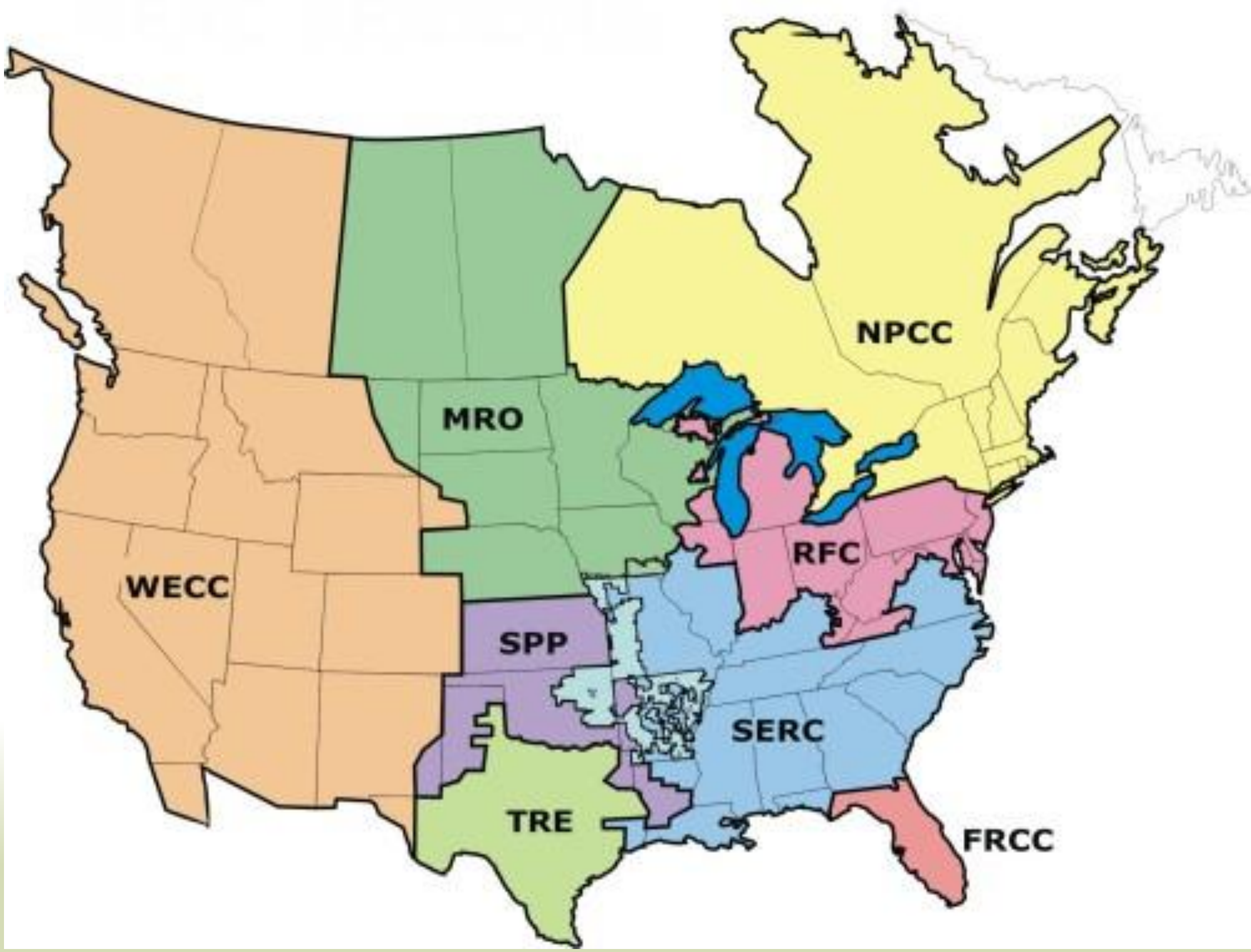
E-Tag Questions for Stakeholders

- Can we identify all specified imports for WCI members?
- From 2008 on, are all dynamically scheduled plants now tagged? Can we fill in data for previous years?
- Are intra-Balancing Authority transactions now consistently tagged? (relevant for BPA and PACE)
- How should BPA-SYS transactions be accounted for?

Updates on the Default Emissions Factor Calculators

- Draft version of the DEF Calculator have been completed for 2006 and 2007
- EIA data for 2008 were not yet available but should be released soon
- Draft DEF Calculators include additional NERC regions and an adjustment for transmission losses

NERC Regions



FRCC - Florida Reliability Coordinating Council
MRO - Midwest Reliability Organization
NPCC - Northeast Power Coordinating Council
RFC – Reliability First Corporation
SERC - SERC Reliability Corporation
SPP - Southwest Power Pool
TRE - Texas Regional Entity
WECC - Western Electricity Coordinating Council

Draft DEF Calculator Results

Draft DEF Calculator Results, metric tons CO_2/MWh

Assumes 2% Transmission Losses, non-WCI sources only

	50% Capacity Factor		60% Capacity Factor		70% Capacity Factor	
NERC Region	**2006**	**2007**	**2006**	**2007**	**2006**	**2007**
MRO	**0.905**	**0.795**	**0.963**	**0.975**	**1.039**	**1.016**
NPPC	**0.581**	**0.557**	**0.570**	**0.548**	**0.569**	**0.581**
RFC	**0.895**	**0.836**	**0.949**	**0.923**	**0.947**	**0.944**
WECC	**0.461**	**0.489**	**0.456**	**0.456**	**0.597**	**0.641**

DEF Questions for Stakeholders

- How often should the factor be updated?
- How far in advance should it be finalized?
- How many years' worth of data should be used? One year or an average of 2 or 3 years?
- How are losses handled on e-tags and what is the appropriate transmission loss factor? Does the loss factor only need to account for losses from actual sources to first Point of Receipt?

DEF Questions for Stakeholders

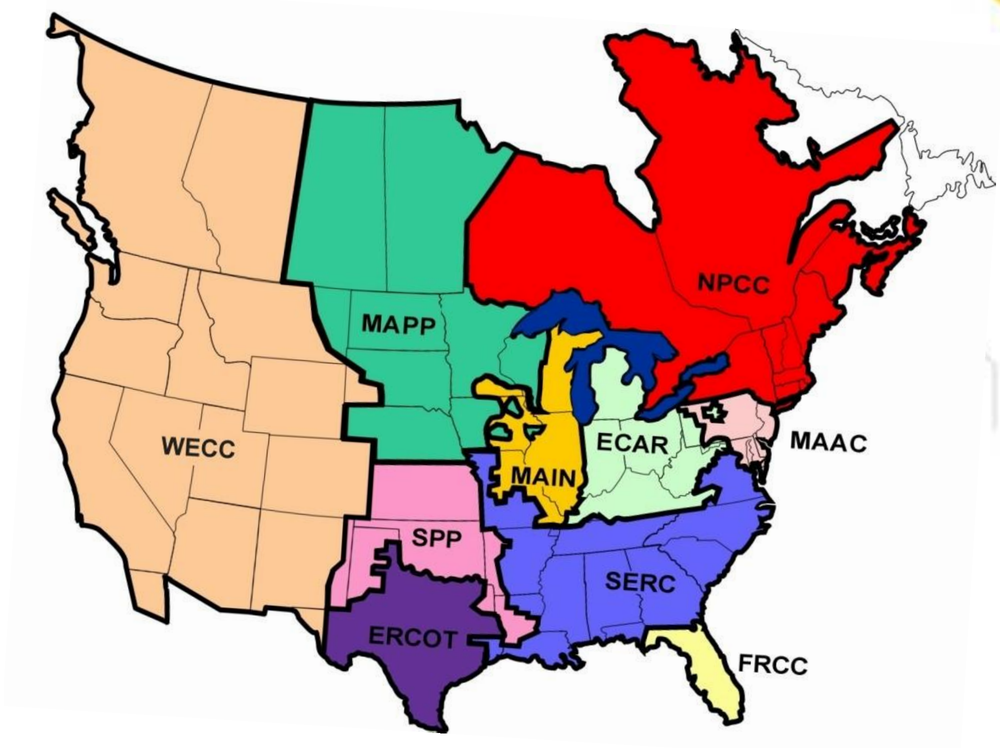
- Should capacity factors be based on nameplate capacity or net summer capacity?
- Should CEMS data reported to EPA be used instead of calculated emissions from reported fuel consumption?

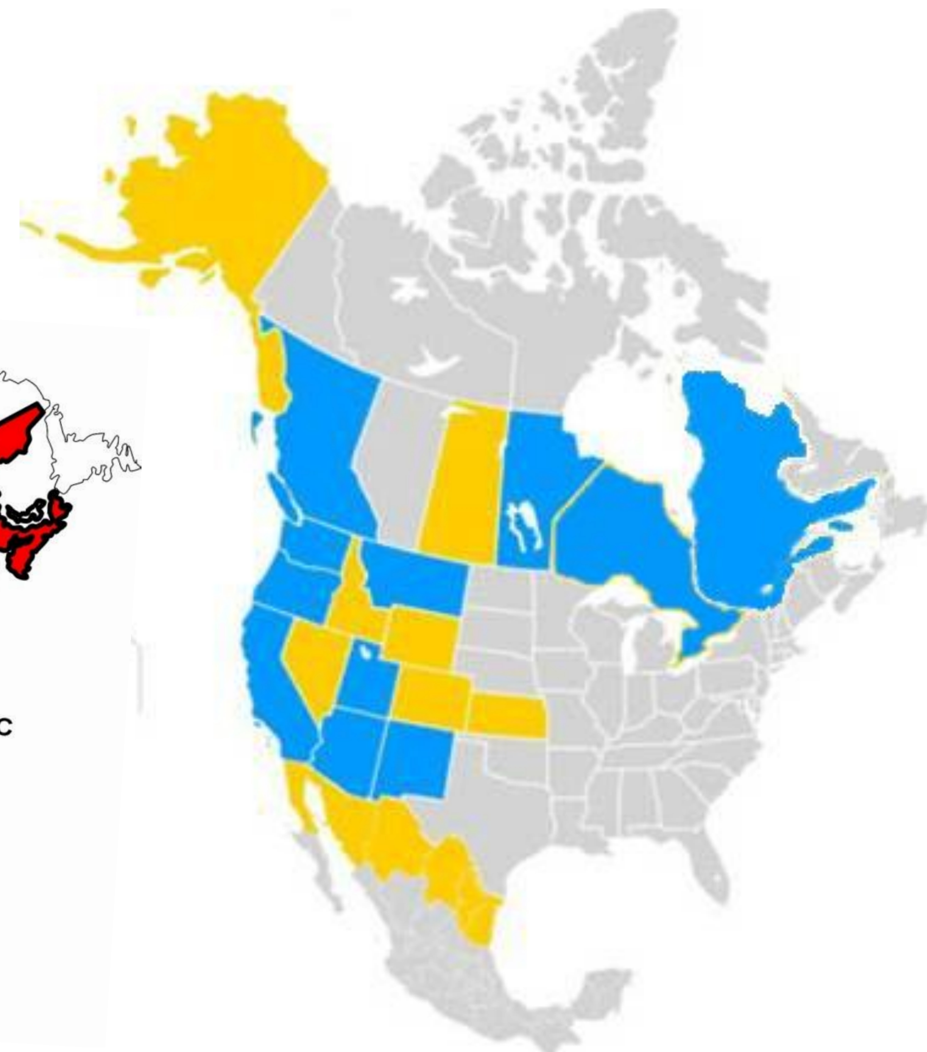
Western Climate Initiative

Introduction to the Electricity Team Items

WCI Electricity Collaborative
Phoenix. AZ
January 21, 2010

Boundaries: Electricity and WCI





Quantifying Leakage Potential

- An essential element of understanding leakage
- Requires market analysis
- WECC system reviewed in E3 Electricity Leakage Study
  - Found limited potential for leakage from coal, some potential for gas
  - FJD approach limited leakage

Quantifying Leakage Potential

- Eastern grid is fundamentally different from WECC for WCI jurisdictions
  - Greater use of market pools (New York, Ontario, PJM) and less use of contracts
  - Coal is more frequently the marginal source
  - Ontario phasing out coal
  - Quebec and Manitoba are predominantly hydroelectric
  - WCI jurisdictions are net exporters
- Eastern leakage study by Navigant to analyze market and leakage potential

Assigning Emissions to Imports

- Need these elements to quantify emissions associated with imports:
  - Level of imports from identified generation (MWh)
    - Apply known specific emission factor from reporting
  - Level of imports from unknown generation (MWh)
    - Aggregated by source region
    - Apply emissions factor for marginal generation in source region
      - role of Default Emissions Calculator

Addressing Imports: Establishing a Baseline

- WCI design calls for the 2012 cap to be based on the best estimate of emissions.
- Proposed process starts from established emissions in a baseline year.
- Emissions from imported electricity must be included in the baseline level.
- Need to identify specified imports and unspecified imports by source region:
  - OATI analysis for WECC
  - Jurisdictional review for Eastern Provinces

Addressing Imports: Administrative Option

- The full First Jurisdictional Deliverer approach may not be appropriate in all jurisdictions:
  - Low levels of imports may not warrant the administrative burden
- Emissions associated with imports must still be accounted for by the consuming jurisdiction
- Examining Administrative Option alternative to account for emissions under the cap

Voluntary Renewable Energy

- The market for voluntary renewable energy has been identified by stakeholders as potentially vulnerable under a greenhouse gas cap and trade system.
- The Electricity Team has reviewed the issue and prepared an issues paper with recommendations for jurisdictions who may wish to address the market for voluntary renewable energy.

Western Climate Initiative

Voluntary Renewable Energy Market: Issues and Draft Recommendations

WCI Electricity Collaborative
Phoenix. AZ
January 21, 2010

Voluntary Renewable Energy (VRE) Market Issues Addressed in Paper

- VRE market (green power programs) has been important for growth of renewable energy.
- With cap and trade (C&T), level of allowable emissions in region is determined by the cap.
- Individual decisions to purchase VRE products may not lead to emission reductions since purchases free up allowances for others.
- VRE market may be impacted if consumers expect emission reduction benefits to be associated with their VRE product purchases.

VRE Market Policy Alternatives

- WCI Partner jurisdictions that wish to address potential impacts from C&T have the option to adjust their baseline allowance budget to reserve (or “set aside”) a pool of allowances for retirement that ensures that emission reductions occur for VRE market purchases.
- Alternatively, WCI Partner jurisdictions may choose not to intervene in the VRE market and let VRE marketers guarantee emission reductions through allowance purchases.

How a VRE Set Aside Might Work

Estimated VRE MWh sold in 2012	Example Set Aside Emission Rate	Allowances in 2012 Reserve	Actual VRE MWh sold in 2012	2012 Allowances Retired by Jurisdiction	2012 Allowances Unused (e.g. for 2013 Set Aside)
1,000,000	0.40 tCO_2e	400,000	900,000	360,000	40,000

1. VRE product sales estimated in advance.
2. Emission reductions from sales estimated.
3. Allowances are "set aside" from budget.
4. Actual sales trued up and allowances retired.
5. Unused allowances rolled over or used for ??.

Treatment of the VRE Market in Other Existing or Proposed Cap and Trade Systems

Cap-and-trade program or proposed legislation	Voluntary Renewable Energy Market Directly Addressed?	Policy Mechanism Used to Address VRE Market
USA – Regional GHG Initiative (RGGI)	**Yes**	Set aside as optional element of RGGI Model Rule.
Europe – EU Emissions Trading System (EU ETS)	**No**	None
USA – American Clean Energy And Security Act of 2009 (Waxman-Markey)	**No**	
USA – Kerry-Boxer (Senate version of ACES)	**No**	
Australia – Carbon Pollution Reduction Scheme (proposed for 2011)	**Yes**	By taking GreenPower (official VRE program) purchases above 2009 levels into account when setting program's emission caps.

Context for VRE Market Issues Paper

- WCI design recommendations provide broad discretion to WCI Partner jurisdictions to reserve allowances for designated purposes.
- Therefore, no recommendation is made as to whether all WCI Partner jurisdictions should implement a VRE set aside program.
- Focus is on recommendations for the key design elements of VRE set asides for those WCI Partner jurisdictions that do choose to implement a VRE set aside program.

Recommendation on Accounting Mechanism for VRE Set Aside Program

- VRE set asides should be based, first and foremost, on transactions verified through established REC tracking systems.
- In addition, where RECs aren't an option, certification through a third-party verification system for voluntary renewable energy that includes, at a minimum, a method of attesting to not having previously transferred the greenhouse gas benefits of the VRE product.
- Harmonization across WCI is important.

Recommendations on Defining Eligible Renewable Energy Project Types

- Jurisdictions should define their own eligibility requirements for their VRE set aside programs. They may choose to mirror existing RPS or other statutory definitions or to define a separate list of qualifying project types.
- Important to recognize that REC tracking systems and VRE certifying organizations also will likely have eligibility criteria that will be applicable to VRE products used for set aside.

Comparison of Options for Geographic Treatment of Voluntary Renewable Energy

Limitation→ ↓ Responsibility	Purchased from/sold to own jurisdiction	Purchased from/sold to any WCI jurisdiction	Purchased from/sold to any capped jurisdiction	Purchased from/sold to any jurisdiction
Purchaser-Based	Equivalent to gen-based, need to account for number of RECs from in-jurisdiction sources	Need to account for number of RECs used from in-WCI sources	Need to account for number of RECs used from all capped (e.g. RGGI) sources	N/A (no need to have purchaser-based version because purchases from uncapped jurisdictions do not need set aside)
Generator-Based	Equivalent to purchaser-based, need to track where RECs are retired	Need to track where RECs are retired	Expands application to sales to entities in other capped jurisdiction such as RGGI or Midwestern Accord jurisdictions, need to track where RECs are retired	Generators receive one certification, good for sales to all jurisdictions, no need to track where RECs retired

Recommendation on Jurisdictional Retirement Responsibility

- Retire allowances using a generator-based approach in which allowances are retired whenever RECs from a facility in that WCI Partner jurisdiction's territory are purchased and retired by a customer in the VRE market with no limitation on the customer's location. Alternatively, the retirement should be based on VRE sales if RECs are not used.
- Need to have harmonized WCI-wide approach on retirement responsibility.

Recommendations on Limits for VRE Set Aside Program

- Jurisdictions should choose whatever upper limit on the allowance retirement amount (if any) and/or program time limit (if any) that is found appropriate for that jurisdiction.
- Need policy to deal with allowance shortfalls.
- Jurisdictions may choose to base time limits on periodic reviews of the cost-competitiveness of the technologies supported by the set aside program.

Recommendation on Emission Attribution for VRE Purchases

- Work together to develop a rate based on a marginal dispatch analysis, such as the WCI Default Emission Factor Calculator, for each major grid region. However, use of this rate should be optional and specific assignment of emissions left to jurisdictional discretion.
- Clearly this work ties in closely with the overall default emission rate work of the WCI.

Next Steps for VRE Issues Paper

- Comments and discussion at today's session.
- Written comments via WCI website.
- Deadline for comments is February 19, 2010.
  - Comments should be directed at draft recommendations to be most useful.
  - All comments get posted on WCI website.
- Final recommendations will be written up once stakeholder comments have been received and processed by the VRE group.

Reflections on the WCI Document

“Voluntary Renewable Energy Market:

Issues and Draft Recommendations

Chris Busch, Ph.D.
WCI Electricity Collaborative
January 21, 2010
Phoenix, AZ

CRS center for resource solutions

Green-e Certified Supply to Voluntary Market (a significant fraction of total supply)

State	2008 MWh generated in this state and certified for sale in the voluntary market by Green-e Energy	Rough estimate of avoided emissions using 2005 EPA e-grid data for WECC*
Arizona	0 MWh	0 tCO_2
California	1,783,000 MWh	963,000 tCO_2
New Mexico	637,100 MWh	344,000 tCO_2
Montana	147,500 MWh	79,700 tCO_2
Oregon	1,869,000 MWh	1,010,000 tCO_2
Utah	23,600 MWh	12,700 tCO_2
Washington	3,229,000 MWh	1,740,000 tCO_2

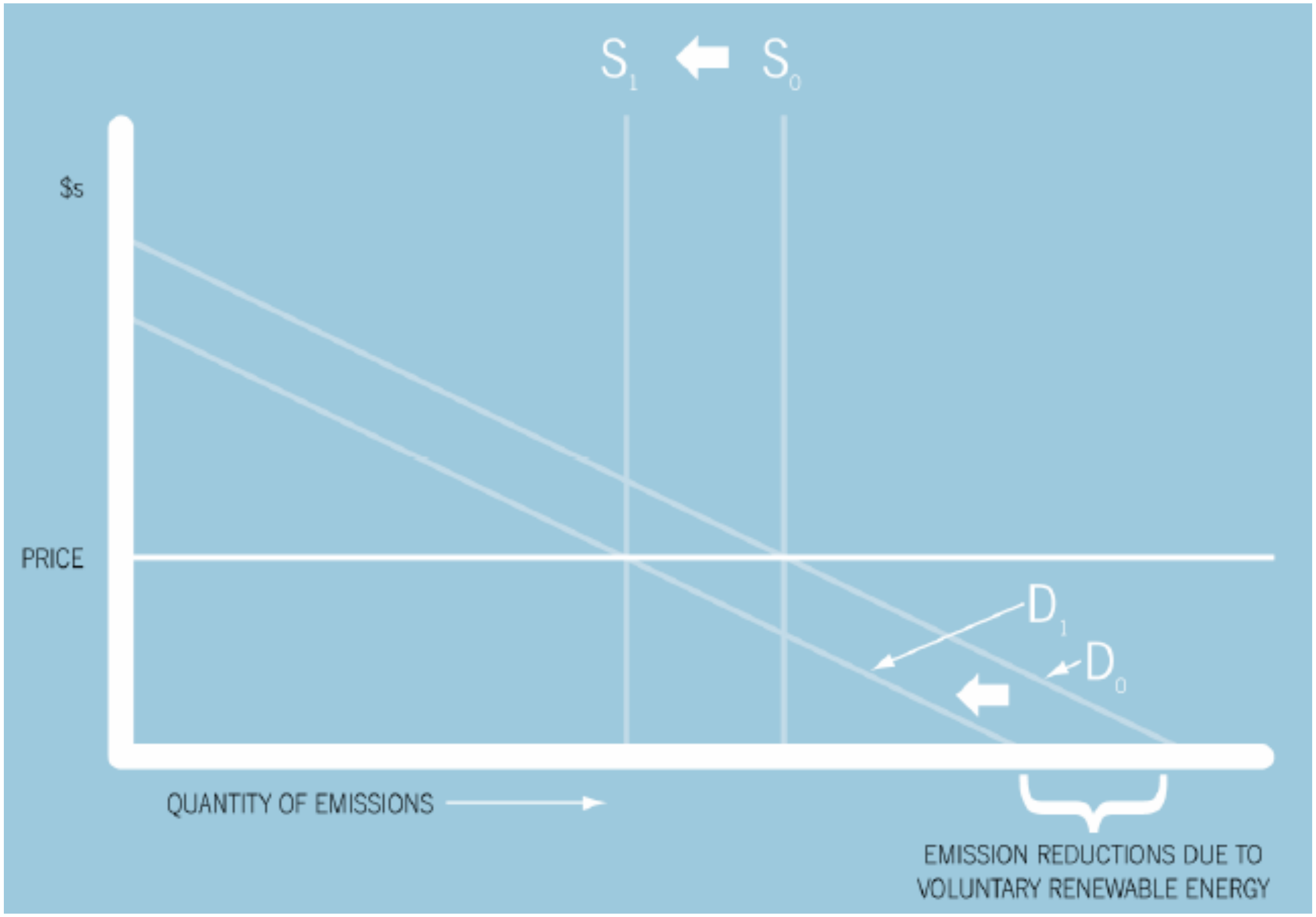
*2005 WECC non-baseload output CO_2 emission rate: 0.54 tonne of CO_2/MWh

http://www.epa.gov/cleanenergy/documents/egridzips/eGRID2007V1_1_year05_SummaryTables.pdf

CRS center for resource solutions

Interaction of supply and demand:

Example of an off-the-top scenario that leaves allowance prices unaffected



CRS center for resource solutions

Observations relevant to the "no intervention" approach

Not yet a foregone conclusion that others besides capped entities will have access to allowances (as is implied).

Savvy corporate and other larger purchasers have driven much of the growth in recent years.

- The top 50 largest green power purchases combined amount to nearly 11.8 billion kilowatt-hours annually (70% of EPA Green Power Partner purchases, EPA data April 2009)

- Carbon claims have been important.

Figure 1. data on real (actual) explosive market growth.

Figure 2. an uncertain forecast of future voluntary market trends.

THANK YOU

Contact

Chris Busch
Policy Director
Center for Resource Solutions
415-568-4284
chris@resource-solutions.org

Western Climate Initiative News

Febuary 2, 2010

This status report is issued monthly from WCI Partner jurisdictions to all interested stakeholders via the WCI list server and website.

Upcoming Events

February 4: Stakeholder Update Call

The next WCI update call will be on February 4 at 12:30 p.m. Pacific. To join by teleconference, dial 1-800-868-1837, participant code 659537#. (Outside the U.S. and Canada dial 404-920-6440.)

March 3: WCI Partners Meeting in Vancouver, BC

The next WCI Partner meeting will be March 3 in Vancouver, British Columbia at the Hyatt Regency Hotel. Stakeholders are invited to attend in-person or via teleconference. If you plan to attend in-person, please register here. To join by teleconference, dial 1-800-868-1837, participant code 659537#. (Outside the U.S. and Canada, dial 404-920-6440.) The agenda will be posted to the website and distributed via the WCI list server when available.

March 4: WCI Goods Movement Collaborative in Vancouver, BC

Following the WCI Partners meeting, the WCI will host a goods movement collaborative. The

In This Issue

California Releases Preliminary Draft Regulation

Manitoba Makes Commitment Towards Cap-and-Trade Legislation

Québec Adopts California GHG Emission Standards for Vehicles

Material Available from WCI Meetings

WCI Electricity Team Issues Draft Recommendations for the Voluntary Renewable Energy Market

WCI and Federal Governments Continue Coordination on Mandatory Reporting Procedures

Comment Period on WCI Complementary Policies White Paper Closing

California Releases Preliminary Draft Regulation

On November 24, 2009 California released a preliminary draft regulation (PDR) that conveys, at a conceptual level, how a broad-based multi-sector cap-and-trade program will work with complementary measures to reduce greenhouse gas emissions to meet the 2020 statewide emissions limit as required under California law (AB 32). The PDR is consistent with the September 2008 WCI program design recommendations, and describes the mechanism for linking to the cap-and-trade programs implemented by the WCI partners.

Manitoba Makes Commitment Towards Cap-and-Trade Legislation

On December 15, 2009, Premier Greg Selinger committed the provincial government to moving forward with legislation enabling the creation of a cap-and-trade system to reduce greenhouse-gas emissions in Manitoba. He said the system will be subject to public consultations in 2010.

"Manitoba is playing a constructive role in focusing on commitments, goals and targets that we and other leading sub-national governments can take," Selinger said. "Market mechanisms like cap-and-trade will play a large role in the global collaborative will be held at the same location at the Hyatt Regency Hotel in Vancouver, BC. Stakeholders are invited to attend in-person or via teleconference. If you plan to attend in-person, please register here. To join by teleconference, dial 1-800-868-1837, participant code 659537#. (Outside the U.S. and Canada, dial 404-920-6440.) The agenda will be posted to the website and distributed via the WCI list server when available.

April 14: WCI Partners Meeting in San Francisco, CA

Details for this meeting will be posted to the WCI website and distributed via the list server when available.

effort to address climate change in a cost-effective manner. Cap-and-trade legislation will complement Manitoba's participation in regional climate-change strategies like the Western Climate Initiative and Midwestern Greenhouse Gas Reduction Accord." For more information, click here.

Québec Adopts California Greenhouse Gas Emission Standards for Vehicles

On December 29, 2009 Line Beauchamp, Minister of Sustainable Development, Environment and Parks, announced that Québec's regulation to adopt California greenhouse gas emission standards for cars and light trucks will come into force in mid-January, 2010, making Québec the first Canadian province to apply North America's strictest standards. At approximately 40% of total emissions, transportation is the largest sector of greenhouse gas emissions in Québec. For more information, click here.

Material Available from WCI Partners and Electricity Collaborative Meetings

Material and presentations from the January 20 Partners meeting and January 21 WCI Electricity Collaborative are available on the WCI website. The first half of the Partners meeting focused on the 2010 work plan for the WCI and the several technical and policy products expected in the coming months.

WCI Electricity Team Issues Draft Recommendations for the Voluntary Renewable Energy Market

Voluntary purchases of renewable energy products have played an important role in expanding the renewable energy market in many WCI jurisdictions. The Electricity Team has examined how the voluntary renewable energy (VRE) market may be affected by the implementation of a greenhouse gas cap-and-trade program. The Electricity Team's draft recommendations describe the issue in greater depth and offer key design elements for a VRE allowance set-aside program for WCI Partner jurisdictions who choose to implement one. Comments on the draft recommendations should be submitted by February 19. To download a copy of the recommendations and submit comments, click here.

WCI and Federal Governments Continue Coordination on Mandatory Reporting Procedures

Several WCI Partner jurisdictions are participating on a team convened by the U.S. EPA to develop data exchange mechanisms between facilities, the EPA, and the states. The team includes Canadian observers and is intended to help harmonize the implementation of state and federal greenhouse gas emission reporting requirements. Similarly, the WCI provinces are working with Environment Canada on the data infrastructure required for mandatory reporting in the provinces.

Comment Period on WCI Complementary Policies White Paper Closing

The WCI Complementary Policies Committee has requested that public comments on its white paper be submitted by January 29, 2010. Any stakeholders still interested in submitting comments should do so as soon as possible. To download a copy of the document or submit comments, click here.

February 18, 2010 2006 and 2007 Draft Default Emissions Calculators

List of Commenters

Pacific Gas and Electric Company

Western Power Trading Forum

February 18, 2010 Draft OATI Analysis of Electricity Flows in the WECC Region from 2005 to 2008

List of Commenters

Modesto Irrigation District, Redding Electric Utility, and Turlock Irrigation District

Puget Sound Energy

March 2, 2010 Oil and Gas Reporting Draft Recommendations

List of Commenters

Amigos Bravos, Biodiversity Conservation Alliance, Colorado Environmental Coalition, Common Ground United, Drilling Santa Fe, Earthworks Oil & Gas Accountability Project, National Wildlife Federation, Natural Resources Defense Council, New Mexico Wildlife Federation, Powder River Basin Resource Council, San Juan Citizens Alliance, Southwest Environmental Center, Western Environmental Law Center, Wildearth Guardians

Independent Petroleum Association of New Mexico

Spectra Energy

Williams Energy

Western Climate Initiative

Issue Paper – Vented and Fugitive Compressor Emissions

Issue:

Compressors are used in the production, processing and transportation of natural gas. Typically, either gas-fired reciprocating compressors (85% of compressor population) or centrifugal compressors (turbines) are used to increase and maintain gas pressure as natural gas is moved from point of production to end-users.

These compressors and associated components are subject to thermal, pressure and mechanical stresses which result in fugitive leaks and loss of natural gas. Additionally, operational practices such as compressor start-up and blowdown also result in vented emissions of natural gas. While numerous studies indicate that these fugitive and vented emissions are a major source of methane and represent a significant economic loss, there are also many leak mitigation technologies available which have been proven to dramatically reduce these emissions. Fugitive emissions sources include: 1) valve leaks – from pressure relief valves, closed blow-down and unit isolation valves, 2) continuous leaks from rod-packing (either wet or dry seals) both during operation and when the unit is in pressurized/standby mode, 3) wet-seal oil degassing and, 4) miscellaneous leaks from fittings, pump and valve seals.

Western Regional Air Partnership (WRAP)/The Climate Registry (TCR) Approach:

The voluntary TCR draft Oil and Gas Production Protocol does not provide methodologies specifically designed to address compressor station emissions. The TCR draft includes compressor fugitive emissions under Fugitive Emissions from wellhead and Oil and Gas Production Installation or Facility. This section of the Protocol lists four methods which reporters may use to estimate these fugitive emissions:

<u>Fugitive Emissions</u>

1). Direct measurement approach where the composition of the processed natural gas is measured, mass emission rates are determined using bagging techniques, hi-volume samplers, or a screening and correlation method.

2). Use of facility level default emission factors (EFs) (EFs for valves, pump seals, connectors etc for three facility types - offshore facilities, oil and gas production facilities, and gas plants).

3). Use of default emission factors for large equipment types (e.g. small and large compressors, separators)

4). Use of facility default emission factors (e.g. off-shore oil production, gas processing)

TCR provides two methods for the determination of blowndown and start-up vented emissions.

Blowdown and Start-Up
1). Use of engineering approach to calculate vented volume for each blowdown or start-up, and record the number of blowdowns and start-ups per reporting period.
2). Record number of blowdowns and compressor starts and use a generic default EF.

EPA Approach: The draft EPA Subpart W requires that reporters screen the following components with an Infrared detection instrument, and then subsequently use a high-volume sampler to quantify emissions from these components:

1) centrifugal compressor wet and dry seals,
2) compressor fugitive emissions,
3) reciprocating compressor rod packing, and,
4) fugitive emissions from open-ended pipes, pump seals, and processing facilities.

EPA allows the use of calibrated bags or meters when high volume samplers cannot capture all fugitive emissions from the sources listed above.

WCI Options:

Option	Pros	Cons
A: Use default emission factors (e.g. 15 Mcf/blowdown)	Easiest of the methods	Data not of sufficient accuracy for cap-and-trade
B: 1) Screen all compressor station gas service components – use EFs to estimate emissions, and 2) quantify major compressor component emissions using Hi-Vol or calibrated bag sampling 3) calculate blowdown and start-up volumes and record number of compressor start-ups and blowdowns	Site specific measurements result in more accurate data. Provides facility operators with the data essential for the design of a mitigation strategy.	More extensive monitoring and sampling involved. Fugitive emissions data generated using EFs would not be cap-and-trade quality. Vented emissions data measured using Hi-Vol or bagging would be cap-and-trade quality.

Table 1. Methodology Options

WCI Reporting Subcommittee Comments and Recommendations:

Because of the significance of both fugitive and vented compressor emissions, a reporting regulation explicitly focused on the identification and quantification all major compressor GHG emissions is the most effective manner to address these fugitive and vented emissions. Studies by both Gas Research Institute (GRI) and Pipeline Research Committee International (PRCI) indicate that compressor components are responsible for more than 80% of the total leakage at compressor stations. In a typical compressor station there may be thousands of components, however only a small fraction of these components contribute significantly to total fugitive emissions from the facility. Thus, WCI recommends the use of Option B which is discussed in detail below.

1) Component screening of all gas carrying components shall be conducted using a handheld device (e.g. OVA, TVA, or IR instrument). Default emissions factors would then be used to estimate fugitive emissions. Because default EF's are by their nature not facility or compressor specific, these emission estimates would not be of cap-and-trade quality. This data would however, provide the site operator with the information necessary to design a mitigation plan to address these fugitive leaks – screening identifies leaks and provides actionable semi-quantitative information concerning leak magnitude. Screening should be conducted on an annual basis.

2) In the case of the major compressor related vented emission sources listed in Table 2 below, emissions should be measured using high-volume sampler and bagging techniques which are much more accurate and quantitative. This data will be sufficiently accurate for inclusion in a cap-and-trade program. The WCI Subcommittee is proposing that emissions sampling and quantification be conducted twice annually – approximately every six months. Because major station maintenance turnarounds are scheduled well in advance, it should be possible for reporters to conduct sampling shortly after station maintenance turnarounds and thereafter at approximately six month intervals. For the purposes of emissions calculation, we assume a linear increase in leak rate during the approximately six month interval between measurements. For instance, if a blowdown valve was found to have a zero leak rate when last sampled, and an emission rate of 500 scf/hr during the present sampling period, a leak rate of 250 scf/hr would be used to calculate emissions over the time interval between these two sampling efforts.

Component	**Compressor Status**		
	Running	Idle/Pressurized	Blowdown/ Pressurized
Rod packing seals	X	X	
Blowdown valve	X	X	
Pressure relief valve	X	X	
Unit isolation valve			X
Wet-seal oil degassing	X		

vent			
Centrifugal compressor seals	X	X	

Table 2. Sampling Matrix - Component and Compressor Status

For most components, measurements must be conducted both when compressors are running and when they are idle and pressurized (see Table 2 for details). Compressor rod seals leak during normal operations but leak rates can increase four-fold when the compressor is idle but remains pressurized. It is interesting to note that the EPA Gas Star Program has found that leaving a compressor pressurized results in lower emissions than the practice of blowing down a compressor when it is placed in idle or standby mode. In the case of unit isolation valves, sampling is required only when compressors are blowdown but remain pressurized.

For vented emission sources listed in Table 2, the WCI Subcommittee is considering establishing a compressor horse-power threshold (200 hp) below which reporters could simply screen the compressor and associated components and use a default EF to estimate emissions for most of their smaller (<200 hp) compressors. Seventy-five percent of compressors below the 200 hp threshold could use a default EF to estimate emissions. For the remaining 25percent of compressors, reporters would be required to carry out the more extensive sampling and quantification measurements. This approach will allow WCI to evaluate the effectiveness and accuracy of this approach. The WCI Subcommittee is seeking comment and data concerning the horse-power distribution of field and processing facility compressors to better evaluate the most effective threshold. Canadian data suggests that a threshold of 250 hp would capture approximately 75% of the compressors in service.

This threshold will not be applied in the case of blowdown and start-up emissions because the start-up and blowdown volumes remain constant. Reporters will be required to use an engineering approach to calculate blowdown and start-up emissions regardless of compressor size.

WCI Quantification Methodology:

Compressor Blowdown and Start-up Emissions - The following methodology (based on CAPP, 2002) shall be used to calculate blowdown and start-up emissions for all compressors, regardless of size.

a). Use engineering approach to calculate the volume of gas released during compressor start-up and blowdown,
b). Record temperature and pressure of gas prior to blowdown,
c). Correct volume of gas released to STP (standard atmospheric temperature and pressure),
d). Record number of blowdowns and start-ups,
e). Determine gas composition (carbon content) semi-annually using standard methods approved by WCI jurisdiction.

<u>Step 1.</u> Calculate the compressibility factor (Z) for natural gas to account for deviation from ideal gas behavior. Z must be calculated for both initial conditions (temperature and pressurize prior to blowdown) and standard temperature and pressure (20°C and 1 atmosphere)

$$Z = a + bP + cT + dP^2 + eT^2 + fPT$$

Where:

- Z= compressibility factor
- P = gas pressure (kPA) – (standard pressure = 101.325kPa)
- T = gas temperature (°C) – (standard temperature = 20°C)
- a,b,c,d,e, and f are correlation coefficients (see Table below)

Correlation Coefficient	Value
a	9.9187E-01
b	-3.3501E-05
c	6.9652E-04
d	6.3134E-10
e	-8.6023E-06
f	2.3290E-07

Table 3 – Correlation Coefficients for Estimating Compressibility Factor for Natural Gas

Step 2. Gas volume released during blowdown is corrected to atmospheric temperature and pressure in the following manner:

$$V_{STP} = V_{BD} \left(T_{STP} / P_{STP} \right) \left(P_C / Z_i * T_C - P_{STP} / Z_{STP} * T_C \right)$$

Where:

- V_{STP} = blowdown volume at standard temperature and pressure (scf)
- V_{BD} = compressor blowdown volume (cf)
- T_{STP} = standard temperature (293.15 °K)
- P_{STP} = standard pressure (101.325 kPa)
- P_C = compressor pressure prior to blowdown (kPa)
- Z_i = natural gas compressibility factor (initial conditions – unit-less)
- T_C = temperature of gas prior to blowdown (°K)
- Z_{STP} = natural gas compressibility factor at STP (unit-less)

<u>Step 3.</u> Emissions are calculated as follows:

$$E_{CH4/CO2} = \sum_{1}^{2} \sum_{1}^{N} V_{STP-B,S} * 1/MVC * MW_{CH4/CO2} * MF_{CH4/CO2} * 0.001$$

Where:

- $E_{CH4/CO2}$ = emissions of methane or carbon dioxide (MT/yr)

N= number of start-ups or blowdowns per sampling interval (semi-annual)
$V_{STP-B,S}$ = blowdown or start-up volume of gas released (volume at STP, V_{STP})
MVC = molar volume conversion factor
$MW_{CH4/CO2}$ = molecular weight of carbon dioxide or methane
$MF_{CH4/CO2}$ = molar fraction of methane or carbon dioxide in gas
0.001 = conversion factor (kg to metric tons)

<u>Compressor Component Emissions</u> – For all compressors greater than 200 hp and 25% of compressors less than 200 hp reporters must conduct quantitative measurements of emissions from the sources listed in Table 2. Hi-volume sampler and/or bagging techniques shall be used to measure gas emission rates.

Emissions shall be calculated in the following manner:

$$E_{CH4/CO2} = \sum_{1}^{2}\sum_{1}^{N} \left(ER_{Ci-F} - ER_{Ci-i}\right)/2 * MF_{CH4/CO2} * 1/MVC * T * 0.001$$

Where:

$E_{CH4/CO2}$ = emission of methane or carbon dioxide (Mt/yr)
N = number of components (see Table 2)
ER_{Ci-F} = gas emissions rate at time of current (final) sampling (scf/d)
ER_{Ci-i} = gas emission rate at time of prior (initial) sampling (scf/d)
$MF_{CH4/CO2}$ = molar fraction of methane or carbon dioxide in gas
MVC = molar volume conversion factor
T = time between sampling periods (decimal days)
0.001 = conversion factor (kg to metric tons)

WCI Monitoring Methodology:

see methodology discussed above.

1) individual components are screened annually,
2) emissions from components list in Table 2 would be quantified using Hi-Vol or bagging techniques semi-annually,
3) gas composition would be determined at least semi-annually.

Stakeholder Input:

Stakeholders have not seen or commented on this Issue Paper.

Western Climate Initiative

Issue Paper -- Contractor Emissions

Note to those reviewing issue paper for the first time:

The contractor emissions issue paper has been developed sequentially by the WCI Reporting Subcommittee over the last months with input from the Oil and Gas Technical Working Group (consisting of industry and environment group representatives). The foundation for this issue paper was the technical discussion that occurred for the development of the WRAP/Climate Registry Oil and Gas Protocol. Those reviewing the issue paper for the first time may want to first focus their reading on the first and last sections: (i) Issue; and, (ii) WCI Subcommittee Discussion and Recommendation prior to looking through the sections on the background and stakeholder comments.

Issue:

Oil and gas installation operations may be conducted by owners/leaseholders or service providers who act as contractors. At some installations there may be fractional owners of wells, each owner having a slightly different ownership group. One company will often be assigned operational control and either performs the exploration and extraction operations itself, or contracts them to a service provider. In these instances, the question arises as to which entity is responsible for reporting emissions: the owner/leaseholder with operational control or the contracted service provider ("contractor").

Owners and leaseholders have raised concerns that reporting contractor emissions could cause significant burden as such emissions are not currently reported in any form. New contractual obligations may be required if the owner/lease holder were to obtain emissions data from the contractor for reporting purposes.

A significant issue could arise from facility splitting if firms were to contract out oil and gas installation operations to avoid both greenhouse gas reporting and a future cap and trade system. In addition, an equity issue is raised as Canadian operators contract out significantly less in the way of equipment such as compressors than their American counterparts. Also significant is the WCI's goal of capturing 90 percent of emissions from each source category. Without capture of contractor emissions it is doubtful that 90 percent of oil and gas production installation emissions will be captured.

Western Regional Air Partnership (WRAP)/ The Climate Registry Approach:

The reporting of emissions from contractor activities was discussed in depth in the WRAP/Climate Registry process, and the technical working group came to the consensus that, as defined by the GHG Protocol Corporate Standard for voluntary reporting, contractor emissions are the Scope 3 indirect emissions of the owner/leaseholder. Although it should be noted that some working group participants felt that certain categories of contractor emissions should be required to be reported by The Climate Registry's voluntary program because those activities were seen to be significant, central and necessary to the production of oil and gas. However, in The Climate Registry's voluntary program Scope 3 emissions are not required to be reported. The WRAP/Climate Registry working group did identify that emissions such as venting are in general considered to be the responsibility of the owner/leaseholder to report and are therefore not contractor emissions. That left contractor activities related primarily to combustion from portable (e.g. mobile drill rigs) or stationary sources as the categories of Scope 3 sources typically found in this sector.

Whether to include contractor emissions under a mandatory reporting program was not addressed in the WRAP/Climate Registry process.

EPA Approach:

In the Mandatory Reporting Rule (MMR), EPA's definition of a facility would not preclude contractor equipment at an installation from being considered a separate facility subject to the MRR and reportable by the owner or operator, or as part of the larger facility. The EPA definition would include in the facility all equipment under "common ownership or common control"; therefore, specifics of the contractual arrangement might determine whether contracted equipment was under the control of the party contracting to purchase services. However, the EPA excludes portable equipment from coverage under MRR Subpart C (General Stationary Combustion), and defines portable equipment to include equipment which is easily transportable and located at a given site for less than twelve months. Portable contractor equipment is often located at a site for periods less than a year, and therefore much of contractor combustions emissions would be excluded from reporting under Subpart C. EPA deferred on the issues of defining the reporting entity for oil and gas production sources and of reporting vented and fugitive emissions from oil and gas sources.

We also note that EPA has addressed policy issues related to contractor emissions in the context of PSD and Title V programs. In several guidance letters, EPA has consistently stated that "contractor-operated units [must] be included as part of the source with which they operate or support" (Ref. 1). Although this policy is not necessarily binding on Subpart W of the Mandatory Reporting Rule, EPA's rationale for this policy is relevant: "the contracting entity can control the relevant aspects of the contract operator's performance through terms of the contract (e.g., the level of production, the requirement to implement and maintain emission control measures, the requirement to comply with all applicable environmental regulations, etc.)" (Ref. 2).

WCI Options:

Option	Pros	Cons
A. Not require reporting of contractor emissions. Neither the oil and gas producer nor the contractor report emissions.	Simple	Facility splitting could be a problem Would capture fewer emissions than other options. Does not match WRAP/Climate Registry approach to leaseholder emissions. Inequitable coverage: creates a two-tier system of facilities with and without contractors. Could result in underreporting contrary to WCI design principle.
B. Require contractors to report if aggregated emissions exceed threshold. Require contractors to report all emissions associated with the operations they are contracted to perform (if in total they exceed the threshold.)	Creates responsibility for contractors to report emissions Would be the simplest scenario for emissions from combustion and portable sources	Added administrative burden for the regulator as emission sources could be covered by several operators and contractors, at a single installation. Does not match WRAP/Climate Registry approach to leaseholder emissions. Facility splitting could create administrative difficulties. Would create a new class of 'facility'.
C. Include venting, fugitive and flaring emissions from a contractor in the emissions of the owner or operator. The oil and gas producer reports all emissions associated with the contractor operations excluding combustion emissions.	Would cover a significant portion of emission sources. Reduces facility-splitting potential through intentional use of contractors. All emissions are generally considered part of a typical oil and gas installation. WRAP/Climate Registry approach identified that these emissions are the responsibility of the leaseholder.	Does not include what could be substantial combustion emissions from contractor activities. Inequitable coverage: potentially creates a two tier system of facilities with and without contractors (for other emission sources).

Option	Pros	Cons
D. Include all emissions in Option C (above) and combustion emissions from contractors, other than portable combustion emissions. The oil and gas producer reports all emissions associated with contractor operations including combustion emissions, other than portable combustion emissions.	Creates equitable coverage. Would cover all emission sources that are typically considered as part of an oil and gas installation. Producer consumption is a significant emission source. Reduces facility-splitting potential through intentional use of contractors. Requirements to track combustion emissions from contractors could be included within contracts.	May require phasing in due to standing contractual obligations. (Could require owners/leaseholders to estimate combustion emissions in the first years to allow importance to be established and to phase in new contractual obligations) More rigorous than WRAP/Climate Registry approach to leaseholder emissions.
E. Include all emissions in D and portable combustion emissions from contractors. The oil and gas producer reports all emissions associated with contractor operations including portable combustion emissions occurring on- site.	Would cover the largest portion of emission sources.	Portable combustion emissions (e.g., onsite emissions from a mobile drilling rig) in the oil and gas industry likely would prove hard to track, creating an administratively burdensome system. More rigorous than WRAP/Climate Registry approach to leaseholder emissions.

Stakeholder Input (from both initial and revised issue papers):

Natural Resources Defense Council (NRDC), Wild Earth Guardians, Western Environmental Law Center

Initial comments on November, 2009 version of issue paper:

- Contractor emissions are significant and must be included in reporting.
- Operators can make GHG emissions data collection part of contracts.
- Operators should be required to report contractor emissions, including combustion (portable and stationary), venting and fugitive emissions.
- Contractor sources should be considered for inclusion on same technical criteria as operator sources (significant emissions in aggregate, availability of cost-effective emissions reduction method).
- Supports Option E.

Subsequent comments are on January, 2010 version of issue paper:

- In the January 21, 2010 teleconference WCI explained that having the owner/operator report contractor emissions harmonizes with EPA's historical approach of reporting contractor emissions at a facility under the Clean Air Act. Owner/operators are in a unique position to select and hire contractors that chose to run low emission units. And, because contractor emissions can be a significant portion of the oil and gas GHG emissions, it is important for the owner/operator to take ownership and have a solid understanding of the full environmental impact of its operation and work collaboratively to select and reward environmentally progressive contractors.
- The main difference between Option D and Option F1/F2 is who does the reporting. In Option D the owner/operator must report all contractor emissions. In Option F1/F2 the owner/operator would report venting, fugitive and flaring emissions, and the contractor would report combustion emissions. We do not see any advantage to the split reporting. We agree with WCI that owner/operator reporting would be preferable, over the split reporting Option F1/F2. Option E, that we support, also requires owner/operator reporting.
- During the January 21, 2010 work group meeting, we inquired how WCI handled contractor emissions within the other WCI GHG Reporting Protocols. WCI explained that contractor emissions at the owner/operator facility were included and reported by the owner/operator. We pointed out that WCI's past precedent for handling contractor emissions was consistent with Options D and E, but not Option F1/F2. We recommended that this fact be listed as a "con" in the proposed Option F1/F2, because Option F1/F2 would not be consistent with the approach taken on other established WCI GHG reporting protocols.
- The difference between our preferred Option E and WCI's new Option D is that all contractor emissions from combustion sources using gasoline, diesel and other liquid fuels provided by a commercial fuel supplier would be excluded. This would essentially eliminate tracking of GHG emissions from all portable/mobile combustion sources [e.g. fleet vehicles, vessels, drill rigs, workover rigs, etc.] that operate on liquid fuels. WCI clarified that it was proposing this exclusion, because WCI has plans to capture GHG emissions from commercial fuel suppliers in a separate protocol (Fuel Supplier's Protocol) under development for 2012.
- We would like to better understand the rationale for including fleet combustion source emissions under the Fuel Supplier's Protocol. It is not clear to us tracking contractor combustion emissions from fleet units under the Fuel Supplier's Protocol will ultimately lead to the GHG emission reduction solutions WCI seeks.
- Since the ultimate goal is to quantify GHG emissions and then identify cost-effective emissions reduction strategies to reduce emissions it seems necessary to track emissions generated by Fuel Suppliers (generated in the fuel production and delivery itself) and by Contractors/Owners/Operators that generate GHG emissions by combusting the liquid fuels in portable/mobile sources.
- We think it would be better to include contractor fleet emissions under the Oil & Gas GHG Reporting Protocol where the owners/operators and contractors have more direct influence on future emission reduction opportunities. We are concerned that if the GHG emission reporting obligation is transferred to the Fuel Supplier's Protocol, the Fuel Suppliers will not have any control over future

emission reduction opportunities for Oil & Gas Contractor equipment, other than controlling the amount and carbon content of fuel sold.

- In Option D, we don't understand why a more rigorous reporting approach is listed as a "con"; we recommend that this comment be placed in the "pro" section of the analysis.

Canadian Association of Petroleum Producers (CAPP)

Initial comments on November, 2009 version of issue paper:

- Supports Option C: Include venting, fugitive and flaring emissions from contractor in the emissions of the owner or operator.
- Canadian rules require metering and reporting of venting and flaring associated with well drilling and servicing activities.
- Emissions associated with operation of drilling and servicing rigs are best reported by operators of that equipment (such as contractors).
- Combustion emissions from operation of well drilling and service rigs in Canada account for about 1.5 percent of upstream O&G emissions. These emissions should be excluded. The level of effort required for well owners/operators to gather the contractor data necessary to estimate these emissions is out of proportion with the benefits achieved of capturing these emissions.

Subsequent comments on January, 2010 version of issue paper:

- Verification of contractor combustion emissions would be difficult because well owners do not have access to the necessary data. Well owners/operators typically do not have access to the data necessary to make the emission estimates and have no power to compel their drilling/servicing contractors to have verifiable data collection systems in place nor to provide the required data.
- Supports Option F1 and F2 because emissions associated with the operation of a production well should be the responsibility of the owner/operator as they have access to the data required to determine the GHG emissions associated with the activity.
- In the case of well drilling and servicing activities, GHG emission sources include flaring and venting associated with gas returned during drilling, well cleanouts and drill-stem tests. In Canada, volume associated with these activities are currently metered and reported to the regulator.
- On the other hand, other GHG emissions associated with the operation of drilling and servicing rigs are best reported by the operators of that equipment. Drilling and servicing contractors are best equipped to estimate and report GHG emissions as they have access to the necessary activity data, which the well owner/operator would not.
- The level of effort required by drilling and servicing contractors to report their GHG emissions would be significantly less than if the owner/operator were to report the GHG emissions from each well. The contractor would merely report their total emissions based on total fuel consumed, in contrast to having to allocate fuel consumption to each well drilled during the year, which is what the owner/operator would be required to do.

Chevron (CVX)

Comments on November, 2009 version of issue paper:

- Support WCI efforts to include significant contractor emissions
- Limit this reporting to fields/basins where these emissions contribute to 95 percent of total.
- Contractors often work on multiple sites in workday; may be difficult to allocate total fuel use among well sites/operators.

American Petroleum Institute (API)

Initial comments on November, 2009 version of issue paper:

- Support Option C (operator reports venting, fugitive and flaring emissions from contractor, but not contractor combustion emissions).
- Producer does not have access to data on contractor fuel use, device specifications, hours of operation.
- WCI could devise simplified methods for reporting of combustion emissions from portable equipment used by field service contractors, as in Option B, to cover such equipment emitting more than threshold amount per year.

Subsequent comments on January, 2010 version of issue paper:

- It is clear that contractors have an important role to play in Oil & Gas operations and they – as independent entities – should have the responsibility to report emissions that are under their operational control.
- Supports in principle Option F1/F2 thus splitting the reporting responsibility between owners and service contractors. Such a reporting split should rest with the owners reporting of emissions from their operations including venting and/or flaring from compression, workover and well completion. Combustion emissions along with fugitive emissions from equipment leaks associated with contractors operations should be included under the F2 option.
- Both oil and gas companies and field service contractors should be required to report GHG emissions from the equipment that is under their operational control whether it is owned or leased.
- Does not concur that this approach would create a new type of “facility” since it is recommending that the reporting boundaries be set at the jurisdiction level with either field operators or field service contractors reporting their applicable emissions for listed sources that exceed certain threshold applicability criteria. Such an approach will simplify data tracking and reporting for contractors by enabling them to integrate accounting for their activities when servicing multiple operators in the same jurisdiction.
- It is essential to minimize confusion and reduce reporting burden by ensuring that the option selected be consistent with EPA’s owner and/or operator approach and the flexibility it has afforded in its GHG mandatory reporting rule (MRR) for joint ownership reporting by a designated official that is acceptable to the applicable parties.
- WCI should retain consistency with its stated policy of harmonizing their reporting requirements

with the EPA MRR rule and should therefore adopt EPA's definition of owner/operator to establish the reporting obligations of both field owners and field service companies reporting obligations.

- WCI should also ensure harmonization with the EPA MRR definition of portable equipment that is exempt from reporting, where such equipment includes emergency generators and mobile and/or easily transportable devices.
- The use of the term 'non-commercial fuels' is open to widely varying interpretations. API views these fuels as field generated fuels prior to the respective 'custody transfer' points where they enter into commerce. WCI ought to confirm and expound on what is meant by this term.

Suncor

Comments on January, 2010 version of issue paper

- Whatever option is chosen, you have to realize that the quality of data that Operators will get from contractors is lower, and at least initially we will have to accept best estimates until long-term contracts can be written requiring better data. Similarly, it will be effectively impossible to get a "reasonable" level of assurance from third-party data sources, so we may have to accept a "limited" assurance level for contractor emissions.

WCI Subcommittee Comments and Recommendation:

The WCI Reporting Subcommittee acknowledges the Technical Work Group comments on contractor emissions. Based on the discussion and the need to capture combustion emissions from contractors, there are two feasible alternatives – a combined Option B and C (termed Option F1/F2), and Option D. They are presented below for clarity. Due to the coverage of portable combustion emissions (e.g. diesel fuel use at a drilling rig) under fuel suppliers in the WCI design, Option E was discarded. Option A was viewed as not covering a sufficient portion of emissions.

The difference between options D and F1/F2 is whether a producer would be responsible for combustion emissions at equipment owned by a contractor, or if a contractor would be responsible for these specific emissions. Both would cover a similar amount of emissions and meet the WCI goal of covering a significant portion of emissions for each industry. Option D would have fewer entities reporting than Option F1/F2.

Due to the control that owners/leaseholders have over production, processing and transmission operations, and given that it would cover all sources normally considered as part of the oil and gas operation, Option D is recommended by the subcommittee. As it is understood that standing contractual agreements may need to be revised, phasing in of reporting may be required. Owners/leaseholders may need to estimate combustion emissions in the first year(s) to phase in new contractual obligations.

For Option D, the reporting requirements for each of the three sectors – production, processing, and transmissions are shown the final Table.

Revised WCI Options (based on stakeholder feedback from November, 2009 version of issue paper):

Option	Pros	Cons
D. An owner or operator would include all venting, flaring, fugitive and combustion emissions (from fuels not obtained by a commercial supplier) from contractors, other than portable combustion emissions. The oil and gas producer reports all emissions associated with contractor operations including combustion emissions from fuels not obtained from a commercial supplier (fuels obtained from a commercial supplier would be covered under a future WCI fuel supplier Essential Requirement quantification method.)	Creates equitable coverage. Would cover all emission sources that are typically considered as part of an oil and gas installation. Producer consumption is a significant emission source. Reduces facility-splitting potential through intentional use of contractors. Requirements to track combustion emissions from contractors could be included within contracts. Contractors would likely quickly install necessary meters and be responsible to the owner/operator.	May require phasing in due to standing contractual obligations. (Could require owners/leaseholders to estimate combustion emissions in the first years to allow importance to be established and to phase in new contractual obligations). Requires administrative steps by the owner/operator to ensure data is received from the contractor. More rigorous than WRAP/Climate Registry approach to leaseholder emissions.

Option	Pros	Cons
F1. Include venting, fugitive and flaring emissions from a contractor in the emissions of the owner or operator. **F2. Require contractors to report combustion emissions (from fuels not obtained from a commercial supplier) if aggregated emissions exceed threshold.** The oil and gas producer reports all emissions associated with the contractor operations excluding combustion emissions (the producer would include their own combustion emissions, from fuels not obtained from a commercial supplier). The contractor reports all combustion emissions (from fuels not obtained by a commercial supplier) (except flaring) associated with the operations they are contracted to perform (if in total they exceed the threshold).	Would cover a significant portion of emission sources. Covers emissions generally considered part of a typical oil and gas installation. WRAP/Climate Registry approach identified that the non-combustion emissions are the responsibility of the leaseholder. Creates responsibility for contractors to report emissions. Would be simplest scenario for a facility to report combustion emissions. Contractors would likely quickly install necessary meters.	Does not include potentially substantial contractor combustion emissions with the classic owner/operator. Inequitable coverage: potentially creates a two tier system of facilities with and without contractors (for other emission sources). Facility splitting could create administrative difficulties. Added administrative burden for the regulator as emission sources could be covered by several operators and contractors. Does not match WRAP/Climate Registry approach to leaseholder emissions. Would create a new class of "facility". Does not match traditional EPA handling of contractor emissions within the total emissions for a facility.

Reporting Requirements (by sector) Under Option D

Sector	Who Reports	What Emissions are Reported
Production	Oil and Gas Producer	All stationary combustion emissions from produced gas and other fuels (with the exception of fuels brought on site by contractors). All fugitive, flaring and venting emissions where methods are provided.
Processing	Oil and Gas Processor (operator of the processing facility)	All stationary combustion emissions for gas and other fuels. All fugitive, flaring and venting emissions where methods are provided.
Transmission	Operator of the transmission facility	All stationary combustion emissions for gas and other fuels. All fugitive, flaring and venting emissions where methods are provided.

References

1. Contract/Temporary Operations and Title V, 11-16-94, in Memoranda for Operating Permits (Title V) – Policy & Guidance Memos, US EPA (www.epa.gov/ttn/oarpg/t5pgm.html).
2. Guidance for Major Source Determinations at DOD, 8-2-96, in Memoranda for Operating Permits (Title V) – Policy & Guidance Memos, US EPA (www.epa.gov/ttn/oarpg/t5pgm.html).

Dear Stakeholder:

The Western Climate Initiative (WCI) Reporting Subcommittee on Oil and Gas has developed draft recommendations for quantifying certain emissions in the upstream oil and gas sector. These recommendations will serve as the basis for the WCI's comments to U.S. EPA on their revised draft reporting rules for the sector (Subpart W). We anticipate EPA will release these draft rules sometime this month. The recommendations will also serve as the basis for the WCI essential mandatory reporting requirements for the upstream oil and gas sector which we hope to complete this calendar year. After EPA has released their final version of Subpart W, the WCI Reporting Committee will develop a set of recommended Essential Requirements for Mandatory Reporting for this sector which will be harmonized with the final EPA rule.

Many of the draft recommendations have been reviewed by a technical workgroup consisting of representatives from the oil and gas industry and the environmental community and are now ready for broader review and input.

The WCI has developed and posted draft recommendations covering eight issues: contractor emissions, compressors, glycol dehydration, sour gas treatment, well unloading, storage tanks, instrument gas and vented methane, and reporting entity and threshold. Comments on these papers should be submitted by March 30 for the Reporting Entity and Threshold Issue Paper and March 16 for the others. The subcommittee may post additional papers in the future.

Please let me know if you have any questions.

Sandra Ely
NMED Environment and Energy Policy Coordinator
(505)827-0351

Western Climate Initiative

Issue Paper -- Defining the Reporting Entity and Threshold

Issue:

Greenhouse gas emission sources in the oil and gas industry often consist of small sources distributed over a broad geographic area that, when taken together, can contribute significantly to total GHG emissions in their regions. Large numbers of these emissions sources are typically owned and/or operated by the same company, although ownership (and operation) is not necessarily determined exclusively on the basis of geographic proximity. While many of the oil and gas emission sources in the oil and gas sector are small, some individual oil and gas facilities are large enough to be captured under the current reporting and verification thresholds. To ensure that a comparable portion of emissions is captured in the oil and gas sector as in other sectors, individual small oil and gas sources may need to be aggregated into oil and gas reporting entities for the purposes of reporting GHG emissions to WCI jurisdictions.

In discussions of this issue, it should be noted that the oil and gas industry in Canada can be vertically integrated (i.e. the producing company can also own the natural gas plant and/or the transmission company), while in the United States such vertical integration is prohibited by Federal Energy Regulatory Commission regulations.

Western Regional Air Partnership (WRAP)/The Climate Registry (TCR) Approach:

The WRAP/TCR approach recommends that emissions be aggregated and reported from small individual oil and gas sources which are owned and/or operated by a company at the field level. Large sources that meet the traditional definition of a standalone facility must be reported separately to maintain transparency. Reporting thresholds would be established at the field level for small sources and at the facility level for sources meeting the traditional definition of a facility. Companies have the option to aggregate multiple fields together up to the state-level for reporting convenience.

EPA Approach:

Not applicable – deferred to final Subpart W.

WCI Options:

The basic option would be to follow the general WRAP/TCR approach (defining the reporting entity as outlined in the first option table below), adding the following detail needed for a mandatory reporting program:

1. Use the WCI (or EPA) facility definition, including the clause: ”are under common control of the same owner(s) or operator(s)” for aggregation purposes. Discard clause b “Are located on one or more contiguous or adjacent sites” and part of clause d of the same definition for aggregation purposes.

For oil and natural gas entities, the "facility" definition would thus be:

"Oil and Natural Gas Facility" means all buildings, plants, structures, installations, and equipment that:

(a) Emit or may emit GHG(s);

(b) Are under common control of the same owner(s) or operator(s);

(c) have the first three digits "211" or "221", or the six digit codes "213111" or "213112" of the North American Industry Classification System (2007), excluding natural gas distribution and (potentially) transmission systems

(d) Operate within a single geologic basin, or process or receive oil or natural gas from the said geologic basin

2. Apply thresholds (as outlined in the second option table below) to the aggregated emissions to create an 'Oil and Gas Reporting Entity'.

3. Jurisdictions may choose to aggregate emissions to a broader level than the WCI determines.

4. Apply to all oil and gas emissions sources covered under EPA Subpart W and those emissions sources not included in Subpart W but to be included in the WCI Oil and Gas Essential Requirement. Apply similarly to all emission sources involved in the transfer of carbon dioxide from one location to another, whether it be for carbon capture and storage, release in another location, enhanced oil recovery, or other purposes.

Defining the Reporting Entity:

Option	**Pros**	**Cons**
A. Do not aggregate emissions. Apply existing facility definition to oil and gas installations	Simple, follows current WCI facility definition.	May not meet WCI principle of covering a significant portion of emissions.
B. Aggregate emissions to the field level	Consistent with WRAP/TCR approach Emission factors likely similar at field level	May not meet WCI principle of covering a significant portion of emissions unless lower thresholds are used. Fields vary in size, potentially creating inequity between leaseholders in different field.
C. Aggregate emissions to the basin level	Extend WRAP/TCR approach to a scale potentially more suitable for a mandatory	Appropriate thresholds would need to be determined.

	program. With appropriate thresholds would likely meet WCI design principle of covering a significant portion of emissions with as few facilities and reporting entities as possible.	Variable emission factors may need to be used in different fields.
D. Aggregate emissions to the jurisdictional level.	Extends WRAP approach to a scale potentially more suitable for a mandatory program. With appropriate thresholds would likely meet WCI design principle of covering a significant portion of emissions with as few facilities and reporting entities as possible.	Appropriate thresholds would need to be determined. Variable emission factors may need to be used in different fields.

Reporting Thresholds:

Option	**Pros**	**Cons**
A. Existing WCI thresholds: 10,000 metric tons reporting, 25,000 metric tons verification.	Follows current WCI standards. Easy to communicate	May not meet WCI principle of covering significant portion of emissions. May need more detailed reports form a reporting entity to understand the distribution of emission sources.
B. Lower thresholds	Would capture a higher portion of emissions and may meet the WCI principle of covering a significant portion of emissions. May not require more detailed reports from a reporting entity to understand the distribution of emission sources.	May or may not meet WCI principle of covering a significant portion of emissions with as few facilities and reporting entities as possible. May increase reporting burden for small companies.

C. Higher thresholds	May reduce reporting burden for small companies. Potentially could meet WCI principle of covering a significant portion of emissions with as few facilities and reporting entities as possible.	May not meet WCI principle of covering a significant portion of emissions. May need more detailed reports from a reporting entity to understand the distribution of emission sources.
D. Base threshold on a similar amount of barrels of oil equivalent	May be easier to determine obligations for the oil and gas industry.	Deviates from WCI emissions threshold approach for reporting and verification.

Note: There is a relationship between how the reporting entity is defined and the appropriate thresholds to use. A broader reporting entity may mean a higher threshold could be used. A smaller reporting entity may mean a lower threshold is needed. The optimum combination of reporting entity definition and threshold to meet the design principle may not be known until one or more years of reported data is available at a finer scale than that ultimately required for the long-term.

Screening:

Some industry representatives are concerned that potential reporting entities may need to undertake significant effort to determine whether or not they meet the reporting threshold. One solution is to specify a screening approach to determine whether a potential reporting entity is obligated to undertake an emissions estimate of its facilities. Screening would involve a simplified approach that provides reasonable clarity that a potential reporting entity has emissions below the reporting thresholds.

Several different screening approaches are possible:

i) A threshold set by the sum of total horse power (hp) capacity for compressors and heat capacity for heater/treaters operated by a reporting entity in a basin with a projected emissions from these activities (based on average activity level) and added to this estimated emissions from venting and flaring. The table below provides some examples. These examples represent only approximate sized equipment that would meet these thresholds.

Threshold Examples for Equipment Types:

Threshold	Engines	Boiler/Heaters/Flares	Vents/Leaks/Blowdowns/Pneumatics
10,000 TPY	2365 hp	21.3 mmBtu/hr heat input (HHV)	47.2 scfm of methane

Emissions from all types of equipment combined could be estimated for comparison to the threshold using the following equation:

$E = [V \times 212 \times (1 - 0.9X)] + [C \times 4.23 \times (1 + X)] + [B \times 470 \times (1 + X)]$

Where:
E = GHG emissions, $MTCO_2e/yr$
B = cumulative boiler, flare, heater burner capacities, mmBtu/hr
C = compressor engine capacities, hp
V = cumulative vented field gas rate, scfm
X = fraction of CO_2 in field gas

ii) A threshold set by the total production volume of a reporting entity in a basin. Specific thresholds could be set for natural gas and different thresholds for crude oil depending on its recovery process, so for example, thermally recovered oil would have a lower production threshold. Studies that have estimated average emissions per unit of output from natural gas or different types of oil production could be used to calculate an expected production cut-off. This approach might be difficult to implement because of the variety of production processes in WCI jurisdictions and the manner in which they change over time.

iii) Where necessary data is available and of good quality (e.g. for some emission sources in Canada), it may be possible to use pre-existing data on natural gas lease fuel use, flaring and venting reported by individual oil and gas facilities pursuant to current regulatory requirements such as those related to conservation or royalty payments. These data can be combined with emission factors to estimate a reporting entity's total emission levels from its facilities. Reporting entities with estimated emission below the reporting cut-off (based on calculations from data reported under oil and gas regulatory requirements) would be exempt from emission reporting.

Screening thresholds would be based on average expected emissions, but set at a conservative level, to allow a margin of error for possible underestimation of actual emissions..

Possible Quantification Methodology:

'Oil and Gas Reporting Entity' emissions could be calculated using the following general approach:

i. Include all oil and gas sources covered by EPA Subpart W, those other sources deemed appropriate and included in the WCI Oil and Gas Essential Requirement and all WCI and/or EPA source categories (e.g. stationary combustion).

ii. Include, exclude, or extend applicability for contractor emissions as determined by the WCI through this process.

iii. Apply emission factors to emission sources at the well, gathering location or field level (as appropriate in the jurisdiction) for true upstream sources. Apply emission factors as otherwise used in EPA Subpart W or the WCI metric ERMR (for use in Canada).

iv. Sum all oil and gas emission sources under common control of the same owner(s) or operator(s) to the field, basin or jurisdiction (as determined by the WCI) level

v. To provide sufficient information to understand distribution of emission sources, to determine potential facility splitting and to determine whether equitable coverage is occurring, provide at a minimum disaggregated reporting for each individual facility within the aggregated 'Oil and Gas Reporting Entity'. Determination of reporting and verification thresholds would be from the aggregated 'Oil and Gas Facility' total, including the facilities reported individually.

vi. Some emission sources that are required to be reported may be determined not appropriate for market trading in combination with the WCI Cap Setting and Allowance Distribution work.

Attention will need to be paid in the compliance and policies of jurisdictions to change of ownership/leasehold, possible facility splitting and/or outsourcing of emissions to contractors.

Stakeholder and Technical Working Group Input:

Natural Resources Defense Council (NRDC), Wild Earth Guardians, Western Environmental Law Center

- Start decision making with assumption of 10K and 25K thresholds.
- Optimum reporting entity may not be known until after 1-2 yrs of collecting fine-scale data.
- Jurisdiction level approach has merit.
- Goals are to ensure capture of cumulatively large emissions from individually small sources, and to avoid unreasonable burdens on individual small operators.
- Operator should be reporting entity.

Canadian Association of Petroleum Producers (CAPP)

- Aggregation to field, basin or jurisdiction level will require operators to estimate emissions for thousands to tens of thousands of small dispersed sources, which will be excessive effort to quantify small portion of emissions.
- Verification of emissions for large number of small dispersed sources will be challenging. Discussions with verifiers indicates that they would be challenged to provide a "reasonable level of assurance" for the estimated emissions from the multitude of small sources within a reasonable level of effort and cost. Verifications to a "limited level of assurance" under the Alberta GHG reduction regulation (entitled the Specified Gas Emitters Regulation) cost in the region of $15,000 CDN to $20,000 CDN per facility with ten to fifteen major sources and a few minor sources.
- Estimate level of effort and cost will increase 100-fold from current Alberta requirements.
- The level of effort required to estimate emissions of these small disperse sources is out of proportion with the magnitude of the emissions.

Chevron (CVX)

- Supports reporting at field level, possibly at basin level.
- Avoid term "aggregation" to reduce unintended triggering of other regulations or permitting requirements.

American Petroleum Institute (API)

- Supports aggregation at the jurisdictional level for reporting purposes provided it is coupled with simplified reporting methodologies, minimizes reporting burden and ensures resources and technological know how available for data collection.
- A clear distinction should be made between the definition of reporting entity and reporting threshold and the meaning of "facility" as used in other regulatory programs or facility permits for the oil and gas industry
- Reports will include listing of the field sites included with the sources being listed by source categories and number of devices in each of these categories at the jurisdiction level. For example, 400 glycol dehydrators of 1 MMBtu/hr each, 10 compressors > 500hp etc.
- Simplified applicability criteria, or a screening tool, should be developed for each source type to determine exceedances of a reporting threshold. Criteria for applicability screening could be based on throughput, capacity or actual emissions, and would be developed collaboratively as part of the rule development process.
- Screening criteria should be selected to capture all significant contributors to GHG emissions and prevent burdensome reporting on immaterial sources such as office heaters, lawnmowers and emergency generators.

WCI Subcommittee Comments and Recommendation:

The WCI Oil and Gas Subcommittee appreciates the Technical Working Group and other stakeholder comments, in particular the potential burden of calculating emissions from a producer's entire operation, in particular as they are not located in a single geographic location, as are the emission sources for a traditional facility. To capture a sufficient portion of emissions from the oil and gas production sector, however, it will be necessary to sum the discrete emission sources into a larger reporting entity. Given that field level reporting was accepted through the WRAP/TCR approach and given the jurisdictional boundaries within the WCI, a minimum would be to determine applicability for a producer at the combination of field and jurisdiction. Given the practical difficulty in determining field boundaries, and the multitude of potential fields, a basin/jurisdiction level approach to determining applicability is recommended. Total emissions for an owner/operator would be summed to the geologic basin level within a jurisdiction to determine reporting and verification obligations.

There is an interaction between the specific emission sources that would be covered by the WCI and the appropriate reporting and verification thresholds. We wish to ensure equity with other sectors, including 90 percent sector coverage, and considering that some emission sources in the oil and gas sector may not be included in market trading because they are not quantifiable to a sufficient level of accuracy. Therefore, the WCI is currently examining the interaction of a basin/jurisdiction level reporting entity definition and the current WCI Essential Requirements of Mandatory Reporting reporting and verification thresholds for this sector. It is possible that a recommendation may emerge that the existing thresholds (10,000 and 25,000 metric tons CO_2e) be used until such a time as reported data demonstrates (in combination with any emission sources not captured in the quantification) that more than 90 percent of emissions are covered. A threshold in units of barrel of oil equivalent is not recommended due to the different levels of emissions at different sources with the same total production or throughput. In addition, given the number of emission sources at disparate locations, the WCI recommends that the WCI Verification Subcommittee address means of ensuring efficient verification of oil and gas reporting entities.

A screening approach is recommended to specify whether a potential reporting entity is obligated to undertake an emissions estimate of its facilities. Screening approaches (i) and (iii) above will be investigated further for possible use.

Issue Paper – Glycol Dehydration

Issue:

Glycol based dehydration units are used in the natural gas industry to remove water from natural gas. Industry estimates that roughly 40,000 glycol dehydration units are in operation. Dehydrators are most typically found at production sites (e.g. storage tank batteries), natural gas processing facilities and natural gas storage and transmission facilities. EPA has identified dehydrator vent stacks as a major source of fugitive emissions for the oil and gas production sector.

Glycol dehydrators function in a manner very similar to amine treaters. The wet natural gas stream is contacted with an absorber solution (glycol) where water (and some hydrocarbons) is removed. The absorber solution (wet/rich glycol) is then regenerated in a reboiler where contaminants are thermally desorbed and separated from the treated glycol (lean glycol) which is then recycled back to the absorber. A flash tank may be installed between the absorber and the reboiler still. A flash tank removes a large fraction of absorbed hydrocarbons by pressure reduction. Flash tank emissions may be released to the atmosphere or captured and used as supplemental fuel or destroyed in a flare or thermal oxidizer. Figure 3.1 depicts one of the more common dehydrator configurations. Emissions of methane in uncontrolled systems will occur at the flash tank (if present) and at the reboiler (still) vent. Stripping gas (e.g. natural gas) may be used in the reboiler to enhance the glycol regeneration process. This stripping gas is subsequently released to the atmosphere if emissions from the reboiler are not controlled.

Glycol circulation pumps (e.g. a Kimray pump) may be natural gas driven. In this case there will be gas emissions associated with the operation of these pumps. The spent Kimray pump gas is usually dumped into the rich glycol stream, and thus will be flashed off up-stream of the reboiler if a flash tank is installed or in the absence of a flash tank, it will be flashed off in the regenerator and vented through the still column to the atmosphere. If this is the case, there is the potential for double-counting these pump emissions – here as part of the flash tank or reboiler emissions and in the regulation section dealing with vented gas-powered pneumatic devices and pumps. One way to address this issue would be to require reporting of Kimray pump emissions using the pneumatic device methodology if the pump emissions are vented directly to the atmosphere. If the Kimray pump gas is routed to the rich glycol stream and, reporters would not be required to meter Kimray pump gas consumption because these emissions would be captured by measurements made at the flash tank or reboiler vent.

If all (or a portion of) dehydrator emissions are controlled, that is pump gas, stripping gas and flash tank and still gas off-gas emissions are sent to a destruction device, they should not be reported here to avoid double counting.

Western Regional Air Partnership (WRAP)/The Climate Registry (TCR) Approach:

The Climate Registry Draft Oil & Gas Production Protocol discusses three methods for the determination of dehydrator methane and carbon dioxide emissions: 1) direct measurement of vent emissions, 2) modeling software, and 3) use of industry default emissions factors.

EPA Approach:

The EPA Draft Subpart W directed reporters to use "simulation software packages, such as GLYCalc™" to calculate dehydrator vent stack emissions.

WCI Options:

Option	Pros	Cons
A: Use industry default emissions factors	Simplest and least labor intensive method	Large degree of error associated with default emission factors – data not rigorous enough for cap and trade
B: Engineering estimation using simulation software (e.g. GLYCalc™)	May be less labor and resource intensive than direct measurement.	There is uncertainty as to the accuracy of simulation software. Method does require that reporters determine a suite of variables such as wet gas temperature, pressure, and composition. Method may be sufficiently accurate for smaller dehydrators.
C: Direct measurement – measure volume (mass) and composition of all vented emissions (reboiler and flash tank)	Most accurate of the methods if sampling accurately reflects standard operating conditions. (Requires site specific sampling and analysis.)	Requires site specific sampling and analysis. Measurements must be made during "normal operation". Changes in dehydrator operational parameters may trigger additional sampling.

WCI is seeking comment as to the advisability of establishing a dehydrator through-put threshold 25 MM scf/d) below which reporters may use simulation software. We are currently seeking information on the distribution of dehydrator through-put capacity (MM scf/d). Above the threshold, direct measurement would be required. Below the threshold, reporters may us Option B – simulation software - to calculate emissions. In the case of Option C additional sampling may be required if dehydrator operational parameters change significantly.

WCI Subcommittee Comments and Recommendation: The WCI subcommittee recommends the use of most accurate methodology, Option C where direct measurements of vented dehydrator emissions are made. A dehydrator throughput threshold of 25 MM scf/d would be established. Emissions from dehydrators above 25 MMscf/d capacity would calculate emissions using Option C methodology. Emissions from dehydrators below this threshold would be calculated using Option B, simulation software. WCI is seeking comment on the accuracy and applicability of GLYCalc and other publically available software applicable to this emissions source.

WCI Quantification Methodology: Methane and carbon dioxide emissions from dehydrators with a gas processing capacity of 25 MM scf/d and greater will be calculated in the following manner:

$$E_{CH4/CO2} = H / MVC * MW_{CH4/CO2} \left(V_{ft} * MF - ft_{CH4/CO2} + V_{rb} * MF - rb_{CH4/CO2} \right) * 0.001$$

Where:

- $E_{CH4/CO2}$ = methane or carbon dioxide emissions (metric tons/year)
- H = hours of dehydrator operation
- MVC = molar volume conversion factor
- $MW_{CH4/CO2}$ = molecular weight of methane or carbon dioxide (kg/kg-mole)
- V_{ft} = emissions flow rate from flash tank vent (scf/hour)
- MF-ft = molar fraction of methane or carbon dioxide in flash tank emissions
- V_{rb} = emissions flow rate from reboiler/still vent off-gas (scf/hr)
- MF-rb = molar fraction of methane or carbon dioxide in reboiler/still gas vent off-gas
- 0.001 = conversion factor (kg to metric tons)

Methane and carbon dioxide emissions from dehydrators with a gas processing capacity of less than 25 MM scf/d will be calculated using simulation software.

Stakeholder Input:

Stakeholders have not yet commented on this Issue Paper.

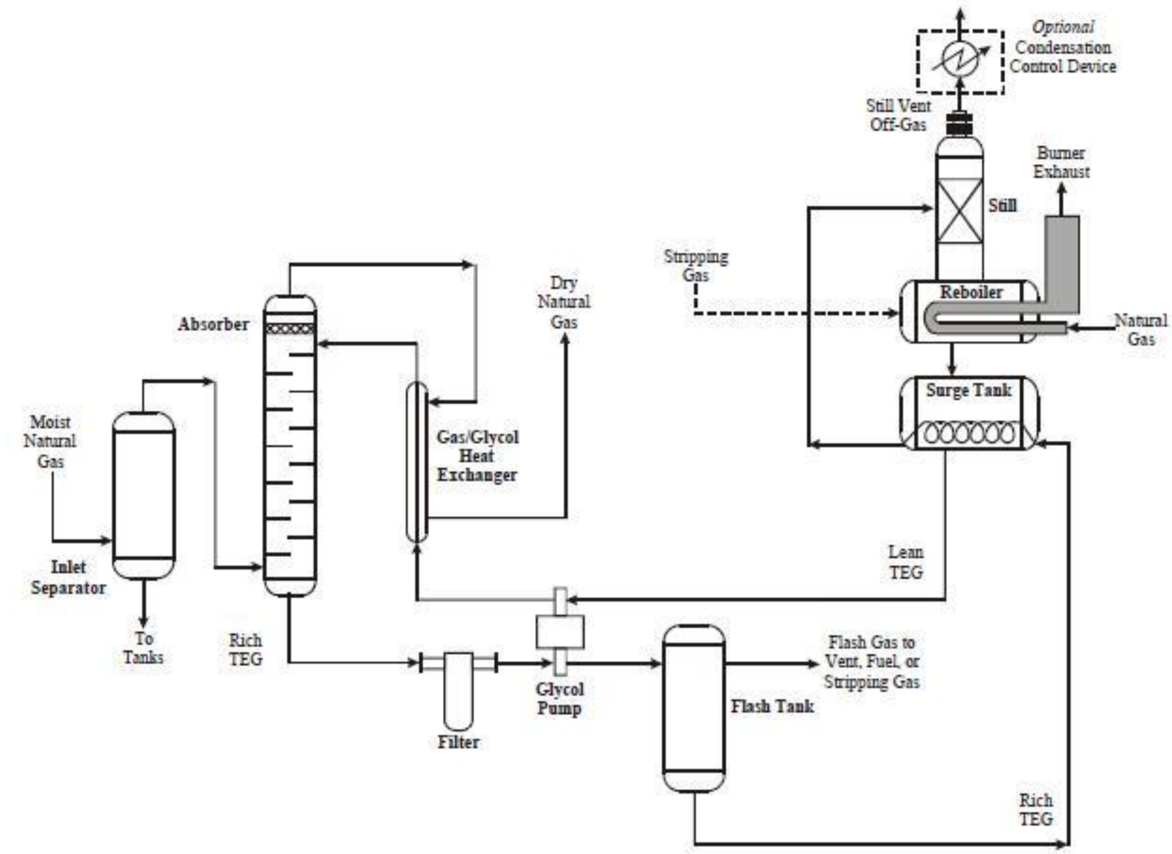


Figure 3-1. Process Flow Diagram for an Example Dehydration Unit

Source: Guidance for 40 CFR 63 Subpart HHH Natural Gas Transmissions and Storage MACT Standard, Colorado Department of Public Health and Environment, July 15, 1999

Issue Paper – Instrument Gas and Vented Methane Emissions

Issue:

Pneumatic control devices employing pressurized natural gas or field gas are commonly used in the natural gas industry. In the production sector these devices perform tasks such as the control and monitoring of gas and liquid flows and levels in dehydrators and separators, temperature in dehydrator regenerators, and pressure in flash tanks. In the processing sector high and low bleed pneumatic devices are used for compressor and glycol dehydration control in gas gathering and booster stations and isolation valves in processing plants. In the transmission sector these devices actuate isolation valves and regulate gas flow and pressure at compressor stations, pipelines, and storage facilities.

Pressurized natural gas or field gas is used as the motive agent and is routinely vented, either continuously or periodically. Many factors influence pneumatic device venting rates and volumes. Important variables are: the gas supply pressure, actuation frequency, and the age, condition and maintenance history of the equipment.

Consequently, these pneumatic devices are a major source of methane emissions from the natural gas industry. In most cases instrument gas is not routinely metered. In a Background Technical Support Document addressing *Fugitive Emissions Reporting from the Petroleum and Natural Gas Industry* EPA states that emissions from natural gas driven pneumatic valve and pump devices are know to be major contributors to fugitive emissions from the oil and gas production sector, accounting for emissions of about 21 million metric tons CO_2e in 2006.

Western Regional Air Partnership (WRAP)/Climate Registry (TCR) Approach:

TCR recommends that oil and gas producers who voluntarily report GHG emissions use the method and emissions factors found in the API Compendium (See below).

EPA Approach:

EPA has not published an emissions calculation methodology specific this vented source.

WCI Options:

Option	Pros	Cons
A. Use Original Equipment Manufactures (OEM) information	Easiest of the methods	Data consistency and reliability questionable.
B. API Compendium (2009) – use available emission factors	Simple methodology	Large uncertainty in the emission factors.

Option	Pros	Cons
C. Measure individual device emissions	Accurate methodology	Labor intensive and expensive. Instrument modification and changes in operating conditions would trigger additional measurements.
D. Meter instrument gas	Most accurate method	Requires installation of piping and meters. Does not provide consumption information for individual devices.

Background on available methodologies:
The options are discussed below.

A. Use of Original Equipment Manufacturers (OEM) data.

In many cases manufacturers' data for equipment bleed rates is available. There are several issues which suggest that significant errors in estimated emissions may result when one uses OEM data. First, there is no industry standard concerning the reporting of instrument bleed rates and thus manufacturers report information in a wide range of units and under varying operating conditions. In addition the data reported by manufacturers has not been independently verified. USEPA has found large discrepancies between OEM bleed rate data and actual field data. As stated above, factors not reflected in available OEM data, such as gas pressure and maintenance history, significantly influence emissions rates. While the American Petroleum Institute API (2009) states that the use of manufactures' data is "the most rigorous approach" the Compendium also acknowledges that manufactures emission rates "tend to be lower than emissions observed."

B. American Petroleum Institute (API) Methods:

API offers several approaches for the calculation of "emissions from a high or continuous bleed device" based on an equation from a Gas Processors Suppliers Association 1987 publication (see API Compendium, Section 5.6 Other Venting Sources, page 5-66). However, this equation is applicable only to high or continuous bleed devices and does not consider factors such as device maintenance history. Emission factors (EFs) for pneumatic devices have been developed. Many of these EFs were published in the 1997 GRI/EPA Report, Methane Emissions from the Natural Gas Industry. The API Compendium compiles these and other EFs (see Table 5-15, pages 5-68 and 5-69) and estimates uncertainties in some cases. Where specified, reported uncertainties range from ±33% to ±407%. This indicates that use of EFs would result in very unreliable estimates of vented methane emissions. In general, the use of EFs may result in relatively accurate emission estimates on a large scale (e.g. for an annual national inventory) but at the facility level EFs which are not site or equipment specific can introduce significant error.

C. Use of site specific measurement:

Actual site specific measurement of vented emissions from low and high bleed pneumatic control devices is accepted to be the most accurate method to quantify methane (and CO_2 if present in the gas) emissions. There are two approaches one may take when conducting site specific measurements.

One may characterize emissions from each pneumatic device at a facility using a bagging technique (or other method) where emissions from the device are captured and the volume of released gas is measured. Gas analysis then allows one to calculate actual CH_4 and CO_2 emissions. This technique is time consuming, labor intensive and expensive. In addition emissions may subsequently change as the result of factors such as maintenance activities and gas pressure changes.

D. Meter Instrument Gas Consumption:

Actual metering of instrument gas consumption and periodic measurement of gas composition will provide a much more accurate determination of GHG emissions. Changes in instrument gas plumbing and installation of one or more gas meters may be required initially and this will result in upfront material and labor costs. However, reporting in subsequent years will be very simple and easy, especially given the fact that periodic gas analysis will be required for other GHG emission calculations (e.g. stationary combustion emissions). In addition, changes in system operating conditions (e.g. line pressure, maintenance activities, instrument modifications) designed to reduce emissions will be reflected in the volume of instrument gas consumed and thus will be easily quantified. Facility operators receive immediate feedback on their efforts to reduce emissions and can also monitor instrument gas consumption in real time.

Stakeholder Input:

Natural Resources Defense Council (NRDC), Wild Earth Guardians, and Western Environmental Law Center

- Recommend allowing reporter choice of either Option C (measure device emissions) or Option D (meter instrument gas).
- Frequent calibration of measurement devices should be required.

Canadian Association of Petroleum Producers (CAPP)

- Supports Options A (use OEM emissions factors) and B (use API emissions factors).
- Fuel gas supply to pneumatic often comes from common fuel line supplying combustion devices; installing meter would require time-consuming and costly re-piping.
- CAPP states that these emissions account for only 5.5% of emissions from oil and gas operations in the Province of British Columbia.

Chevron (CVX)

- Direct measurement is impractical and cost prohibitive given the age and number of these devices in the field.
- Supports the use of Option B (use API emissions factors).
- Absolute volume of emissions from this source will decrease over time as more companies are using low-bleed devices in new installations.

American Petroleum Institute (API)

- Support Option B (use emission factors from API Compendium 2009).
- On-site measurement of emissions vented from these devices requires substantial effort and would not be sufficiently accurate for cap and trade programs.
- API suggests using engineering and industry standard approaches to estimate these emissions.

SunCor

- SunCor states that installing individual meters on each device would be prohibitively expensive.

WCI Subcommittee Comments and Recommendation:

The WCI Reporting Committee Oil and Gas Subcommittee recognizes that methane emissions from natural gas driven pneumatic devices represent not only a significant greenhouse gas source but also significant lost revenue to industry and lost royalties to the regulating jurisdiction. It is estimated that in the production and transmission sectors there are 400,000 pneumatic devices used to monitor and control liquid levels and flows, gas flows and levels in dehydrators, and control pressure in flash tanks (EPA – Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry). In addition, there are currently available many methodologies and technological fixes to effectively and economically reduce or eliminate these emissions (and save money). Many mitigation options identified by EPA have pay-back times of less than one year. Whether this GHG emission source ultimately is covered as part of a cap-and-trade program or addressed through an offset approach, it is essential that emissions be accurately quantified.

The magnitude and importance of this GHG source and the myriad of available emissions reduction strategies, suggest that direct measurement of these emissions is required. Where default emissions factors are available (from OEM or API) the accuracy and applicability of these EFs to real world operational conditions is questionable at best (see API Compendium, 2009). These EFs do not and cannot accurately reflect current emissions or emission reductions achieved through such procedures as enhanced maintenance, cleaning and tuning, repair/replacement of leaking gaskets, tube fittings and seals, or adjustments made to control loops to lower emissions.

Only direct measurement of pneumatic device emissions (Options C and D) will provide the rigor required for either cap-and-trade or offset programs. Option C, the direct measurement of emissions from individual devices, is both time consuming and costly. Furthermore, the accuracy of periodic single measurements in assessing long term emissions is questionable and additional measurements would be required to accurately assess the efficacy of emission reduction efforts.

Thus Option D is deemed to be the most accurate methodology to 1) accurately measure current emissions from pneumatic devices and 2) quantify emission reductions resulting from mitigation and control measures. The subcommittee recognizes that requiring metering of all pneumatic devices would, in some cases, require significant upfront costs associated with materials and labor needed to re-plumb and instrument large facilities with many pneumatic devices. The present WCI recommendation does not require a meter be installed for each device – only that pneumatic device and pump gas consumption be metered. In addition, the subcommittee recommends that metering not be required for low bleed devices and instead engineering calculations would be accepted. Although engineering calculations are not the most accurate mechanism to measure emissions from low bleed devices, the error would be small since the total emissions from these sources are small. In addition, the subcommittee also recommends a phased-in approach where, in year one, 50% of all high bleed and continuous bleed devices must be metered. In year two, all gas consumption for all pneumatic devices and pumps shall be metered excluding low bleed or no bleed devices. While low bleed and no bleed devices would be exempt from direct metering requirements, emissions should be estimated using default EFs. The subcommittee does not recommend requiring installation of a dedicated meter for each pneumatic device. In most cases it should be possible to meet the requirements by plumbing all or multiple pneumatic device gas supply lines through a single meter. In year one, emissions from all unmetered devices must be quantified using available EFs (API or OEM). Methane and CO_2 emissions shall be calculated in the following manner:

$$E_x = V_g * MW_x / MVC * F_x * 0.001$$

Where:

Ex = CO_2 or CH_4 emissions (metric tonnes/year)

V_g = volume of instrument gas consumed (scf/year)

MW_x = molecular weight of CO_2 (44.01kg/kg-mole) or CH_4 (16.04 kg/kg/mole)

MVC = molar volume conversion (scf/kg-mole)

F_x = molar fraction of X (X= CO_2 or CH_4)

0.001 = conversion factor (kg to metric tonnes)

Issue Paper – Sour Gas Treatment

Issue:

Produced gas may contain high concentrations of corrosive acid gas species - sulfur species such as H_2S and CO_2. These gases are removed in acid gas removal units (AGR) or sulfur recovery units (SRU). These units typically use an amine compound to strip sulfur containing gases and carbon dioxide from field gas. Amine treaters have components similar to those used in gas dehydrators – an absorber, liquid circulation pump, and absorber regenerator. Carbon dioxide emissions occur 1) at the absorber regenerator (reboiler vent) where most absorbed CO_2 is emitted and 2) as a result of tail gas treatment where incineration in a flare or destruction device converts any remaining carbon containing species to CO_2. Methane emissions also occur at the absorber regenerator (reboiler vent) where methane absorbed in the amine is released to the atmosphere. See Figure 1.

In some parts of the US and Canada, greenhouse gas emissions vented from sour gas treatment units can be significant. New Mexico has two coal bed methane gas sweetening plants that each reported vented CO_2 emissions close to 1.0 MMT in 2008.

Western Regional Air Partnership (WRAP)/ The Climate Registry (TCR)

Approach: The August 2009 Draft TCR Oil and Gas Production Protocol provides four methods for determining GHG emissions. These methods are shown in the table below (Options A thru D).

EPA Approach: In Subpart W – EPA proposed that reporters use simulation software such as ASPEN™, AMINECalc™, or TSWEET (Option D below).

WCI Options:

Option	Pros	Cons
A. Mass balance approach – measure carbon content and volume of incoming acid gas and treated sweet gas.	Accurate method if sampling is conducted at intervals that accurately characterize annual emissions picture.	Sampling acid gases such as H_2S can be dangerous. Sampling frequency may need to be quarterly or semi-annually. Not as accurate as the direct measurement approach (Option B)

B. Determine CH_4 and CO_2 content of reboiler vent emissions and volume of gas vented from reboiler.	Accurate method if sampling is conducted at intervals that accurately characterize annual emissions picture. This option appears to be the most accurate of the four methods.	Sampling acid gases such as H_2S can be dangerous.
C. Use default emissions factors (API, 2009)	Least labor and resource intensive method	Very high uncertainty associated with available EF's. Resulting data is not cap-and-trade quality
D. Use a model (API AMINECalc™ ,ASPEN™, or TSWEET)	Data collection requirements can be less burdensome.	Models also require reporters to gather input data. Accuracy questionable - models may significantly underestimate emissions. The AMINECalc model is designed to output VOC data which must then be converted to methane using the gas methane content or a default factor.

Option B, where reporters quantify both the volume (or mass) and composition of vent gases, appears to be the most accurate of the methods presented here. If emissions from a flash tank and/or a reboiler vent are captured, used and/or destroyed elsewhere (e.g. tail-gas which is incinerated or vented gas used as a supplemental fuel) these emissions would be reported elsewhere and not thus not reported using this methodology to avoid double-counting.

WCI Reporting Subcommittee Comments and Recommendation:

The WCI Subcommittee recommends using the direct measurement (Option B) methodology. Direct measurement of emissions should provide the most accurate data for this important GHG source. The number of sources that will require direct measurement in the US is manageable. A Gas Research Institute study suggests that most acid gas removal operations are located at approximately 400 gas processing plants nationally. These sources should be capable of conducting gas measurements, if they are not already doing it currently. Option A (the mass balance approach) also involves direct measurement – however the Option B measurement regime should better constrain the emissions calculation and thus provide better data. The WCI Subcommittee proposes that emissions sampling be conducted on a quarterly basis.

There are indications that modeling approach (Option D) using software modules such as AMINECalc™, GLYCalc™, and TSWEET may underestimate emissions. The Colorado Department of Public Health and Environment, Air Pollution Control Division in their Guidance Document –

Form APCD-206, Amine Sweetening Units states that "*experience indicates that AMINECalc 1.0 significantly underestimates still vent emissions from amine sweetening units. Therefore, the Division discourages the use of this modeling software*." Option C, the use of default Emission Factors, would not provide data of sufficient quality for a cap-and-trade program.

WCI Quantification Method:

Emissions of CO_2 and CH_4 from amine treaters will be calculated in the following manner:

$$E_{CH4/CO2} = \sum_{1}^{n} [(V_{FG} * MF_{FG-CH4/CO2} * MW_{CH4/CO2} \div MVC) +$$
$$(V_{OG} * MF_{OG-CH4/CO2} * MW_{CH4/CO2} \div MVC)] * 0.001$$

Where:

$E_{CH4/CO2}$ = emissions of CH_4 or CO_2 (MT/yr)
n = quarterly sampling interval (1-4)
V_{FG} = volume of flash gas emitted per quarter (scf)
$MF_{FG-CH4/CO2}$ = molar fraction of CH_4 or CO_2 in flash gas
$MW_{CH4/CO2}$ = molecular weight of CH_4 or CO_2
MVC = molar volume conversion factor
V_{OG} = volume of reboiler off-gas emitted per quarter (scf)
$MF_{OG-CH4/CO2}$ = molar fraction of CH_4 or CO_2 in still vent off-gas
0.001 = conversion factor – kg to metric tons

WCI Monitoring Methodology:

Quarterly samples of flash tank and still vent off-gas from the amine reboiler should be collected and analyzed for methane and carbon dioxide content. If accurate measurement of flow volume from amine treater flash tank and/or the amine reboiler are available, reporters should use this data. If flow is not monitored, reporters may use an engineering calculation to determine volume of mass flow. In either case volume should be determined with an accuracy of ±5%. Reporters should exercise car to avoid double-counting as flash tank emissions may be capture and used as a fuel and emissions from the reboiler may be directed to a flare or incinerator.

Stakeholder Input:

Stakeholders have not yet seen or commented on this issue paper.

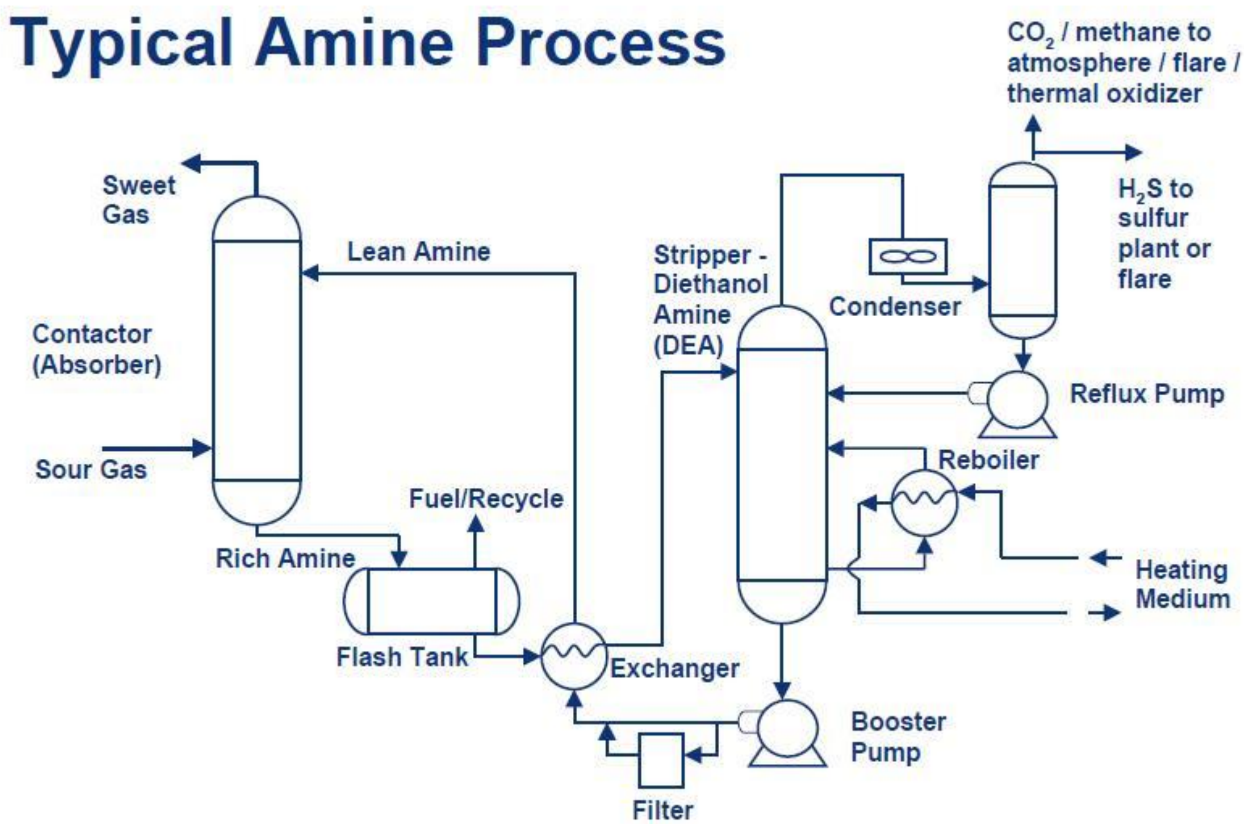


Figure 1: A Typical Amine Process Diagram

Source: US EPA, Acid Gas Removal Options Minimizing Methane Emissions, available at www.epa.gov/gasstar/documents/acid_gas_removal_options_08_21_07.pdf

Issue Paper -- Storage Tanks

Issue:

Storage tanks provide temporary storage of liquids prior to the point when produced liquids are moved off site in a pipeline or mobile tanker for processing. Emissions of methane (and CO_2 if present in significant quantities in produced liquids) occur through several mechanisms.

Flashing losses occur when the produced liquid experiences a change in pressure. For instance as produced oil is pumped from the well it experiences a pressure drop as it exits the pipe and enters the tank. Dissolved gases such as methane and carbon dioxide may flash off as the pressure is reduced.

Working losses occur as a result of the filling and emptying of the storage tank. Tank headspace gases containing methane and carbon dioxide are emitted from the tank as the tank fills. As the tank is emptied the reverse process occurs, outside air is drawn into the tank. The liquid in the tank then re-equilibrates with this introduced air.

Breathing losses of headspace air containing methane and carbon dioxide occur as the tank gas volume expands and contracts in response to environmental conditions such as ambient temperature, solar insulation, and atmospheric pressure.

Flashing, breathing and working losses must all be characterized to insure an accurate estimation of storage tank GHG emissions.

Storage tank emissions occur when produced liquids are sent to atmospheric storage at the following locations:

1. wellhead sites
2. tank batteries
3. compressor stations
4. gas plants
5. where liquids in a gas line are “pigged”

EPA estimates that Storage Tank venting emits on the order of 9 Bcf (billion cubic feet) of methane annually, which is approximately 1 million metric tons CO_2e. EPA states that emissions from crude oil and condensate storage tanks are known to be a “major contributor(s) to the total petroleum and natural gas production segment fugitive emissions”.

Western Regional Air Partnership (WRAP)/The Climate Registry (TCR) Approach:

WRAP has not specifically addressed the issue of accurately determining GHG (CH_4 and CO_2) emissions from storage tanks in the up-stream oil and gas sector. A method using the EPA TANKS Model was included in the WCI Essential Requirements for the Refinery sector.

EPA Approach:

EPA has not officially published an emissions calculation methodology specific for this source. A method was published in Subpart W of the Draft Reporting Rule (see §98.233(d)(8) – page 1167). Subpart W was subsequently withdrawn prior to release of the EPA Final Rule.

Briefly, the EPA Subpart W method requires that reporters:

a) Measure the volume of vapor escaping each storage tank over a representative period of operation.

b) Determine the vapor composition by chemical analysis.

c) Calculate fugitive emissions using this data.

The details of this method are shown below:

1. Calculate the total annual hydrocarbon vapor fugitive emissions using Equation W-7

$$E_{a,h} = Q \times ER \qquad \text{(Eq. W-7)}$$

Where:

$E_{a,h}$ = hydrocarbon vapor fugitive emissions at actual conditions Q = storage tank total annual throughput

ER = measured hydrocarbon vapor emissions rate per throughput (e.g. cubic feet/barrel) determined from §98.234(j)(2) (page 1181).

ER is measured using a flow meter described in paragraph (h) for a test period that is representative of the normal operating conditions of the storage tank throughout the year and which includes a complete cycle of accumulation of hydrocarbon liquids and pumping out of hydrocarbon liquids from the storage tank.

2. Estimate hydrocarbon vapor volumetric fugitive emissions at standard conditions using calculations in paragraph (e).

3. Estimate CH_4 and CO_2 volumetric fugitive emissions from volumetric hydrocarbon emissions using Equation W-8 (page 1168).

$$E_{s,i} = E_{s,h} \times M_i \qquad \text{(Eq.W-8)}$$

Where:

$E_{s,i}$ = GHG i (CH_4 and CO_2) volumetric fugitive emissions at STP

$E_{s,h}$ = hydrocarbon vapor volumetric fugitive emissions at standard conditions

M_i = mole percent of GHG i in the hydrocarbon vapors; the hydrocarbon analysis shall be conducted using ASTM D1945 03

4. Estimate CH_4 and CO_2 mass fugitive emissions from GHG volumetric emissions using the calculations in paragraph (g)

$$Mass_{s,i} = E_{s,i} \times \rho_i \qquad \text{(Eq. W-11)}$$

Where:

$Mass_{s,i}$ = GHG i (CH_4 or CO_2) mass fugitive emissions at STP

$E_{s,i}$ = GHG i volumetric fugitive emissions at STP

P_i = density of GHG i; 1.87 kg/m^3 for CO_2 and 0.68 kg/m^3 for CH_4

Background on Available Methodologies:

A recent study commissioned by the Texas Commission on Environmental Quality (TCEQ) provides an in-depth analysis of available methods for the determination of storage tank emissions. The following modeling methods were compared with actual measurements of storage tank emissions which were conducted in a manner very similar to the EPA Subpart W method detailed above.

1. TANKS 4.09 (EPA model)
2. Vasquez-Beggs + TANKS 4.09
3. GOR + TANKS 4.09
4. Valko-McGagn + TANKS 4.09
5. Hysis VOCs
6. E&P Tank – RVP VOCs
7. E&P Tank – GEO/RVP VOCs
8. AP-42 LPO VOCS
9. GRI-HAPCalc VOCs

The final report concluded that "each model reviewed has limitations and shortcomings. No one model resulted in the extremely strong correlation to measured data." Measurements were made at thirty-six production sites. The models also required measurement of input variables such as GOR (gas oil ratio). The GOR is a difficult measurement given that the recovered liquid/gas mixture from a well must be collected and maintained at pressure prior to analysis. The report states that the TCEQ considers direct measurement the most accurate method to quantify storage tank fugitive emissions. A copy of this report, Upstream Oil and Gas Storage Tank Project Flash Emissions Models Evaluation Final Report, July 16, 2009 is available on the WCI Reporting Committee SharePoint website.

The API Compendium (2009) also contains a discussion of several of the models available (see Section 5.4 Storage Tank Emissions, page 5-40). API states that direct measurement provides accurate emissions estimates but "this approach is generally expensive and time consuming for large numbers of tanks."

WCI Options:

The WCI subcommittee recognizes that direct measurement of the volume and composition of fugitive emissions emitted from storage tanks is the most accurate quantification method. While volumetric emissions at a storage tank can be completed in as little as 24 hours, questions remain concerning the accuracy of a single or several emissions measurements when applied to calculate annual emissions.

Modeling approaches require input data (such as GOR, API, separator pressure, stock tank gas molecular weight and specific gravity, oil gravity, etc.) which may require extensive gas and oil analysis. These models do not appear to provide a higher level of accuracy than direct measurement of GOR does.

Stakeholder Input:

Natural Resources Defense Council (NRDC), Wild Earth Guardians, and Western Environmental Law Center

- Direct measurement of volume and composition is the most accurate method, and is preferred. NRDC does support use of the proposed GOR methodology.
- Requirements should state that testing must be done during representative operating conditions.
- Propose testing quarterly, or when operating conditions change.
- Would consider some logical thresholds for mandatory direct measurement, perhaps including:
    - mandatory direct measurement on quarterly basis for all tanks over a size/emissions threshold;
    - for tanks under the threshold, initial direct measurement to obtain site specific data for calibration of a tank model; four quarterly tests to calibrate, then can model if modeling shows reasonably accurate results;
    - reduced frequency of direct measurement based on a showing that actual tank emissions do not vary significantly;
    - return to direct measurement if operating conditions change.

SunCor

- SunCor supports the use of the GOR method for “live” (as opposed to “stabilized”) fluids at storage tanks where no vapor recovery takes place.

Canadian Association of Petroleum Producers (CAPP)

- Prefer the use of modeling to estimate emissions.
- Direct measurement is complicated because of technical difficulties.

- Direct measurement is not guaranteed to be more accurate than modeling because it would have to cover wide range of possible operating modes; uncertainty is estimated to be about ± 20-25%.
- CAPP states that in British Columbia, storage tanks account for only 0.1% of up-stream oil and gas sector emissions.

Chevron (CVX)

- Given the large number of tanks and operating modes, a requirement to use direct measurement on all tanks would be extremely burdensome and would raise worker safety issues.
- Many modeling methods would be adequate for most application.
- Chevron is currently reviewing the modeling methods and will have more specific recommendation after Jan. 1.

American Petroleum Institute (API)

- Proposed Subpart W method should not be used. It is overly prescriptive, burdensome, costly, and problematic.
- Most tanks are very small; distribution of size/throughput has a long tail.
- Measurement across a complete cycle of operation would require sampling throughout entire year.
- Emissions flow rates and compositions for flashing tanks can be reliably determined using process simulation models such as HySys or ProSim. These are used by industry in facility design and are becoming method of choice for regulatory purposes.
- Sampling of emissions from a fixed roof tank is impractical on a routine basis. For external floating roof tanks it is impossible to obtain a representative sample.
- Many tanks have either vapor recovery or thermal control of VOCs, to meet regulatory requirements or for operational or safety reasons.
- At many sites, particularly offshore production platforms, tank vents cannot be safely accessed to enable direct measurement.
- The Subpart W method is not feasible for tanks in the hull of floating facilities due to the nature of the tank's service and the inaccessibility of the tank vent.
- API Recommendations:
  - Tanks with low throughput (< 10 bbl/day): allow use of E&P Tanks to determine flow and vapor composition.

- Since the emissions estimation is for CH_4, determination of standing and breathing losses is not necessary.
- Allow process simulation model approaches as an alternative to direct measurement.
- Tanks with VRU are not significant GHG sources and should be excluded from reporting, especially since they would emit CO_2 rather than CH_4 from the thermal control unit. Process simulation models could be used to determine flow and composition to the control device.
- Tanks where the vent cannot be safely accessed should be excluded from the requirement to quantify and report emissions.
- Storage tanks in the hull of floating offshore vessels should be excluded from reporting.
- Tanks handling hydrocarbon liquids with little or no CH_4 content (e.g., diesel fuel, stabilized oil) should be excluded from reporting.

- API recommends the use of the GOR measurement method on a formation wide basis, rather than at individual production sites where production is 10bbl/d or greater.

WCI Subcommittee Comments and Recommendation:

After reviewing stakeholder comments and considering the many available models and methodologies, the subcommittee recommends that the results of a periodic laboratory determination of GOR (Gas Oil Ratio) from a pressurized liquid sample (2009 API Compendium, #2 on p. 5-41) be used to quantify methane and carbon dioxide emissions at storage tank batteries where daily production exceeds a threshold value (>10 bbl/day). Semi-annually a pressurized liquid sample will be collected at a point downstream of all field separators and prior to the point where produced liquid is flashed to atmospheric pressure (that is, where it enters the storage tank). In the laboratory, the sample is allowed to equilibrate to atmospheric pressure, the volume of gas generated measured (i.e. GOR determined) and a sample of the evolved gas collected and analyzed for methane and carbon dioxide content. Additional testing is required when a well is connected to or disconnected from the battery, or changes in separator operational parameters are made. Emissions calculated in this manner assume that the methane generated in this measurement is ultimately released to the atmosphere (where there is no vapor recovery in-place). At storage tank batteries where production is below the threshold (<10 bbl/day) E&P TANKS would be used to determine flow and vapor composition.

The assumption implicit with this approach is that only flashing losses are important for methane emissions from storage tanks. While small amounts of methane and carbon dioxide will be emitted during subsequent storage and handling, all the methane emissions quantified by this method will be attributed to the initial depressurized storage tank. Storage tanks equipped with vapor recovery units (VRU) required by permit or rule are exempt. It should not be necessary to limit measurements to land-based storage tanks containing condensate and crude oil. At off-shore production platforms, collection of pressurized samples for determination of GOR should be straightforward as it does not require access and sampling of the tank itself (platform legs may be used as temporary storage at off-shore facilities). The method is not affected by the sampling and safety limitations associated with the initially proposed EPA Subpart W method.

Methane and CO_2 emissions at storage tank batteries where the oil production rate is 10 barrels per day or greater shall be calculated in the following manner:

$$E_{CH4/CO2} = \sum_{1}^{n} GOR * PR * 1/MVC * MW_g * MF_{CH4/CO2} * 0.001$$

Where:

$E_{CH4/CO2}$ = methane or carbon dioxide emissions (metric tonnes/year)

n= number of measurement periods in the reporting period (n=2)

GOR = Gas Oil Ration (scf/bbl)

PR = oil production rate (bbl/measurement period)

MVC = molar volume conversion

MWg = molecular weight of the gas (kg/kg-mole)

$MF_{CH4/CO2}$ = mass fraction of methane or carbon dioxide in gas (kg CH_4/kg gas)

0.001= conversion factor (metric tonnes/kg)

Methane and carbon dioxide emissions at storage tank batteries where the oil production rate is less than 10 barrels per day shall calculate methane emissions using the E&P TANKS Model.

Western Climate Initiative

Issue Paper – Well Unloading (Well Blowdowns)

Issue:

The accumulation of liquids in mature gas wells reduces gas production rates and may stop gas production entirely. This fluid must be removed to maintain gas production. To eliminate accumulated fluids, a well may be “blowndown”, - vented to atmospheric pressure to purge liquids from the well. The practice of blowing down a well can occur on a weekly basis, last anywhere from a few minutes to hours and thus may result in significant methane emissions. The magnitude of gas released is a function of wellhead pressure and temperature, event duration, size of the vent line, and produced gas and liquid properties. There is discrepancy about the significance of this emission source in the oil and gas sector, highlighting the need for accurate reporting. Although, in the Background Document for the draft Subpart W regulation, EPA estimated the methane emissions from this source to be 9 billion scf/yr in 2006, the EPA also reported that they thought that this source was underestimated.

Western Regional Air Partnership (WRAP)/The Climate Registry (TCR) Approach:

The Climate Registry (TCR) Draft Oil & Gas Production Protocol provides reporters with an engineering methodology to calculate well blowdown emissions. This method was derived from the API Compendium (2009) and calculates unloading duration (rather than using a measured value) “based on field conditions (formation, depth, etc.)”.

EPA Approach:

The draft and final EPA Mandatory Reporting of Greenhouse Gases rule did not contain a methodology for the determination of emissions resulting from well unloading.

WCI Options:

Option	Pros	Cons
A: Estimation based on GRI/EPA emissions factor	Simplest method. Assumes that the integrated average flow over the blowdown period is 56.25 percent of full well flow.	Data quality questionable. Duration of blowdown not measured.
B: TCR/API	More accurate than Option A	Does not determine individual blowdown event emissions but assumes that all events are of the same duration.
C: CAPP (2002)	Appears to be the most	Requires sampling and site

1) calculate mass flow rate of gas and liquid 2) correct for mass of produced liquid 3) calculate mass flow rate of gas, multiply by event duration.	accurate methodology. Calculates emissions for each blowdown event.	specific data collection.

Option B – Detail:

TCR and American Petroleum Institute (API) present the following calculation methodology for the determination of well blowdown emissions:

$$E_{CH4/CO2} = 9{,}781x10^{-7} * 1/Z * \left(D_{casing}\right)^2 * (Depth) * P * f_{CH4/CO2} * MW_{CH4/CO2} * N/yr * 1/2204.62$$

Where:

$E_{CH4/CO2}$ = emissions of CH_4 or CO_2 (tonnes/yr)

Z = compressibility factor (assumed to be 1 for an ideal gas)

D_{casing} = casing diameter (inches)

Depth = well depth (feet)

$MW_{CH4/CO2}$ = molecular weight of CH_4 or CO_2 (lb/lbmole)

$f_{CH4/CO2}$ = molar weight of CH_4 or CO_2 (lb/lb-mole)

N = number of blowdowns per year

2204.62 = conversion factor (lbs to tonnes)

This method does not calculate emissions from individual well blowdown events or include the well blowdown duration in the calculation, but rather assumes that emissions are the same for each blowdown event regardless of the duration.

Option C – Detail:

1) The Canadian Association of Petroleum Producers (CAPP) approach models the vent process as isentropic flow of an ideal gas through a nozzle:

$$m_t = A^* * P_0 / \sqrt{T_0} * \sqrt{k/R} * 1/\left(k+1/2\right)^{(k+1)/(2*k-2)} * 1000$$

Where:

m_t = total mass flow rate of gas and water vapor from the unloading (kg/s)

A^* = cross sectional area of the unloading valve or vent pipe (m^2)

P_0 = wellhead pressure (kPa)

T_0 = wellhead temperature (K°)

K = specific heat ratio – 1.32 for natural gas

R = universal gas constant (kJ/kg K) (8314.5/gas molecular weight)

2) The quantity of water produced is then calculated:

$$m_w = V * \rho_w / t$$

Where:

m_w = mass flow rate of water produced by the unloading event (kg/s)

V = volume of liquid water produced by the unloading event (m^3)

P_w = density of liquid water (1000 kg/m^3)

t = duration of the blow down event (s)

3) The mass flow rate of gas released is then calculated by subtracting the water mass flow rate from the total mass flow rate:

$$m_v = m_t - m_w$$

Where:

m_v = mass flow rate of gas released

4) The total volume of gas released is then calculated:

$$V = m_v * t / W_v * 23.6449$$

Where:

V = volume of gas released (m^3)

W_v = molecular weight of the vapor released (kg/kg-mole)

23.6449 = the volume (m^3) occupied by one kg-mole of an ideal gas at 15°C and 101.325 kPa.

5) Methane and carbon dioxide emissions are then calculated:

$$E_{CH4/CO2} = \sum_{1}^{n} V_g * MW_{CH4/CO2} * 1/MVC * MF_{CH4/CO2} * 0.001$$

Where:

$E_{CH4/CO2}$ = mass of methane or carbon dioxide released (metric tons/yr)

n= number of blowdown events per year

V_g = volume of gas released for each event

$MW_{CH4/CO2}$ = molecular weight of methane or carbon dioxide

MVC = molar volume conversion factor

$MF_{CH4/CO2}$ = molar fraction of methane or carbon dioxide (20% = 0.20)

0.001 = conversion kg to metric tons

WCI Reporting Subcommittee Comments and Recommendation: The WCI Subcommittee recommends the use of Option C**.** Option C appears to be the most accurate of the available methods. This method calculates emissions for each blowdown event (Option B does not). This ability is critical if reductions in emissions resulting from operator initiated changes in well operational parameters are to be assessed. Method A does not result in data quality sufficient for cap-and-trade.

WCI Quantification Methodology: See Option C.

WCI Monitoring Methodology: See Option C above.

Stakeholder Input:

Stakeholders have not yet provided comment on this Issue Paper.

References:

1. API Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry (2009), Appendix B. Additional Venting Calculation Information, B.7.2 - Calculating Well Unloading Emissions (from CAPP, 2002).
2. Canadian Association of Petroleum Producers (CAPP), Estimation of Flaring and Venting Volumes from Upstream Oil and Gas Facilities, May 2002, page 31, 3.2 Intermittent Sources, 3.2.1 Well Blowdowns.

Western Climate Initiative

Hyatt Regency Vancouver
655 Burrard Street
Vancouver, BC

Remote Access: Call 1-800-868-1837**, **code 659 537#
(1-404-920-6440 for outside the U.S. and Canada)

<u>Wednesday, March 3, 2010</u>

8:00 am	**Convene** (Plaza A & B Meeting Room) Welcome and Introductions Agenda Review
8:15 am	**WCI Updates**
8:45 am	**Update on the Drafting of Economic Modeling Report** Review and discuss the status of drafting the Phase III economic analysis. Discuss path forward for completion of report and talking points.
9:30 am	**Break**
9:45 am	**Offsets Committee** Review and approve Offsets Definition and Criteria Draft Recommendations Paper. Review and discuss final DNV report on Evaluating Existing Protocols against WCI's offset critiera. Discuss next steps.
12:00 pm	**Lunch Break**
1:00 pm	**CSAD: Offset Limit Recommendation** Review and approve final Offset Limit Recommendation.
1:30 pm	**Electricity Team Status Update**
2:15 pm	**Markets Oversight** Briefing and discussion on the draft recommendations for market oversight. Review of draft recommendations for public release and comment.
2:45 pm	**Reporting Committee Status Update**
3:00 pm	**Break**

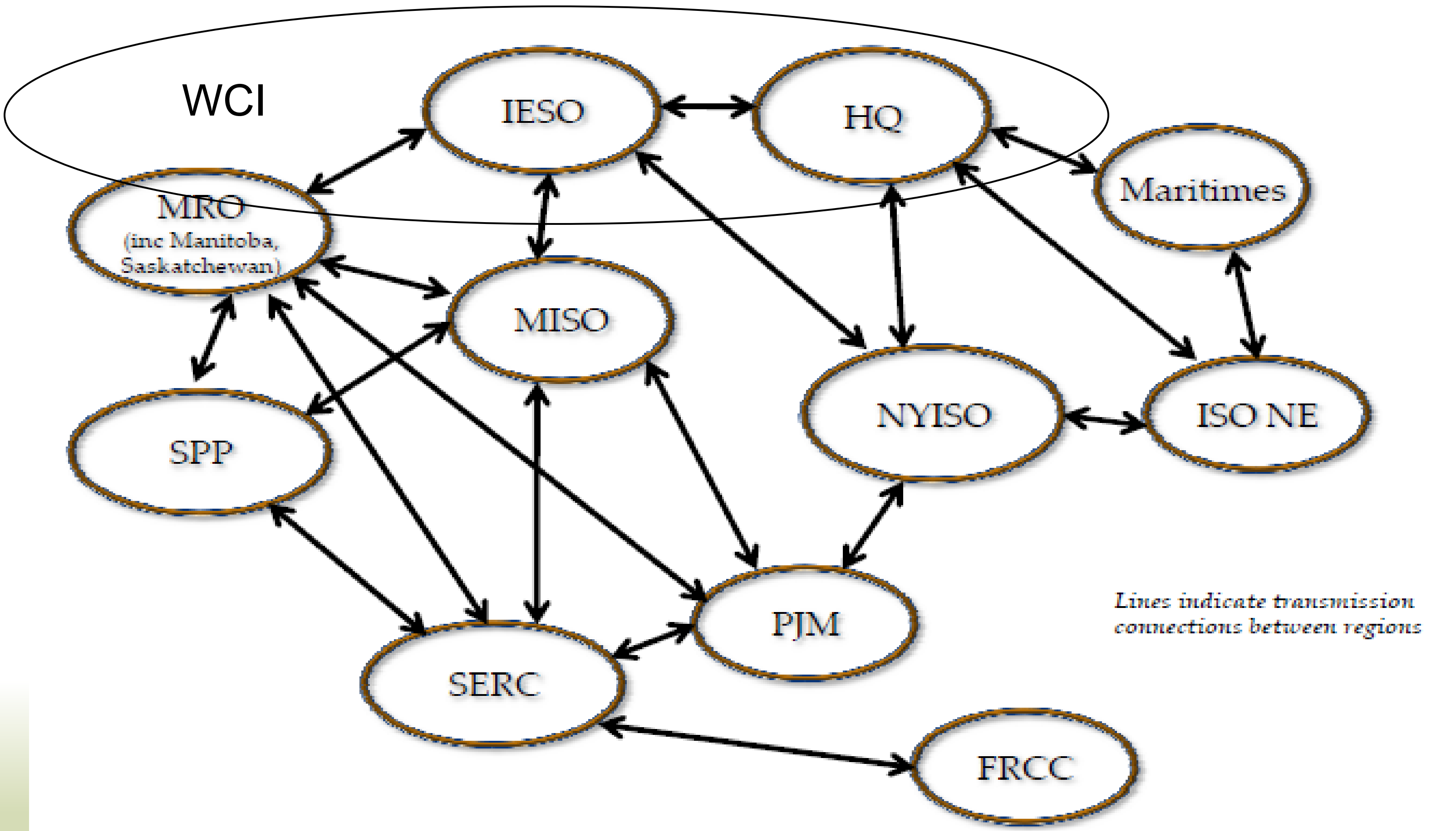
3:15 pm	**Complementary Policy Committee Status Update**
3:45 pm	**Liaison Reports** Update on activity at the federal level in U.S. and Canada. Identify opportunities for ongoing WCI involvement.
4:00 pm	**Wrap-up and Discuss Upcoming Meetings**
4:30 pm	**Open Comment Period**
5:00 pm	**Adjourn**

Western Climate Initiative

Eastern Leakage Study

Update and Preliminary Results

Eastern Interconnection



Navigant Modeling

- Navigant presented results of modeling to WCI Electricity Industry Collaborative Meeting in Phoenix on January 21.
- Posted on public WCI website at:

  http://www.westernclimateinitiative.org/component/remository/Electricity-Team-Documents/Jan-21-2010-Electricity-Collaborative-(Phoenix)/Update-on-Eastern-Leakage-Study/
- Key questions the study addresses for the eastern WCI partners:
  - Expected reduction in WCI generation and emissions with various carbon and import charges
  - Offsetting increases in non-WCI generation and emissions
  - Impact of exempting non-fossil generation outside WCI from import charges (potential for shuffling)
  - Impact of aligning with RGGI and MGGRA

Navigant Modeling

- PROMOD simulates the hourly operation of generation and transmission across the markets/regions
- For each hour, PROMOD commits and dispatches units in order of increasing generation cost until hourly demand is met, while taking into account unit operating constraints and transmission limits

Limitations

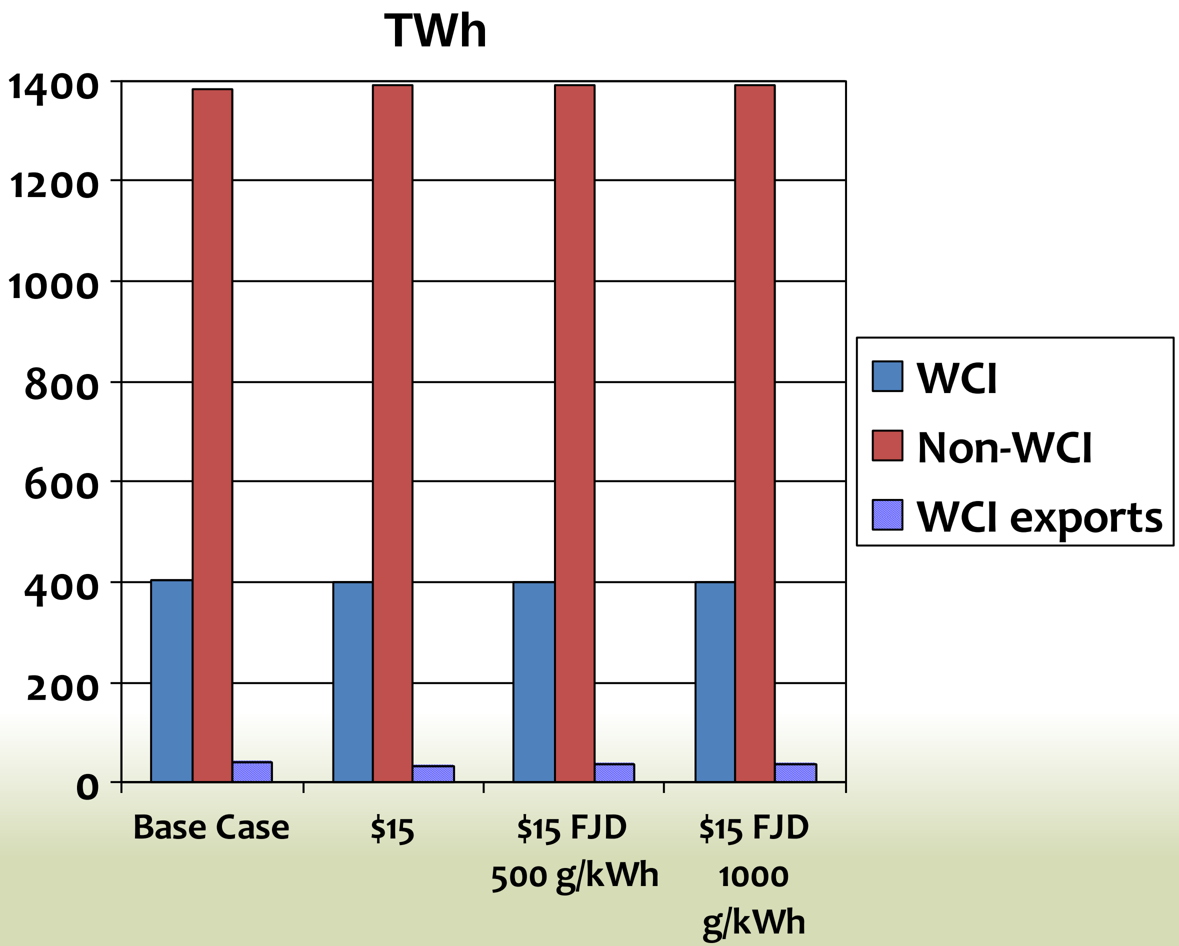
- Static analysis
- Available power plants are fixed
  - Annual output of non-fossil plants is fixed
  - Only fossil output can change
- Demand is fixed

Scenarios Defined

- Scenarios with \$15, \$30, \$60/metric tonne [US\$]
- Applied to carbon-generating units in Quebec, Ontario, Manitoba that generate more than 25,000 metric tons of CO_2 annually
- FJD charges
  - Defined on basis of assumed carbon content of imported power – 500 kg/MWh, 1000 kg/MWh
  - In terms of \$/MWh adder, translates to 50% or 100% of WCI allowance price for each scenario
  - applied to all power imported into WCI provinces from non-WCI regions (simple scenarios) or just to imports from carbon-producing units (contract shuffling scenarios)

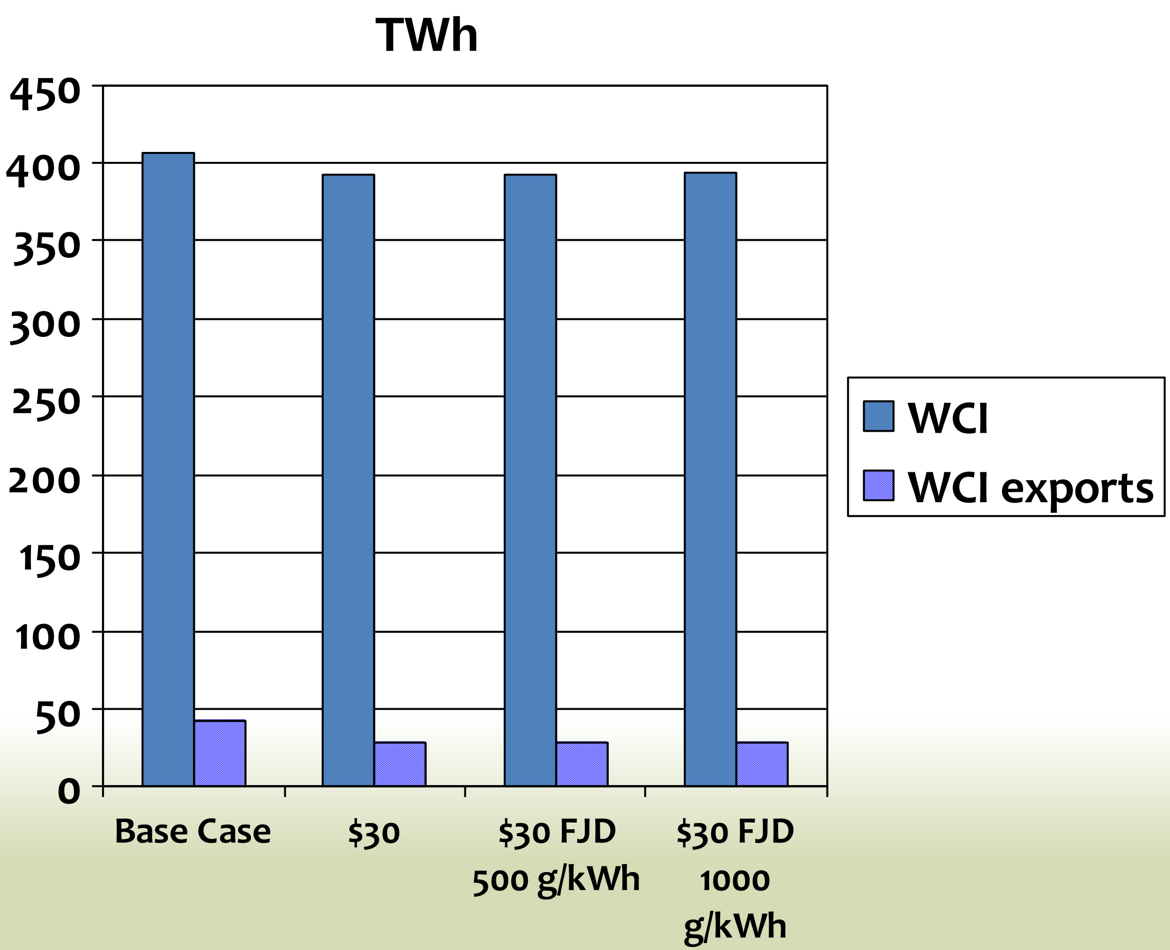
Modeling Results – Simple Scenarios

2012 Projection with $15 Allowance Price



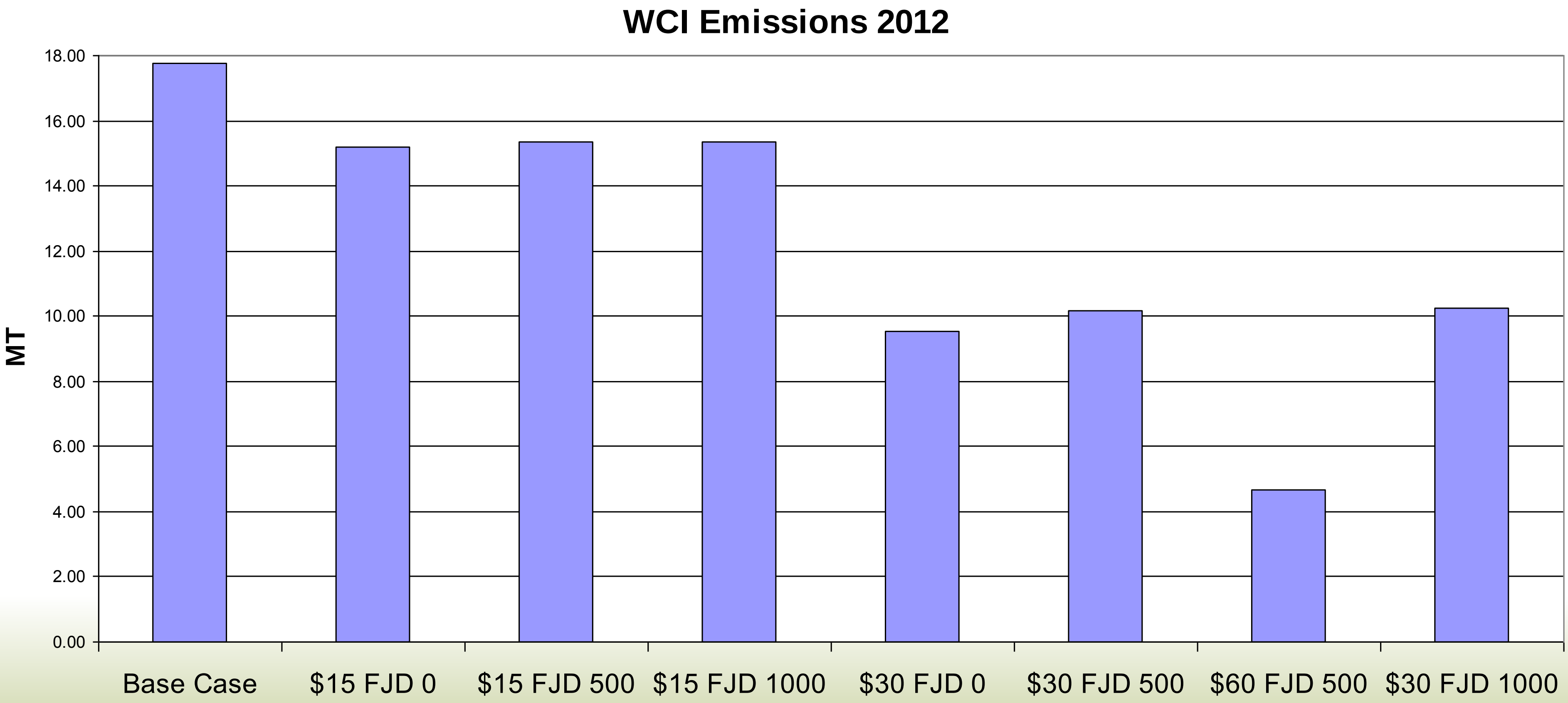
WCI eneration	TWh
Base	405.6
$15	399.1
$15 FJD 500	399.5
$15 FJD 1000	399.5
WCI Exports	
Base	41.7
$15	35.4
$15 FJD 500	35.8
$15 FJD 1000	35.8

2012 Projection with $30 Allowance Price

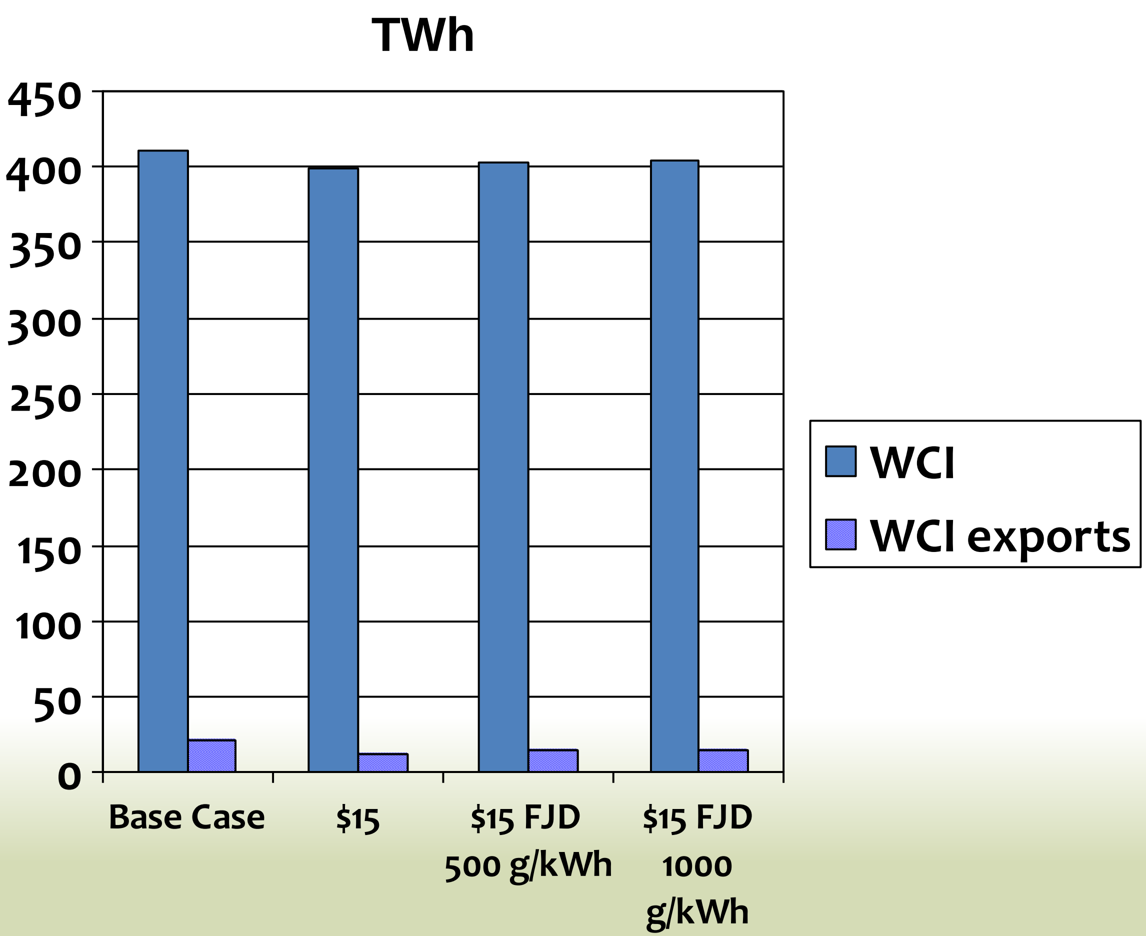


WCI Generation	TWh
Base	405.6
$30	391.6
$30 FJD 500	392.4
$30 FJD 1000	392.5
WCI Exports	
Base	41.7
$30	28.3
$30 FJD 500	28.9
$30 FJD 1000	28.9

2012 Projection for Emissions

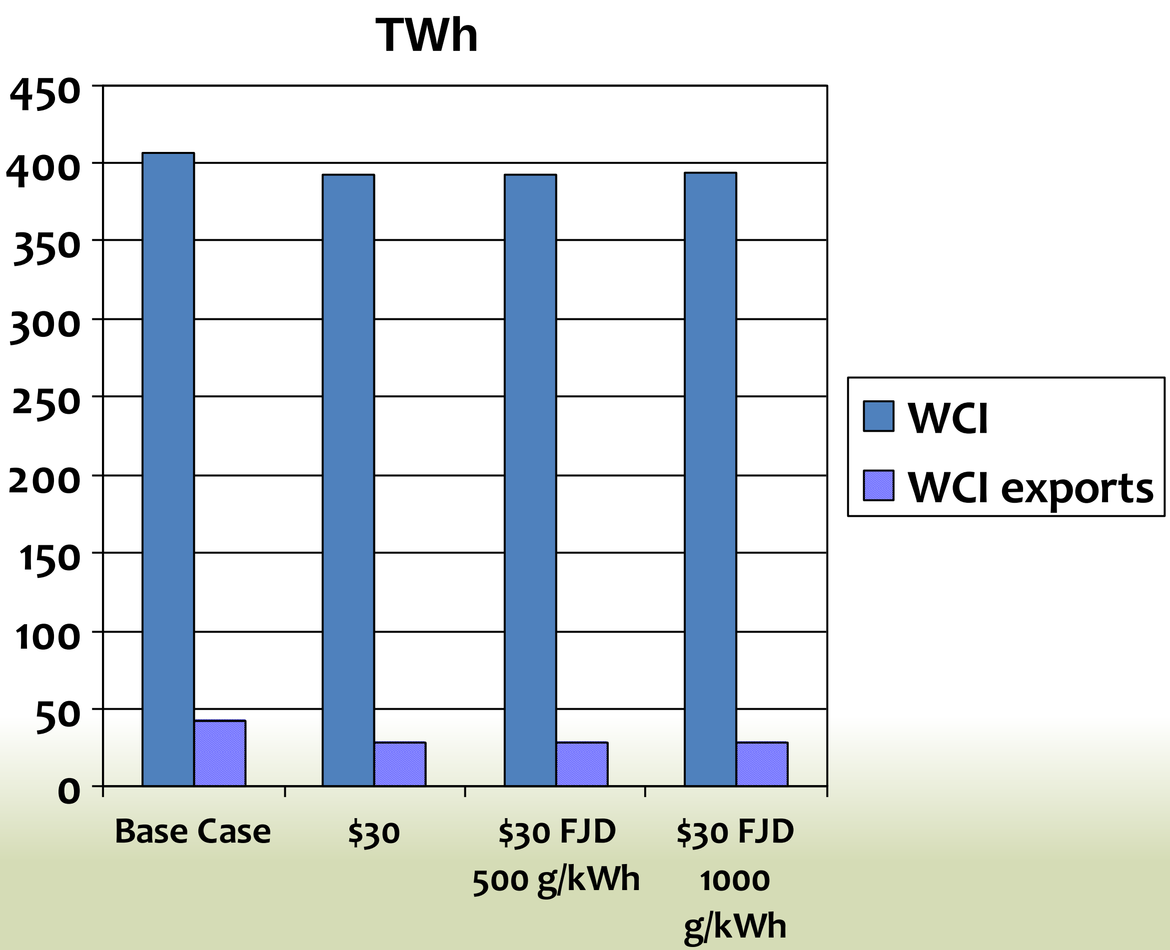


2020 Projection with $15 Allowance Price



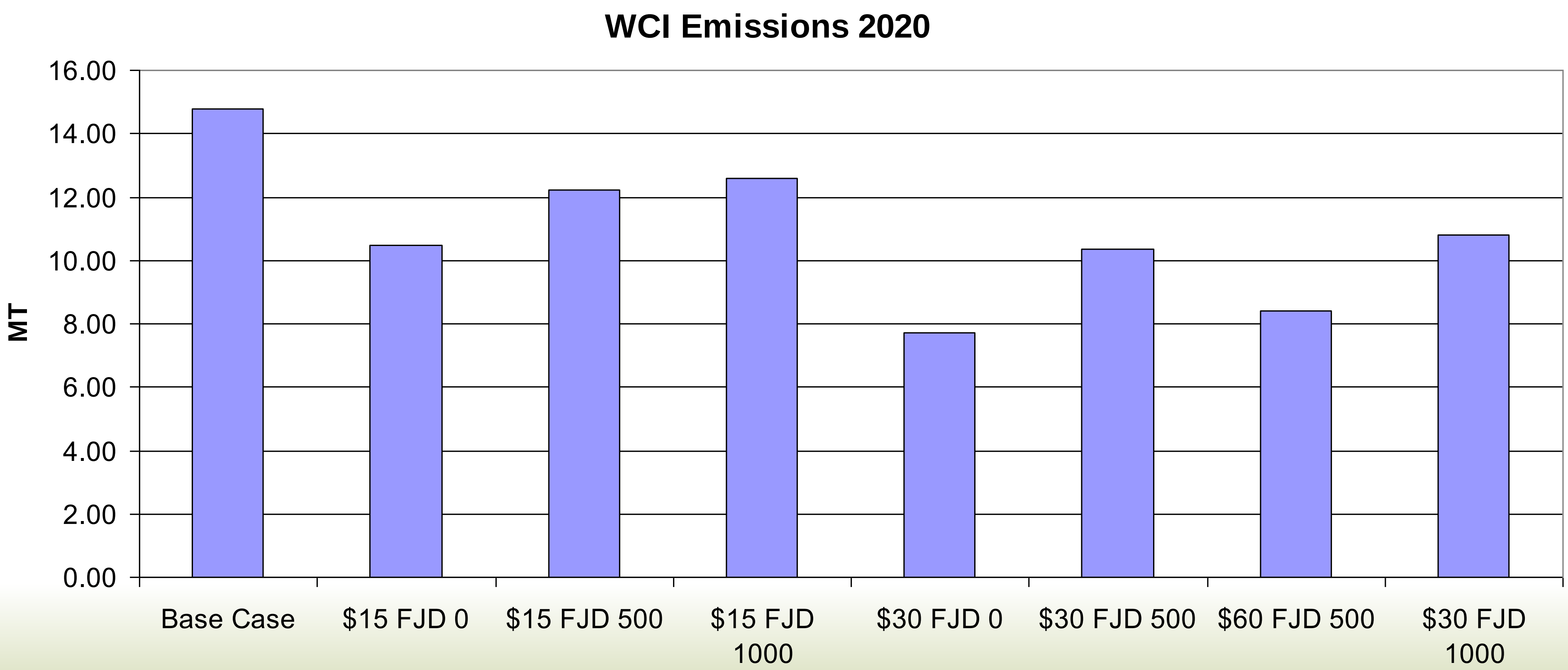
WCI Generation	TWh
Base	409.6
$15	398.6
$15 FJD 500	403.0
$15 FJD 1000	404.1
WCI Exports	
Base	21.1
$15	12.7
$15 FJD 500	14.9
$15 FJD 1000	15.3

2020 Projection with $30 Allowance Price

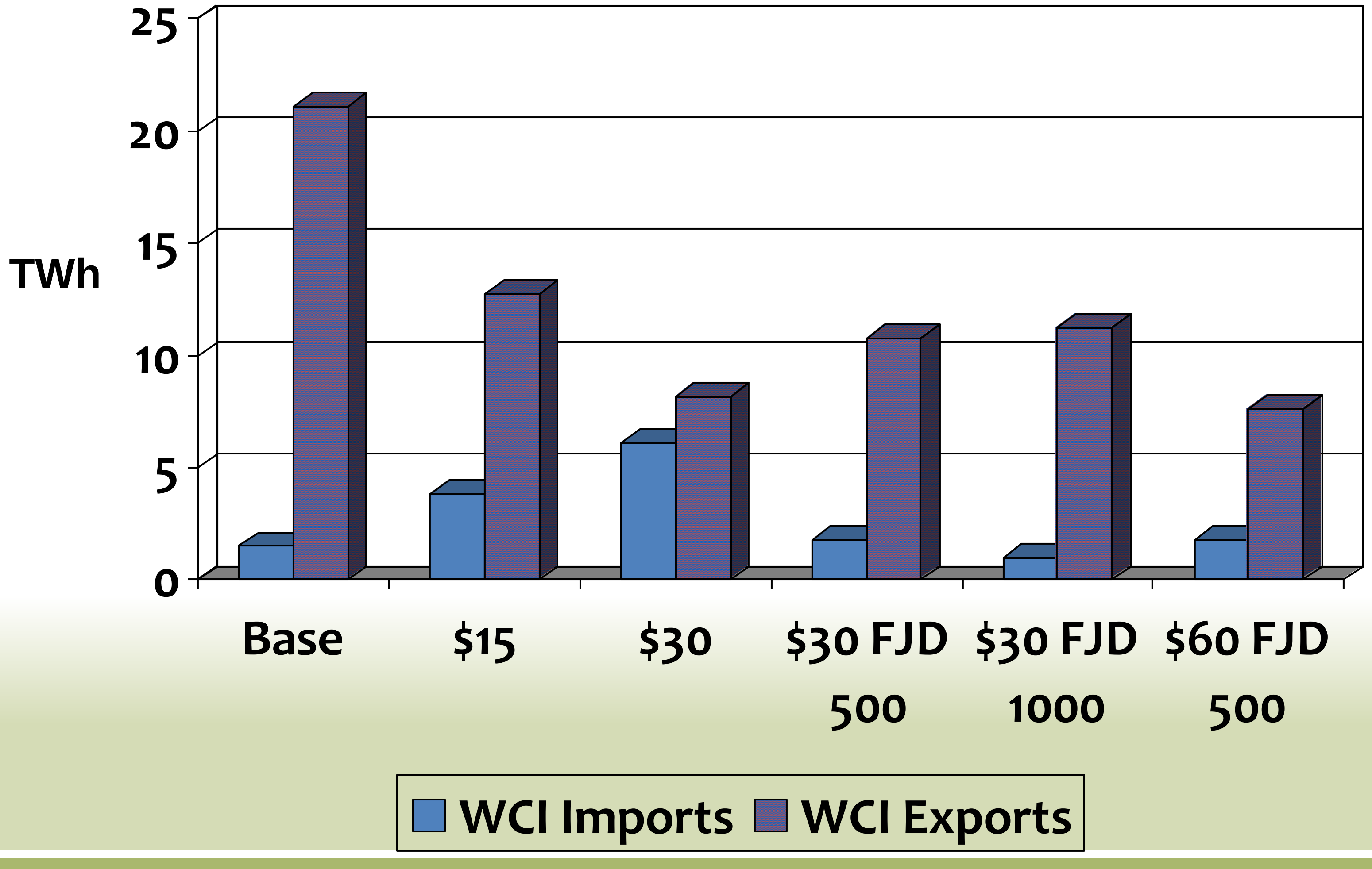


WCI Generation	TWh
Base	409.6
$30	391.8
$30 FJD 500	398.9
$30 FJD 1000	400.1
WCI Exports	
Base	21.1
$30	8.2
$30 FJD 500	10.8
$30 FJD 1000	11.2

2020 Projection for Emissions

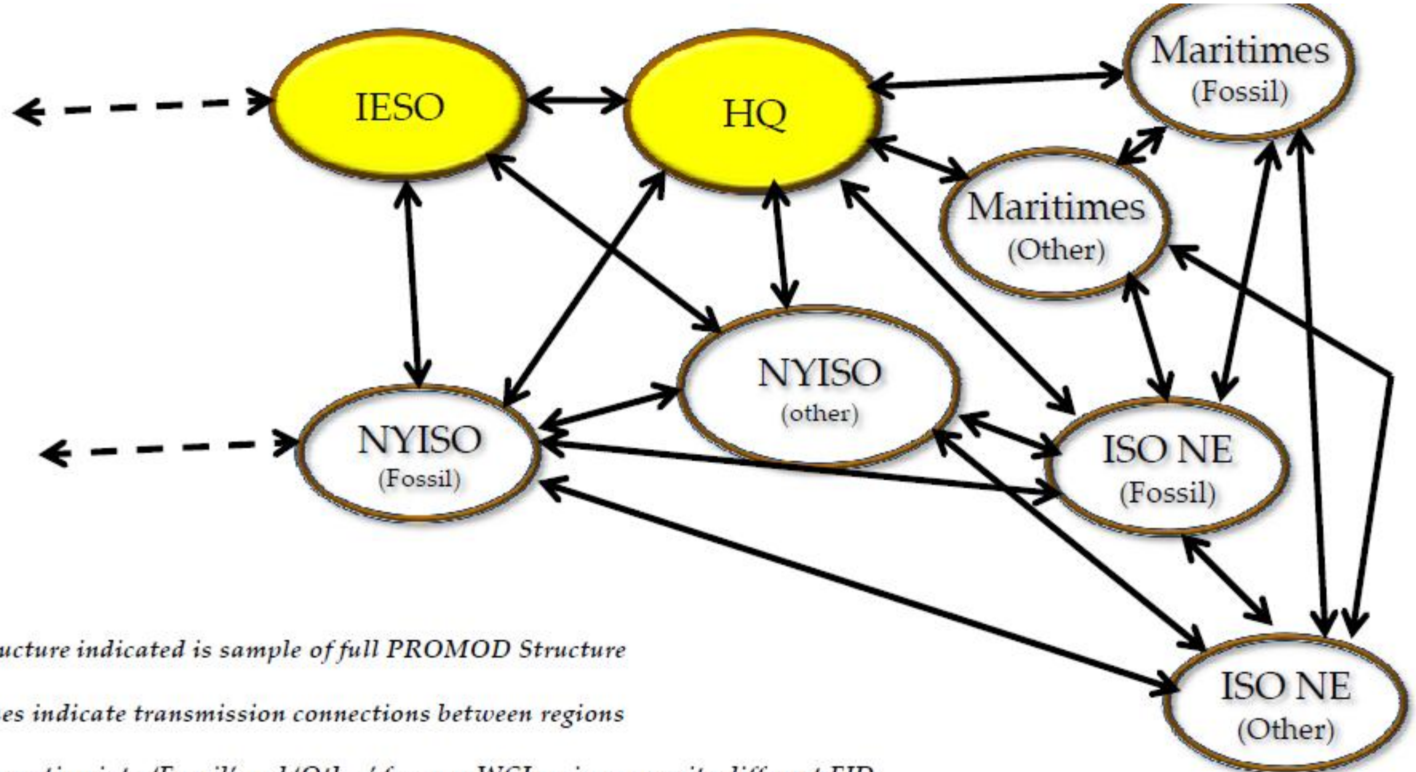


Effect on WCI Imports and Exports: 2020



Modeling Results – Complex Scenarios

Modeling Results – Complex Scenarios

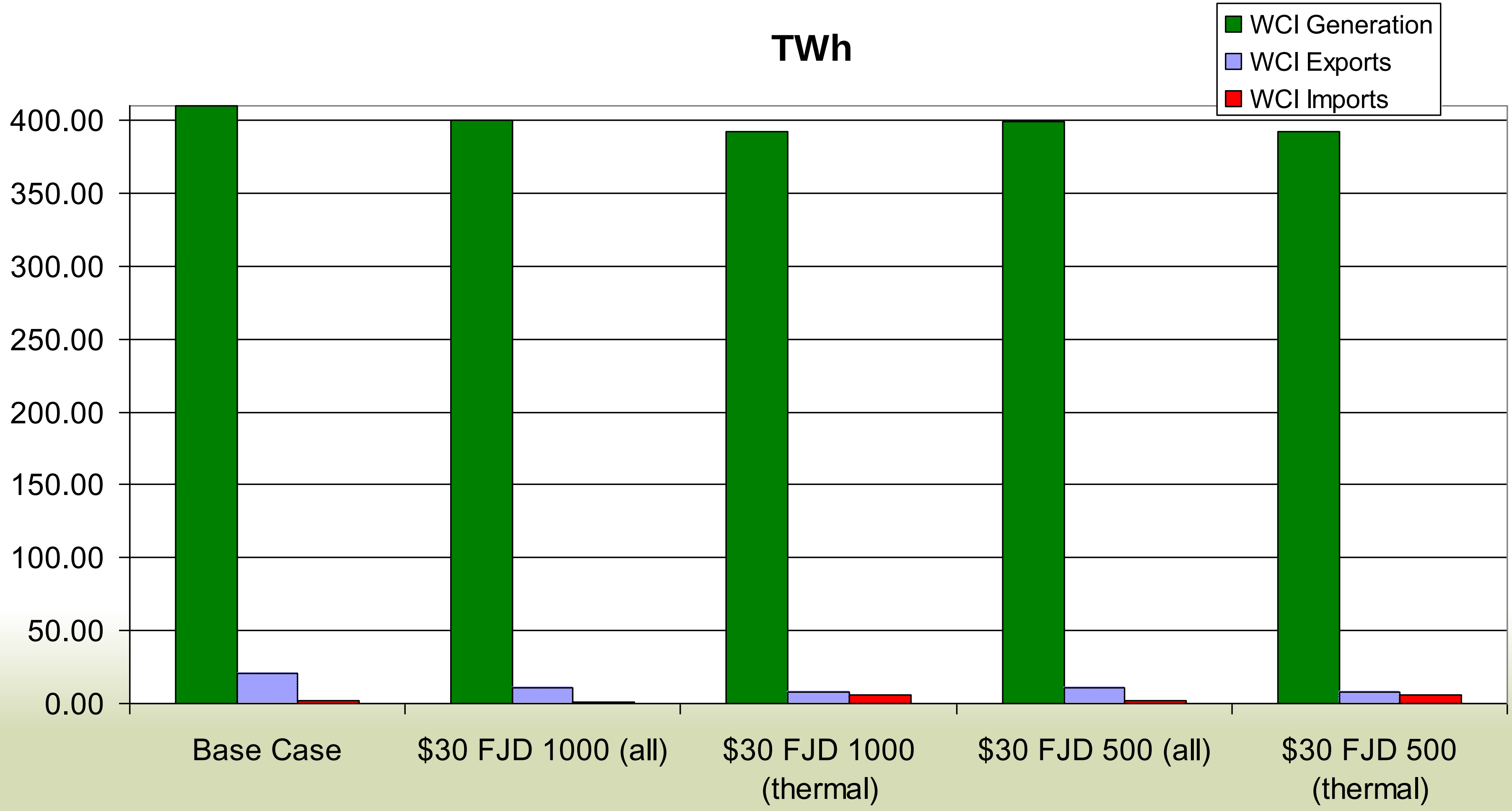


Structure indicated is sample of full PROMOD Structure

Lines indicate transmission connections between regions

Separation into 'Fossil' and 'Other' for non-WCI regions permits different FJD tariffs for different unit types based on carbon content

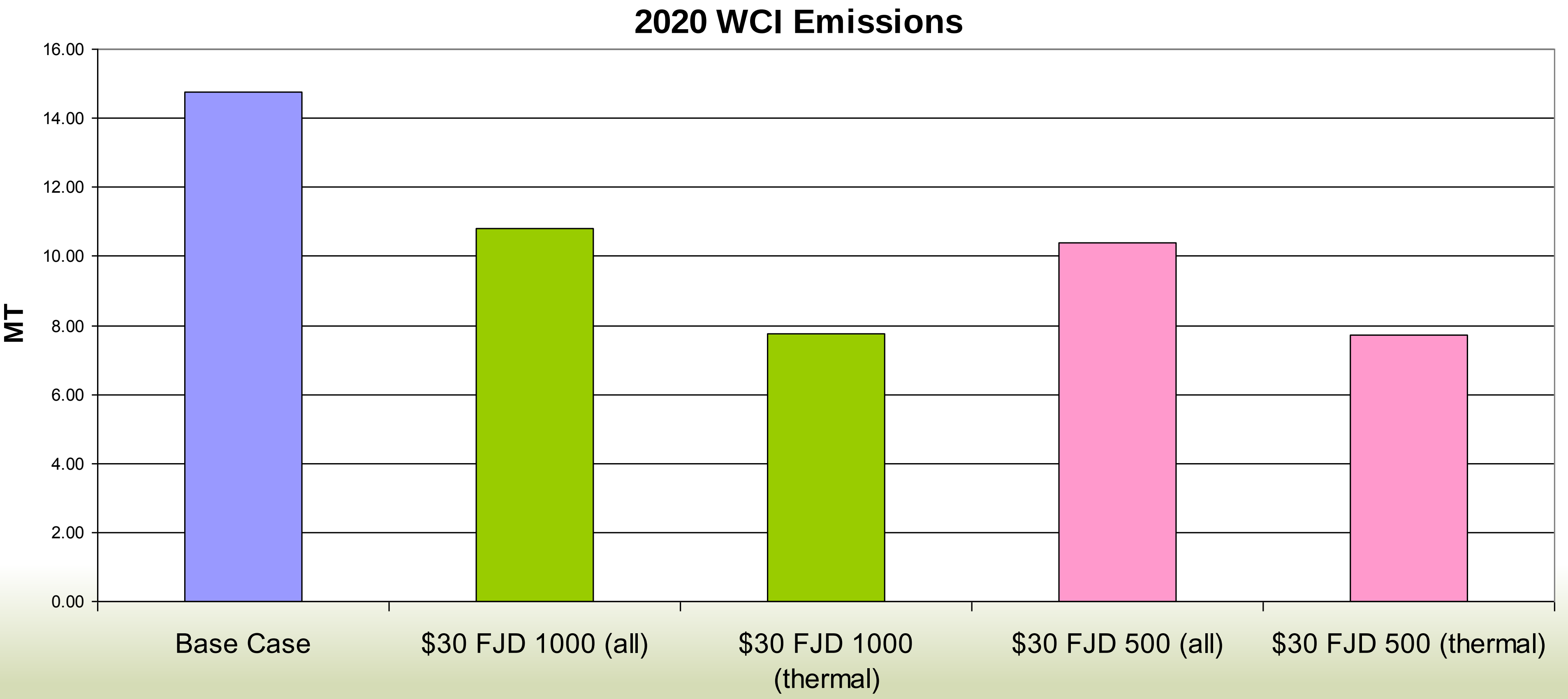
2020 Projection with $30 Allowance Price



2020 Projection with $30 Allowance Price

	WCI Generation (TWh)	WCI Exports (TWh)	WCI Imports (TWh)
Base	409.6	21.1	1.5
Allowance Price $30 FJD 0	391.8	8.2	6.1
Allowance Price $30 FJD 1000 g/kWh (all units)	400.1	11.2	1.0
Allowance Price $30 FJD 1000 g/kWh (thermal units)	391.9	8.3	6.0
Allowance Price $30 FJD 500 g/kWh (all units)	398.9	10.8	1.8
Allowance Price $30 FJD 500 g/kWh (thermal units)	391.9	8.3	6.0

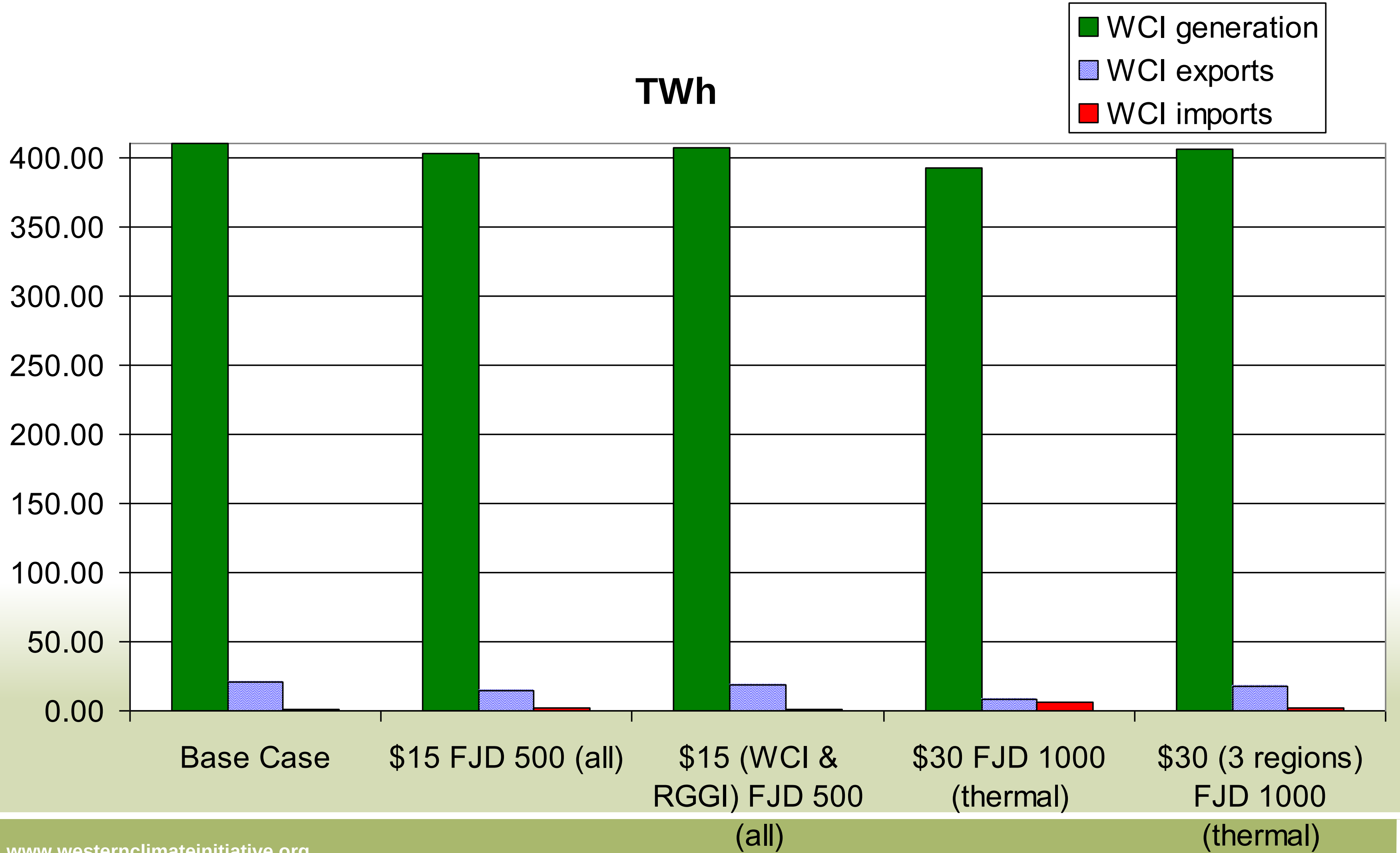
2020 Projection Emissions - Complex



RGGI/MGGRA Coordination

- Base case scenarios assume:
  - RGGI allowance price $2.06 per metric ton; MGGRA no carbon pricing. Both were subject to FJD charges where appropriate.
- Three scenarios explored what would happen if WCI, RGGI and/or MGGRA worked together to adopt similar carbon pricing regimes, and were therefore exempt from each other's FJD charges.
  - For scenarios with RGGI and MGGRA allowance prices aligned, FJD charges applied to flows into WCI or RGGI/MGGRA rather than just into WCI.

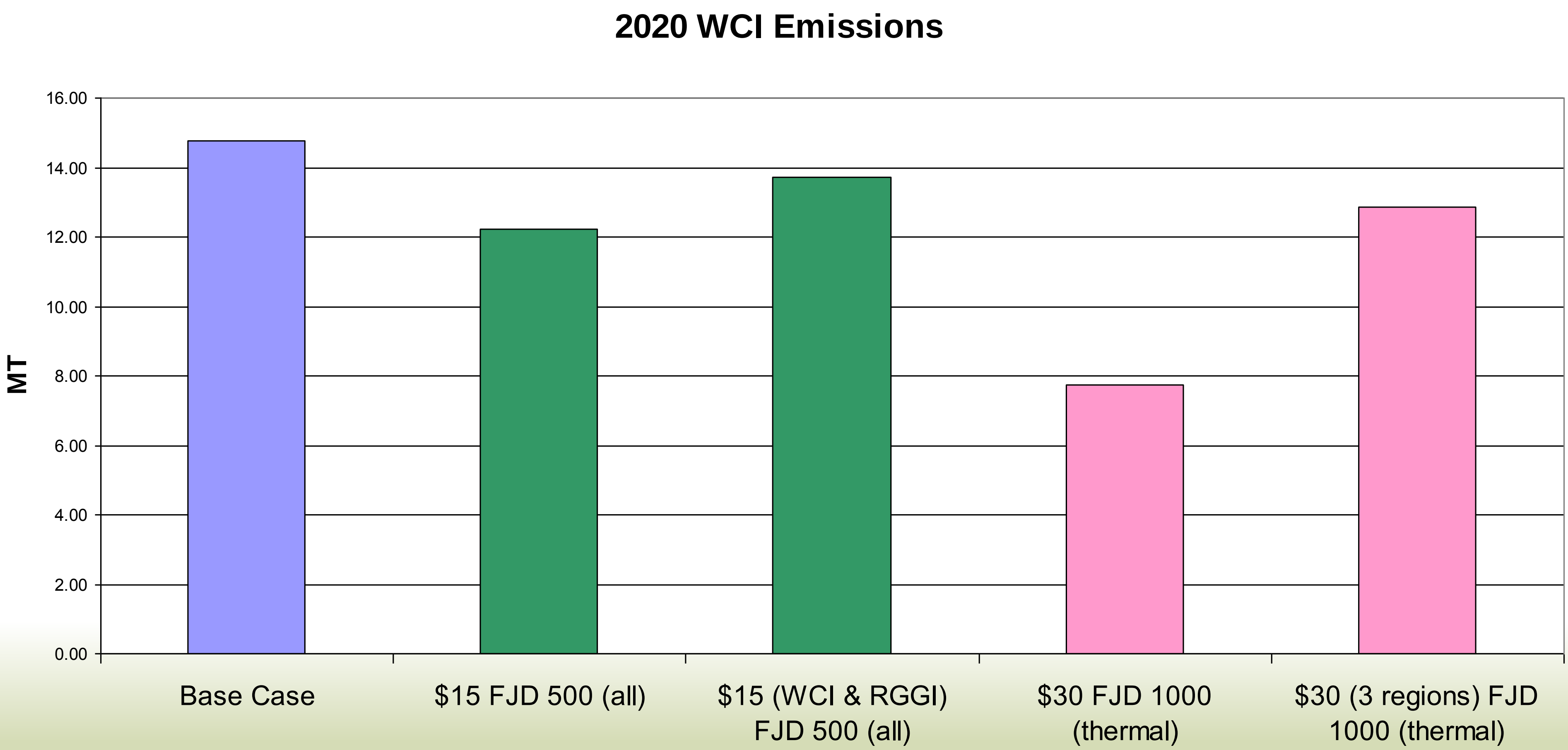
2020 Projection – RGGI/MGGRA



2020 Projection – RGGI/MGGRA

	WCI Generation (TWh)	WCI Exports (TWh)	WCI Imports (TWh)
Base	409.6	21.1	1.5
Allowance Price $15 (WCI) FJD 500 g/kWh (all units)	403.0	14.9	1.8
Allowance Price $15 (WCI and RGGI) FJD 500 g/kWh (all units)	407.0	18.7	1.4
Allowance Price $30 (WCI) FJD 1000 g/kWh (thermal units)	391.9	8.3	6.0
Allowance Price $30 (WCI, RGGI, MGGRA) FJD 1000 g/kWh (thermal units)	405.7	18.1	1.9

2020 Projection Emissions – RGGI/MGGRA



Modeling Conclusions

- WCI generation and eastern WCI CO2 emissions levels are strongly affected by the eastern WCI CO2 allowance price
  - WCI generation and WCI emissions decrease as the WCI allowance price increases
  - At a given allowance price, increasing the default emissions factor only slightly affects imports / exports and WCI generation
  - Most generation change occurs in Ontario
- Where contract shuffling was permitted, there was a further ~ 25% reduction in eastern WCI CO2 emissions. WCI imports are higher in these cases.
- Where coordination of WCI/RGGI/MGGRA occurs, imports into the WCI are reduced relative to scenarios where contract shuffling occurs, meaning there is less incentive for WCI to use imports rather than their own generation.
- Significant (-2%) total emission (WCI and non-WCI) reductions occurred only in the scenario where coordination of WCI/RGGI/MGGRA occurs. In all other scenarios, total emission changes are 0.1% or less.

Next Steps

- Final report being drafted by Navigant and will be reviewed by WCI.
- Final report will be posted on WCI website

  http://www.westernclimateinitiative.org/

Western Climate Initiative

Market Oversight
Draft Recommendations

Partner Meeting, Vancouver, British Columbia

March 3, 2010

Market Oversight Objectives

- "The recommended design will provide opportunities to obtain low-cost emission reductions through emission trading, allowance banking, and inclusion of an offsets component."

WCI Design Recommendations, September 23, 2008

- "The WCI Partner jurisdictions and stakeholders want appropriate safeguards and oversight of the allowance and offset credit trading markets and want them to function efficiently."

Materials for Markets Workshop, April 9, 2009

Principles

- **Efficiency**: The market is designed to operate efficiently so that greenhouse gas (GHG) emission reductions can be achieved at the least cost. An efficient market means that allowance and offset credit prices reflect supply and demand, and accurately reveal the value of allowances and offset credits.

- **Effective Oversight**: The design and oversight of the market is effective in preventing or minimizing fraud, manipulation, and speculative excess.

Oversight Recommendations Process

- Public workshop April 9, 2009
- White Paper November 18, 2009
- Stakeholder call December 2, 2009
- Draft Recommendations paper
- Stakeholder call
- Final Recommendations paper
- Detailed Program Design contributions

Draft Recommendations

- Allowances, Offset Certificates, and Derivatives
- Market Participants
- Holdings and Transfers
- Market Monitoring

Allowances, Offset Certificates, and Derivatives

- #1: Treat Allowances as Commodities for Market Oversight Purposes
  - Implies primary regulation of derivatives by provincial securities commissions and US federal regulators
- #2: Information on Derivatives Positions
- #3: Treat Allowances and Offset Certificates Identically for Market Oversight Purposes

Market Participants

- #4: Establish Legal Relationship with Market Participants Through Compliance Instrument Ownership Interest and Tracking System
- #5: Do Not Limit Market Participation to Compliance Entities
- #6: Require Registration of Intermediaries as Market Professionals

Holdings and Transfers

- #7: Holdings Limits
- #8: Require Use of a Centralized Quotation System for Transactions
- #9: Require Reporting of Beneficial Ownership
- #10: Information Required for Compliance Instrument Transfer
- #11: Holdings and Transfer Information Disclosed to Public

Information on Derivatives Positions

- Mirror information to derivatives regulators for real-time monitoring
- Forensics
- Support for “providing appropriate technical and other compliance assistance” (Design Rec., §12.5)

- Data currently not collected
- Could not see whole market
- Infrastructure costs
- Debate over transparency benefits

For More Information:

- Michael Gibbs, California, Markets Committee Co-Chair

  mgibbs@calepa.ca.gov
- Jim Whitestone, Ontario, Markets Committee Co-Chair

  jim.whitestone@ontario.ca

Western Climate Initiative

Offsets Definition and Criteria and Report on Existing Protocols

WCI Partners Meeting
Vancouver, BC
March 3, 2010

Overview

1. For Partner approval: public release of the Offsets Definition and Criteria Draft Recommendations Paper
2. For Partner Approval: Report on existing Protocols

Offset Definition

Section	Draft Recommendation
3.1	A WCI offset certificate is issued by a WCI Partner Jurisdiction and represents a reduction or removal of one metric ton of carbon dioxide equivalent (tCO2e). The reduction or removal must meet the WCI's essential criteria for reductions and removals to be real, additional, permanent, and verifiable. Reductions and removals must also be clearly owned, adhere to an approved protocol, and result from a project located in a qualifying geographic area.

Real

Section	Draft Recommendation
4.1	A WCI offset certificate represents a reduction or removal of one metric ton of CO_2e that results from a clearly identified action or decision. A WCI offset project's reduction or removal is quantified using accurate and conservative methodologies that appropriately account for all relevant greenhouse gas sources and sinks and leakage risks. WCI offset projects result in direct emissions reductions or removals that take place at sources controlled by the project proponent.

Additional

Section	Draft Recommendation
5.1	Offsets may only be issued for the portion of greenhouse gas emissions reductions or removals that occur above the reductions or removals achieved under the baseline scenario. When possible, protocols will use a sectoral performance standard to determine additionality. For project types where a performance standard approach cannot be taken due to insufficient data availability, varying regional conditions, or other difficulties, or where a more appropriate method is justified, the WCI Partner Jurisdictions may alternatively consider recommending protocols with the appropriate additionality tests. The baseline scenario shall be set to reflect a conservative estimate of business-as-usual performance or practices for the relevant type of activity in the absence of an offset program. The baseline scenario must, at a minimum, include any reduced or sequestered GHG emissions that result from activities required by any existing binding agreement, consent order, regulation, or law in the jurisdiction where the project is located. *When reductions or sequestrations are obtained via a government incentive program, the baseline scenario must include the part of the reductions or sequestrations corresponding to the amount of the financial incentive.* Additionality will be applied to create a level playing field for all Partner

Permanent (1 of 2)

Section	Draft Recommendation
6.1	With respect to offset project activities, permanence means either that reductions or removals are not reversible or that, if reductions or removals are reversible, then requirements outlined in the remainder of this recommendation are met. Sequestration projects must ensure the atmospheric effect of their greenhouse gas removal will endure for a period that is comparable to the atmospheric effect achieved by non-sequestration projects. The duration for this period is to be based upon current scientific findings that are widely accepted and followed. The current international standard of 100 years has been established by the UNFCCC and will be followed by the WCI. The WCI will adopt new international standards (likely UNFCCC) if/when they are updated. Offset projects where the reduction or removal is maintained for less than the WCI standard may be pro-rated and/or replaced in order to maintain the environmental integrity of the offsets system. If pro-rating is allowed for a project type it will be included in the appropriate WCI approved protocol)

Permanent (2 of 2)

Section	Draft Recommendation
6.1	Project proponents shall follow or establish effective (i) monitoring systems, (ii) risk mitigation approaches, and (iii) contingency plans which address how, in the event of a reversal that is the result of proponent intention or negligence, any affected offset certificates will be replaced. The contingency plan shall include specific mechanisms that are exercisable at the time a reversal is identified whether or not the proponent is solvent, exists in its original form, and/or has ownership of or responsibility for the project. The WCI partner jurisdictions will establish mechanisms to address reversals that are not the result of proponent intention or negligence and to ensure replacement of credits where proponent's contingency measures prove inadequate.

Verifiable

Section	Draft Recommendation
7.1	With respect to offset project activities, verifiable means that a GHG reduction or removal, or assertion thereof, is well documented and transparent such that it lends itself to an objective review by a qualified verifier. Verifiers for WCI offsets will be independent third parties who have been accredited to a standard acceptable by the WCI Partner Jurisdiction in which the project is registered.

Transparency

Section	Draft Recommendation
8.1	The WCI offset system will provide transparency such that sufficient and appropriate protocol, project and certificate information is disclosed to allow offset system participants and the general public to make decisions with reasonable confidence.

Report on existing Protocols

Purpose of the Report

- Assist the WCI to identify protocols that could be incorporated into a WCI offsets system

Scope of the Report

- Review of 31 protocols from 11 offset programs particular to ten project types in agriculture, forestry, and waste management

Final DNV Report on existing Protocols

Next steps:

- Cover memo being prepared
- Public release anticipated in March
- Webinar following public release
- Public comment period

Carbon Neutral Event

Pacific Carbon Trust

PacificCarbonTrust.ca

Pacific Carbon Trust
Growing BC's Green Economy

Western Climate Initiative: Partners' Meeting

March 3, 2010

Pacific Carbon Trust

Objectives

1 **Introduction**

Introduce Pacific Carbon Trust and its mandate within the provincial climate change framework

2 **Perspective**

Share how PCT is driving BC's offset market forward

3 **PCT and WCI**

Highlight how we can work together to grow the low carbon economy in BC and North America

Pacific Carbon Trust was launched with an ambitious dual mandate

Deliver quality BC-based **offsets** to clients and support growth of the **low-carbon economy** in BC

- New commercial BC Crown corporation
- Capitalised at $24 million
- Exclusive supplier of 1,000,000 tonnes annually for carbon neutral public sector
- Aggressively sourcing high-quality BC offsets to meet this demand
- Sourced over 300,000 tonnes from 15 offset projects – and more soon
- Acquiring clients outside of government

BC is pursuing an innovative approach to creating an offset market

Creating **Demand** for Carbon Offsets

- Carbon Neutral Public Sector
- Municipal Charters

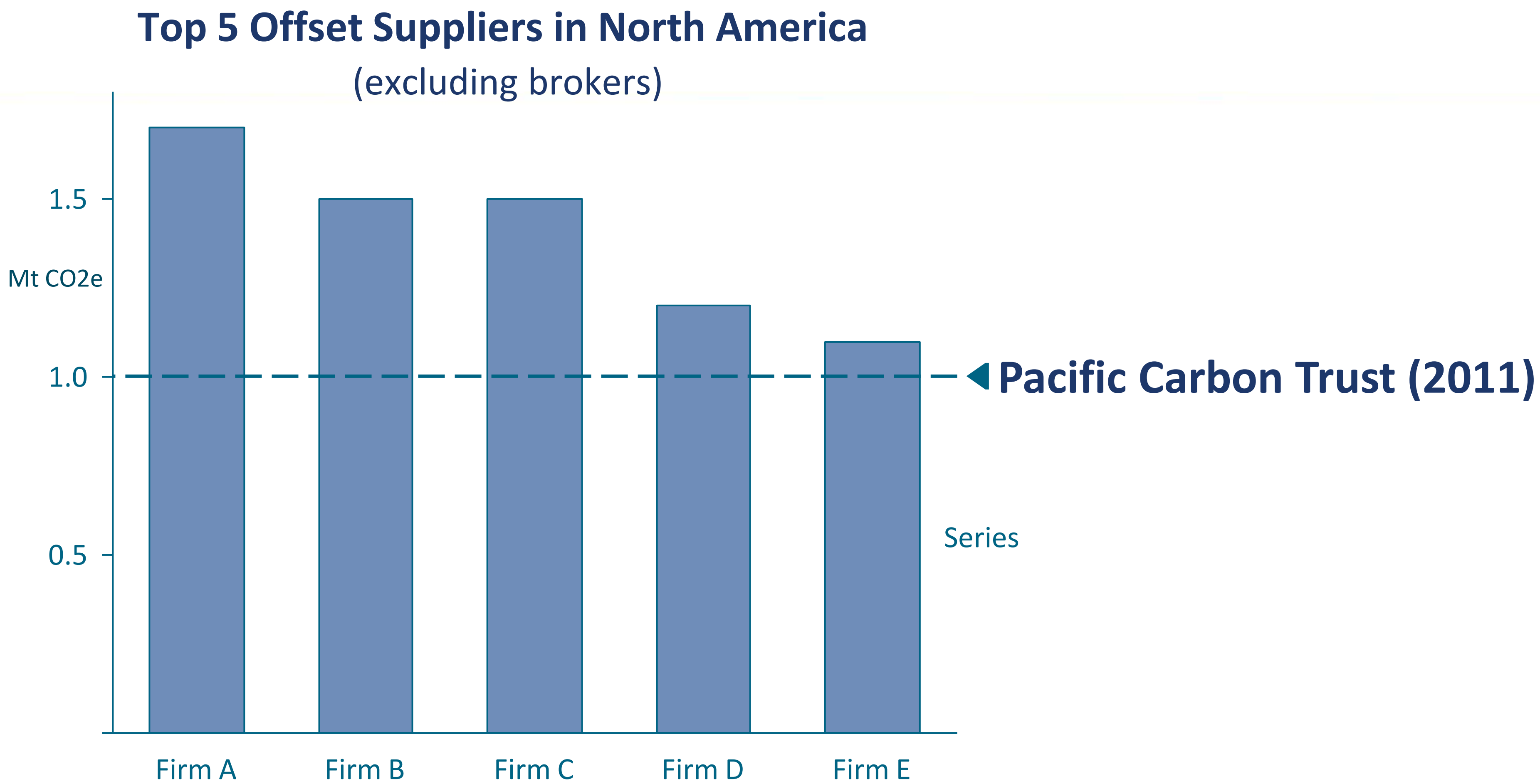
AND

Building the **Supply** of Carbon Offsets

- Strong Price Signal
- BC Offset Regulation

1	Fundamentally changing the **economics** of the investment decision by putting a **price** on carbon
2	Combining **rigorous** offset standards and **financial** incentives to spur innovative clean technology
3	**Identifying** and **removing barriers** at a structural and project level

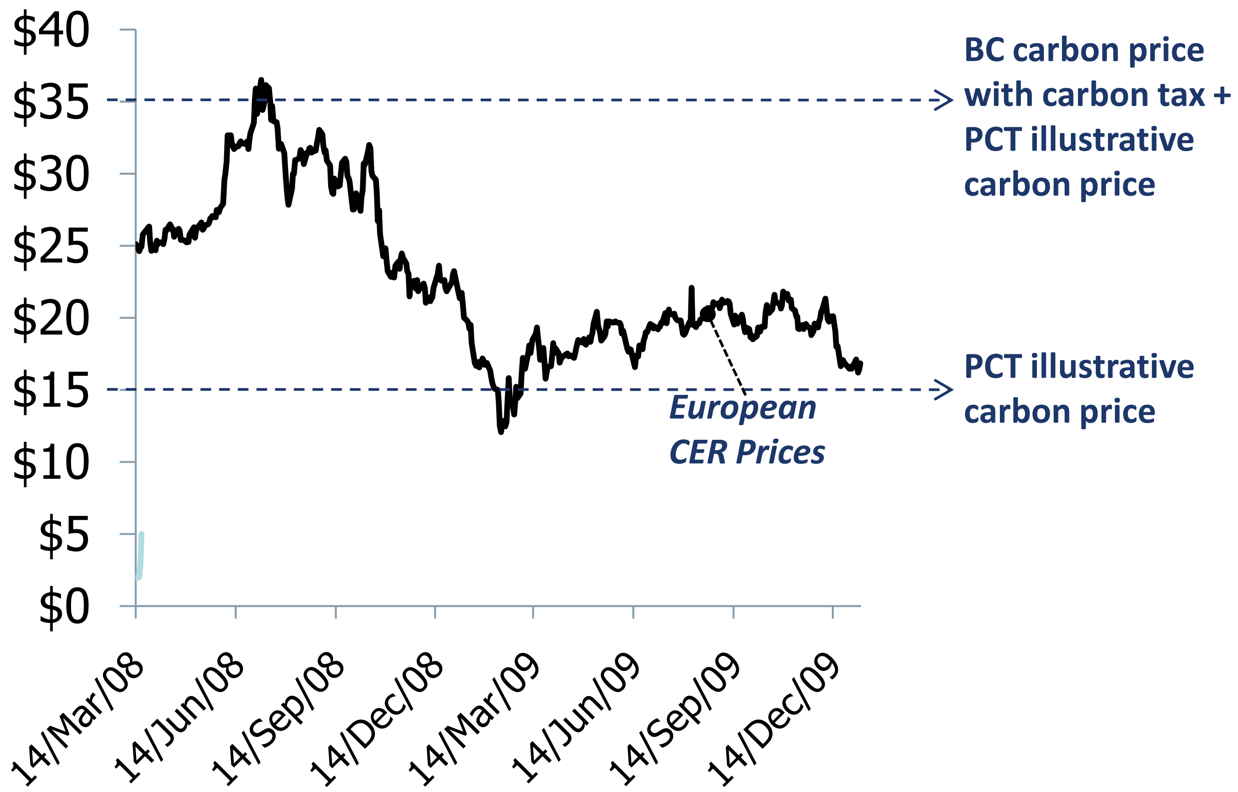
Pacific Carbon Trust will be one of the largest offset suppliers in North America next year



Source: Bloomberg New Energy Finance.
Confidential data from the State of the Voluntary Carbon Markets Report, 2009

BC has a globally significant carbon price from the carbon tax and investments that PCT is making in GHG reductions

Carbon pricing comparison ($CAD / tonne CO2e)



Pacific Carbon Trust pursues 3 core types of offset projects

	Opportunity	Description	Sample projects
1	**Low carbon fuel supply opportunities**	▪ Facilitating switch to a fuel source with lower CO2 emissions (e.g. from coal to natural gas)	▪ Switch from natural gas to biomass
2	**Energy efficiency initiatives**	▪ Reducing amount of energy required to achieve similar output ▪ Minimizing waste energy lost from a process (e.g. methane loss)	▪ Elimination of waste methane from landfills ▪ Coal mine methane destruction ▪ Co-Gen / CHP
3	**Terrestrial carbon sequestration**	▪ Increased storage of CO2 in sinks, such as forests ▪ Capture and sequestration of CO2 from industrial emissions	▪ Forestry projects ▪ Carbon Capture and Storage (CCS)

Revenues from offsets can make the difference in adopting clean technology and energy efficiency equipment

Initial Projects in PCT's Portfolio

1

Industrial Fuel Switching

- Lafarge - Richmond
- 189kT CO_2 over 3 yrs
- Ability to monetize CO2 reductions allowed for fuel switch from coal to biomass

2

Agricultural Sector Fuel Switching

- Greenhouses - Lower Mainland
- 2 projects – 98kT CO_2 reduction over 5 years
- Sale of offsets allowed for switch to biomass based fuels

3

Agricultural Sector Energy Efficiency

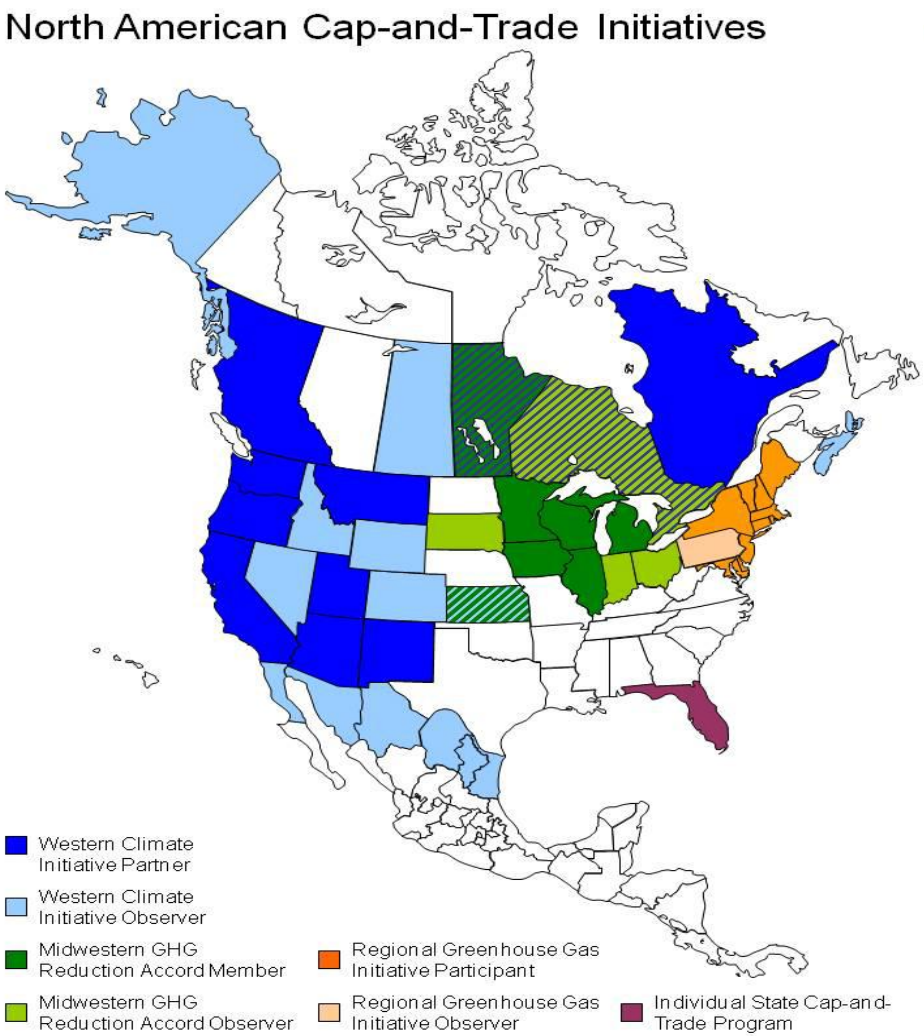
- Energy Curtains – Lower Mainland
- 2 projects – 43kT CO_2 reduction over 5 yrs
- Sale of offsets allowed investments in energy saving technologies

4

Energy Efficiency & Cleantech

- Hotels across BC
- 10 projects – 11 kT CO_2
- Intelligent fuel switching systems

PCT wants to work with you to build the North American carbon market



Where we're heading:

- 1 million tonnes of offsets annually
- Economic incentives for early action and adopting new technologies
- Market infrastructure in place and tested
- Engagement with offset organizations throughout North America

Pacific Carbon Trust

Carbon Neutral Event

Pacific Carbon Trust

Pacific Carbon Trust

6th Floor, 747 Fort Street
Victoria, BC V8W 3E9
Cell 250-507-8130
Tel 250-952-6295
Fax 250-952-6783
www.PacificCarbonTrust.ca

David Moffat

DIRECTOR,
BUSINESS DEVELOPMENT

David.Moffat@pacificcarbontrust.ca

Pacific Carbon Trust

Reporting Committee

- Task 1: Harmonization of WCI Essential Requirements for Mandatory Reporting (ERs) with EPA Mandatory Reporting Rule (EPA Rule)
  - Products and Timing
    - In Process: Committee technical work to review EPA Rule and identify changes needed for
      - WCI Program
      - Conformance to Canadian regulatory norms
    - March-April: First present final recommendations, stakeholder calls and comments
    - April: Final ERs
    - Resources: No additional needed

Reporting Committee, *cont.*

- Task 2: Develop Essential Requirements for Mandatory Reporting of Oil and Gas Exploration and Production and Natural Gas Processing
- Production and timing:
  - In Process: Ongoing calls with subcommittee/stakeholder Technical Working Group
  - April 1: WCI comments to US EPA on re-proposed Subpart W of their mandatory reporting rule
  - December: First present harmonized ERs for Mandatory Reporting for Oil and Gas, stakeholder comment period
  - January 2011: Approve final ERs
  - Resources: Seeking EPA funding

Agenda

Western Climate Initiative and Goods Movement Collaborative

8:30am to 4:00pm, March 4, 2010

Hyatt Regency Vancouver, Vancouver, BC

Meeting Objectives:

1) Inform participants of the North American transportation industry's GHG emission pathways and the differences in managing sectors (marine, rail and truck) across WCI Partners jurisdictions;
2) Identify specific emission reduction opportunities in the transportation sectors;
3) Initiate dialogue on transportation industry treatment within the WCI; and
4) Determine next steps for continued transportation industry engagement in WCI.

		Lead Presenters
8:30 – 8:45	**1. Call to Order: Opening Remarks** • Introductions • Review Purpose and Agenda • Context for today's discussion	Tim Lesiuk (BC)
8:45 – 10:00	**2. North American Transportation Sector and Climate Change** • Introduction and Overview ○ Defining the sector ▪ Differences between goods movement and personal transportation ○ Major sources of emissions across subsectors • Focusing on freight transportation – tools for a unified approach ○ Marine ○ Rail ○ Truck • Treatment and challenges of addressing the Transportation sector under other GHG programs ○ North American ▪ Tailpipe emission standards ▪ Low carbon fuel standard ▪ BC Carbon Tax ▪ Cap and trade ▪ Smartaway	Mike Gerbis, Delphi John Fowlis, Seaspan Normand Pellerin, CN Bob Purdy, Fraser Basin Council Jotham Peters, M.K. Jaccard
10:00 – 10:15	**Break**	
10:15 – 12:00	**3. Facilitated Breakout Groups** • Split into key subsectors to discuss ○ What is the right outcome for this sector in a carbon constrained world (modes, optimizations, fuels, vehicles, infrastructure and logistics)? ○ Key challenges for sector to achieving these outcomes ○ Transition strategies to a low carbon sector ▪ Industry ▪ Government ▪ Consumers ○ Near and mid-term actions (research, competitiveness, infrastructure, policy, incentives) ▪ Industry ▪ Government	Facilitators: Dennis Cunningham, IISD Nick Nigro, PEW Mike Gerbis, Delphi
12:00 – 1:00	**Lunch**	
1:00 – 1:15	**Minister Penner, Ministry of Environment, Government of British Columbia**	Minister Penner
1:15 – 2:30	**Subsector Presentations**(15-20 minutes each)	All
2:30 – 2:45	**Break**	
2:45 – 3:45	**4. Collaborative Discussion** • Group evaluation of presented materials	All
3:45 – 4:00	**5. Wrap up and Next Steps**	Tim Lesiuk (BC) Michael Gibbs (CA)

Western Climate Initiative Goods Movement Collaborative

Objectives for the Day

- **Inform participants** – NA transportation industry's GHG emissions
- **Identify opportunities** – to reduce GHG emissions in the transportation sector
- **Initiate dialogue** - on transportation industry treatment within the WCI
- **Identify next steps** - for continued transportation industry engagement in WCI

DelphiGroup
Environmental Strategies. Business Solutions.

Format for the Day

- 8:45 - 10:00 Context setting presentations
- 10:00 - 10:15 Break
- 10:15 - 12:00 Breakout Sessions
- 12:00 – 1:00 Lunch
- 1:00 – 2:15 Summary Presentations
- 2:15 – 2:30 Break
- 2:30 – 3:30 Collaborative Discussion
- 3:30 – 4:00 Wrap Up and Next Steps

DelphiGroup
Environmental Strategies. Business Solutions.

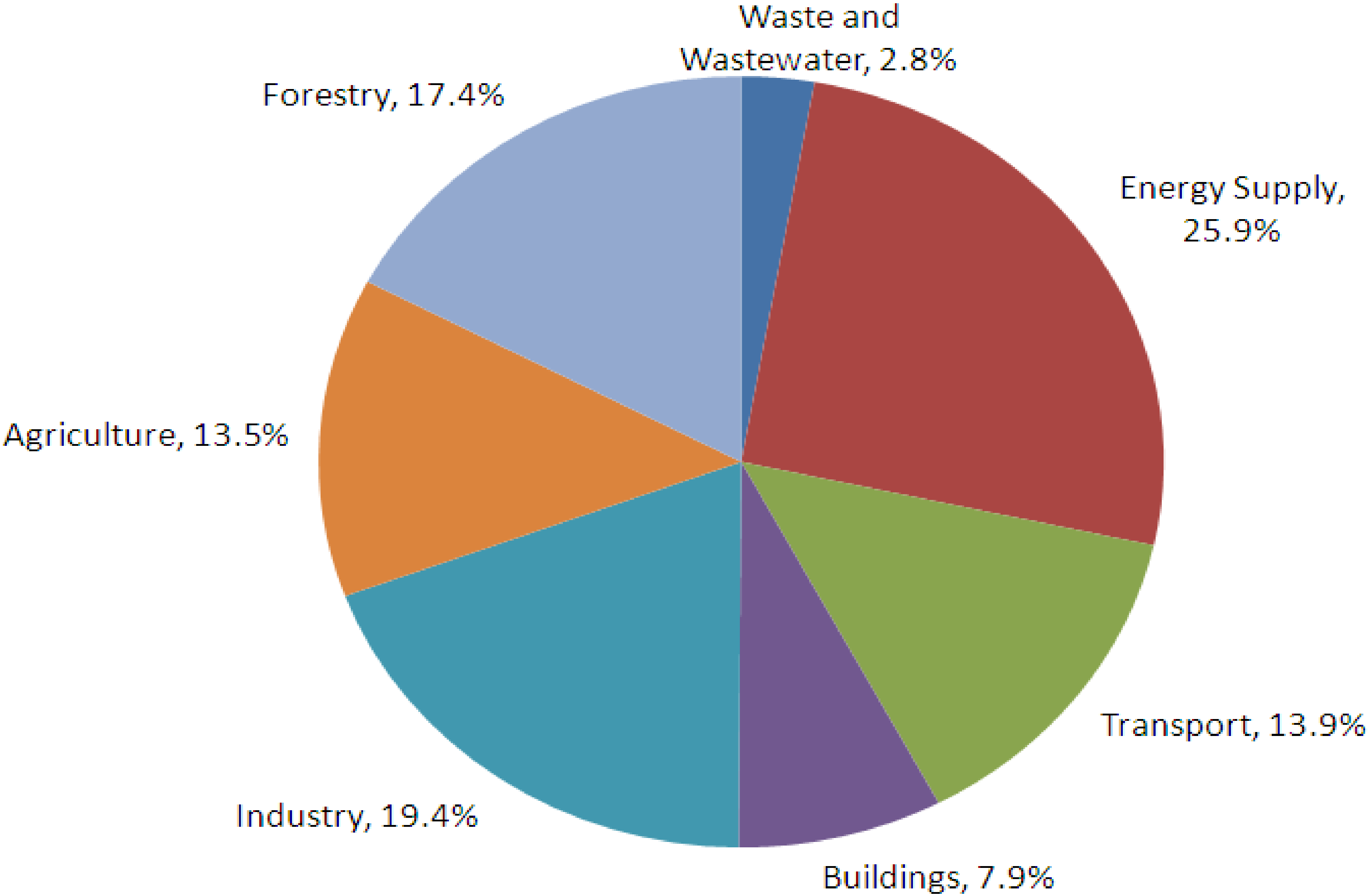
  

Delphi Group
Environmental Strategies. Business Solutions.

Introduction to Greenhouse Gases in the Transportation Sector

Human Activities emit huge amounts of GHGs

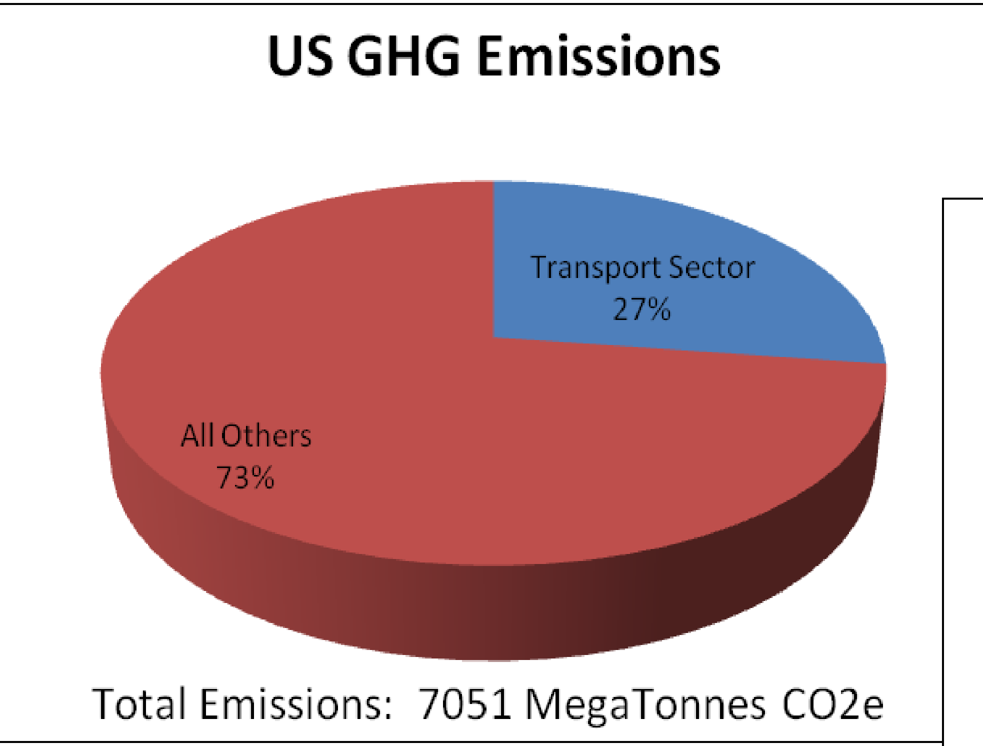
Global human GHG emissions

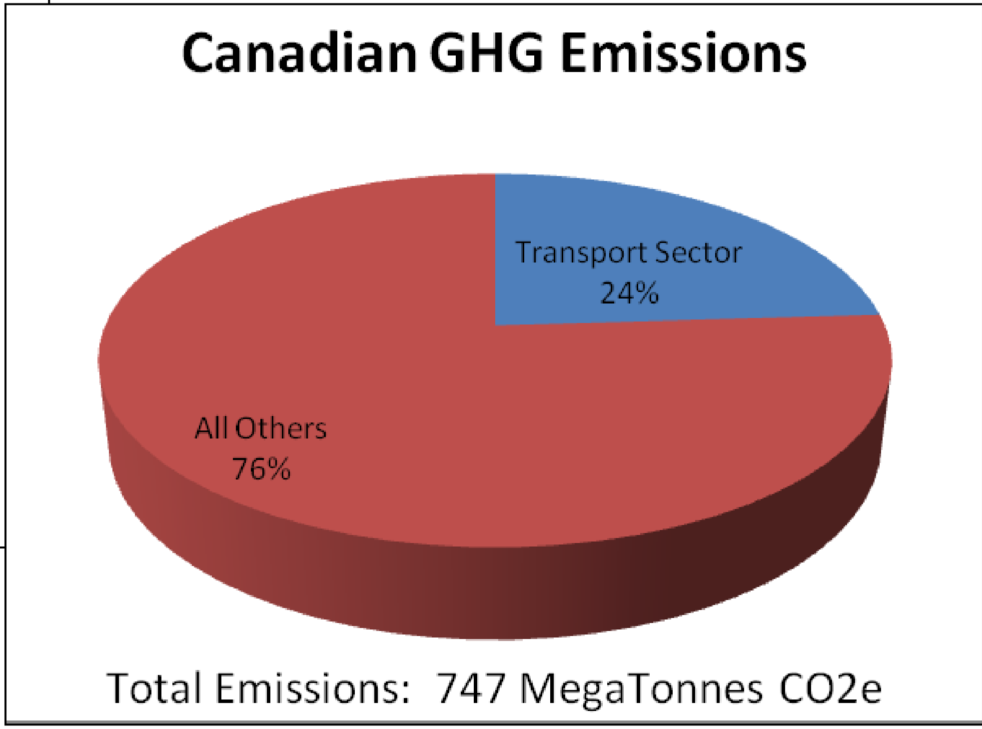


Transportation Sector

- Personal
  - Passenger cars
  - Passenger light trucks
- Goods movement
  - Freight light trucks
  - Medium & heavy duty trucks
  - Commercial aviation
  - Rail
  - Marine
- Other

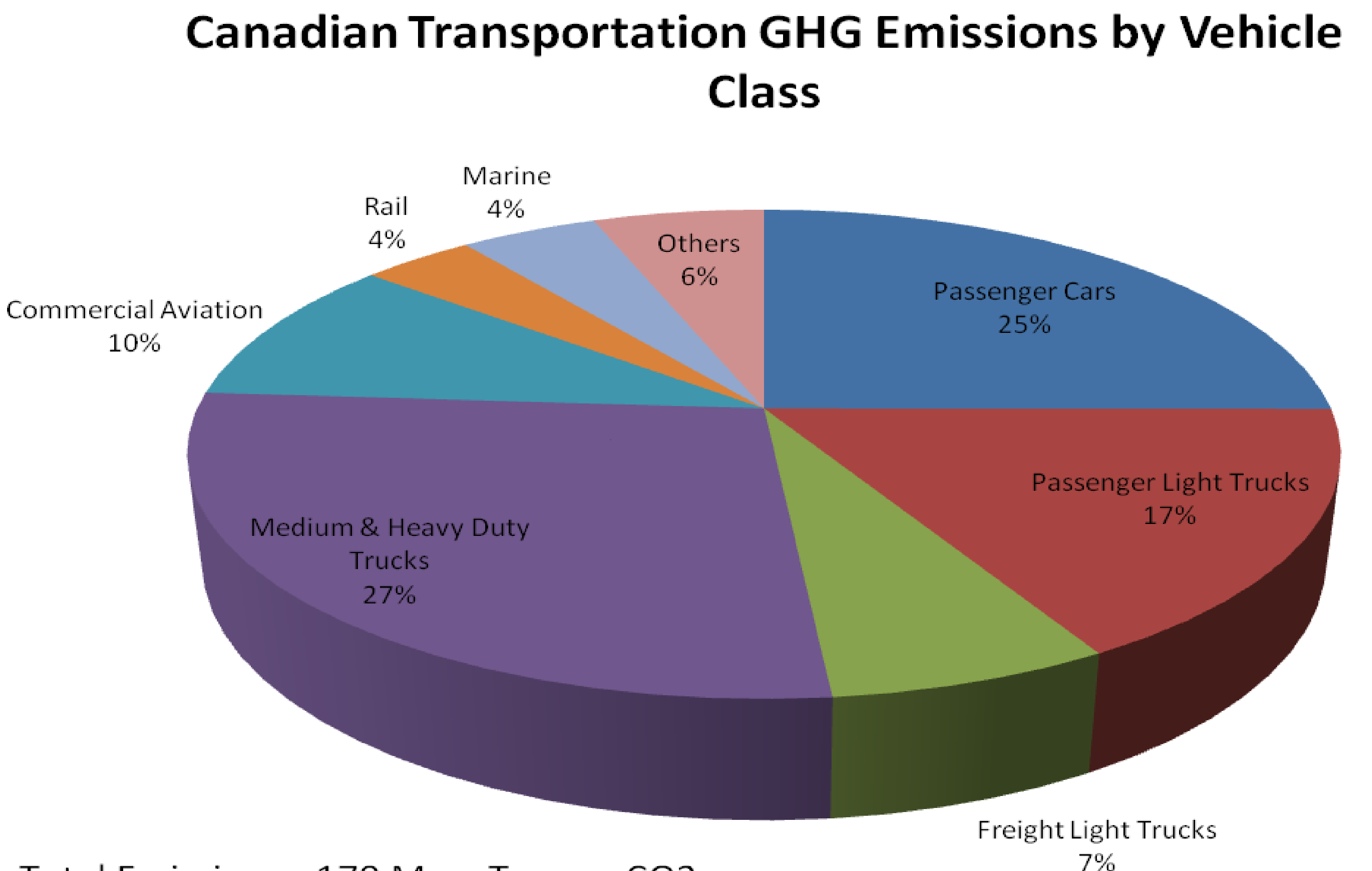
Transport Emissions (2007)





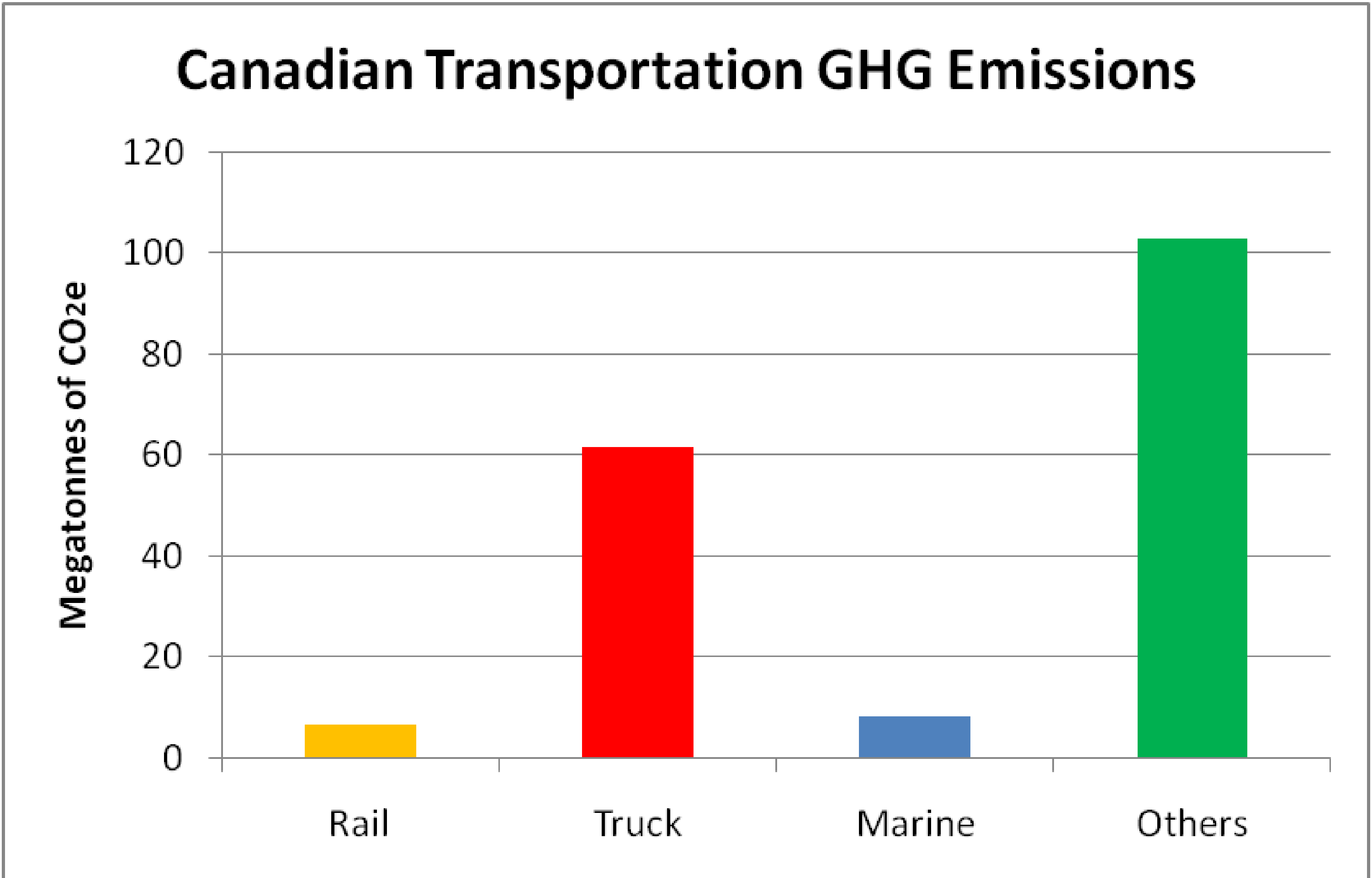
DelphiGroup
Environmental Strategies. Business Solutions.

Transportation Emissions - In Greater Detail

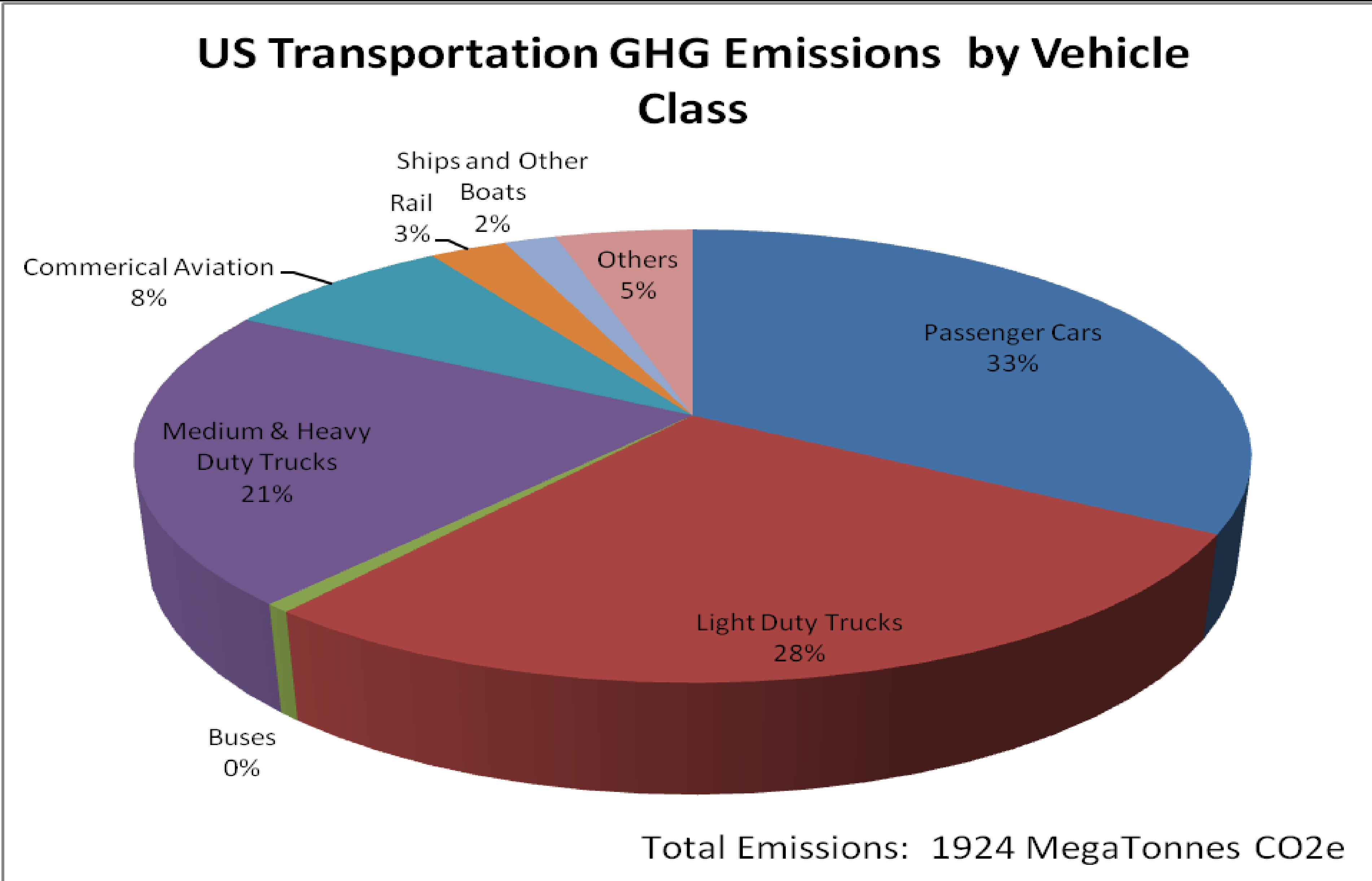


Total Emissions: 179 MegaTonnes CO_2e

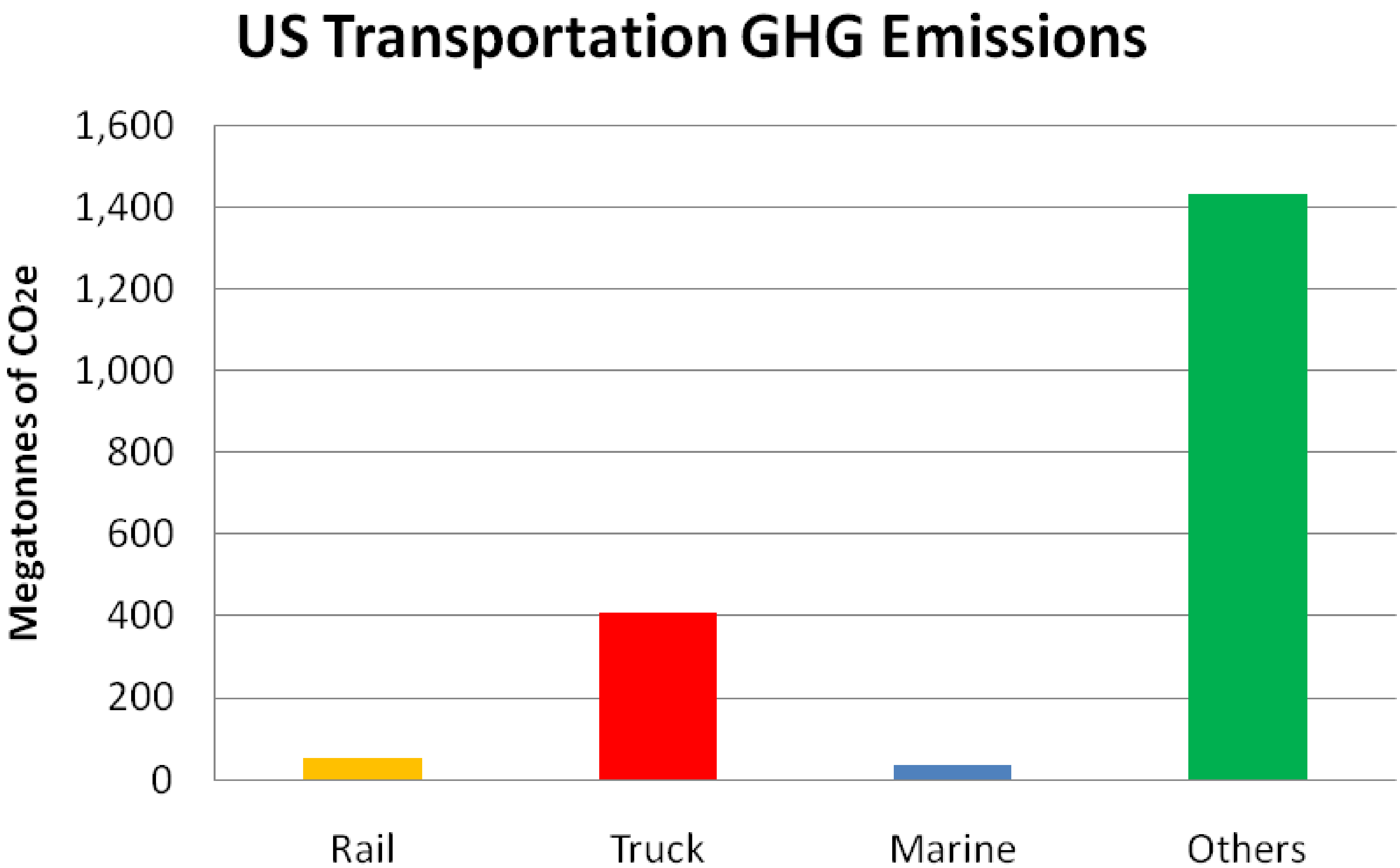
Examining Emissions from Select Classes



Transportation Emissions



Examining Emissions from Select Classes



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1. U.S. Environmental Protection Agency. Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 - 2007. [Online] April 15, 2009. http://www.epa.gov/climatechange/emissions/downloads09/GHG2007entire_report-508.pdf.

2. Natural Resources Canada. Comprehensive Energy Use Data Tables. Office of Energy. [Online] December 01, 2009. http://www.oee.nrcan.gc.ca/corporate/statistics/neud/dpa/tablestrends2/tran_ca_8_e_4.cfm?attr=0.

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Next Presentations

- Marine Sector
  - John Fowlis - Vice President Fleet Engineering, Seaspan International
- Rail Sector
  - Normand Pellerin – AVP Environment, CN
- Trucking Sector
  - Bob Purdy - Director, External Relations & Corporate Development, Fraser Basin Council
- Policy Review
  - Jotham Peters, M.K. Jaccard

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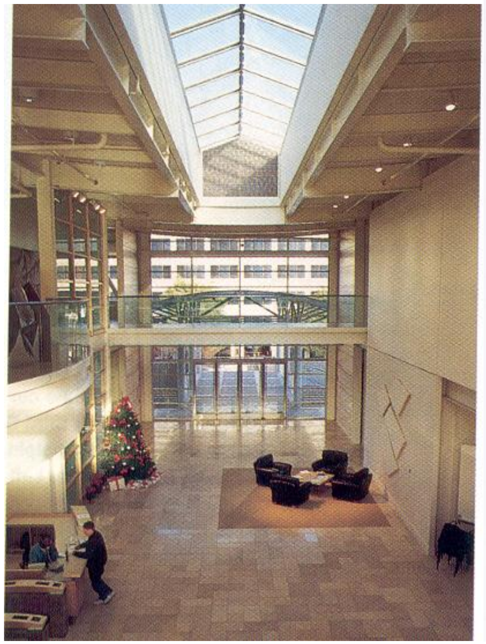
Questions??



"Negligence is defined as doing the same thing over and over even though you know it is dangerous, stupid or wrong. Now that we know, it's time for a change. Negligence starts tomorrow."

William McDonough, Architect

DelphiGroup
Environmental Strategies. Business Solutions.

Marine GHG opportunities

Western Climate Initiative

John Fowlis
Vice President Fleet Engineering
Seaspan International

Slides 4, 5, 6 courtesy of
Stephen Brown,
President
Chamber of Shipping of British Columbia

Marine Activities in Western Canada

- International shipping and Trade
- Domestic marine transportation
- Public marine transportation
- Fisheries
- Government vessels
  - Coast Guard
  - Dept of Fisheries
  - Navy
- Recreational

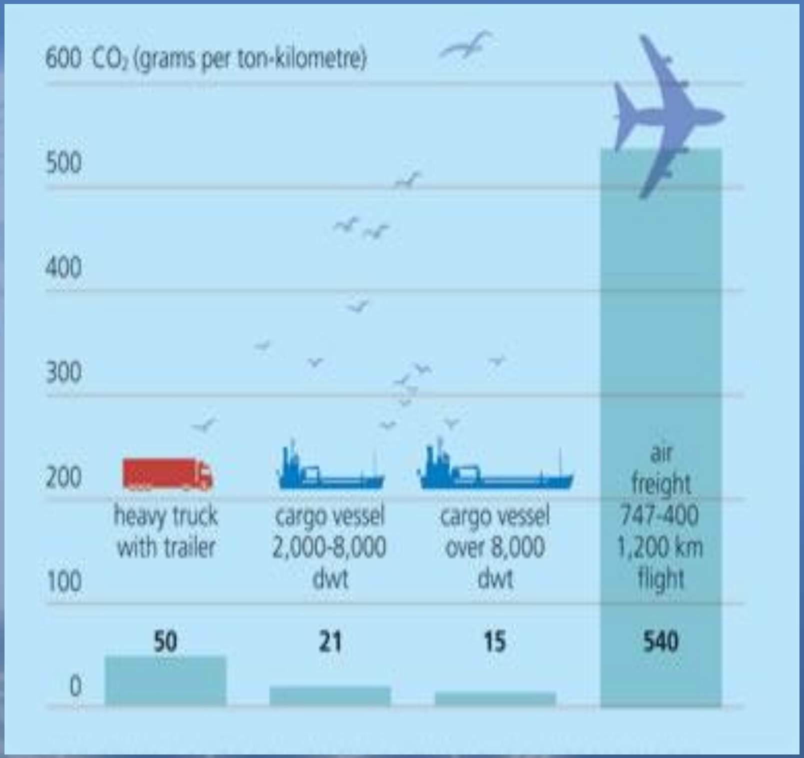
seaspan

International Shipping Initiatives

- Led by IMO
- Deep sea fleet predominantly uses HFO as fuel.
- Attention has been on Sulfur reductions
- GHG reduction initiatives driven by governments and customers.
- use of light fuels in ports or shore power
- Economy of scale and speed effect GHG

ATMOSPHERIC POLLUTION

- The shipping industry is a small contributor to the total volume of atmospheric emissions compared to road vehicles and air transport as well as public utilities such as power stations.
- Atmospheric pollution from ships has reduced in the last decade on account of improvements in engine efficiency, hull design, and the use of larger ships.
- .



CHAMBER of SHIPPING

WHAT MORE CAN BE DONE?

- Owners are extremely proactive in seeking a reduction in emissions and an increase in fuel efficiency.
- At the same time there is acknowledgment of the worldwide concern related to atmospheric pollution and the role of the shipping industry.
- The industry is therefore fully engaged in discussions at IMO on substantial further reduction of ships' emissions.

CASE STUDY “MSC DANIT”
14,000 TEU CAPACITY CONTAINER SHIP

DESIGN CRITERIA

- LOA approx 380 m
- Beam approx 52 m
- Design draft of 14 m
- Guaranteed speed of 24 knots
- Fn approx. 0.207 *
- 90% MCR with 15% sea margin

*Fn = factor of vessel design speed to size)

TO ACHIEVE

- Reduction in wave resistance by more than 50 percent
- Better propulsion
- Generation of stable wave patterns
- Higher vessel robustness
- Optimal trim

Domestic Shipping in BC

Cargos transported on BC Coast

- Forest sector
  - Logs
  - Cut lumber
  - Pulp / paper
  - Wood chips
  - Chemicals
- Bulk products
  - Oil / refined products
  - Gravel / Limestone / silica / coal
  - Salt
- Domestic freight
  - Ferries and passenger ships
  - Trailers
  - Project cargos
  - Specialty cargos / oversized load

Opportunities for Domestic Marine GHG reductions

- Replace older engines in vessels with new clean(er) engines
- Leverage economy of scale
- Voyage planning / speed reductions
- Alternate propulsion,

Opportunities to reduce GHG in other modes and increase Marine GHG for a net gain

- Marine Transportation represents 4% total GHG in transportation
- Marine is 1.4x more efficient than rail and 3.5x more efficient than trucks in fuel burned / ton mile moving bulk cargos.
- Marine requires limited infrastructure construction and maintenance.

- Where possible marine transportation of goods can reduce heavy truck traffic on roads and reduce overall GHG on a tons delivered basis.
  - In BC and Washington state there are several possible opportunities to leverage this advantage.
  - It will not happen without impetus from regulators / local governments

seaspan

Challenges in GHG reductions

- Limited applications of hybrid technology
- Alternative Fuel supply and cost
- Energy efficiency is not a new concept in marine transportation systems.
- Largest gains will come from a cultural shift in the public and the workplace.
- Existing emissions legislation will increase GHG output of new diesels to reduce NOx and SOx emissions.

Gaining "Traction for Action" in On-Road Transportation

March 4, 2010

Fraser Basin Council

Presentation Summary

1. Fraser Basin Council Overview
2. The Challenge: Transportation Sector GHG Emissions
3. The Council's Fleet Greening Initiatives
4. Opportunities Ahead

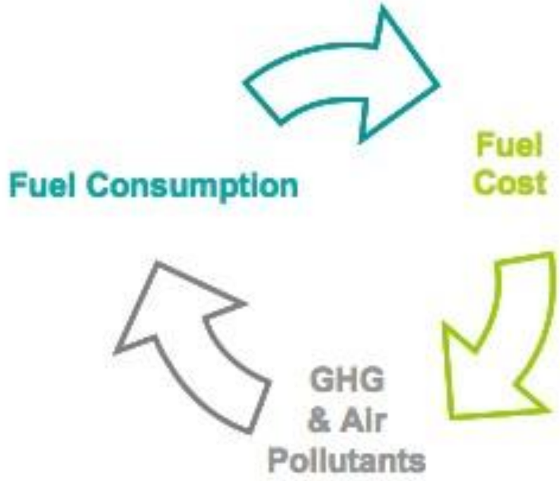
Fraser Basin Council

- Non-government organization formed in 1997
- Key roles: catalyst, facilitator, “bridge builder”, sustainability educator
- Uses inclusive governance approach involving:
    - All Orders of Canadian Government
    - Private Sector
    - Civil Society
- Implementing programs across BC and Canada

Fraser Basin Council

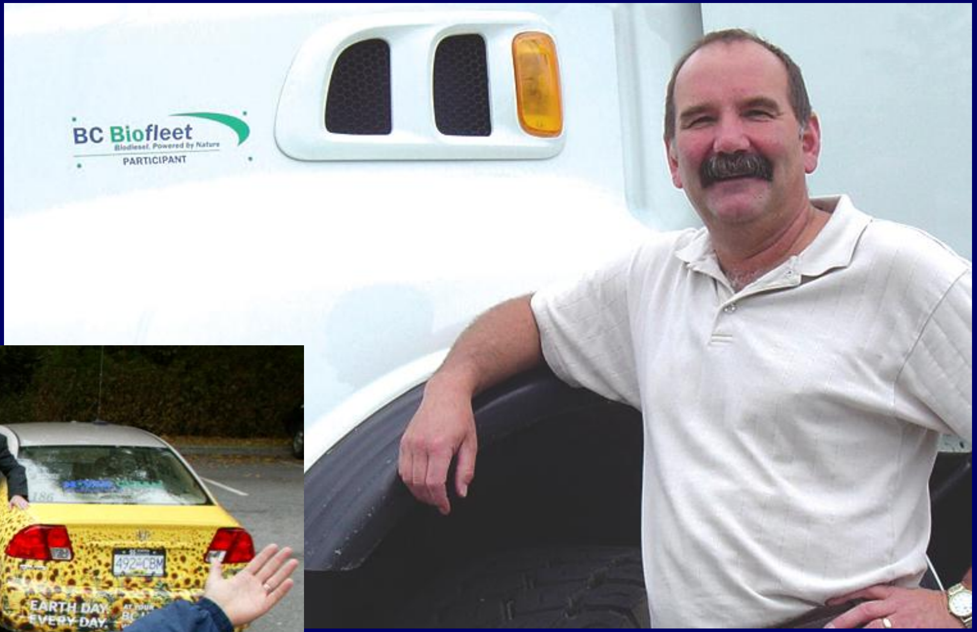
The Challenge: Transportation GHG Emissions

- GHG emissions continuing to grow
- GHG emissions in transportation ~36% of total emissions in BC
- On-road commercial transport about 8%
- *Many opportunities for emission reductions*



E3 fleet
Energy Environment Excellence

North America's First Green Rating System for Fleets



Fraser Basin Council

E3 Fleet: Program Priorities

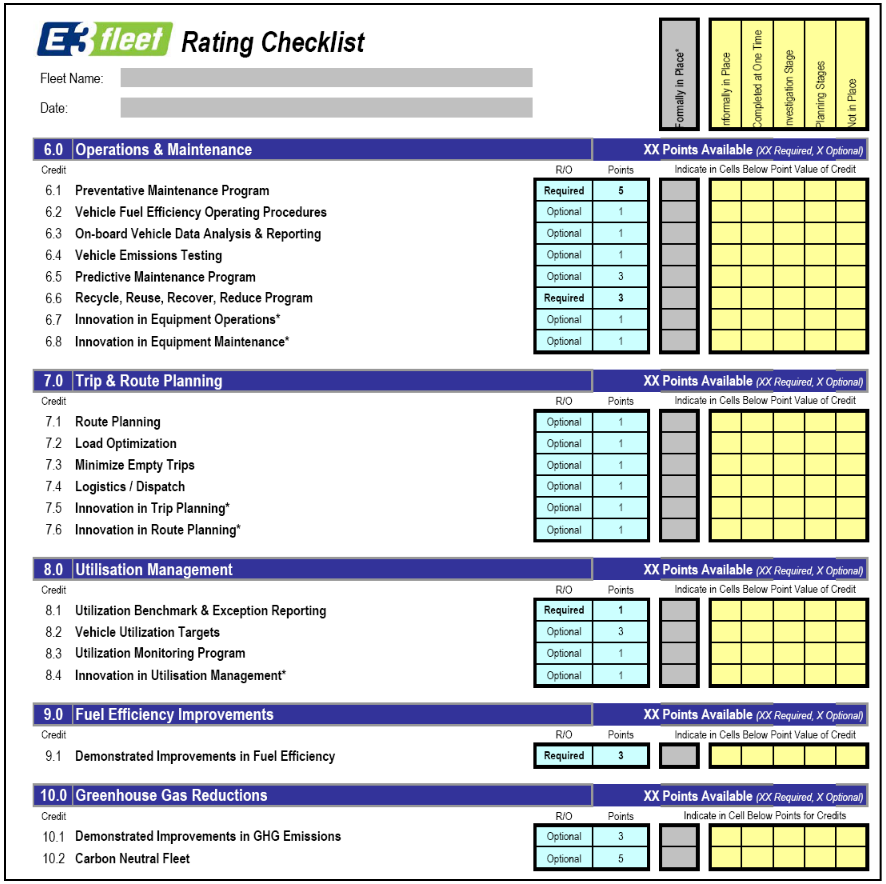
- Integrated analysis and rating program services
- Promote and recognize cost and emissions reduction successes
- Lead / coordinate demonstration programs
- Provide tools to evaluate efficiency alternatives
- Provide practices / technologies knowledge

Fraser Basin Council

E3 Fleet Rating

Points achievable in the following areas:

1. Green Fleet Action Plan
2. Training & Awareness
3. Idling Reduction
4. Vehicle Purchasing
5. Fuel Data Management
6. Operations & Maintenance
7. Trip & Route Planning
8. Utilisation Management
9. Fuel Efficiency
10. Emissions Performance



E3 fleet Rating Checklist

Fleet Name:

Date:

Formally in Place* | nformally in Place | Completed at One Time | nvestigation Stage | Planning Stages | Not in Place

Credit		R/O	Points
6.0	**Operations & Maintenance** — XX Points Available (XX Required, X Optional)		
6.1	Preventative Maintenance Program	Required	5
6.2	Vehicle Fuel Efficiency Operating Procedures	Optional	1
6.3	On-board Vehicle Data Analysis & Reporting	Optional	1
6.4	Vehicle Emissions Testing	Optional	1
6.5	Predictive Maintenance Program	Optional	3
6.6	Recycle, Reuse, Recover, Reduce Program	Required	3
6.7	Innovation in Equipment Operations*	Optional	1
6.8	Innovation in Equipment Maintenance*	Optional	1
7.0	**Trip & Route Planning** — XX Points Available (XX Required, X Optional)		
7.1	Route Planning	Optional	1
7.2	Load Optimization	Optional	1
7.3	Minimize Empty Trips	Optional	1
7.4	Logistics / Dispatch	Optional	1
7.5	Innovation in Trip Planning*	Optional	1
7.6	Innovation in Route Planning*	Optional	1
8.0	**Utilisation Management** — XX Points Available (XX Required, X Optional)		
8.1	Utilization Benchmark & Exception Reporting	Required	1
8.2	Vehicle Utilization Targets	Optional	3
8.3	Utilization Monitoring Program	Optional	1
8.4	Innovation in Utilisation Management*	Optional	1
9.0	**Fuel Efficiency Improvements** — XX Points Available (XX Required, X Optional)		
9.1	Demonstrated Improvements in Fuel Efficiency	Required	3
10.0	**Greenhouse Gas Reductions** — XX Points Available (XX Required, X Optional)		
10.1	Demonstrated Improvements in GHG Emissions	Optional	3
10.2	Carbon Neutral Fleet	Optional	5

Indicate in Cells Below Point Value of Credit

Indicate in Cell Below Points for Credits

Fraser Basin Council

E3 Fleet System Results

City of Vancouver and Corp of Delta

- BC's First Gold Rated Fleets
- Corporate members:
  - Novex courier
  - Bell Canada
  - Canadian Springs
  - Hydro One

Emissions Reduction Impact in BC

- 150 fleet commitments to reduce emissions (40,000 vehicles)
- 15,000 vehicles with better performance
- Estimated emissions reductions since 2007:
  - 23,000 tonnes of greenhouse gases
  - 150 tonnes of NOx
  - 3 tonnes of PM2.5

Fraser Basin Council

Trucking Efficiency Examples

Promising Advancements:

- Hybrid trucks - Savings of 20-40% in urban environment
- Electric trucks- Coming soon to urban fleets
- Driver behavior changes - achieving early reductions

Fraser Basin Council


Opportunities for MORE Traction for Action:

- Join an influential and motivated collaboration
- Enhance support for real world demonstrations
- Increase influence on purchasers of fleet services
- Policy/regulatory support for technologies once viability is confirmed
- Continued support for the Council's knowledge, skills and relationships network

Fraser Basin Council

Thank You!

Fraser Basin Council

Hybrid Trucks

- Savings of 20-40% in urban environment
- Trucks now available from OEMs for class 3-7
- Strong interest from fleets
- Fuel savings don’t yet justify incremental cost (~$50k), but getting close

Electric Trucks

- Coming soon to urban fleets
- Zero tailpipe emissions
- Incremental capital costs much higher (e.g. 2-3X)
- First truck coming to Novex fleet soon…

Driver Training: Port Metro Vancouver

- Driver behaviour can affect performance by 10-20%
- Pilot training program for container trucking fleet (urban), with future work to build on results
- Combining with telematics provides ultimate tracking solution

Fraser Basin Council

Focusing on Rail Freight Transportation Emission Reductions

Normand Pellerin
Assistant Vice President
Environment

CN-WCI Transportation Collaborative
March 4 2010 • Vancouver, BC

OUTLINE

Rail Emission Sources

Regulatory Approach

Rail Emission Reduction Opportunities

Opportunities

Challenges

Key rail emission sources

- Line-haul locomotives
- Switch yard locomotives
- Other fleets: trucks, vehicles, cranes, tractors, gen sets, heaters and reefers
- Facilities: terminals, shops, and other buildings

A fragmented approach to regulation

Government of British Columbia	CARBON TAX
Government of Alberta	ASSISTANCE PROGRAM
Government of Quebec	CAP & TRADE – MODAL SHIFT
U.S. EPA	EMISSION REGULATIONS – LOCOMOTIVES AND ENGINES

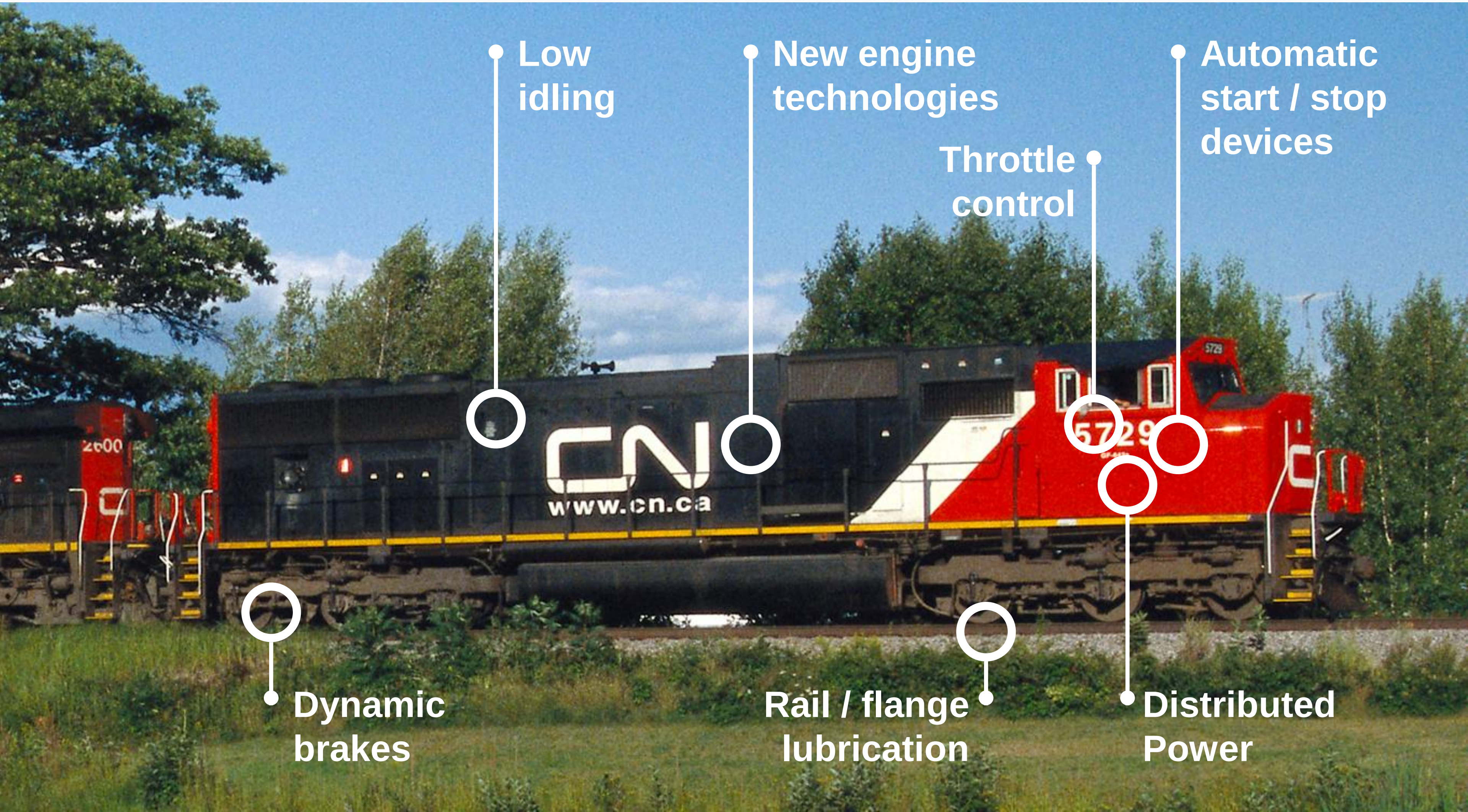
Tenacity is required

Voluntary programs and pending regulation

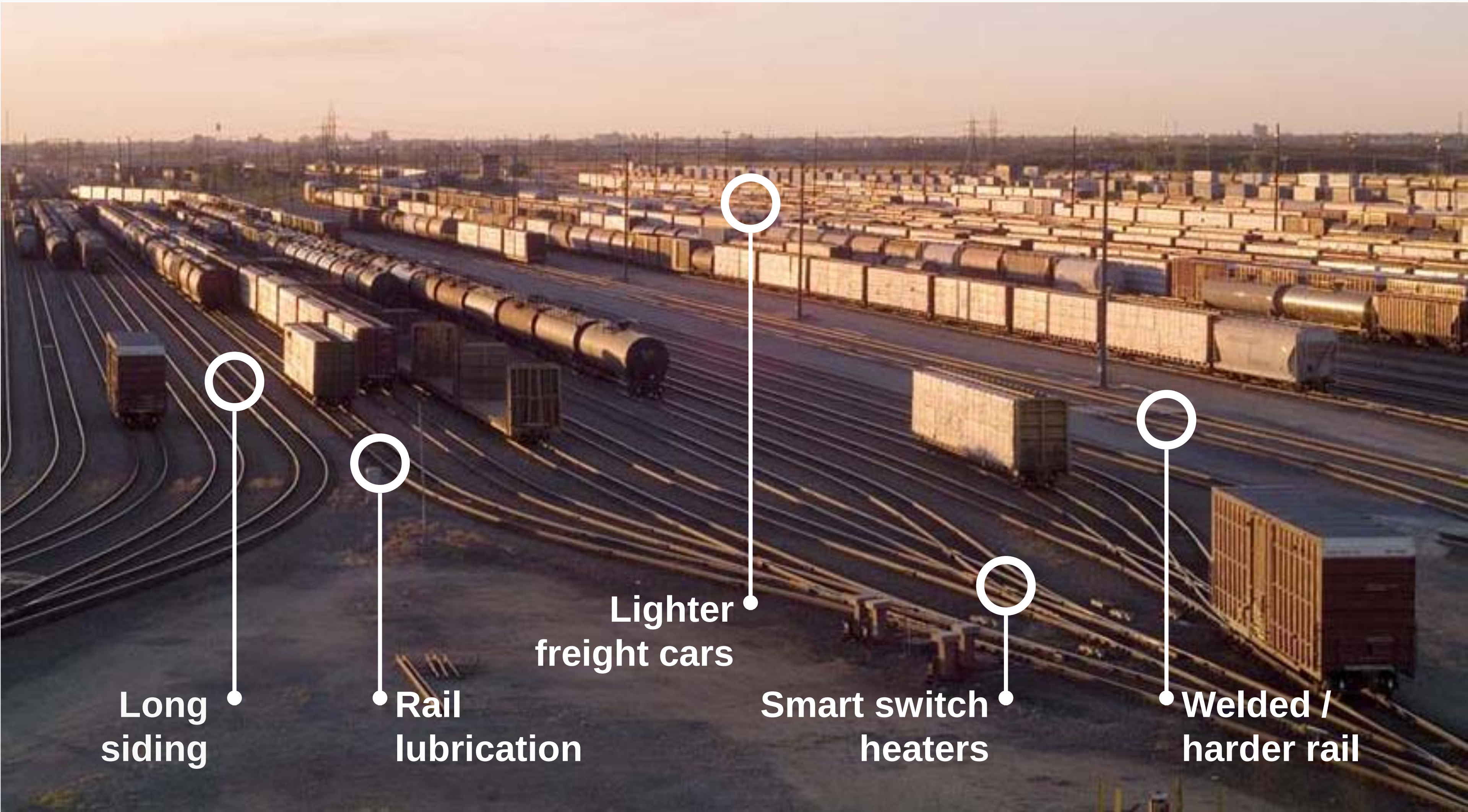
Environment Canada/RAC	Voluntary agreement to reduce emissions intensity over time
U.S. SmartWay Agreement	Increase energy efficiency while reducing air pollution & GHGs
Renewable Fuel Content	Increase % renewable content in diesel
Federal Government	Proposed emission standards following expiration of RAC MOU in 2010

Change = Risk and Opportunity

Rail emission reduction opportunities - new and upgraded locomotives



Rail emission reduction opportunities – on the rails and in yards



Rail emission reduction opportunities – operating and training for efficiency

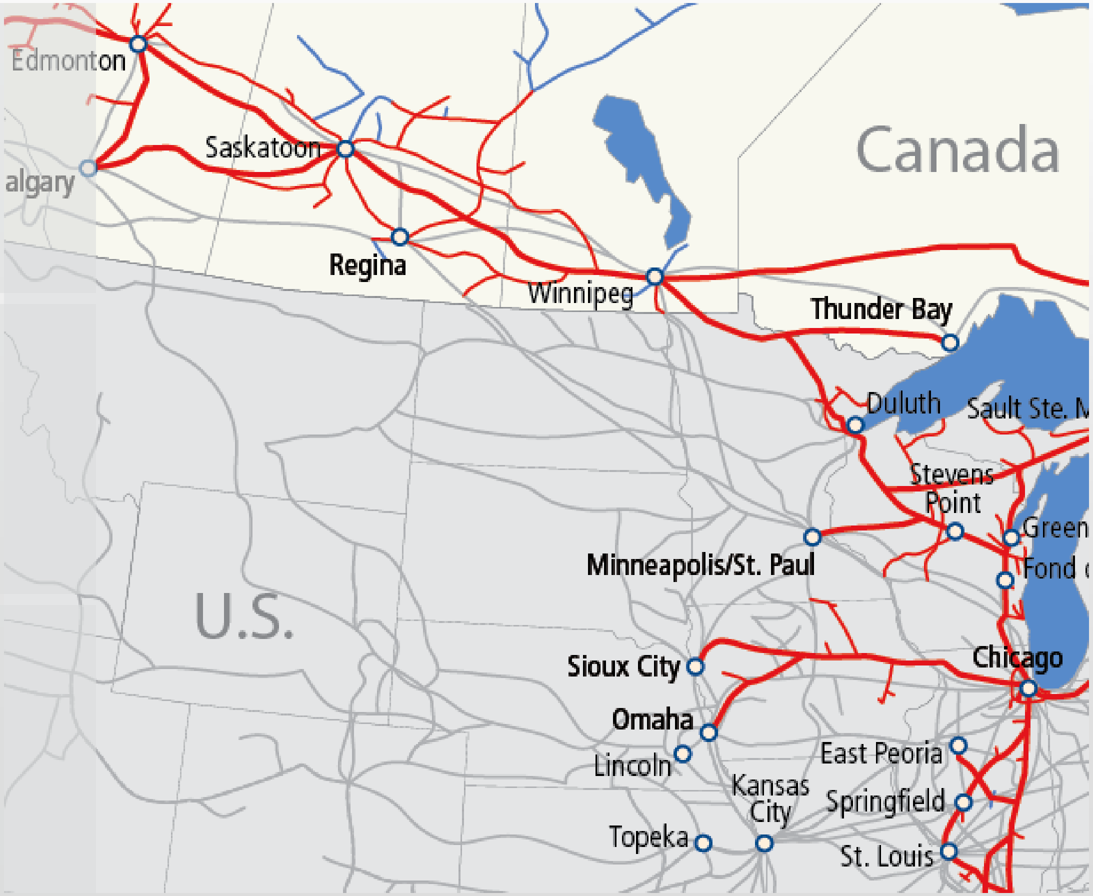
- Crew training focused on fuel conservation
- Locomotive shutdowns
- Streamlined car handling practices to switch only the number of cars needed
- Train pacing, coasting and braking strategies
- Notch limiting

Routing protocols and co-production - partnering to create efficiency

Routing protocols define the shortest, most efficient routes

Co-production leverages existing infrastructure to maximize fluidity and capacity

Results in less fuel used and minimizes the impact on the environment



Opportunities

- Operational efficiencies/costs
- Government R&D support
- Technological innovation
- Enhanced branding & positioning
- New/emerging markets
- Carbon credits

Challenges

- **Evolving regulatory landscape**
- **New technologies can present risks or costs**
- **Training is required to change the way we work/operate**
- **Industry measures and standards are required**

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Policies to Achieve Deep Emission Reductions in Transportation

Goods Movement Collaborative
March 4, 2010

Jotham Peters
M.K. Jaccard and Associates, Inc.

MKJA
MK Jaccard and Associates Inc

Outline

- Context
- Summary of key challenges with reducing emissions from transportation
- Policies available to induce emissions reductions

Context

- In British Columbia, greenhouse gas emissions from transportation accounted for 25 Mt CO_2e in 2005, representing over a third of total emissions.
- Under the Climate Action Plan emissions from transportation are expected to stabilize, but not decline.
- Reaching a 33% reduction from 2006 levels of emissions by 2020, and deep long-term targets for emissions in 2050 will require a more significant reduction from transportation.

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MK Jaccard and Associates Inc

Challenges reducing emissions in transportation

- Energy efficiency actions alone will not achieve deep reductions
- Abatement options to achieve deep reductions are not yet commercially available
  - Battery-electric vehicles
  - Battery exchanges for electric vehicles
  - Biofuels
  - Hydrogen

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Policy options to reduce emissions in transportation

- Carbon tax:
  - GHG Reductions:
    - Targets all decisions that affect emissions
    - Emissions of vehicle stock is uncertain
  - Compliance Costs:
    - Costs are limited to the price for emissions
- Tailpipe emissions standard:
  - GHG Reductions:
    - Emissions of vehicle stock is more certain
  - Compliance Costs:
    - Costs are less certain

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MK Jaccard and Associates Inc

Policy options to reduce emissions in transportation, continued

- Mandates for sales zero-emissions vehicles:
  - GHG reductions:
    - Very effective at inducing technological change
  - Costs of compliance:
    - Dependent on the cost of the low- or zero-emissions vehicles and the price for fuel
- Low-carbon fuel standard:
  - GHG Reductions:
    - Encourages the adoption of low- or zero-emissions fuels (i.e., biofuels, electricity)
    - Questionable whether this policy can effect upstream emissions, if these emissions occur outside the jurisdiction

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Concluding remarks

- There are likely to be trade-offs between the certainty of achieving an emissions reduction and the costs of compliance.
- Regulatory policies (such as the zero emission vehicle standard) are likely to provide greater certainty that zero-emissions vehicles will be commercialized.

Thank-you!
Questions?

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Policy	*Emissions Reductions*	*Compliance Costs*	*Induce Technological Change*
Carbon Tax	Pros: Targets all decisions that affect vehicle emissions.	Pros: Costs are limited to the price of the carbon tax	Pros: Uniform signal to innovate any process that affects emissions.
	Cons: Reductions are sensitive to other variables (e.g., price for oil).		Cons: Still sensitive to other variables.
Tailpipe emissions standards	Pros: More certain than carbon tax	Cons: Costs of the policy are uncertain.	Pros: Strong incentive to improve emissions intensity of vehicles.
	Cons: Does not influence vehicle use		Cons: No incentive to reduce emissions via other actions (e.g., improved public transit)

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<table>
<tr><th>Policy</th><th>Emissions Reductions</th><th>Compliance Costs</th><th>Induce Technological Change</th></tr>
<tr><td rowspan="3">Low carbon fuel standard</td><td>Pros: May influence upstream emissions from oil production</td><td rowspan="3"></td><td>Pros: Encourages development of biofuels.</td></tr>
<tr><td>Pros: Encourages biofuel adoption</td><td rowspan="2">Cons: Less likely</td></tr>
<tr><td>Cons: It is difficult to influence decisions outside your jurisdiction in a global economy</td></tr>
<tr><td rowspan="2">Information programs (e.g., Smartway)</td><td>Pros: Improves information.</td><td rowspan="2">Pros: Costs are minimal</td><td rowspan="2">Policy not intended to induce technological change.</td></tr>
<tr><td>Cons: Unlikely to have a significant effect if implemented by itself.</td></tr>
</table>

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Western Climate Initiative

WCI Recommendations for Implementing the Offset Limit

March 11, 2010

Background

As part of the design for the WCI Regional Cap-and-Trade Program, the WCI Partner jurisdictions recommended that a rigorous offset system be developed and implemented. The purpose of the offset system is to reduce compliance costs while encouraging emission reductions, innovation, and technology development for sources and sinks not covered by the cap-and-trade program.

The Design Recommendations for the WCI Regional Cap-and-Trade Program specify that a majority of emission reductions required under the program occur at covered entities and facilities. Consequently, for compliance purposes, the WCI Partner jurisdictions set a limit on the use of offset credits issued by WCI Partner jurisdictions, as well as the use of offset credits and allowances from other GHG emission trading systems that are recognized by the WCI Partner jurisdictions, to no more than 49 percent of the total emission reductions from 2012 to 2020. [1] This limit and rationale are established in the WCI's Design Recommendations (September 23, 2008). This document provides the Partners' recommendation on how this limit should be implemented.

To develop this recommendation, the WCI Cap Setting and Allowance Distribution (CSAD) Committee produced two background papers, conducted an in-person stakeholder dialogue, and solicited and carefully considered written comments from over 30 stakeholders. In May 2009, the CSAD issued a white paper (May 2009) describing options to address the following questions related to implementation of the WCI offset limit:

1. What mechanism should be used to impose the limit?
2. How should the offset limit be applied across jurisdictions?
3. How should the limit be applied across compliance periods?

On the basis of input received and further deliberations, the Committee developed a draft recommendation on how to implement the offset limit, which was posted for comment on October 6, 2009. The WCI Partners considered these comments in preparing the final recommendations presented here.

[1] It is important to note that where there is reference to the "offset limit", it should be understood to encompass not only offsets issued by WCI Partner jurisdictions, but also offsets and allowances issued by other GHG emission trading systems approved for use in the system by the WCI Partner jurisdictions.

Recommendations

The WCI Partners make the following recommendations for limiting the use of all offsets, and allowances issued by other GHG emission trading systems recognized by the WCI Partner jurisdictions (all such commodities hereafter referred to simply as "offsets"):

1. **The WCI Partners recommend limiting the use of offsets at the point of regulation[2].** The Partners find that limiting offset use is preferable to limiting offset supply; nearly all stakeholder comments concur with this finding. Compared to a supply limit, a use limit should result in lower overall compliance costs for covered sources.[3] Furthermore, the Partners recommend a use limit be applied as a percentage of compliance obligations (i.e., emissions) at the point at which WCI compliance will rest. This option provides predictability for covered sources, is relatively simple to implement, and minimizes both administrative and compliance costs relative to a supply limit.

2. **The WCI Partners recommend that a common offset use limit be implemented across Partner jurisdictions**. A common limit provides equal opportunity to covered sources across the WCI region, and helps to ensure that the overall limit will not be exceeded. However, as stated in the WCI Design Recommendations, each WCI Partner jurisdiction will have the discretion to set a lower limit. Several stakeholders recommended a differentiation of offset limits among jurisdictions to provide greater flexibility and to provide entities with more access to offsets where tighter emission reduction targets have been adopted. The CSAD Task 3 (competitiveness) group will consider whether the common use limit might pose competitiveness concerns for entities in jurisdictions that have adopted lower emission targets relative to historical levels, and if so, how to address these concerns.

3. **The WCI Partners recommend that the offset limit be set at an equal percentage of compliance obligations across compliance periods.** This option allows for the use of a greater number of offsets in earlier compliance periods (adjusting for the expansion of program scope in 2015), thus easing the transition into the cap and trade program. Some stakeholders favored increasing access to offsets over time either to encourage greater investment in emission reductions in early periods or to allow for greater offset

[2] The precise point of compliance (entity, facility, or other unit) for each type of emissions source is not the subject of this recommendations paper, and will be determined separately. However, for a better understanding of where compliance will rest, see section 2 of the September 23, 2008 Design Recommendation for the WCI Regional Cap-and-Trade Program.

[3] It is important to note that where there is reference to "covered sources", it should be understood to encompass: industrial sources, electricity producers and deliverers, and fuel deliverers, blenders and distributors.

use in later periods, when allowance prices are expected to be higher. The WCI Partners believe the recommended approach accommodates this form of cost control since covered sources may maximize their use of offsets in early periods in order to create and bank excess allowances for use in later periods, in lieu of where an increasing number of offsets would be permitted.

4. **The WCI Partners recommend no carry-over mechanism be added to the offset limit.** Considering that offsets themselves are fully fungible and that offset-to-allowance arbitrage can help to fully utilize offsets, the Partners find that the potential benefits of a carry-over mechanism are not worth the complexity it would introduce in the system design and administration. The Partners prefer to maintain the simplicity and certainty of the offset limit and therefore do not recommend the adoption of an offset carry-over mechanism.

5. **The WCI Partners recommend that changes in membership of the WCI cap-and-trade program not affect the offset limit established at the start of the program unless those changes cumulatively result in an increase to the offset limit equal to or greater than one half of a percentage point.** While changes in membership might affect the calculation of the offset limit (to reflect 49% of emissions reductions), the more important consideration is to establish a clear and predictable offset limit so that covered sources and offset project developers can make plans and investments accordingly. Partners will proceed with increasing the offset limit only when new membership would cumulatively result in an increase to the offset limit equal to or greater than one half of a percentage point.

For a description of the offset limit options considered and the criteria and process used to arrive at these recommendations, see the Offset Limit Draft Recommendations Paper and public comments posted on the WCI website.

Western Climate Initiative News

March 30, 2010

This status report is issued monthly from WCI Partner jurisdictions to all interested stakeholders via the WCI list server and website.

In This Issue

WCI Partners Welcome New Canadian Co-Chair

WCI Partners Approve Final Recommendations on Limiting the Use of Offsets

WCI Electricity Team Invites Stakeholder Comment on Documents Regarding Electricity Imports

Material Available from WCI Partners Meeting and Goods Movement Collaborative

New Mexico Seeks Public Comment on Draft Document Outlining Options for Greenhouse Gas Emissions Trading in New Mexico

State of Washington and WCI Hosting a Benchmarking Symposium

Upcoming Events

April 14: Partners Meeting and Stakeholder Dialogue in San Francisco

The next WCI Partner meeting will be April 14 in San Francisco, CA at the Sir Francis Drake Hotel. Click here and register if you plan to attend in person. The meeting will take place from 9:00 am to 12:30 pm. Following the meeting, the WCI Partners will host a stakeholder dialogue at the nearby Marriot Marquis Hotel from 3:30 to 5:00 pm. This time and venue will enable broader stakeholder participation, as well as coordination with pre-conference activities of the annual Navigating the American Carbon World conference. Details on the WCI meetings will be posted to the website and distributed via the WCI list server when available.

May 19: Benchmarking Symposium in Seattle

The symposium, described in the adjacent column of this newsletter, will take place from 8:30 am to 4:30 pm in downtown Seattle, WA. The exact location and other details will be posted to the WCI website and distributed via the WCI list server when available.

WCI Partners Welcome New Canadian Co-Chair

At their March 3 meeting in Vancouver, the WCI Partners thanked Tim Lesiuk (Province of British Columbia) for his leadership serving as the WCI Canadian Co-chair during the 2009 term. The Partners welcomed Robert Noel de Tilly (Province of Québec) as the new WCI Canadian Co-chair for the 2010 term.

WCI Partners Approve Final Recommendations on Limiting the Use of Offsets

To assure a majority of emission reductions required under the cap-and-trade program occur at covered entities and facilities, the WCI Cap Setting & Allowance Distribution Committee released draft recommendations in October 2009 to limit the use of offsets issued by the WCI, as well as offsets and allowances issued by other trading systems that are recognized by the WCI Partner jurisdictions, to no more than 49 percent of the total emission reductions from 2012 to 2020. The WCI Partners considered public comments on the draft recommendations, further discussed the recommendations at their March 3 meeting in Vancouver, and have since approved the recommendations with some modifications. The final recommendations are available here.

WCI Electricity Team Invites Stakeholder Comment on Documents Regarding Electricity

May 20: Partners Meeting in Seattle
The specific location and agenda for this meeting will be posted to the website and distributed via the list server when available.

Imports

On February 18, the WCI Electricity Team posted three documents to the WCI website that were presented at the January 21 Electricity Industry Collaborative and invited stakeholder input on these documents. Interested stakeholders that have not yet submitted their comments should do so as soon as possible. Click here to access and comment on the Draft Open Access Technologies Inc. (OATI) analysis of electricity imports in the Western Electricity Coordinating Council (WECC) region. Click here to access and comment on the 2006 Draft Default Emissions Factor Calculator and the 2007 Draft Default Emissions Factor Calculator.

Material Available from WCI Partners Meeting and Goods Movement Collaborative

Material and presentations from the March 3 Partners Meeting and March 4 Goods Movement Collaborative in Vancouver, BC are available on the WCI website. The Partners meeting was an opportunity for Partners to continue their collective work to develop a detailed design for the WCI cap-and-trade program. The detailed design will represent the cumulative set of decisions Partners have made through the WCI committee work. Partners also discussed regional collaboration on complementary policies and broader action to advance clean energy with other regional and national initiatives. The Goods Movement Collaborative was a chance for Partners to engage with representatives of various transportation industry sectors (marine, rail and truck) and identify specific emissions reduction opportunities and opportunities for continued engagement.

New Mexico Seeks Public Comment on Draft Document Outlining Options for Greenhouse Gas Emissions Trading in New Mexico

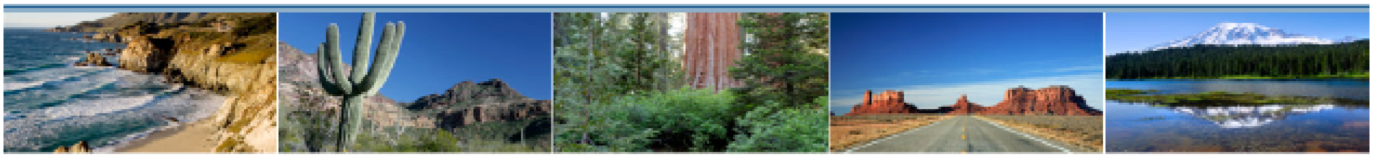
On March 16, the New Mexico Environment Department released a draft issues paper, consistent with the Design Recommendations of the WCI, on Greenhouse Gas Emissions Allowance and Trading in New Mexico. "It's important for the [New Mexico] Environmental Improvement Board to adopt a cap-and-trade program that will best suit the needs of our state," said New Mexico Environment Department Secretary Ron Curry. "This paper helps to clarify the options that are available for us." Click here for the paper and to submit comments.

State of Washington and WCI Hosting a Benchmarking Symposium

The Washington State Department of Ecology and the WCI will host a Greenhouse Gas (GHG) Benchmarking Symposium from 8:30 am to 4:30 pm on May 19 in downtown Seattle, WA (location to be announced). A GHG benchmark is a quantity of emissions per unit of industrial output or production, and is meant to enable comparison of facilities according to a common measure. Speakers, panelists, and participants at the symposium will address a number of topics and discuss questions such as:

- What are industry GHG benchmarks?
- What role can benchmarks play under various policy approaches to reducing GHG emissions, such cap-and-trade programs, performance standards, or voluntary actions?
- What are the benefits and challenges of developing and applying benchmarks?

Western Climate Initiative



Electricity Leakage Analysis Summary Report

March 2009

Electricity Sub-committee
Western Climate Initiative

Prepared by:

Snuller Price, Arne Olson and Amber Mahone
Energy and Environmental Economics, Inc.

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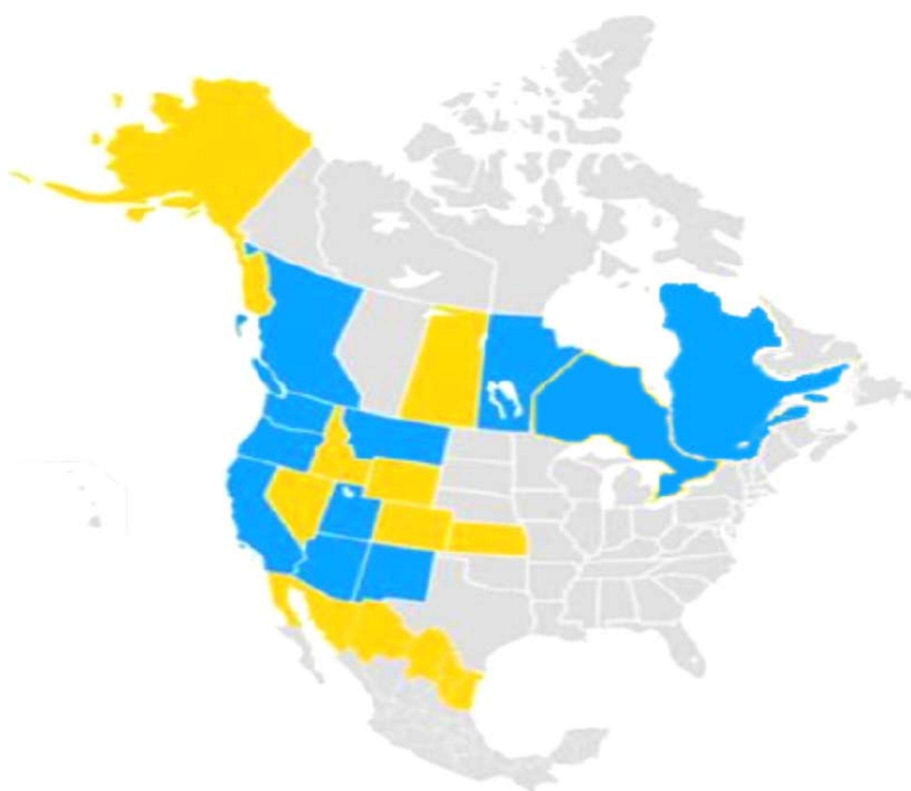
<u>Contact Information for Technical Questions</u>

Snuller Price, Partner
Energy and Environmental Economics, Inc.
101 Montgomery Street, Suite 1600
San Francisco, CA 94104
(415)391-5100
snuller@ethree.com

1 Introduction

The Western Climate Initiative (WCI) is a collaboration between seven U.S. Governors and four Canadian Premiers. Its purpose is to facilitate a way for WCI Partners to reduce total greenhouse gas (GHG) emissions in the region to 15 percent below 2005 levels by 2020.[1] The regulatory structure and rules governing the WCI are still under development by Partner states and provinces; however it is clear that the WCI will focus on a market-based cap and trade program as one means of achieving this collective emissions reduction goal. Figure 1 below shows the WCI Partner states and provinces in blue and the WCI Observer states and provinces in yellow.

Figure 1. WCI Partner and Observer States and Provinces

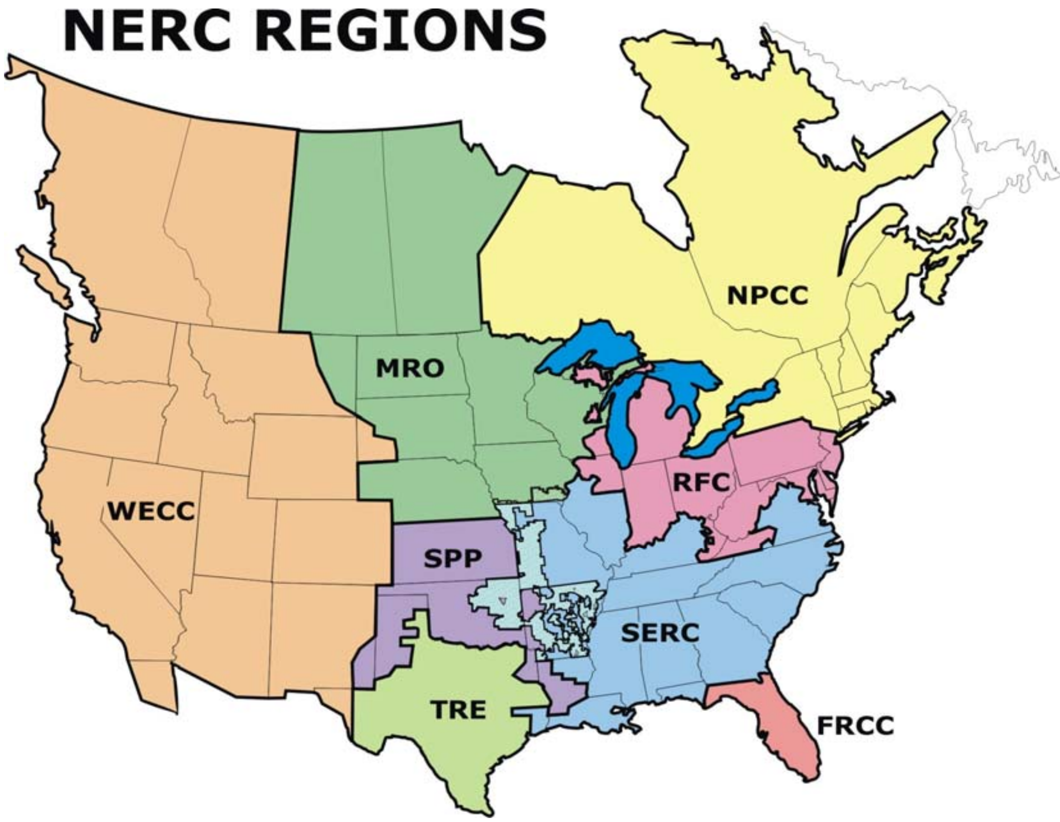


[1] Thirteen Western states and provinces are observers to the WCI but are not currently committed to a greenhouse gas reduction target. More information about the WCI is available at www.westernclimateinitiative.org

In September 2008, the Western Governor's Association engaged Energy and Environmental Economics, Inc. (E3) to investigate the potential for 'leakage' of greenhouse gas emissions from the electricity sector under the WCI. In greenhouse gas regulation terminology, 'leakage' in the electricity sector refers to the potential for a shift in electricity generation from sources in GHG regulated jurisdictions to jurisdictions without such regulation. Leakage from the regulated regions can undermine the cap and trade market by distorting actual emissions levels and providing incentives to shift, rather than reduce, GHG emissions.

The potential for leakage exists because not all of the states and provinces that WCI jurisdictions can trade electricity with have adopted GHG caps that are equivalent to the WCI GHG cap. In the North American Electric Reliability Corporation (NERC) Regions, such as the Western Electricity Coordinating Council (WECC) (where the majority of the WCI states and provinces are located), or the Northeast Power Coordinating Council (NPCC) (where Ontario and Quebec are located), electricity moves relatively freely across the system. Figure 2 shows that many of the states and provinces in the WECC and NPCC regions are not Partners in the WCI (WCI Partners are shown in blue in Figure 1). Therefore, to assess leakage potential, we evaluate how well the proposed WCI regulations would track GHG obligations associated with electricity flows between WCI and non-WCI states and provinces.

Figure 2. North American Electric Reliability Corporation Regions[2]



To perform the WCI leakage analysis, we make use of the detailed 2020 WECC system dispatch simulation completed in early 2008 for the California Public Utilities Commission (CPUC), the California Energy Commission (CEC), and the California Air Resources Board (CARB). This earlier modeling effort sought to analyze California's greenhouse gas policy options in the electricity sector. Using the generator dispatch and CO_2 emissions data from that modeling work, we were able generate estimates of the potential for leakage among the Western WCI members.[3] E3 did not have similar data available for Manitoba, Ontario, or Quebec, so these Partner provinces are not included in the analysis. This summary report provides an overview of the analysis performed for the WCI and presented to the WCI Electricity Subcommittee Technical Working Session in Salt Lake City, Utah on October 16th, 2008.

[2] Image source: http://www.nerc.com/page.php?cid=1|9|119

[3] E3 performed the original modeling work, on which this WCI analysis is based, for the CPUC and CARB under the CEC and CPUC's Joint-Agency Rulemaking on Greenhouse Gas Regulatory Strategies in California (CPUC R.06-04-009/CEC #07-OIIP-1). Documentation of this work is available on the E3 website at: http://www.ethree.com/CPUC_GHG_Model.html

1.1 WCI Electricity Sector Design Recommendations

Since its launch in February 2007, the WCI Partners have been working to design a comprehensive greenhouse gas emissions reduction plan. On September 23rd, 2008, the WCI released proposed reporting standards for emissions and design recommendations for a cap and trade emissions reduction scheme. The Design Recommendations suggest that electricity sector emissions generated within WCI Jurisdictions, and emissions from electricity generated outside of the WCI that is delivered to a WCI Partner Jurisdiction for consumption in the WCI, should be included in the WCI regulatory approach.

The Design Recommendations also state that for the electricity sector, the point of regulation is the First Jurisdictional Deliverer (FJD). The FJD is defined in the following way: "For sources within WCI jurisdictions the FJD is the generator. For power that is generated outside the WCI jurisdictions (or generated by a federal entity or on tribal lands) for consumption within a WCI Partner jurisdiction, the FJD is the first entity that delivers that electricity over which the consuming WCI partner jurisdiction has regulatory authority."[4]

To understand how FJD might become operational in the WCI it is useful to define several key terms.[5] These are 1) specified imports, 2) unspecified imports, and 3) a deemed emissions rate.

- *Specified imports:* Electricity imports into WCI jurisdictions whose CO_2 content is known and claimed by the FJD. These imports are called 'specified' because they are designated by the deliverer as originating from a specific generator.
- *Unspecified imports:* Electricity imports whose source is not known, such as purchases from a non-WCI trading hub, and thus whose CO_2 obligation is not

[4] Western Climate Initiative, September 23rd 2008, "Design Recommendations for the WCI Regional Cap-and-Trade Program," Section 2.2, pg. 3. Available at: http://www.westernclimateinitiative.org/ewebeditpro/items/O104F20432.PDF

[5] For additional background, see the November 10th 2008, "Straw Proposal on Reporting GHG Emissions Associated with Electricity Imported from non-WCI Jurisdictions." Available at: http://www.westernclimateinitiative.org/ewebeditpro/items/O104F20477.pdf

known. These imports may also be referred to as market purchases or power pool purchases.

- *Deemed emissions rate:* The CO_2 emissions rate (CO_2 per MWh) applied to unspecified imports into the WCI. The WCI Partners have not yet decided how a deemed emissions rate might be selected and implemented in the WCI.

This report takes the WCI Design Recommendations as a starting point, and seeks to quantify the leakage potential under different regulatory scenarios. The regulatory scenarios analyzed in this report are used as a means of analyzing some of the important considerations regarding the implementation of FJD to reduce leakage. The report also highlights some of the important design choices for an FJD point of regulation which are still under development by the WCI partners, such as considerations in setting the deemed emissions rate for unspecified electricity imports into WCI Jurisdictions and the importance of tracking coal generation located outside of the WCI which delivers power into WCI jurisdictions.

2 Research Questions

To understand the potential challenges to implementing and enforcing an environmentally rigorous cap and trade program in the WCI electricity sector, we identify three key, related issues: 'coverage', 'shuffling' and 'leakage'. Together, these concepts address important electricity sector considerations for developing a cap and trade program.

'Coverage' is measured as the share of emissions attributable to WCI consumption that is captured by the market design. Thus, the key question we investigate related to coverage is:

- How well does the WCI system cover the actual CO_2 emitted by the electricity sector associated with electricity consumption in WCI Jurisdictions?

Higher coverage is reflective of a more comprehensive GHG regulatory strategy. The key determinant of coverage in the electricity sector is the treatment of emissions generated outside the WCI but delivered into a WCI jurisdiction. After assessing the coverage of different regulatory strategies, we then consider the potential for contract 'shuffling.'

Shuffling is defined as an action that reduces regulated CO_2 obligations without any actual change in power plant operations or reduction in actual emissions. Contract shuffling is basically an accounting problem. Because generators in the WCI will be regulated at the source, contract shuffling is limited to changes in the attribution of the sources of power imported from non-WCI locations. An example of contract shuffling would be if the obligation for CO_2 emissions from a non-WCI coal plant could be shifted from a WCI jurisdiction to a non-WCI jurisdiction, without actually reducing the emissions from the coal plant. For example, the Deliverer of the energy from a non-WCI coal plant to a WCI Partner state may sell the energy from the coal plant to a non-WCI load serving entity (LSE) and then buy energy from a non-WCI hydro facility to deliver to the WCI. The key question regarding contract shuffling is:

- What is the potential to reduce the amount of CO_2 accounted for in the WCI by changing power contracts and power sales, without actually changing total CO_2 emissions?

The third potential source of problems with electricity sector GHG regulation is 'leakage.' Leakage is defined as a shift in power plant operations or investment from WCI to non-WCI jurisdictions, which reduces WCI CO_2 emissions while increasing non-WCI CO_2 emissions. An example of this would be if a coal-fired generator were built outside of the WCI jurisdictions in order to serve WCI electricity demand, and then delivered electricity to the WCI without incurring the full CO_2 obligation associated with the coal generation. We identify two related questions to investigate with regard to leakage:

- What is the potential to change *generator operations* to shift CO_2 emissions from the WCI to non-WCI jurisdictions?
- What is the potential to change *new generation investment* choices to shift CO_2 emissions from the WCI to non-WCI jurisdictions?

3 Analysis Approach

There are many possible analytic approaches which could address the four research questions described above. In this project, we sought to build on prior analysis which E3 performed for the CPUC and the CARB in 2007 and 2008 to analyze California's greenhouse gas policy options in the electricity sector. For the CPUC and CARB project, we developed a 2020 forecast of generation, CO_2 emissions and transmission flows based on the results of a production simulation dispatch model, called PLEXOS.[6] The PLEXOS model uses a least-cost, constrained dispatch algorithm to simulate how generators in the WECC would likely operate in 2020. PLEXOS contains a full model of generators in the WECC and the WECC high voltage transmission system, and provides hourly energy flows across each major transmission line in the WECC.

Using the PLEXOS results, we were able to estimate the generator dispatch, emissions levels, and the imports and exports between major WECC 'zones' based on estimates of 2020 generation, loads, forecasted fuel costs and variable costs. This strategy to leverage existing modeling work allowed this WCI leakage analysis to be completed within a one-month time frame. However, this strategy also means that the analysis was limited by the availability of pre-existing modeling data. The data used in this analysis is based on a single snapshot of forecast generation and transmission in 2020 in the WECC and Manitoba, Ontario and Quebec are not included in the analysis. In addition, we were not able to apply differential CO_2 prices in WCI versus non-WCI jurisdictions to estimate how different CO_2 prices or fuel prices would affect the generator dispatch.[7] However, we believe that our findings are robust across reasonable ranges of natural gas and CO_2 prices, and that the PLEXOS data is useful to apply for the purposes of this analysis.

The results of the PLEXOS generator dispatch simulation allow us to estimate the energy production for each generator in the WECC. Figure 3 below shows the percentage of energy generated by fuel-type for generators located in WCI and non-WCI jurisdictions. As the figure shows, 16% of the energy produced by generators located in the WCI use coal, and over 50% of the non-WCI's generation is expected to come from coal. This is significant for GHG regulation, because coal-fired generation produces approximately twice the CO_2 emissions per MWh as natural gas-fired generation.

[6] More information on the PLEXOS software and analysis team is available at http://www.plexossolutions.com/

[7] In the model, natural gas and coal prices are based on forecasts from March 2008 NYMEX forward price data. 2020 California natural gas prices are forecast at $7.85/MMBtu and 2020 coal prices are forecast at $1.01/MMBtu in real 2008 dollars.

Figure 3. 2020 Generation by Fuel Type in WCI and Non-WCI Jurisdictions (including tribal land located in WCI states) within the Western Electricity Coordinating Council

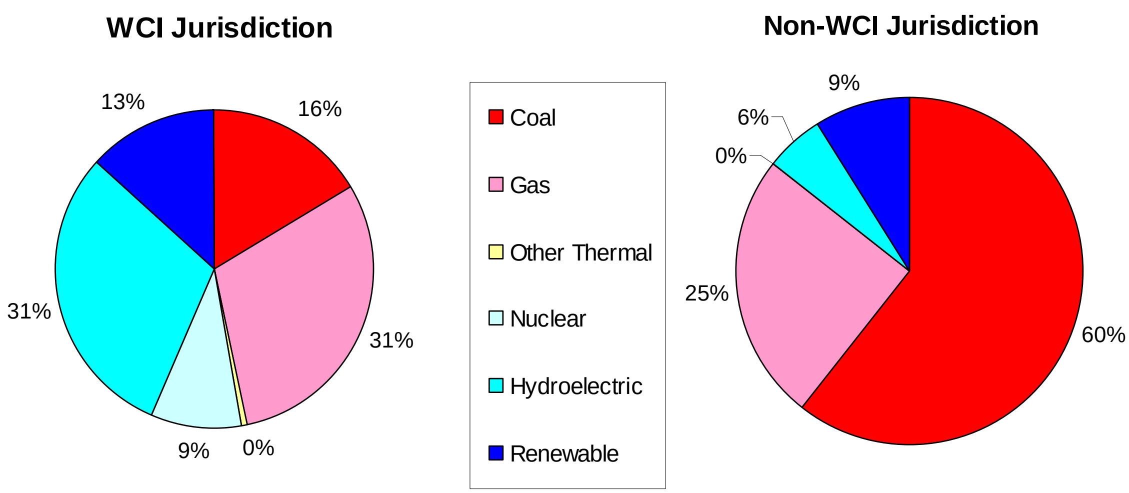


Table 1 below shows the same data as Figure 3 above, but shows actual generation in terms of 2020 forecasted energy (GWh). The coal generators located on tribal lands include Navajo, Four Corners and the proposed Desert Rock coal plant, which is projected to be operational by 2020. Although these generators are physically located within Arizona and New Mexico, which are both WCI Partner states, regulation of the emissions from these generators would not fall within the purview the WCI because they are located within Native American reservations.

Table 1. 2020 Generation by Fuel Type in WCI and Non-WCI Jurisdictions within the Western Electricity Coordinating Council

Regulation at the Source
Generation (GWh)

	WCI	Non-WCI	Tribal Lands	TOTAL
Coal	126,675	146,510	42,556	*315,741*
Gas	233,015	77,355	0	*310,371*
Other Thermal	3,257	0	0	*3,257*
Nuclear	72,512	0	0	*72,512*
Hydroelectric	231,716	17,477	0	*249,193*
Renewable	103,298	27,653	0	*130,951*
TOTAL	*770,473*	*268,995*	*42,556*	*1,082,024*

4 Coverage Results

Before evaluating the potential for contract shuffling or leakage, it is important to first understand how much of the WCI's electricity sector emissions would be covered under different regulatory regimes. As discussed above, 'coverage' is measured as the share of CO_2 emissions attributable to WCI consumption that is captured by the market design.

4.1 Approach

In this section we address the question: "How well does the WCI regulatory system cover the actual CO_2 emitted by the electricity sector associated with electricity consumption in WCI states?" Since the details of the FJD point of regulation are still under development, it is not possible to answer this question will full certainty. Therefore, we bound the problem by estimating two book-ends, representing the amount of emissions which would be covered under two different regulatory approaches. We then discuss how coverage under the WCI-proposed FJD regulatory approach could vary, depending on the ultimate FJD rules. The 'book-ends' of emissions coverage evaluated here represent two regulatory scenarios:

- *The 'source-based' point of regulation*. A source-based point of regulation is defined as a regulatory approach that only covers emissions from generators which are physically located within the WCI. The source-based approach would not regulate any emissions associated with imported electricity. Because the source-based point of regulation does not regulate imported electricity, it is the low 'book-end' in the analysis.

- *The 'consumption-based' point of regulation*. We define a consumption-based point of regulation as an approach which would account for the emissions from all generators producing electricity for consumption within the WCI. Thus, in this approach, the physical location of the power plant is not important. Since it is impossible to actually track electrons from a power point to the load source, the consumption-based regulatory approach is a theoretical construct rather than an actual regulatory strategy. In this analysis we approximate a consumption-based approach by using known utility contract and ownership data to assign emissions to loads. This approach is imperfect, because we do not have complete

> information about all contracts and generator ownership – many of these contracts are confidential, and many contractual relationships will change by 2020. Thus, the consumption-based emissions estimate represents our best estimate of the actual emissions associated with electricity consumption in WCI Partner jurisdictions. The consumption-based analysis results in a higher estimate of WCI electricity sector emissions because it includes the estimated carbon content of imported electricity.

Developing an estimate of the source-based emissions is a fairly straightforward accounting task which simply requires assigning generators to WCI and non-WCI jurisdictions based on their physical location. In contrast, developing the consumption-based emissions estimate requires some research into the individual contracts and ownership of generators by LSEs.[8] The main focus of this research on generator contracts and ownership was to correctly assign the coal generators to WCI and non-WCI jurisdictions for the purpose of assessing regulatory coverage, contract shuffling and leakage potential. This research revealed that currently, nearly every coal generator in the WECC is owned or directly contracted by a utility. In other words, there is currently very little unspecified coal generation in the WECC power pool. This finding is significant because if WCI FJD regulations could successfully track these coal contracts, the integrity of the WCI GHG cap could be improved. The implications of this finding will be discussed in more detail in the sections 5 and 6 of this report.

A secondary focus was to assign hydroelectric, renewable, and nuclear generation to WCI and non-WCI jurisdictions. E3 did not attempt to assign specific natural gas generators directly to jurisdictions in this analysis; instead, natural gas CO_2 emissions were treated as a 'residual' and the average natural gas mix was assigned to the remaining load in each region after the coal, hydro, nuclear, and renewable generation was assigned.

For example, in the consumption-based approach, if an LSE which operates in California owns a percentage of the output of a coal plant located in Utah, that share of the coal plant's CO_2 emissions would be assigned to the California load serving entity. As another

[8] A spreadsheet containing E3's assumptions about the assignment of generators to load serving entities and states is available on the E3 website at: http://www.ethree.com/E3_Public_Docs.html

example, if a load serving entity's service territory spans both WCI and non-WCI states, the emissions from the LSE's generators would be assigned to the WCI and non-WCI states proportionally to their load in both jurisdictions under a consumption-based regulatory approach. Under a source-based approach, only the physical location of the generators would matter, not the utility service territory.

The ratio of the source-based emissions to the consumption-based emissions provides an estimate of the percentage of the total WCI electricity sector emissions which would be covered by a source-based regulatory approach.

4.2 Findings

Our analysis suggests that if the CO_2 associated with the imports of electricity were not regulated, as would be the case under a source-based point of regulation, approximately 74 percent of the electricity sector's emissions would be covered by the WCI in 2020. This estimate is based on the ratio of the emissions which would be covered under a source-based point-of-regulation (216 million metric tons (MMT) of CO_2), to the emissions which would be covered by a consumption-based point-of-regulation (293 MMT of CO_2).[9]

Table 2 and Table 3 below represent the 2020 estimated CO_2 emissions of WCI and non-WCI jurisdictions based on the source-based emissions accounting approach and the consumption-based emissions accounting approach.

Table 2. 2020 Greenhouse Gas Emissions by Jurisdiction Based on Accounting for Emissions at the Source

Regulation at the Source
MMT CO2

	WCI	Non-WCI	Tribal Lands	TOTAL
Coal	122	145	41	*309*
Gas	90	30	0	*119*
Other	4	0	0	*4*
TOTAL	*216*	*175*	*41*	*432*

[9] 216 MMT CO2 ÷ 293 MMT CO2 = 74%

Table 3. 2020 Greenhouse Gas Emissions by Jurisdiction Based on Accounting for Emissions Based on Consumption

Regulation based on Consumption
MMT CO2

	WCI	Non-WCI	TOTAL
Coal	179	129	*309*
Gas	110	9	*119*
Other	4	0	*4*
TOTAL	*293*	*139*	*432*

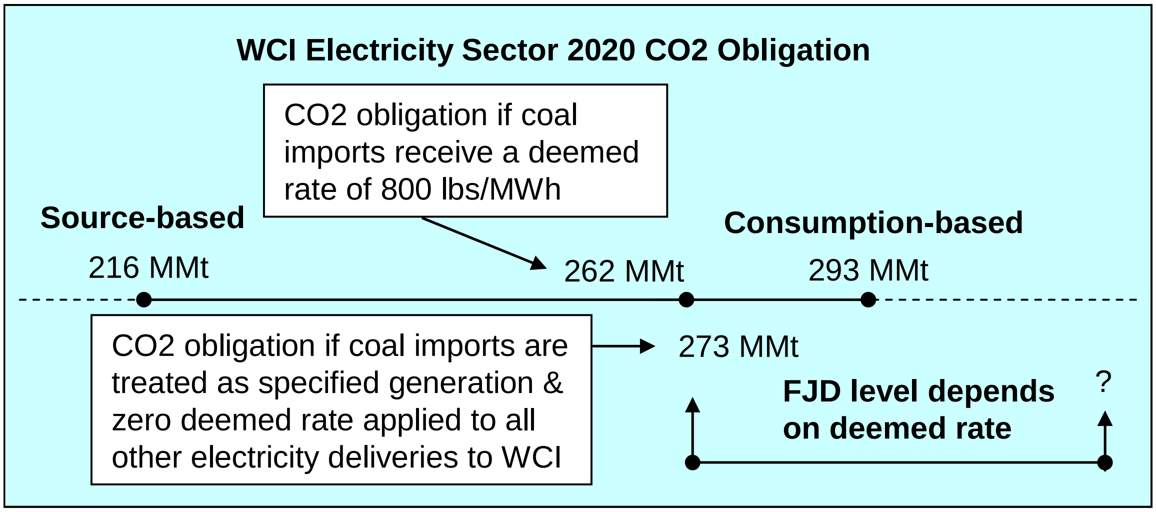
The WCI-recommended approach of applying the FJD point-of-regulation could result in a coverage level which is close to the consumption-based emissions estimate. How close the FJD coverage level ultimately is to a consumption-based emissions level will depend on the rules for FJD which are ultimately adopted, including the deemed emissions rate applied to unspecified imports and the treatment of non-WCI coal generation which is delivered into the WCI.

Figure 4, below, compares the CO_2 obligation under a purely source-based approach versus a consumption-based approach, and highlights the importance of the deemed emissions rate for unspecified power in determining the level of coverage achieved by the WCI. If the deemed rate is set to zero, and all coal imports are regulated as specified generation, then the coverage improves from 216 MMT CO_2 to 273 MMT $CO_{2.}$

If the deemed rate is set close to the ‘actual’ average emissions intensity of unspecified generation, which currently is mostly natural gas-fired generation, the FJD approach could approach the theoretical consumption-based emissions coverage level. It is important to note that the emissions intensity of unspecified generation will vary by hour and by region. Therefore, it is not possible to select a single, fixed deemed emissions intensity rate which will always result in the same emissions obligations to all Deliverers as the consumption-based approach.

Also, recall that currently nearly all coal-fired generation represents specified power. Whether this remains true going forward will depend, in part, on how FJD regulations are constructed to track existing coal ownership and coal contracts. However, even under the best regulatory strategy, it may not be possible to guarantee that currently specified coal generation will remain specified power in the future. If specified coal generation switches to unspecified power by operating in a merchant generation mode, for example, this could reduce the electricity-sector coverage of the WCI system, and increase the challenges surrounding the deterrence of GHG leakage and shuffling.

Figure 4. Estimate of the Emissions of the WCI Electricity Sector in 2020 Based on Different Regulatory Approaches



To demonstrate how the deemed emissions intensity of the FJD approach could result in different levels of emissions coverage, consider two possible cases.

1) In case 1, all coal contracts and coal ownership contracts with utilities serving WCI load are known. If it were possible to track all of the emissions from these specified coal power plants, their power deliveries to the WCI could be tagged with their actual emissions intensity. The remaining, unspecified electricity deliveries into the WCI would face a deemed emissions rate. If the deemed rate is zero, the resulting WCI electricity sector CO_2 obligation would be 273 MMT CO_2. This is 20 MMT lower than the more accurate consumption-based approach, but still significantly improved over the source-based regulatory approach. Here, 93% of the GHG emissions from the electricity sector are covered under the WCI, compared to the consumption-based theoretical maximum. At a deemed emissions rate closer to 800 or 900 lbs/MWh for unspecified system power coverage will approach 100% of the consumption based theoretical maximum, assuming coal contracts can be separately tracked and tagged with their actual emissions rate.

2) In case 2, specified coal ownership and contracts of out-of-state coal generators ***cannot*** be tracked. In this case, all coal power delivered to WCI jurisdictions would receive a

deemed emissions rate instead of their actual emissions rate. For purposes of this example, if a deemed rate of 800 lbs/MWh were applied to all coal-fired power delivered to the WCI, coverage would decrease by 31 MMT CO_2. Thus, the total coverage of the WCI system would be reduced to 262 MMT CO_2. In this scenario, coverage would be approximately 89% of the theoretical ideal of the consumption-based approach. Another possibility, if specified coal contracts cannot be tracked, is to set the deemed CO_2 emissions rate closer to that of a conventional coal plant (eg. 2,200 lbs CO_2/MWh). In this case, deliveries of power into the WCI from natural gas generation with lower emissions intensities would most likely switch to specified generation to avoid being assessed at the higher deemed emissions rate. In addition, market purchases with unknown origin would receive the emissions rate of coal, most likely driving power out of the market pool and into specified power contracts. This could decrease market liquidity. With a deemed emissions rate of 2,200 lbs CO_2/MWh coverage of the WCI system would be high, although the extent of coverage under this system would depend on power marketers behavior in response the high deemed rate.

These scenarios demonstrate that coverage can be greatly improved by tracking, to the extent possible, emissions from specified generation, especially of existing non-WCI coal generation that is delivered into the WCI. The deemed emissions rate could then be used simply to improve coverage of the remaining, unspecified power pool electricity deliveries, which should be mostly natural gas generation once the coal contracts are tracked separately. Conversely, if emissions from specified coal generation is not explicitly accounted for, it becomes problematic to set a single appropriate deemed rate, because both coal and gas would receive the same emissions rate despite their very different emissions profile. Setting a deemed emissions rate also reduces the incentive for contract shuffling and leakage which can affect the effectiveness of the regulatory system, as discussed in sections 5 and 6.

Figure 4, above, also shows that if the deemed rate is set too high (low), the WCI may end up with a higher (lower) CO_2 obligation than it should. On the high end, the CO_2 obligation could increase indefinitely, depending on the deemed rate, until the point at which energy deliverers find it more attractive to either 1) curtail energy deliveries, or 2) specify the source and emissions content of all electricity imported into the WCI. This outcome would have a deleterious effect on the liquidity of energy markets.

This analysis of coverage highlights the importance of accounting for the carbon content of electricity imports into the WCI to the extent it is practical to do so. The FJD recommendation seems to be an appropriate method of ensuring that the coverage of the WCI electricity sector emissions exceeds 74 percent. The coverage analysis discussed here also helps to provide some insights regarding the upper bound on the potential for contract shuffling, as discussed in the next section.

5 Contract Shuffling Results

Contract shuffling is an action that reduces regulated CO_2 obligations without any change in operations or total emissions. Since all generators located in WCI partner jurisdictions will be regulated under FJD, the potential for shuffling only exists for generators located outside the WCI. We identify two principle types of contract shuffling:

1) ***Specified power → lower-carbon, specified power:*** Emissions could be 'shuffled' from specified generation with a high CO_2 content to specified generation with a lower CO_2 content. In this case, imported power is shifted from a relatively dirty source to a relatively clean generation source. Total emissions, however, would remain unchanged. If, for example, it was possible for a WCI jurisdiction to swap some of its specified, imported power from coal to hydro or natural gas, without resulting in a change in either the coal plant or the hydro or natural gas facility's operational patterns, the emissions of the coal plant would be 'shuffled' to zero (in the case of shuffling to hydro) or effectively cut in half (in the case of shuffling to natural gas).

2) ***Specified power → lower-carbon, unspecified power:*** Emissions could be shuffled from their actual, specified generation level to the deemed emissions intensity. This would occur if previously specified generation were able to shift to unspecified generation and claim a lower, deemed emissions rate. For example, assume that a WCI jurisdiction imports power from a specified coal plant. Also, assume that the WCI jurisdiction is thus tagged with the coal plant's emissions. After CO_2 regulations are put in place, assume the WCI entity is able to eliminate this coal contract, and import unspecified power instead. This would mean that the coal plant emissions were shuffled to unspecified power at the deemed emissions intensity, assuming that the coal plant still operates as it did before the shuffling transaction.

We evaluate the potential for contract shuffling under both of these circumstances.

5.1 Approach

If there were no limits on contract shuffling, all electricity imports from a non-WCI jurisdiction to a WCI-jurisdiction could theoretically be shuffled to zero emissions. This situation would result in emissions coverage equivalent to the source-based point-of-regulation, where electricity imports are not regulated. In this case, up to 77 MMT of CO_2 could be shuffled, or 26 percent of the WCI electricity sector CO_2 obligation, as seen in Table 4 below.

Table 4. Unconstrained Contract Shuffling Potential

MMT CO2

	WCI States	Non-WCI States	Change in CO2
Coal	57	-57	*0*
Gas	20	-20	*0*
Other	0	0	*0*
TOTAL	*77*	*-77*	*0*

5.1.1 Shuffling to 'Specified' Zero-Carbon Emissions

However, appropriate regulatory structures could limit contract shuffling, making the unconstrained shuffling case unrealistic. For contract shuffling to occur, two criteria must be met:

1) A CO_2-emitting generator which is not physically located in the WCI, but which directly serves WCI load (through ownership or contractual obligation), must be able to avoid CO_2 regulation; and

2) A cleaner generator, which is not physically located in the WCI and which does not directly serve WCI load (through ownership or contractual obligations) must be able to claim it is exporting specified power into the WCI.

If both of these criteria are met, it is possible for contract shuffling to occur. A WCI Partner jurisdiction could claim that, over time, more of its imported power comes from specified, low-carbon sources, while more of the non-WCI load is served by high-carbon generation. This is despite the fact that no actual reduction in emissions has occurred.

One of the most significant sources of low-carbon generation, which could be a candidate for shuffling, is hydroelectric power. Nearly 20,000 GWh of hydroelectric power is located within the non-WCI Western States and Provinces. However, the vast majority of this power is not available to be used for contract shuffling because of existing contractual obligations and restrictions on the resale of federal hydro allocations.[10] Table 5 below shows the amount of hydroelectric energy which is located within or currently contractually-obligated to non-WCI jurisdictions.

Table 5. Hydroelectric generation in the non-WCI states in the WECC (GWh/year)

Hydroelectric Generation (GWh)

	AB	CO	ID	WY	TOTAL
Federal Hydro	0	1984	3667	1279	6929
Non-Federal Hydro	2051	1380	9386	577	13394
Total	*2051*	*3364*	*13053*	*1855*	20324

In the worst-case contract shuffling scenario, specified coal power which is currently imported into the WCI would be shuffled to a zero-carbon source, such as hydroelectric power. If this scenario were to occur, 20 MMT of CO_2 could be shuffled and could effectively avoid regulation under the WCI. However, if it were not possible to use Federal hydroelectric power for contract shuffling purposes, the potential for shuffling

[10] This report does not provide a legal interpretation of the regulations surrounding the re-sale of federal hydropower. However, we do note that, in general, re-sale of federal hydropower is discouraged. The Western Area Power Administration (WAPA), which oversees a large share of the federal hydropower in the West, requires as part of its General Power Contract Provisions (Section 4, para. 17) that, “The Contractor shall not sell any firm electric power or energy supplied under the contract to any electric utility customer of the Contractor for resale by that utility customer.” Similar provisions apply to the Bonneville Power Authority (BPA) administered federal power. The Bonneville Power Act of 1937 amended the U.S. code, §16USC832d(a), to read, “Contracts for the sale of electric energy to any private person or agency other than a privately owned public utility engaged in selling electric energy to the general public, shall contain a provision forbidding such private purchaser to resell any of such electric energy so purchased to any private utility or agency engaged in the sale of electric energy to the general public, and requiring the immediate canceling of such contract of sale in the event of violation of such provision.” BPA is authorized to sell “unused excess power” under certain conditions as described in U.S. code, §16USC832m(b).

from coal to hydro power would fall to only 13 MMT of CO_2. If it were not possible to use other non-Federal hydroelectric power for shuffling, due to careful tracking of ownership and contractual obligations, contract shuffling potential would fall even further. Table 6 below shows the worst-case scenario for contract shuffling, in terms of CO_2 shuffled from coal power to hydro power, in each of the non-WCI states and provinces in the WECC. As the table shows, even in this unlikely circumstance, the contract shuffling potential using hydroelectric power is fairly limited.

Table 6. Maximum Shuffling Opportunity for non-WCI Hydro in the WECC (MMT CO_2/year)

MMT CO2

	AB	CO	ID	WY	TOTAL
Federal Hydro	0	2	4	1	7
Non-Federal Hydro	2	1	9	1	13
Total	2	3	13	2	20

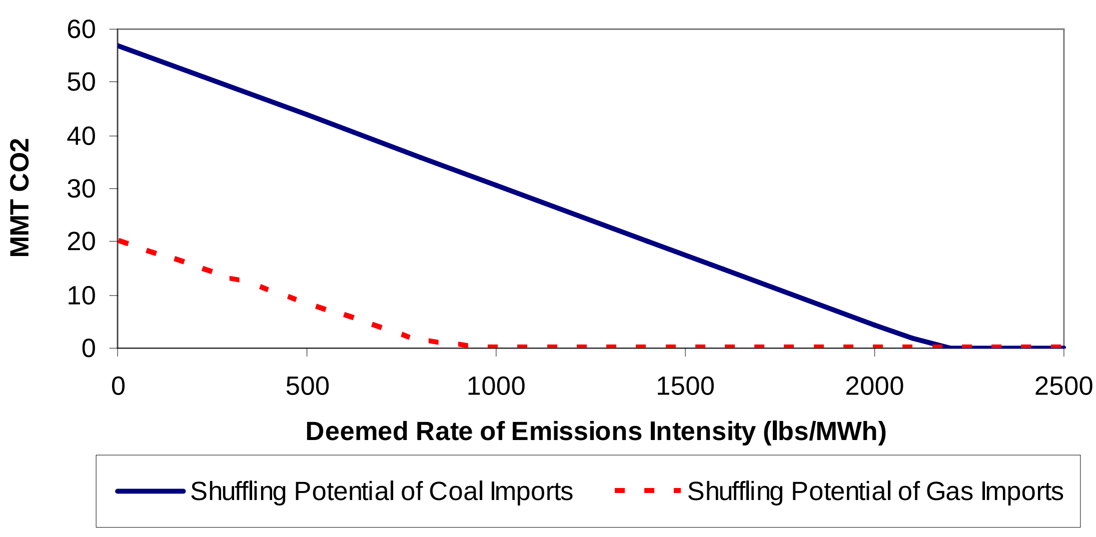
The only other sources of zero-carbon generation which could be used for contract shuffling to specified sources are nuclear or renewable energy generators. However, all nuclear generators in the WECC are located in WCI (see Table 1), thus limiting the potential for using nuclear energy for contract shuffling. Unspecified, non-WCI renewable energy could also be used for shuffling. However, we expect that most of this generation is specified for compliance with state renewable portfolio standards (RPS), thus limiting the potential for using renewable energy for contract shuffling as well. While we don't have data regarding what percentage of renewable generation is currently specified, or will be specified in 2020, the fact that nearly every state in the WECC has an RPS target which has not yet been met implies that renewable generation should remain a valuable source of specified power.

5.1.2 Shuffling to 'Unspecified' Emissions

The other type of shuffling potential which we evaluate is the possibility of shuffling emissions from specified power to 'unspecified' power. As discussed in Section 1.1, under the FJD regulatory approach, specified imports would likely be tagged with their actual emissions. In contrast, unspecified power, would be tagged with a deemed emissions intensity. The deemed emissions rate therefore plays a central role in the incentives to shuffle from specified to unspecified power.

Figure 5 below shows how the choice of the deemed emissions rate affects the incentive to shuffle both coal and natural gas-fired generation to unspecified power. If the deemed emissions rate were set at zero, up to 57 MMT of CO_2 from coal plants could be shuffled, while 20 MMT of CO_2 from natural gas-fired generation could be shuffled. As the deemed emissions rate increases, the incentive to shuffle to unspecified power decreases for both coal and natural-gas fired generation. Once the deemed emissions rate is equal to the emissions intensity of a natural gas fired generator (approximately 800 or 900 lbs CO_2/MWh), it is no longer possible to shuffle CO_2 from natural-gas fired generation. However, at this deemed rate, over 30 MMT CO_2 of emissions from specified coal-fired generation could still be shuffled to the GHG equivalent of natural gas generation. In the absence of other regulations on coal, to eliminate the incentive to shuffle specified coal to the "deemed rate", the rate would need to be closer to 2,200 lbs CO_2/MWh. However, a deemed rate which was set this high would basically force all natural-gas fired generation into specified contracts, reducing liquidity in short-term electricity markets. Therefore, to reduce the incentive for shuffling from specified to unspecified power, the deemed emissions rate should probably be set somewhere near the emissions intensity of a typical natural gas-fired generator.

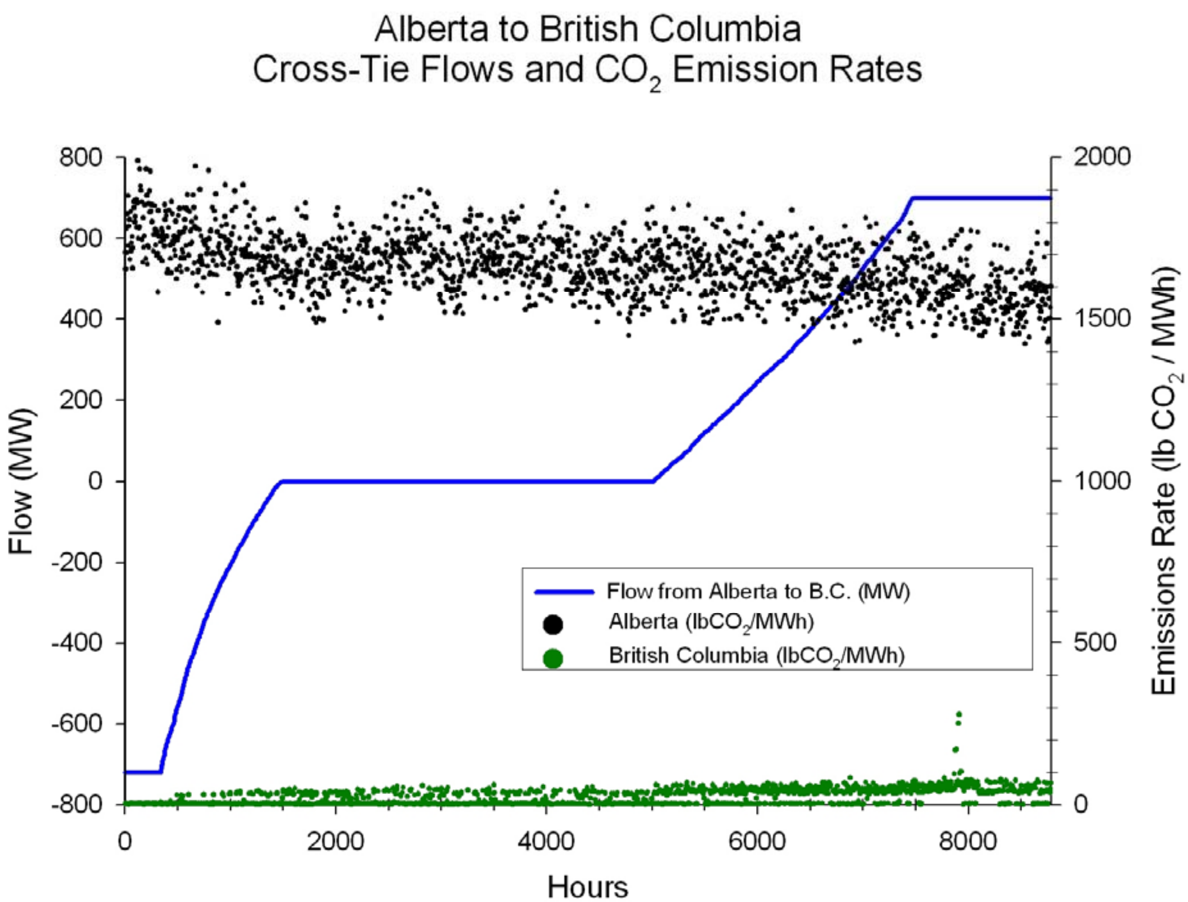
Figure 5. Shuffling Potential from Specified to Unspecified Power for Coal and Natural Gas-fired Generation as a Function of the Deemed Emissions Intensity



5.1.3 Regionally-Specific Deemed Emissions Rates

It is beyond the scope of this analysis to make recommendations regarding an optimal level for a deemed emissions rate. However, we do point out that the average emissions intensity of unspecified power is not the same in all regions of the WECC. This reality suggests that it may be worthwhile to consider establishing different deemed rates for specific non-WCI regions. Figure 6 below, for example, illustrates the simulated average hourly emissions intensity of British Columbia and Alberta over a one-year period in 2020.

Figure 6. Hourly Average Emissions Intensity of Alberta and British Columbia and the Hourly Power Flows across the Alberta-British Columbia Transmission Line



The black dots represent the average hourly emissions intensity of all generators in Alberta. As can be seen on the right-side axis, the average emissions intensity of Alberta generation varies by hour between 2,200 lbs CO_2/MWh to 1,400 lbs CO_2/MWh. In contrast, the average emissions intensity of generators in British Columbia (B.C.) is much lower, less than 200 lbs CO_2/MWh in nearly every hour of the year. The blue line represents the hourly flow of power over an Alberta-B.C. transmission line in the PLEXOS simulation. In the figure, the hourly flows are sorted from lowest to highest. Positive flows represent power moving from Alberta to B.C. The transmission line is operating at full capacity with power flows from Alberta to B.C. during approximately 1500 hours (approximately 2 months) of the year. Negative flows represent power moving from B.C. to Alberta. The transmission line is operating at full capacity with power flows from B.C. to Alberta during approximately 500 hours (less than 1 month) of the year. The rest of the year, the transmission line is not operating at full capacity, and could carry additional power transfers from one region to the other.

Figure 6 demonstrates two important points. First, since the Alberta-B.C. transmission line is not currently utilized at full capacity for most hours of the year, it would be possible to import additional power to B.C. from Alberta. Secondly, the average emissions intensity of Alberta is much closer to that of a coal-fired generator than a natural-gas fired generator. This implies that it may be appropriate to consider setting the deemed emissions rate for imports from Alberta power to B.C. well above the level of a natural-gas fired generator. There may be other transmission links connecting high carbon intensity, non-WCI jurisdictions to WCI jurisdictions to consider when establishing deemed emissions rates. As a starting point, a CPUC straw proposal suggests creating deemed emissions factors that are disaggregated by the following major geographic zones: Alberta, Western U.S. (NV, ID, WY, and CO), Mexico, central U.S./Canada (MN, ND, SK), and northeastern U.S.[11] More research into the issue of regional deemed factors may be warranted.

5.2 Findings

The potential for contract shuffling among the Western members of the WCI is relatively limited if an FJD point of regulation is pursued and specified power contracts are tracked

[11] See the November 10th 2008, "Straw Proposal on Reporting GHG Emissions Associated with Electricity Imported from non-WCI Jurisdictions." Available at: http://www.westernclimateinitiative.org/ewebeditpro/items/O104F20477.pdf

and reported. Tracking specified generation imports seems to be an important component of creating a solid WCI regulatory regime. This implies that reporting rules should probably be developed which focus on tracking and accounting for specified coal-fired generation.

In addition, applying a deemed emissions rate to unspecified electricity delivered to WCI Partner jurisdictions (for consumption in the WCI) eliminates the incentive to shuffle emissions from all generation that has an emissions rate less than or equal to the deemed rate. Contract shuffling is further limited if hydroelectric generation under Federal control is not available for contract shuffling due to the rules governing the use of Federal hydroelectric power which restrict resale of delivered energy (see footnote 10 for an elaboration on this point). Finally, special consideration of how to regulate electricity delivery on some WCI-to-non-WCI transmission paths may be warranted, including the development of separate regionally-specific, or transmission path-dependent, deemed emissions rates.

6 Leakage Results

Leakage from the electricity sector is defined as a shift in generation which reduces WCI CO_2 emissions while increasing non-WCI CO_2 emissions. We identify two principal types of electricity sector leakage:

1) A change in power plant operations, such that generation in non-WCI jurisdictions increases and generation in WCI jurisdictions decreases.
2) A shift of new power plant investment into non-WCI jurisdictions as a means of generating more power for import into the WCI without incurring all of the CO_2 obligations.

Unlike contract shuffling, which results in a reduction in CO_2 emissions in the regulated jurisdiction on paper only, leakage could potentially increase total WECC-wide emissions even as reported WCI emissions drop.

6.1 Approach

In order for leakage to occur <u>due to a change in the operations</u> of existing power plants, two criteria must be met:

1) Non-WCI generators must have the capacity to increase their output.
2) The transmission ties from WCI to non-WCI jurisdictions must have available capacity to import additional power.

In order for leakage to occur <u>due to a change in investment</u> in new power plants two criteria must be met as well:

1) The transmission ties from WCI to non-WCI jurisdictions must have available capacity to import additional power.
2) The new generation (resulting from new investment) must be sold into the WCI either as:
    a. unspecified power at a deemed emissions rate which is lower than the generator’s actual emissions rate, or

b. specified generation at a deemed emissions rate which is lower than the generator's actual emissions rate. The barriers to shuffling, discussed above, would also apply in this case.

Fortunately, there are natural limits to leakage, which combined with appropriate regulatory design of the FJD rules, could reduce the potential for leakage.

6.1.1 Leakage Resulting from a Change in Existing Power Plant Operations

We first consider leakage resulting from a change in power plant operations. The next two figures provide some indication of the potential for this type of leakage. Figure 7 shows the coal-fired generators located in the WECC; non-WCI coal plants are indicated with blue triangles. As might be expected, all of these coal-fired generators are operating at a capacity factor above 80 percent, which is near the technical limit of a coal plant. This means that there is little possibility for leakage to occur due to an increase in existing coal-fired power plant generation.

Figure 7. Available Capacity among Coal-Fired Generators in the WECC

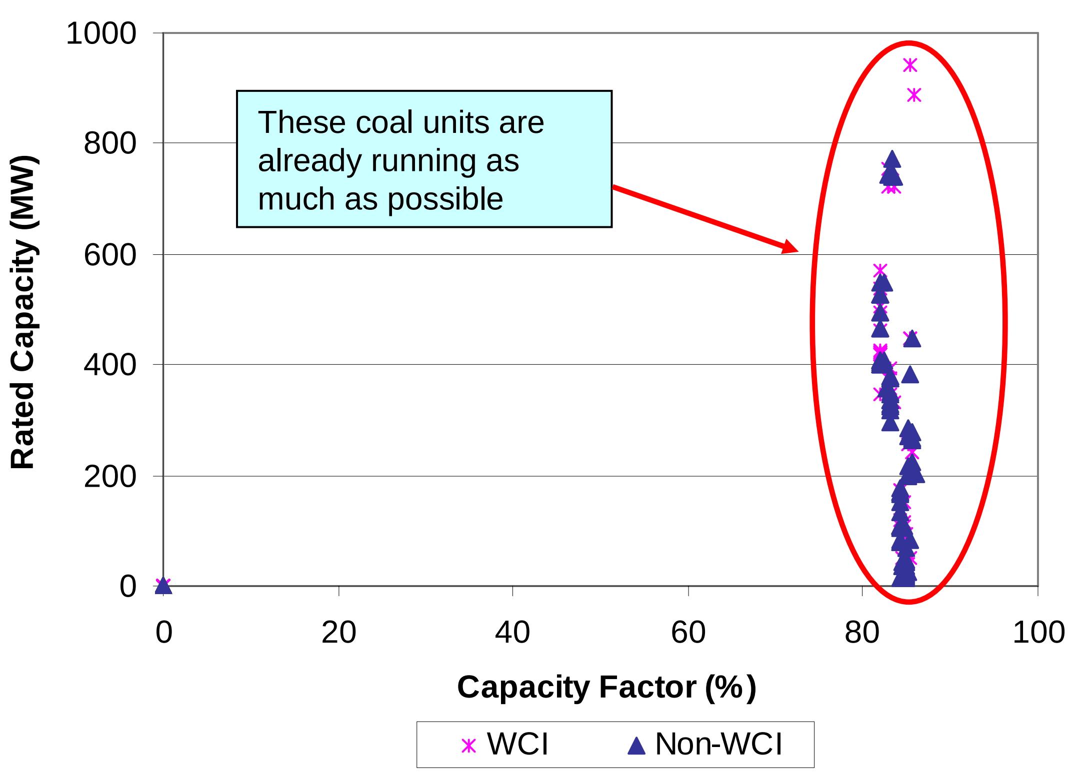
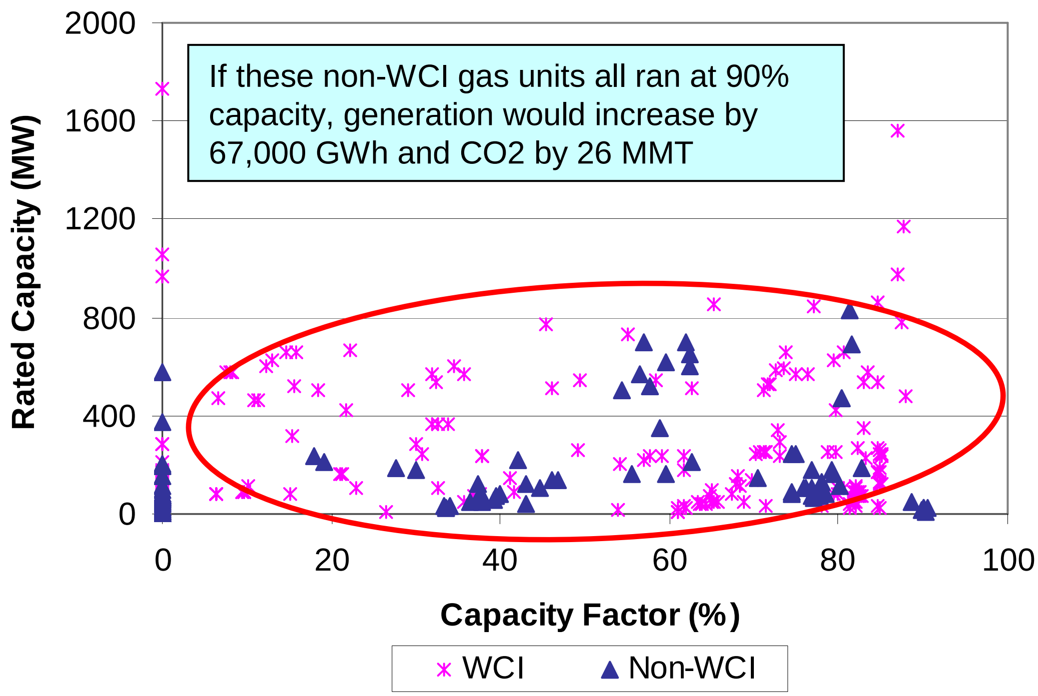


Figure 8 shows the combined-cycle natural gas units located in the WECC; the units located outside the WCI are indicated with blue triangles.[12]

Figure 8. Available Capacity among Combined-Cycle Natural Gas Generators in the WECC



Many of these combined cycle gas turbines (CCGT) are not operating at their full technical potential, which for most units is probably close to a capacity factor of 90 percent. Therefore, leakage could occur by increasing the hours of operation of existing non-WCI combined cycle gas units and backing down natural gas generation in WCI jurisdictions. In the extreme case, if all of the non-WCI CCGT units increased their hours of operation to a 90 percent capacity factor, replacing zero-carbon generation, emissions could increase by 26 MMT of CO_2. However, in order for these emissions to 'leak', there would need to be a way to import this natural-gas power into the WCI without counting all of the associated emissions towards the WCI's emission obligation. If the deemed emissions rate for unspecified power were set near the emissions intensity of a combined-

[12] The figure does not include combustion turbines which would be used for peaking power.

cycle natural gas unit, the potential for leaking these 26 MMT of CO_2 could be nearly eliminated.[13]

6.1.2 Leakage Resulting from a Change in Power Plant Investment

This section investigates the question of whether GHG regulation in the WCI could increase the economic incentive to build new fossil generation in non-WCI jurisdictions as a means of avoiding CO_2 regulation. We consider the economics of building a coal plant in the WCI compared with the economics of building a coal plant in non-WCI jurisdictions as a means of illustrating the worst-case scenario for this form of leakage. We do not consider the case of leakage due to new investment in natural gas fired generation in non-WCI jurisdictions. The example presented here would look similar for the new natural gas generator case. In addition, if the deemed emissions rate were set near to the emissions intensity of natural gas fired generation this would basically eliminate the incentive for leakage through new natural gas fired generation.

There are three cases of new, non-WCI coal generation investment which are worth considering in this analysis:

1) The coal developer could sign a long-term contract with a load-serving entity in the WCI. In this case, there would be no potential for leakage if the FJD emissions reporting rules tracked this contract as specified generation.

2) The coal developer could sell the new generation into the WCI as unspecified (system) power. In this case, the FJD deemed emissions rate would apply.

3) The coal developer could sell its power to a non-WCI entity, and thus free-up other low-carbon generation for sale into the WCI. This case would reflect a combination of leakage and shuffling.

Cases 2 and 3 above represent a leakage potential. There are three key variables which drive the new-generation investment economics in these two cases: 1) the price of

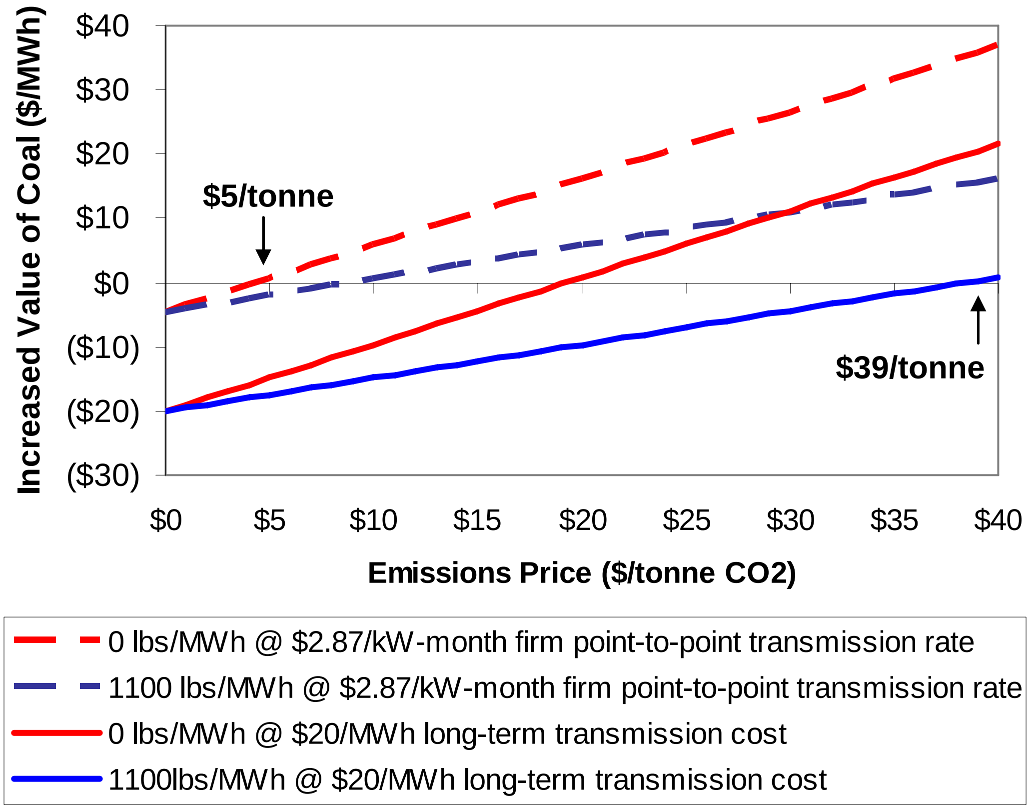
[13] The emissions intensity of combined cycle natural gas turbines varies slightly among units, and can also vary by temperature, so there is not a single emissions rate which would be applicable to all natural gas units in the WECC. Also, note that we have excluded combustion turbines (CTs) from this leakage analysis, under the assumption that CTs are used for load following and local capacity and not for energy needs.

transmission from a non-WCI to a WCI jurisdiction, 2) the deemed emissions rate for unspecified power, and 3) the price of CO_2 emissions in the WCI.

Figure 9 below demonstrates how changes in these three variables impact the economic incentive for leakage through new investment in a coal-fired generator in a non-WCI jurisdiction. The vertical axis represents the incremental, or additional economic incentive, in terms of dollars per MWh, to build a non-WCI coal plant for the purposes of importing the power into the WCI. When the incremental value of coal ($/MWh) is positive, this indicates that there would be an economic *incentive* to build the power plant. When the incremental value of coal ($/MWh) is negative, there is an economic *disincentive* to build the new power plant. The dotted lines represent scenarios where transmission costs are assumed to be lower compared to the scenarios represented by the solid lines.[14] Here, we have selected two typical, indicative transmission costs for illustrative purposes. Actual transmission costs will vary by region and by the specific circumstances of the new generator.

[14] In this example, we assume that the cost of construction for a new coal plant is identical in WCI and non-WCI jurisdictions.

Figure 9. Incremental Economic Incentive to Build New Coal-Fired Generation Outside the WCI, as a Function of Transmission Price, CO_2 Price and the Deemed Emissions Intensity (0 lbs CO_2/MWh or 1,100 lbs CO_2/MWh)



As can be seen, higher transmission costs reduce the incentive for leakage through new generation investment. Likewise, a higher deemed rate for unspecified power reduces the economic incentive for building new generation in non-WCI jurisdictions. This is because power deliverer of the new coal generation, if selling unspecified power, will face a higher emissions burden as the deemed rate increases. In contrast, as the price of CO_2 emissions in the WCI increases, the economic incentive to build new generation in non-WCI jurisdictions increases. This is because under this leakage scenario, the power generated in a non-WCI jurisdiction but delivered to the WCI would not face the full CO_2 price associated with its emissions.

Figure 9 shows that if there is no deemed emissions rate (0 lbs CO_2/MWh), and if the firm point-to-point transmission rate is $2.87/kW-month, then the CO_2 price in the WCI must be greater than $5/tonne CO_2 before there is an increased economic incentive for a developer to build new coal-fired generation in a non-WCI jurisdiction to serve WCI load. Under these conditions, and at a CO_2 price less than $5/tonne, the developer would be indifferent between constructing the coal plant in the WCI or outside the WCI. In contrast, if the deemed emissions rate were higher (in this example, 1,100 lbs CO_2/MWh), and if long-term transmission prices were higher (in this example, $20/MWh), then the CO_2 price would have to be much higher, above $39/tonne CO_2 in this example, before developers would face an increased economic incentive to build new coal fired generation in a non-WCI jurisdiction to serve WCI load.

If a new coal plant's emissions cannot be tracked by FJD reporting rules, we conclude that the potential for leakage due to new generation investment is limited by three key factors: 1) the price of CO_2 in the WCI (lower CO_2 prices reduce the incentive for leakage), 2) the cost of building new transmission (higher transmission costs reduce the incentive for leakage), and 3) the deemed emissions rate (higher deemed emissions rates reduce the incentive for leakage).

6.2 Findings

This section has discussed two types of leakage potential in the electricity sector: leakage due to a change in operation of existing generation and leakage due to a change in investment in new generation. The leakage potential from each is relatively limited, and may be further deterred through appropriate FJD policies regarding the treatment of electricity delivered into the WCI. However, this report does not speculate on the expected effectiveness of the FJD approach – this will ultimately depend on how the regulations are implemented and enforced.

There is very little leakage potential from existing non-WCI coal plants, since these currently operate near their maximum technical capacity. The potential for leakage due to a change in operation of natural gas fired generation could be problematic if there were no regulation of unspecified energy delivered into the WCI through a deemed rate. If the deemed emissions rate for unspecified energy were set somewhere between the emissions intensity of a coal-fired generator and a gas-fired generator, the economic incentive for leakage due to increased generation from natural gas would be drastically curtailed.

The economic incentive for leakage through new investment is limited by several factors, including the cost of transmission, the deemed emissions intensity of unspecified electricity and the CO_2 price in WCI jurisdictions. In addition, leakage from new coal-fired generation investment could be further deterred if reporting standards required tracking specified deliveries of coal-generation into the WCI, and if the standards required that specified generation receive its actual emissions rate rather than a deemed emissions rate.

The deemed rate also serves to reduce the economic incentive to build new coal generation in non-WCI jurisdictions to serve WCI load. For example, if the deemed emissions intensity for unspecified delivered energy were set at 1,100 lbs CO_2/MWh, then the CO_2 price in the WCI would need to be above $10 to $30/tonne CO_2, depending on the price of transmission access. If new transmission needed to be built to deliver new coal-fired generation into the WCI, the economic barrier to this type of leakage would be even higher. In addition, the numerous other barriers to new coal-fired generation investments further reduce the possibility of this form of leakage. Environmental opposition and limitations on water availability in the West are two examples of non-economic barriers to new coal generation.

7 Conclusions

This report has considered the coverage of the WCI's electricity sector emissions under different regulatory approaches, and concluded that the FJD approach is an appropriate way to increase coverage of electricity sector emissions. Without any regulation of emissions from electricity generated outside the WCI and delivered into WCI Partner jurisdictions, only about 74 percent of the WCI's total electricity sector emissions would be covered. Electricity sector emissions in the WCI can be increased above 74 percent depending on the choice of the deemed emissions rate and other FJD reporting rules.

The potential for contract shuffling and leakage can also be limited by effective regulatory design. FJD has the potential to greatly reduce the potential for both shuffling and leakage, especially if the deemed emissions rate for unspecified electricity deliveries into the WCI is set at an appropriate level. This report does not analyze regional emissions intensities of electricity in depth, but we suggest that WCI consider regionally-specific deemed emissions rates that reflect regional differences in generation resources.

Contract shuffling in the WCI is limited by the availability of unspecified low-carbon generation, and by the deemed emissions rate. Assuming that Federal hydroelectric generation and all renewable energy can be tracked as specified power, the potential for contract shuffling in the WCI is only approximately 13 MMT CO_2, and may be lower if other hydroelectric generation is unavailable for shuffling due to long-term contracts and ownership rights to the hydroelectric power.

The leakage potential is limited as well. There is basically no possibility of leakage through increased operation of existing coal generation, because these units already operate at full capacity. There is some potential for leakage through increased operation of existing natural gas generation, but this potential could be severely curtailed by a deemed emissions rate set near or just above the emissions intensity of a typical natural gas-fired generator. The leakage potential due to changes in investment patterns is harder to quantify, but it is limited by transmission availability, FJD rules and other non-economic factors limiting new investment in coal-generation.

In sum, the WCI-proposed approach for regulation of GHG emissions from the electricity sector has the potential to maximize emissions coverage and to limit contract shuffling and leakage. Moving forward, we recommend that the WCI Partners consider establishing a deemed emissions rate which is near or just above the emissions rate of natural gas-fired generation. As this summary report has demonstrated, this will improve coverage of the regulatory system, will reduce the economic gains of shuffling emissions to unspecified, or system power, and could eliminate the incentive for leakage to non-WCI natural gas generation, among other benefits.

We also recommend that the WCI Partners consider tracking and regulating specified imports of coal power into the WCI. Tracking specified imports of coal power both increases coverage and reduces the ability to shuffle coal-fired generation to system power or to low-carbon generation. Tracking and regulating specified coal generation could also eliminate the potential for leakage from new non-WCI coal.

Western Climate Initiative

Market Oversight
Draft Recommendations

April 1, 2010

Executive Summary

The Western Climate Initiative is a collaboration of seven US states and four Canadian provinces to reduce greenhouse gas emissions, including the design and implementation of a cap-and-trade program. The WCI is working through five committees, including the Markets Committee, to complete tasks and deliverables for implementation. Recommendations on oversight of markets for greenhouse gas allowances and offset certificates (“compliance instruments”) is among the Markets Committee’s tasks. This document provides draft recommendations on market oversight. Following public comment and continued work by the Markets Committee, the Committee will issue Final Recommendations.

The Markets Committee has used a variety of sources of information in developing its recommendations, including published reports, presentations, stakeholder comment, contact with market participants and regulators, and contracting with outside advisers. It adopted principles to guide its work and recommendations.

The Markets Committee has identified twelve items as the tools or decisions WCI Partner jurisdictions can use or make to establish effective oversight of compliance instruments. The Draft Recommendations are:

1. Treat Compliance Instruments as Commodities for Market Oversight Purposes
2. Information on Derivatives Positions
3. Treat Allowances and Offset Certificates Identically for Market Oversight Purposes
4. Establish Legal Relationship with Market Participants Through Compliance Instrument Ownership Interest and Tracking System
5. Do Not Limit Market Participation to Compliance Entities
6. Require Registration of Intermediaries as Market Professionals
7. Holdings Limits

8. Require Use of a Central Limit Order Book for Secondary Market Transactions
9. Require Reporting of Beneficial Ownership
10. Information Required for Compliance Instrument Transfer
11. Secondary Market Holdings and Transfer Information Disclosed to Public
12. Market Monitoring

In many cases, the Draft Recommendations are interrelated, and changing one could change another. Importantly, the first Draft Recommendation implies the adoption of an existing framework for regulating compliance instrument derivatives. Consequently, Draft Recommendations 3 – 12 are primarily focused on secondary markets.

In considering Draft Recommendations, the Markets Committee recognized and attempted to weigh a number of factors that were often difficult to predict and sometimes were in competition. These included transparency, market liquidity, allowing markets to evolve, adopting best practices and lessons from more mature markets, leadership, resource demands on jurisdictions and participants, unique characteristics of markets for compliance instruments, and enforceability. The Committee believes that the resulting Draft Recommendations describe policies that will enhance the ability of the cap-and-trade program to contribute to greenhouse gas emissions reductions at relatively low cost, provide regulatory oversight, and promote market participant confidence. The Committee welcomes comment on the Draft Recommendations individually and collectively, and in particular on:

A. Whether the tools available to WCI Partner jurisdictions for market oversight have been completely and correctly identified;
B. Whether the Draft Recommendations would correctly maximize the environmental and economic benefit to the public and support WCI's Principles of Market Oversight;
C. Whether the Committee should recommend collection of derivatives position information from market participants, including on over-the-counter derivatives; and if so, what of that information to disclose to the public; and
D. The Draft Recommendation to require secondary market trades to use a central limit order book.

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1 Purpose and Background

The Western Climate Initiative (WCI) is a cooperative effort of seven U.S. states and four Canadian provinces that are collaborating to identify, evaluate, and implement policies to reduce greenhouse gas (GHG) emissions, including the design and implementation of a regional cap-and-trade program. The WCI began in February 2007 with the governors of Arizona, California, New Mexico, Oregon, and Washington, who have since been joined by the premiers of British Columbia, Manitoba, Ontario, and Quebec, and the governors of Montana and Utah. Participation in the WCI reflects each Partner jurisdiction's strong commitment to identifying, evaluating, and implementing collective and cooperative actions to address climate change.

In September 2008, the Partner jurisdictions released the final "Design Recommendations for the WCI Regional Cap-and-Trade Program."[1] The first compliance period for the cap-and-trade program will begin January 1, 2012, covering GHG emissions from electricity generation (including emissions associated with imported electricity), combustion at large industrial and commercial facilities, and industrial process emissions for which adequate measurement methods exist. Starting in 2015, the program's coverage expands to include transportation fuels in addition to residential, commercial, and small industrial combustion. Thus, by 2015 the cap-and-trade program will cover almost 90% of GHG emissions in the Partner jurisdictions.

In February 2009, the Partner jurisdictions released the WCI 2009 – 2010 Work Plan, describing the approach to implementing the Design Recommendations.[2] The WCI is working through five committees: Offsets, Reporting, Complementary Policies, Cap Setting and Allowance Distribution, and Markets. The Work Plan describes the tasks and deliverables for each committee. The purpose of one of the Markets Committee's tasks, "market oversight," is to recommend measures to ensure that the allowance and offset certificate trading market is organized properly to operate reliably and prevent or minimize manipulation. This task was included in the work plan based on the consensus among WCI Partner jurisdictions on the need to provide effective oversight to assure an efficient and transparent carbon market.

These Draft Recommendations are based on the information collected and reviewed by the Markets Committee on market oversight approaches and issues. The information was obtained through several means, including the following:

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[1] The Design Recommendations and accompanying Background Report can be found at http://westernclimateinitiative.org/the-wci-cap-and-trade-program/design-recommendations.
[2] The 2009 – 2010 Work Plan can be found at http://westernclimateinitiative.org/component/remository/general/workplans/2009-2010-WCI-Work-Plan/.

- The Markets Committee held a stakeholder workshop on market oversight in Seattle, Washington in April 2009. The Committee presented a draft set of principles of market oversight, and a list of questions for discussion with those who attended in person or online.[3] Stakeholders were invited to submit written comments.[4] Stakeholders' responses guided the Committee's consideration of issues and the Committee revised the principles of market oversight as set forth below. The principles guided the Committee's research, analysis, and deliberation, and will continue to do so as the Committee progresses towards final recommendations.

- The Markets Committee made a presentation to the WCI Partners on September 16, 2009, at a public meeting in Toronto, Canada, and invited stakeholder comment at the meeting.

- The Markets Committee made a presentation to the WCI Partners on November 18, 2009, at a public meeting in Santa Fe, New Mexico, and invited stakeholder comment at the meeting.

- The Markets Committee issued a white paper on market oversight[5] on November 19, 2009, and invited written public comment by December 18, 2009. Eleven parties submitted comments.[6]

- The Markets Committee held a stakeholder call December 2, 2009, to present and discuss the market oversight white paper.[7]

- The Markets Committee made a presentation to the WCI Partners on March 3, 2010, at a public meeting in Vancouver, British Columbia, and invited stakeholder comment at the meeting.

- The Markets Committee held a webinar with the market monitor used by the Regional Greenhouse Gas Initiative (RGGI).[8]

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[3] The principles and questions can be found at http://westernclimateinitiative.org/component/remository/func-startdown/25/. Market oversight was one of three tasks for which the Committee developed draft principles for comment; the others were auction design and compliance verification and enforcement.
[4] Stakeholder comments were submitted to the WCI website, and can be found at http://westernclimateinitiative.org/documents/public-comments/document/2.
[5] The white paper can be found at the WCI website, at http://westernclimateinitiative.org/component/remository/func-startdown/174/.
[6] Comments can be found at the WCI website, at http://westernclimateinitiative.org/public-comments/document/13.
[7] The presentation from the stakeholder call is available on the WCI website, at http://westernclimateinitiative.org/component/remository/Markets-Committee-Documents/Market-Oversight-White-Paper-Presentation/.

- The Markets Committee consulted with U.S., Canadian, state, and provincial regulatory authorities, and received input from European market regulators, potential market participants, trade associations, market infrastructure providers, and other stakeholders.

- The Markets Committee conducted a literature review with the assistance of our task advisor at the Nicholas Institute for Environmental Policy Solutions at Duke University.

Through this process, the Committee acquired substantial knowledge about the types of regulation in place in existing financial markets, the roles of regulators and exchanges, and the scope of existing carbon-related financial products.

In this document, "compliance instrument" refers to either an allowance or an offset certificate, unless otherwise noted. This document builds on the definitions and discussion in the market oversight White Paper without restating them, in most cases.

2 Principles

These principles were adopted with the publication of the white paper on November 18, 2009, and have been modified only to change "allowance" to "compliance instrument" and "offset credit" to "offset certificate" to standardize nomenclature. They serve as guidelines for developing oversight of the compliance instrument and associated derivatives trading markets to assure maximum environmental and economic benefit to the public.

- **Fairness:** All market participants, especially covered entities, have fair and equal access to the market.

- **Efficiency:** The market is designed to operate efficiently so that greenhouse gas (GHG) emission reductions can be achieved at the least cost. An efficient market means that allowance and offset certificate prices reflect supply and demand, and accurately reveal the value of allowances and offset certificates.

- **Effective Oversight:** The design and oversight of the market is effective in preventing or minimizing fraud, manipulation, and speculative excess.

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[8] The presentation from the webinar is available at http://westernclimateinitiative.org/component/remository/Markets-Committee-Documents/Monitoring-Emissions-Allowance-Markets/.

- **Transparency and the Reporting and Disclosure of Relevant Information:** Transparency in the design and the operation of the allowance and offset credit market builds and retains public confidence.

    - Reporting of relevant information to regulatory authorities and public disclosure of information has important benefits. It enables regulatory authorities to conduct effective oversight and ensure compliance. It also helps to ensure market efficiency, effective oversight, and compliance and enforcement. The release of information can change the decisions of market participants, which impacts the prices of allowances and offset credits. Timely, accurate, coordinated and consistent release of market-relevant information allows all market participants to have equal access to public information.
    - The reporting and disclosure requirements for compliance, verification and enforcement balance these benefits against the need for entities to protect certain sensitive information. The potential to disclose certain information that could be used to manipulate the market is also considered. This balancing is consistent with applicable law relating to the disclosure of information.

- **Administrative Simplicity and Cost:** Proposed rules are designed to be understood and enable entities to have a clear compliance path. Administrative costs and transaction costs are minimized for all parties, consistent with the need to provide effective oversight.

- **Accountability:** All entities involved in the allowance and offset credit market, as either regulators or market participants, are accountable for their actions. The responsibility, authority, and capacity to conduct the necessary oversight and take appropriate action are fully defined for all agencies charged with compliance, verification and enforcement.

- **Conflicts of Interest:** Conflicts of interest between market participants, monitors, and regulators are prevented.

3 Stakeholder Comments on White Paper

The Markets Committee received 11 written comments to the white paper. The Committee identified and asked for comment on three key issues, as well as general comment on the content of the white paper.

The first key issue was, "Whether current U.S. and Canadian regulation of commodity markets is appropriate." Five commenters responded to this issue. In general, the comments favored treating allowances as commodities, rather than construct a new definition or new framework for their regulation. One commenter, however, said that though allowances would fit the framework for regulation as commodities, oversight of over-the-counter (OTC) derivatives beyond current commodity oversight was needed.

The second key issue was, "Whether to place restrictions on OTC instruments." Seven commenters responded to this issue. Six commenters recommended not restricting the use of OTC instruments, citing their flexibility and the costs of clearing in exchange transactions. Of those six, three recommended requiring more information on such transactions than is currently reported to regulators. One commenter recommended restricting transactions to exchanges, to reduce complexity and the risk of market manipulation.

The third key issue was, "The appropriate transparency and disclosure requirements." Five commenters responded to this issue. They said that an appropriate balance of transparency and confidentiality, as well as the costs and benefits of collecting particular data, exists. Three commenters recommended that more information be revealed to regulators than would be made public, and specifically recommended aggregation of data prior to public disclosure. On the December 2, 2009 stakeholder call, some stakeholders requested a specific proposal to respond to. One commenter made specific recommendations on information requirements to restrict the use of inside information.

Commenters made further recommendations to the WCI Partner jurisdictions. Two described recommended roles for a central market monitor. Two requested clarification of the legal authority jurisdictions had over allowance markets, as prerequisites for determining the specific recommendations for oversight. A short discussion of the roles of provincial, state, and federal regulatory authorities is in section 5 of this paper. The Final Recommendations paper will include a more detailed discussion.

Some comments addressed issues outside the scope of the market oversight task, and some commenters took issue with phrasing in the white paper. Two commenters requested a fuller acknowledgement than in the white paper of the possibility and consequences of market manipulation. One commenter requested more information on the risks of low market liquidity, including the risk that liquidity would be harmfully low.

4 Draft Recommendations

The Draft Recommendations presented here incorporate the information the Markets Committee has received and developed on market oversight. Among the general conclusions the Committee reached is that many aspects of oversight are interrelated. In many cases, a Draft Recommendation below depends on the implementation of another Draft Recommendation. For each Draft Recommendation, the Committee has noted these relationships; if one were to change, others likely would as well. For this reason, the Committee has considered the Draft Recommendations as a package.

Of particular note is Draft Recommendation 1 (Treat Compliance Instruments as Commodities for Market Oversight Purposes). It does not recommend that the Partner jurisdictions implement new restrictions on the trading of derivatives. This influences the discussion of the further Draft Recommendations, especially by narrowing the focus of several to secondary markets.

Second, some of the Draft Recommendations imply or require particular technical capabilities in a cap-and-trade compliance instrument tracking system. Where this is the case, the requirements are discussed with the Draft Recommendation. An electronic tracking system provides complete accounting of compliance units, recording the real-time status of issuance, holdings and transfer of compliance units between accounts, and providing the function to reconcile reported emissions for each compliance period with the compliance entity's holdings.

4.1 Allowances, Offset Certificates, and Derivatives

4.1.1 Draft Recommendation 1: Treat Compliance Instruments as Commodities for Market Oversight Purposes

4.1.1.1 Background

Commodity cash and derivatives markets are closely linked, and activity in one will affect behavior in the other. Nevertheless, they are different in definition and in legal framework and warrant separate treatment. The market oversight white paper described commodity derivatives and the regulatory framework for them, and the discussion here builds on that.

4.1.1.2 Options

The first of the "key issues" the Markets Committee asked for comment on in the white paper was:

A) Whether cap-and-trade compliance instruments should be treated as commodities, which would place them in the context of a body of existing law and regulation, or
B) Whether to attempt to define compliance instruments in such a way that they would not be commodities, and develop a new body of law and regulation.

4.1.1.3 Evaluation of Options

As described in the market oversight white paper, "Commodities are goods that are interchangeable with other goods of the same type." Cap-and-trade compliance instruments in the US Acid Rain Program, RGGI, and the European Union Emissions Trading Scheme (EU ETS) have been treated in many ways as commodities by market participants and regulators. Though they are instruments that will ultimately be used to satisfy legal requirements, as finite resources they have market prices.

Whether to treat compliance instruments as commodities for market oversight purposes is a fundamental question in the US especially, because federal law preempts the states from certain regulation of commodity derivatives. By “derivatives” we mean both exchange-traded instruments, such as futures and options contracts, as well as instruments traded over-the-counter. Therefore, determining that compliance instruments are commodities places the responsibility for regulation of their derivatives in the US primarily with the US Commodity Futures Trading Commission (CFTC). The advantages to this include the long history of futures and options regulation, and staff and infrastructure resources at the CFTC. The disadvantages include potentially less control of the non-cash markets by the Partner jurisdictions.

Like energy commodities, compliance instruments could be considered an input to many kinds of economic activity, including production of electricity and use of transportation fuels. In addition to concern that financial manipulation might benefit a few persons at the expense of many, high volatility and higher-than-expected prices in compliance instrument markets have the potential to undermine public support for a cap-and-trade program, which could make achievement of environmental goals more difficult. Partners, therefore, might weigh tradeoffs between transparency, market efficiency, prices, and volatility differently from the legislators and regulators who have established the framework for commodity derivatives regulation.

Participants trading compliance instruments in existing carbon markets have generally treated them as commodities. Many firms that are covered in existing cap-and-trade programs require energy commodities as inputs. As with commodities, compliance instrument prices should reflect market fundamentals, such as economic conditions and industrial production more than the decision of a single firm. (In contrast, the price of a firm’s securities can be linked closely to the business decisions of that firm.)

In its consideration of alternatives to treating compliance instruments as commodities, the Markets Committee found three additional strong arguments not to create an alternative framework. First, the definition of “commodity” in the Commodity Exchange Act[9] is sufficiently broad that it would be difficult to devise a definition of compliance instruments that would not place their derivatives under CFTC regulation in the US. Second, no alternative framework rose up as superior. Third, though the Canadian provinces each have a securities commission that regulate derivatives, in general, because of federal preemption, the US state governments

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[9] 7 U.S.C. 1a (4)

retain less authority to regulate national financial markets and, as a result, creating the regulatory capacity for oversight of compliance instrument derivatives traded on national markets could require a significant investment of time and funds.

4.1.1.4 Experience in Existing Environmental Cap-and-Trade Programs

In the US, Acid Rain Program and RGGI compliance instrument derivatives are regulated by the CFTC as commodity derivatives. In the EU ETS, regulation of derivatives is performed by individual countries. That said, most of the exchange-based derivatives activity takes place on the European Climate Exchange, based in London, which is regulated as a commodity derivatives exchange by the UK Financial Services Authority.

4.1.1.5 Draft Recommendation

The Markets Committee recommends that compliance instruments be treated in the same framework and by the same regulators as commodities for the purpose of derivatives regulation. This implies the primacy of the provincial securities commissions and the CFTC in oversight of that aspect of the market. The Committee recommends a close coordination of oversight efforts between agencies of the Partner jurisdictions and US federal regulators.

4.1.1.6 Relationship to Other Draft Recommendations

A discussion on the collection and dissemination of data on derivative positions is included in Draft Recommendation 2 (Information on Derivatives Positions). Some of the data that could be collected is not currently collected by the CFTC or provincial securities commissions, and would then be an exception to the general recommendation that compliance instruments be treated like other commodities.

The remainder of the Draft Recommendations would then apply only to secondary markets in compliance instruments.

4.1.1.7 Requirements of Tracking System

This Draft Recommendation does not imply technical requirements of the tracking system.

4.1.2 Draft Recommendation 2: Information on Derivatives Positions

4.1.2.1 Background

The WCI cap-and-trade program will likely lead to the development of a market for compliance instrument derivatives, as covered entities seek to hedge the cost and availability of compliance instruments in order to meet their compliance obligations. In the United States, regulation of commodity derivative markets occurs at the federal level. In Canada, these markets are regulated at the provincial level. Currently, derivative trading in energy commodity markets occurs in a variety of venues including regulated exchanges and through private “over-the-counter” (OTC) contracts. Market regulators in Canada and the United States do not track OTC trading of energy-related derivatives as closely as exchange-traded contracts. As a result, it is difficult to track trading activity across the energy derivative markets. Efforts are underway in both countries to reform market regulation, in part because of concerns that OTC opacity allows for undetectable manipulative behavior or drives speculative bubbles. These efforts may increase surveillance of OTC trading but the likely outcome is unclear.

4.1.2.2 Options

The Markets Committee identified the following options regarding collection of information on derivative positions:

A. Collect on an ongoing basis information on derivative positions from those with accounts in the cap-and-trade tracking system or ownership interest in a compliance instrument that is additional to the information currently collected by commodities regulators;
B. Collect on an ongoing basis information on derivative positions from some entities, e.g., registered intermediaries;
C. Do not collect derivative position information on an ongoing basis, but ensure that regulatory authorities are authorized to collect and fully disclose derivative position-related information in a timely fashion on an as-needed basis, including information that would be material to an investor’s decision to acquire or dispose of a derivative;
D. Do not collect additional information on derivative positions.

Depending upon which of the options above the Markets Committee recommends, the WCI cap-and-trade program may or may not have information on derivative positions to retain internally or disclose publicly. If information on derivative positions is collected on an ongoing basis, the Markets Committee has identified the following options for disclosure of derivatives market information:

A. Disclose all derivative positions reported (i.e., those of participants with tracking system accounts or ownership interest in a compliance instrument);
B. Disclose the largest derivative positions (e.g., exceeding a certain percentage of the total market);
C. Disclose derivative positions aggregated to a level similar to the Commodity Futures Trading Commission Commitments of Traders reports; or
D. Do not disclose information on derivative positions.

The Markets Committee has considered the following options in terms of how derivatives market information could be disclosed:

A. Directly through a central derivatives information repository, and through search functions;
B. Through exchanges where transactions occur;

C. Through periodic WCI market reports published on a website; and/or,
D. Situationally by commodities derivatives regulators, as they deem appropriate.

Frequency of data collection will also have important consequences for each of the above options. The Markets Committee has considered daily, weekly, monthly, and quarterly disclosures.

4.1.2.3 Evaluation of Options: Data Collection

Rationale for Data Collection

Three main benefits may accrue from collecting data on account holders' derivative positions. First, though data on exchange transactions is relatively transparent to regulators, the Partner jurisdictions appear to be in a position to collect information on OTC transactions that is not currently routinely accessible to market monitors. Data collection as part of the cap-and-trade program could supplement the regular efforts to monitor compliance instrument derivatives markets; the data could be transmitted to provincial and US federal monitors. A consolidated repository of information on the compliance instrument derivatives markets across jurisdictions and trading venues could enhance transparency of the cap-and-trade market.

Second, in the event of unexpected or suspicious activity, the derivatives position data collected could serve a forensic purpose as regulators examined market activity and traced causes.

Third, as stated in the Design Recommendations for the WCI Regional Cap-and-Trade Program, "the WCI Partner jurisdictions are committed to providing appropriate technical and other compliance assistance to the program participants."[10] If it is using derivatives contracts as part of its strategy, an entity may be better able to demonstrate that it is on track and managing its risk in the accumulation of compliance instruments during a compliance period if derivative positions are reported. (In the EU ETS, the majority of the market is in derivatives, not the spot market. Derivatives would not be reflected in the tracking system until settlement.)

Timing

To identify trading irregularities as they occur and initiate immediate enforcement actions, regulators need to receive and evaluate market data on an ongoing basis. Product innovation and market structure changes challenge regulators, in their policymaking role, to constantly consider whether the current regulatory framework continues to provide investor protection and market integrity given new products and structures. Collecting, aggregating, maintaining,

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[10] "Design Recommendations for the WCI Regional Cap-and-Trade Program," Western Climate Initiative, September 23, 2008, http://www.westernclimateinitiative.org/component/remository/general/design-recommendations/Design-Recommendations-for-the-WCI-Regional-Cap-and-Trade-Program/ (Accessed February 12, 2010), p. 13.

and analyzing large amounts of data requires informational technology and staff resources. The cost of collecting data more frequently should also be weighed against its benefits.

If the goal is more limited, e.g. to identify trends and maintain data for use during longer-term enforcement actions, daily reporting by market participants becomes less important. In that instance, weekly or monthly reports may be sufficient to monitor general trends in trading behavior and have on record in the event enforcement actions become necessary.

Proposed Derivative Reforms

Systematic ongoing collection of OTC derivatives data would go beyond the approach currently used by commodities regulators in North America, which may be seen to be an advantage or disadvantage. The Partner jurisdictions may feel that a nascent market created by government action has intrinsic differences from other commodities, including necessary public support, to say that the standards and tools of effective oversight are also different. The Partners jurisdictions may wish to anticipate or influence the financial reform efforts in favor of reporting OTC derivatives. Requiring such reporting in advance of the uncertain outcome of such reform efforts would make a strong statement about its importance in effective market oversight, and could influence the reforms.

US federal legislative proposals on financial market reform generally would require increased reporting and disclosure of OTC derivatives. In May 2009, the US Treasury Department released a proposal to reform OTC derivative markets.[11] A key component of the proposal is mandatory clearing of standardized contracts and giving the regulators authority to determine whether a contract is standardized or not.

The US House of Representatives passed a financial reform bill in December 2009 that addresses mandatory clearing and transparency.[12] Title III of the bill applies to derivative markets and creates a presumption that standardized swap transactions will be cleared. The clearing requirement does not apply if one of the counterparties (a) is not a swap dealer or major swap participant, (b) is using swaps to hedge a commercial risk, or (c) notifies the CFTC how it meets financial obligations when entering into non-cleared swaps. If one of these exemptions applies and a swap transaction is not cleared through a registered clearing facility, the transaction must be reported to a registered swap repository. If no repository will accept the transaction, the transaction must be reported directly to the CFTC.

[11] "Regulatory Reform Over-the-Counter Derivatives," US Department of the Treasury press release, May 13, 2009, http://www.ustreas.gov/press/releases/tg129.htm (Accessed March 14, 2010).

[12] "House Approves Historic New Rules to Govern America's Financial System," House Committee on Financial Services press release, December 11, 2009, http://house.gov/frank/pressreleases/2009/12-11-09-fsc-press-release-final-bill.html (Accessed March 14, 2010).

Senate Banking Committee Chairman Christopher Dodd released a financial reform bill on March 16, 2010. As in the bill that passed the House of Representatives, Senator Dodd's bill would require central clearing of standardized OTC contracts. The bill includes exemptions for certain swap transactions, but would require the CFTC to consult a Financial Stability Oversight Council before issuing an exemption. The Dodd bill would expand the CFTC's jurisdiction over OTC instruments and grant federal regulators and clearing houses a role in determining whether clearing is required; regulators would have to pre-approve contracts before clearing houses could clear them. The bill would require federal regulators to determine margin requirements for un-cleared transactions and also require data collection through clearing houses or swap repositories. The Senate has not acted on the Dodd bill, and the Senate Banking Committee may amend the OTC provisions during the committee process.

Collecting information about derivatives contracts from registered intermediaries (e.g., brokers, merchants, traders, advisors, and pool operators) could provide regulators with a more complete picture of market activity, thereby helping regulators identify and prevent fraudulent activity. The WCI Partner jurisdictions could collect information from these entities about the products offered and sold during the reporting period, including volume, prices, contracting parties, types of contracts, and locations of the trades.

Arguments

There may be a number of drawbacks to collecting data on account holders' derivative positions. First, assuming the implementation of Draft Recommendation 4 (Establish Legal Relationship with Market Participants Through Compliance Instrument Ownership Interest and Tracking System), the WCI Partner jurisdictions may not be able to collect derivatives information from some entities who have neither tracking system accounts nor ownership interest in compliance instruments. Such participants represent a potentially large portion of the derivatives market. For example, entities who only participated in cash-settled derivatives markets would not need to hold accounts. Entities trading physically-delivered derivatives could still avoid holding accounts if they closed their positions before the delivery date. In addition, violations of the reporting requirement might not be visible to regulators; whether or not a report was complete in its listing of OTC derivatives would be difficult to determine.

Second, the potential benefit of collecting information on derivatives positions must be weighed against the potential increase administrative burden and cost for regulators and for the compliance entities that use derivatives to manage their risk. It may be challenging to anticipate new financial innovations that lead to market manipulation by analyzing the information on derivatives positions, so regulators may be limited to primarily using the information for forensic purposes.

Third, due to the nature of OTC derivatives, it may be difficult to collect derivatives positions information in a sufficiently consistent manner through the tracking system to allow broad analysis.

It is important to note that mandatory reporting of OTC derivative positions would require development of a new information technology platform. There exist companies that provide repository services and associated automated processing services for OTC derivatives. WCI Partner jurisdictions may therefore consider that there are models for collection of derivatives information that would not require an investment of funds from the jurisdictions. However, the process to select a provider would demand time and resources.

The International Swaps and Derivatives Association (ISDA) has recently concluded the selection of independent systems as global repositories for interest rate and equity derivatives, and is rumored to be considering a selection process for a commodity derivatives repository. If ISDA designates a repository, it could be a strong candidate for selection by the WCI jurisdictions as well, depending in part on the access regulators would have to collected data.

4.1.2.4 Evaluation of Options: Public Disclosure

In the view of at least one trade association of professional derivatives market participants (ISDA), policy makers tend to view transaction transparency—meaning in this circumstance "public disclosure"—as a desirable end in itself.[13] In contrast, ISDA asserts, the academic literature tends to view transparency as a means to an end, for example, improved market efficiency, which implies the existence of tradeoffs. On the one hand, ISDA states, transparent markets might be more efficient from the standpoint of the information content of prices; but on the other hand, transparent markets might be less efficient when considering spreads and other transaction costs. For example, ISDA asserts that one would expect mandated transparency to lead to increased explicit costs (e.g., for accounting) because of the necessity to maintain both systems and staff to comply with the requirements; in addition, central reporting structures, if used, might charge fees to reporting firms.

ISDA argues that this trade-off suggests that market transparency should be evaluated in the context of specific market circumstances and public policy should push for higher transparency only in those cases where it can demonstrably make markets more efficient and more beneficial to users. To the extent that market participants demand more transparency as markets mature, ISDA believes that financial markets are likely to evolve ways to address market participants' desire for more information relevant to their trading and risk transfer

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[13] "Transparency and over-the-counter derivatives: The role of transaction transparency," International Swaps and Derivatives Association, Research Note, No. 1, 2009, http://www.isda.org/researchnotes/pdf/ISDA-Research-Notes1.pdf (Accessed March 10, 2010).

decisions. Mandated transparency, in contrast, specifies a particular solution across the board. ISDA cautions that such a "one-size-fits-all policy" runs the danger of disregarding the inherent nature of specific markets and could short-circuit the evolution of market-based transparency provision that would otherwise arise in response to real market demands.

The current Chairman of the CFTC, Gary Gensler, has a different view. In his words, "[t]he financial regulatory system failed the American public."[14] He has testified that "as a critical component of reform… we have to bring comprehensive regulation to the over-the-counter (OTC) derivatives markets. We must lower risk, promote greater market integrity and improve market transparency." He proposes to "eliminate exclusions and exemptions from regulation for OTC derivatives," such that the law "covers the entire marketplace, without exception." The reforms he proposes have many components, only one of which is public disclosure. On that subject, he calls for "mandatory public disclosure of aggregate data on swap trading volumes and positions." Rather than arguing for transparency as a desirable end in itself, Chairman Gensler argues for transparency and other steps "to protect the American Public."

Canada's financial regulatory system has fared well through the economic recession, illuminating an alternate perspective. Prime Minister Stephen Harper delivered a message at the World Economic Forum in Davos, Switzerland that "Canada believes that financial sector regulation… must not be excessive." Canada's model is based on a simpler regulatory approach that focuses more on the outcomes the regulated community must achieve than how they are achieved, to ensure innovation is not stifled.

In comments to the WCI Markets Committee on the market oversight white paper issued November 19, 2009, several commenters recommended greater transparency in and oversight of the OTC derivatives markets.

In this issue as in many that the Markets Committee is considering, there may be a tradeoff between a desire to allow a secondary market to evolve and a desire to adopt lessons and best practices from experience in other markets.

4.1.2.5 Comparison to Other Markets

In the United States, the Commodity Exchange Act (CEA) and its implementing regulations require that regulated exchanges provide information regarding derivative trades to the CFTC.

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[14] "Testimony of Chairman Gary Gensler, Commodities Futures Trading Commission Before the House Committee on Agriculture," September 22, 2009, http://www.cftc.gov/ucm/groups/public/@newsroom/documents/speechandtestimony/opagensler-10.pdf (Accessed March 10, 2010).

This information is collected on a daily basis and includes aggregated position limits and trading activity for all of their members. The aggregated data for each member includes:

> open long and short positions, purchases and sales, exchanges of futures for cash, and futures delivery notices for the previous trading day. This data is reported separately by proprietary and customer accounts by futures month, and for options by puts and calls, expiration date and strike price.[15]

The CEA also requires regulated exchanges to make data available to the public regarding trading volume, open contracts, futures delivery notices, exchanges for cash, and prices.[16]

Futures commission merchants, members of regulated exchanges, and foreign brokers must provide a daily report to the CFTC regarding "special accounts," those with futures and options positions above the reporting level specified by the CFTC. The requirement to provide this specific data is referred to as the CFTC's Large Trader Reporting Program.[17] The reports must include data regarding "each futures position, separately for each reporting market and for each future, and each put and call options position separately for each reporting market...."[18] Reporting entities must aggregate their interest in or control of multiple accounts for the purpose of determining whether their positions trigger reporting requirements.[19]

In Canadian provinces, the obligation to report positions or trades is determined by exchange rules. For example, in Quebec all members of the Montréal Exchange,[20] a derivatives exchange, must disclose to the exchange their net positions when they exceed a certain threshold that triggers the reporting requirement. There are no obligations to disclose, on a daily basis, information to the regulator, the Autorité des marchés financiers (AMF).

The US Acid Rain Program, RGGI, and the EU ETS do not require special reporting of OTC derivatives in compliance instrument markets.

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[15] http://www.cftc.gov/industryoversight/marketsurveillance/ltrp.html
[16] 17 CFR Part 16.
[17] "Large Trader Reporting Program," http://www.cftc.gov/industryoversight/marketsurveillance/ltrp.html (Accessed March 15, 2010).
[18] 17 CFR 17.00(a)(1).
[19] 17 CFR 17.00(a)(2).
[20] "Home page – Montreal Exchange: the Canadian Financial Options and Futures Exchange," http://www.m-x.ca/accueil_en.php?changeLang=yes& (Accessed March 15, 2010).

4.1.2.6 No Draft Recommendation

The Markets Committee has not yet decided upon a Draft Recommendation on the collection and public disclosure of derivative positions. The Committee requests public comment on this issue.

4.1.2.7 Requirements of Tracking System

Collecting information on derivative positions would require the establishment of a repository for that information. Such a repository could, but is not required to be, a part of the compliance instrument tracking system. If the repository and tracking system are different, protocols for information exchange between them may be necessary.

4.1.3 Draft Recommendation 3: Treat Allowances and Offset Certificates Identically for Market Oversight Purposes

4.1.3.1 Background

The WCI cap-and-trade design involves two types of compliance instruments: allowances and offset certificates. There are differences between the creation and use of these two types of compliance instruments. First, Partner jurisdictions will issue offset certificates for projects that can demonstrate that removed or avoided emissions are real, additional, verifiable, and permanent. That process will have requirements for information transparency and disclosure, project approval, monitoring, and treatment of the risk of reversal that are separately being considered by the Offsets Committee. The process by which allowances are created and issued, in a predetermined quantity, will be different. Second, the WCI Partners have approved final recommendations for limiting the use of offset certificates to meet compliance.[21] Third, offset projects and allowances have differing risks; offset certificates may carry some risk of reversal, depending on jurisdictions' policy choices. Partly for these reasons, the market prices for allowances and offset certificates are different in the EU ETS, and likely to be different in a WCI market. Further, the number of offset certificates will be much smaller than the number of allowances.

4.1.3.2 Options

The Markets Committee has identified the following options for treatment of different types of compliance units:

A. Treat allowances and offset certificates identically for market oversight purposes; or,
B. Establish distinct requirements for offset certificates.

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[21] "WCI Recommendations for Implementing the Offset Limit," Western Climate Initiative, March 11, 2010. http://westernclimateinitiative.org/component/remository/func-startdown/224/ (Accessed March 18, 2010).

4.1.3.3 Evaluation of Options

For the purposes of this section, the Markets Committee considered the Market Oversight Draft Recommendations to define the scope of the policy decisions. In the case of each of the eleven other Draft Recommendations, the Committee evaluated the different nature of allowances and offset certificates and the additional complexity that would likely follow if the types of compliance instruments were treated differently.

In two cases, Draft Recommendation 7 (Holdings Limits) and Draft Recommendation 12 (Market Monitoring), the much smaller number of offset certificates could lead to differences in the implementation of a recommendation. In each, for example, the definition of market power would be different. However, these are likely to be quantitative differences rather than qualitative differences.

4.1.3.4 Experience in Existing Environmental Cap-and-Trade Programs

No offset certificates are issued in the Acid Rain Program, and none have yet been issued in RGGI. To the best of our knowledge, offset certificates usable for compliance in the EU ETS are treated, like allowances, as commodities.

4.1.3.5 Draft Recommendation

The Markets Committee recommends that the WCI cap-and-trade system treat allowances and offset certificates identically for market oversight purposes.

4.1.3.6 Relationship to Other Draft Recommendations

All other Draft Recommendations assume the adoption of this one, and are written for compliance instruments without distinction.

4.1.3.7 Requirements of Tracking System

This Draft Recommendation implies no additional requirements of a tracking system.

4.2 Market Participants

4.2.1 Draft Recommendation 4: Establish Legal Relationship with Market Participants Through Compliance Instrument Ownership Interest and Tracking System

4.2.1.1 Background

The WCI Partner jurisdictions intend to create a system to track compliance instruments. The instruments would exist as electronic records rather than physical certificates. The Partner jurisdictions are designing the requirements for this tracking system, and considering options for implementation.

This paper describes Draft Recommendations on market oversight. For each, the Markets Committee evaluated enforceability of the Draft Recommendation. A consideration for enforceability is the existence and nature of the relationship between the regulator and the market participant. The nature of the relationship will differ, for example, depending on whether or not a person has a legal obligation to surrender compliance instruments (is a “compliance entity”).

The nature of the relationship will also hold some combination of a “regulatory” relationship, and a “contractual” relationship. Here, a regulatory relationship is considered to be mandatory for designated persons, with the authority of a regulator established by statute and written into the regulations of a jurisdiction. A “contractual” relationship would be one voluntarily entered into by a person, with a counterparty of one or more jurisdictions or the tracking system, that provides the person the ability to take certain actions, under certain conditions. These types of relationships also imply differences in enforcement actions.

The Partner jurisdictions will have established relationships with the entities that will have compliance obligations under the cap-and-trade program. These relationships include reporting requirements and surrender obligations, though they are not the subject of these Draft Recommendations, which are focused on the activities around the holding and trading of compliance instruments.

The Markets Committee is particularly interested in defining the relationship between regulators and entities that do not have a compliance obligation under the cap-and-trade program.

4.2.1.2 Draft Recommendation

The Markets Committee recommends that either or both of having ownership interest in a compliance instrument and having an account in the tracking system would establish a legal relationship between one or more regulators and the account holder. These relationships would entail certain obligations of the entity.

4.2.1.3 Relationship to Other Draft Recommendations

Among the obligations entailed by holding an account in the tracking system would be Draft Recommendations 6 (Require Registration of Intermediaries as Market Professionals) and 9 (Require Disclosure of Beneficial Ownership). In addition, this Draft Recommendation assumes the implementation of Draft Recommendation 5 (Do Not Limit Market Participation to Compliance Entities), that compliance entities not be the only market participants. If participation is limited to compliance entities, the need to create a regulatory relationship to implement trading rules would probably be largely satisfied.

4.2.1.4 Requirements of Tracking System

This Draft Recommendation suggests a conceptual role for the tracking system. Technical requirements may include the ability to perform enforcement actions, such as revocation or suspension of trading for an entity or for all accounts.

4.2.2 Draft Recommendation 5: Do Not Limit Market Participation to Compliance Entities

4.2.2.1 Background

A WCI carbon market could involve diverse participants who may trade to satisfy a compliance obligation, purchase for resale to emitters, speculate on the price of compliance instruments, or diversify an investment portfolio. Entities that could participate in the carbon market may include compliance entities, investors, brokers and other intermediaries. Each entity would play a different role in the market.

Even if compliance entities receive allowances without charge from a government, the number may not be equal to their obligation, perhaps due to growth or contraction in their emissions or policy decisions on the quantity or formula for distribution. These entities may then choose to purchase additional compliance instruments from the primary or secondary market, or sell compliance instruments they will not require for compliance or for other reasons. In early 2009, industrial facilities in the EU ETS sold allowances, many freely allocated, to raise cash when other avenues of raising funds became more difficult.[22]

Though they would not be required to hold compliance instruments for compliance, other categories of participants could play market roles. Brokers and other intermediaries may, for a fee, arrange trades of compliance instruments between parties, or provide advice or other services. Investors may desire to be market participants to profit from trading.

4.2.2.2 Options

With regard to the secondary market, the WCI cap-and-trade program could either:

A) Limit market participation to compliance entities; or,
B) Open market participation to non-compliance entities.

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[22] E.g., "Carbon Markets 2009," IFSL Research, July 2009, http://www.ifsl.org.uk/upload/Carbon_Markets_2009.pdf (accessed October 1, 2009).

The Market Committee is separately developing Draft Recommendations on participants in the auctioning of allowances (primary market).

4.2.2.3 Evaluation of Options

The WCI Partner jurisdictions have received oral and written comments from stakeholders suggesting that market participation be limited to compliance entities. Many of these comments referred specifically to auctions, which are the subject of a separate WCI white paper, but may also be addressed in the context of secondary markets. The concerns expressed can be summarized as:

1) That participation by non-compliance entities will increase the price of allowances.
2) That participation by non-compliance entities increases the chances of market manipulation.
3) That participation by non-compliance entities will limit access to allowances.

The first concern may be related to questions regarding the role of speculation in markets. Investors can play important roles in competitive markets by increasing liquidity. A healthy market is “liquid,” meaning there is a sufficient number of buyers and sellers in the marketplace to allow trading to take place. Larger numbers of market participants make it more likely that there will be counterparty (i.e., another party willing to participate in a trade). A market with less liquidity may be subject to more price volatility and it may be more difficult for entities needing to buy compliance instruments to locate willing sellers. Unlike a traditional commodity market, a compliance instrument market will not have natural sellers outside of the primary market. Consequently, concerns about potential “excess” speculation by investors must be weighed against these benefits of allowing investors access to the carbon market.

The second concern implies either that more market participants increases the ease or risk of manipulation, or that non-compliance entities might attempt market manipulation while compliance entities would not. However, a larger number of market participants would most likely make manipulation more difficult, not less, by increasing liquidity and making control of a significant proportion of compliance instruments by one or a few persons harder.

The Markets Committee assumes for this discussion that the fraction of potential market participants who would attempt a manipulation is small. However, the potential for damage from a successful manipulation is large, and has precedent in recent experience in energy markets in WCI Partner jurisdictions, notably the energy crisis of 2000 – 2001. The Committee believes that participants who would consider an attempt to manipulate the market exist both among compliance and non-compliance entities. Limiting market participation to compliance entities would exclude some number of beneficial participants without measurable benefit in changing the fraction of participants who would consider market manipulation.

The third concern is that non-compliance entities may hold compliance instruments for some period of time, making them unavailable to compliance entities that may need them for compliance. There are many possible non-compliance reasons to hold compliance instruments; the auction design recommendation report commissioned by RGGI identifies five:[23] speculation; allowance market manipulation; electricity market interference; competitive advantage; and external compliance. In none of these cases would market risks be reduced by restricting the market to compliance entities, save potentially external compliance.[24] When restricting a market reduces liquidity, in fact, the risks are increased. Though this risk might be enhanced by allowing non-compliance entities to participate, it is nevertheless very small, as it has not been proposed by the existing GHG cap-and-trade programs, RGGI and the EU ETS.

In addition to considering whether participation limits are desirable, the Committee has considered whether they are practical. Fairly and reliably determining who has a compliance obligation in advance of the reporting deadline for a given year's emissions is not possible. The identities of compliance entities will also change as some enter or leave the program due to changes in their emissions or change in program scope, such as the inclusion of transportation fuels and residential and commercial fuel combustion in the second compliance period.

Limiting participation to compliance entities would also be difficult to enforce. For example, a person who would like to attempt a market manipulation but was otherwise excluded by participation rules might purchase some fractional interest in a facility that was a compliance entity, with an agreement that the person could trade as a representative of the entity. Under Draft Recommendation 1 (Treat Compliance Instruments as Commodities for Market Oversight Purposes), US states in the WCI would not have primary jurisdiction over derivatives markets and would therefore have constrained ability to enforce a participation limit in markets considered broadly.

4.2.2.4 Experience in Existing Environmental Cap-and-Trade Programs

The Acid Rain Program, RGGI, and EU ETS do not limit participation to compliance entities.

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[23] "Auction Design for Selling CO2 Emission Allowances Under the Regional Greenhouse Gas Initiative," Charles Holt, William Shobe, Dallas Burtraw, Karen Palmer, Jacob Goeree, October, 2007, section 9, "Hoarding of Allowances," http://www.rggi.org/docs/rggi_auction_final.pdf (Accessed October 6, 2009).

[24] "External compliance" is the possibility of another cap-and-trade program accepting WCI compliance instruments in lieu of its own, without any reciprocal acceptance of the program's compliance instruments by WCI jurisdictions.

4.2.2.5 Draft Recommendation

The Markets Committee recommends that both compliance and non-compliance entities be allowed to participate in the secondary compliance instrument market. Broad participation would be beneficial, and narrow participation harmful, to an compliance instrument market, especially in its early stages. Limiting participation to compliance entities would not be an effective policy to reduce the potential for market manipulation.

4.2.2.6 Relationship to Other Draft Recommendations

Draft Recommendation 6 (Require Registration of Intermediaries as Market Professionals) describes a requirement for a type of participant, assuming that intermediaries who are not compliance entities could be participants.

4.2.2.7 Requirements of Tracking System

The adoption of this Draft Recommendation would require that the tracking system be able to accommodate more accounts, and potentially more trades, than one for a program with limited participation.

4.2.3 Draft Recommendation 6: Require Registration of Intermediaries as Market Professionals

4.2.3.1 Background

There will likely be numerous types of market participants in the WCI cap-and-trade program. Each account holder would be required to provide some information (e.g., identifying information) to regulators in order to establish an account, a process that could be called "registration."

One category of market participants could be "intermediaries," which would include traders, dealers, advisers and investment managers in the market. There exist precedents of registration requirements for intermediaries operating in the majority of commodities derivatives markets and in limited commodities markets. In both the US and Canada, some commodities derivatives traders are required to register with regulators and/or self-regulatory organizations. This process is also widely referred to as "registration." According to the National Futures Association (NFA), "The primary purposes of registration are to screen an applicant's fitness to engage in business as a futures professional and to identify those individuals and organizations whose activities are subject to federal regulation." [25] The screening can improve consumer and market protection. In this discussion, the question is whether to require that persons be subject

[25] "Registration," National Futures Association, http://www.nfa.futures.org/NFA-registration/index.HTML (Accessed February 11, 2010).

to the requirements of knowledge of trading law, capital requirements, etc. that are needed to trade or offer professional advice on derivatives in the US and Canada, as described below. This type of registration is referred to in this paper as "market professional registration."

In the US, the CFTC oversees market professional registration of entities engaged in trading of commodities and derivatives. The CFTC authorizes the NFA, a private organization, to perform registration processing functions on behalf of the Commission. Regulation of similar activities in Canada is performed by a combination of provincial regulatory authorities, a national database, and the Investment Industry Regulatory Organization of Canada (IIROC). Like the NFA, the IIROC is a private organization.

Under both countries' regulatory systems, entities must determine whether the business being conducted qualifies as trading or advising under the applicable law. If the activity does fall within the applicable law, the next step is to determine whether there is an exemption from the requirement to be registered set out in the law. If there is no exemption, the person or firm will be required to obtain market professional registration in order to conduct trading activities.

US Registration Requirements[26]

The US Commodity Exchange Act sets forth registration requirements for entities engaged in trading commodities and regulated derivative transactions. The CFTC identifies the following categories of market participants that must register with the NFA unless they qualify for an exemption:

- **Merchants**
  - Futures Commission Merchant (FCM) – A FCM is an individual or organization which does both of the following:
    - Solicits or accepts orders to buy or sell futures contracts or options on futures and
    - Accepts money or other assets from customers to support such orders.
  - Agricultural Trade Option Merchant (ATOM) – Any person that is in the business of soliciting or entering option transactions involving an agricultural commodity listed in the CEA that are not conducted or executed on or subject to the rules of an exchange.
- **Brokers**
  - Introducing Broker (IB) – A person who is engaged in soliciting or in accepting orders for the purchase or sale of any commodity for future delivery on an

[26] "Intermediaries," Commodity Futures Trading Commission, http://www.cftc.gov/industryoversight/intermediaries/index.htm (Accessed February 11, 2010)

    exchange who does not accept any money, securities, or property to margin, guarantee, or secure any trades or contracts that result therefrom.
    - Floor Broker (FB) – A person with exchange trading privileges who executes trades for others by being personally present in the pit or ring for futures trading.
- **Floor Trader** (FT) – A person with exchange trading privileges who executes his or her own trades by being personally present in the pit or ring for futures trading.
- **Commodity Trading Advisor** (CTA) – A person who, for pay, regularly engages in the business of advising others as to the value of commodity futures or options or the advisability of trading in commodity futures or options, or issues analyses or reports concerning commodity futures or options.
- **Commodity Pool Operators** (CPOs) – A person engaged in a business similar to an investment trust or a syndicate and who solicits or accepts funds, securities, or property for the purpose of trading commodity futures contracts or commodity options. The commodity pool operator either itself makes trading decisions on behalf of the pool or engages a commodity trading advisor to do so.
- **Associated Person** (AP) – An individual who solicits or accepts (other than in a clerical capacity) orders, discretionary accounts, or participation in a commodity pool, or supervises any individual so engaged, on behalf of a FCM, IB, CTA, CPO, or an ATOM.

The NFA develops registration requirements for each category of intermediary listed above. In general, the registration requirements include a completed registration form with information about the activities of the intermediary, an application fee, NFA membership dues, and fingerprint cards for principals and associated persons, as well as proficiency requirements.

FCMs and IBs must also include a financial statement (if the firm does not meet minimum capital requirements, it may face additional reporting requirements), and a description of procedures regarding the following:

- money laundering;
- business continuity and disaster recovery;
- electronic order routing;
- promotional materials;
- supervision of associated persons;
- customer complaints; and
- margins/segregation (if applicable).

Canadian Registration Requirements

i. Provincial legislation

Depending on their type of market activity, intermediaries may be required to register with provinces and with the Investment Industry Regulatory Organization of Canada. The statute that establishes jurisdiction in a province and territory varies. In most provinces and territories

The Securities Act establishes the requirement to register to trade or advise in the trading of securities or derivatives.

In Ontario and Manitoba, The Commodity Futures Act requires that entities register with the provincial regulator before trading or providing advice regarding the trading of exchange-traded derivatives. The Act also provides jurisdiction to define what will be included under the term “commodity.”

In Quebec, registration to trade or provide advice in exchange traded or over the counter derivatives is mandated in The Derivatives Act.

The legislation in each province permits enactment of regulations or rules that provide the detailed requirements to obtain or maintain registration. In many cases these requirements are consistent among the provinces and territories and are referred to as National Instruments (when all jurisdictions have adopted the requirements) or Multilateral Instruments (when one or more jurisdictions have not adopted the requirements).

Canadian Securities Administrators interpret and apply the “National Instrument 31-103,” enacted in September 2009, and Companion Policy 31-103CP “Registration Requirements and Exemption,” which contain categories and requirements for registration of individuals and firms for trading or advising in exchange contracts.

ii. National Registration Database

In Canada, the National Registration Database[27] (NRD) is an internet-based system which provides firms and individuals with the ability to file most registration information electronically with any number of the provinces and territories. The use of NRD is mandated by all provinces and territories for securities and derivatives registrations.

The forms that are required to be used and submitted on NRD are standardized.

iii. Investment Industry Regulatory Organization of Canada (IIROC)

In all provinces and territories in Canada, in most cases a business or individual in the business of trading or advising in the trading of derivatives contracts is required to be a member of the IIROC. IIROC has been recognized as a self regulatory organization responsible for setting standards and regulating the conduct of its members.

[27] “National Registration Database Information | Site d’information de la BDNI,” National Registration Database, http://www.nrd-info.ca/ (Accessed February 11, 2010)

The inclusion of the IIROC membership requirement by the provincial and territorial regulators means the same standards apply to all Investment Dealers in the business of carrying out derivatives transactions in Canada.

Applicability of the provincial and territorial laws, as well as the requirements of IIROC establishes a comprehensive set of proficiency, capital, solvency, and client relationship requirements. In addition there is authority to conduct compliance audits of members, investigate and take action to suspend or cancel registration, and take action to stop activities that pose a risk to markets and market participants.

4.2.3.2 Options

The Markets Committee has identified the following options:

A. Requiring every account holder to register as a commodities market professional .
B. Requiring every account holder in the business of advising or trading on behalf of other entities to register as a commodities market professional.
C. Not requiring any market participants to register as a commodities market professionals.

In addition, the Committee considered with whom an entity would register: with the state and provincial governments, or with a third party.

4.2.3.3 Evaluation of Options

As stated by the NFA, the two primary advantages of requiring registration are to screen the fitness of potential traders, and an identification of those traders to regulators. The disadvantages are that market professional registration requirements impose burdens on the entities that are required to register, as well as on the governments enforcing the requirements and the entity (government or third-party) that establishes criteria and evaluates applicants against them. In addition, assuming the implementation of Draft Recommendation 4 (Establish Legal Relationship with Market Participants Through Compliance Instrument Ownership Interest and Tracking System), WCI Partner jurisdictions would be able to require registration of account and compliance instrument holders, but may not have the ability to require registration of entities without tracking system accounts or ownership interest in compliance instruments.

Requiring market professional registration would also create an enforcement obligation for government regulators to maintain and monitor registration data.

The specialized expertise to register as a market professional is not typically found in the firms that will be compliance entities, and so would have to be acquired if all participants were required to register. The NFA's two arguments for registration are also weaker when considering compliance entities: First, they have been identified to regulators through their compliance obligation. Second, it could be argued that they have been "pre-screened" by their very inclusion in the cap-and-trade program—that is, regulators have already determined them to be fit to trade.

Intermediaries with tracking system accounts could similarly be said to be identified to Partner jurisdiction regulators. However, they would not necessarily be identified to US federal regulators in the way that derivatives traders are. In addition, it may aid confidence in the market to have intermediaries "screened" as described above. Especially in a new market, participant confidence in intermediaries is important. Many prospective intermediaries are already registered to trade commodity derivatives, and standards for, e.g., record keeping and accounting for customer funds are reasonable protections for clients.

Intermediaries without tracking system accounts or ownership interest in compliance instruments, who are active only in the secondary market, may fall outside this requirement, which could weaken its effect.

The Partner jurisdictions could require market professional registration with an agency of the jurisdiction. This would allow for determination of the specific market professional registration requirements appropriate for the regional cap-and-trade system, and could expand upon existing registration requirements in Canada. It could also mean that requirements would not necessarily be subject to changes in US law. It could further provide for consistency across jurisdictions. Partner jurisdictions would also have full access to registration documents and any required reports.

Alternatively, Partners jurisdictions could require market professional registration with a third party. Doing so could reduce administrative costs for governments by shifting the burden to define requirements, evaluating applications, and receiving reports. The WCI Partners could contract with an independent market monitor to facilitate market professional registration, or attempt to establish relationships with the NFA and/or the IIROC. As noted above, many potential intermediaries are already registered with those organizations.

4.2.3.4 Experience in Existing Environmental Cap-and-Trade Programs

Neither RGGI nor the US Acid Rain Program requires market professional registration to participate in the secondary market. Derivatives trading in both markets, including registration requirements, is overseen by the CFTC.

4.2.3.5 Draft Recommendation

The Markets Committee recommends that brokers, merchants, and advisors who hold accounts in the tracking system and are in the business of trading or offering financial advice regarding

WCI compliance instruments be required to register as market professionals with an SRO to do so. Compliance entities and entities trading on their own behalf should not be required to register. The Committee recommends that Partner jurisdictions use or establish relationships with the NFA and IIROC to authorize them to register intermediaries on the jurisdictions' behalf.

4.2.3.6 Relationship to Other Draft Recommendations

This recommendation assumes the implementation of Draft Recommendation 4 (Establish Legal Relationship with Market Participants Through Compliance Instrument Ownership Interest and Tracking System), Draft Recommendation 1 (Treat Compliance Instruments as Commodities for Market Oversight Purposes), and Draft Recommendation 5 (Do Not Limit Market Participation to Compliance Entities).

4.2.3.7 Requirements of Tracking System

Adoption of this Draft Recommendation would necessitate a way to associate a registration number with a tracking system account.

4.3 Holdings and Transfers

4.3.1 Draft Recommendation 7: Holdings Limits

"Market power" is the ability of an entity to move prices through its behavior. Market power can be derived from the control of a large fraction of the instruments in question. Though not all exercises of market power are malign, some are intended to manipulate the market. The Markets Committee is interested in the possibility of reducing the risk of market manipulation by limiting the accumulation of market power. One mechanism it has identified is the use of "holdings limits," or limits on the number of compliance instruments any one entity could control in the tracking system. The Committee has commissioned a consultant's report on holdings limits, and will consider that report among other information as it works towards final recommendations.

4.3.2 Draft Recommendation 8: Require Use of a Central Limit Order Book for Secondary Market Transactions

4.3.2.1 Background

In secondary market trading, counterparties exchange cash or its equivalent for prompt delivery of compliance instruments. Any other type of transaction or contract—one, for example, in which counterparties agree to exchange cash for compliance instruments at some future date—is not a secondary-market trade but a derivative contract, and is subject to derivatives market regulations. For the purpose of discussion in this section, adoption of Draft Recommendation 1 (Treat Compliance Instruments as Commodities for Market Oversight Purposes), is assumed, implying no new restrictions on derivatives trades. The discussion here will then be of secondary markets.

Secondary market trades may be executed in a variety of venues, with different characteristics, including how market participants determine prices, transparency, and clearing. The Markets Committee has focused on three types of venues: exchanges, central limit order books (CLOBs), and "over the counter" (OTC) transactions.

Exchange Transactions:
Exchanges are trading venues that have agreed rules for membership, trade reporting, order matching, and many other facets of transactions. One set of rules determines how buyers and sellers agree on prices. In general, exchanges maintain "order books." An order is the instruction to buy (a "bid") or sell (an "offer" or "ask") under certain conditions. A "limit order" is the instruction to buy or sell a certain quantity at a certain price (the bid or ask price). A "market order" is the instruction to buy or sell a certain quantity at the best price available. The order book lists the bids and offers, arranged by price and then by the time the order was placed. If there are a bid and offer at the same price, an order matching system will pair them and the transaction will be completed, for the volume of the smaller order. The remainder of the larger order remains on the order book for a subsequent match. In very liquid markets, the time between the posting of an order and its fulfillment is very short.

Members of an exchange can see the entire order book, and the available orders—both price and volume—contain information that will influence orders they place. For example, the "bid-ask spread" is the difference between bid prices and offer prices. A trader would typically place an order within the spread. Visibility of the order book may tend to keep the spread smaller, as a central price is clear to market participants. However, exchange order books and transactions are typically anonymous.

Exchanges typically make the price and volume of transactions publicly available after they have been executed.

Exchange transactions also imply other services to participants, including settlement (the exchange of money and goods or instruments) and clearing (in which a central organization is the counterparty for both the buyer and the seller). Clearing is discussed in more detail in the next section.

Central Limit Order Book Transactions:
A central limit order book (CLOB) is separable from the other services of an exchange. A CLOB would be an order book visible to market participants. A "hard" CLOB would, like the order-matching system on an exchange, execute matching orders automatically. A hard CLOB would

allow orders either anonymously or with an identification of the participant. A “soft” CLOB would be a central location to post and find bids and offers, but would not automatically match them; traders would have to separately contact each other to complete the transaction. A soft CLOB could not be anonymous. Bids and offers would be as transparent as on an exchange. Post-transaction data could also be reported by a CLOB; this could be largely automatic on a hard CLOB, where orders were automatically and bindingly matched, but on a soft CLOB participants would have to report final prices and volume for public disclosure. Final prices and volume might well be different than the posted order as a result of the counterparties’ negotiation.

Clearing, if it were used, and settlement would be through venues other than the CLOB, selected by the counterparties.

Over-the-Counter Transactions:
For purposes of this discussion, “OTC” refers to cash market trades of compliance instruments that bypass centralized quotation and execution systems, and which may trade outside the bid-ask spread listed on those systems. There is no central order book; prices are determined by bilateral negotiation between parties, who may refer to data on transactions in other venues, if they are available, to determine a fair price. In most OTC markets, there is no prompt and automatic reporting and disclosure of price and volume, making activity relatively opaque. Whether this opacity is damaging is subject to debate, and depends among other things on the liquidity of trades in more transparent venues. Clearing, if it is used, and settlement are through venues chosen by the counterparties.

4.3.2.2 Options

The Markets Committee has identified two categories of options in trading venues.
The first category is whether or not to require transparency in orders:

A. Require all secondary market transactions to occur on one or more exchanges.
B. Require orders for all secondary market transactions to be posted on a hard CLOB.
C. Require orders for all secondary market transactions to be posted on a soft CLOB.
D. Allow OTC transactions without use of a central order book.

The second category is whether or not to require clearing of all transactions, independent of order book transparency.

4.3.2.3 Evaluation of Options

Choice of Venue
The Markets Committee seeks a recommendation that would maximize both market transparency and market liquidity. It believes that both are needed for price discovery for compliance instruments, which is necessary for entities to make efficient decisions on

investments and compliance strategies. However, there may be tradeoffs between transparency and liquidity.

Transparency is important for several reasons. First, transparency is crucial to market participants' evaluation of the trades they are considering. Participants without knowledge of the current buying and selling interest in the form of firm bid and ask quotations and transaction reports are at a distinct disadvantage in assessing the value of traded assets. Thus, transparency is crucial to pricing efficiency, the market's ability to accurately reveal the value of traded assets. In addition, transparency permits investors to evaluate whether the market is treating them fairly by identifying the best available price. Without access to the prices other market participants are paying for the same asset, they cannot effectively determine whether they have paid a fair price.

Second, access to accurate market information enhances the ability of regulatory examiners and independent auditors to carry out their respective responsibilities to ensure that transactions and positions are priced appropriately.

Pre-trade market transparency is supported by exchange-based and central limit order book trading. Pre-trade transparency makes the price and quantity of actionable buying and selling interest accessible to all market participants.

Post-trade transparency makes the price and size of the most recently executed trades accessible to all market participants. An exchange or a hard CLOB could make immediate post-trade transparency automatic. If a transaction price is required to transfer allowances from one account to another, post-trade transparency from all venues, including OTC, could also be supported by publication of data submitted to the tracking system (see section 4.3.4). However, timing is crucial. If the market is changing rapidly, delays in reporting by participants could obscure important information. The Markets Committee is concerned about the enforceability of requirements to report transactions promptly.

In a wholly OTC secondary market, buyers or sellers would solicit prices by telephone or email from whatever subset of intermediaries or potential counterparties they have the time and resources to contact, and hope that they have gotten a fair price. If traded prices are not promptly reported, traders cannot confirm whether or not they have obtained a fair price. In the absence of centralized collection and reporting of quotations and traded prices, intermediaries such as brokers and broker-dealers may emerge as market makers, offering pockets of liquidity to counterparties who might not otherwise find each other. The less transparent the market is, the more reliant compliance entities and others would be on intermediaries that would charge fees for transactions and could have significant information advantages.

At the same time, intermediaries can increase liquidity. First, a broker may have a broader understanding of a market than compliance entities or other participants, and may be able to facilitate negotiation of trades. Second, dealers may act as “market makers,” willing to either buy or sell compliance instruments at any time. Market makers make money on the spread, always attempting to sell allowances for a price higher than they paid. The narrower the spread is, the less incentive there is for an intermediary to be a market maker. Narrower spreads could then decrease liquidity.

Selecting one or a small number of trading venues may “drive liquidity” to that venue and ensure that buyers and sellers can find each other. However, exchanges and CLOBs fund themselves in part through fees which, though small, may discourage some transactions. Liquidity is not only affected by policy decisions, but can affect them as well. The importance of driving transactions to one or more regulated platforms depends in part on the liquidity of other pieces of the market. If a sufficient number of transactions occur that the current fair market price for a compliance instrument is discernable from widely available data, e.g., from exchanges, then bid and ask spreads should be small and transactions should seldom deviate far from that price. However, if secondary market transactions are rare, the reported price could be quite volatile, and current orders opaque.

The derivatives markets also play roles in price discovery and liquidity that may affect the tradeoffs in a policy decision to select one or more venues. The various inputs to consider appear to be impossible to predict.

In principle, multiple venues could be linked to a single quotation system. As an example of such a system, in the secondary market for US equity securities, all exchanges and Alternative Trading Systems (ATSs) are required to contribute their quotations in real time to a central quotation system called a securities information processor. The collection, processing, and distribution of quotations is a central function of a collection of rules, practices, and infrastructure known as the national market system (NMS). The purpose of the NMS is to ensure transparency, effective oversight, fairness and pricing efficiency. Nearly all secondary-market transactions of U.S. securities listed on exchanges and ATSs are executed at prices within the NMS’s published bid-ask spread for listed shares, and last-trade price and quantity are available in real time to all market participants.

Customization in OTC transactions and duration of OTC contracts compared to illiquid long-term markets are often cited as reasons to allow OTC derivative contracts. However, in secondary markets, neither of these is a strong argument: there is very little to customize, and the timescale is short by definition. An exception is repurchase or “repo” agreements, in which compliance instruments are sold by one entity to another, with an agreement that the first entity will buy them back in the future. This is effectively creating a loan with the compliance instruments as collateral. Technically derivatives, repos still require an OTC transfer of ownership.

Partner jurisdictions could enforce use of a particular venue by requiring an identifying number for an order or executed transaction to accompany transfers of allowances from one account to another. The venue could be required to provide information on transactions to the jurisdictions, as well as quotations and last-trade prices. Compliance entities might be offered low- or no-cost access to order-matching services at the designated venue (though see section 4.2.2 for a discussion of identifying compliance entities).

However, there is a blurry line between the secondary and derivatives markets. The European Climate Exchange offers a standard contract for European Union Emission Allowance Daily Futures, which are settled by physical delivery in at most two business days. If the Draft Recommendation 1 (Treat Compliance Instruments as Commodities for Market Oversight Purposes) is adopted and the Partner jurisdictions make no collective recommendations to restrict derivatives trades, then restrictions on secondary market transactions might be easily dodged by firms creating forward contracts with very short expirations. Treatment of allowance transfers that are the fulfillment of derivatives contracts and not secondary market transactions would be another implementation consideration. Also, compliance entities might desire to transfer compliance instruments between facilities owned by a single company, or between entities owned by the same holding company. From 1994 – 2003, only about half of the allowance transfers in the U.S. Acid Rain Program were between "economically distinct organizations."[28] The implications for creating and enforcing exceptions to a venue requirement should be considered.

Clearing

In a recent case of a systemic problem due to counterparty risk, the September 15, 2008 bankruptcy filing of Lehman Brothers was part of, and greatly accelerated, a financial panic, in part because Lehman Brothers was counterparty to many other large financial institutions in a variety of transactions. Its collapse left counterparties uncertain about their losses, and uncertain about the exposure of others. This uncertainty helped to freeze financial activity.

The clearing organizations associated with exchanges require from all members security deposits that can be used if a member defaults on its contracts. In this way, the risk of default

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[28] WCI staff analysis of data at "Trading Activity Breakdown | Market Analyses | Assessments and Tools | Clean Air Markets | Air &", Environmental Protection Agency, http://www.epa.gov/airmarkt/progress/transtable.html (Accessed January 4, 2010).

from one company is shared by clearing members. The members then have a strong incentive to set the rules for membership and for transactions to balance default risk and the cost of doing businesses.

Clearing through a central counterparty can reduce the risk of systemic problems by setting requirements for collateral, limiting the exposure of any single member, and collecting information for regulators and the public. On the other hand, clearing organizations may not be willing to guarantee all trades that would be economically efficient, and will charge for their services. The clearing function is typically integrated with trade confirmation, netting, registry (or "depository") and settlement services. Without clearing organizations, traders would need to individually evaluate the credit risk of every trade and counterparty, and establish separate payment and delivery arrangements with each counterparty. Central counterparty clearing reduces transaction processing costs for participating traders, and enables higher trading volumes by streamlining post-trade processing. However, clearing is effectively the extension of credit by the central counterparty, which comes at some cost. Many end users of commodities can obtain similar credit for at smaller expense, and so prefer not to clear transactions.

Though there are differing opinions about the advantages of clearing, in general it is believed to reduce the risk of systemic problems by reducing or redistributing counterparty risk. This risk is larger in derivatives markets, where positions may be built up over some period of time, and during which time the price may change, than in secondary market transactions, which are settled in the matter of a day or two at an agreed-upon price.

In a typical secondary-market exchange, only firms that sustain a high volume of trades are clearing members. Lower-volume or occasional traders trade through intermediaries (brokers or asset managers, e.g.) that are also clearing member firms. It is not necessary to operate as a clearing member firm in order to benefit from the transaction-processing efficiencies of a cleared market. However, requiring an intermediary that is a clearing member is potentially a cost to compliance entities and others.

4.3.2.4 Experience in Existing Environmental Cap-and-Trade Programs

Neither the Acid Rain Program nor RGGI requires secondary market transactions to go through a single venue, quotations to be reported to a central service, or clearing for secondary market transactions.

4.3.2.5 Draft Recommendation

The Markets Committee recommends that orders for secondary market transactions be required to be reported to a "hard" central limit order book to centralize liquidity and enhance transparency. The CLOB could be the order-matching system of a designated exchange or another system designated by the WCI Partner jurisdictions. Considering all the tradeoffs identified above, the Committee believes that the public is best served by clear and immediate price signals. However, we recognize that this is a particularly complex issue and we invite stakeholder comment on this Draft Recommendation.

In the event that the CLOB is not part of an exchange, the Committee does not recommend requiring clearing of non-exchange transactions. The risks identified are small in secondary markets.

4.3.2.6 Relationship to Other Draft Recommendations

This Draft Recommendation relies on the adoption of Draft Recommendation 4 (Establish Legal Relationship with Market Participants Through Compliance Instrument Ownership Interest and Tracking System). It assumes the adoption of Draft Recommendations 1 (Treat Compliance Instruments as Commodities for Market Oversight Purposes); 5 (Do Not Limit Market Participation to Compliance Entities), and 10 (Information Required for Compliance Instrument Transfer).

4.3.2.7 Requirements of Tracking System

The tracking system would be required at least to accept and verify a transaction number from the central limit order book before compliance instruments were transferred between accounts. The tracking system could potentially provide the function of the central limit order book.

4.3.3 Draft Recommendation 9: Require Reporting of Beneficial Ownership

4.3.3.1 Background

When one person holds property (or some other interest) for the benefit of another person, the person holding the property is referred to as the “record” or “legal” owner and the person for whom the property is being held is referred to as the “beneficial,” “equitable,” or "indirect" owner. For example, where title to land is registered in the name of a trustee who holds the property for the benefit of the owners of the trust, the trustee is the record owner and the beneficiaries of the trust are the beneficial owners. Similarly, when a brokerage firm holds securities (e.g., stock certificates) in their own firm’s name (their “street name”) for their customers’ accounts with the firm, the firm is the legal owner and the customers are the beneficial owners.

4.3.3.2 Options

WCI Partner jurisdictions have several options regarding reporting of beneficial ownership, including, but not limited to the following:

A. Requiring that account holders publicly disclose beneficial ownership;

B. Requiring that account holders report beneficial ownership to regulators on a confidential basis;
C. Require that account holders maintain records of beneficial ownership and produce such records upon written request of regulators; or
D. Not require that account holders maintain records of or disclose information regarding beneficial ownership.

Should the WCI jurisdictions elect to require reporting of beneficial ownership to regulators and/or disclosure to the public, decisions must also be made regarding the timing of such disclosures. For example, disclosure of the beneficial ownership could be required

A. When an account is opened on the registry;
B. Contemporaneously with any transaction transferring ownership
C. On a periodic basis, or
D. With some other fixed or variable requirement regarding the timing of the disclosure.

4.3.3.3 Evaluation of Options

The different options outlined above in 4.3.3.2 have significant implications for the regulators charged with the administration, monitoring and enforcement of the compliance instrument markets and the overall cap and trade program. In addition, the different options have impacts on the level of transparency in the market. Below we discuss the major implications identified to date.

The regulators responsible for prevention of manipulation and speculative activity that leads to price distortion in the compliance instrument markets will benefit from access to information regarding the beneficial ownership of compliance instruments. Absent this information, regulators may not be able to perform their duties, which may include: (a) monitoring the market for manipulative trading schemes such as “wash” sales, which are trades that appear to be between two parties but are really between different accounts controlled by the same person; (b) detecting the accumulation of substantial positions in compliance instruments that could allow the beneficial owner to exercise of market power; (c) enforcing a holdings limit or other rule designed to avoid speculative activity that leads to price distortion; or (d) providing accurate and timely information on the compliance instrument and derivatives market to other regulators (e.g., US federal regulators of derivatives markets).

In addition, the regulators responsible for environmental compliance could also benefit from access to information regarding beneficial ownership. Those regulators may want the ability to track the actual compliance instrument holdings of reporting sources (at least at a business entity level) over time, rather than simply at the end of a three-year compliance period. Such information would allow early detection of sources that have (a) taken insufficient steps to procure the compliance instruments they will need at the end of the compliance period, or (b) appear to be taking on excessive risk through the accumulation of a large excess of compliance instruments. Such assessments would be difficult, if not impossible, without accurate information as to the beneficial ownership of compliance instruments.

The public disclosure of beneficial ownership has several potential implications we have identified to date. Public disclosure of beneficial ownership would enhance the transparency of the cap and trade program. This may help maintain pubic confidence in the program. Transparency in ownership also would allow local interests to track the market position of local sources. Transparency in ownership would enhance the flow of information in the market, which could lead to improved efficiency. Transparency in ownership also puts more "eyes" on the market, increasing the likelihood that market violations will be detected and reported. Transparency in ownership could also reveal corporate trading strategies; however, such information may already be public for a large number of sources (e.g., because the account holder and owner are one and the same, or because disclosure is required by another regulator such as the SEC or a Utilities Commission).

4.3.3.4 Experience in Existing Environmental Cap-and-Trade Programs

In existing emissions markets in the United States, the EPA and RGGI have set up at least two classifications of accounts on their registries: compliance accounts and general accounts. Each facility with a compliance obligation must have a compliance account registered in its own name. In creating the compliance account, EPA and RGGI regulations require that the facility disclose the names of the legal and equitable owners and operators of all emitting units at the facility, identify those units in detail and assign an individual as the authorized account representative. Since the compliance account is tied to a single facility, it is relatively easy to track beneficial ownership.

Under the EPA's and RGGI's regulations, general accounts may be opened by a facility, a person owning one or more facilities, or a person with no compliance obligation (e.g., brokers, dealers, banks, individuals, non-governmental organizations, etc.). General accounts are opened in the name of the representative and her company or organization, as opposed to the name of a single facility. Registration of a general account requires identification of "all parties with an ownership interest in the allowances held in this account."[29] If the parties to an account change, the form must be amended and resubmitted within 30 days.[30] In this way, the EPA and RGGI appear to capture some beneficial ownership information both up front and on an ongoing basis through the registration process.

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[29] "Instructions for General Account Form," Environmental Protection Agency Form 7610-5 (Revised 12-2009), http://www.epa.gov/airmarkets/business/docs/forms/gen_acct2010.pdf (Accessed February 22, 2010).
[30] US Code of Federal Regulations, Title 40, section 73.31 (c)(iv).

In addition, all persons or groups participating in a RGGI auction must disclose their beneficial relationships to other persons and groups participating in the auction. Information on beneficial ownership is gathered via a thorough an online application system for participants in the regional auctions and is used, in part, to ensure that participants comply with the 25% purchase limit.

Not currently gathered by RGGI and the EU ETS, however, is each beneficial owner's fractional interest in compliance instruments in an account. This information would be necessary if the WCI Partner jurisdictions were to decide to fully evaluate an entity's holdings (see section 4.3.1).

4.3.3.5 Draft Recommendation

The Markets Committee recommends that account holders be required to report beneficial ownership of all compliance instrument holdings to regulators on a confidential basis, including each owner's share in an account. This means each participant in compliance instrument markets where WCI compliance instruments are sold will be obligated to report any party who sponsors or benefits from an agent's activities.

The Committee further recommends that account holders be required to report changes in the fractional ownership of compliance instruments in an account immediately upon the transaction, even if the transaction does not involve a transfer of allowances between accounts.

When some portion of the ownership information is proprietary, it should be kept confidential.

4.3.3.6 Relationship to Other Draft Recommendations

This Draft Recommendation assumes the adoption of Draft Recommendations 4 (Establish Legal Relationship with Market Participants Through Compliance Instrument Ownership Interest and Tracking System), 5 (Do Not Limit Market Participation to Compliance Entities), 6 (Require Registration of Intermediaries as Market Professionals), and interacts with Draft Recommendations 10 (Information Required for Compliance Instrument Transfer), and 11 (Secondary Market Holdings and Transfer Information Disclosed to Public). Implementing a holdings limit, discussed in Draft Recommendation 7 (Holdings Limits), would require disclosure of beneficial ownership to regulators.

4.3.3.7 Requirements of Tracking System

If disclosure of beneficial ownership is required, the tracking system would need to accommodate multiple owners for accounts, their fractional ownership, and mechanisms to update this information quickly as it changes.

4.3.4 Draft Recommendation 10: Information Required for Compliance Instrument Transfer

4.3.4.1 Background

Assuming the adoption of Draft Recommendation 4 (Establish Legal Relationship with Market Participants Through Compliance Instrument Ownership Interest and Tracking System), the tracking system would hold the record of ownership of compliance instruments. Collection of basic information would be required upon transfer of ownership to make the tracking system a reliable repository and to collect market information that is important for transparency. (Draft Recommendation 11 considers which of this collected information would be disclosed to the public).

4.3.4.2 Options

At a minimum, the tracking system, to be a complete record of ownership, would need to record for each transfer:

A. The account of origin, and name of the authorized person for that account;
B. The receiving account;
C. The serial numbers of the compliance instruments being transferred (and by implication the quantity being transferred); and,
D. The date and time of the transfer.

Any number of additional data could be collected; the Markets Committee has identified the following to be of particular interest:

E. Changes to beneficial ownership;
F. The name of an authorized person for the account that will receive compliance instruments;
G. The compliance instrument price and currency (US or Canadian dollars);
H. Date of the contract, if different from date of transfer (e.g., for derivatives contracts);
I. Other information related to derivatives transactions.

4.3.4.3 Evaluation of Options

A minimum amount of information must be kept by the tracking system in order for it to be a reliable record of ownership. Additional information may assist regulators in oversight of the market, and disclosure to the public would increase market transparency. These benefits can be weighed against the additional burden to participants of reporting more information, and to regulators in collecting and analyzing it.

Draft Recommendation 9 (Require Disclosure of Beneficial Ownership) includes a discussion of beneficial ownership. Draft Recommendation 8 (Require Use of a Centralized Order-Matching

System for Transactions) includes a discussion of a centralized quotation service. Draft Recommendation 11 (Secondary Market Holdings and Transfer Information Disclosed to Public) includes a discussion of public disclosure of both account holder information and secondary market information.

In general, it is only a small amount of additional reporting burden to request the name of the authorized person for the receiving account. In the case of exchange trading where transactions are netted and anonymous, the jurisdictions may choose to require a net report of accounts from which or to which allowances were transferred. The compliance instrument price for the transaction could be challenging if, for example, compliance instruments were bundled with another product (electricity or natural gas) with a single price. However, the Partner jurisdictions could insist on a price report.

The price and date of contract could also be challenging for some derivatives. For example, an exchange-traded futures contract is settled at an agreed-on date, with the product transferred for a settlement price that is likely to be different than the price at which the contract was purchased. The gain or loss is computed at some interval, say, daily, and added to or subtracted from the margin accounts of market participants. The "date of contract" and price would then have to be carefully defined in order to avoid confusion.

4.3.4.4 Experience in Existing Environmental Cap-and-Trade Programs

The Acid Rain Program does not require price information or any information about the date of a contract to deliver compliance instruments. RGGI requires price information for any transfer between non-affiliated entities, as well as date of contract; the date of contract is defined to be the settlement date.

4.3.4.5 Draft Recommendation

The Markets Committee recommends requiring identification of: the name of the authorized person for the account of origin; the number of the account of origin; the name of the authorized person for the account that receives compliance instruments; the account receiving compliance instruments; the serial numbers of the compliance instruments being transferred, and the compliance instrument price. It further recommends requiring a net report from an exchange or any organization that nets transactions. It recommends that the tracking system supply the time and date stamp. If the Partner jurisdictions require collection of derivative positions (Section 4.1.2) it would be duplicative to require information on date of contract.

4.3.4.6 Relationship to Other Draft Recommendations

This Draft Recommendation assumes the adoption of Draft Recommendations 4 (Establish Legal Relationship with Market Participants Through Compliance Instrument Ownership Interest and Tracking System), 5 (Do Not Limit Market Participation to Compliance Entities), 8 (Require Use of a Centralized Order-Matching System for Transactions), 9 (Require Disclosure of Beneficial Ownership), and 11 (Secondary Market Holdings and Transfer Information Disclosed to Public).

4.3.4.7 Requirements of Tracking System

This Draft Recommendation would require the tracking system to allow and require that the fields for all the above named data, as well as net reports, and supply a time and date stamp with the submission of information.

4.3.5 Draft Recommendation 11: Secondary Market Holdings and Transfer Information Disclosed to Public

4.3.5.1 Background

As stated in the Market Oversight white paper released in November 2009, the central purpose of a market mechanism is to aggregate and transmit price information. With full, true and plain disclosure, both regular and timely, market participants can use the information to determine a fair market price. In the secondary market, it is important for participants to have reliable, good quality and timely information about outstanding bids and offers, and recent trades, so they can discover the right price and act accordingly.

The WCI Markets Committee has proposed the principle of "Transparency and the Reporting and Disclosure of Relevant Information," to acknowledge that the release of information on the operation of the compliance instrument market builds and retains public confidence, and can change the decisions of market participants.

> "A transparent marketplace could provide carbon market participants, regulators, and potentially the general public with information to determine where carbon instruments are trading, the entities involved in the transactions, the trading volume, and the prices at which they are trading. This, in turn, could allow government officials and market watchdogs to quickly determine the cause(s) of unusual price volatility. In addition, information about prices, volume, and bid/ask spreads could also help market participants make informed investment decisions, thereby reducing some of the causes of price volatility in the first place."[31]

[31] Source: "U.S. Carbon Market Design: Regulating Emission Allowances as Financial Instruments", Jonas Monast, Jon Anda, Tim Profeta, Duke University, February 2009, CCPP 09-01, working paper, Climate Change Policy Partnership http://www.nicholas.duke.edu/ccpp/ccpp_pdfs/carbon_market_primer.pdf (Accessed March 30, 2010).

As noted in section 4.3.3.4, RGGI and the Acid Rain Program have created two types of accounts: general accounts, which any person may have and can be used for trading; and compliance accounts, which are established for entities that must surrender compliance instruments matching their emissions to satisfy a regulatory obligation. The Partners are developing requirements for a tracking system; the Markets Committee considered the possibility of two types of accounts in developing this Draft Recommendation.

4.3.5.2 Options

Account Information Disclosure

The Markets Committee has considered the following options for public disclosure of account holder information:

A. Account representative for compliance and trading accounts;
B. Owner/operator associated with compliance accounts;
C. Beneficial owners of compliance units held within account;
D. State/province in which account representative is located.

Secondary Market Information Disclosure

The Markets Committee has considered the following options in for public disclosure of compliance instrument transfers:

A. Trade volume, quantity and settlement prices of compliance units traded;
B. Names of counterparties to each transaction;
C. Names of beneficial owners;
D. Compliance account holdings;
E. Trading account holdings.

The Markets Committee has considered the following options for means of disclosure of secondary market information:

A. Directly through the online tracking system, and through search functions;
B. Through exchanges where transactions occur; and/or,
C. Through periodic WCI market reports published on the WCI website.

The Markets Committee has considered the following options for the frequency and timing of the secondary market information disclosure:

A. In real time for volumes and prices;
B. Daily for volumes and prices; and/or,
C. Quarterly or post-regional auctions for summaries.

4.3.5.3 Evaluation of Options

The WCI Markets Committee recognizes that a balance must be struck between the benefits of transparency and the need for entities to protect certain sensitive information, consistent with applicable law relating to the disclosure of information. Some information may reveal competitive positions that would do more to assist market manipulation than prevent it. Thus, certain information collected through the tracking system or other aspects of the WCI cap and trade system should not be disclosed publicly in its original reported form. In some cases information can be aggregated in order to maintain the anonymity of the actors while still relaying important market information.

The WCI Partner jurisdictions will have access to the raw information reported to the tracking system, as it is required for regulatory authorities to conduct effective oversight and monitor compliance. In its Final Recommendations, the Markets Committee may recommend restrictions on staff of those regulatory authorities who have access to confidential market information collected through the tracking system from operating in the market, to prohibit insider trading based on undisclosed material information and tipping.

The key characteristics that the WCI Markets Committee seeks in terms of disclosed information are that it is:

- Full;
- Straightforward;
- Good quality;
- Reliable;
- Regular; and,
- Timely.

The holdings in a compliance account are useful to reveal to support compliance, as an indication of whether a regulated entity is on track to retiring as many compliance instruments as are required to cover its covered emissions for a compliance period. However, holdings in trading account are not required for the same purpose, and may reveal sensitive information. The total number of compliance instruments within the cap and trade will be publicly established by the Partner jurisdictions as they create their allowance budgets.

The increased transparency resulting from a high frequency of market information disclosure must be balanced against the administrative cost to market participants and regulatory authorities to report, collect and process that information within the given timeframe.

4.3.5.4 Experience in Existing Environmental Cap-and-Trade Programs

Existing environmental cap and trade programs handle public disclosure in the following ways:

DISCLOSURE	EU ETS: Community Independent Transaction Log	RGGI: RGGI COATS[32]
Delivery	Information on all transactions (transfer, issuance, etc. of allowances) recorded by the Community Independent Transaction Log, including originating and destination account number, holder and type. This information will be made available online and at EU level but not until five years after the year in which the transaction took place. Price is not recorded in ETS registries or in the CITL.	RGGI CO_2 Allowance Tracking System (COATS) allows public to view, customize and download reports of allowance market activity
Account information	Varies by country. In the UK, reports listing operator holding accounts and person holding accounts are published on UK registry website. Reports are updated regularly.	Account number, account name, facility owner/operator (for compliance accounts), parties with an ownership interest in the allowances in the account (for general accounts), account type, authorized account representative, and state are all public.
Transaction information	Counterparties not disclosed.	Transaction type, financial transaction date, RGGI COATS allowance transfer recordation date, price and number of allowances for each transaction, and weighted average price of all transactions during the range of dates specified by the query are public. Counterparties not disclosed.
Trading/active account holdings	Number of instruments in each account is not disclosed.	Number of instruments in each account is not disclosed.
Compliance/ retirement account holdings	Not applicable.	Number of instruments in each account is not disclosed.
Derivatives positions	Not disclosed.	Not disclosed.
Market reports	Exchanges and news services produce daily and real-time market reports.	Exchanges and news services produce market reports; the third-party market monitor prepares a public report on each auction.

4.3.5.5 Draft Recommendation

The WCI Markets Committee recommends the following:

Tracking system account information publicly disclosed on an ongoing basis:

[32] RGGI > CO2 Allowance Tracking System > Data in RGGI COATS > Public Reports (http://www.rggi.org/tracking/data/public_reporting)

A. Account representative for compliance and trading accounts;
B. Owner/operator associated with compliance accounts;
C. Names of beneficial owners of compliance units held within account;
D. State or province in which account representative is located.

Market information publicly disclosed daily through the tracking system:

E. Compliance account holdings.

Market information not publicly disclosed:

F. Names of counterparties and beneficial owners to each transaction;
G. Fraction of each beneficial owner's interest in an account;
H. Trading account holdings.

4.3.5.6 Relationship to Other Draft Recommendations

Assuming the adoption of Draft Recommendation 8 (Require Use of a Central Limit Order Book for Secondary Market Transactions), price information will be publicly disclosed through that mechanism, and need not be duplicated through the tracking system. This Draft Recommendation also relies on the implementation of Draft Recommendations 9 (Require Disclosure of Beneficial Ownership) and 10 (Information Required for Compliance Instrument Transfer). Draft Recommendation 2 (Information on Derivatives Positions) includes a related discussion on disclosure of derivatives position information.

4.3.5.7 Requirements of Tracking System

This Draft Recommendation implies that the tracking system must:

- Be online;
- Have some services of the tracking system accessible to the public;
- Have some services of the tracking system restricted to account holders, to authorized staff of regulatory authorities, or to system maintenance service providers;
- Have filters such that, for example: compliance account holdings are shown but general trading account holders are not;
- Have the ability to generate customized reports for regulatory authorities.

4.4 Market Monitoring

4.4.1 Draft Recommendation 12: Market Monitoring

The Markets Committee believes that a third-party contractor may improve oversight by complementing and supplementing the monitoring of the Partner jurisdictions. For its Final Recommendations, the Committee will evaluate options more fully and may describe the recommended role of a contractor.

5 Roles of Provincial, State, and Federal Regulatory Agencies

The Markets Committee is analyzing market oversight jurisdiction at the US federal and state and Canadian federal and provincial levels, for both secondary and derivatives markets. Specifically, the committee is examining whether WCI jurisdictions currently have the authority to implement the recommendations made for oversight of the secondary market, and what agencies have this authority. In its Final Recommendations, the Committee intends to include a discussion of jurisdiction for the oversight authorities recommended, as well as coordination between the relevant regulatory bodies.

6 Conclusion

The Markets Committee believes that these Draft Recommendations, collectively, are in accord with the principles adopted for market oversight, and that they provide good risk management in balancing the potential for market manipulation against the potential to stifle legitimate market activity. It has also identified some areas where additional work is required to make a recommendation. The Committee welcomes comment on the Draft Recommendations individually and collectively, and in particular on:

A. Whether the tools available to WCI Partner jurisdictions for market oversight have been completely and correctly identified;
B. Whether the Draft Recommendations would correctly maximize the environmental and economic benefit to the public and support WCI's Principles of Market Oversight;
C. Whether the Committee should recommend collection of derivatives position information from market participants, including on over-the-counter derivatives; and if so, what of that information to disclose to the public;
D. The Draft Recommendation to require secondary market trades to use a central limit order book.

Incorporating stakeholder comment on the Draft Recommendations among other sources of information, the Committee plans to release Final Recommendations before June 30, 2010.

April 5, 2010 Market Oversight Draft Recommendations

List of Commenters

Clean and Reliable Energy Supply Consortium

Coalition for Emission Reduction Projects

Deep River Group

Fontaine, Joe

International Emissions Trading Association

Monitoring Analytics

Montreal Climate Exchange

Morgan Stanley Capital Group, Inc.

Pacific Carbon Exchange

Sacramento Municipal Utility District

Southern California Public Power Authority

Western Climate Advocates Network

Western Power Trading Forum

Western Climate Initiative

Market Oversight
Draft Recommendations

Stakeholder Conference Call

11:00 a.m. Pacific time, April 20, 2010

www.westernclimateinitiative.org

Western Climate Initiative

- A collaboration of seven U.S. states and four Canadian provinces to reduce greenhouse gas emissions
- Design of cap-and-trade program; now in implementation phase
- 2009 – 2010 work plan: Detailed Design Summary by June, 2010
- Markets Committee includes market oversight task

Market Oversight Objectives

- "The recommended design will provide opportunities to obtain low-cost emission reductions through emission trading, allowance banking, and inclusion of an offsets component."

WCI Design Recommendations, September 23, 2008

- "The WCI Partner jurisdictions and stakeholders want appropriate safeguards and oversight of the allowance and offset credit trading markets and want them to function efficiently."

Materials for Markets Workshop, April 9, 2009

Oversight Recommendations Process

- Public workshop April 9, 2009
- White Paper November 18, 2009
- Stakeholder call December 2, 2009
- Draft Recommendations paper April 1, 2010
- Stakeholder call April 20, 2010
- Close of comments April 30, 2010
- Final Recommendations paper
- Detailed Program Design contributions

Draft Recommendations

Four categories:

- Allowances, Offset Certificates, and Derivatives
- Market Participants
- Holdings and Transfers
- Market Monitoring

Allowances, Offset Certificates, and Derivatives

- #1: Treat Compliance Instruments as Commodities for Market Oversight Purposes
  - Implies primary regulation of derivatives by provincial securities commissions and US federal regulators
- #2: Information on Derivatives Positions
- #3: Treat Allowances and Offset Certificates Identically for Market Oversight Purposes

Market Participants

- #4: Establish Legal Relationship with Market Participants Through Compliance Instrument Ownership Interest and Tracking System
- #5: Do Not Limit Market Participation to Compliance Entities
- #6: Require Registration of Intermediaries as Market Professionals

Holdings and Transfers

- #7: Holdings Limits
- #8: Require Use of a Central Limit Order Book for Secondary Market Transactions
- #9: Require Reporting of Beneficial Ownership
- #10: Information Required for Compliance Instrument Transfer
- #11: Secondary Market Holdings and Transfer Information Disclosed to Public

Market Monitoring

- #12: Market Monitoring

Request for Stakeholder Comments

A. Whether the tools available to WCI Partner jurisdictions for market oversight have been completely and correctly identified;

B. Whether the Draft Recommendations would correctly maximize the environmental and economic benefit to the public and support WCI's Principles of Market Oversight;

C. Whether the Committee should recommend collection of derivatives position information from market participants, including on over-the-counter derivatives; and if so, what of that information to disclose to the public; and

D. The Draft Recommendation to require secondary market trades to use a single central limit order book.

For More Information:

- Michael Gibbs, California, Markets Committee Co-Chair

  mgibbs@calepa.ca.gov

- Jim Whitestone, Ontario, Markets Committee Co-Chair

  jim.whitestone@ontario.ca

- Mark Wenzel, California, Market Oversight Task Group Lead

  mwenzel@calepa.ca.gov

Western Climate Initiative

Offset System Essential Elements Draft Recommendations Paper

April 2010

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1 Executive Summary

This paper is the second paper issued by the WCI Offsets Committee as part of its efforts to design the WCI Offset System. The first paper, entitled *Offset Definition (Task 1.1) and Eligibility Criteria (Task 1.2) White Paper*[1] ("the Criteria White Paper") was released in July and presented options for defining a WCI offset and the essential criteria. The release of the first paper was followed by a period of gathering stakeholder input through webinars and written comments.[2] This recommendations paper was prepared by members of the WCI Offsets Committee based on the first options paper, stakeholder feedback, and input from WCI Partners. This recommendations paper presents draft recommendations for the offset definition and essential criteria. Following the release of this paper, stakeholders will have an opportunity to provide feedback prior to issuing the final WCI recommendations. A final recommendations paper is expected to be released in early spring 2010.

For ease of reference, all of the draft recommendations in this paper are copied in Table 1.0 below.

Table 1.0 Draft Recommendations

Section	Criteria	Draft Recommendation
3.1	Offset Definition	A WCI offset certificate is issued by a WCI Partner Jurisdiction and represents a reduction or removal of one metric ton of carbon dioxide equivalent (tCO_2e). The reduction or removal must meet the recommended essential criteria for reductions and removals to be real, additional, permanent, and verifiable. Reductions and removals must also be clearly owned, adhere to recommended protocols, and result from a project located in a qualifying geographic area.
3.2.1	Offset Ownership	An offset project proponent must have legal ownership of the greenhouse gas emission reduction or removal resulting from the offset project. The offset project proponent will be responsible for all statements and information provided to the

[1] Available at: http://www.westernclimateinitiative.org/components/com_publiccomments/documents/WCI-Offset_Definition_and_Criteria_072409.pdf
[2] The stakeholder comments are archived here: http://www.westernclimateinitiative.org/public-comments/document/7

		WCI Partner Jurisdiction issuing the offset certificate during the creation of the offset certificate and verification of the reduction or removal. The WCI Partners should establish a registry of offset certificates issued and make the registry publicly available.
3.2.2	Use of Recommended Protocols	A WCI Partner jurisdiction will issue WCI offset certificates for compliance with the WCI cap-and-trade program only from projects which employ protocols that have been recommended through the WCI protocol review process ("WCI offset protocols").
3.2.3	Geographic Limits	A WCI Partner jurisdiction may issue offset certificates for projects located within its own jurisdiction as well as jurisdictions outside the WCI cap-and-trade region within North America. A WCI Partner jurisdiction will accept offset certificates issued by other WCI Partner jurisdictions. As described in section 9.8 of WCI's design document, WCI Partner jurisdictions may also accept offset certificates from outside North America.
4.1	Real	A WCI offset certificate represents a reduction or removal of one metric ton of CO_2e that results from a clearly identified action or decision. A WCI offset project's reduction or removal is quantified using accurate and conservative methodologies that appropriately account for all relevant greenhouse gas sources and sinks and leakage risks. WCI offset projects result in emissions reductions or removals that take place at sources controlled by the project proponent.
4.2.1	Quantification, Uncertainty, and Accuracy	Quantification: WCI Partner Jurisdictions shall ensure that net emission reductions or removals are capable of being measured or modeled in a reliable and repeatable manner that includes all relevant sources and sinks. Quantification methodologies for GHG emissions or emission reductions shall: • Be appropriate to the GHG source or sink • Be current at the time of quantification • Consider local conditions, whenever applicable • Account for uncertainty – be calculated in a manner that yields accurate and reproducible results • When uncertainty is above the defined threshold, apply the principle of conservativeness to GHG accounting. During quantification procedures, project proponents shall

		convert each type of GHG to metric tons of CO2e. In addition, WCI offset protocols shall use uniform quantification methods whenever feasible. Uncertainty and accuracy: Quantification methodologies and measurement techniques shall set standards for acceptable statistical precision and be based on the best available science. They shall also reduce bias, except for promoting conservative estimates. When uncertainty remains high in quantifying the amount of a greenhouse gas emission reduction or removal, the principle of conservativeness shall be applied. Principle of conservativeness: Where uncertainties are above the defined threshold, offset quantification methods should use more conservative quantification parameters, assumptions, and measurement techniques that minimize the risk of overestimating emission reductions and removals credited for a given project. The principle should be employed when significant uncertainties arise to ensure a higher level of confidence that all calculated reductions are real.
4.2.2	Leakage	To address activity-shifting and market leakage, WCI Partner Jurisdictions will require assessments of whether functional equivalence has been maintained within projects and require that protocols include methods for leakage assessments. WCI offset protocols will evaluate functional equivalence for each project. WCI offset protocols will also require an assessment of potential leakage associated with each project type. In general, WCI jurisdictions prefer the following methods to review leakage risk: • A quantitative assessment of leakage will be performed whenever possible. • When a quantitative assessment is not feasible, a qualitative risk assessment will determine whether the risk of systematic leakage is significant or not. • WCI offset protocols will include a threshold to identify significant leakage. If leakage is found to be above the threshold, the protocol quantification methodology will include a factor to account for leakage.

5.1	Additional	The WCI Partner jurisdictions intend for additionality to be established in a manner that will require offset projects to be evaluated against a baseline that reflects conservative assumptions that are consistent across all WCI jurisdictions. These assumptions will be described in the procedures for setting a baseline in WCI offset protocols. Modeling or other methods of developing the baseline shall use assumptions, methodologies, and values that provide the WCI Partner jurisdictions with assurance that GHG reductions or removals from a project are not over-estimated (consistent with the principle of conservativeness in 4.2.1). When possible, the baseline shall be set using a sector-specific or activity -specific performance standard; otherwise a project-specific baseline may be used. Performance standards used to establish a baseline will be set so as to reflect the most stringent regulatory requirements and legal requirements of any WCI Partner jurisdiction (those requirements leading to the most conservative calculation of emission reductions). When a project specific baseline is used, the baseline will be set so as to reflect all binding agreements, regulatory requirements and legal requirements in the jurisdiction where the project is located.
5.2.1	Eligibility Date	Offsets may only be awarded for projects that are initially commenced on or after September 23, 2008; the date of the WCI Design Recommendations that identified the priority project types for WCI offsets. Offsets may be awarded for all GHG reductions or removals occurring after September 23, 2008. An offset project proponent must apply to register its project with a WCI Partner Jurisdiction within one year of project commencement. Projects that commenced prior to finalization of the applicable protocol must apply within one year of the protocol's finalization.
5.2.2	Crediting Period	The crediting period for non-sequestration WCI offset projects will be 10 years, which may be once renewed for an additional 10 years. The crediting period for sequestration projects will be specified by the applicable protocol. However, any individual crediting period may not exceed 25 years before a renewal, and the total crediting period including all renewals may not exceed

		100 years. Renewal of a project at the end of a crediting period will include a reevaluation of a project's additionality and reevaluation of how the reductions are quantified and verified. Thus, the baseline scenario will be reevaluated at each renewal.
6.1	Permanent	With respect to offset project activities, permanence means either that reductions or removals are not reversible or that, if reductions or removals are reversible, then the text outlined in the remainder of this recommendation are met. Sequestration projects must ensure the atmospheric effect of their greenhouse gas removal will endure for a period that is comparable to the atmospheric effect achieved by non-sequestration projects. The duration for this period is to be based upon current scientific findings that are widely accepted and followed. The current international standard of 100 years has been established by the UNFCCC and will be followed by WCI Partner jurisdictions. WCI Partner jurisdictions will adopt new international standards (likely UNFCCC) if/when they are updated. Offset projects where the reduction or removal is maintained for less than the WCI standard may be pro-rated and/or replaced in order to maintain the environmental integrity of the offsets system. If pro-rating is allowed for a project type it will be included in the appropriate WCI offset protocol) Project proponents shall follow or establish effective (i) monitoring systems, (ii) risk mitigation approaches, and (iii) contingency plans which address how, in the event of a reversal that is the result of proponent intention or negligence, any affected offset certificates will be replaced. The contingency plan shall include specific mechanisms that are exercisable at the time a reversal is identified whether or not the proponent is solvent, exists in its original form, and/or has ownership of or responsibility for the project. WCI Partner Jurisdictions will establish mechanisms to address reversals that are not the result of proponent intention or

		negligence and to ensure replacement of credits where proponent's contingency measures prove inadequate.
7.1	Verifiable	With respect to offset project activities, verifiable means that a GHG reduction or removal, or assertion thereof, is well documented and transparent such that it lends itself to an objective review by a qualified verifier. Verifiers for WCI offsets will be independent third parties who have been accredited to a standard acceptable by the WCI Partner Jurisdiction in which the project is registered.
7.2.1	Validation	With regards to WCI offsets, validation is a review by an independent third party to assess the likely result of reductions or sequestration from a proposed project that would use a WCI offset protocol. The WCI Partner Jurisdictions may not require third party validation in all cases but may approve protocols that require a validation step.
7.2.2	Enforceable	Each Partner Jurisdiction will, to the extent permissible by law, put in place sufficient compliance/enforcement mechanisms and detail for the jurisdiction to compel compliance with its requirements and with WCI offset protocols.
7.2.3	Material	Material misstatement means that errors, omissions or an aggregation of both in the reported GHG reductions or assertion exceeds a ±5% threshold. For a WCI offset, the verifier must be able to state with reasonable assurance the total reported reductions or removals are free of material misstatement.
8.1	Transparency	The WCI offset system will provide transparency such that sufficient and appropriate protocol, project and certificate information is disclosed in a timely manner to allow offset system participants and the general public to make decisions with reasonable confidence.
8.2	Co-Benefits	WCI Partners recognize the environmental, social, economic and health benefits that may arise from an offset project and the offset system will focus on those benefits directly related to mitigating climate change. A WCI offset project is required only to result in a greenhouse gas emission reduction or removal.
8.3	Assessment of Environmental or Social Impacts	WCI offset projects must meet all applicable local environmental regulations and be in compliance with all applicable laws in the jurisdiction where the project is located. If environmental or socioeconomic assessments of the

		proposed project have been done, the project's registration application should reference this work and include a summary of the findings. Protocols for specific offset project types may require analysis of environmental and socioeconomic impacts beyond what the local jurisdiction would otherwise require and may require additional mitigation of potential negative impacts.

2 Purpose and Background

The purpose of the WCI Offset Committee is to make recommendations to the WCI Partner Jurisdictions on the design and operation of the offset system as part of the WCI cap-and-trade program. In particular, this paper includes the Offsets Committee's recommendations for criteria that reductions must meet in order to demonstrate that reductions from offset projects are rigorous enough to meet compliance obligations within the regional cap-and-trade program. The WCI's September 2008 Design Recommendations included that the criteria ensure offsets result in a GHG reduction or removal that is real, additional, permanent, and verifiable.[3] The design of the offsets system must also ensure that the quantification of the GHG reduction or removal is accurate and not double-counted. According to the WCI's design principles, reductions from offsets must also be enforceable by the WCI Partner jurisdictions.

This Draft Recommendations White Paper is the second stage in developing a clear definition of a WCI greenhouse gas (GHG) offset and the detailed eligibility criteria for GHG offset projects used for compliance purposes as identified in the WCI 2009/10 Work plan released February 2009. On July 24, 2009 the WCI Offsets Committee released the *Offset Definition (Task 1.1) and Eligibility Criteria (Task 1.2) White Paper* ("the Criteria White Paper") describing options for defining a WCI GHG offset and the WCI essential offset criteria (real, additional, verifiable, and permanent), as well as other principles and technical considerations that are important in establishing criteria for the WCI offset system. On July 30, 2009 and August 27, 2009, the WCI Offset Committee held stakeholder webinars to discuss the released white paper. Stakeholders also submitted written comments via the WCI website by the August 21, 2009 deadline.

[3] WCI Design Recommendations for the WCI Regional Cap-and-Trade Program: September 23, 2008; revised March 13, 2009. p. 10 Available at: http://www.westernclimateinitiative.org/ewebeditpro/items/O104F21252.pdf.

Specifically this draft recommendations white paper provides the following:

- a draft recommendation for the criteria, reflecting the criteria's essential requirements
- a summary of stakeholder comments received, and
- a discussion of the criteria recommendation.

Each of the additional principles and technical considerations are nested under the related essential criteria or included in Section 8's "Other considerations." These principles and technical considerations include ownership, use of recommended protocols, and geographic limits (Section 3); quantification, uncertainty and accuracy, conservativeness, and leakage (Section 4); additionality tests, baseline determination, eligibility date, and crediting period (Section 5); validation, enforcement, and materiality (Section 7); and transparency, co-benefits, and assessment of environmental and social impacts (Section 8).

The purpose of this draft recommendation paper is to seek stakeholders' input prior to a final decision by the WCI Partner jurisdictions.

These recommendations will provide the basis for further work of the WCI Offsets Committee. The next paper to be released by Task 1, referred to as the "*Process White Paper"* will present options for detailed requirements for the registration, validation, monitoring, quantification, reporting, verification, certification, and issuance of offsets; aspects of regulation and enforcement related to offsets that should be included in the cap-and-trade essential elements; and functions of the regional administrative body and tracking system related to the offset system. Task 3, the review and development of WCI offset protocols; will use the draft recommendations as the basis for the offset protocol evaluation. It will also provide a basis for Task 2's review of offsets and allowances from outside the WCI jurisdictions. The recommendations from Task 1 may not universally apply to Task 2. Rather Task 2 will have to determine the extent to which the criteria and supporting criteria are appropriate to offsets from other systems. For example, this paper includes a recommendation for the appropriate length of crediting periods used by WCI Partner Jurisdictions. That does not imply that the offsets any other system which uses crediting periods of a different length would be ineligible to meet compliance obligations established by WCI Partners Jurisdictions.

This paper frequently employs the terms such as "WCI offset", "WCI offset projects" and "WCI Offset System". This paper uses the terms to succinctly describe an offset certificate issued by a WCI Partner Jurisdiction, the projects from which these offsets are generated and resulting system created by WCI Partner Jurisdictions.

3 Definition of an Offset

The offset definition should establish the tradability of offsets and provide guidance about their fungibility within the WCI cap-and-trade program. The definition should also address how offsets are created and recognized.

3.1 Offset

A major consideration for defining an offset is how broad the definition should be. For example, the definition could require that offsets meet all WCI recommendations; alternatively, the system recommendations could be specified in the offset definition itself or referred to in other parts of the regulation or program design. The Criteria White Paper discussed three options:

- Option A: Specific parameters or requirements included in the definition;
- Option B: General parameters or requirements covered in the definition with specific requirements referred to elsewhere in the document; and
- Option C: Specific parameters or requirements with the condition that additional requirements specified in the WCI offset system must be met.

The draft recommendation below most closely resembles Option B.

3.1.1 Draft recommendation

A WCI offset certificate is issued by a WCI Partner Jurisdiction and represents a reduction or removal of one metric ton of carbon dioxide equivalent (tCO_2e). The reduction or removal must meet the recommended essential criteria for reductions and removals to be real, additional, permanent, and verifiable. Reductions and removals must also be clearly owned, adhere to recommended protocols, and result from a project located in a qualifying geographic area

3.1.2 Summary of stakeholder input

Stakeholders offered various comments regarding the offset definition. The comments generally support a simpler offset definition and/or a definition that is open and flexible to cover any projects that have direct or indirect potential to reduce emissions. Stakeholders wanted to ensure fungibility across WCI Partner Jurisdictions to increase market fluidity.

3.1.3 Explanation of draft recommendation

The WCI Offsets Committee is recommending a definition using Option B because it is simple, flexible, and should support a robust offset market. The proposed offset definition requires that WCI offsets meet the essential criteria of the WCI offsets system (i.e., real, additional, permanent, and verifiable) but does not specify parameters or requirements for those criteria.

Carbon dioxide equivalent is an internationally accepted standard of measurement of the radiative forcing of greenhouse gases. Establishing that a WCI offset represents one metric ton carbon dioxide equivalent (tCO_2e) allows it to be employed interchangeably with a WCI emission allowance which also represent one tCO_2e. It also facilitates linkage internationally, which is a design principle of the WCI program,[4] with other programs using this accepted measurement standard.

One issue which the WCI Offsets Committee internally debated for its draft recommendation was whether to define the offset as the reduction or removal itself or as the compliance unit. The recommendation above equating an offset with the compliance unit is based on the understanding that a reduction or removal is just a reduction or removal until a WCI Partner Jurisdiction has recognized it as an offset through the issuance of a compliance unit. The committee also discussed whether the definition should include a positive statement that offsets are tradable and bankable. Since these features seemed to more appropriately belong to the domain of the overall cap-and-trade program than to the offsets system, such a statement was not included.

3.2 Other considerations

This section further discusses three key considerations referenced in the final sentence of the offsets definition draft recommendation. These considerations are offset ownership, use of recommended protocols, and geographic limitations of recognized offsets.

3.2.1 Ownership issues

Establishing clear ownership of the emissions reductions generated by an offset project is important prior to registration, acceptance, and issuance of offsets in the WCI program. In regards to ownership, it is useful to distinguish between ownership claims to a reduction or removal prior to the issuance of compliance and the ownership of those compliance units after their issuance. The draft recommendation below focuses on the former, while the latter is an issue for a subsequent paper.

3.2.1.1 Draft recommendation

An offset project proponent must have legal ownership of the greenhouse gas emission reduction or removal resulting from the offset project. The offset project proponent will be responsible for all statements and information provided to the WCI Partner Jurisdiction issuing the offset certificate during the creation of the offset certificate and verification of the

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[4] See the final bullet point in the WCI Design Principles section on pages 52-53 of the WCI Design Recommendations Document.

reduction or removal. The WCI Partners should establish a registry of offset certificates issued and make the registry publicly available.

3.2.1.2 Summary of stakeholder input

Nearly all respondents supported a clear delineation of offset ownership. Many of the respondents supported the creation of a centralized registry, and/or legal contracts that specify and establish ownership claims.

3.2.1.3 Explanation of draft recommendation

Clear rules around ownership are necessary in a trading system. The draft recommendation attempts to reduce the likelihood of disagreement over ownership by clarifying the expectations for the project proponent. The proponent may or may not have an ownership interest in the project itself or in the emissions source(s) or sink(s) that lie within the project's boundaries. The proponent may be a person(s) or entity(ies) acting on behalf of the project owner(s). The identity of the project owner (who receives the issued compliance units) and the project proponent (who makes the offset application), as well as their relationship to each other, must be clear.

After issuance, the WCI offsets system will require tracking offsets, perhaps through a registry. Registry rules would govern ownership of the issued compliance units. Possible provisions and recommendations for an offset registry or other tracking methodologies are a topic for the WCI Offsets Committee's upcoming Process White Paper.

3.2.2 Use of recommended protocols

The WCI Partners will recommend protocols that will detail specific instructions for project developers, describe standard approaches, equipment, procedures and requirements for projects. The protocols will apply to all aspects of the project life cycle including: planning, operation, monitoring, calculation, reporting, and verification. Recommended protocols must meet the WCI's essential criteria.

3.2.2.1 Draft recommendation

A WCI Partner jurisdiction will issue WCI offset certificates for compliance with the WCI cap-and-trade program only from projects which employ protocols that have been recommended through the WCI protocol review process ("WCI offset protocols").

3.2.2.2 Summary of stakeholder input

Stakeholders supported the use of existing protocols from other programs. None suggested that the WCI Partners should not consider using or adapting protocols that have already been developed.

3.2.2.3 Explanation of draft recommendation

Establishing WCI offset protocols help ensure the integrity of the offsets issued and accepted by the WCI Partner Jurisdictions. The WCI Offsets Committee Task 3 (Offset Protocols) group is evaluating which existing protocols in the priority project type areas meet the WCI Partners' recommended criteria and are consistent with ISO standards. Protocols will be recommended for WCI Partner Jurisdiction review and will include adequate stakeholder engagement prior to final WCI Partner Jurisdiction adoption.

3.2.3 Geographic limits

Geographic limits can take different forms and may restrict offsets from certain geographic areas. One form would restrict from where WCI Partners might accept offsets; another would restrict where the WCI Partners might issue offsets. The WCI Partners have previously indicated a restriction of this latter type. More specifically, the WCI Design Document (September 23, 2008) recommended that the WCI Partner Jurisdictions would issue offsets for reductions or removals only in the three North America countries Canada, Mexico, and the United States. The recommendation in this paper reaffirms that earlier policy decision.

3.2.3.1 Draft recommendation

A WCI Partner jurisdiction may issue offset certificates for projects located within its own jurisdiction as well as jurisdictions outside the WCI cap-and-trade region within North America. A WCI Partner jurisdiction will accept offset certificates issued by other WCI Partner jurisdictions. As described in section 9.8 of WCI's design document, WCI Partner jurisdictions may also accept offset certificates from outside North America.

3.2.3.2 Summary of stakeholder input

Many stakeholders' responses to the *Criteria White Paper* included comments regarding geographic limits. Some stakeholders opposed setting geographic limits because doing so would limit potential compliance cost savings. Multi-national organizations would be restricted from pursuing their lowest cost offset projects regardless of location and organizations with offset projects located outside of Canada, Mexico, and the United States would be excluded. Other stakeholders expressed a preference for limiting offset projects to States and Provinces.

3.2.3.3 Explanation of draft recommendation

As the Design Recommendations document stated, "The WCI Partner jurisdictions encourage the development of offset projects located inside WCI Partner jurisdictions for compliance purposes in the WCI cap-and-trade regulatory program in order to capture collateral benefits associated with some offsets projects, such as health, social, and environmental benefits."[5] In addition, there are practical concerns about implementing and overseeing an offset system beyond North America. Even within North America, MOUs or other agreements between WCI Partner jurisdictions and non-WCI jurisdictions may be needed to help oversee projects located outside of the WCI jurisdictions.

The WCI Partner Jurisdictions are concerned that offset reductions or removals are not counted in multiple registries. They will have to develop a mechanism to ensure reductions are not counted in both the WCI offset system and any other offset system.[6]

The WCI Partner Jurisdictions may still accept offsets generated from reductions or removals outside these three countries, but another program authority will have to issue those offsets. As part of its work under Task 2, the WCI Offsets Committee will recommend standards for evaluating and (if appropriate) accepting compliance units (offsets and allowances) from other programs.

4 Defining the criterion Real

4.1 Real

The WCI offset criteria must ensure that all offset projects generate real GHG reductions or removals. WCI offset protocols must ensure that the quantification of a reduction or removal is accurate and not double counted.[7] For this reason, robust accounting methods are essential to any offsets system. Inaccurate or incomplete accounting could lead to crediting offset reductions that did not actually occur. Offsets can be used in place of emissions reductions at capped sources, and thus offsets become fungible compliance units. It is therefore critical that offset reductions or removals are real in order to ensure the integrity of the cap-and-trade system.

4.1.1 Draft recommendation

A WCI offset certificate represents a reduction or removal of one metric ton of CO_2e that results from a clearly identified action or decision. A WCI offset project's reduction or removal is quantified using accurate and conservative methodologies that appropriately account for all

[5] *Ibid*. p. 40.
[6] This may be a topic in part for the upcoming *Process White Paper*, specifically relating to the offset tracking system as part of Task 1.5.
[7] WCI Design – Section 9.2 (September 2008)

relevant greenhouse gas sources and sinks and leakage risks. WCI offset projects result in emissions reductions or removals that take place at sources controlled by the project proponent.

4.1.2 Summary of stakeholder input

Several stakeholders believe that a definition of real is necessary. Some stakeholders contended that a specific definition of real is not needed and suggested that issues around real and double counting be addressed in verification or certification. Some stakeholders included in their comments that the WCI Partners should issue offsets for indirect emission reductions achieved through electricity efficiency.

4.1.3 Explanation of draft recommendation

Assuring that offsets are real is closely related to other criteria such as permanent, verifiable, and quantifiable. Permanence is discussed in Section 6, verifiable in Section 7, and quantification, uncertainty, conservativeness, accuracy, and leakage are discussed later in this section.

It is vital that reductions or removals in the WCI program are not double counted and not claimed in other voluntary or mandatory GHG trading programs. The *Process White Paper* will detail administrative options and mechanisms to register, track, and retire offsets in order to prevent double counting. The registration and tracking systems play a key role in ensuring rigorous accounting – the transfer of ownership of an offset credit must be clearly defined and documented.

WCI offsets must be generated from reductions or removals within the project boundary of a registered project. Only reductions which occur at controlled sources may be included in the project boundary. For example, renewable energy and energy efficiency projects (typically) result in indirect emission reductions. These would not be recognized under the WCI offset criteria.

In addition, WCI Design recommendations describes offsets as "… emission reduction project[s] undertaken to address emissions *not included* in a cap-and-trade program" (emphasis added).[8] The electricity sector will be subject to the cap. This recommendation was designed to prohibit double counting by the offsets system.

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[8] WCI Design (September 23, 2008) footnote 13.

At least one stakeholder responding to the Criteria White Paper advocated for allowing offsets from industrial source emitters which fall below the threshold for inclusion in the cap and trade program. Projects which occur outside of capped sectors or generate reductions at facilities that fall below the threshold for compliance could be eligible for offsets.

Real is generally understood to mean that all credited emission reductions or removals genuinely took place. Thus, real offsets have the following requirements:

- Account for uncertainty and accuracy in calculating reductions or removals (Section 4.2.1)
- Require sound quantification methodologies (Section 4.2.1)
- Prohibit double counting (Section 4.1.3)
- Account for emissions leakage (Section 4.2.2)
- Ensure reductions or removals are permanent (Section 6)
- Verify reductions or removals (Section 7)

4.2 Supporting criteria

This section examines supporting criteria for real: quantification, uncertainty, and accuracy are considered, followed by a section addressing leakage.

4.2.1 Quantification, uncertainty, and accuracy

Accurate quantification ensures that offsets represent real reductions that can be converted into a common currency that accurately reflects the GHG reductions or removals generated by of an offset project.

Sound methods to measure and quantify GHG reductions are a prerequisite for eligible offset project types. Quantification methods will be subject to periodic review to make sure they reflect current science and accurate GHG accounting practices. In addition, it is worthwhile to encourage consistency in quantification and monitoring procedures across project types.

Higher levels of uncertainty in calculating emission reductions from project activities lead to lower levels of confidence that all offsets generated by a project are real. It is vital for an offsets system to consider how to address uncertainty within project protocols.

A number of offset programs employ a principle of conservativeness to address uncertainty and ensure that emissions reductions are real. The concept is that where uncertainty exists, it is best to credit reductions where there is high confidence that reductions actually occurred. This option is distinct from using a discount factor to address uncertainty. A principle of conservativeness would mean using uncertainty values at the lower end of the range whenever possible to ensure that there is a high level of confidence that all calculated reductions are real.

4.2.1.1 Draft recommendation

Quantification: WCI Partner Jurisdictions shall ensure that net emission reductions or removals are capable of being measured or modeled in a reliable and repeatable manner that includes all relevant sources and sinks. Quantification methodologies for GHG emissions or emission reductions shall:

- Be appropriate to the GHG source or sink
- Be current at the time of quantification
- Consider local conditions, whenever applicable
- Account for uncertainty – be calculated in a manner that yields accurate and reproducible results
- When uncertainty is above the defined threshold, apply the principle of conservativeness to GHG accounting.

During quantification procedures, project proponents shall convert each type of GHG to metric tons of CO_2e. In addition, WCI offset protocols shall use uniform quantification methods whenever feasible.

Uncertainty and accuracy: Quantification methodologies and measurement techniques shall set standards for acceptable statistical precision and be based on the best available science. They shall also reduce bias, except for promoting conservative estimates. When uncertainty remains high in quantifying the amount of a greenhouse gas emission reduction or removal, the principle of conservativeness shall be applied.

Principle of conservativeness: Where uncertainties are above the defined threshold, offset quantification methods should use more conservative quantification parameters, assumptions, and measurement techniques that minimize the risk of overestimating emission reductions and removals credited for a given project. The principle should be employed when significant uncertainties arise to ensure a higher level of confidence that all calculated reductions are real.

4.2.1.2 Summary of stakeholder input

Quantification: Several stakeholders commented on quantification. Support was expressed for conservative quantification methods or approaches in general. There was support for the use of existing quantification methods where possible and a call to customize quantification methods for local environmental conditions. In addition, the stakeholders generally supported the use of methods and models for quantification that are peer reviewed, based on science, and rigorous.

Uncertainty and accuracy: Public comments generally supported an assessment of uncertainty, although proposed methods varied. Stakeholders generally commented that assessments of uncertainty may vary by scale. Some suggested that uncertainty be considered in the quantification methods not as stand-alone assessments, while others suggested that uncertainty discounts should be applied or that project types with high uncertainty should be excluded.

Conservativeness: Stakeholders who provided public comments on this topic generally (but not uniformly) supported the use of "conservative" methods for quantifying offsets.

4.2.1.3 Explanation of draft recommendation

Quantification generally means that reductions must be accurately quantified and includes these components:

- Using calculation methods that are measurable, credible, and reproducible.
- Undergoing periodic review of quantification methods to ensure appropriateness and consideration of local conditions.

Uncertainty assessments should be carried out, whenever possible, during protocol review and development phases. The assessment should determine if uncertainty is or is not significant.

Where appropriate, project protocols should strive to set standards for precision and allowable error defined by acceptable standards for statistical sampling at the project level. Statistical accuracy and precision (reduced error) standards will increase confidence in quantification methods and thus the overall quantity of offsets credited for a given project. Protocols should provide straightforward guidelines on how to assess uncertainty and how to appropriately adjust the quantification based on risk assessments or analysis of sampling confidence.

Periodic review of protocols is recommended to ensure that quantification methods reflect current science and adequately address uncertainty, accuracy, and conservativeness.

An initial step in scoping and developing an offset project is to reduce uncertainty and error to the extent possible during protocol development and review stages. In dealing with uncertainties in protocol quantification the protocol should apply principles of conservativeness should be used to ensure that any resulting offsets are real and not over-estimated.

A principle of conservativeness should be applied when relatively uncertain parameters or data sources are used to determine baselines and the quantification of project GHG reductions and removals. Employing this principle when high levels of uncertainty are encountered during protocol development would make reductions and removals more likely to be under-estimated instead of over-estimated.

Protocols should call for project documentation that details how chosen assumptions and parameters are conservative (more details and guidance in *Process White Paper*). Use of this principle does not dictate the use of the "most conservative" set of assumptions and methodologies. Implementing a principle of conservativeness means erring on the side of caution, and it requires balancing standards for accuracy with the need for cost-effective offset projects. When less accurate methods are selected, more conservative assumptions and methodologies should be applied at the protocol level.

4.2.2 Leakage

Leakage is an increase in GHG emissions outside of a project's boundary as a result of the offset project's activity. Reviewed offset systems often define two types of leakage:

- **Activity-shifting leakage:** greenhouse gas emissions that result from the displacement of activities from inside the project's boundary to locations outside of the project's boundary as a result of the project activity.
- **Market leakage: greenhous**e gas emissions that occur outside a project's boundaries resulting from substitution or replacement due to the project activity impacting an established market for goods

As discussed in the Criteria White Paper, there are several options available to address leakage. One is to require that each WCI offset protocol include a method to account for leakage in emission reductions or removal calculations specific to a project type. A second option is to have a project validation step that requires an opinion or assessment of leakage risk associated with a project. This step would require further elaboration and guidance to determine the outcome and significance of the validator's opinion or assessment. A final option to assess leakage is to use standard algorithms and methods for leakage quantification – as CDM does for some of their methodologies. .

4.2.2.1 Draft recommendation

To address activity-shifting and market leakage, WCI Partner Jurisdictions will require assessments of whether functional equivalence has been maintained within projects and require that protocols include methods for leakage assessments. WCI offset protocols will evaluate functional equivalence for each project. WCI offset protocols will also require an assessment of potential leakage associated with each project type. In general, WCI jurisdictions prefer the following methods to review leakage risk:

- A quantitative assessment of leakage will be performed whenever possible.
- When a quantitative assessment is not feasible, a qualitative risk assessment will determine whether the risk of systematic leakage is significant or not.

- WCI offset protocols will include a threshold to identify significant leakage.

If leakage is found to be above the threshold, the protocol quantification methodology will include a factor to account for leakage.

4.2.2.2 Summary of stakeholder input

Stakeholder comments generally supported the consideration of leakage, although proposed methods varied. Several suggested that leakage should be addressed in protocol development, and some suggested that it be addressed through discount rates.

4.2.2.3 Explanation of draft recommendation

Emissions leakage is an important concern for any offsets system. Market leakage is difficult to address on a regional level because commercial markets are often national or multi-national in scale. Ensuring functional equivalence means that project proponents must demonstrate that emissions are not shifted within an organization or entity (from within the project boundary to sources or sinks outside the project boundary). Practical leakage quantification methods do exist. For this reason, WCI jurisdictions prefer that project protocols:

- Quantify leakage risks whenever possible,
- Conduct a qualitative assessment of leakage risk when quantification of leakage proves to be unfeasible, and
- Employ factors to address leakage when risk is determined to be significant within the project type protocol.

If leakage risk is found to be medium or high, then the protocol quantification methodology should include a factor to account for leakage to ensure that offsets generated in the system are real.

5 Defining the criterion Additional

The concept of additionality addresses the need for offsets to represent reductions or removals of GHG emissions that would not have otherwise occurred but for the incentive provided by the offset program. Additionality is essential to maintaining the integrity of the emissions cap. To be considered additional, emissions reductions or sequestrations are those that occur beyond the business-as-usual baseline of emission activity that would occur without the offset project.

5.1 Additionality and Baseline

In defining additionality it is important to identify the type of tests that will be used to ensure the offset activity would not have occurred on its own in the absence of the WCI offset opportunity. The *Criteria White Paper* identified these options for analyzing additionality:

Option A: Project Specific – The additionality of each individual project activity is scrutinized through application of specific additionality tests.

Option B: Performance Standard – For each sector or project type, a performance standard is established where projects meeting or exceeding the standard are considered to be additional.

Option C: Protocol Specific Approach – Approach to additionality assessment may vary by protocol, seeking to adopt the best approach for each sector or class of activities.

Option D: Hybrid Approach – A combination of Options A, B, and C would set a performance standard, but still include some aspects of a project-specific additionality, and may vary by protocol.

In order to determine if a project is additional the baseline emissions for that project must be modeled. The options to estimate the baseline scenario revolve around how to estimate the emission activity that would occur in the absence of the offset project. One option is to use a regulatory floor of required compliance activity as the baseline scenario. Another option is to use sector specific performance standards as the measure of baseline emission activity. The WCI Partner Jurisdictions could also require that baselines be estimated for individual offset projects such one based on historical practices on an individual piece of land. Alternatively, baselines can be calculated at a sector-specific scale where an aggregate of project activity is estimated as the baseline.

5.1.1 Draft recommendation

The WCI Partner jurisdictions intend for additionality to be established in a manner that will require offset projects to be evaluated against a baseline that reflects conservative assumptions that are consistent across all WCI jurisdictions. These assumptions will be described in the procedures for setting a baseline in WCI offset protocols. Modeling or other methods of developing the baseline shall use assumptions, methodologies, and values that provide the WCI Partner jurisdictions with assurance that GHG reductions or removals from a project are not over-estimated (consistent with the principle of conservativeness in 4.2.1).

When possible, the baseline shall be set using a sector-specific or activity -specific performance standard; otherwise a project-specific baseline may be used. Performance standards used to establish a baseline will be set so as to reflect the most stringent regulatory requirements and legal requirements of any WCI Partner jurisdiction (those requirements leading to the most conservative calculation of emission reductions). When a project specific baseline is used, the baseline will be set so as to reflect all binding agreements, regulatory requirements and legal requirements in the jurisdiction where the project is located.

5.1.2 Summary of stakeholder input

There was fairly little stakeholder input about how the WCI Partner Jurisdictions should specifically define additionality. However, the WCI Partners received comments that supported all four of the additionality options highlighted above. Of those that commented directly on the options, many preferred Option D, with significant support for Option B as well. This indicates widespread preference to a performance standard approach to additionality and baseline, but at the same time some flexibility to incorporate alternative tests should a performance standard approach proves infeasible.

Stakeholders generally favored that specific methods to estimate baseline be laid out in protocols. There was also some support for modeling the baseline using historical practices in either one or multiple years prior to the start date of the project and for using performance standards that exceed common practice. For stakeholders that commented on project-specific additionality tests, there was some support for common practice tests but at the same time, near unanimous dislike for financial, funding, or investment tests.

5.1.3 Explanation of draft recommendation

The recommended definition of additionality and baseline is consistent with the International Standards Organization's (ISO) 14064-2 standard by defining what is additional as reduced or sequestered emissions beyond any reductions or sequestration achieved under a baseline scenario. At a minimum, the baseline scenario must incorporate reductions or sequestration of emissions required through regulation or other legal requirements. Offset projects can generate offsets for early adoption of activities that will be required in the future by a current or expected regulation until the requirement takes effect. However, new regulations or requirements that were not implemented or expected during project registration or renewal will not affect project additionality until the end of the current crediting period.

Each WCI offset protocol must lay out the methodologies that a project proponent shall use to determine additionality and model the baseline scenario. The WCI Partners prefer protocols that take a performance standard approach to determining additionality. In this method, the baseline is set as the performance standard or the minimum actions required by law, whichever is higher. When a performance standard approach is not the best alternative for a certain project type or it will take a number of years to develop a reasonable performance standard, the WCI Partners may recommend including protocols that use alternative methods as long as they meet the criteria for determining additionality and baseline.

Regulatory baselines are viewed by the WCI Partners as a minimum. The WCI Partners intend to use baselines that exceed this minimum by favoring performance standards since performance standards generally set higher baselines and are thus more conservative. Performance standards are designed to capture common practice or business-as-usual investment activity such that there is high confidence that the reductions or removals of greenhouse gas emissions by offset projects exceed those already occurring – especially when what is already occurring exceeds regulatory requirements.

The WCI Partners are retaining the option of using proportional additionality as the means to develop performance standards for sequestration projects in agriculture and forestry. Proportional additionality models sector activity in aggregate – the level of project activity that would occur absent the WCI offset program (i.e., baseline activity) and the level of aggregate project activity that is induced in response to the WCI offset program. The portion of a projects emissions reductions or sequestration over the sectoral baseline is considered additional.

The WCI Partners' draft recommendation for additionality and baseline sets an overall standard but at the same time provides flexibility by deferring to the offset protocols the specific methods used to achieve the standard. For example, protocols may include additionality tests for project types that do not lend themselves to a performance standard approach. In this way, protocols for project types that otherwise would be excluded can still be included in the WCI offset program. The WCI Offset Committee generally concurs with the prevailing view of commenting stakeholders concerned about using investment, funding or financial barriers tests in determining additionality. Thus, the WCI offsets system will not require them on a system-wide level, although they could be required by a protocol where they are deemed appropriate for a given project type.

5.2 Supporting criteria

Two other considerations related to additionality—eligibility date and crediting period—related to additionality are discussed in this section.

5.2.1 Eligibility date

The issues regarding eligibility date can be divided into two areas: the earliest start date that offset projects may be undertaken to be eligible for inclusion in the WCI offset system and the earliest year in which offsets arising from a project can be eligible for verification and use in the WCI Partner jurisdictions. The first seeks to identify a cut-off date, where projects initiated before that date would not be eligible. If the date identified in the first is before the start of the first WCI compliance period (i.e., 2012), the second gets at what vintages of offsets arising from these projects may be used in the WCI jurisdictions. The consideration is whether reductions need to occur over the same time period as the emissions that they are offsetting or whether earlier offsets can be banked and used against later emissions. For projects undertaken before 2012, one approach would be to consider the reductions occurring before 2012 to be early actions, while reductions after 2012 would generate offsets (subject to crediting period limits).

The *Criteria White Paper* outlined three primary options for eligibility dates for project initiation and qualifying reductions:

- both dates coincide with the launch of WCI cap-and-trade program in 2012
- project initiation may precede 2012, but WCI Partners may issue offsets only for reductions in 2012 or later
- project initiation may precede 2012, and the WCI Partners may issue offsets for all reductions resulting from project activity (at least through the initial crediting period).

5.2.1.1 Draft recommendation

Offsets may only be awarded for projects that are initially commenced on or after September 23, 2008; the date of the WCI Design Recommendations that identified the priority project types for WCI offsets. Offsets may be awarded for all GHG reductions or removals occurring after September 23, 2008.
An offset project proponent must apply to register its project with a WCI Partner Jurisdiction within one year of project commencement. Projects that commenced prior to finalization of the applicable protocol must apply within one year of the protocol's finalization.

5.2.1.2 Summary of stakeholder input

There was support from stakeholders who would be either offset purchasers or developers for both a start-date and eligibility date pre-2012. The suggested dates ranged from 2000 to the year the jurisdiction sourcing the project joined the WCI.

5.2.1.3 Explanation for draft recommendation

The WCI Partners recommend a project start and eligibility date of the date the WCI Design Framework was released. This supports the discussions about establishing a WCI offset system and the need to establish a rigorous offset system to support WCI Partner Jurisdictions. By choosing one date for all jurisdictions we provide consistency in eligibility across all jurisdictions. We also believe that the chosen date provides a good compromise. It hopefully works to bring offsets into the WCI system in the early years, while ensuring the quality of offsets allowed into the system. Projects will be able to seek verification for offsets based on the WCI Jurisdictions' recommended protocol for the offset project type. Verified offsets for the reduction or sequestration of emissions occurring before 2012 will still need to meet the strict monitoring and verification standards laid out in each protocol. For any offsets that have previously been issued in any voluntary or compliance offset system, those offsets must be retired or removed from the other system before a WCI Partner Jurisdiction may issue a compliance unit in recognition of that reduction.

5.2.2 Crediting period

A crediting period determines how long an offset project is eligible to generate offsets once it has been approved by a WCI Partner Jurisdiction. Different project types may have different crediting periods. For example, sequestration projects tend to have longer crediting periods because their gradual greenhouse gas removals occur over longer timescales. In general, the length of crediting period should give project developers some certainty in their investment. Another option is to adopt shorter crediting periods but at the same time allow for their renewal based on a periodic review of conditions for eligibility. All or some of the following could be re-evaluated at the time of renewal and only those projects passing would be renewed:

Eligibility– Is the project type still eligible as a WCI offset project?

Applicable Protocol – Besides questions of additionality and baseline, has the WCI Partner Jurisdiction adopted a revised or new protocol for the project type that is now applicable?

Additionality and Baseline – Are their new regulatory or other legal requirements that need to be incorporated into the project baseline? Similarly, have performance standards evolved since the original baseline determination? For project types that originally needed to pass project-specific additionality tests, are there now available performance standards that could be used as an alternative?

Quantification – Is there opportunity to incorporate new quantification methods that reduce the uncertainty in the measurement of offsets or modeling of baselines?

5.2.2.1 Draft recommendation

The crediting period for non-sequestration WCI offset projects will be 10 years, which may be once renewed for an additional 10 years. The crediting period for sequestration projects will be specified by the applicable protocol. However, any individual crediting period may not exceed 25 years before a renewal, and the total crediting period including all renewals may not exceed 100 years.

Renewal of a project at the end of a crediting period will include a reevaluation of a project's additionality and reevaluation of how the reductions are quantified and verified. Thus, the baseline scenario will be reevaluated at each renewal.

5.2.2.2 Summary of stakeholder input

Stakeholder comments on the length of crediting periods varied. Many comments stated it was necessary to credit offsets for a minimum period of time in order to provide some investment certainty for project developers. Many stakeholders supported longer crediting periods with more opportunity for renewals, including some who favored unlimited renewal of crediting periods. By contrast, others generally supported shorter initial crediting periods with fewer opportunities to renew.

5.2.2.3 Explanation of draft recommendation

The recommendation above tries to balance investment certainty with the need to develop a rigorous offset system. Project types eligible for offsets will likely be subject to advances in common practice, technological revolutions, increasing regulatory standards, and other factors that make periodic reevaluation of additionality prudent.

Presently the WCI Offsets Committee is recommending a fixed 10-year crediting period for all non-sequestration projects. Alternatively, the Committee considered recommending that crediting periods be determined by the applicable protocol but no longer than 10 years. Since there was not a non-sequestration project type currently under consideration for which the Committee thought a period shorter than 10 years would be clearly preferred, the Committee is recommending this uniform period, although it acknowledges that this recommendation may need future reevaluation.

The recommendation also recognizes that sequestration require long-term investment and commitment by project developers and provides the option of longer crediting periods for them. Within a crediting period, protocols for projects with longer crediting periods may require updates to changes in quantification methodologies to reflect current science. For sequestration projects, there is not a cap on the number of renewals, just a cap on the total length of the crediting period including all renewals.

Renewal of a project at the end of a crediting period will include a reevaluation of a project's additionality and reevaluation of how the reductions are quantified and verified. Thus, the baseline scenario will be reevaluated at each renewal. For projects whose crediting period has expired and not been renewed, previously verified offsets will still need to meet protocol requirements for permanence, and any reversal of previously verified reductions remain subject to the WCI Partner Jurisdictions' enforcement provisions.

6 Defining the criterion Permanent

The *Criteria White Paper* outlined a range of options for the definition and implementation of permanence. This section reviews stakeholder comments to that paper and offers the WCI Partners' draft recommendation for ensuring permanence.

6.1 Permanent

As an offset element, permanence refers to the duration of an emission reduction. Permanence needs to be addressed in projects which involve a risk or reversal, most notably geologic and terrestrial (i.e., carbon that is stored in biomass and soil) sequestration of carbon. The draft recommendation below outlines the mechanisms required to ensure equivalency of offset emissions reductions across different project types.

Implementation mechanisms discussed in the *Criteria White Paper* fell into two broad categories: *ex ante* and *ex post facto*. *Ex ante* mechanisms do not guarantee against a reversal but do make a legally binding commitment which, in the case of land-based projects, "run with the land" and can serve to reduce the risk on non-permanence. *Ex post facto* obligations provide assurance in the case of failure of permanence and are achieved through replacement of lost tons.

6.1.1 Draft recommendation

With respect to offset project activities, permanence means either that reductions or removals are not reversible or that, if reductions or removals are reversible, then the text outlined in the remainder of this recommendation is met.

Sequestration projects must ensure the atmospheric effect of their greenhouse gas removal will endure for a period that is comparable to the atmospheric effect achieved by non-sequestration projects. The duration for this period is to be based upon current scientific findings that are widely accepted and followed. The current international standard of 100 years has been established by the UNFCCC and will be followed by WCI Partner jurisdictions. WCI Partner jurisdictions will adopt new international standards (likely UNFCCC) if/when they are updated.

Offset projects where the reduction or removal is maintained for less than the WCI recommended standard may be pro-rated and/or replaced in order to maintain the environmental integrity of the offsets system. If pro-rating is allowed for a project type it will be included in the appropriate WCI offset protocol)

Project proponents shall follow or establish effective (i) monitoring systems, (ii) risk mitigation approaches, and (iii) contingency plans which address how, in the event of a reversal that is the result of proponent intention or negligence, any affected offset certificates will be replaced. The contingency plan shall include specific mechanisms that are exercisable at the time a reversal is identified whether or not the proponent is solvent, exists in its original form, and/or has ownership of or responsibility for the project. WCI Partner Jurisdictions will establish mechanisms to address reversals that are not the result of proponent intention or negligence and to ensure replacement of credits where proponent's contingency measures prove inadequate.

6.1.2 Summary of stakeholder input

Stakeholder groups offered valuable feedback on the permanent criterion. There was consensus that the environmental integrity of the offsets system needs to be ensured. There was also broad agreement that the benchmark of permanent should be a 100 year standard. Methods for ensuring the environmental effect of this standard varied, but the objective of ensuring that sequestration offsets may be employed with equal confidence as emission allowances or non-sequestration offsets was universal.

Stakeholder comments included these suggestions which vary from the draft recommendation:

- creating temporary or short-term credits
- having the purchaser of sequestration offsets assume the liability of replacement in the event of a reversal
- avoiding long-term monitoring as much as possible
- allowing a *force majeure* safe harbor (i.e., in the event of an unintentional reversal, project proponents would not be immediately liable for offset replacement, although they would be required to accrue additional removals to build carbon stocks up to the level that had been depleted)

6.1.3 Explanation of draft recommendation

Strictly speaking the true time frame for permanence is forever. However, practicality and GHG accounting conventions suggest a more finite time be utilized. The second IPCC report effectively established a 100-year standard for permanence. This was adopted by the UNFCCC. The WCI Partners intend to remain consistent with international GHG accounting conventions. Thus, as UNFCCC conventions are updated the WCI Partner recommendations will also be updated. Still, the WCI Offsets Committee envisions that the standard for permanence in effect at the start of a project's crediting period would remain the standard for reductions achieved in that crediting period and would not be changed retroactively. This certainty should facilitate investor confidence.

The draft recommendation establishes strict liability for intentional or avoidable reversals. It also establishes the broad recommendation of monitoring and risk mitigation for all sequestration projects, but specific requirements may vary by project type. Thus, guidelines will be established through a combination of universally applied WCI offset program essential elements and WCI offset protocols which may allow for flexibility by project.

Protocols for sequestration projects should require the projects in general, and their monitoring and risk mitigation plans in particular, be developed and carried out in a manner which considers project specific risks from climate change. These risks might include susceptibility to fire, drought, flooding, windstorms, or insects. Risk mitigation plans could include *ex ante* permanence mechanisms such as conservation easements.

Contingency plan measures to be established or followed by the proponent to ensure the replacement of offsets in the event of an intentional reversal or a reversal which occurs as the result of proponent negligence might include:

- Contractual or other arrangements for securities, contingency funds, discounts or set-asides
- Insurance or other guarantees

Ultimately the WCI Partner Jurisdictions will adopt measures and mechanisms that provide a degree of confidence that the environmental credibility of the offset system is assured. Potential WCI Partner contingency plan measures might include:

- A buffer pool (established through contributions which would be determined through a project risk assessment)
- Contractual or other arrangements for securities, contingency funds, discounts or set-asides
- Insurance or other guarantees established to replace offsets in the event of a reversal

7 Defining the criterion Verifiable

This section provides the WCI Partners' draft recommendation for defining the verifiable offset criterion. This section also includes recommendations for three other supporting criteria.

7.1 Verifiable

For something to be verifiable, it must be transparent and documented well enough that a person can objectively review the GHG assertion or reduction and make a finding that the GHG assertion or reduction is accurate. However, the biggest question related to the term verifiable is who will be that person objectively reviewing the GHG assertion or reduction.

As outlined in the *Criteria White Paper*, there are three options for whom that person should be. The first is to follow international convention and only allow third-party independent verifiers to verify GHG assertions or reductions. An alternative is for jurisdictions to play that role, and the last option is to allow the project developers to self-certify that they are providing accurate and truthful information about reductions.

7.1.1 Draft recommendation

With respect to offset project activities, verifiable means that a GHG reduction or removal, or assertion thereof, is well documented and transparent such that it lends itself to an objective review by a qualified verifier. Verifiers for WCI offsets will be independent third parties who have been accredited to a standard acceptable by the WCI Partner Jurisdiction in which the project is registered.

7.1.2 Summary of stakeholder input

Most stakeholder comments supported third-party verification.

7.1.3 Explanation of draft recommendation

In order for a stated GHG reduction to be verifiable it must be developed using transparent methods and be well documented. Only reductions that meet these conditions lend themselves to careful review by a third-party. Review should be conducted by an accredited verifier that is recognized by WCI Partner Jurisdictions. The WCI's Reporting Committee is building accreditation mechanisms and criteria for third-party verification of reported emissions. The WCI's offset system could build on that work and help foster a consistent approach to verification within the overall program. Most importantly, independent third-party verification of offsets is an international practice in existing voluntary programs and in the CDM.

7.2 Supporting Criteria

7.2.1 Validation

Validation is the process of reviewing the documentation and other information related to an offset project before it is actually implemented. The process provides assurance to the project developer that they are meeting the full requirements of the project protocol and the project is expected to produce GHG reductions if implemented as documented. WCI Partners could choose to recommend validation or make it optional. In either case, a project developer may be able to use a third-party validator or a jurisdiction could play that role.

7.2.1.1 Draft recommendation

With regards to WCI offsets, validation is a review by an independent third party to assess the likely result of reductions or sequestration from a proposed project that would use a WCI offset protocol. The WCI Partner Jurisdictions may not require third party validation in all cases but may approve protocols that require a validation step.

7.2.1.2 Summary of stakeholder input

Several respondents suggested that validation be optional or at the discretion of the project developer. Others supported mandatory validation including requiring third-party audit of application materials, or including validation as part of the verification process.

7.2.1.3 Explanation for draft recommendation

In a program where standardized protocols for specific project types must be approved, validation may not be necessary. Programs, like CDM, require validation because each reduction project is considered unique and project protocols allow some flexibility in how they are applied. Since the draft recommendations in this document also include following a standardized project protocol approach, validation would be an extra unnecessary step.

If the WCI Partners recommend that validation be optional at the discretion of the project developer and is thereby an option that has no legal weight within the WCI program, it is not necessary to develop a definition or include the concept in WCI Partner rule-making language. Implementing this option could be as simple as making project developers aware that they may engage a consultant to review their documentation and proposed project before it is implemented.

7.2.2 Enforceable

Enforceability is key to maintaining the WCI offset system's integrity. Enforcement ensures that the parties involved with the WCI offset system comply with the protocols and system recommendations.

7.2.2.1 Draft recommendation

Each Partner Jurisdiction will, to the extent permissible by law, put in place sufficient compliance/enforcement mechanisms and detail for the jurisdiction to compel compliance with its requirements and with WCI offset protocols.

7.2.2.2 Summary of stakeholder input

Stakeholders offered few comments for defining enforceable. Stakeholder comments generally supported offsets being enforceable. One comment supported strict enforcement for the WCI offset program. Another comment suggested supporting local enforcement and suggested enforcement should be similar to those in other environmental programs. Another comment suggested that capped entities that purchase offsets must be held responsible for surrendering valid credits for their emissions.

7.2.2.3 Explanation of draft recommendation

Since a definition for "enforceable" was not found in any existing offset system, the Black Law Dictionary was referenced to draft the recommended definition above. Although it does not define "enforceable," it does define "enforce" and "enforcement."[9]

Experience shows that compliance is ensured only by assurance that enforcement can be taken. Compliance assurance mechanisms in the enforcement process must be sufficiently effective to ensure enforceability within the WCI offset system. Compliance mechanisms are not directly referenced in the definition of enforceable above, but the Process White Paper will expand upon them and how their role in the enforcement process relates to enforceability. The following is a non-exhaustive list of enforcement mechanisms for further consideration:

- MOUs or contracts;
- Legal authority;
- Transparency;
- Penalty structures and mechanisms for collecting fines;
- Enforcement staff, infrastructure and capacity necessary to enforce;
- Registration and tracking system to establish and track ownership;
- Attestation of Title;
- Prohibitions for "double counting";
- Monitoring, reporting and third-party verification;
- Mechanism for project reversals, and
- Recourse for early project termination.

Another issue which the draft recommendation above does not address is the relationship between the enforcing regulatory authority and project proponents, as well as with any other persons or entities participating in the offsets system. The WCI's Design Recommendations document stated that "each WCI Partner jurisdiction will retain and/or enhance its regulatory and enforcement authority and responsibilities to enforce compliance with the cap-and-trade program within its own jurisdiction,"[10] and similarly that, "offset projects must also be enforceable by the individual WCI partner jurisdiction that is issuing the credit, and the credit must be verifiable by the individual WCI Partner jurisdiction that is accepting it."[11] The recommendations and provisions of the WCI offset system must be enforced to ensure that

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[9] *"…Enforce. To put into execution, to cause to take effective; as, to enforce a particular law, a writ, a judgment, or the collection of a debt or fine; to compel obedience to...". Also: "Enforcement. The act of putting something such as a law into effect; the execution of a law; the carrying out of a mandate or command".* (Taken from Black's Law Dictionary, Sixth Edition, Centennial Edition (1891-1991) page 528. No definition was available for "enforceable".)

[10] WCI Design Recommendations, p. 12.

[11] Ibid. p. 10.

offset system participants follow the rules and do not harm the integrity of the offsets system. The Process White Paper will lay out additional options for the relationship between the WCI's regulatory authorities and offset system participants.

7.2.3 Material

A term of art specific to verification is 'materiality.' This term relates to a threshold where differences above that number in reported emissions/reductions are deemed unacceptable. The WCI Essential Reporting Requirements document has a materiality threshold of ±5%, consistent with EU ETS and The Climate Registry. As briefly discussed in the Criteria White Paper, the WCI offset system could have a lower materiality threshold to be conservative. In regards to materiality, the WCI offset system could also apply an asymmetric materiality threshold that would entail not allowing any errors that overestimate the total emission reductions but accepting errors that underestimate reductions within a prescribed materiality threshold.

The term "material misstatement" refers to any error or aggregation of errors found by a verifier that would cause a verifier to believe with reasonable assurance that the GHG assertion does not meet the materiality threshold.

7.2.3.1 Draft recommendation

Material misstatement means that errors, omissions or an aggregation of both in the reported GHG reductions or assertion exceeds a ±5% threshold. For a WCI offset, the verifier must be able to state with reasonable assurance the total reported reductions or removals are free of material misstatement.

7.2.3.2 Summary of stakeholder input

WCI Partners received limited stakeholder input regarding materiality criteria. Comments received supported the ±5% threshold.

7.2.3.3 Explanation of draft recommendation

The recommended threshold of ±5% for the WCI offsets system is consistent with the materiality threshold for emitters with mandatory reporting obligations in the WCI Jurisdictions (as described in the Essential Reporting Requirements document). Neither the WCI Offsets Committee nor its stakeholders have identified a sufficient reason to alter the materiality threshold for offsets from what has previously been suggested for mandatory reporting.

8 Other considerations

In addition to the main criteria of real, additional, permanent, and verifiable, the WCI Offsets Committee also identified other factors to consider. Those factors were discussed previously in the Criteria White Paper. Following the format of the previous sections in this paper, this section includes for each of those factors a recap of that discussion, a draft recommendation, a summary of stakeholder comment, and an explanation for the draft recommendation.

8.1 Transparency

Transparency means that assumptions and methodologies for offset projects and protocols should be clearly explained and available for the public and system users. Transparency standards should allow users and stakeholders to assess and replicate projects and protocols in the offsets system.

Options to enhance transparency focus on increasing stakeholder input and public comment on project and protocol development, as well as public access to offset project information, except where important confidentiality issues exist.

8.1.1 Draft recommendation

The WCI offset system will provide transparency such that sufficient and appropriate protocol, project and certificate information is disclosed in a timely manner to allow offset system participants and the general public to make decisions with reasonable confidence.

8.1.2 Summary of stakeholder input

Overall stakeholders expressed their support for transparency within the WCI offset system. Specifically stakeholders supported a transparent protocol development process with public access to information on offset projects, tracking numbers, ownership, selling price, audit/enforcement activities, use for compliance and protocol quantification methodologies that are well documented for all algorithms and models. Some stakeholders qualified their support that information should be made available with consideration of confidentiality concerns. Some stakeholders supported public comment of offset protocols, project documents, credit issuance and enforcement, while other stakeholders supported limited public consultation, suggesting exclusion public consultation for project registration.

8.1.3 Explanation of draft recommendation

As identified in the WCI Offsets Task 1, the forthcoming Process White Paper will evaluate information needs for system users and the public, including details on how the review and approval of offset projects and protocols will take place, as well as standards for information releases. This paper confirms the importance of transparency and the Process White Paper and subsequent draft recommendations will identify options when the paper is released.

8.2 Co-benefits

Offset projects provide benefits in the form of greenhouse gas reductions or removals. An offset project may also lead to a number of other benefits ("co-benefits") beyond the emission reductions or removals. These co-benefits may include categories such as air quality improvements and economic development activity. Whether to require offset projects to generate co-benefits is an important question in establishing an offset system. Most offset systems do not require projects to generate co-benefits with some exceptions, most notably the Clean Development Mechanism. Note that this question is focused on the generation of co-benefits above and beyond what may exist prior to implementation of the offset project, and not on maintaining or mitigating the loss of co-benefits in existence prior to the project.

8.2.1 Draft recommendation

WCI Partners recognize the environmental, social, economic and health benefits that may arise from an offset project and the offset system will focus on those benefits directly related to mitigating climate change. A WCI offset project is required only to result in a greenhouse gas emission reduction or removal.

8.2.2 Summary of stakeholder input

Most stakeholder comments did not support requiring project co-benefits to be generated in order for a project to receive credit as a WCI offset. Some stakeholders generally supported making the presence of co-benefits either a necessary criterion to receive credit, or a weighting factor when evaluating offset projects against each other. Others supported requiring documenting, but not requiring, co-benefits in the process to apply for and credited with compliance units.

8.2.3 Explanation of draft recommendation

The draft recommendation on co-benefits keeps the WCI offset program focused on greenhouse gas reductions and removals—the reason behind establishing the WCI regional cap-and-trade program. A WCI offset makes no claim to any benefits or properties associated with the offset project other than the greenhouse gas emission reduction or removal resulting from implementation of the project. Any benefits attributable to an offset project beyond the greenhouse gas reduction or removal properties of the project are incidental to the offset. Under this recommendation, the WCI Partners remain neutral on how co-benefits associated with an offset project may be treated or claimed by policies or programs other than the greenhouse gas cap-and-trade program. By remaining "policy neutral" regarding co-benefit attributes associated with an offset project, jurisdictions are free to take different approaches towards using these attributes in emerging attribute valuation schemes, such as ecosystem service markets (e.g., markets in habitat protection or wetland mitigation).

8.3 Assessment of Environmental or Social Impacts

Offset projects reduce or remove greenhouse gas emissions. However, offset project activity may impact its environment or social environment. Transparency can be enhanced by informing stakeholders about the impacts of an offset project. Examples of options for assessing the impacts of offset projects include requiring documentation of impacts in the project plan, a policy of "offsets should do no net harm," requirements to meet all local environmental regulations, or having no specific requirement.

8.3.1 Draft recommendation

WCI offset projects must meet all applicable local environmental regulations and be in compliance with all applicable laws in the jurisdiction where the project is located. If environmental or socioeconomic assessments of the proposed project have been done, the project's registration application should reference this work and include a summary of the findings. Protocols for specific offset project types may require analysis of environmental and socioeconomic impacts beyond what the local jurisdiction would otherwise require and may require additional mitigation of potential negative impacts.

8.3.2 Summary of stakeholder input

Stakeholders were divided about whether the WCI Partner Jurisdictions should require projects to provide an assessment of environmental or social impacts. Some stakeholders stated that they do not support any recommendations for impact assessments. Other stakeholders suggested that WCI Partner Jurisdictions should ensure that offset projects do no net environmental or social harm through consultation in the protocol development process. Others suggested that projects provide proof, through an EIA assessment or other form, which the project does not result in net negative impacts.

8.3.3 Explanation of draft recommendation

WCI Design Recommendations state that the WCI cap-and-trade system will aim to "[maximize] total benefits in jurisdictions throughout the region, including reducing air pollutants, diversifying energy sources, and advancing economic, environmental, and public health objectives, while also avoiding localized or disproportionate environmental or economic impacts" (p. 52). The draft recommendation is consistent with this earlier policy direction. WCI Partners will consider recommending additional assessments on a case by case basis as part of their protocol recommendation process.

9 Conclusion

This paper provides the WCI Partner Jurisdictions' draft recommendations for defining a WCI offset and defining the WCI Partners' main offset criteria of real, additional, permanent and verifiable. It has also offers recommended definitions for other criteria in support of the offset definition and main offset criteria, as well as recommendations for a few other considerations. This paper summarizes stakeholder response to the Criteria White Paper and attempts to explain the reasoning for the Committee's recommendations.

The WCI Offsets Committee will receive stakeholder comment on this paper and its recommendations before issuing its final recommendations. Written comments may be received via the WCI website through May 12, 2010. As with the Criteria White Paper, the WCI Offsets Committee will also hold two stakeholders calls. The first call on Thursday April 22, 2010 from 10:30 a.m. to 12:00 p.m. Pacific Time will provide an initial presentation and discussion of this paper. The second call on Wednesday May 5, 2010 from 9:00to 10:30 a.m. Pacific Time will be focused on hearing from stakeholders and responding to stakeholder questions.

The WCI Offsets Committee poses these questions to stakeholders:

- What is your impression of the draft recommendations overall and individually?
- What has been your experience with offset systems utilizing these or similar recommended definitions for an offset and its essential criteria? Have the advantages of these definitions outweighed the disadvantages?

This is the second paper from the WCI Offsets Committee Task 1 work. A forthcoming white paper will cover the process of registration, validation, monitoring, quantification, reporting, verification, certification, and issuance of offsets.

This draft recommendations paper supports the WCI Offsets Committee's work to reach final definitions for a WCI GHG offset and the detailed eligibility criteria for GHG offset projects for compliance purposes.

April 12, 2010 Offset System Essential Elements Draft Recommendations Paper

List of Commenters

Biothermica Technologies Inc.

Bumpus, Adam

Canadian Association of Petroleum Producers

Canadian Parks and Wilderness Society

Carbon Offset Providers Coalition

Climate Action Reserve

Coalition for Emission Reduction Projects

First Record Carbon, LLC

Forest Products Association of Canada

Industry Provincial Offsets Group

International Emissions Trading Association

International Rivers

Offsets Working Group

Ontario Energy Association

Pacific Gas and Electric Company

Pearl Earth Sciences Corp

RRI Energy, Inc.

Soil Conservation Council of Canada

Southern California Public Power Authority

Stuhrman, Robert

TerraPass

The Nature Conservancy

The Pacific Forest Trust

Utah Business Climate Change Coalition

Waste Management, Inc.

Western Climate Advocates Network

Weyerhaeuser

April 13, 2010 Commissioned Offset Protocol Review Report

List of Commenters

3Degrees

Biothermica Technologies Inc.

California Forestry Association

Canadian Association of Petroleum Producers

Climate Action Reserve

Coalition for Emission Reduction Projects

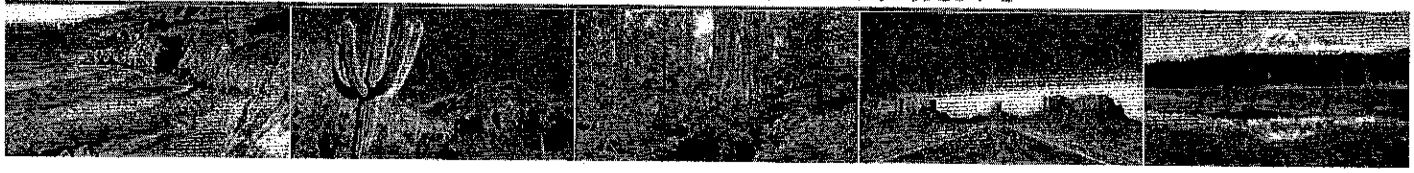
EOS Climate

Pacific Gas and Electric Company

Southern California Public Power Authority

Waste Management

Western Climate Initiative



Offset Protocol Review Report

Offset Committee, Task Group 3

April 2010

The *WCI Design Recommendations* establishes a rigorous offset system to support the WCI cap-and-trade program.[1] The WCI design goes on to prioritize project types in agriculture, forestry and waste management for investigation and development to participate in the offset system. Other project types outside the capped sectors in the cap-and-trade program may also participate in the offset system.

The WCI's Offsets Committee was tasked with developing recommendations for offset criteria and carrying out the joint review, adaptation, and development of protocols by the Partner jurisdictions. WCI Partners have publicly released draft recommendations on criteria for offsets in an offsets system.[2] The draft offset criteria are being designed to ensure that all offsets credits issued or accepted by WCI Partner jurisdictions are real, additional, permanent, verifiable, and enforceable. The attached report is part of the Offset Committee's effort to coordinate the review and adaptation of existing protocols in the priority project types outlined above against the WCI draft offset criteria. The WCI Partners' intent is to build off the existing work done on offset protocols. The result of this work identify how well existing protocols satisfy the WCI criteria. The Offsets Committee will then concentrate on modifications to existing protocols for priority project types or developing new protocols where suitable ones do not exist. Stakeholder input will be sought in modifying or developing protocols.

Following a competitive and open RFP process, WCI Partners contracted Det Norske Veritas (DNV) to evaluate existing offset protocols. The goal of the evaluation was to help the WCI Partners identify opportunities to incorporate existing protocols into an offset system. The evaluation included 31 protocols from 11 offset systems particular to ten project types in agriculture, forestry, and waste management.

[1] As described in Section 9 of the *Design Recommendations for the WCI Regional Cap-and-Trade Program, September 23, 2008* (http://www.westernclimateinitiative.org/ewebeditpro/items/O104F21252.pdf).
[2] Available at www.westernclimateinitiative.org/component/remository/Offsets-Committee-Documents/Offset-Criteria-Draft-Recommendations/.

The WCI Partners asked DNV to evaluate protocols from existing offset systems to determine whether each protocol:

- Corresponds to the offset criteria as outlined in the WCI's *Offset System Essential Elements Draft Recommendations Paper*;
- Meets the relevant requirements described in the ISO framework, and
- Is applicable to the geographies of the Partner jurisdictions.

WCI Partners invite stakeholder comments on the report's evaluation. These comments will assist the Offsets Committee as they make a recommendation to WCI Partners on adapting existing offset protocols. In recommending adapted protocols for WCI Partner jurisdictions' adoption, the WCI Partners will work to:

- Review existing materials for the protocol project type, including DNV's evaluation, the changes from previous versions of the protocol and the existing public comments on the protocol.
- Draft proposed amendments to the protocol.
- Release the draft protocol for public review, requesting stakeholders for specific feedback on those portions of protocols that have been amended.
- Analyze and incorporate public input.

Each WCI Partner jurisdiction may then choose to put the protocol into force in its own jurisdiction either directly and/or by reference, as its rules allow.

DNV

DET NORSKE VERITAS

Report for:
The Western Climate Initiative

Review of Existing Offset Protocols Against WCI Offset Criteria

February 26, 2010

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1 EXECUTIVE SUMMARY

The purpose of this report is to provide the results of the evaluation of protocols identified by the Partners in the Western Climate Initiative (WCI). The goal of the evaluation was to help the WCI identify opportunities to incorporate existing protocols into a new offset system created by the WCI. The evaluation included 31 protocols[1] from 11 offset systems[2] particular to ten project types in agriculture, forestry, and waste management.

The WCI Partners asked DNV to evaluate protocols from existing offset systems to determine whether each protocol:

- Corresponds to the offset criteria as outlined in the WCI's *Offset System Essential Elements Draft Recommendations Paper*
- Meets the relevant requirements described in the ISO framework, and
- Is applicable to the geographies of the Partner jurisdictions.

In practice, DNV could not identify instances where a protocol satisfies the WCI guidelines without also satisfying ISO guidelines. As a result, DNV's evaluation focused on whether the protocol's provisions correspond to WCI guidance with respect to the following WCI criteria:

- Real (which is based on the following WCI supporting criteria)
    - Quantification
    - Uncertainty & Accuracy
    - Conservativeness
    - Leakage
- Additional
- Permanent
- Verifiable
- Applicable to the regions within the WCI's jurisdiction

For each of these criteria, DNV worked with WCI Offsets Committee members to establish evaluation guidelines to be used to determine if the protocol:

- Appears to correspond to WCI and ISO definitions for this criterion.
- Is likely to correspond to, with modification, WCI and ISO definitions for this criterion.
- Could correspond to, with significant modification, WCI and ISO definitions for this criterion.

For the protocols that did not appear to match the WCI's draft criteria, DNV identified potential modifications to the protocols that would enable the WCI to consider them in accordance with the WCI draft criteria. DNV also sought to identify the degree of difference between the protocol and the WCI's criteria, and whether revisions to the protocols would require editorial revisions or research-based modifications. While DNV estimated the degree of change required, it did not estimate the amount of time or effort necessary to make the identified changes--an editorial change is not necessarily an easy one.

DNV was not asked to evaluate the WCI draft offset definitions, criteria, and guidelines outlined in *Offset System Essential Elements Draft Recommendations* or to provide DNV's own interpretation of any of these guidelines while carrying out this evaluation. The protocols are evaluated solely on the basis of their apparent conformance with WCI recommendations as written.

Summary of Evaluations for each Protocol and Criterion

[1] For the purposes of this report, the term protocol refers to the guidance, procedures, and methodologies that detail procedures for creating offsets under an offset system.

[2] For the purposes of this report, the term offset system refers to an organization or entity that has sought to provide guidance to implementing greenhouse gas reductions and/or to creating offsets through projects.

Table 1 summarizes DNV's findings, with each color corresponding to an assessment of the degree of change that would be necessary for the protocol to correspond to WCI's guidelines. In addition to the color coding, black dots represent modifications appearing to require conceptual or research-based changes, while clear dots represent modifications that appear to be editorial in nature.

The paragraphs below summarize commonalities and differences found in the protocols, by project type. It is not a complete description of findings and is instead intended to highlight the most notable aspects of the review.

Soil sequestration:
Neither the Alberta Offset System nor the Chicago Climate □xchange corresponds to the criteria for quantification, leakage, additionality, and permanence□the reasons for this are similar across the two protocols:

- □eographic applicability is an issue, and the protocols need new parameters and emission factors to make their quantification methods applicable to all three countries, i.e., the United States, Canada, and Mexico. The same is true for additionality, as both protocols use a performance test that is country/region specific.
- Neither protocol justifies why leakage is not a concern.
- Neither protocol meets the WCI criterion for permanence because they do not adequately ensure that carbon is stored at least 1□□ years.

Manure management:

- The CDM methodology corresponds to all the WCI criteria, except for the criterion additional, and so is the closest to meeting the WCI criteria as-is. That said, the CDM methodology is the only protocol that takes a project-by-project approach to additionality, rather than the WCI's preferred performance-based approach.
- □eographic applicability is an issue, and the protocols need new parameters and emission factors to make their quantification methods applicable to all three countries, i.e., the United States, Canada, and Mexico. The same is true for additionality, as both protocols use a performance test that relies on market penetration rates that are country/region specific.
- In cases where □□ncertainty and accuracy□is not met, it is because protocols do not require managing uncertainties by, for example, requiring discounting.
- Most of the manure management protocols do not explicitly address leakage, except for the CDM and Climate Leaders, which do.
- All the protocols require third-party certification except for the Climate Leaders.

Rangeland Management:
Only the CC□ protocol was reviewed in this project type.

- □eographic applicability is an issue, and the protocol needs new parameters and emission factors to make its quantification method applicable to all three countries. The same is true for additionality.
- It does not meet the WCI criterion for permanence because it does not adequately ensure that carbon is stored at least 1□□ years.

Afforestation & Reforestation:

- With respect to baseline and project quantification, CC□, CAR and Climate Leaders rely upon models and look-up tables that are specific to regions and types of trees. For that reason, these protocols need modification to ensure that the look-up tables are appropriate to all WCI regions, but the CDM and R□□I protocols seem to be applicable to projects in any countries/regions because they rely upon sampling.
- CC□ and R□□I do not consider leakage emissions. While Climate Leaders and CDM require quantifying leakage emissions, the CAR protocol requires determining leakage risks percentage from the decision tree provided in the protocol.

- The CC□, CAR, and Climate Leaders protocols all use a performance standard approach to ensure additionality, and so need modifications to the thresholds to make them applicable to all three countries.
- Among all the reviewed afforestation and reforestation protocols, the CDM and R□□I protocols are the only ones to take a project-by-project approach to additionality.
- The CDM is the only system that issues temporary credits to ensure permanence. The other protocols require withholding proportion of offsets to compensate for reversals. The CAR protocol is the only one that tries to ensure carbon is stored at least for 1□□ years by requiring signing a 1□□-year-commitment.
- All the protocols except for the Climate Leaders require a third-party verification.

Forest Management:
Only the CC□ and CAR protocols were reviewed for this project type, and there were key differences in how each deals with leakage and with permanence.

- While the CC□ assumes leakage emissions are zero without justification and therefore provides no measures for addressing any potential leakage, the CAR protocol requires determining the leakage risk percentages
- The CC□ requires that all project proponents reserve a certain percentage of offsets to ensure permanence, while CAR requires withholding certain percentages depending upon risks of reversals

Forest Preservation & Conservation:
The CAR protocol is the only one reviewed in this project type.

- It did not meet the WCI criteria for quantification and additional because the models, parameters, and performance tests are applicable only to the California region.

Urban Forestry:
CC□ and CAR protocols were reviewed.

- While the CC□ protocol assumes leakage emissions are zero without justification and therefore provide no measures for addressing any potential leakage, the CAR protocol addresses any leakage by denying registration of offsets in that year that activity-shifting leakage is confirmed from a tree maintenance plan.
- The CC□ requires that all project proponents reserve a certain percentage of offsets to ensure permanence, but CAR does not make a similar requirement.

Landfill Gas:
Protocols from the Alberta Offset System, CAR, □□-A□S, and Climate Leaders all need parameters that are applicable to projects in all three countries. CC□, CDM and R□□I protocols do not need such modifications.

- □xcept for the Climate Leaders protocol, leakage emissions are considered to be insignificant and are not accounted for. The Climate Leaders protocol provides a quantification methodology that needs to be applied in case where leakage is a concern. The CC□, CDM and R□□I protocols do not justify why leakage emissions are not a concern.
- The CC□, CAR and Climate Leaders protocols takes a performance standard based approach to additionality. These protocols need modifications to the additionality thresholds as they are not applicable to al three countries.
- Climate Leaders is the only protocol that does not require third-party verification.

Waste and Wastewater Treatment:
The CDM methodologies in the waste and wastewater category are rated as closer to WCI criteria because they use global parameters or refer to region specific parameters found in the IPCC guideline for quantification, which are applicable to all three WCI regions. Other protocols in this project type use

parameters that are regional-specific (but not specific to all three regions), which means that they do not meet the WCI's sub-criterion for quantification and additionality.

- The CDM compost protocol corresponds to the WCI criteria (with the exception of crediting period and early starting date, an issue shared by all protocols).
- The CDM wastewater protocol has an additional issue with leakage because though it asserts that the risk of leakage is not present, it does not justify its assertion.
- The Alberta Waste Water protocol corresponds to the WCI criteria with the exceptions of the criteria additional and quantification, both due to issues of geographical applicability. (Again, this is with the exception of crediting period and early starting date, an issue shared by all protocols).
- The Alberta Compost protocol shares the issues of the Alberta Waste Water protocol but additionally does not address leakage risk.
- The □□-A□S protocol shares the issues of geographical applicability and, additionally, fails to justify why leakage is not a concern.

Table 1: Summary Matrix of Evaluations for each Protocol and Criterion

Project Type	Protocol	Real: Quantification	Real: Uncertainty & Accuracy	Real: Conservative	Real: Leakage	ADDITIONAL	P□RMAN□NT	V□RIFIA□L□
Soil Sequestration	Alberta Offset System	●			○	●	○	
	Chicago Climate □xchange	●			○	●	○	
Manure Management	Alberta Offset System		○		○	●		
	Chicago Climate □xchange	●	○		○	●		
	Clean Development Mechanism					○		
	Climate Action Reserve	●			○	○		
	Regional □reenhouse □as Initiative	●	○	○	○	●		
	US □PA Climate Leaders	●	○			●		○
Rangeland Management	Chicago Climate □xchange	●				●	○	
Afforestation & Reforestation	Chicago Climate □xchange	●	○		●	●	●	
	Clean Development Mechanism					○	○	
	Climate Action Reserve	●			●	○		
	Regional □reenhouse □as Initiative		○	○	●	○	●	
	US □PA Climate Leaders	●	○	○		●	●	○
Forest Management	Chicago Climate □xchange	●	○		●	●	●	
	Climate Action Reserve	●			●	●		
Forest Preservation & Conservation	Climate Action Reserve	●			●	○		
Urban Forestry	Chicago Climate □xchange	●	○		●	●	●	
	Climate Action Reserve	●		○		●		
Landfill Gas	Alberta Offset System	●	○			○		
	Chicago Climate □xchange		○		○	●		
	Clean Development Mechanism		○		○	○		
	Climate Action Reserve	●				●		
	□□ □A□S	●				○		
	Regional □reenhouse □as Initiative	●	●	○	○	○		
	US □PA Climate Leaders	●	○	○		●		○
Waste and Wastewater Treatment	Alberta Offset System Compost	●	○		○	●		
	Alberta Offset System Waste Water	●				●		
	CDM Compost					○		
	CDM Waste Water				○	○		
	□□ □A□S	●			○	○		

Appears to correspond to WCI and ISO definitions for this criterion.	● Would involve conceptual or research-based modification
Likely to correspond to, with modification, WCI and ISO definitions for this criterion.	○ Would involve editorial modification
Could correspond to, with significant modification, WCI and ISO definitions for this criterion.	

2 INTRODUCTION

The purpose of this report is to provide the results of DNV's evaluation of protocols[3] identified by the Partners in the Western Climate Initiative (WCI). The goal of the evaluation was to assess how easily the existing protocols could be incorporated into an offset system for the Western Climate Initiative (WCI), should the WCI choose to do so. The initial list for consideration included □□ protocols from 11 offset systems□ particular to ten project types in the agriculture, forestry, and waste management sectors.

Table 2: Protocols Listed by Offset System and Project Type (Identified by the WGA[5])

● = Approved protocol or methodology
◉ = protocol or methodology under development
○ = protocol or methodology considered for future

	Alberta Offset System	American Carbon Registry (ACR)	Chicago Climate Exchange (CCX)	Clean Development Mechanism (CDM)[1]	Climate Action Reserve (CAR)	GE Energy Financial Services & AES (GE-AES)	New South Wales (NSW)	Regional Greenhouse Gas Initiative (RGGI)	U.S. DOE 1605 (b)	U.S. EPA Climate Leaders	Voluntary Carbon Standard (VCS)[2]
Agriculture											
Soil sequestration	●[3]		●[4]		○[5]				●[6]		●[7]
Manure management (including anaerobic digestion)	●[8]	◉[9]	●[10]	●[11]	●[12]	●[13]		●[14]		●[15]	
Rangeland management	○[16]	○[9]	●[4]		○[5]				●[6]		●[7]
Forestry											
Afforestation / Reforestation	◉[17]	●[18]	●[19]	●[20]	●[21]	○[22]	●[23]	●[14]	●[6]	●[24]	●[7]
Forest management		●[18]	●[19]		●[21]				●[6]	◉[25]	●[7]
Forest pres. /conservation		●[18]	●[19]		●[21]	○[22]			●[6]		●[7]
Forest products		●[18]	●[19]		●[26]				●[6]		●[7]
Urban forestry	◉[17]		●[19]		●[27]				●[6]		
Waste Management											
Landfill gas	●[28]	◉[9]	●[10]	●[29]	●[30]	●[31]		●[14]		●[32]	
Waste and wastewater treatment	●[33]			●[34]		●[35]					

Note: in some cases, a dot in this table represents more than one protocol. In other cases, a protocol addresses more than one project type or dot.

The WCI's offset criteria are outlined in its *Offset System Essential Elements Draft Recommendations Paper*[6], in which a WCI offset is defined as:

> a quantified, independently verified reduction or removal of a greenhouse gas (□□□). It is expressed as one metric ton, or one tonne, of carbon dioxide equivalent. Offsets credits must meet the WCI essential criteria requirements for the WCI Offset System. A WCI offset is tradable, and bankable for future use, and may be used by a capped emitter to meet compliance obligations.

and defines the WCI's requirements that the offset be:

[3] For the purposes of this report, the term protocol refers to the guidance, procedures, and methodologies that detail procedures for creating offsets under an offset system.

[4] For the purposes of this report, the term offset system refers to an organization or entity that has sought to provide guidance to implementing greenhouse gas reductions and/or to creating offsets through projects.

□ *Request for Proposals: Review of Existing Offset Protocols for Consistency with Western Climate Initiative Offset Draft Criteria.* Western □overnor's Association. □uly 31, 2□□□ Available online at http://www.westernclimateinitiative.org/component/remository/Offsets-Committee-Documents/

□Offset System □ssential □lements Draft Recommendations Paper. *Western Governor's Association.* Forthcoming.

- Real (which is based on the following supporting WCI criteria)
  - Quantification
  - Uncertainty & Accuracy
  - Conservativeness
  - Leakage
- Additional
- Permanent
- Verifiable

The WCI Partners asked DNV to evaluate protocols from the existing offset systems listed above to determine whether each protocol appears to:

- Meet the WCI offset criteria,
- Meet ISO 1□□□□-2[□], 1□□□□-3[□], and 1□□□□[□] requirements, and
- Is applicable to the geographies of the Partner jurisdictions.

DNV was not asked to evaluate the WCI draft offset definitions, criteria, and guidelines outlined in *Offset System Essential Elements Draft Recommendations* or to provide DNV's own interpretation of any of these guidelines while carrying out this evaluation, and did not do so. The protocols are evaluated solely on the basis of their apparent conformance with WCI guidelines as written.

In cases where an offset system provides system-level guideline documents (e.g., Alberta), DNV reviewed these additional documents because specific information such as project starting dates are only specified in the system guidance documents and not at each protocol level. DNV, however, did not review any previous versions of the protocols or background information about how the protocols were developed. DNV's assessment is based on a □strict reading□of the protocols, which means that DNV did not carryout a technical review of the protocol or use our professional judgment to make inferences where information was not explicitly provided in the protocol.

For the protocols that did not fully correspond to the WCI guidelines, DNV identified potential modifications to the protocol. DNV's evaluation was framed within the context of how much modification would be necessary to meet the WCI's guidelines. DNV's evaluation refers to the conceptual degree of change required for a protocol to conform to WCI guidelines, not to the amount of work, time, or effort necessary to make that change. That said, DNV further identified whether the necessary changes appear to be editorial in nature or are instead research-based.

It can be noted that no protocol perfectly met all of the WCI conditions, if only because none of the specified protocols provide region-specific factors or rules for all potential projects in the United States, Canada, and Mexico. For all project types, crediting periods and project start dates fail to match up with the WCI. It also cannot be concluded that any given protocol could never be made to fully correspond to the WCI guidelines, with sufficient modification.

DNV excluded from the analysis the following protocols that the WCI had initially suggested in the *Request For Proposals*, for the specified reasons:

- U.S. DO□ 1□□□(b), as they do not refer to specific stand-alone project activities, and so cannot be fairly evaluated against project-specific protocols□

[□] *ISO 14064-2:2006: Specification with guidance at the project level for quantification, monitoring and reporting of greenhouse gas emission reductions or removal enhancements.* (2□□□). Available at http://www.iso.org

[□] *ISO 14064-3:2006: Specification with guidance for the validation and verification of greenhouse gas assertions.* (2□□□). Available at http://www.iso.org

[□] *ISO 14065:2007: Requirements for greenhouse gas validation and verification bodies for use in accreditation or other forms of recognition.* (2□□□). Available at http://www.iso.org

- All protocols listed in the VCS, as they do not provide quantification methodologies for soil sequestration, rangeland management, or forestry projects, and so cannot be fairly evaluated against offset qualification/quantification protocols. These documents are rather guidelines for quantification/qualification of offsets[1□]□
- CC□ Forest Preservation/Conservation, as it no longer exists under the revised CC□ guidelines□
- New South Wales, as they do not provide quantification methodologies, and so cannot be fairly evaluated against offset qualification/quantification protocols□
- American Carbon Registry forestry protocol, as it does not provide its own quantification methodology□and
- All Forest Products protocols, as they do not refer to specific stand-alone project activities, and so cannot be fairly evaluated against project-specific protocols.

After this initial review, 31 protocols were considered for further analysis, including some protocols that DNV substituted for protocols that the Partners had identified:

- CC□ 2□□□ protocols for the protocols described in the 2□□□ Rulebook Chapter □, as these have displaced the 2□□□ rules.
- CDM ACM □□1□ for AMS-3.D (covering manure management), and AM □□1□ for AMS-III.□ (covering wastewater treatment) as these are applicable to large-scale projects whereas those identified by the WCI are not.

For each of the WCI criteria (real, additional, permanent, and verifiable), DNV evaluated each protocol to determine if it:

- Appears to correspond to WCI and ISO definitions for this criterion.
- Is likely to correspond to, with modification, WCI and ISO definitions for this criterion.
- Could correspond to, with significant modification, WCI and ISO definitions for this criterion.

For each of the WCI criteria, DNV applied a general evaluation approach as described in Table 3, as well as criterion-specific evaluation metrics as specified in Table □

To draft the guidelines, DNV reviewed each of the WCI's draft criteria and determined that they were consistent with the ISO framework□in the evaluation, there was no instance in which a protocol met the WCI criteria and failed to meet the ISO criteria.

[10] At the time of this writing there were several Agriculture, Forestry and Other Land Use (AFOLU) protocols being proposed and going through the VCS approval process, but none that had been approved.

General Evaluative Approach Used

Table 3: Evaluations Possible for Each Criterion

Appears to correspond to WCI and ISO definitions for this criterion.
Likely to correspond to, with modification, WCI and ISO definitions for this criterion.
Could correspond to, with significant modification, WCI and ISO definitions for this criterion.

where "modification" and "significant modification" refer to the conceptual degree of change required, rather than to the amount of work, time, or effort necessary to make that change.

The criterion "real" consists of sub-criteria "quantification", "uncertainty & accuracy", "conservativeness" and "leakage." Evaluation for "real" is a summary result of the four sub-criteria and in cases where a sub-criterion was assessed to "could correspond to with significant modification", and then the overall evaluation for "real" corresponds to that result.

DNV's choice of the above evaluation was based on the corresponding guidelines summarized below (matched by color):

Table 4: Evaluation Guidelines for Determining if a Protocol Meets Each Criterion

	Evaluation
REAL	
Quantification	Protocol clearly states project boundaries, quantification methodology based on recognizable scientific sources and emission factors are appropriate to all the WCI jurisdictions.
	Uses default values that are not appropriate to all the WCI regions. Alternatively, Project boundary is not clearly stated.
	No quantification methods are provided.
Uncertainty & Accuracy	Protocol provides guidelines to reduce uncertainty/bias and quantification methodologies are based on recognizable scientific sources. The protocol discounts to adjust for high uncertainty. Additionally, the protocol requires that the proponent institute quality assurance measures in data management.
	Protocol does not appear to be based on recognizable scientific sources or does not institute quality assurance measures for data measurement. Alternatively, protocol does not manage uncertainty, for example, by requiring discounting emission reductions to adjust for high uncertainty.
	Protocol does not identify uncertainty or provide guidelines to reduce uncertainty.
Conservativeness	The protocol provides a principle of conservatism or assertion that parameter values are selected so as to underestimate rather than overestimate the calculation of emission reductions.
	The conservativeness of the parameters is not justified.

Leakage	Protocol identifies sources of leakage. If leakage is a concern, quantification/qualification and management of leakage are required. If leakage is qualified as opposed to quantified, the protocol justifies why quantification is not possible.
	The protocol finds that leakage is a concern but does not establish guidelines to mitigate the risk
	There is no evidence that the protocol examines leakage. Alternatively, the protocol states that leakage is not a concern but does not justify the assertion.

ADDITIONAL	Additionality is assessed via a performance test that is appropriate for all WCI jurisdictions. Further, the protocol meets criteria for start date and crediting period. Alternatively, the protocol uses a project-specific approach that ensures that at a minimum the project is not required by law. Further, the protocol meets criteria for start date and crediting period.
	The protocol employs a performance test or project specific additionality test (that at a minimum ensures the project is not required by law) but does not meet the criteria for crediting period or start date. Alternatively, the analysis used to justify the performance test is not appropriate for the entire WCI region.
	The protocol applies no additionality test, either performance or project-based, and do not ensure that the project was not required by law.

PERMANENT	The protocol assesses the risk for reversal. If present, it establishes or requires that the project proponent establish: a monitoring system, a risk mitigation approach, and a contingency plan for the case of reversal. Further, the protocol has the legal means to enforce the contingency plan and the plan is adequate for the risk of reversal over a 1□□ year time span. Reversals could be balanced, for example, by the set-aside of a certain number of offsets or the issuance of temporary credits. Alternatively, non-sequestration projects automatically meet the WCI criteria for permanence.
	The protocol assesses the risk for reversal. If present, it establishes or requires that the project proponent establish: a monitoring system, a risk mitigation approach, and a contingency plan for the case of reversal. □owever, the protocol□s plan is inadequate for the risk of reversal over a 1□□ year time span.
	The protocol describes a sequestration project but does not provide any requirements for preventing, managing, or compensating for reversals.

VERIFIABLE	Protocol requires documents, evidence and data be available for 3rd party verification.
	The protocol does not require verification.

Work Process Flowchart

The flowchart below illustrates the process by which DNV conducted this assessment. □rey boxes refer to documents or work product□ tangible objects that can be referenced. White boxes refer to actions that were taken to modify the preceding document or to make an assessment.

ISO Documents
WCI Draft Recommendations Paper
Step 1: Reviewed ISO and WCI documents and pulled out text relevant to the WCI's criteria (Real, Additional, Permanent, Verifiable, and Applicable to the regions within the WCI's jurisdiction)
Relevant text from ISO and WCI documents (see Appendix 2)
Step 2: Drafted for approval by WCI Offsets Committee Members □valuation □uidelines to determine what □appears to correspond to□ □is likely to correspond to, with modification□ and □could correspond to, with significant modification□the relevant text from ISO and WCI documents.
□valuation □uidelines for Determining if a Protocol Meets □ach Criterion (Table □ in this document, page 11)
Step 3: Developed evaluative questions for DNV team to use when determining what the protocol text would need to state in order to meet WCI's □valuation □uidelines.
□valuative Questions (see Appendix 2)
Step □ Reviewed Protocol Text and Offset System □uidance Documents and pulled out text relevant to the WCI's criteria
Relevant Protocol Text (see Appendix 2)
□xcel-based tracking sheet relevant text from ISO and WCI documents, relevant text from Protocols, and DNV's □valuative Questions (see Appendix 2)
Step □ Asked question: According to □valuative Questions, what category does the relevant protocol text apply to□Assigned each criterion to green, yellow, or blue category as appropriate.
Step □(when appropriate): Where not green, determine what must be done to qualify as green. Make judgment of whether the necessary changes are editorial or research-based in nature.
DNV Assessments (Sections □-12 of this document)

3 STAKEHOLDER PROCESS OF EACH OFFSET SYSTEM

As part of its review, DNV summarized the stakeholder process of each offset system.

Offset System	Stakeholder Process
Alberta Offset System	The Alberta government first provides feedback to protocol developers. The protocol then goes through three rounds of review. The first is by an expert technical review committee, and the second is by a broader stakeholder group. If there are no objections, the protocol is posted for the final public review for 3□days.
Chicago Climate Exchange	A technical subcommittee drafts protocols, and protocols are posted on the website for public review and comment.
Clean Development Mechanism	All proposed new CDM baseline and monitoring methodologies go through a public comment process. The CDM Executive Board approves methodologies.
Climate Action Reserve	The Climate Action Reserve develops offset protocols in an open, transparent and consensus-based process. It takes a multi-stakeholder approach to developing protocols.
GE Energy Financial Services & AES	Proposed methodologies are assigned a point of contact within Greenhouse Gas Services, LLC and this person is responsible for drafting the methodology and securing stakeholder input. Greenhouse Gas Services, LLC is ultimately responsible for the adoption of new methodologies.
Regional Greenhouse Gas Initiative	The Model Rule was developed by the RGGI Staff Working Group, comprised of staff members from the environmental and energy regulatory agencies in each participating state. This effort was supported by a regional stakeholder process that engaged the regulated community, environmental groups, and other organizations with technical expertise in the design of cap-and-trade programs.
U.S. EPA Climate Leaders	The U.S. EPA developed the protocols. It is possible to propose a new protocol. When a new protocol is proposed, the EPA reviews it. The protocol review process is not well defined or transparent, and appears to have no public stakeholder consultation process.
American Carbon Registry	Excluded from the review
DOE 1605 (b)	Excluded from the review
VCS	Excluded from the review
New South Wales	Excluded from the review

4 SOIL SEQUESTRATION PROTOCOLS[11]

4.1 Alberta Offset System Quantification Protocol for Tillage System Management, Version 1.3

	Evaluation
REAL	Could correspond to, with significant modification, WCI and ISO definitions for this criterion. *Aspects of criterion definition that are met:* The protocol meets Uncertainty & Accuracy and Conservativeness. (See below) *Modifications that are necessary to fully meet:* The protocol would need to modify Quantification and Leakage (See below)
Quantification	Likely to correspond to, with modification, WCI and ISO definitions for this criterion. *Aspects of criterion definition that are met:* The protocol clearly states project boundaries and quantification methodology are based on recognizable scientific sources. *Modifications that are necessary to fully meet:* The protocol would need to develop emission factors that are appropriate to all the WCI jurisdictions.
Uncertainty & Accuracy	Appears to correspond to WCI and ISO definitions for this criterion. *Aspects of criterion definition that are met:* Protocol provides guidelines to reduce uncertainty bias and quantification methodologies are based on recognizable scientific sources. The protocol discounts to adjust for high uncertainty. Additionally, the protocol requires that the proponent institute quality assurance measures in data management. *Modifications that are necessary to fully meet:* NA
Conservativeness	Appears to correspond to WCI and ISO definitions for this criterion. *Aspects of criterion definition that are met:* The protocol provides a principle of conservatism or assertion that parameter values are selected so as to underestimate rather than overestimate the calculation of emission reductions. *Modifications that are necessary to fully meet:* NA
Leakage	Could correspond to, with significant modification, WCI and ISO definitions for this criterion. *Aspects of criterion definition that are met:* NA

[11] This project type includes improved tillage management (both the Alberta Offset System and Chicago Climate Exchange) and permanent grassland cover (Chicago Climate Exchange only).

	Modifications that are necessary to fully meet: The protocol would need to examine concerns over leakage and, if leakage is a concern, to quantify or qualify the leakage and manage it. Leakage is unlikely to be an issue for this project type, as leakage would require that tillage activities be transferred to areas where tillage is currently not practiced. That said, the protocol would at least need to justify its analysis of why leakage is not a concern.
ADDITIONAL	Likely to correspond to, with modification, WCI and ISO definitions for this criterion. *Aspects of criterion definition that are met:* The protocol uses a performance test and ensures that reductions are not required by law. Further, the protocol meets the WCI criterion for crediting period. *Modifications that are necessary to fully meet:* The protocol would need to establish a performance test that analyzes market penetration for the implementation of no-till farming in Mexico and the US, not just to Canada.
PERMANENT	Likely to correspond to, with modification, WCI and ISO definitions for this criterion. *Aspects of criterion definition that are met:* The protocol assesses the risk for reversal, which is found present. It establishes a monitoring system, a risk mitigation approach, and a contingency plan for the case of reversal in the form of an assurance factor that discounts the total crediting value over each year of the □□-year crediting period to account for expected reversals during those □□ years. *Modifications that are necessary to fully meet:* The protocol's contingency plan would need to be adequate over a □□□-year time span. The current crediting period of the protocol is □□ years, with renewal of □□ years.
VERIFIABLE	Appears to correspond to WCI and ISO definitions for this criterion. *Aspects of criterion definition that are met:* Protocol requires □rd party verification and sufficient enforcement mechanisms exist. *Modifications that are necessary to fully meet:* □A

4.2 Chicago Climate Exchange Rules for Exchange Soil Offsets Continuous Conservation Tillage and Conversion to Grassland: Soil Carbon Sequestration Offset Project Protocol, Updated as of 9/30/2009

	Evaluation
Real	Could correspond to, with significant modification, WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol meets Uncertainty □ Accuracy and Conservativeness. □See below□ *Modifications that are necessary to fully meet:* The protocol would need to modify □uantification and Leakage □See below□
Quantification	Likely to correspond to, with modification, WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol clearly states pro□ect boundaries and □uantification methodology are based on recognizable scientific sources. *Modifications that are necessary to fully meet:* The protocol would need to develop emission factors that are appropriate to all the WCI □urisdictions. It currently uses a US database to describe soil type, and would need to develop e□uivalent emission factors for Canada and Mexico.
Uncertainty & Accuracy	Appears to correspond to WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol provides guidelines to reduce uncertainty bias by providing default factors for proponents to use. It cites □uantification methodologies that are based on recognizable scientific sources in the form of peer-reviewed □ournals. The protocol discounts by □□□ to ad□ust for high uncertainty. Additionally, the protocol re□uires that the proponent institute □uality assurance measures in data management. *Modifications that are necessary to fully meet:* □A
Conservativeness	Appears to correspond to WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol provides a principle of conservatism and provides assertions that it selected its parameters so as to underestimate rather than overestimate the calculation of emission reductions. Default emission factors were selected by taking the average of se□uestration rates for specific regions published in peer-reviewed academic literature and discounting that number by □□□. The literature *Modifications that are necessary to fully meet:* □A

Leakage	Could correspond to, with significant modification, WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* □A *Modifications that are necessary to fully meet:* The protocol would need to examine concerns over leakage and, if leakage is a concern, to □uantify or □ualify the leakage and manage it. If leakage is stated to not be a concern, the protocol would need to □ustify its analysis.
Additional	Likely to correspond to, with modification, WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol uses a performance test to ensure that the pro□ect activity is not common practice by citing that professional soil scientists in the USDA and academia estimate between □-□□□ of US farmland is currently managed under continuous conservation tillage and asserting that the implementation of continuous conservation tillage therefore does not meet CC□'s threshold for common practice. It also ensures that reductions are not re□uired by law. □urther, the protocol meets the WCI criterion for crediting period. *Modifications that are necessary to fully meet:* The protocol would need to ensure that its performance test analyzes market penetration for the implementation of no-till farming in Mexico and the Canada, not □ust to the United States. □urther, the start date would need to be modified from □anuary □, □□□□.
Permanent	Likely to correspond to, with modification, WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol assesses the risk for reversal, which is found present. It establishes a monitoring system, a risk mitigation approach, and a contingency plan that discounts average se□uestration rates by □□□ to account for the loss of carbon should pro□ect participants return to conventional tillage. The □□□ of credits that are withheld from the pro□ect participant are kept in a Soil Carbon Reserve Pool that is released to the Pro□ect □wner at the end of the crediting period. *Modifications that are necessary to fully meet:* The protocol's contingency plan would need to be ade□uate over a □□□-year time span.
Verifiable	Appears to correspond to WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* Protocol re□uires □rd party verification, and sufficient enforcement mechanisms exist. *Modifications that are necessary to fully meet:* □A

5 MANURE MANAGEMENT PROTOCOLS

5.1 Alberta Offset System Quantification Protocol for the Anaerobic Decomposition of Agricultural Materials

	Evaluation
Real	Could correspond to, with significant modification, WCI and ISO definitions for this criterion. *Aspects of criterion definition that are met:* The protocol meets Quantification, and Conservativeness (See below) *Modifications that are necessary to fully meet:* The protocol would need to modify Uncertainty and Accuracy, and Leakage (See below)
Quantification	Appears to correspond to WCI and ISO definitions for this criterion. *Aspects of criterion definition that are met:* The protocol clearly states project boundaries, quantification methodology based on recognizable scientific sources and emission factors are appropriate to all the WCI jurisdictions. *Modifications that are necessary to fully meet:* *NA*
Uncertainty & Accuracy	Likely to correspond to, with modification, WCI and ISO definitions for this criterion. *Aspects of criterion definition that are met:* The protocol provides guidelines to reduce uncertainty/bias and quantification methodologies are based on recognizable scientific sources. Additionally, the protocol requires that the proponent institute quality assurance measures in data management. *Modifications that are necessary to fully meet:* The protocol would need to be modified to manage uncertainty, for example, by requiring discounting emission reductions to adjust for high uncertainty.
Conservativeness	Appears to correspond to WCI and ISO definitions for this criterion. *Aspects of criterion definition that are met:* The protocol provides a principal of conservatism or assertion that parameter values are selected so as to underestimate rather than overestimate the calculation of emission reductions. *Modifications that are necessary to fully meet:* NA

Leakage	Could correspond to, with significant modification, WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* □A *Modifications that are necessary to fully meet:* There is no evidence that the protocol examines leakage. The protocol would need to be modified to address the leakage issues. If it is not a concern, the protocol would need to □ustify the assertion.
Additional	Likely to correspond to, with modification, WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol re□uires that the pro□ect is not re□uired by law. *Modifications that are necessary to fully meet:* The technology threshold would need to be modified to be applicable to the entire WCI region.
Permanent	Appears to correspond to WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* This is a non-se□uestration pro□ect protocol. *Modifications that are necessary to fully meet:* □A
Verifiable	Appears to correspond to WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol re□uires □rd party verification. *Modifications that are necessary to fully meet:* □A

5.2 Chicago Climate Exchange Agricultural Methane Collection and Combustion Offset Project Protocol

	Evaluation
Real	Could correspond to, with significant modification, WCI and ISO definitions for this criterion. *Aspects of criterion definition that are met:* The protocol meets Conservativeness (See below) *Modifications that are necessary to fully meet:* The protocol would need to modify Quantification, Uncertainty and Accuracy, and Leakage (See below)
Quantification	Likely to correspond to, with modification, WCI and ISO definitions for this criterion. *Aspects of criterion definition that are met:* The protocol clearly states project boundaries, quantification methodology based on recognizable scientific sources *Modifications that are necessary to fully meet:* The protocol would need to be modified to include appropriate factors for the other eligible regions (i.e., Canada and Mexico)
Uncertainty & Accuracy	Likely to correspond to, with modification, WCI and ISO definitions for this criterion. *Aspects of criterion definition that are met:* The protocol provides guidelines to reduce uncertainty/bias and quantification methodologies are based on recognizable scientific sources. Additionally, the protocol requires that the proponent institute quality assurance measures in data management. *Modifications that are necessary to fully meet:* The protocol would need to be modified to manage uncertainty, for example, by requiring discounting emission reductions to adjust for high uncertainty.
Conservativeness	Appears to correspond to WCI and ISO definitions for this criterion. *Aspects of criterion definition that are met:* The protocol provides a principal of conservatism or assertion that parameter values are selected so as to underestimate rather than overestimate the calculation of emission reductions. *Modifications that are necessary to fully meet:* NA

Leakage	Could correspond to, with significant modification, WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* □A *Modifications that are necessary to fully meet:* The protocol would need to □stify why leakage is not a concern. The protocol states that it does not expect agricultural methane pro□cts to result in leakage emissions, but does not explicitly state why.
Additional	Likely to correspond to, with modification, WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol employs a performance test. *Modifications that are necessary to fully meet:* The protocol would need to be modified to include a technology threshold applicable to Canada and Mexico-based pro□ect. The pro□ect starting date as well as the crediting period would need to be ad□usted.
Permanent	Appears to correspond to WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* This is a non-se□uestration pro□ect protocol. *Modifications that are necessary to fully meet:* □A
Verifiable	Appears to correspond to WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol re□uires □rd party verification. *Modifications that are necessary to fully meet:* □A

5.3 Clean Development Mechanism, ACM0010 "Consolidated baseline methodology for GHG emissions reductions from manure management systems"

	Evaluation
Real	Appears to correspond to WCI and ISO definitions for this criterion. Aspects of criterion definition that are met: The protocol meets Quantification, Uncertainty and Accuracy, Conservativeness, and leakage. (See below) *Modifications that are necessary to fully meet:* NA
Quantification	Appears to correspond to WCI and ISO definitions for this criterion. *Aspects of criterion definition that are met:* The protocol clearly states project boundaries. Quantification methodology based on recognizable scientific sources and emission factors are appropriate to all the WCI jurisdictions. *Modifications that are necessary to fully meet:* NA
Uncertainty & Accuracy	Appears to correspond to WCI and ISO definitions for this criterion. *Aspects of criterion definition that are met:* The protocol provides guidelines to reduce uncertainty bias and quantification methodologies are based on recognizable scientific sources. The protocol discounts to adjust for high uncertainty. Additionally, the protocol requires that the proponent institute quality assurance measures in data management. *Modifications that are necessary to fully meet:* NA
Conservativeness	Appears to correspond to WCI and ISO definitions for this criterion. *Aspects of criterion definition that are met:* The protocol provides a principal of conservatism or assertion that parameter values are selected so as to underestimate rather than overestimate the calculation of emission reductions. *Modifications that are necessary to fully meet:* NA
Leakage	Appears to correspond to WCI and ISO definitions for this criterion. *Aspects of criterion definition that are met:* The protocol identifies sources of leakage. The protocol provides quantification methods for leakage emissions. *Modifications that are necessary to fully meet:* NA

Additional	Likely to correspond to, with modification, WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol uses a pro□ect-specific approach that ensures that at a minimum the pro□ect is not re□uired by law. *Modifications that are necessary to fully meet:* The pro□ect starting date and the crediting period would need to be ad□usted.
Permanent	Appears to correspond to WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* This is a non-se□uestration project protocol *Modifications that are necessary to fully meet:* □A
Verifiable	Appears to correspond to WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol re□uires □rd party verification. *Modifications that are necessary to fully meet:* □A

5.4 Climate Action Reserve Livestock Project Reporting Protocol Capturing and destroying methane from manure management systems

	Evaluation
Real	Could correspond to, with significant modification, WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol meets Uncertainty □ Accuracy and Conservativeness □See below□ *Modifications that are necessary to fully meet:* The protocol would need to modify □uantification and Leakage □See below□
Quantification	Likely to correspond to, with modification, WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol clearly states pro□ect boundaries, □uantification methodology based on recognizable scientific sources *Modifications that are necessary to fully meet:* The protocol would need to be modified to include factors that are applicable to pro□ects in Canada. The defaults are specific to the U.S. In addition to this protocol, the Climate Action Reserve has another livestock protocol that is applicable to Mexico.

Uncertainty & Accuracy	Appears to correspond to WCI and ISO definitions for this criterion. *Aspects of criterion definition that are met:* The protocol identifies potential uncertainties, provides guidelines to reduce uncertainty/bias, and references recognizable scientific sources. The protocol discounts to adjust for high uncertainty. Additionally, the protocol requires that the proponent institute quality assurance measures in data management. *Modifications that are necessary to fully meet:* NA
Conservativeness	Appears to correspond to WCI and ISO definitions for this criterion. *Aspects of criterion definition that are met:* The protocol provides a principal of conservatism or assertion that parameter values are selected so as to underestimate rather than overestimate the calculation of emission reductions. *Modifications that are necessary to fully meet:* NA
Leakage	Could correspond to, with significant modification, WCI and ISO definitions for this criterion. *Aspects of criterion definition that are met:* NA *Modifications that are necessary to fully meet:* There is no evidence that the protocol examines leakage. The protocol would need to be modified to address the leakage issues. If it is not a concern, the protocol would need to justify the assertion[illegible].
Additional	Likely to correspond to, with modification, WCI and ISO definitions for this criterion. *Aspects of criterion definition that are met:* The protocol employs a performance test. *Modifications that are necessary to fully meet:* The protocol would need to be modified to include a technology threshold applicable to Canada-based project. In addition to this protocol, the Climate Action Reserve has another livestock protocol that is applicable to Mexico. The project starting date as well as the crediting period need to be adjusted.

[illegible] When examining leakage, DNV performed a strict reading of protocol document language to determine whether leakage was addressed and, if so, how. A protocol that does not address leakage explicitly (perhaps because it indirectly addresses it by defining the project boundary so that any affected emissions sources are included in the project activity) would need to justify in the protocol why leakage is not a concern. DNV did not examine whether a project boundary was defined so as to avoid leakage concerns due to project activities.

Permanent	Appears to correspond to WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* This is a non-se□uestration pro□ect protocol. *Modifications that are necessary to fully meet:* □A
Verifiable	Appears to correspond to WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol re□uires □rd party verification. *Modifications that are necessary to fully meet:* □A

5.5 Regional Greenhouse Gas Initiative Model Rule

	Evaluation
Real	Could correspond to, with significant modification, WCI and IS□ definitions for this criterion. Aspects of criterion definition that are met□ □A Modifications that are necessary to fully meet□ The protocol would need to modify □uantification, Uncertainty and Accuracy, Conservativeness, and Leakage □See below□
Quantification	Likely to correspond to, with modification, WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol clearly states □uantification methodology based on recognizable scientific sources *Modifications that are necessary to fully meet:* Some of the factors provided are applicable to the U.S. region□states. □ew factors that are applicable to pro□ects in Canada and Mexico are needed. The protocol would need to be modified to clearly define the pro□ect boundary.
Uncertainty & Accuracy	Likely to correspond to, with modification, WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol provides guidelines to reduce uncertainty□bias and □uantification methodologies are based on recognizable scientific sources. Additionally, the protocol re□uires that the proponent institute □uality assurance measures in data management. *Modifications that are necessary to fully meet:* The protocol would need to be modified to manage uncertainty, for example, by re□uiring discounting emission reductions to ad□ust for high uncertainty.

Conservativeness	Could correspond to, with significant modification, WCI and IS□ definitions for this criterion. Aspects of criterion definition that are met□ □A Modifications that are necessary to fully meet□ The conservativeness of the parameters is not □ustified. The protocol would need to provide parameter values that are selected so as to be biased toward underestimation rather than overestimation of emission reductions.
Leakage	Could correspond to, with significant modification, WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* □A *Modifications that are necessary to fully meet:* There is no evidence that the protocol examines leakage. The protocol would need to be modified to address the leakage issues. If it is not a concern, the protocol would need to □ustify the assertion.
Additional	Likely to correspond to, with modification, WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol employs a performance test. *Modifications that are necessary to fully meet:* The protocol would need to be modified to include a technology threshold applicable to Canada and Mexico-based pro□ect. The pro□ect starting date as well as the crediting period need to be ad□usted.
Permanent	Appears to correspond to WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* This is a non-se□uestration pro□ect protocol. *Modifications that are necessary to fully meet:* □A
Verifiable	Appears to correspond to WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol re□uires □rd-party verification. *Modifications that are necessary to fully meet:* □A

5.6 US EPA Climate Leaders GHG Inventory Protocol- Offset Project Methodology for Managing Manure with Biogas Recovery Systems

	Evaluation
Real	Likely to correspond to, with modification, WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol meets Conservativeness, and Leakage □See below□ *Modifications that are necessary to fully meet:* The protocol would need to modify □uantification, and Uncertainty and Accuracy □See below□
Quantification	Likely to correspond to, with modification, WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol clearly states pro□ect boundaries, □uantification methodology based on recognizable scientific sources *Modifications that are necessary to fully meet:* The protocol would need to be modified to include appropriate factors for the other eligible regions □i.e., Canada and Mexico□ Some parameters are U.S.-based pro□ect specific.
Uncertainty & Accuracy	Likely to correspond to, with modification, WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol provides guidelines to reduce uncertainty□bias and □uantification methodologies are based on recognizable scientific sources. Additionally, the protocol re□uires that the proponent institute □uality assurance measures in data management. *Modifications that are necessary to fully meet:* The protocol would need to be modified to manage uncertainty, for example, by re□uiring discounting emission reductions to ad□ust for high uncertainty.
Conservativeness	Appears to correspond to WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol provides a principal of conservatism or assertion that parameter values are selected so as to underestimate rather than overestimate the calculation of emission reductions. *Modifications that are necessary to fully meet:* □A

Leakage	Appears to correspond to WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol identifies sources of leakage. While it states that leakages are not a concern, it re□uires □uantifying such emissions if it is determined that leakage emissions are significant. *Modifications that are necessary to fully meet:* □A
Additional	Likely to correspond to, with modification, WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol employs a performance test. *Modifications that are necessary to fully meet:* The protocol would need to be modified to include a technology threshold applicable to Canada and Mexico-based pro□ects. The pro□ect starting date as well as the crediting period needs to be ad□usted.
Permanent	Appears to correspond to WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* This is a non-se□uestration project protocol. *Modifications that are necessary to fully meet:* □A
Verifiable	Could correspond to, with significant modification, WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* □A *Modifications that are necessary to fully meet:* The protocol would need to be modified to re□uire a third party verification.

6 RANGELAND MANAGEMENT PROTOCOLS

6.1 Chicago Climate Exchange Sustainably Managed Rangeland Soil Carbon Sequestration Offset Project Protocol

	Evaluation
Real	Likely to correspond to, with modification, WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol meets Uncertainty □ Accuracy, Conservativeness, and Leakage. □See below□ *Modifications that are necessary to fully meet:* The protocol would need to modify □uantification □See below□
Quantification	Likely to correspond to, with modification, WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol clearly states project boundaries and □uantification methodology are based on recognizable scientific sources. *Modifications that are necessary to fully meet:* The protocol would need to develop emission factors that are appropriate to all the WCI □urisdictions. It currently uses a US database to describe soil type, and would need to develop e□uivalent emission factors for Canada and Mexico.
Uncertainty & Accuracy	Appears to correspond to WCI and IS□ definitions for this criterion *Aspects of criterion definition that are met:* The protocol provides guidelines to reduce uncertainty bias by providing default factors for proponents to use. It cites □uantification methodologies that are based on recognizable scientific sources in the form of peer-reviewed □ournals. The protocol discounts by □□□ to ad□ust for high uncertainty. Additionally, the protocol re□uires that the proponent institute □uality assurance measures in data management. *Modifications that are necessary to fully meet:* □A
Conservativeness	Appears to correspond to WCI and IS□ definitions for this criterion *Aspects of criterion definition that are met:* The protocol provides a principle of conservatism and provides assertions that it selected its parameters so as to underestimate rather than overestimate the calculation of emission reductions. Default emission factors were selected by discounting by □□□ the average of se□uestration rates published in peer-reviewed academic literature for specific regions. *Modifications that are necessary to fully meet:* □A

Leakage	Appears to correspond to WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol identifies sources of leakage, and activity-shifting leakage is found to be a concern. It then re□uires that project proponents □□enroll all owned or controlled rangeland that is eligible for offsets to be enrolled in the CC□ and that □□stocking rates on land outside the eligible rangeland have not increased as a result of the project activity. *Modifications that are necessary to fully meet:* □A
Additional	Likely to correspond to, with modification, WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol uses a performance test to ensure that the project activity is not common practice by citing USDA findings that there is the opportunity to make □distinct categorical Rangeland conditions improvements on approximately □□□ of privately managed acres□□p.□□□and asserting that the protocol□s re□uirements for □best in class□Rangeland management practices ensure that project activities have not been practiced on □□□ of eligible acres. It also ensures that reductions are not re□uired by law. □urther, the protocol meets the WCI criterion for crediting period. *Modifications that are necessary to fully meet:* The protocol would need to ensure that its performance test analyzes market penetration for the implementation of no-till farming in Mexico and the Canada, not □ust to the United States. □urther, the start date would need to be modified from □anuary □, □□□□.
Permanent	Likely to correspond to, with modification, WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol assesses the risk for reversal, which is found present. It establishes a monitoring system, a risk mitigation approach that discounts the credits issued each year to account for reversals due to drought years, and a contingency plan that discounts average se□uestration rates by □□□ to account for the loss of carbon should project participants return to conventional tillage. The □□□ of credits that are withheld from the project participant are kept in a Soil Carbon Reserve Pool that is released to the Project □wner at the end of the crediting period. The protocol also provides an additional contingency approach for periods of prolonged drought. *Modifications that are necessary to fully meet:* The protocol□s contingency plan would need to be ade□uate over a □□□-year time span.
Verifiable	Appears to correspond to WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol re□uires □rd party verification, and sufficient enforcement mechanisms exist. *Modifications that are necessary to fully meet:* □A

7 AFFORESTATION & REFORESTATION PROTOCOLS

7.1 Chicago Climate Exchange Forestry Carbon Sequestration Project Protocol

	Evaluation
Real	Could correspond to, with significant modification, WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol meets Conservativeness □See below□ *Modifications that are necessary to fully meet:* The protocol would need to modify □uantification, Uncertainty and Accuracy, and Leakage □See below□
Quantification	Likely to correspond to, with modification, WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol clearly states pro□ect boundaries, □uantification methodology based on recognizable scientific sources *Modifications that are necessary to fully meet:* The protocol would need to be modified to include appropriate factors for the other eligible regions □i.e., Canada and Mexico□ Some parameters are U.S.-based pro□ect specific.
Uncertainty & Accuracy	Likely to correspond to, with modification, WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol provides guidelines to reduce uncertainty□bias and □uantification methodologies are based on recognizable scientific sources. Additionally, the protocol re□uires that the proponent institute □uality assurance measures in data management. *Modifications that are necessary to fully meet:* The protocol would need to be modified to manage uncertainty, for example, by re□uiring discounting emission reductions to ad□ust for high uncertainty.
Conservativeness	Appears to correspond to WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol provides a principal of conservatism or assertion that parameter values are selected so as to underestimate rather than overestimate the calculation of emission reductions. *Modifications that are necessary to fully meet:* □A

Leakage	Could correspond to, with significant modification, WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* □A *Modifications that are necessary to fully meet:* The protocol would need to □ustify why leakage is not a concern. The protocol asserts that it does not expect forestry pro□ects to result in leakage emissions, but does not defend its assertion.
Additional	Likely to correspond to, with modification, WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol employs a performance test. *Modifications that are necessary to fully meet:* The protocol would need to be modified to include a technology threshold applicable to Canada and Mexico-based pro□ect. The pro□ect starting date as well as the crediting period need to be ad□usted.
Permanent	Likely to correspond to, with modification, WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol assesses the risk for reversal. If present, it establishes or re□uires that the pro□ect proponent establish□a monitoring system, a risk mitigation approach, and a contingency plan for the case of reversal. All pro□ects are re□uired to reserve □□□ of offsets. *Modifications that are necessary to fully meet:* The protocol would need to be modified to include a re□uirement for assessing risks of reversal. The protocol would need to be modified to ensure that carbon is se□uestered over □□□ years. Currently, the participants are re□uired to sign a contract to commit for □□ years.
Verifiable	Appears to correspond to WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol re□uires □rd party verification. *Modifications that are necessary to fully meet:* □A

7.2 Clean Development Mechanism AR-ACM0001 "Afforestation and Reforestation of Degraded Land"

	Evaluation
Real	Appears to correspond to WCI and ISO definitions for this criterion. *Aspects of criterion definition that are met:* The protocol meets Quantification, Conservativeness and Leakage (See below). *Modifications that are necessary to fully meet:* NA (See below)
Quantification	Appears to correspond to WCI and ISO definitions for this criterion. *Aspects of criterion definition that are met:* The protocol clearly states project boundaries, quantification methodology based on recognizable scientific sources and emission factors are appropriate to all the WCI jurisdictions. *Modifications that are necessary to fully meet:* NA
Uncertainty & Accuracy	Appears to correspond to WCI and ISO definitions for this criterion *Aspects of criterion definition that are met:* The protocol provides guidelines to reduce uncertainty bias and quantification methodologies are based on recognizable scientific sources. The protocol manages uncertainty. Additionally, the protocol requires that the proponent institute quality assurance measures in data management. *Modifications that are necessary to fully meet:* NA
Conservativeness	Appears to correspond to WCI and ISO definitions for this criterion. *Aspects of criterion definition that are met:* The protocol provides a principal of conservatism or assertion that parameter values are selected so as to underestimate rather than overestimate the calculation of emission reductions. *Modifications that are necessary to fully meet:* NA
Leakage	Appears to correspond to WCI and ISO definitions for this criterion. *Aspects of criterion definition that are met:* The protocol identifies sources of leakage. The protocol provides quantification methods for leakage emissions. *Modifications that are necessary to fully meet:* NA

Additional	Likely to correspond to, with modification, WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol uses a pro□ect-specific approach that ensures that at a minimum the pro□ect is not re□uired by law. *Modifications that are necessary to fully meet:* The pro□ect starting date and the crediting period would need to be ad□usted.
Permanent	Likely to correspond to, with modification, WCI and IS□ definitions for this criterion. Aspects of criterion definition that are met□ The CDM deals with permanence issues by issuing temporary credits. Modifications that are necessary to fully meet□ The protocol would need to be modified to include legal means to enforce the contingency plan and the plan is ade□uate for the risk of reversal over a □□□ year time span.
Verifiable	Appears to correspond to WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol re□uires □rd party verification. *Modifications that are necessary to fully meet:* □A

7.3 Climate Action Reserve Forest Project Protocol, Version 3.1 October 22, 2009

	Evaluation
Real	Likely to correspond to, with modification, WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol meets Uncertainty and Accuracy, and Conservativeness □See below□ Modifications that are necessary to fully meet□ □uantification, and Leakage □See below□
Quantification	Likely to correspond to, with modification, WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol clearly states pro□ect boundaries, □uantification methodology based on recognizable scientific sources *Modifications that are necessary to fully meet:* The protocol would need to be modified to include factors that are applicable to pro□ects in outside of California. Currently, the growth pro□ection models approved are only applicable to the pro□ects in California. In addition, Appendix □ is specific to California.[□□]
Uncertainty & Accuracy	Appears to correspond to WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol identifies potential uncertainties, provides guidelines to reduce uncertainty/bias, and references recognizable scientific sources. The protocol discounts to adjust for high uncertainty. Additionally, the protocol re□uires that the proponent institute □uality assurance measures in data management. *Modifications that are necessary to fully meet:* □A
Conservativeness	Appears to correspond to WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol provides a principal of conservatism or assertion that parameter values are selected so as to underestimate rather than overestimate the calculation of emission reductions. *Modifications that are necessary to fully meet:* □A

[□□] At the time of this writing CAR had only provided factors applicable to California□future release of factors applicable to the entire United States were forthcoming.

Leakage	Likely to correspond to, with modification, WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol identifies sources of leakage. Leakage is □ualified as opposed to □uantified. Based upon determined leakage risk percentage, discount factors are applied to account for potential leakage. *Modifications that are necessary to fully meet:* Protocol would need to □ustify why leakages are not □uantified as opposed to □ualified.
Additional	Likely to correspond to, with modification, WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol employs a performance test. *Modifications that are necessary to fully meet:* The protocol would need to be modified to include a technology threshold applicable to pro□ects outside of California. Currently, the performance threshold provided in the protocol is applicable to pro□ects within California. The pro□ect starting date as well as the crediting period need to be ad□usted.
Permanent	Appears to correspond to WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol assesses the risk for reversal. If present, pro□ect proponents are re□uired to establish a monitoring system and a risk mitigation approach, and the protocol provides a contingency plan for the case of reversal. Additionally, the protocol the legal means to enforce the contingency plan and the plan is ade□uate for the risk of reversal over a □□□ year time span. Based upon the risk rating, it re□uires setting aside a portion of credits. *Modifications that are necessary to fully meet:* □A
Verifiable	Appears to correspond to WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol re□uires □rd party verification. *Modifications that are necessary to fully meet:* □A

7.4 Regional Greenhouse Gas Initiative Model Rule

	Evaluation
Real	Could correspond to, with significant modification, WCI and ISO definitions for this criterion. Aspects of criterion definition that are met: Quantification Modifications that are necessary to fully meet: The protocol would need to modify Uncertainty and Accuracy, Conservativeness, and Leakage (See below)
Quantification	Appears to correspond to WCI and ISO definitions for this criterion. *Aspects of criterion definition that are met:* The protocol clearly states project boundaries, quantification methodology based on recognizable scientific sources and emission factors are appropriate to all the WCI jurisdictions. *Modifications that are necessary to fully meet:* NA
Uncertainty & Accuracy	Likely to correspond to, with modification, WCI and ISO definitions for this criterion. *Aspects of criterion definition that are met:* The protocol provides guidelines to reduce uncertainty/bias and quantification methodologies are based on recognizable scientific sources. In addition, the protocol manages uncertainty, for example, by requiring discounting emission reductions to adjust for high uncertainty. *Modifications that are necessary to fully meet:* The protocol would need to be modified to include requirements for quality assurance measures for data measurement.
Conservativeness	Could correspond to, with significant modification, WCI and ISO definitions for this criterion. Aspects of criterion definition that are met: NA Modifications that are necessary to fully meet: The conservativeness of the parameters is not justified. The protocol would need to provide parameter values that are selected so as to be biased toward underestimation rather than over estimation of emission reductions.
Leakage	Could correspond to, with significant modification, WCI and ISO definitions for this criterion. *Aspects of criterion definition that are met:* NA *Modifications that are necessary to fully meet:* There is no evidence that the protocol examines leakage. The protocol would need to be modified to address the leakage issues. If it is not a concern, the protocol would need to justify the assertion.

Additional	Likely to correspond to, with modification, WCI and ISO definitions for this criterion. *Aspects of criterion definition that are met:* The protocol ensure that the project is not required by law. *Modifications that are necessary to fully meet:* The project starting date as well as the crediting period would need to be adjusted.
Permanent	Likely to correspond to, with modification, WCI and ISO definitions for this criterion. *Aspects of criterion definition that are met:* The protocol assesses the risk for reversal. If present, it establishes or requires that the project proponents establish a monitoring system, a risk mitigation approach, and a contingency plan for the case of reversal. All projects are required to reserve [illegible] of offsets. *Modifications that are necessary to fully meet:* The protocol would need to be modified to include a requirement for assessing risks of reversal. The protocol would need to be modified to ensure that carbon is sequestered over [illegible] years. The protocol does not specify the length of the legal commitment.
Verifiable	Appears to correspond to WCI and ISO definitions for this criterion. *Aspects of criterion definition that are met:* The protocol requires 3rd party verification. *Modifications that are necessary to fully meet:* NA

7.5 US EPA Climate Leaders GHG Inventory Protocol- Offset Project Methodology for Reforestation/Afforestation

	Evaluation
Real	Could correspond to, with significant modification, WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol meets Leakage □See below□ *Modifications that are necessary to fully meet:* The protocol would need to modify □uantification, and Uncertainty and Accuracy, and Leakage □See below□
Quantification	Likely to correspond to, with modification, WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol clearly states pro□ect boundaries, □uantification methodology based on recognizable scientific sources *Modifications that are necessary to fully meet:* The protocol would need to be modified to include appropriate factors for the other eligible regions □i.e., Canada and Mexico□ Some parameters are U.S.-based pro□ect specific.
Uncertainty & Accuracy	Likely to correspond to, with modification, WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol provides guidelines to reduce uncertainty□bias and □uantification methodologies are based on recognizable scientific sources. *Modifications that are necessary to fully meet:* The protocol would need to be modified to manage uncertainty, for example, by re□uiring discounting emission reductions to ad□ust for high uncertainty. In addition, the protocol would need to be modified to include re□uirements for □uality assurance measures for data measurement.
Conservativeness	Could correspond to, with significant modification, WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* □A *Modifications that are necessary to fully meet:* The conservativeness of the parameters is not □ustified. The protocol would need to provide parameter values that are selected so as to be biased toward underestimation rather than over estimation of emission reductions.

Leakage	Appears to correspond to WCI and ISO definitions for this criterion. *Aspects of criterion definition that are met:* The protocol requires that sources of leakage be identified and quantified if they are determined significant. *Modifications that are necessary to fully meet:* NA
Additional	Likely to correspond to, with modification, WCI and ISO definitions for this criterion. *Aspects of criterion definition that are met:* The protocol employs a performance test. *Modifications that are necessary to fully meet:* The protocol would need to be modified to include a technology threshold applicable to Canada and Mexico-based projects. The project starting date as well as the crediting period need to be adjusted.
Permanent	Likely to correspond to, with modification, WCI and ISO definitions for this criterion. *Aspects of criterion definition that are met:* The protocol assesses the risk for reversal. If present, it establishes or requires that the project proponents establish a monitoring system, a risk mitigation approach, and a contingency plan for the case of reversal. *Modifications that are necessary to fully meet:* The protocol would need to be modified to include a requirement for assessing risks of reversal. The protocol would need to be modified to ensure that carbon is sequestered over 100 years. Currently, the protocol only specifies that "carbon accumulated from reforestation/afforestation must be monitored over an extended period of time to properly accounted for variable growth rates and reversal risk."
Verifiable	Could correspond to, with significant modification, WCI and ISO definitions for this criterion. *Aspects of criterion definition that are met:* NA *Modifications that are necessary to fully meet:* The protocol would need to be modified to require a third party verification.

8 FOREST MANAGEMENT PROTOCOLS

8.1 Chicago Climate Exchange Forestry Carbon Sequestration Project Protocol

	Evaluation
Real	Could correspond to, with significant modification, WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol meets Conservativeness □See below□ *Modifications that are necessary to fully meet:* The protocol would need to modify □uantification, Uncertainty and Accuracy, and Leakage □See below□
Quantification	Likely to correspond to, with modification, WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol clearly states pro□ect boundaries, □uantification methodology based on recognizable scientific sources *Modifications that are necessary to fully meet:* The protocol would need to be modified to include appropriate factors for the other eligible regions □i.e., Canada and Mexico□ Some parameters are U.S.-based pro□ect specific.
Uncertainty & Accuracy	Likely to correspond to, with modification, WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol provides guidelines to reduce uncertainty□bias and □uantification methodologies are based on recognizable scientific sources. Additionally, the protocol re□uires that the proponent institute □uality assurance measures in data management. *Modifications that are necessary to fully meet:* The protocol would need to be modified to manage uncertainty, for example, by re□uiring discounting emission reductions to ad□ust for high uncertainty.
Conservativeness	Appears to correspond to WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol provides a principal of conservatism or assertion that parameter values are selected so as to underestimate rather than overestimate the calculation of emission reductions. *Modifications that are necessary to fully meet:* □A

Leakage	Could correspond to, with significant modification, WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* □A. *Modifications that are necessary to fully meet:* The protocol would need to □ustify why leakage is not a concern. The protocol □ust states that it does not expect forestry pro□ects to result in leakage emissions.
Additional	Likely to correspond to, with modification, WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol employs a performance test. *Modifications that are necessary to fully meet:* The protocol would need to be modified to include a technology threshold applicable to Canada and Mexico-based pro□ect. The pro□ect starting date as well as the crediting period would need to be ad□usted.
Permanent	Likely to correspond to, with modification, WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol assesses the risk for reversal. If present, it establishes or re□uires that the pro□ect proponents establish□a monitoring system, a risk mitigation approach, and a contingency plan for the case of reversal. All pro□ects are re□uired to reserve □□□ of offsets. *Modifications that are necessary to fully meet:* The protocol would need to be modified to include a re□uirement for assessing risks of reversal. The protocol would need to be modified to ensure that carbon is se□uestered over □□□ years. Currently, the participants are re□uired to sign a contract to commit for □□ years.
Verifiable	Appears to correspond to WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol re□uires □rd-party verification. *Modifications that are necessary to fully meet:* □A.

8.2 Climate Action Reserve Forest Project Protocol

	Evaluation
Real	Likely to correspond to, with modification, WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol meets Uncertainty □ Accuracy and Conservativeness □see below□ Modifications that are necessary to fully meet□ □uantification, and Leakage □See below□
Quantification	Likely to correspond to, with modification, WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol clearly states pro□ect boundaries, □uantification methodology based on recognizable scientific sources. *Modifications that are necessary to fully meet:* The protocol would need to be modified to include factors that are applicable to pro□ects in outside of California. Currently, the growth pro□ection models approved are only applicable to the pro□ects in California. In addition, Appendix □ is specific to California.[□□]
Uncertainty & Accuracy	Appears to correspond to WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol identifies potential uncertainties, provides guidelines to reduce uncertainty/bias, and references recognizable scientific sources. The protocol discounts to ad□ust for high uncertainty. Additionally, the protocol re□uires that the proponent institute □uality assurance measures in data management. *Modifications that are necessary to fully meet:* □A
Conservativeness	Appears to correspond to WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol provides a principal of conservatism or assertion that parameter values are selected so as to underestimate rather than overestimate the calculation of emission reductions. *Modifications that are necessary to fully meet:* □A

[□□] At the time of this writing CAR had only provided factors applicable to California□future release of factors applicable to the entire United States were forthcoming.

Leakage	Likely to correspond to, with modification, WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol identifies sources of leakage. Leakage is □ualified as opposed to □uantified. Based upon determined leakage risk percentage, discount factors are applied to account for potential leakage. *Modifications that are necessary to fully meet:* The protocol would need to □ustify why leakages are not □uantified as opposed to □ualified.
Additional	Likely to correspond to, with modification, WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol employs a performance test. *Modifications that are necessary to fully meet:* The protocol would need to be modified to include a technology threshold applicable to pro□ects outside of California. Currently, the performance threshold provided in the protocol is applicable to pro□ects within California. The pro□ect starting date as well as the crediting period need to be ad□usted.
Permanent	Appears to correspond to WCI and IS□ definitions for this criterion. Aspects of criterion definition that are met: The protocol assesses the risk for reversal. If present, pro□ect proponents are re□uired to establish a monitoring system and a risk mitigation approach, and the protocol provides a contingency plan for the case of reversal. Additionally, the protocol the legal means to enforce the contingency plan and the plan is ade□uate for the risk of reversal over a □□□ year time span. Based upon the risk rating, it re□uires to set aside a portion of credits. Modifications that are necessary to fully meet: □A
Verifiable	Appears to correspond to WCI and IS□ definitions for this criterion. *Aspects of criterion definition that are met:* The protocol re□uires □rd party verification. *Modifications that are necessary to fully meet:* □A.

Western Climate Initiative

Markets Committee Task 6: Auction Design White Paper

April 14, 2010

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1. Introduction

The Western Climate Initiative (WCI) is a cooperative effort of seven U.S. states and four Canadian provinces that are collaborating to identify, evaluate, and implement policies to reduce greenhouse gas (GHG) emissions, including the design and implementation of a regional cap-and-trade program. Auctioning will strengthen the aim of the cap-and-trade program by establishing a price for carbon that will inform industry's investment decisions and promote abatement. The WCI Partner jurisdictions released *Design Recommendations for the WCI Regional Cap-and-Trade Program* in September 2008.[1] The program design recommends auctioning a portion of the emission allowances created under the program and coordinating a regional auction.

This white paper is the first step in developing recommendations for the design of the regionally coordinated auction, as called for in the WCI 2009 – 2010 work plan released February, 2009. It will inform decisions on auction design, including identifying design decisions to be made and assessing their inherent tradeoffs.

The remainder of this paper is organized as follows:

- Section 2 presents the draft auction Design Principles released by WCI in April 2009.
- Section 3 presents the parameters being examined to define the auction design.
- Section 4 summarizes the auction designs used in other programs.

2. Auction Design Principles

The auction design principles are guidelines that help inform decisions regarding the auction design to ensure that the auction maximizes environmental and economic benefits. They reflect a set of common principles developed to guide the overall WCI market design effort, including the auction. The principles were developed with input from WCI Partner jurisdictions and stakeholders at a meeting held on April 9th, 2009, in Seattle, Washington.

- *Fairness:* All market participants, including compliance entities, should have fair and equal access to allowance auctions.

- *Efficiency:* The market is designed to operate efficiently so that greenhouse gas emission reductions can be achieved at the least cost. An efficient market means that allowance and offset prices reflect supply and demand, and accurately reflect the value of allowances and offset credits to entities having compliance obligations. The auction design chosen should contribute to market efficiency.

- *Effective Oversight:* The design and oversight of the allowance auctions do not contribute to fraud, manipulation, and speculative excess.

- *Transparency and Openness:* Transparency in the design and the operation of the allowance auction builds and retains public confidence.

[1] The program design recommendations document *Design Recommendations for the WCI Regional Cap-and-Trade Program* is available at: http://www.westernclimateinitiative.org/the-wci-cap-and-trade-program/design-recommendations

- Reporting of relevant information to regulatory authorities and public disclosure of information has important benefits. It enables regulatory authorities to ensure effective oversight, compliance, and enforcement, all of which are necessary for market efficiency.
- The release of information to the public can change the decisions of market participants, which in turn determine the prices of allowances and offset credits. Timely, accurate, coordinated and consistent release of market-relevant information allows all market participants to have equal access to public information.
- The reporting and disclosure requirements for compliance verification and enforcement balance these benefits against the need for entities to protect certain sensitive information. The potential to disclose certain information that could be used to manipulate the market is also considered. This balancing is consistent with applicable law relating to the disclosure of information.

- *Administrative Simplicity and Cost:* The auction is designed to be as simple as possible for participants and administrators. Administrative costs and transaction costs are minimized for all parties, consistent with the need to provide effective oversight.

- *Accountability:* All entities involved in the allowance and offset credit market, as regulators of the market or as participants, are accountable for their actions. The responsibility, authority, and capacity to conduct the necessary oversight and take appropriate action are fully defined for all agencies charged with compliance verification and enforcement.

- *Conflicts of Interest:* Conflicts of interest between auction participants, monitors, and regulators are prevented.

- *Compatibility with Other Markets:* Entities that participate in allowance auctions may also be participants in other markets, such as the secondary market where allowances are traded, or electricity wholesale markets. The auction design considers potential consequences of interactions between the operation of the auction and the operation of other markets and mitigates potential impacts.

3. Parameters

A large number of auction procedures are currently in use in various public sector auctions around the world. Auction operators generally select procedures based on the assessment of the characteristics of the expected participants, the nature and number of the items being sold, whether the auction will be repeated or whether the items will be actively sold on a secondary market, as well as other objectives the operator may have. The implication is that no procedure is optimal for all auctions.

Each auction procedure is defined by a set of design features or parameters. The WCI partners have identified ten parameters that must be set while accommodating the auction design principles set forth in Section 2 (Auction Design Principles) as well as the decisions contained in the WCI Design Document.

a. Auction Format

There are three main auction format elements to be considered: the number of rounds, the bid format and the pricing mechanism.

The auction operator will consider whether the expected auction participants have uniform access to market information, to evaluate possibilities for manipulation. Each bidder's private valuation of the item being auctioned would be the marginal cost to the bidder of one tonne of direct emission reduction from its operations.

If market information is available, either from previous auction results, trades on secondary markets, or studies evaluating the cost of direct abatement strategies for industry, then auction participants will be able to form good estimates of competitors' valuation of the allowances. Bidders will then worry less about the winner's curse (over bidding) and can increase their bids to be closer to their actual private value of an allowance.

Number of Rounds

Auctions may consist of one round of bidding or multiple rounds. Single round formats can be highly efficient even though bidders are known to shade their bids away from their actual private value and toward the expected auction closing price. Multiple round formats are used when the operator expects that bidders may not initially bid their private marginal values. Auction operators expect competition from multiple bidding rounds to result in a final bid equal to the highest private value among the bidders. The auction operator could specify the number of bidding rounds or alternatively, the auction could use a clock mechanism, where the initial auction price is chosen by the operator and price is then adjusted either upwards or downwards at fixed increments each round until the cumulative bid equals the number available.

Bid Format: Open or Sealed bid

The auction operator chooses between open and sealed bids by deciding whether there is benefit to having competitors see all the bids. The main benefit to open bids is that bidders can observe whether their bids are higher or lower than their competitors' bids. This tells them whether their private valuation of the item is shared by their competitors. This knowledge could prevent participants from reducing their bids to avoid the winner's curse. Of course, bid information is only of value if there are multiple rounds of bidding or if the auction is repeated.

The potential downside to open bidding is that bidders may collude to manipulate the auction price. To collude, bidders may signal their intentions and their identities through their bids. Bids can also be used in multi-unit auctions to retaliate against uncooperative bidders. Operators of multi-round auctions with open bidding could avoid some of these potential issues by specifying bid rules to limit signalling or by using a clock mechanism. Auction operators can avoid both problems by using a single round sealed bid format.

Pricing mechanism: Uniform price or pay as bid format

The operator of a multi-unit auction has two main options in the manner the clearing price will be set. First, the operator may specify a single winning price paid by all winners, known as a uniform price format. Alternatively, the operator may choose to have all winners pay their exact bid price, which is known as a pay as bid format.

In a uniform price format, there are two main design choices: first price and second price. Typically, in a multi-unit auction the auction price is set by awarding a unit to the highest bidder and working down the list of bids until the number of winners equals the number of units auctioned. At that point, the operator can set the auction price using the lowest winning bid (first price format), or by the highest losing bid (second price format.) One reason for choosing the second price format is to avoid having bidders worry about the winner's curse. This is less of an issue in multi-unit repeated auctions. The main risk in using the second-price format is that there may be a large difference between the first and second prices. Auction operators might be reluctant to sell items at a much lower price than the winners actually bid. This is unlikely to be a problem in emission allowance auctions where there are likely to be many bids clustered around the auction closing price. In this case, there will generally be either no difference or, at most, a very small difference between the last accepted bid and the first rejected bid.

Table 2 describes the objectives and highlights some tradeoffs for each of the design options.

Table 2: Basic options for auction type[2]

Design Element	Objectives	Tradeoffs
Number of Rounds		
Multiple Rounds Open Bidding and Clock Formats	• Bidders may adjust private valuation based on other bids	• Provides information on demand schedules during auction • Small bidders can obtain market valuations from larger players and vice versa • Manipulation is possible by signaling during bidding in open bid format, not in clock format • Tests have shown clock auctions more prone to collusive outcomes
Single Round	• Efficiently auction large number of items	• Bidders without good information on competitors' valuations may bid less than their private value to avoid winner's curse • Presence of repeated auctions or active secondary market reduces the winner's curse phenomenon
Bidding Format		
Sealed Bid Bidders do not see other participants' bids before the auction closes	• Limits manipulation by minimizing opportunities to signal • Format simpler and more common to emission markets	• Reveals less information about bidders' demand schedules to other participants than open bids • Less information is not a problem if there is an active secondary market (as is expected).
Open Bid Bidders see other participants' bids before the auction closes	• Bidders learn and adjust to competitors' valuations of the item • Smaller bidders are able to piggy-back off larger players when it comes to price discovery	• Potential for manipulation by signaling in multi-round auctions • Potential for retaliation among bidders in repeated or multi-round auctions
Price Mechanism		
Pay-as-bid	• Winning bidders pay their bid for item	• Bidders may learn that others paid much less for allowances • Bidders will avoid overpaying by setting bids by the price they expect the auction to yield, rather than their own valuation of the item
Uniform Price	• All allowances are sold at the lowest successful bid price (or the first rejected bid)	• Bidders may try to drive down marginal price to reduce their cost in a multiunit auction • Conversely, bidders might bid high to ensure receipt of allowances with the knowledge they will pay lowest winning price • Sellers may learn that buyers were willing to pay much more if successful bid amounts are released

[2] Refer to Section 4.0 – Other Jurisdictions for examples on how these basic options for auction type can be used in conjunction.

b. Reserve Price

It is the WCI jurisdictions' intent that the allowance auction design process will determine: the percentage of allowance budgets to be auctioned, the reserve price, the fraction of unsold allowances retired, and the fraction of unsold allowances retained by the individual WCI Partner jurisdictions.[3]

The WCI design calls for a minimum auction level of ten percent of the allowance budget in the first compliance period (2012-2014), increasing to twenty-five percent in 2020.[4]

There is also existing WCI policy on the use of reserve prices and unsold allowances. To manage the risk of setting the program cap too high, resulting in over allocation, the WCI design recommendations paper suggests the use of a reserve price. The WCI recommendations paper also suggests the application of a reserve price for at least five percent of allowances auctioned, but WCI jurisdictions are also considering maintaining a reserve price for all auctions.

If allowances remain unsold at the reserve price, the WCI design recommendations specify that a fraction of the unsold allowances will be retired. The remaining un-retired/unsold allowances may be auctioned at a later date or returned to the jurisdictions for other uses. Further, "[a]ny WCI Partner jurisdiction that does not participate fully in the auction with the reserve or minimum price will retire the same proportion of its allowance budget as those retired by the WCI Partner jurisdictions that participated in the auction."

The reserve price feature could be used in the WCI auction system to advance several objectives.

First, the reserve price could ensure allowances are not sold below the seller's opportunity cost. In private auctions the opportunity cost is typically the expected price at which a seller could sell the item in an alternative venue. The WCI Design Document does not consider direct sales of allowances, so no alternate sales venue exists. The opportunity cost could also be viewed as the value of the item in an alternative use, such as retiring them to benefit the environment.

Second, the reserve price could reduce the incentive for market manipulation by reducing the expected profits from colluding to lower the closing price.

Third, the reserve price would guard against low prices resulting from the cap being set too high. The failure to maintain a minimum price in the presence of low prices could discourage efforts by businesses to reduce their own emissions or create offset projects.

The WCI Design Recommendations indicate that at least five percent of each Partner's annual allowance budget should be auctioned with a reserve price feature. The stated purpose of the reserve price was to guard against over allocation. The Design Recommendations do not include a specific destination for the unsold allowances, only that the Partners should decide what fraction to retire and what fraction to return to the Partner jurisdictions for use in approved programs.

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[3] *Design Recommendations for the WCI Regional Cap-and-Trade Program*, September 2008 http://www.westernclimateinitiative.org/the-wci-cap-and-trade-program/design-recommendations

[4] *Design Recommendations for the WCI Regional Cap-and-Trade Program*, September 2008

To apply a reserve price, the auction operator must decide which objective forms the basis in setting the reserve price, and which determines the method of calculating a reserve price. The operator must also determine when the reserve price will be released to bidders.

Setting the Reserve Price to Limit Price Decreases

Whether the objective is to limit the price depressing effects of over allocation or market manipulation, the auction operator would need an estimate of the expected auction clearing price. The expected clearing price could be estimated from secondary market activity or economic modeling. For example, RGGI applied economic modeling to forecast market prices prior to the first auction and the development of a secondary market for allowances. Generally, the auction operator uses the estimated variability to set the reserve price sufficiently below the expected price so that it does not interfere with normal variability.

Setting the Reserve Price Percentage

Currently RGGI has a fixed reserve price of $1.86. However, RGGI rules specify that this be replaced with a reserve price based on market prices once sufficient data is available. Once this criterion is satisfied, RGGI has indicated it will set its reserve price at 80% of the expected auction closing price (See Table 3).

WCI could also consider setting a reserve price percentage to reflect the secondary market. The reserve price in the first WCI compliance period would be based on forecast and modeling data as WCI may not have sufficiently reliable price information from the secondary market. WCI could modify the reserve price after receiving secondary market data.

Setting the Reserve Price to Support Direct Reductions

The value of allowances allocated to set-aside programs also provides a method of setting a reserve price. Consider a set-aside used to support investment in new technologies. The reserve price could be set using an estimate of the cost of reductions provided by the new technologies supported by the set-aside, with the intent being to prevent over allocation from delaying investment in direct emission reductions. This approach could result in setting a reserve price high enough to interfere with the price discovery objective of the auction by setting a price higher than many potential bidders' private valuation.

Determining when to reveal the reserve price

If WCI commits to setting a reserve price, a decision must also be made on when to reveal the reserve price to participants: prior to the auction, during the auction, or after the auction.

The advantage of revealing the reserve price after the auction is to reduce market manipulation. If bidders intend to bid below their private values, they would run the risk of losing an allowance award if they drive the apparent market-clearing bid price below the (unknown) reserve price.

Revealing the reserve price prior to the auction reduces the bidders' need to balance the goal of purchasing an allowance below their private value with the risk of losing an allowance award by bidding below the reserve price. In a repeated auction sophisticated bidders will likely derive a good estimate of the method WCI might use to set a reserve price so the unknown reserve price feature would lose its effectiveness over time.

One advantage of revealing the reserve price prior to the auction is transparency. Those with a private valuation for the item below the reserve price would not participate in the auction. Another advantage is fairness; all bidders would know the reserve price reducing possible advantage of those bidders who are able to accurately estimate the reserve price.

The risk of revealing the reserve price prior to the auction is that it may influence bid schedules, reduce clearing prices for the allowances, and reveal to bidders the potential scope of for manipulation. This may occur if the reserve price is viewed by participants as providing a target for manipulation. This concern is more important if a high reserve price reduces the number of bidders. As long as there many participants in the auction, then it is unlikely that the reserve price would serve as a focal point for bidding because there would be big profits to be made from bidding closer to the expected market value of the allowances. The presence of a secondary market is a much more compelling focal point for competitive traders.

In the long term, the question of releasing the reserve price prior to auction may be moot in the case of a repeated, multi-unit auction (such as WCI is considering). Revealing the reserve price after each auction would inform participants of the method used to set the reserve price. This allows the participants to accurately forecast the reserve price for the next auctions.

Table 3 provides a summary of the reserve price rules in the UK ETS, RGGI, and the planned Australian Carbon Pollution Reduction Scheme. All three trading schemes apply a reserve price, but differ in their decision to make the reserve price known to participants prior to the auction.

Table 3: Reserve price rules applied or planned in other trading programs

Trading Program	Reserve Price Rule
UK – EU ETS	Reserve price is based on the secondary market price in the most liquid EUA market and not made available to participants.
RGGI	Reserve price will be set at 80% of the expected auction closing price, and made available to participants before the auction.
Australia – Carbon Pollution Reduction Scheme	Reserve price will be set at some level below the expected market price and made available to participants prior to the auction.

c. Unsold Allowances

If the WCI does not receive bids above the reserve price for the number of allowances offered at each auction then WCI must have a procedure for reallocating the unsold allowances. The Design Recommendations direct that partners will retire a fraction (effectively tightening the cap) of the unsold allowances which would help prevent chronic oversupply of allowances. The remaining fraction of unsold allowances would be retained by the partner jurisdiction for distribution in future compliance periods consistent with WCI Partner direction. The uses may include auctioning, set-asides or allocations. This section reviews two potential options for unsold allowances, and compares each option to immediate retirement.

Carry Forward to Next Auction

Carrying unsold allowances forward to a future auction is administratively simple and maintains a greater potential supply of allowances than immediate retirement. The risk, however, is that a significant amount of allowances could be carried forward over multiple auctions. If the initial oversupply was large enough, and WCI decided not to retire unsold allowances, several auctions may result in unsold allowances before the surplus is cleared. This may exaggerate the effect of an initial over allocation, compared to a policy of immediate retirement. This result could give the impression that the cap was set too high, not just initially, but over the entire period during which the reserve price resulted in unsold allowances.

Contingent Set-Aside Release Option

Unsold allowances could be used in a set-aside reserve to be released for auction at a predetermined release price. This approach lowers the risk of a glut of allowances building up as is possible under the carry-forward model, and provides some relief from temporary price spikes. The number of allowances in the contingency set-aside account would be known to all parties through the transparency of the allowance tracking system. The availability of a set-aside reserve, to be released during periods of high prices would have the benefit of moderating reactive bidding behavior of those speculating on future shortages.

To implement the measure, partner jurisdictions would have to agree on a release price mechanism as well as the proportion of unsold allowances to be used for the contingent set-aside reserve.

d. Vintages

Vintage refers to the year during or after which the allowance in question may be used for compliance purposes. Typically, in an emissions trading scheme, the regulator can issue allowances for compliance in the current or any future compliance period, although it is possible that allowances can be made available without temporal restrictions. That is, the regulator may sell or issue any vintage. Alternatively, an emissions trading scheme can forego the concept of vintages altogether. Selling allowances without vintages has the distinct advantage of significantly lowering administrative and the transaction costs associated with compliance.

There are several reasons to consider issuing future vintages. First, if current-year allowances could be used for compliance in future years then they would likely be valued more highly (effectively increasing the price). Issuing future vintages could increase the liquidity of the market and so ease the price pressure on current compliance vintages. In so doing the regulator decreases the chance of a spike in price in the early years that could trigger calls for the abandonment of the program. Second, future vintages are useful to businesses as a hedge against future compliance liabilities. However, a well functioning carbon market should see the development of instruments that allow them to do this.

Third, issuing future vintages contributes to the long-term viability of the program by creating an interest in program continuation. (If the program is superseded by U.S. and/or Canadian federal programs, the existing allowances may be recognized by that program as is proposed in the American Clean Energy and Security Act of 2009). Fourth, vintages may be part of borrowing mechanisms in trading systems, though this feature is not yet part of the WCI.

One disadvantage with respect to auctioning future vintages is the ability of liable entities to purchase them. To address working capital constraints from liable entities, the Australian government has agreed to provide deferred payment arrangements which allow entities to make final payment and take receipt of permits over an extended time period after the conclusion of the auction.

Notwithstanding the benefits of selling future vintages, the decision to sell them is independent of the actual design of the auction and will be considered by Partner jurisdictions a later date. We assume that vintages exist for the purposes of this section.

Other vintage questions to be considered by Partner jurisdictions are:
How far in advance and how often should allowances be sold and how should their sale relate to the auction of current-period allowances?

Simultaneous or consecutive auctions

Different vintages can be auctioned either simultaneously or consecutively. If a multiple-round auction format is chosen, simultaneous auctions of different vintages can be complicated for bidders to follow. However, it affords the bidders the ability to use information from one vintage auction to inform its decisions on participation in another, thus increasing the efficiency of the auction. It is expected that with clear instructions and adequate training simultaneous auctions will become less complicated for bidders to follow. While consecutive auctions are easier for participants to follow, they do not allow participants the opportunity to execute a plan to minimize costs by substituting certain vintages for others (recall that, with banking, allowances of current or past vintages are interchangeable).

If the auction format is a sealed bid, the complexity of the auction process decreases. While firms may face some challenge in determining what to include in the sealed bid for each auction, the execution of the auction itself is straightforward and is the responsibility of the auctioneer.

e. Lot Size

Lot size refers to the number of allowances bundled together as an auction unit. In the development of an auction design, Partner jurisdictions must consider how many allowances will be offered as a unit for purchase.

Smaller lot sizes allow for more flexibility bidding strategies by allowing bidders to define their offer curves over more price levels than for large lot sizes. Entities that want to participate in the allowance auction, but have relatively small operating budgets may benefit from the flexibility that comes with lower gross pricing resulting from smaller lot sizes.

One consideration in determining the lot size is the emission profiles of compliance entities. By understanding the compliance obligations of participants in the cap and trade program, the number of auctions per compliance period and the lot size can be coordinated to ensure that participants have the opportunity to obtain the necessary allowances to meet their obligation. For example, if there are four auctions per year over a three year compliance period and a lot size of 1,000 - an entity needing 25,000 allowances could spread its purchases over all 12 auctions. If the lot size were larger, perhaps 10,000 allowances or more, the entity would need to purchase three lots and will have an opportunity to do this over a maximum of three auctions. This would be less of a problem if allowances were available on the secondary market in smaller lots.

Another consideration in determining lot size is future plans to reduce the compliance threshold. If the threshold drops to 10,000 tonnes, then the smallest emitters (those with 10,000 allowance obligations) would be more dramatically impacted by a larger lot size. A 10,000 or 5,000 allowance lot size would allow these smaller entities only one or two opportunities to purchase allowances at auction.

WCI Partner jurisdictions should further consider sizes of contracts likely to be traded on private exchanges for compatibility with auction lot sizes. Matching lot sizes to those normally traded in the secondary market could enhance the development of the secondary market and reduce friction overall.

Table 4 highlights the lot sizes of RGGI, the UK ETS and the Carbon Pollution Reduction Scheme.

Table 4: Lot Sizes

Trading Program	**Lot Size**
RGGI	1,000
UK ETS	1,000 in the competitive portion, maximum bid of 10,000 allowances in the non-competitive portion.[5]
Australia: Carbon Pollution Reduction Scheme	To be determined - set low enough to allow participation by some emitters with less than the 25,000 tonne threshold[6].

f. Timing and Frequency of Auctions

The frequency of allowance auctions requires a balance between administrative complexity and flexibility for participants. First, increased frequency can aid in developing liquid forward markets and by providing a stabilized spot market through continuous new supply. In addition, frequent auctions can offer participants a regular price signal from which to inform their decisions. Second, increased frequency is useful if the regulator wants to require a smaller capital commitment for each auction and address cash flow shortages for potential bidders. If auctions are infrequent, emitters that wish to acquire allowances in the primary market need to buy larger proportions of their requirements each time. This would require larger, less frequent outlays which could be a problem for small firms. This was a particular concern in the design of the Australian Carbon Pollution Reduction Scheme.[7] As

[5] If the non-competitive portion is over-subscribed, priority is given to bids of lower than 1,000 allowances, which is the standard minimum lot size on the secondary market. Remainder are allocated on a pro rata basis
[6] The current general threshold for triggering a liability under the Carbon Pollution Reduction Scheme is 25,000 tonnes of CO_2e. This is complicated by the fact that some entities will be liable for their emissions below 25,000 tonne threshold. Lot size is likely to be set low enough to participate at the auction.
[7] Carbon Pollution Reduction Scheme: Australia's Low Pollution Future
http://www.climatechange.gov.au/publications/cprs/white-paper/cprs-whitepaper.aspx

a result, Australia is considering monthly auctions. Third, increased frequency allows bidders to adjust their strategies over time as they gain experience with the process. Of course, holding more auctions is easier when there are a large number of allowances to auction. Fourth, increased frequency has the advantage of making market manipulation difficult, that is, it is more difficult to coordinate, and organize manipulative behavior.

However, auctions are costly endeavors and each one implies additional administrative costs for bidders and sellers alike. There are also scheduling constraints on the number of auctions that can be executed each year. For example, RGGI holds auctions quarterly, but each one has a 60-day lead time. Using the same approach for a monthly auction could be potentially confusing and could create perpetual overlap.

Conversely, offering frequent auctions may serve to keep secondary market prices consistent with the demand schedule revealed during the auction process

The WCI Partner jurisdictions may also consider holding auctions in advance of or after the compliance period. Compliance entities may prefer to purchase allowances once their emissions for the compliance period are known. An auction held after the end of the compliance period but before the reconciliation of emissions and allowances[8] may be beneficial to firms that do not wish to hold allowances for a significant period of time. It could provide a means of addressing compliance needs (other than the secondary market) for firms with emissions in excess of planned allowances, especially if there is an immature and potentially illiquid secondary market.

Another issue for some businesses is assured opportunity, which is access to or ownership of allowances to sign long-term contracts. Assured opportunity is generally necessary to secure new project financing. This is a common issue in the electricity generation industry.

Another timing concern is the perceived need to have some allowances available (e.g., by auction) before the compliance period for which they are issued. An early allowance auction allows businesses to manage risk by securing allowances before producing emissions, and establishes an early price signal to facilitate secondary market activity.

g. Participant Access

A decision regarding which entities may be permitted to, and which entities may be restricted in purchasing allowances is in part related to the design of the overall program as opposed to the auction itself. Most carbon schemes allow non-restrictive access meaning that any entity that can hold an allowance can participate in the auction. However, it is possible to make it more restrictive by dividing access along compliance/non-compliance entity lines.

There are two types of participant access restriction: (1) restricting those who may be permitted to purchase allowances at an auction and (2) restricting access to the auction mechanism itself.

Auction Participation

[8] Commonly called true up, where emitters exceeding the established thresholds are required to relinquish a sum of allowances and credits equal to their emissions of $CO2e$.

One option for making the auction more restrictive is restricted participation. Restricted participation would allow only compliance entities to participate in the auction, as opposed to allowing any entity that can hold allowances to participate. Advocates of restricted participation in the auction tend to believe that the auction price will be more influenced by a larger number of auction participants rather than the overall demand in the markets. Therefore, they suggest that allowing more auction participants might increase allowance demand and drive the price up, whereas limiting auction participation could address concerns of increasing allowance prices (from speculating, non-compliance entities).

Conversely, advocates of unrestricted participation in the auction site several competing views. First, if the desired if a desired outcome from the auction of allowances is an indication of market value for the auctioned good, full market participation in the auction should be pursued in the design. Non-compliance entities can provide a service to the market by reducing price volatility. For example, they could prop up demand for allowances when it would otherwise fall due to broader macroeconomic factors, and release those allowances back into the market when demand rises.

Restricted participation is not typical of other schemes. This may be due in part to the perception that allowing non-compliance entities to participate in the auction can increase market liquidity, and in part because it is difficult to determine who is and who is not a compliance entity.

Auction Access

Notwithstanding the potential restriction on the acquisition of allowances via auction participation limitations, it is possible to restrict access in another way. Regulators can require entities interested in obtaining allowances to submit bids via a smaller group of pre-arranged intermediaries that deal directly with the government in the auction. Where the number of potential participants is large, the administrative burden associated with vetting financial assurance and checking for evidence of money laundering can be significant. In the UK, bidders must either apply to become intermediaries or bid through intermediaries (i.e., have intermediaries act as their proxies at the auction). Importantly, the intermediary approach also shifts the risks associated with non-payment to the intermediaries.

The intermediary approach is not common, possibly due to stakeholder concerns about the revelation of their business strategy to the intermediaries, especially where intermediaries are (potential) competitors. Control of sensitive business information is an important issue to many firms. Furthermore, the use of intermediaries creates a new set of issues for the regulator to monitor, i.e., supervision of the intermediaries.

In addition, the intermediary approach reduces competition at the auction, which may hamper the price discovery of the auction process. Such a strategy should only be used if there is strong evidence that the administrative savings would be large.

Non-Competitive Bids/Uniform-price auctions

A non-competitive bid is where bidders submit a request for a fixed number of allowances prior to the auction, agreeing to pay the auction clearing price.
For the auction to be equitable, all potential bidders must believe they have a legitimate opportunity to obtain allowances. Some entities, in particular small emitters, may not be able to afford the number of allowances that are in the minimum lot size. The UK has taken a direct approach to this issue. Under some of the UK's EU ETS auctions, a maximum of 30

percent[9] of the allowances available are reserved for non-competitive bids. These non-competitive bidders pay the eventual auction clearing price for the number of allowances they wish to purchase.

There is a precedent for this approach in electricity markets. Non-competitive bids are used in some electricity markets by generators that need to be dispatched (i.e., will be generating electricity regardless) and are not price-responsive. The objective is to allow extremely risk-averse compliance entities, especially those without activity in commodity markets, the ability to obtain allowances without quantity risk or risk of overbidding. Setting a quantitative limit on the amount of allowances set aside for the non-competitive bids requires a method of allocating participation if the non-competitive bids are oversubscribed.

The designers of the Australian Carbon Pollution Reduction Scheme decided that a non-competitive bid mechanism was not necessary to protect small or risk-averse bidders. It was judged that an ascending clock auction format would reduce the information asymmetry between large and small bidders, to the extent that one exists.

The non-competitive bid approach used in the UK was used for the first time in the second phase of the EU ETS and based on stakeholder feedback as well as information from the first phase of the auction.[10] Given the current limited information about compliance entities in the WCI, stakeholder input will likely be the most effective approach to understanding auction participation limitations for compliance entities.

Consignment

Allowance holders may also wish to sell allowances using the auction platform designed for primary market distribution.

While the focus throughout most of this paper has been on WCI Partner jurisdictions as sellers of allowances, this need not be the case. Other allowance holders may wish to sell allowances, and some of those may wish to do so without participating in the secondary market. In cases such as this, it is possible that the regulatory entity could sell the other parties' allowances on a consignment basis. This type of transaction is sometimes called a double-sided auction. The EPA offers this service as part of the auction of SO_2 allowances in the Acid Rain Program (see below). A double-sided auction was also proposed for the Australian Carbon Pollution Reduction Scheme.

Generally, this approach is likely to be favored by allowance holders who lack the technical expertise to confidently participate in the secondary market. For these allowance holders, permitting the regulatory body to sell your excess allowances is an attractive option, and one that would likely minimize transaction costs.

Many current systems have not incorporated consignment selling as a design feature in their auctions. Soliciting stakeholder feedback could be useful at this point to better understand the interest in potential consignment opportunities and challenges.

[9] This limit was chosen to strike the balance between the needs of smaller compliance buyers and ensuring that there is enough competition in the 'competitive' stage of the auction, which is what determines the clearing price. The percentage will be kept under review.
[10] UK representative presentation to WCI Markets Task 6. January 9th, 2009

h. Financial Assurance

Many auction programs, including RGGI, require financial assurance to ensure participants are able to cover the value of their bids. Financial assurance usually consists of adequate bond ratings, letters of credit, or similar instruments of comparable quality. Other entities who are unable to meet financial qualifications levels may deposit cash in escrow to cover their bids. The RGGI Auction Platform automatically rejects any bid that violates a bidder's financial security limits. When financial disclosure tools are used, design experts suggest levying penalties against any party that is unable or unwilling to pay for its winning bid[11].

i. Information and Transparency

The collection of information related to auctions along with transparent use and publication of that information plays a central role in building confidence in market-based programs. In general, the greater the level of transparency and disclosure of information, the more trust stakeholders, compliance entities, and others place in the value and integrity of the auction program. However, public disclosure of confidential information that compromises business positions of auction participants diminishes confidence in the allowance market and may have negative consequences outside of the cap and trade program. Decisions regarding what information to collect and eventually publish must balance the interests of transparency and confidentiality.

Clear rules for auction participation and administration lead to greater transparency. The RGGI design team used the following guidance to assist in development of their auction rules: "… auction rules should be transparent and available to everyone who might want to participate. The rules should not discriminate against any potential qualified participants."[12]

In addition to transparent rules, transparency in the auction execution, monitoring and reporting of results further fosters confidence in each auction. To ensure transparency, experts who designed the auction for RGGI suggested that the auction clearing price and the identities of winning bidders be disclosed publicly after each auction. However, RGGI does not disclose the quantity of allowances purchased by each winning bidder to protect proprietary information and tacit collusion by bidders buying fixed shares of available allowances.

To balance the interests of transparency with proprietary or business confidential information, auction operators may also release aggregated information on trading activity to the public. This ensures transparency without compromising an entity's ability to do business. For example, RGGI's independent market monitor provides public information on the percent of purchases going to entities with compliance obligations. RGGI also provides sixty days advance notice before upcoming auctions.

The RGGI auction design team asserts that "the actual value bid by each auction participant…" and "information about losing bidders should not be disclosed."[13] In this vein,

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[11] Auction Design for Selling CO2 Emission Allowances Under the Regional Greenhouse Gas Initiative Final Report. October 26, 2007. page 41
http://www.rggi.org/docs/rggi_auction_final.pdf

[12] Auction Design for Selling CO2 Emission Allowances Under the Regional Greenhouse Gas Initiative Final Report. October 26, 2007. page 22

[13] Auction Design for Selling CO2 Emission Allowances Under RGGI. Final Report. October 2007.
http://www.rggi.org/docs/rggi_auction_final.pdf

not that RGGI's auction results are posted as quickly as possible after the conclusion of an auction.

Partners may also wish to consider the adoption of beneficial ownership disclosure requirements. The RGGI auction rules require all applicants to disclose their direct and indirect corporate associations with other applicants and bidding associations, beneficial relationships to other persons and groups participating in the auction. Information on beneficial ownership is gathered via a thorough on-line application system for participants in the regional auctions and is used, in part, to ensure that participants comply with the 25% purchase limit described in "Preventing Market Manipulation" below. Beneficial Ownership information may be considered proprietary because it has the potential to reveal business strategies outside of the allowance auction and market. The decision to disclose this information publicly must be weighed against potential impacts to confidential business strategies.

j. Avoiding Market Manipulation

Manipulation occurs when market participants engage in activities with the intent to artificially raise or lower the price of allowances. Market manipulation occurs when multiple bidders coordinate their bidding in an attempt to lower the price they pay for allowances at auction.[14] In an effort to deter market manipulation and other forms of broader market manipulation RGGI included the, use of: a single-round sealed-bid uniform-price auction, a limit on the size of purchases at a given auction, and an open and transparent auction program. Auction monitoring is another tool the regulator may use to deter market manipulation.

An open and transparent auction improves competition and limits opportunities for market manipulation. A percentage limit on the number of allowances a single entity may purchase in a single auction "… raises the cost of using the auction to corner the market without placing too stringent a restriction…" on what compliance entities can purchase.[15] It is expected that WCI market participants will have small compliance obligations, relative to the total pool of available allowances, and that new entrants will have access to allowances and offsets through the secondary market. Therefore, setting a percentage limit will not impose an excessive burden on participating firms because WCI does not anticipate that any one entity will have that large a share of the WCI market. In addition, purchasers can access an auction periodically (e.g., quarterly) – which further reduces the inconvenience of a percentage limit. Such a limit can also be a means of protecting inexperienced participants from purchasing more allowances than they will need.

WCI can consider working in partnership with existing and interested agencies in the design of monitoring criteria to guide and regulate the allowance auction program. Existing market monitoring activities by federal and state agencies and provincial agencies could be examined by the WCI Partner jurisdictions to ensure that the appropriate criteria are used for detecting market manipulation and for sharing information regarding the performance of the allowance market and the auction. The Markets Oversight task group is charged with consideration of secondary market monitoring; there may be room for coordination of monitoring for both aspects of WCI program operation through a common market monitor. In addition, auction design elements may be incorporated to reduce the possibility of broader market manipulation. For example, as a means of discouraging hoarding within

[14] Auction Design for Selling CO2 Emission Allowances Under RGGI. Final Report. October 2007.
[15] Auction Design for Selling CO2 Emission Allowances Under RGGI. Final Report. October 2007.

the allowance market, the regulator can set a single auction purchase limit for any applicant or associated applicants.

A number of entities may be able to provide auction oversight or monitoring assistance including[16]:

- Federal Energy Regulatory Commission (FERC)
- Commodity Futures Trading Commission (CFTC)
- Securities and Exchange Commission (SEC)
- The US Environmental Protection Agency (US EPA)
- The Independent System Operators
- Other market monitors hired by WCI

The RGGI auction design team explored coordination opportunities with all of these agencies and organizations. The CFTC currently exercises jurisdiction over derivatives in existing SO_2, NO_X, and CO_2 markets in the U.S., and parallel agencies in the European Union are doing the same for its emissions markets. In future GHG markets, the CFTC could expand its oversight to include new emissions derivatives markets.

RGGI contracted Potomac Economics as an independent market monitor to monitor auction activities and results. This group analyzes auction data including (but not limited to) the clearing price, total allowances sold, the quantity of each vintage sold, the range of prices bid, the number of entities with winning bids, and the percentage of allowances purchased by entities with a compliance obligation.

RGGI definition of principle to… "**Guard against collusion and/or market manipulation:** The allowance auction should be designed in a way that limits opportunities for bidders to actively or tacitly collude to keep prices low. To the extent possible, the auction also should limit opportunities for bidders to bid up the price of allowances above the competitive price, which we refer to as hoarding. Because collusion and hoarding are potential issues in the allowance market, and not just the auction, there may be a limit to the ability of an auction design to limit incentives for hoarding."[17]

[16] Options for Limiting Market Manipulation, Washington State Department of Ecology. November 11, 2008. URL: http://www.ecy.wa.gov/climatechange/2008CTdocs/10102008_LimitingMarketManipulation.pdf
[17] Auction Design for Selling CO2 Emission Allowances Under RGGI. Final Report. October 2007 http://www.rggi.org/docs/rggi_auction_final.pdf

4. Other Jurisdictions

Introduction

Auctioning has long been touted as the best method to allocate allowances in an emissions trading scheme. There are now several examples of the use of auctions in new emissions trading schemes. These include:

- the Regional Greenhouse Gas Initiative (RGGI)
- United Kingdom Emissions Trading Scheme (UK ETS)
- Australia's Carbon Pollution Reduction Scheme
- the United States Environmental Protection Agency's SO_2 (Acid Rain Program) Auction
- Virginia's NO_X auction

The United States Treasury bill auction also provides an example of a well established auction.

Common Features

Most auctions evaluated share at least two criteria or values: fairness and allocative efficiency.

Fairness is important because: (1) the auction itself should not change the playing field for competing firms, (2) the perception of fairness is critical to the acceptance of the auction by all stakeholders: no one will embrace a process that is seen to give an unwarranted advantage to others.

Allocative efficiency is a measure of the degree to which the allowances go to the entities that value them most. Value can be expressed as the return that the firm can generate on the asset, and therefore what it is willing to pay to obtain it.

The auctions examined below also have common approaches to certain aspects of auction design. For example, all the examined auctions have a reserve price. This common adoption reflects a perceived value in establishing a reserve price as a way to create a credible auction and a deterrent to market manipulation.

Another characteristic that is common to all the auction designs reviewed is that they are open to all qualifying bidders. They are not restricted to compliance entities alone.

Regional Greenhouse Gas Initiative

The Regional Greenhouse Gas Initiative (RGGI) is an initiative of ten northeastern states to cap GHG emissions from approximately 200 fossil fuel-fired electricity generation facilities with capacities greater than twenty-five megawatts. The ten states enacted the program with regulations based on a RGGI model rule, but functionally it is a regional compliance market. Each state must allocate at least twenty-five percent of its allowances by auction, although several have chosen to sell more. States may distribute the remaining allowances in a manner of their own choosing.

The overall cap is 188 million tons, with no entity forecast to demand more than 12 percent of available allowances.[18] The first compliance period is 2009-2012; however, the first auctions were held in September and December 2008. The auctions were successful, with significant bidding activity leading to clearing prices ($3.07 and $3.32, respectively), well above the reserve price in both cases.[19] Most allowances (>80%) were purchased by compliance entities but some non-compliance entities bought allowances as well.[20] Demand was high, as both auctions were at least 3.5 times oversubscribed and each saw approximately sixty bidders participating.[21]

Distinguishing Features:

Auction type
- single-round, uniform-price, sealed-bid auction

Advantage
- simple, transparent and provides good price discovery
- familiar to electricity generation companies
- single round restricts the amount of information that is revealed to competing firms that could be used to engage in market manipulation

Reserve price – what level?
- Reserve price set at $1.86 for all auctions to date.

Vintages and lead time (when to sell each vintage)
- RGGI sells future vintages in advance of compliance periods.
- At all four auctions held in 2009 (March, June, September and December), the RGGI states sold 2012 allocation year allowances, the first year of the next compliance period.
- RGGI has committed to sell five percent of its allocation year 2012 allowances by the end of 2009.
- At the March 2010 auction RGGI will offer allocation year 2013 allowances.
- RGGI has committed to sell five percent of its allocation year 2013 allowances by the end of 2010.

Lot size
- The allowances are sold in lots of 1,000 (i.e., 1,000 tons)
- At the December 2009 auction, approximately 28,591 lots were available from the 2009 vintage, while 2,175 lots were available from the 2012 vintage.

Unsold allowances
- All allowances were sold in the first five auctions.
- 573,540 allocation year 2012 allowances were unsold at the December 2009 auction.
- There are State specific regulations on unsold allowances.

Timing and frequency of auctions
- All states are expected to sell at least a portion of their allowances in auctions held quarterly in each of year of the first compliance period.

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[18] http://rggi.org/docs/Auction%203%20News%20Release%20MM%20Report.pdf
[19] http://www.rggi.org/docs/Auction_3_Auction_Notice_News_Release.pdf
[20] http://www.rggi.org/docs/Auction%202%20Post%20Settlement%20Auction%20Report.pdf
[21] ibid.

- Allowances are made available for sale in an evenly distributed manner during the first control period.
- To prepare the market in advance of the launch of the initiative, RGGI sold some allowances at two advance auctions in September and December 2008.

Method of participant access

- Entities interested in obtaining allowances must be qualified to gain access to the auctions. Once qualification is complete, the applicants submit appropriate financial assurance, and then the registered entities or their agents participate in the online auction directly.

Financial assurance

- All participants in RGGI auctions must submit some form of financial assurance in advance of the auction.
- Depending on the financial sophistication and health of the prospective participant, the three following forms of assurance are accepted: a letter of credit from a US bank, cash, or a bond from a US bank.
- Without this assurance, qualified applications cannot participate in an auction.
- The auction platform is designed to reject bids that exceed a bidder's financial assurance amount

Information and transparency

- After each auction, RGGI releases the results along with an assessment of the auction proceedings, prepared by an independent market monitor.

- The total number of allowances sold and the clearing price are released along with the market monitor auction report. Once settlement is complete, RGGI states release additional details, including:
  - the pre-auction estimate of dispersion of demand for allowances;
  - the dispersion of actual bids;
  - the proportion of allowances purchased by type of bidder (compliance, environmental and other non-compliance);
  - amounts of allowances awarded to bidders (names not released), and
  - a summary of bid prices, showing the minimum, maximum, average and clearing price.

Monitoring

- As indicated above, RGGI has contracted a third party to observe the auctions and, in addition to the actual results, report on the degree to which the auction met RGGI's goals of transparency, effectiveness and, most importantly, any signs of market manipulation.

- In the six auctions already held, there was no sign of either market manipulation.

United Kingdom: European Union Emissions Trading System (EU ETS)

The United Kingdom participates in the EU Emissions Trading system which is one of the key policies introduced by the European Union to help it meet its Kyoto Protocol commitment to reduce emissions to 8 per cent below 1990 levels by 2012. The system covers emissions from electricity generation and the main energy-intensive industries. The EU ETS currently covers approximately 11,500 installations, which account for approximately 45 percent of the EU27's CO2 emissions (2.2 $GtCO_2e$). The EU ETS is currently in its second phase (2008-2012), which followed a three year pilot phase that ran from 2005 to 2007. Prior to the inception of the EU ETS, the UK ran a voluntary domestic emissions trading program from 2002 to 2006.

Before the start of EU ETS Phase II, each member state was required to submit to the European Commission a National Allocation Plan (NAP) in which it described how and to whom it would allocate allowances during the four years of the second trading period. Member states were allowed to auction up to 10% of their allowances each year.

The UK NAP provides for an allocation of 246 million allowances to covered sectors during each year of EU ETS Phase II. It has chosen to auction seven percent of these allowances, equal to 17 million allowances per year, or 85 million over the entirety of Phase II[22] Allowances sold at auction are deducted from the nominal allocation to Large Electricity Producers. The auctions are open to any entity that holds an EU ETS Registry account.

Some UK auctions will have two bidding stages: (1) a non-competitive element, aimed at smaller emitters who need to buy allowances for compliance purposes; and (2) a competitive element. Other auctions will only provide the competitive element. The first auction (competitive only) was held in November 2008 and was four times oversubscribed with a clearing price of €16.15.[23] The most recent auction of 4.4 million allowances on February 4, 2010 was almost seven times oversubscribed and cleared at €12.66.

A centralized EU-wide cap, which will decline annually, on emissions for Phase III (2013 onwards), will mean that there is more ambition, certainty and consistency across the EU. The number of allowances sold at auction will be greatly increased. In 2012, electricity generators in most EU countries will be required to purchase 100% of their allowances at auction, and free allocation to other non-trade-exposed EU ETS sectors will be gradually phased out by 2020. Overall across Europe, at least 60% of allowances will be auctioned by 2020, compared to around 3% in phase II.

Distinguishing Features:

Auction type

Competitive Portion

- Single round (static) uniform-price auction
- Chosen for simplicity and resulting cost effectiveness, but also because of limited incentives for market manipulation

Non-Competitive Portion (proposed)

- up to 30% of allowances available at any auction could be set aside for the non-competitive process[24]
- bidders in this portion of the auction agree to pay the clearing price for any allowances received
- if oversubscribed, government will first fill the smallest orders, in preference of the smaller compliance entities
- stems from government concern that smaller compliance entities may otherwise have problems obtaining allowances in the auction and find it harder to access the secondary market.[25]

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[22] http://www.dmo.gov.uk/docs/ETS/etspr230209.pdf
[23] http://www.defra.gov.uk/environment/climatechange/trading/eu/operators/auctioning.htm
[24] http://www.defra.gov.uk/environment/climatechange/trading/eu/pdf/phase2-consultation.pdf
[25] http://www.defra.gov.uk/environment/climatechange/trading/eu/pdf/phase2-consultation.pdf

Reserve price - what level?

- Used, but not announced in advance
- If the auction clearing price is less than the reserve price, the reserve price will be the price to be paid for each allowance at auction
- The reserve price is calculated based on the prevalent secondary market price at the time of the auction.[26]
- Government announces whether the reserve price was triggered after the close of each auction.

Vintages and lead time (when to sell each vintage)

- There are no yearly vintages
- Phase II (2008-12) allowances can be used for compliance in phase III (2013 onwards)
- Plans for auctioning in phase III are still in development. The European Commission is expected to publish its proposals for the auctioning rules for phase III soon

Lot Size

- 1,000 in the competitive portion
- maximum bid of 10,000 allowances in the non-competitive portion. No minimum bid size

Unsold allowances

- Unsold allowances sold in future Phase II auctions

Timing and frequency of auctions

- Initially planned for quarterly auctions, but government maintains the option to increase frequency
- For example, the UK Debt Management Office has announced that there will be eight auctions in 2010.

Method of participant access

- In the competitive part of the auction, use of approved intermediaries that collect and submit bids on behalf of bidders is mandatory
- There are currently seven intermediaries also called Primary Participants. All seven intermediaries are investment banks but other organizations that meet the eligibility criteria can apply
- The UK Government believes that intermediaries can best carry out the critical role of implementing checks to guard against potential money laundering activities and providing assurance of the financial standing of bidders.

Financial assurance

- Handled through Primary Participants

Information and transparency

- limited information is released soon after the conclusion of each auction, including:
  - clearing price
  - total bids received
  - number of allowances allocated to competitive bids

Monitoring

- The Treasury contracts and independent third party to monitor the auction and report on its execution.

[26] ibid

- The monitor looks for signs of market manipulation, while observing the transparency of the process. The findings are published soon after the auction's conclusion.

Australia: Carbon Pollution Reduction Scheme

Australia proposes to launch the Carbon Pollution Reduction Scheme in July 2011. For the first year of the scheme (July 1 2011 to June 30 2012) there will be a fixed price operating, that is, permits will be available to liable entities for a fixed charge of $10. This is intended to help companies transition to the scheme. These permits cannot be banked for future use and will be immediately surrendered. During the fixed price period there will be auctions of future vintage permits. Currently Australia intends to auction a portion of 2012-13, 2013-14, 2014-15 vintage permits in 2011-12.
Australia's Department of Climate Change released a White Paper explaining the Scheme details on December 15, 2008.

The aim of the auction is to have a fair, equitable process that aids price discovery. The proposed scheme shares many characteristics with other auction designs, in terms of the reserve price, openness to access and general philosophy. However, Australia will include to two unique features: (1) double-sided auction, allowing those receiving allowances by administrative distribution to sell them in the auction (2) deferred payment, Australian authorities are considering a deferred payment option to help address cash flow concerns expressed by many compliance entities.
The Australian scheme will auction around 70 per cent of the permits, with the rest administratively allocated. With a smaller auction pool, settings such as the reserve price, the frequency of auctions and the auction schedule take on an added significance

Distinguishing Features:

Auction type

- Simultaneous ascending clock auctions used for multiple vintages (option to submit sealed proxy bid)

Benefits

- To further simplify the process for smaller entities, participants will be allowed to submit sealed proxy bids (bidders submit in advance their demand schedule for allowances at various price levels)
- Generates a uniform price for all winning bidders
- Market manipulation less of a concern in Australian scheme because there are many compliance entities with similarly-sized obligations

Reserve price - what level?

- Tool to increase efficiency and speed of auction not intended as a price floor
- Reserve price will be based on, but well below anticipated market price
- Goals are to limit benefits of market manipulation while increasing efficiency of the auction process[27]
- Notify participants of the reserve price prior to auction

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[27] Carbon Pollution Reduction Scheme: Australia's Low Pollution Future
http://www.cramton.umd.edu/papers2005-2009/australia-carbon-pollution-reduction-scheme-chapter-9-auctions.pdf

Vintages and lead time (when to sell each vintage)

- At least one of the monthly auctions (usually the first) will include the sale of allowances for the current year plus the three following compliance periods.
- This will help facilities plan production and foster the development of the secondary market
- Regulator acknowledges that this will increase the complexity of the auction operation but believes the benefits will outweigh the concerns

Bid restrictions – single entity parcel size

- Bidders will be restricted to 25% of allowances available for a given year at each auction
- Given 16 auctions per vintage, this means that a bidder may win a maximum of 1.6% of the allowances available for any one vintage at any particular auction.

Unsold allowances

- Details are being finalized

Lot Size

- Details currently being finalized

Timing and frequency of auctions

- Auctions will be held monthly
- The last auction of allowances for a given compliance period/year will occur after the year has ended but before the compliance reconciliation period, allowing compliance entities to purchase allowances after they know the actual emissions they need to address
- With the advance auctions, there are 16 scheduled opportunities for bidders to obtain allowances of each vintage

Method of participant access

- Direct access (no intermediaries)
- Subject to financial assurance, the auctions will be open to all
    - Limits market manipulation
    - Fosters development of a secondary market

Financial assurance

- Some form of financial guarantee will be required to participate in the auction
- Details to be confirmed

Information and transparency

- Auction results will be made public as soon as possible after the auction concludes
- In addition to the clearing price, the number of allowances demanded at each price will be published
- Individual bids will not be published

Monitoring

- Regulator will appoint an independent panel to review operation of the Scheme soon after its launch.
- Australian Securities and Investments Commission (ASIC) will have power to investigate and prosecute market manipulation; market will be subject to the same effective safeguards as the bond market.
- Additional rules will protect against individual entities manipulating auctions
- Banking and borrowing provisions intended to act as deterrents to market manipulation as well

- Further protection afforded by measures already contained in the Trade Practices Act.

US EPA: SO_2

The Acid Rain Program was created under the 1990 Clean Air Act Amendments to reduce the adverse effects of acid deposition through reductions in annual emissions of SO_2 and NO_X primarily from fossil-fuel burning electricity generation. The Act calls for SO_2 reductions from all sources of 10 million tons from 1980 emission levels, largely achieved through a cap and trade program which imposes a permanent emission cap on SO_2 emissions from electric generating units (EGUs) at power plants. The program initially affected about 2,500 EGUs (roughly 220 plants), but now encompasses around 560 coal fired plants plus gas fired and fuel oil plants.

This national program has two phases. All Phase I utilities were in the Midwest and on the east coast. Now, Phase II of the program covers the 48 continental states. Phase I auctions started in 1993, Phase II started in 2000. There is an opt-in program (voluntary entry into program), but only about only ten facilities chose to do this.

Auction type

- Single round, discriminatory price
- Regular auction: descending order (Congress specified descending order)
- EPA may sell other entities' allowances on a consignment basis

Auction Awards

- The auctions sell allowances on the basis of bid price, starting with the highest priced bid and continuing until all allowances have been sold or the number of bids is exhausted. EPA may not set a minimum price for allowances from the Auction Reserve.
- Allowances are sold from the Auction Reserve before allowances offered by private holders are sold. Offered allowances are sold in ascending order, starting with the allowances for which private holders have set the lowest minimum price requirements. Offered allowances are sold until the allowance supply is depleted, bids are used up, or the minimum price for the next set of offered allowances exceeds the purchase price of the next bid.

Reserve price - what level?

- No minimum price for auction

Vintages and lead time (when to sell each vintage)

- The SO_2 allowance auction consists of two parts:
  1. a spot allowance auction, in which allowances are sold that can be used in that same year for compliance purposes, and
  2. an advance auction for the sale of allowances that will become usable for compliance seven years after the transaction date, although they can be traded earlier.

Table: Allowances Offered at Auctions

Year of Auction	Spot Auction	Advance Auction*
1998	150,000	125,000
1999	150,000	125,000
2000 and after	125,000	125,000

* Not useable until seven years after purchase.

Lot Size

- Can purchase as little as 1 allowance. 1 allowance = 1 ton

Bid Restrictions

- Bidders must send sealed offers containing information on the number and type (spot or advance) of allowances desired and the purchase price to EPA, no later than three business days prior to the auctions. Each bid must also include a wire transfer, certified check, or letter of credit for the total bid cost.

Unsold allowances

- EPA returns proceeds and unsold allowances from the auctioning of reserve allowances on a pro rata basis to those units from which EPA originally withheld allowances to create the Auction Reserve.

Timing and frequency of auctions

- Once per year – usually the last Monday of March each year

Method of participant access

- The auction was initially meant to be for new entrants, but now it is open to any qualified bidder

Financial assurance

- Participants must complete a Letter of Credit, wire check, or certified check.

Information and transparency

- Philosophy is to share as much data as possible including raw hourly emissions data (limited by capacity and emissions monitoring is quarterly). Data is unit by unit.
- Allowance transactions: details available through on-line queries, allowing access to the allowance tracking database.

Monitoring

- Once per year, there is nothing in the rules that prevents someone from buying all of the allowances. Only 2.8% of allowances are sold via auction.
- It is apparent that market manipulation was not a significant concern; the auction was designed mainly for new entrants into program.

Virginia: NO_X

Under the EPA's NO_X State Implementation Plan (SIP) program to reduce smog in the eastern United States, Virginia received an annual 500,000 tonne cap. Most allowances were distributed free of charge to firms with historical rights to emit. About eight percent of 2004-2005 allowances (1,885 tons per year) were reserved for new sources and auctioned. Revenue for 2004 and 2005 vintages was $10.5 million, 19% above target.

In the Virginia NO_X trading program, allowances are bankable, but there is a form of flow control. If over 10% of allowances surrendered during a given year are from a previous year, previous year allowances are worth only 50% of face value (i.e., vintages are not perfect substitutes for one another). There can be no borrowing against future issuance of allowances.

The primary goal of the commonwealth in the execution of the NO_X allowances auction was to maximize revenue. Simplicity was important, given regulators only had two months to design the auction from the time the decision was made to hold one. Transparency was also

Other Auction Types Considered

- Simultaneous (Combinatorial) Discriminatory Sealed Bid
  - Format: (P_{04}, Q_{04}; P_{05}, Q_{05}) P = Price willing to pay for *up to* Q the stated quantity. Gives the auctioneer some flexibility in awarding vintages.
  - Fairly simple and transparent.
  - Because auction is not iterative there is less chance for market manipulation between participants.
  - May be subject to the winners curse b/c of discriminatory pricing.
- Simultaneous (Combinatorial) Uniform-price English Clock (uniform)
  - Linked clocks auction off vintages simultaneously.
  - Good under elastic demand conditions
  - Involves complicated modifications to let the system handle substitutions of vintages efficiently.

a stated goal of the auction design.

Auction Type

Virginia employed two sequential English clock auctions for the 2004 and 2005 allowances. While their models indicated simultaneous English clock auctions would maximize revenue, the option was dismissed as too complicated given time constraints.

Auction Participation

- The auction attracted both regulated entities (energy companies) and brokerage houses

Frequency

- Only one auction each for vintages 2004 and 2005. The 2004 vintage allowances were sold in a morning auction, 2005 vintages in an afternoon auction.

Information Sharing

- Virginia Freedom of Information Act required that all bid information be released including the identities of winners and losers along with their bids.

US Treasury: Sale of Treasury Bills

The United States Treasury has a long experience auctioning Treasury Bills and other marketable securities. The auctions are open to individuals and institutional investors. To accommodate smaller, less sophisticated investors, the Treasury offers non-competitive access to the securities, but with a $5 million limit on the value of securities that can be obtained in this manner. Prospective buyers can also bid through intermediaries such as brokers. The Treasury offers bills, notes, bonds and Treasury Inflation-Protected Securities (TIPS) at auction.

Distinguishing Features

Auction type

- Sealed bid, uniform price
- Competitive Bidders: submit as many bids as they want stating the quantity they are willing to buy at a given price.
- Non-Competitive Bidders – Place a bid stating the quantity they wish to buy. Pay either the clearing price or the quantity-weighted average of the winning competitive bids.

Auction Awards

- Accept all non-competitive bids
- Accept all bids from federal reserve bank
- Demand of highest price competitive bidders are met until supply is allocated

Bid Restrictions

- Competitive bidders: 35 percent of securities on offer (net long position)
- Non-Competitive bidders: $1 million for bills and $5 million for notes

Timing and frequency of auctions

Examples:

- All bills except 52 week bills and cash management bills are auctioned weekly.

Lot Size

- $100.00

Method of participant access

- Both competitive and non-competitive (Usually 15-20%) bidders

Information and transparency

Through a press release available online the Treasury Department announces the following information:

- The amounts of accepted bids and the amount of securities awarded;
- The range of accepted yields or discount rates;
- The proration percentage;
- The interest rate for a note or bond;
- A breakdown of the amounts of noncompetitive and competitive bids accepted from, and awarded to, the public;
- The amounts of bids tendered and accepted from the Federal Reserve Banks for their own accounts;
- The bid-to-cover ratio; and
- Other information that the Department may decide to include.

Monitoring

- Penalty for non-compliance of the auction rules or failure to pay for issued securities.

April 14, 2010 Auction Design White Paper

List of Commenters

International Emissions Trading Association

Montreal Climate Exchange

Ontario Energy Association

Ontario Federation of Agriculture

Pacific Carbon Exchange

Pacific Gas and Electric Company

Puget Sound Energy

Southern California Public Power Authority

Spectra Energy

The Clean and Reliable Energy Supply Consortium

Western Climate Advocates Network

Western Climate Initiative

Auction Design White Paper Overview

Stakeholder Conference Call

9:00am Pacific, April 29, 2010

Markets Committee Mission

- Coordinate the development of recommendations on issues and elements needed to guide the proper development and operation of a robust allowance and offset credit trading market.

Auction Principles

- The following auction design principles inform decisions regarding the auction and guide the overall WCI market design effort.

The 8 principles for developing the auction design are:

Fairness	*Efficiency*
Effective Oversight	*Transparency & Openness*
Administrative Simplicity and Cost	*Accountability*
Compatibility with other markets	*Conflict of Interest*

Auction Parameters

- following parameters are essential in defining the structure of the auction and are discussed in the White Paper:

The 10 parameters discussed in the white paper are:

Auction Format
Reserve Price
Unsold Allowances
Vintages
Lot Size
Timing and Frequency of Auctions
Participant Access
Financial Assurance
Information and Transparency
Avoiding Market Manipulation

Parameters

Auction Format:

- how participants can bid on allowances, for example:

  a) Sealed Bid Single Round

  b) Ascending/Descending Clock multiple rounds

Reserve Price:

- the minimum allowance price that the seller will accept.
- existing WCI direction is that a reserve price be applied.

Parameters Cont.

Unsold Allowances:

- may occur if the reserve price is higher than the auction market clearing price.
- can be retired, rolled forward, or held as a contingency.
- Existing WCI position: partners will retire a fraction of the unsold allowances, the remaining fraction retained for distribution in future compliance periods consistent with WCI partner direction.

Vintages:

- vintage allowances are sold prior to the compliance period for which they become valid.
- vintages help with price discovery but also increase the complexity of auction.

Parameters Cont.

Lot Size:

- refers to the number of allowances bundled together for offering as an action unit.
- smaller lot size allows flexibility in the bidding strategy and makes auction participation more affordable for non-compliance entities.

Timing and Frequency of Auctions:

- advantage of frequent auctions: market liquidity, price stabilization and discouraging collusion.
- disadvantage of frequent auctions: increase in administrative costs.

Parameters Cont.

Participant Access:

- restricting access to the auction may benefit compliance entities by decreasing the number of overall bidders thereby influencing the auction price.
- open access supports market liquidity.

Financial Assurance:

- required from bidders to ensure they are able to cover the value of their bids (e.g., bonds, letters of credit).
- prequalification of participants is essential to the integrity of the auction.

Parameters Cont.

Information and Transparency:

- transparency increases the integrity of the auction program.
  - Mitigate collusion

Avoiding Market Manipulation:

- there are several ways to minimize collusion, manipulation and hoarding. For example:
  - Encourage many bidders to participate in the auction.
  - auction monitoring, single round bidding, sealed bidding and uniform price method.
  - limit amount of allowances that can be obtained at a single auction.
  - Maintaining an open and transparent auction.

Other Jurisdictions

- Regional Greenhouse Gas Initiative (RGGI)
- United Kingdom – European Trading System (UK ETS)
- Australia: Carbon Pollution Reduction Scheme
- US Environmental Protection Agency: SO_2
- US Treasury: Sale of Treasury Bills

Jurisdictional Review:

Regional Greenhouse Gas Initiative

Auction Format	Single round, uniform-price sealed-bid auction
Reserve Price	$1.86 (set initially by modelling, then based on secondary market price)
Unsold Allowances	There are state specific regulations on unsold allowances.
Vintage	Sells future vintages
Lot Size	1,000 tons
Timing and Frequency	Auctions are held quarterly, in each year of the compliance period
Participant Access	Interested entities must be qualified to gain access to auctions.
Financial Assurance	Participants must submit financial assurance before the auction. Three forms of assurance are accepted: letter of credit, cash or bond.
Information and Transparency	After each auction, results and auction assessment are released. Latter is produced by a third party
Monitoring	Third party observation

Jurisdictional Review Cont.

UK Emissions Trading System (EU ETS)

Auction Format	Single round, uniform price auction and a non-competitive bid process
Reserve Price	Used but not announced in advance. Based on a prevalent secondary market price at time of auction.
Unsold Allowances	Unsold allowances are sold in future phase II auction
Vintage	No yearly vintages
Lot Size	1,000 in the competitive portion. Max bid of 10,000 allowances in the non-competitive portion. No min bid.
Timing and Frequency	Quarterly initially. Has increased frequency
Participant Access	Mandatory use of primary participants (also called intermediaries)
Financial Assurance	Handled through primary participants
Information and Transparency	Limited information released after the auction: clearing price, total bids, number of allowances sold in competitive bid.
Monitoring	Independent third party monitors the auction and reports on the execution

Jurisdictional Review Cont.

Australia: Carbon Pollution Reduction Scheme

Auction Format	Simultaneous ascending clock auction
Reserve Price	Below anticipated market price. Participants will be notified of the RP before the auction.
Unsold Allowances	Details being finalized
Vintage	One of the monthly auctions will sell allowances for the current year plus the three following compliance periods
Lot Size	Details being finalized
Timing and Frequency	Held monthly, 16 auctions per vintage
Participant Access	No intermediaries, open to all (subject to financial assurance)
Financial Assurance	Required. Details to be confirmed
Information and Transparency	Auction results will be made public: incl. clearing price & number of allowances at each price.
Monitoring	Independent panel to review operation after it launches. Market manipulation will be investigated and prosecuted

Jurisdictional Review Cont.

US Environmental Protection Agency SO_2

Auction Format	Single round discriminatory price. Descending order
Reserve Price	No reserve price
Unsold Allowances	EPA returns unsold allowances to those the EPA originally withheld allowances from.
Vintage	Both spot allowance auction and an advance auction
Lot Size	Can purchase as little as 1 allowance. 1 allowance = 1 ton
Timing and Frequency	Occurs once per year
Participant Access	Open to any qualified bidder
Financial Assurance	Three options: a wire transfer, certified check or letter of credit for the total bid cost
Information and Transparency	Share as much data as possible. Details are available through online queries
Monitoring	No rule preventing a buyer from purchasing all allowances sold via auction

Jurisdictional Review Cont.

US Treasury: Sale of Treasury Bills

Auction Format	Sealed bid uniform price. Competitive and non-competitive bids.
Reserve Price	N/A (treasury bills typically sold at a discount from the par amount)
Unsold Bills	N/A
Vintage	N/A
Lot Size	$100.00
Timing and Frequency	All bills except 52-week bills and cash management bills are auctioned weekly
Participant Access	Competitive and non-competitive bidders (Corporation, Government-related entity, trust or fiduciary estate, individual, foreign and international monetary authority, other)
Financial Assurance	Depends on bidding method. Treasury direct requires debit entry to a deposit account or submission payment with a bid
Information and Transparency	Results of all public auctions are released in a press release after each auction. Available on website
Monitoring	Penalty for non-compliance of the auction rules or failure to pay for issued securities

Questions?

Western Climate Initiative

WCI Partners Meeting

Sir Francis Drake Hotel
450 Powell Street
San Francisco, CA

*Remote access: Call **1-800-868-1837** toll free in the U.S. and Canada (1-404-920-6440 for outside the U.S. and Canada), **participant code 659 537#***

Wednesday, April 14, 2010

8:30 am	**Convene (Empire Ballroom)** • Welcome and Introductions • Agenda Review • WCI Updates
8:45 – 10:15 am	**Detailed Design Summary Working Sessions:**
	Section 1: What is the purpose of this Detailed Program Design?
	Section 2: How are key terms defined?
	Section 8: How will the offsets component be administered?
10:15 am	**Break**
10:30 am	**GHG Emissions Reporting Updates** • **Essential Requirements for Reporting** • **Oil and Gas Reporting Update** • **Proposed Updates to the U.S. EPA Mandatory Reporting Rule** • **The Climate Registry Reporting Software**
11:45 pm	**Wrap-up and Discuss Upcoming Meetings**
12:00 pm	**Adjourn Partner meeting. Stakeholder Dialogue will convene at the San Francisco Marriott at 3:30 p.m.**

Western Climate Initiative

WCI Stakeholder Dialogue

San Francisco Marriot
55 Fourth Street
San Francisco, CA

Remote access: Call ***1-800-868-1837*** *toll free in the U.S. and Canada*
(1-404-920-6440 for outside the U.S. and Canada), ***participant code 659 537#***

<u>Wednesday, April 14, 2010</u>

3:30 pm **Welcome and Introductions**

3:45 pm **Cap and Trade Program Design Issues**
- Introductory Remarks
- Stakeholder Q&A

4:15 pm **Offsets Program**
- Introductory Remarks
- Stakeholder Q&A

4:45 pm **Complementary Policies**
- Introductory Remarks
- Stakeholder Q&A

5:15 pm **Open Q&A**

6:00 pm **Adjourn**

Western Climate Initiative

COVERING EMISSIONS FROM IMPORTED ELECTRICITY: AN ADMINISTRATIVE APPROACH

May 2010

Introduction

The point of regulation for electricity imported into a WCI jurisdiction is the First Jurisdictional Deliverer (FJD)[1] using the individual boundary approach, which is the recommended approach for all Partner jurisdictions.[2] The FJD approach ensures appropriate price signals are maintained in WCI jurisdictions for imported electricity.

The Partners tasked the Electricity Team to also explore how regulation of imported power covered by the cap-and-trade system could be accomplished through an administrative approach.[3] The administrative approach is less preferred, but is recognized as potentially necessary to address individual Partner jurisdiction circumstances. In particular the administrative approach may be best suited to jurisdictions with low levels of imports. This paper describes and evaluates this way to implement coverage of emissions associated with imports, explains how the two different approaches will interact, and recommends that the administrative approach be available to Partner jurisdictions where appropriate.

The Administrative Approach

The Electricity Team has developed an administrative approach to address import emissions. The administrative approach would establish a mechanism for reserving allowances for retirement to "cover" emissions attributable to imported power. The mechanism would be established and operate as follows:

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[1] http://www.westernclimateinitiative.org/the-wci-cap-and-trade-program/design-recommendations.
[2] http://www.westernclimateinitiative.org/component/remository/Electricity-Team-Documents/Announcement-Regarding-the-FJD-Approach.
[3] http://www.westernclimateinitiative.org/component/remository/Electricity-Team-Documents/Formation-of-the-Electricity-Team.

- Emissions for imported electricity consumed in the Partner jurisdiction are forecasted and included in the jurisdiction's allowance budget in addition to the jurisdiction's internal emissions, beginning with the 2012 best estimate emissions forecast and are trued up to actual emissions in 2012.[4]

- The jurisdiction places the imported electricity allowances in a reserve equal to forecasted imported electricity emissions.

- The jurisdiction monitors and tracks emissions from imported electricity for each compliance period.

- At the end of each compliance period, the jurisdiction retires allowances from the reserve equal to total imported electricity emissions for the compliance period.

- In the event that the number of allowances placed in the reserve pool based on the forecast exceeds the number of allowances needed to cover emissions attributable to imported electricity, those allowances will be retired. This will avoid over-inflating the jurisdiction's emissions cap due to the overestimation of import emissions.

- In the event that emissions from imported electricity exceed the number of allowances in the reserve pool, however, the jurisdiction must increase the number of allowances deposited into the reserve pool using allowances otherwise intended for use by sources with a compliance obligation under the cap-and-trade program.

Unlike the FJD approach, the administrative approach does not impose a compliance obligation on the first deliverer of electricity originating outside the Partner jurisdiction's boundary. Instead, the jurisdiction retires allowances on its own from the reserve pool, thereby ensuring that the emissions attributable to imported electricity are "covered" and the integrity of the emissions cap is maintained.

Addressing Competitiveness in the Absence of a Price Signal

The administrative approach does not attach a price signal to imported emissions, and as a result it would give a price advantage to imported electricity over electricity generated within the jurisdiction. The resulting market distortion can be minimized by other requirements. An Emissions Performance Standard, for example, would restrict the displacement of cleaner sources within the jurisdiction by more emissions-intensive imports. Long term contracts for generation also provide stability in the market and would prevent displacement for the covered generation. A Renewable Portfolio Standard provides for a minimum quantity of renewable power in the overall generation supply, and may play a role in restricting displacement. Jurisdictions predominantly supplied by low emission and low operating cost generation such as

[4] Starting budgets for partners that commence their cap-and-trade programs later than 2012 would have to be adjusted.

hydro, wind and nuclear are inherently protected against displacement from other higher operating cost generation, such as coal and gas-fired generation, since the higher cost generation is not competitive in their market.

The Electricity Team recommends that a jurisdiction implementing the administrative approach give consideration to the potential for an advantage to imports and implement additional measures as appropriate.

Interaction of Administrative and FJD Approaches

Because it is contemplated that some Partner jurisdictions will implement the FJD approach while others will implement the administrative approach, the Electricity Team has considered how the two approaches will interact. One possible concern is that there could be an incentive to flow power through an administrative jurisdiction and subsequently into an FJD. If power is moved into the administrative jurisdiction in one transaction, and then moved into an FJD jurisdiction in another transaction, the party moving the power could avoid incurring an allowance obligation and gain a price advantage. A method to address this would entail the FJD jurisdiction imposing an allowance obligation on all power entering from the administrative approach jurisdiction, unless the importer can show that the imported power already incurred a direct allowance obligation.

In some cases it could be possible for a load serving entity in an administrative jurisidiction to arrange to meet their load with imported power and transfer the domestic generation to an FJD jurisdiction, for a net profit[5]. The power would meet the test of the FJD jurisdiction since it was generated in a WCI jurisdiction and could demonstrate an allowance obligation. This incentive could lead to increased imports into the administrative jurisdiction, putting pressure on their reserve pool. It could also lead to a reduced price signal in the FJD jurisdiction. To address these circumstances, mutually acceptable arrangements between jurisdictions using the two approaches could be employed. A possible approach would be to identify such transactions so an allowance obligation can be imposed on the importer by the FJD jurisdiction, rather than drawing down the reserve pool in the administrative approach jurisidiction. Alternatively an administrative approach jurisdiction may be able to restrict the actions of their load serving entities or remove the profit incentive from such transactions through regulatory actions.

[5] Example: consider an FJD jurisdiction (A), administrative approach jurisdiction (B) and non-WCI jurisdiction (C). Each jurisdiction has gas-fired generation which can generate at a cost of $50/MWh. The allowance cost in A and B amounts to $10/MWh for gas-fired generation. Transmission tariffs amount to $2/MWh between each jurisdiction. The prevailing market price will be $60/MWh in A and B, and $50/MWh in C.
A load-serving entity in B has a long term contract for 1000 MWh of B generation daily. The current cost of 1000 MWh is $60,000, and the entity recovers $65,000 from customers for a net revenue of $5,000.
Now the load-serving entity arranges to import 1000 MWh from C at a cost of $50,000 plus $2,000 tariff to meet its load. B must account for the emissions by reducing its reserve pool – the entity faces no direct cost. The entity then bids its 1000 MWh of contracted generation into A for $59/MWh (underbid to ensure the power is taken). The bid is accepted and the entity receives the prevailing price of $60/MWh. In total, the entity now realizes [revenues of $65,000 from customers plus $60,000 from A] less [contracted power cost of $$60,000 and imports of $50,000 and transmission tariffs of (2 x $2,000)] for a net revenue of $11,000. Note that if the bid of $59/MWh set the market price in A, then the entity would still be ahead, realizing a net revenue of $10,000. The price signal in A would now be weakened.

The team has concluded that the two approaches are compatible, provided that (a) the jurisdiction accurately monitors and tracks emissions from imported electricity for each compliance period; (b) power entering an FJD jurisdiction from the administrative approach jurisdiction incurs an allowance obligation unless the importer can prove a previous obligation; and (c) mutually acceptable arrangements are in place as necessary to address other circumstances.

Emissions Monitoring and Reporting under the Administrative Approach

Ideally, jurisdictions implementing the administrative approach would implement full reporting of emissions related to electricity imports. Full reporting may not be necessary, however, to carry out the administrative approach. Under the administrative approach it is only necessary to calculate emissions for aggregate electricity imports that "sink" in the jurisdiction. Some jurisdictions have the authority to require their utilities to report imports indirectly. For example, Washington and Oregon require all utilities to disclose annually their fuel mix for electricity sales to end users in their jurisdiction. Utilities are also required to identify the source of their fuels.

Partners can collect information through the Energy Information Agency (EIA) in the US and the National Energy Board in Canada, the Western Interchange Pool, e-tags and other sources to quantify and assess trends in imported electricity. Canadian provinces also typically have a single system operator for the province, which can provide a further source of information on imported electricity.

The OATI work product analyzing data from the Western Electricity Coordinating Council (WECC) is designed to estimate historical electricity imports into each WCI member jurisdiction in WECC from non-member areas and provides an example of a potential approach in answering this question. It provides records of aggregate 2005-2008 transactions from one balancing authority to another within WECC.

Thresholds for Applying the Administrative Approach

The Electricity Team was asked by Partners to consider the implications of applying an emissions and/or imports threshold as a condition to implementing the administrative approach rather than the FJD approach. The Partners recognize that the administrative approach does not remove the incentive to import electricity created when in-Partner generators are placed under the cap. While other measures can reduce the resulting displacement potential, thresholds could also be used to ensure that market effects are limited.

Partner jurisdictions with small imports or relatively minor emissions from imported electricity could use the administrative approach without significant market effects, provided imports and emissions remain below threshold levels.

For jurisdictions with low marginal cost generation as described previously, thresholds would not be necessary to address internal generation displacement. Thresholds based on historical import levels could form part of a mutually acceptable agreement as a means of tracking market effects and identifying the need for further measures.

Western Climate Initiative

To All Interested Parties:

The Western Climate Initiative Partners have expressed an interest in effective market oversight to ensure an efficient and transparent carbon market. The WCI's Markets Committee issued a Market Oversight White Paper in November, 2009, and Draft Recommendations April 1, 2010. The Committee requested comment on the Draft Recommendations by April 30, 2010.

The Draft Recommendations document identified twelve market oversight policy decisions. One of the identified decisions was whether or not to implement "holdings limits," limits on the number of allowances or offset certificates any entity could control. WCI Partners commissioned a consultant's report on this issue, to review the history, theory, and use of similar limits in other markets, as well as recommendations on their use in a regional cap-and-trade program. The Partners contracted with Dr. Jeffrey H. Harris of the University of Delaware to provide the report and recommendations. His work is attached, and available at the WCI website (http://www.westernclimateinitiative.org/component/remository/Markets-Committee-Documents/Report-on-Holdings-Limits/).

The WCI Partners intend to release final recommendations, including a recommendation on holdings limits, by June 30, 2010. To facilitate its deliberations, the Committee requests comment on the commissioned report by June 4, 2010. Dr. Harris will present his work and be available to answer questions during a webinar on May 25, 2010, at 11:00 a.m. Pacific Time. For audio, dial 1-800-868-1837 and use participant code 659 537#. To view the presentation, go to https://www.accuconference.com/customer/join/, enter the same conference number and participant code and a screen name. Comments may be submitted to the WCI website at http://www.westernclimateinitiative.org/public-comments/document/31.

Sincerely,

The Western Climate Initiative Markets Committee

Report on Holdings Limits

To the Western Climate Initiative Markets Committee

Prepared by Jeffrey H. Harris
Alfred Lerner College of Business and Economics
University of Delaware

May 6, 2010

Analysis of Holdings Limits
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Executive Summary

The Western Climate Initiative (WCI) Markets Committee aims to coordinate the development of recommendations on issues and elements needed to guide the proper development and operation of a robust allowance and offset credit trading market.

This report puts forth recommendations to the WCI Market Committee regarding the adoption and implementation of holdings limits for the proposed allowance and offset credit trading markets. The report discusses holdings limits in the broader context of efficient and effective market regulation, with an emphasis on how holdings limits might serve to mitigate manipulation in the secondary market for allowances and credits.

Key observations of this report are as follows:

- Market manipulation should be a concern for cash-settled contracts such as allowance and offset credit trading markets.
- Market manipulation reduces participation in the market, inhibiting trading volume, reducing market depth and adding to market volatility.
- The size of an individual trader holdings relative to the size of the market (contracts outstanding) or to the size of the market float (contracts available for trade) are appropriate metrics for monitoring/inhibiting market manipulation.
- Excessive trading can also be used to manipulate allowance and offset markets.
- Since trading behavior changes even with the threat of market manipulation, regulators in the allowance and offset credit markets should employ proactive market surveillance policies.
- Allowances and offset credits issued via primary market auctions and traded in a secondary market are susceptible to manipulation in both the auction and secondary markets.
- Auction design and secondary market trading are linked. Frequent auctions with broad-based access (and participation) can help to minimize manipulation in the secondary market.
- Extant theory on position limits requires an estimate of the price change tolerance of the regulator and a measure of illiquidity in the secondary market for trading of allowances. In this regard, theory is of little practical use to the nascent (prospective) market.
- Nevertheless, most derivative markets apply a form of holdings limits in deference to the real and active manipulation from various market participants.

In this light, and in consideration of the myriad components that contribute to the application of holdings limits, ***this report recommends that the WCI Market Committee apply holdings limits in the allowance and credit trading markets be set as 10 percent of the first 25,000,000 allowances issued plus 2.5 percent of any additional allowances issued each year.***

Section I. Manipulation and Market Power

In financial markets, manipulation involves actions that change market prices such that prices do not reflect the true fundamental value of the financial asset. When manipulation occurs, market participants may lose faith in the prices determined in the marketplace. In this light, participants may scale back or even cease to participate in markets subject to manipulation. Thus, a direct consequence of manipulation is that market quality suffers—when participation drops, trading volume falls, transaction costs increase, liquidity is diminished and the volatility of prices rises as well. In fact, the mere threat of manipulation can undermine confidence in market prices and therefore will have similar consequences.

Potential market manipulators, like other economic actors, respond to incentives in the marketplace. Manipulators typically reap economic gains (at the expense of other traders) as a result of their manipulative actions. Active market surveillance that sheds light on and imposes costs on manipulators can inhibit market manipulation. To the extent that manipulators seek economic rewards from their activities, market structures and surveillance cannot fully eliminate manipulation. Proper policies, however, can serve to tilt the balance of costs and benefits toward the goal of minimizing manipulation in the market.

This paper discusses holdings limits, one dimension of market design that can assist in limiting market manipulation. Importantly, holdings limits should be integrated with comprehensive market design, surveillance and penalty structures to be effective.[1] Indeed prospective holdings limits depend crucially on market regulators having both accurate holdings information and the authority to influence market participant holdings. Properly designed, holdings limits can tilt the power balance away from manipulators in favor of robust and efficient allowance and offset credit trading markets.

A. Forms of Market Manipulation

Manipulation can take on many forms. Manipulation may involve direct trading in the market to move prices or more indirect actions such as releasing erroneous information to other traders (whose trades, in turn, may push prices away from fundamental values). To inhibit manipulation in the former case, markets can establish rules regarding trading activities. To inhibit manipulation in the latter case, markets must implement more costly surveillance tools because actions taken away from the exchange are more difficult (and expensive) to monitor.

Although perhaps not directly related to the issue of holdings limits, various types of market manipulation are worthy of mention. In fact, a comprehensive set of rules

[1] A broad literature discusses whether various U.S. markets deter manipulation effectively and efficiently (see e.g. Abolafia (1985), Easterbrook (1986), Edwards and Edwards (1984), Fischel (1986), Fischel and Grossman (1984) and Fischel and Ross (1991)).

governing holdings limits should fit within an overarching market surveillance scheme, some of which relate more closely to these various manipulative strategies.

One form of manipulation, disclosure manipulation, involves information releases. Disclosure manipulation occurs when a market participant propagates false or misleading information regarding the value or volume of a security to other participants. In greenhouse gas markets, for instance, an end user may manipulate the market through false disclosures. Consider, for example, a major factory operator that anticipates (unbeknownst to the market) falling short of the necessary allowances in the near term. The factory operator might falsely release information that they have already adequately purchased the requisite number of allowances, thereby sending a false demand signal to the market. If the market believes that demand is lower than anticipated, market prices might fall, affording the opportunity for the manipulator to purchase the allowance shortfall at discounted prices.

Although large holdings may not indicate manipulation *per se*, large holdings may (even if inadvertently) convey misleading information to other traders in the market. Large holders, for instance, may be perceived as more credible (or more informed) to other market participants. To this extent, the holdings of market participants may be of interest to market regulators who are interested in deterring manipulative disclosures. And, as with most other manipulative schemes, traders with large holdings stand to benefit the most from successful manipulative efforts.

Action-based manipulation should also concern market regulators. Action-based manipulation involves deeds performed to affect the value of an asset by means other than trading. In the greenhouse gas market, for instance, an action-based manipulation scheme may involve an end user of allowances taking other less transparent actions to offset greenhouse gas emissions (such as planting trees) to reduce their demand for allowances while selling off allowances in the market. If these less transparent actions are not disclosed to market participants before the allowances are sold, the end user benefits from selling at artificially high prices. The market only partially learns of the decrease in demand when the allowances are sold. The full reduction in demand is only completely known with full disclosure of the alternative offset program.

Of course, actions are typically more costly for manipulators than are information releases (the tree planting program, for instance, may be quite expensive). The added expense of action-based manipulation is therefore likely to make these manipulative schemes less common, but they cannot be ignored altogether. As with other prospective manipulative schemes, a comprehensive surveillance program will consider the prospect when monitoring market participants.

Indeed, as with other types of manipulation, the size of holdings in the marketplace may not be directly related to the prospects of action-based manipulation. However, to the extent that large holdings are positively associated with a greater number of activities that could affect the secondary market for trading allowances (more diverse business activities, for instance), large holders may have greater opportunities to attempt and execute these schemes. Likewise, to the extent that action-based manipulation schemes create greater net benefits to large holdings, large holders should be monitored accordingly.

A form of action-based manipulation involves active trading in financial markets. Trade-based manipulation, for instance, has been modeled by Hart (1977), Jarrow (1992), Kumar and Seppi (1992), Allen and Gale (1992), and Chakraborty and Yilmaz (2004, 2008). In this form of manipulation, a trader can cause artificial price fluctuations simply by buying and selling an asset in hopes that other market participants follow suit. To the extent that large holdings convey the appearance of an information advantage to others in the market, traders with large holdings may be better able to induce others to follow suit on any manipulative trading strategy employed.

Although disclosure and action-based manipulations should concern market regulators, these forms are only tangentially related to holdings limits. They link to holdings limits only in the sense that large positions largely benefit the most from manipulative strategies, so that smaller holdings limits will necessarily reduce the prospective gains from manipulation. Market power is the primary concern of holdings limits, which we discuss in more detail below.

B. Market Power and Manipulation

The Federal Trade Commission defines market power as the ability of a firm to alter the market price of a good or service from competitive levels for a significant amount of time. In a perfectly competitive market, no participant possesses market power so that all market participants can be sure that prices observed in the marketplace represent the fair value for the good or service provided. Perfect competition can be predicated on a market having infinite numbers of buyers and sellers, on no barriers to entry, on perfect information (known to all participants), on zero transaction costs, on homogenous products and on firms consistently behaving as profit maximizers.

Of course, real world conditions dictate that markets commonly reflect less-than-perfect competition. No market can have large numbers of (let alone an infinite number of) buyers and sellers at all points in time, for instance. When markets are less-than-perfect, some participants can have market power, an advantage over others. Market participants that have market power can be alternatively referred to as "price makers," while those without market power are “price takers.”

Market power traditionally results from a participant’s control of a significant portion of or information about the market. These participants may be able to erect barriers to entry and/or gain proprietary information that is not known to others, creating further impediments to a perfectly competitive market. Ultimately those holding market power and setting prices might profit at the expense of others, discouraging price takers from participating. Market regulators, therefore monitor and surveil market participants in an effort to foster competition and limit market power that may distort fair prices for all.[2]

The Lerner (1934) and Herfindahl-Hirshman (HHI) indexes are commonly used to measure market power within specific product markets. In the area of antitrust, the HHI is used to evaluate the effect of proposed mergers on social welfare, industry prices and output. The HHI metric can capture the welfare loss (relative to perfect competition) of various industry structures. Importantly, the metric is typically applied to product markets where market power or collusive agreements can reduce output.

Regulatory Point #1: In allowance and offset markets, market concentration (large holdings) can create distortions in market prices.

In the context of allowance and offset credit markets (and financial markets more generally), market concentration might also create distortions in pricing. There is a tradeoff between market liquidity and the risk of holding large positions. Market makers have to be compensated for holding larger positions (Grossman and Miller (1988)). If any single trader demands liquidity that exceeds the supply of liquidity available from market makers, this liquidity demand may push prices higher.

For the allowance and offset credit market, the potential for price distortions is a real and tangible threat. Holders of allowances and credit offsets are likely to be more interested in holding (and perhaps even encouraged to hold) for the long term rather than in providing liquidity. For this reason these traders are unlikely to be induced to contribute liquidity to the market during periods when liquidity is in short supply until prices change quite substantially.

To illustrate the potential for short-term price distortions, consider a common manipulation scheme known as "banging the close" in which a large trader might take advantage of an illiquid market. Traders with relatively larger trading positions have a greater incentive to influence closing prices (which typically serve as price benchmarks to the investing public) since the cost of affecting closing prices is the same for all traders, but the gains to changing closing prices are proportional to the trader's position.[3] To "bang the close" a trader would engage in uneconomic trading to influence closing prices to their advantage. For instance, a trader holding a long position may buy substantial quantities leading up to the close in order to raise the value of the rest of their holdings (even if there were no other reason to buy).

If manipulation schemes like "banging the close" are of concern, then potential holdings limits would best be defined in terms of market share—that is, holdings limits should be set proportional to the number of outstanding allowance and offset credits. Large holders have a greater incentive to manipulate the market since they stand to benefit

[2] Market power can also be a result of collusion by multiple market participants, so that regulatory oversight should not simply focus on individual firms, but should also include dimensions to oversee interactions among multiple market participants.
[3] For this reason, larger positions (or large traders more generally) are typically monitored more closely than small positions (traders).

most from existing holdings. In addition, since larger markets are generally characterized by greater liquidity, small holders are unlikely to affect market prices. Therefore, the relevant regulatory concern is the size of an individual trader's holdings relative to the size of the market.[4]

Regulatory Point #2.1: The size of individual trader holdings relative to the size of the market should be the focus of regulation in allowance and offset markets.

1. Market Power-based Manipulation Theory

A number of market power-based manipulation theories demonstrate that manipulation can occur in both continuous trading markets and auction markets. Many of these models are relevant to the question of holdings limits in greenhouse gas markets, given that they rely on the relative market share or market power held by individual (or groups of) traders. Market manipulation affects asset prices and, by extension, derivative prices that are based on asset prices. In the economic sense, manipulation drives prices to levels that do not reflect intrinsic economic value (often referred to as fundamental value). Pirrong (1995) articulates the detriments of market power-based manipulation. He notes that market power-based manipulation is bad for the market and impedes the price discovery and risk management purposes of financial derivatives markets by distorting patterns of trading and consumption. Indeed, market participants other than the manipulator are victimized by losses when they transact at prices other than fundamental value.

One common form of market power based manipulation involves a market squeeze. Market squeezes occur when a long trader holds a position representing a quantity that is larger than what might be reasonably supplied to the market without distorting prices. When demand or supply do not immediately adjust to traders wishing to trade a large number of contracts, market squeezes can also distort prices in the short run (see Figlewski (1984) and Merrick (1988)). Sustained squeeze-generated price distortions dissipate the economic role of futures and forward markets (and, by extension, to other hedging instruments) by significantly reducing the effectiveness of a contract for hedging. In this regard, manipulation of derivative markets arising from market power can also generate social costs by diminishing or even eliminating hedging opportunities.

The cash settlement feature of allowance and offset markets minimizes the potential for market squeezes, since the cost for cash settlement is typically much lower than for physical settlement. Agricultural products, for instance, involve significant storage and transportation costs which are largely irrelevant to allowance markets. However, squeezes may be possible in allowance markets as well, if individual trader positions exceed the quantity available for purchase or sale.

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[4] Indeed, more than one trader might simultaneously attempt to change prices, so that a measure of aggregate concentration may also be relevant. In two-sided markets, the disparity of concentration between the long and short sides might be most relevant. With high concentrations on each side of the market, traders attempting to move prices upward would be met with an equal and opposing set of traders attempting to move prices downward, with the net effect on prices perhaps close to zero.

Pirrong (2008) notes that there is a difference between the total number of allowances or offset credits issued and the number readily available for purchase or sale. In economic terms, the available supply of contracts is known as the float. In theory, as noted above, the size of individual trader positions relative to the size of the market should be the focus of regulation. However, although perhaps not immediately evident, the size of the market for allowance and offset credits is not necessarily the same as the market float. In that the float more adequately describes liquidity available to the market, the potential for market manipulation may be more likely related to the relative size of individual trader positions to the float (rather than to the number of contracts outstanding).

Regulatory Point #2.2: The size of individual trader holdings relative to the size of the float in the market should be the focus of regulation in allowance and offset markets.

Some theories focus on how manipulators can use an excessive number of trades to exert market power to their benefit. Leoni (2008), for instance, examines how a single "strategic agent" can use market power in financial markets to strategically affect the market prices.[5] In this model, other market participants make forecasts about the ability of the strategic agent to exert market power and account for these forecasts when they trade. In this framework, the strategic agent uses high levels of trading volume to create the opportunity to *indirectly* control market prices. These theories provide some incentive for regulators to not only consider holdings limits, but to also limit excessive trading.

Regulatory Point #3: Excessive trading can also be used to manipulate allowance and offset markets.

Pirrong (2008), building on Pirrong (2004), examines various market power based manipulations scenarios in futures markets. He demonstrates that short traders who have information that a dominant long trader has market power will rationally partially (or entirely) liquidate positions prior to expiration to avoided being squeezed. In this regard, even the threat of manipulation in the allowance and offset markets can change trading behavior. In fact, the prospect of manipulation alone can increase trading costs for other participants as some traders will pay a premium for protection against manipulation. To the extent that market regulation can deter manipulative schemes, effective regulation reduces the premium paid for protection, making most other participants better off while encouraging greater market participation.

Regulatory Point #4: Even the threat of manipulation can change trading behavior so regulators should also be proactive in market surveillance activities.

[5] This work builds on Sandroni (2005).

Auction markets can also be manipulated. Inspired by the Salomon Brothers' Treasury note manipulation episode of 1991[6], Chatterjea and Jarrow (1998) determine that market power-based manipulation can occur when an auction market is accompanied by secondary market trading in the same product—conditions that exist in the allowance and offset credit markets.

In the Chatterjea and Jarrow model, a potential manipulator observes order flow in the forward market to assess demand and then overbids in the primary auction market to obtain a dominant market share and market power. The manipulator, holding a dominant long position, then profits from short traders who need to deliver in the forward market. Importantly, Chatterjea and Jarrow document that this type of manipulation depends on the structure of the auction. Manipulation is possible in a discriminatory auction format in which the winner pays the price of their bid but likely would not occur in a uniform price auction where all winners pay the price of the last accepted winning bid.[7]

Nyborg and Strebulaev (2004) revisit the topic of multiple unit auctions and short squeezes. They conclude that there is a tradeoff when designing an auction format: discriminatory auctions will generate more revenue for the party holding the auction but are more susceptible to short squeezes while uniform auctions will neutralize the effectiveness of a market power based manipulator.[8]

Regulatory Point #5: In allowance and offset markets, information from order flow in the secondary market can be used to manipulate the primary auction market. The manipulator gains market power from large holdings generated in the auction.

The design of the auction market has implications for the potential for market manipulation along other dimensions as well. An auction that is limited to participants that produce greenhouse gases directly will, by definition, have a smaller market float. As noted above, markets with relatively smaller market float are more susceptible to manipulation so that a prudent auction design (intended to minimize manipulation) includes broad-based access to the allowance auction process.

2. Empirical Evidence on Market-power Based Manipulation

Examples of market power-based manipulation incidents abound in a host of markets around the world.[9] Most existing empirical work on manipulation relies primarily on

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[6] Salomon bid aggressively in the May 1991 auction for two-year Treasury notes and ultimately controlled 94% of the securities. Using market power Salomon squeezed short traders in the pre-auction forward market, causing significant losses for others (US Government (1992)).
[7] Jarrow (1994) also notes that cash markets accompanied by derivative trading also create the opportunity to manipulate.
[8] See also empirical evidence from the 1991 Treasury auctions in Nyborg and Sundaresan (1996).
[9] Recent international examples include the 1997 squeeze of the London International Futures and Options Exchange's Italian Government Bond futures contract and the 1996 Tokyo Stock Exchange market power manipulation of Japanese government debt. A partial list of high-profile events within the U.S. include the 1991 Salomon Brothers T-note squeeze noted above and manipulation attempts in oil

price data (see, for instance the empirical analysis of squeezes in Jegadeesh (1993) and Jordan and Jordan (1996)). In a notable exception, Merrick et al. (2005) combine trader position data with price data to develop a more richly-detailed view of an attempted delivery squeeze in the U.K. gilt bond futures contract. They document that prices become distorted from their fundamental values as a result of the attempted squeeze. Market depth is also diminished by the attempted squeeze, demonstrating that other traders actively respond to attempted manipulation schemes to the detriment of market quality.

Regulatory Point #7: Market manipulation reduces participation in the market, inhibiting trading volume, reducing market depth and adding to market volatility.

Section II. Manipulation and Contract Design

Various contract design features affect the level of concern about potential manipulation. In addition to the auction features, settlement terms, the frequency of allocative auctions, and rules for banking/contract expiration can each affect manipulation in greenhouse gas allowance and offset markets. The following discusses settlement terms and the frequency of auctions/banking terms in more detail.

A. Cash vs. Physically Settled Contracts

There are two major types of settlement that exist in derivatives markets. Physical settlement requires the delivery of the underlying asset of the contract. The seller normally transfers the physical asset to the exchange, which in turn transfers it to the buyers of the contract. Physical delivery is commonly practiced in the commodity and bond markets although actual delivery of the underlying asset rarely occurs in practice as traders typically offset their positions in the market before the delivery date. Cash settlement involves a cash payment based on the underlying reference rate, such as an index or asset value. Counterparties settle by paying/receiving the loss/gain related to the contract at expiration.

Much of the literature on manipulation distinguishes between cash and physical settlement since these contract terms affect the manipulator's incentives. Although much of this research does not directly apply to holdings limits, contract settlement terms often affect the risk faced by traders. Holding the benefits of manipulation constant, a potential manipulator facing lower risk from settlement terms may be more likely to act nefariously.

Physical settlement has been criticized in the literature since physical settlement creates an opportunity for market power and delivery manipulation to occur.[10] Physical

(1996), tin (1980-1981, 1984-1985), silver (1979-1980), and soybean (1977) markets. See Jarrow (1992) and Pirrong (1995) for additional episodes.

[10] In fact, some investment funds are not allowed by rule to establish positions in physically-settled markets because they risk being left with the underlying asset. Garbade and Silber (1983) argue that the

settlement also puts more a strain on exchanges which have to organize, monitor and maintain a fair and orderly delivery process. Lien (1989) analyzes the hedging effectiveness of cash and physically settled contracts. While largely disregarding factors like market manipulation and the accuracy of prices in the cash market, he illustrates that cash settlement is generally preferable to physical settlement.

Two events in the derivative markets generated a relevant strand of literature that empirically compares the performance of financially and physically settled contracts. The first event involved the switch from physical to cash settlement for the feeder cattle futures contract trading on the Chicago Mercantile Exchange (CME). The second is the switch from cash to physical settlement for Australian individual share futures contracts.

For CME feeder cattle, Rich and Leuthold (1993) examine robust cash prices from 27 reporting stations to show that markets are uniformly more stable (and resistant to manipulation) under cash settlement terms.[11] Lien and Yang (2004) examine a move in the opposite direction--the switch from cash to physical settlement for Australian individual stock futures traded on the Sydney Futures Exchange. Employing robust econometric techniques, they find consistent results that cash settlement terms provide more robust market prices--both spot and futures market variability are higher with physical delivery.

Although cash settlement may make markets more robust to manipulation in a relative sense, research shows (see e.g. Jones (1982), Garbade and Silber (1983) and Cornell (1997)) that market manipulation can still disrupt, and perhaps render impractical, cash-settlement of derivatives contracts. Indeed, as Cornell and Kumar and Seppi (1992) point out, illiquid assets do not make good candidates for cash-settlement terms since illiquid assets are more prone to market manipulation. For instance, manipulation of a physically-settled contract may involve relatively expensive delivery of the underlying asset.

Kumar and Seppi (1992) build upon Kyle (1985) and model manipulation in cash-settled markets within a two-period setting with asymmetric information. They demonstrate that cash settlement inhibits corners and squeezes in derivatives markets, but manipulation can still exist in the spot market.

The cash-settlement feature of the proposed Western Climate Initiative allowance and offset credit market should help mitigate concerns about market manipulation. Jones

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high cost of delivery for physically-delivered contracts induces short investors to take precautionary actions to prevent squeezes, perhaps skewing market prices. Additionally, long investors who want to avoid costly delivery may flock out of the market simultaneously, also affecting market prices.

[11] Elam (1988) first examines the effect of change in settlement procedures in feeder cattle markets. Schroeder and Mintert (1988) expand the Elam hedge ratio model to Texas, Kansas, Missouri and Illinois feeder cattle cash markets while Kenyon et al. (1991) examine the Oklahoma City and Southwest Virginia markets. Subsequently, Schmitz (1997) and Lien and Tse (2002) show reduced risk for live cattle warehouse certificate delivery and cash market feeder cattle delivery markets (relative to physical delivery).

(1982) notes that financially settled contracts are also superior to physically settled contracts for convergence (a measure of effective pricing between spot and derivative assets) if, among other things, the underlying cash market is immune to manipulation. Generally speaking, the literature suggests that cash settlement improves market quality and provides relatively lower risks during the settlement period.

B. Auction Frequency and Banking Allowances

The design of the greenhouse gas allowance and offset market has implications for the propensity for these markets to be squeezed. For example, it is likely that the regular issuance of new allowances will create incentives for traders to attempt a squeeze when new allowances are forthcoming. It may be optimal for traders to sell off positions in advance of these auctions, even when allowances have no expiration date and might be carried over/banked from period to period (Pirrong (2008)). As traders sell off positions, the market may become less liquid and more prone to market squeezes.

The ability to carry over allowances across auction cycles may help to bolster liquidity in the period leading up to new auctions. The caveat, of course is that simply having more allowances outstanding does not ensure that liquidity will be added into the market. As discussed above, the market float of allowances does not always equate to the number of outstanding allowances. If long-term participants are not induced to provide liquidity without sufficient price incentives, the ability to carry allowances forward may not bolster liquidity. However, other things being equal, market liquidity can be no worse off with the ability to bank allowances.

Section III. Market Regulation and Holding/Position Limits

It is often difficult to differentiate between legitimate economic trades and manipulative trades. In fact, it is even more difficult to differentiate accurately in a timely fashion, that is, either during or shortly after a manipulative event. Pirrong (1996) argues that this difficulty is best addressed by applying severe *ex post* penalties on manipulative behavior. In this light, strong punitive measures can help to deter potential manipulation. However, as Pirrong (1996,1997) notes, strong *ex post* penalties have not always been effectively imposed by U.S. courts and markets. These facts perhaps explain why markets have applied various other regulatory tools (including holding/position limits) to deter market manipulation.

In the interest of preserving fair market prices for all, many financial market regulators use a combination of reporting thresholds, position limits, position accountability levels and market surveillance activities to monitor the trading of individual market participants and groups of market participants. In order to best monitor trader behavior, many markets require periodic reporting of trading positions to a market regulator and/or market operators. Reporting thresholds typically balance the cost of reporting with position sizes so that relatively small positions may not have to be consistently reported. Given the fixed cost of reporting, small positions are commonly exempt from reporting.[12] As a rule, however, market surveillance activities depend critically on the availability of accurate trading and position data.

Given the availability of position data, position limits can serve to complement market surveillance activities in financial markets. Indeed position limits can be applied differentially across time and across markets. In U.S. futures markets, for instance, different position limits are applied to the spot (delivery) month and across both individual contract months and for all months combined. For cash-settled contracts, the settlement period is an important time. During the settlement period transitory volatility may result when hedged traders unwind positions without enough liquidity available in the market.

Position accountability levels represent a somewhat less restrictive regulatory tool. Accountability levels are typically set for large positions that hold the potential for manipulative market behavior. In this sense, a trading position rising to an accountability level may trigger greater reporting requirements or may require enhanced interactions between market regulators and the trader. Accountability levels typically do not serve as hard and fast limits, but rather as thresholds that signal to regulators the potential for market manipulation. The market regulator typically reserves the right to greater control over the trader's positions when accountability levels are crossed. As the name suggests, a position accountability level typically triggers greater accountability from traders exceeding the level. For instance, a trader holding a position that exceeds and accountability level may be forced to report more details about their trading intent, may be precluded from adding to their position, or may even be forced to liquidate a portion of their position as the regulator sees fit.

In this context, holdings limits serve as one tool among many for market regulation. At one end of the spectrum, position reporting serves as a baseline for collecting appropriate position data. Accountability levels serve to trigger differential regulatory oversight to various positions. Holdings limits more strongly prohibit trader positions from exceeding a given size. Each can be valuable tools among the many strategies employed by market regulators in applying efficient and effective surveillance mechanisms to ensure market integrity.

A. Holding/Position Limit Theory

Extant theory on holding/position limits remains relatively sparse, particularly theory applied to cash-settled contracts. Nevertheless, the disruptive trading of manipulators in cash-settled derivatives markets is typically thought to be isolated at or near the time of cash settlement. Although there is little theory on applying a timeframe for position limits, markets typically consider short horizons (of a few days, or perhaps a week) prior to settlement as candidates for limits.

[12] The U.S. Commodity Futures Trading Commission (CFTC), for instance, sets reporting thresholds individually by market to ensure that their Large Trader Reporting System includes 70-90 percent of open interest in each futures contract.

For physically-delivered contracts, Kyle (1984) develops a theoretical model where position limits can be effective in limiting the ability of traders to manipulate the market. This model analyzes market manipulations, specifically squeezes in the deliverable contract month, and draws conclusions as to how more general policy applications might be utilized to reduce price distortions that result from market squeezes. The Kyle model can be applied to analyze a variety of policy applications, including delivery differentials, additional deliverable supply, cash settlement, and position limits. As his theoretical model pertains to position limits, Kyle concludes that effective position limits can be devised to reduce market manipulation at contract expiration for physically settled contracts. He notes, however, that successful position limit policies would also need to address the difficulty and ineffectiveness of monitoring positions owned by different traders actually managed collectively.

Dutt and Harris (2005) note that cash-settled contracts can also be subject to manipulation schemes, particularly from disruptive trading of large positions near the settlement date. In light of the fact that optimal position limits depend on information that is not available in practice, they devise a general model of *prudent position limits* as a function of:

- the market regulator's tolerance for price changes,
- a contract multiplier (a measure of the size of the contract) and
- the illiquidity of the underlying instrument.

Dutt and Harris begin by modeling a trader's incentive to manipulate the market. That is, they presume that the benefits of manipulation will be proportional to the aggregate size of manipulative trades while the cost of the manipulation will be proportional to the square of the aggregate size of manipulative trades. As the manipulator trades, prices are pushed further away from true economic value so that costs increase faster than the benefits. Eventually then, a manipulator faces the tradeoff between the cost of being discovered and the benefits reaped by manipulative trading. When the costs exceed the benefit, the manipulator will cease trading.

Ultimately, and more specifically, Dutt and Harris determine that prudent position limits are dictated by the regulator's price change tolerance divided by an illiquidity measure. We discuss applications of this model to allowance and credit markets in Section IV below.

B. Empirical Evidence

Research papers by Gastineau (1992), Telser (1993) and Grossman (1993) each question the wisdom of imposing position limits to address manipulation concerns. For the most part, these papers typically note that effective surveillance programs make positions limits unnecessary. Gastineau and Telser specifically propose that surveillance should be favored over limits, while Grossman states that position limits can force trading into alternative markets. While thought-provoking and provocative, these studies simply argue their case and do not provide empirical support for their claims.

Importantly, however, Dutt and Harris (2005) take their model to the data using empirical limits from cash-settled derivatives markets like equity index futures and options markets. Using data from the Chicago Mercantile Exchange, the Chicago Board of Options Exchange, the Philadelphia Stock Exchange and American Stock Exchange, Dutt and Harris find that existing position limits far exceed the prudent position limits that their model proscribes for most equity index futures and options products. In fact, they find almost no correlation between their prudent limits and those applied by these exchanges.

Nevertheless, the Dutt and Harris framework provides a framework for assessing prospective holding limits. They demonstrate that the liquidity of the market is an important determinant of limits. For example, contracts based on narrow indices of illiquid securities may benefit more from position limits than contracts based on liquid securities.

This research highlights, more generally, how position limits can minimize manipulation by limiting the size of derivative positions and notes that, compared to the costs of added surveillance, these benefits are potentially achieved at a lower cost. The authors find that current derivative index limits are not consistent with the limits proposed by the model, which suggests possible sources of economic inefficiency.

Section IV. Determining Holding/Position Limits

In practice, holding/position limits have been utilized in conjunction with other regulatory mechanisms such as market surveillance activities, large trader reporting requirements, and position accountability levels. In U.S.-regulated futures markets, position limits have been set for single month contracts, for specific products (all months combined) and for the delivery month. Jurisdiction for setting position limits in the U.S. is typically delegated to the futures exchange except for agricultural products, where Federal position limits are set and administered by the CFTC.

Most of these limits include exemptive relief for *bona fide* hedging purposes. Commercial entities engaged in the market for hedging purposes are typically exempt from limits since their holdings are presumed to relate to risk management activities emanating from the operation of commercial activities. Notably, however, exemptions are typically granted and monitored by the market regulator to ensure that the trading activities of these commercial firms do indeed represent risk management. In this regard, greenhouse gas emitters might also be considered for exemptions, but should be subject to reporting requirements and regular review by the regulator.

In determining position limits by market, the regulator typically weighs the benefits of developing market liquidity with the potential harm that might result from manipulation by large position. Federal limits on agricultural products are currently set by formula, using a two-tier structure. Federal limits are set as 10 percent of the lagged (by one year) open interest in contracts up to 25,000 contracts and 2.5 percent of open interest thereafter (see Table 1).

The two-tier structure allows for greater market share in less liquid markets, allowing traders to aggregate up to 10 percent market share in order to facilitate market liquidity when the market is realtively small. For markets that develop and expand beyond 25,000 contracts, liquidity concerns are mitigated while the concern for manipulation is increased. With the second tier limits imposed, the allowable positions shrink as a percentage of market share. For instance, with a 50,000 contract market, limits are set at 3,125 contracts (10 percent of the first 25,000 plus 2.5 percent of the next 25,000), representing just 6.25% of market share.

The CFTC revisits the position limits annually in order to adjust limits based on the formula. Indeed, although these Federal limits are reassessed annually to reflect the current size and liquidity of the market, the CFTC does not necessarily apply the formula mechanically. When the formula calls for an increase in position limits, the CFTC commonly asks for public comment. Consistent with the Dutt and Harris (2005) model, the CFTC appears to exercise judgment in their tolerance for higher position limits. Given concerns about agricultural prices, for instance, most agricultural position limits have not been adjusted upward in the past three years, despite a marked growth in open interest. This results in most current agricultural position limits to be somewhat below the limits that would otherwise be dictated by the Federal formula.

In the realm of European carbon trading, there are two notable exchanges: Bluenext, a Paris-based climate exchange offering spot and futures contracts and the European Climate Exchange (ECX), a U.K.-based climate exchange offering spot, futures and options contracts. Bluenext lists contracts for European Union Allowances (EUAs) , which are allotted by member states and Certified Emission Reductions (CERs) while the European Climate Exchange lists contracts on CERs. EUAs are now issued via a uniform price auction of 400,000 allowances amounting to 10% of global supply. Derivatives traded in Europe are physically settled.

Volume on the two exchanges has increased in notional value from €2.1 billion in 2005, to €68 billion in 2009. With contracts listing on ICE Futures Europe, the ECX has the lion's share of trading volume among global climate exchanges. Figure 1 below presents global exchange volumes.

Investors in the ECX include compliance-based traders who have emissions to offset (e.g. Industrials, Utilities), intermediaries/investors (e.g. Banks, long only funds), project developers, and speculators.

The contracts traded on the ECX fall under the regulation of the U.K.'s Financial Services Administration (FSA) and follow a similar compliance structure that applies to other products on ICE Futures Europe including Brent Crude Oil and West Texas Intermediate Crude Oil contracts. All market participants have daily trading limits in place determined by their Clearing Member. The ICE Futures Europe compliance department constantly monitors the level of open interest per market participant as well. Although no specific position limits are applied in advance, if a position is suspicious then the participant will be contacted for accountability. If deemed necessary, traders will be asked (or perhaps forced) to reduce the size of the position.

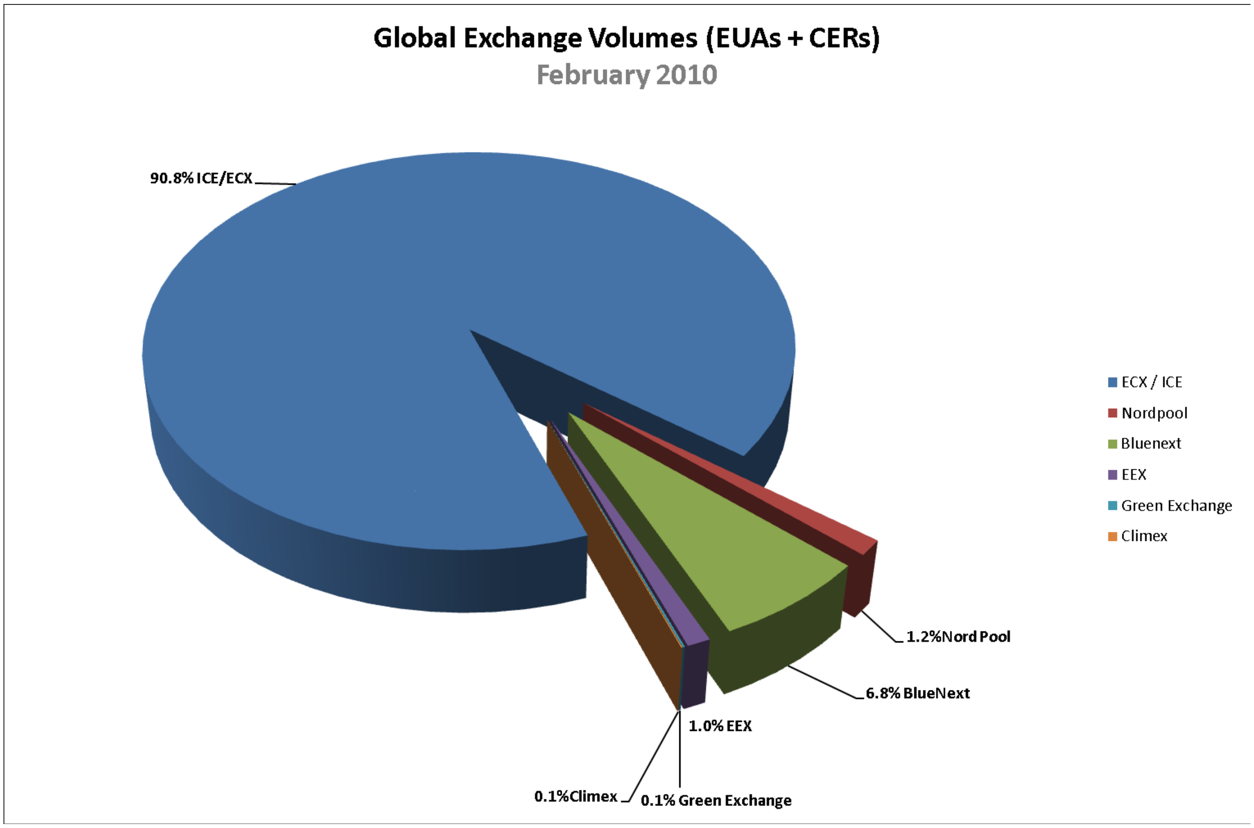

Figure 1: Global Exchange Volume of European Union Allowances (UARs) and Certified Emission Reductions (CERs)
Source: European Climate Exchange

In addition, the exchange applies a "bust range" of €0.50 to ECX contracts. The bust range limits bids and offers to prices no lower or higher, respectively, than €0.50 from the last traded price. The bust range was lowered in 2009 from €0.85 as a precautionary measure to prevent high/low ticking (which would be classified as market manipulation).

Both theory and practice can help guide in determining the optimal level of holding limits that might be applied in greenhouse gas allowance and offset trading markets. Theory (Dutt and Harris (2005)) dictates that both the market regulator's tolerance for price changes and the illiquidity of the underlying instrument should play a role. Unfortunately, for a market with only prospective trading and nascent regulation, theory offers little practical advice since neither component is known.

However, empirical work in the stock market presented in Dutt and Harris suggests a common risk tolerance might be to allow for a three percent change in prices. Likewise, they present stock illiquidity measures ranging from below 27 to above 752, with a mean near 150.[13] Empirically, then, this model suggests an extremely wide range of prudent position limits differing by a magnitude of thirty or more (the ratio of 752 over 27).

Once trading begins in the market, an empirical estimate from allowances can be attained (although since market liquidity can vary over time, an average illiquidity measure can only approximate an optimal position limit level). In the meantime, we are left with existing practice as a guide. Given that the FSA does not publicly disclose position limits, the CFTC limits must suffice along this dimension.

Section V. Holding Limit Recommendations

Theory suggests that limits on trader holdings can be combined with more costly surveillance activities to effectively regulate markets. As discussed above, market regulators can apply a myriad of contract terms, market mechanisms, surveillance activities, and trading rules in order to best minimize the prospects of manipulation in allowance and offset credit markets. Any recommendations for applying holdings limits should not only be grounded in theory, but should also be anchored to the specific characteristics of the market that also relate to manipulation.

In terms of contract design, we know that cash-settled contracts are less prone to manipulation relative to physically-settled contracts.

In terms of market design, we know that participation in the primary auction for allowances can have an impact on potential manipulative activities. To the extent that allowance auctions are open and accessible to a wide variety of participants, this feature makes the secondary market less prone to manipulation.

However, since the market float can be a significant factor in manipulative schemes, the ability for participants to bank allowances from year to year might reduce market float and increase the potential for manipulation.

Unfortunately, extant theory (Dutt and Harris (2005)) on position limits requires an estimate of the price change tolerance of the regulator and a measure of illiquidity in the secondary market for trading of allowances. In this regard, theory is of little practical use to the nascent (prospective) market with no trading history and limited regulatory experience.

Additionally, most markets apply some degree of holdings limits to contracts, recognizing the real possibility of manipulation in derivatives markets.

In this light, it would be prudent to recommend that greenhouse gas allowance and credit markets implement holdings limits be set with the two-tier structure applied to futures markets. Namely, holdings limits should be set as 10 percent of the first

[13] ITG Inc. and Goldman, Sachs graciously shared illiquidity measures for this exercise. Notably, illiquidity measures from the two sources overlap, but differ substantially at the extremes.

25,000,000 allowances issued plus 2.5 percent of any additional allowances issued each year. This two-tier structure allows for greater market share as the nascent market develops liquidity, and scales back (in terms of market share) as the market grows and matures.

To illustrate, assume an initial allocation of 250,000,000 allowances in the first year of the program. Traders not allocated allowances for commercial greenhouse gas emissions would be limited to holdings that do not exceed 8,125,000 allowances during this first year (10 percent of 25,000,000 plus 2.5 percent of the next 225,000,000), representing just 3.25 percent market share. Assuming the cap-and-trade program expands in the second year to an allocation of 300,000,000 allowances, traders would be subject to holdings limits of 8,750,000 allowances (or 2.9 percent market share).

These holdings limits should be applied to any entity that is not allocated allowances to offset commercial emissions of greenhouse gases. The holdings of commercial entities (firms which are allocated allowances) will be dictated by rules governing annual allocations and the banking of allowances from year to year.

Importantly, this report recognizes that the adjustment and maintenance of holdings limits is a dynamic process and this recommendation should be viewed in that light. In a new market with little information, the recommendation falls back on tried and true mechanisms that have been applied successfully in U.S. futures markets. As the nascent market for allowances and credits matures, these limits should be reassessed for an appropriate fit.

Table 1: Summary of Current Position Limits on Various Futures Exchanges

Panel A: Chicago Board of Trade-listed Contracts

CBOT			
Contract	**Spot Month**	**Single Month**	**All Months Combined**
Corn	600	13,500	22,000
Oats	600	1,400	2,000
Wheat	600	5,000	6,500
Soybeans	600	6,500	10,000
Soybean Oil	540	5,000	6,500
Soybean Meal	720	5,000	6,500

Panel B: Chicago Mercantile Exchange-listed Contracts

CME			
Contract	**Spot Month**	**Single Month**	**All Months Combined**
Live Cattle	450	5,400	
Lean Hogs	950	4,100	
Pork Bellies	100	800	1,000
Feeder Cattle	300	1,600	

Panel C: New York Mercantile Exchange-listed Contracts

NYMEX					
	Position Limits			**Accountability Levels**	
Contract	**Spot Month**	**Single Month**	**All Months Combined**	**Single Month**	**All Months**
Cocoa	300			6,000	6,000
Coffee	100			5,000	5,000
Cotton	50	2,500	5,000		
Sugar	100			9,000	9,000
Crude Oil	3,000			10,000	20,000
Natural Gas	1,000			6,000	12,000
Heating Oil	1,000			5,000	7,000
Gasoline Blendstock (RBOB)	1,000			5,000	7,000

Panel D: Intercontinental Exchange-listed Contracts

ICE					
	Position Limits			Accountability Levels	
Contract	Spot Month	Single Month	All Months Combined	Single Month	All Months
Cocoa	1,000	3,500	5,000	6,000	6,000
Coffee	500			5,000	5,000
Cotton	300				
Sugar	5,000			10,000	15,000

Panel E: COMEX-listed Contracts

COMEX			
	Position Limits	Accountability Levels	
Contract	Spot Month	Single Month	All Months
Gold	3,000	6,000	6,000
Silver	1,500	6,000	6,000

Panel F: Treasury Contracts

Treasuries	
Auction Award Limit	35% of auction - Net Long Position

Panel G: Listed Option Exchanges

OCC Option Exchanges Dependent on underlying stock trading volume (Net Position)
250,000
200,000
75,000
50,000
25,000

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Further Reading

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May 14, 2010 Commissioned Report on Holdings Limits

List of Commenters

International Emissions Trading Association

Morgan Stanley Capital Group Inc.

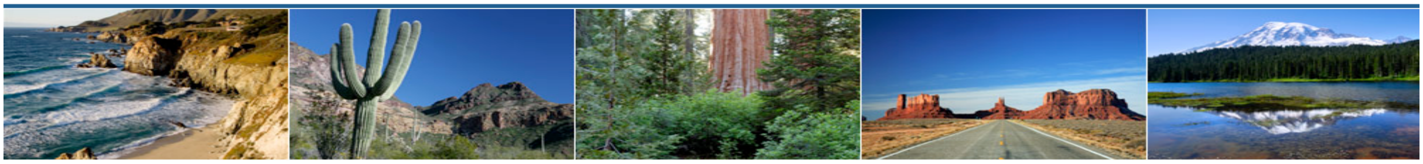
Pacific Gas and Electric Company

RRI Energy, Inc.

Southern California Public Power Authority

Western States Petroleum Association

Western Climate Initiative



Public Announcement
Treatment of Renewable Energy Certificates in the WCI Cap-and-Trade Program

Several states have passed renewable portfolio standards that require electricity load-serving entities to include a minimum amount of renewable electricity in the portfolio of electricity sources used to serve their customers. Most of these programs use Renewable Energy Certificates (RECs) to track compliance and ensure that no renewable megawatt hours are double-counted.

Many states with renewable portfolio standards allow RECs to be sold separately from the generated electricity. The electricity from which RECs have been separated is often referred to as “null” power. In order to prevent double counting of the zero-GHG attribute of renewable electricity in greenhouse gas (GHG) cap-and-trade programs, either the null power or the RECs should carry the zero-GHG attribute. If RECs carry the attribute, they could be bundled with electricity from other sources to negate or reduce the compliance obligation associated with the electricity. Under this approach, WCI Partner jurisdictions would then have to attribute emissions to the null power in order to maintain accurate GHG accounting; otherwise, reported emissions would be lower than actual emissions.

The WCI Partners recommend that RECs have no role in the WCI Partner jurisdictions’ mandatory GHG reporting and compliance protocols. Under this approach, the compliance obligation of first jurisdictional deliverers of electricity would be based only on the actual GHG emissions occurring as a result of generating electricity (as described in the Design Recommendations for the WCI Regional Cap-and-Trade Program). First jurisdictional deliverers with a GHG compliance obligation would not be able to use RECs to reduce their compliance obligations, and null power would not have GHG emissions attributed to it.

Western Climate Initiative News

May 17, 2010

This status report is issued monthly from WCI Partner jurisdictions to all interested stakeholders via the WCI list server and website.

Upcoming Events

May 19: Benchmarking Symposium in Seattle

The WA State Department of Ecology and the WCI will host a GHG Benchmarking Symposium from 8:30 am to 4:30 pm at The Westin in downtown Seattle. Speakers, panelists, and participants will discuss what benchmarks are, how they can be constructed, and the leading policy approaches for using benchmarks to reduce GHG emissions. Click here to register your attendance (there is no fee) or to obtain an agenda, webinar, and other meeting information.

May 20: Partners Meeting in Seattle

Stakeholders are invited to attend the next WCI Partners meeting in-person or via teleconference on May 20 at The Westin in downtown Seattle. There is no charge to participate in the meeting, but participants planning to attend in-person are asked to register to ensure sufficient capacity. To join the meeting via teleconference, dial 1-800-868-1837, and enter code 659 537# (1-404-920-6440 for outside the U.S. and Canada). The agenda is posted here.

In This Issue

British Columbia Introduces Updates to Its Cap and Trade Act and a New Clean Energy Act

WCI Partners Recommend Renewable Energy Certificates Have No Role in Compliance With Their Cap-and-Trade Program

WCI Markets Committee Releases Consultant Report on Allowance and Offset Holding Limits

WCI Markets Committee Issues Draft Recommendations for Market Oversight

WCI Markets Committee Issues Auction Design White Paper

WCI Offsets Committee Releases Draft Recommendations for Offsets System Essential Elements

WCI Offsets Committee Releases Consultant Report Reviewing Current Offset Protocols

Québec Announces Funding for Climate Change Adaptation

British Columbia Introduces Updates to Its Cap and Trade Act and a New Clean Energy Act

Updates to BC's Cap and Trade Act, first introduced in 2008, were recently introduced to the BC Legislative Assembly. The amendments further clarify existing statutory power to enable implementation of details of the cap-and-trade program that BC has been developing in collaboration with its WCI partners. A vote is expected prior to the adjournment of the legislative session in the first week of June and will be followed by intentions papers to consult on proposed regulations.

BC's new Clean Energy Act was introduced on April 28. The legislation would enable BC Hydro, the provincially-owned crown corporation, to aggregate clean and renewable energy and offer customers outside BC the opportunity to secure long-term agreements for clean power at competitive prices to assist them in meeting their climate action and renewable energy objectives.

WCI Partners Recommend Renewable Energy Certificates Have No Role in Compliance With Their Cap-and-Trade Program

May 25: Stakeholder Call to Discuss Consultant Report on Allowance and Offset Holding Limits

A stakeholder conference call to discuss this report (see adjacent column) will be hosted on May 25 at 11:00 am Pacific Time. To join the call, dial 1-800-868-1837, and enter code 659 537# (1-404-920-6440 for outside the U.S. and Canada). To view the presentation as it is being discussed, click here and enter the same phone number, participant code, and screen name.

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WCI Markets Committee Releases Consultant Report on Allowance and Offset Holding Limits

In its Market Oversight Draft Recommendations (see article below), the Markets Committee identified twelve policy decisions, including whether or not to implement "holdings limits," limits on the number of allowances or offset certificates any entity could control. The WCI Partners commissioned a consultant's report on this issue, to review the history, theory, and use of similar limits in other markets, as well as recommendations on their use in a regional cap-and-trade program. The Partners contracted with Dr. Jeffrey H. Harris of the University of Delaware to provide the report and recommendations

To facilitate deliberations on final recommendations for holding limits, the Committee requests comment on the commissioned report by June 4, 2010. Dr. Harris will present his work and be available to answer questions on May 25, 2010 at 11:00 Pacific Time. Click here for details on the webinar.

WCI Markets Committee Issues Draft Recommendations for Market Oversight

On April 5, the WCI Markets Committee issued draft recommendations to ensure that the allowance and offset credit trading market is organized properly to operate reliably and prevent or minimize manipulation. The Committee identified twelve policy decisions and examined the background, options, and pros and cons for each. A public stakeholder conference call was hosted on April 20 to discuss the draft recommendations, and written comments were due April 30. Next steps include public release and input on the Committee's consultant report on holding limits (see above article) and final recommendations by the WCI Partners.

WCI Markets Committee Issues Auction Design White Paper

The WCI Design Recommendations for a Regional Cap-and-Trade Program call for a portion of the emission allowances to be auctioned. This white paper, released April 15, is the first step in developing recommendations on auction design. It identifies design decisions to be made and assesses their inherent tradeoffs. A public stakeholder conference call was hosted on April 29 to discuss the white paper, and written comments were due May 7. Next steps include draft recommendations from the Committee on the auction design.

WCI Offsets Committee Releases Draft Recommendations for Offsets System Essential Elements

Released on April 13, these draft recommendations define offsets and essential criteria to ensure that all offset credits issued or accepted by WCI Partner jurisdictions are real, additional, verifiable, and enforceable. The draft recommendations are based on stakeholder feedback and Partner input since the Committee's release of its offset definition and criteria white paper in July 2009. Public stakeholder conference calls were held on the draft recommendations on April 22 and May 5. Next steps include review of stakeholder comment and finalization of the recommendation by WCI Partners.

WCI Offsets Committee Releases Consultant Report Reviewing Current Offset Protocols

On April 13, the WCI Offsets Committee released a report for public comment that evaluates how each of several existing offset protocols correspond to the WCI draft offset definition and criteria (see article above), meets the relevant requirements described in the ISO framework, and is applicable to the geographies of the Partner jurisdictions. The report was prepared by Det Norske Veritas (DNV) and focuses on protocols in the agriculture, forestry, and waste management sectors, which are identified as priority project types in the Design Recommendations for the WCI Regional Cap-and-Trade Program. Next steps include modifications to existing protocols or developing new protocols where suitable ones do not exist. Stakeholder input will be sought in this process.

Québec Announces Funding for Climate Change Adaptation

On April 30, 2010, the Government of Québec announced that it would spend $8,725,000 over three years to combat heat islands. A total of 14 projects will be funded in four different regions: Montréal, Québec City, Montérégie, and Lanaudière. The projects will lessen the impact of climate change on public health by improving air quality and by decreasing smog episodes. They will also increase vegetation density, create shade zones, and protect against high ambient temperatures and ultraviolet radiation. Selected in a public request for proposals process, the 14 projects will be funded out of a $30 million budget managed by the Ministère de la Santé et des Services Sociaux, as part of the 2006-2012 Climate Change Action Plan.

SYMPOSIUM ON UNDERSTANDING THE VALUE OF BENCHMARKING

Westin Hotel – Fifth Ave Meeting Room, 1900 5th Ave., Seattle, WA
Wednesday, May 19, 2010

WASHINGTON STATE DEPARTMENT OF ECOLOGY

WESTERN CLIMATE INITIATIVE

Call-in: (800) 868-1837, passcode 659 537# (Outside U.S. and Canada, dial: (404) 920-6440)
Webinar: https://www1.gotomeeting.com/join/115725897 *(Questions will be collected via the webinar interface)*

**Morning Objectives - ** Address the following questions:
What are benchmarks?

How are benchmarks constructed?

What are the leading policy approaches for using benchmarks to reduce GHG emissions?

8:30 am **Registration**

9:00 am **Welcome and Symposium Overview**

- Janice Adair, Washington State Department of Ecology
- Michael Gibbs, US Co-Chair of WCI, California EPA
- Bill Ross, Ross & Associates, Facilitator

9:15 am **Overview of Current Efforts in Industry Benchmarking to Improve Industrial Performance**

- **Michael Lazarus, Stockholm Environment Institute (SEI)**
  Michael Lazarus, co-author of the SEI *White Paper* on greenhouse gas benchmarking, will provide an overview of current efforts in industry greenhouse gas benchmarking and introduce the *White Paper* under development for the Department of Ecology.

9:30 am **A Look into Existing Policy Approaches that Use Benchmarking to Improve Industrial Energy Performance**

- **James Bradbury, World Resources Institute**
  Industry Benchmarking and Federal Climate Legislation
  James Bradbury will provide a status update of the use of greenhouse gas benchmarks in proposed federal climate legislation, including the Waxman-Markey and Kerry-Graham-Lieberman bills.
- **Judi Greenwald, Pew Center on Global Climate Change**
  Using Benchmarks to Develop Regulatory Performance Standards
  Judi Greenwald will provide an overview of possible approaches to developing and using benchmark-based GHG performance standards under existing environmental law.
- **Betsy Dutrow, US EPA ENERGY STAR Industrial Sector Partnership**
  "A Voluntary Approach: ENERGY STAR® Benchmarking of Industrial Plant Energy Performance"
  Betsy Dutrow will provide an overview of EPA's approach for benchmarking industrial plant energy performance and will review the successes and challenges of benchmarking plant performance.
- Panel Discussion / Q&A

10:45 am **Break**

11:00 am **Methods for Constructing Benchmarks**

- **Hauke Hermann, Öko Institute**
  Data-driven, Benchmark Curve Approach and Lessons from the European Union's Emissions Trading System
  Hauke Hermann is a consultant to the EU, and will discuss the process underway to establish industry GHG benchmarks for carbon-intensive, trade-exposed industries under the EU's cap-and-trade program.
- **Gale Boyd, Duke University** (*via phone*)
  The ENERGY STAR® Approach to Developing Benchmarks of Industrial Plant Energy Performance
  Gale Boyd, as part of EPA's ENERGY STAR® Industrial Team, constructs the models that form the basis for benchmarking the energy performance of industrial plants in the U.S. He will describe the data, methods, and challenges of benchmarking these plants.
- **Peter Erickson, SEI**
  Issues and Options for Benchmark Development in the U.S.
  Peter Erickson, co-author of the SEI *White Paper* on greenhouse gas benchmarking, will describe key issues and options for developing GHG benchmarks in Washington and the U.S.
- Panel Discussion / Q&A

12:15 pm **Lunch break (on your own)**

Afternoon Objectives - Address the following questions:
What are the benefits and challenges of developing and applying benchmarks?

What data constraints limit benchmarking and how might they be overcome?

How do responses to these questions differ depending on how benchmarks are used?

1:30 pm Key Issues for Industry GHG Benchmarking

- **Ken Martchek, Alcoa**
  Ken Martchek will provide a national perspective of considerations in addressing this session's key topics: benefits and challenges of benchmarking, data constraints, and striking a balance between detail and aggregation in benchmarks across industry sectors.
- **Industry Panelists:**
  - Pam Barrow, Northwest Food Processors Association
  - Anthony Chavez, Weyerhaeuser
  - Jeff Jacobson, Cardinal Glass
  - Curtis Lesslie, Ash Grove Cement Company
  - Ken Martchek, Alcoa
- **Research Panelists:**
  - James Bradbury, World Resources Institute
  - Betsy Dutrow, US EPA ENERGY STAR
  - Peter Erickson, Stockholm Environment Institute
  - Judi Greenwald, Pew Center
  - Hauke Hermann, Öko Institute
- Bill Ross, Moderator
- Michael Lazarus, SEI, Co-Moderator

3:30 pm Break

3:45 pm Observations and Next Steps for the Benchmarking Project

- Janice Adair, Washington State Department of Ecology

4:30 pm Adjourn

To view the draft White Paper, please visit: http://www.ecy.wa.gov/climatechange/GHGbenchmarking.htm
Comments on this draft are requested by Friday, June 4, 2010 to benchmarking.wa@sei-us.org

Issues and Options for Benchmark Development

Peter Erickson

Stockholm Environment Institute – US, Seattle

WA Ecology/WCI Symposium on Understanding the Value of Benchmarking, May 19, 2010, Seattle, WA

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Overview

- Key benchmark design decisions
- Other issues
- Path forward

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Key Design Decisions

- **Ambition** – average, best available, top percentile?
- **Scope and boundaries** – direct only or total, including indirect?

$$\textbf{Benchmark} = \frac{\textbf{Emissions}}{\textbf{Unit of Output}}$$

- **Level of aggregation**: Balance between aggregation & specificity
- **Data** sources

All facets influenced by benchmark application

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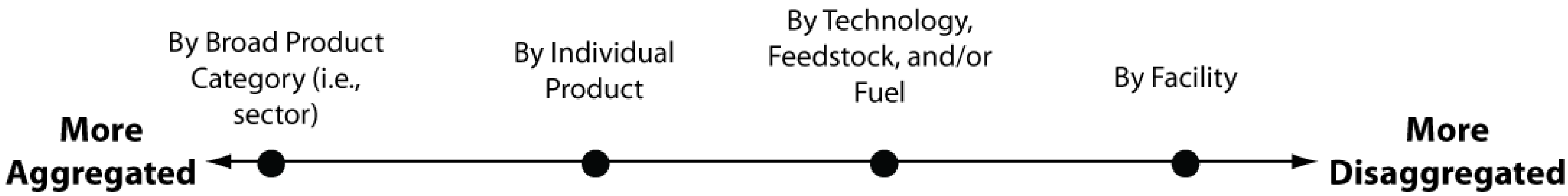
Sample Levels of Aggregation



Aluminum	Cast aluminum, rolled aluminum	Anode type	e.g., Intalco, Ferndale
Cement	Clinker (white or grey)	Wet vs. dry kiln	e.g., Ash Grove Cement, Seattle
Glass	Flat, container, fiber glass	Fraction of recycled cullet used	e.g., Cardinal Glass, Winlock
Paper	Newsprint, writing paper, market pulp	Mechanical versus chemical pulp	e.g., Norpac, Longview
Steel	High-alloy steel, hot-rolled steel, EAF steel	EAF vs. BOF, integrated versus rolling mill	e.g., Nucor Steel, Seattle

Level of Aggregation

- Need balance between:
  - **Specificity**: enables meaningful comparisons across facilities; and
  - **Aggregation**: enables broad application, provides big enough pool for benchmark to provide incentive effect
- Benefits and challenges exist for each level of aggregation

Benefits and Challenges of Aggregation

- Broad product category
  - Benefits: Simplicity
  - Challenges: Intermediate products
- Product-specific
  - Benefits: Rewards top-performers, provides long-term incentive
  - Challenges: Data, defining products
- Facility-specific
  - Benefits: recognizes site-specifics
  - Challenges: Limited incentive for best performance

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Aggregation Depends on Policy Context!

- **Cap-and-trade:**
  - Intent of output-based allocation is to avoid carbon leakage while retaining CO_2 price signal
  - Some level of aggregation may be okay (e.g., "one product, one benchmark")
- **Regulatory**
  - Benchmark directly determines level of emissions and plant viability
  - Differentiation / disaggregation may be appropriate
- **Voluntary**
  - Differentiated benchmarks may encourage participation

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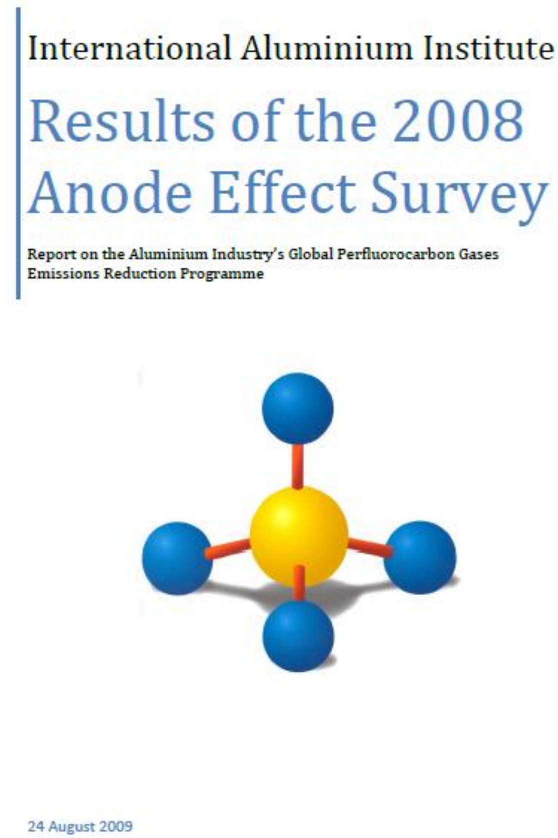
Data Sources

- Four types
  - Industry groups and associations
  - Government surveys
  - Air permits
  - Mandatory GHG reporting rules
- Need for improved data is widely recognized
- Consistent, rigorous protocols should be applied equally for benchmark construction and application

Data: Industry Sources



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Data: Government Surveys

- MECS

U.S. Energy Information Administration
Independent Statistics and Analysis

Home > Households Buildings & Industry > Manufacturing Energy Consumption Survey (MECS) > 2006 Data Tables

2006 Energy Consumption by Manufacturers--Data Tables

Released June 2009

- Census

U.S. Census Bureau

Annual Survey of Manufactures (ASM)

- USGS

USGS
science for a changing world

2008 Minerals Yearbook

Each source has only a piece of the puzzle

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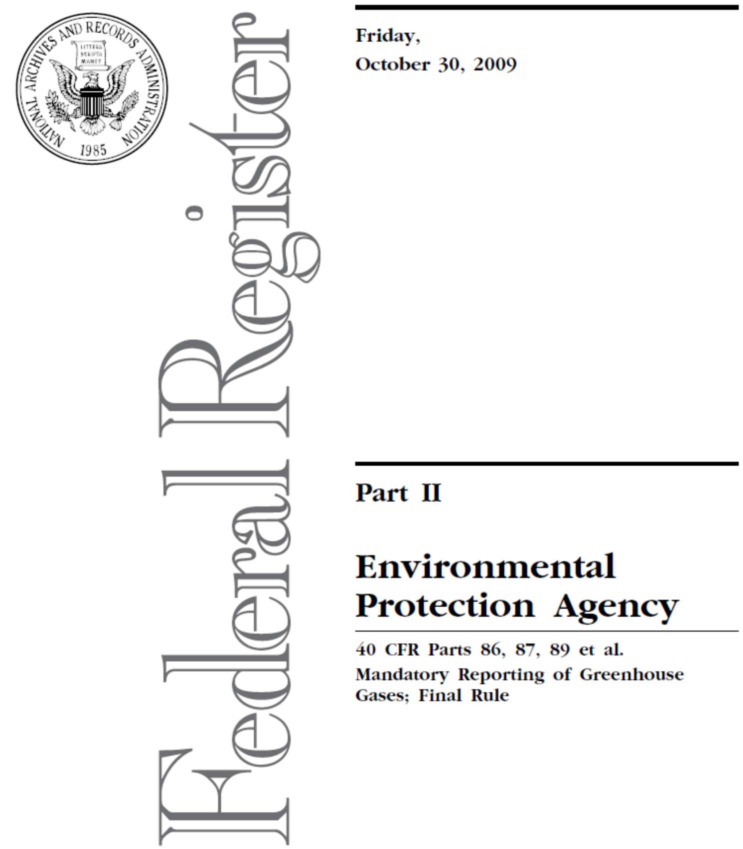
Data: Air Permits

- Some air agencies use permit data to estimate GHGs
- Ecology and local air agencies use permit information on facility production and other data to estimate GHGs
- Large number of disparate data sources complicates use

Data: GHG Reporting Rules

- All facilities in some sectors
  - E.g., aluminum, cement
- Most sectors if:
  - > 25,000 tCO_2e nationally
  - > 10,000 tCO_2e in Washington State
- Data due Oct 2010 in WA State, March 2011 nationally



Federal Register

Friday,
October 30, 2009

Part II

Environmental Protection Agency

40 CFR Parts 86, 87, 89 et al.
Mandatory Reporting of Greenhouse Gases; Final Rule

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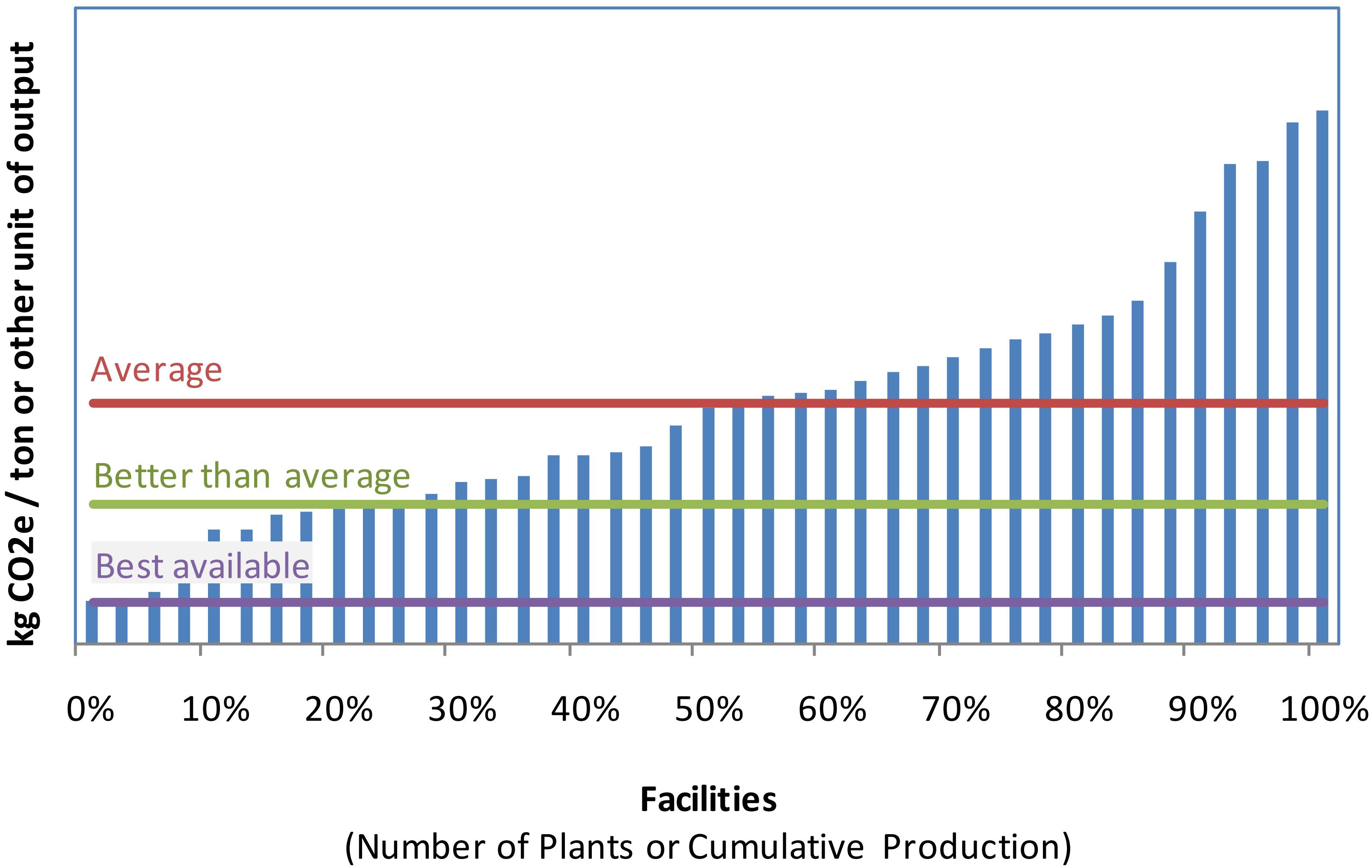
Benchmark Ambition



Ambition Depends on Policy Context, Too!

- **Cap-and-trade:**
  - What level of output-based rebate appropriate to address leakage and competitiveness?
  - Average industry performance (as in draft US legislation) or best practices (as in EU's top 10%)?
  - Insights from economic modeling (e.g., US Interagency Report on Competitiveness and Leakage)
- **Regulatory**
  - Benchmark sets allowable emissions level and may determine plant viability
  - More ambitious benchmarks where abatement less expensive?
- **Voluntary**
  - Differentiation of benchmark ambition can help distribute costs across sectors

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Ambition in Washington State

- Governor Gregoire’s Executive Order 09-05 calls for benchmarks developed by the Department of Ecology to “be based on industry best practices, reflecting emission levels from highly efficient, lower emitting facilities in each industry sector.”

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Scope / Boundaries

- Direct emissions only
  - Benefits: Simpler, aligns best with cap-and-trade and reporting rules
  - Challenges: Could encourage "leakage", if it induces switching from fuel use to purchased electricity or steam
- All (including indirect) emissions:
  - Benefits: Includes more emission-causing activities over which facilities have control (e.g. electricity use); captures emission impact of switching to/from electricity
  - Challenges: Data needs and complexity
- Considerations for Scope also vary by policy approach

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Other Issues

- **Combined heat and power**, or use of waste gases (paper and pulp, steel, and others)
- **Feedstock quality and quantity**: Use and quality of recovered/recycled feedstock (glass, aluminum, steel)
- **Facilities that produce multiple products** (paper or steel mills)
- **Integrated vs. non-integrated facilities** (paper and pulp and steel)
- **Alternative definitions of the final product** (e.g. cement or clinker)

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Potential Elements of a Path Forward on Benchmarking

- Build Data Sets
  - GHG Reporting rules
  - Industry partnerships
  - Federal – State partnerships for MECS, Census, other data?
- Pick one or more policy contexts for further benchmark analysis/development
  - Disaggregation, Ambition, Scope All Depend on Policy Context!
- Pilot in select sector(s)

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For more information

- Website: http://www.ecy.wa.gov/climatechange/GHGbenchmarking.htm
- Draft White Paper Comment Period through June 4
- Contact us at benchmarking.wa@sei-us.org

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Benchmarking in the EU

Symposium on understanding the value of benchmarking

Hauke Hermann

Seattle, May 19, 2010

Disclaimer

- The views and opinions presented in this presentation are partly based on results from research commissioned by the German Federal Environment Agency and the European Commission.
- The contents of this presentation does not necessarily reflect any official position.

Overview

- Target functions of benchmarks and consequences for the design
- The history: How were benchmarks used in the EU ETS from 2005-2012?
- The future: How will benchmarks be used in the EU ETS from 2013 onwards?
- Conclusions

The EU Emissions Trading Scheme
Some background information

Öko-Institut e.V.
Institut für angewandte Ökologie
Institute for Applied Ecology

- **The EU ETS is a multi-national ETS**
  - 27 EU Member States, 2.2 (2005) → 2.4 bn t CO2e (2013)
  - Linking: CDM & JI, Norway, Iceland, Liechtenstein, etc
- **The EU ETS is a downstream ETS**
  - Power generation
  - Combustion installations > 20 MW
  - Other installations in energy-intensive industries (cement, iron and steel, glass, ceramics, refineries, etc)
  - From 2013: N2O emissions from large industrial point sources
  - From 2011: aviation included
- **The EU ETS is a multi-period scheme**
  - Pilot phase 2005-2007
  - Second phase 2008-2012
  - Third phase 2013-2020

Benchmarking
Definitions and specifications

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- **Benchmarking is an approach to assess performance based on objective and transparent criteria and indicators**
- **The design of benchmarks and benchmarking strongly depends on the specific purpose** (… not all existing benchmarking approaches are suitable to the needs of an ETS and not all benchmarking approaches are suitable to all targets)
  - Voluntary approaches
  - Regulatory approaches
  - Emissions trading schemes (ETS)
- **Target functions of benchmarking within the EU ETS**
  - Compensation (especially during the phase-in; 2005-2007)
  - Rewarding early action (especially during the phase-in; 2005-2007)
  - Preventing (operational and/or investment) leakage; from 2013 onwards

Different target functions lead to different designs

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- **Target functions in an ETS**
  - Preventing leakage is the main objective for continued free allocation within the EU ETS
  - At the same time Benchmarking as an approach for free allocation should minimize distortions of the carbon price signal
- **Target functions for voluntary approaches**
  - Comparing the efficiency of different installations
  - Showing the abatement potential (e.g. in a technology class)
- **Target functions for regulatory approaches**
  - Incentivize emissions abatement below the benchmark
  - Fair distribution of abatement costs might make a technology differentiation necessary

Example: the role of indirect emissions

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- **Do the target function influence the treatment of indirect emissions from electricity consumption?**
- **The benchmarks in the EU ETS are only based on direct emissions**
  - There will be a separate financial compensation for electricity intensive process with a carbon leakage problem
  - No need to take indirect emissions into account as the carbon price is included in the electricity price
- **Benchmarks for voluntary approaches and regulatory approaches should take indirect emissions into account**
  - Not taking indirect emissions into account might lead to the perverse incentive to increase the use of electricity

Some history

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- **Emissions trading started in January 2005 in the EU:**
  - **Grandfathering** based on historic emissions in the years 2000 to 2002 for **incumbents**
  - Main question: How to allocate to **new entrants** (installations starting after 2005)?
  - **Benchmarks for new entrants** were developed for electricity, heat, **cement**, bricks and glass based on best available technology (BAT)
- **From 2013 onwards:**
  - **Benchmarking for incumbents and new entrants based on the 10% most efficient installations**

The allocation formula in the EU

- **Allocation is more than one benchmark**

Allocation formula

$A = BM_e \cdot P\ [\cdot \alpha_{cap}]$

A	free allocation [EUA]
BM_e	emission benchmark [t CO_2/t product]
P	historic production
α_{cap}	adjustment factor to adjust allocation to the cap

History: Benchmarking for cement

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- **Case study: benchmarking for cement in Germany**
  - Derived from the textbook
  - Benchmark was aimed to reflect emissions of best available technology
  - German new entrants benchmark (2005-2012)
    0.805 …0.845 t CO2 per t clinker (depending on chosen technology) + 7500 full load hours
  - Process emissions 0.53 t CO_2 / t clinker + 3 GJ / t clinker * fuel mix of coal = 0.805 t CO2 per t clinker
  - 7500 full load hours

German Benchmarking curve for cement clinker (2007)

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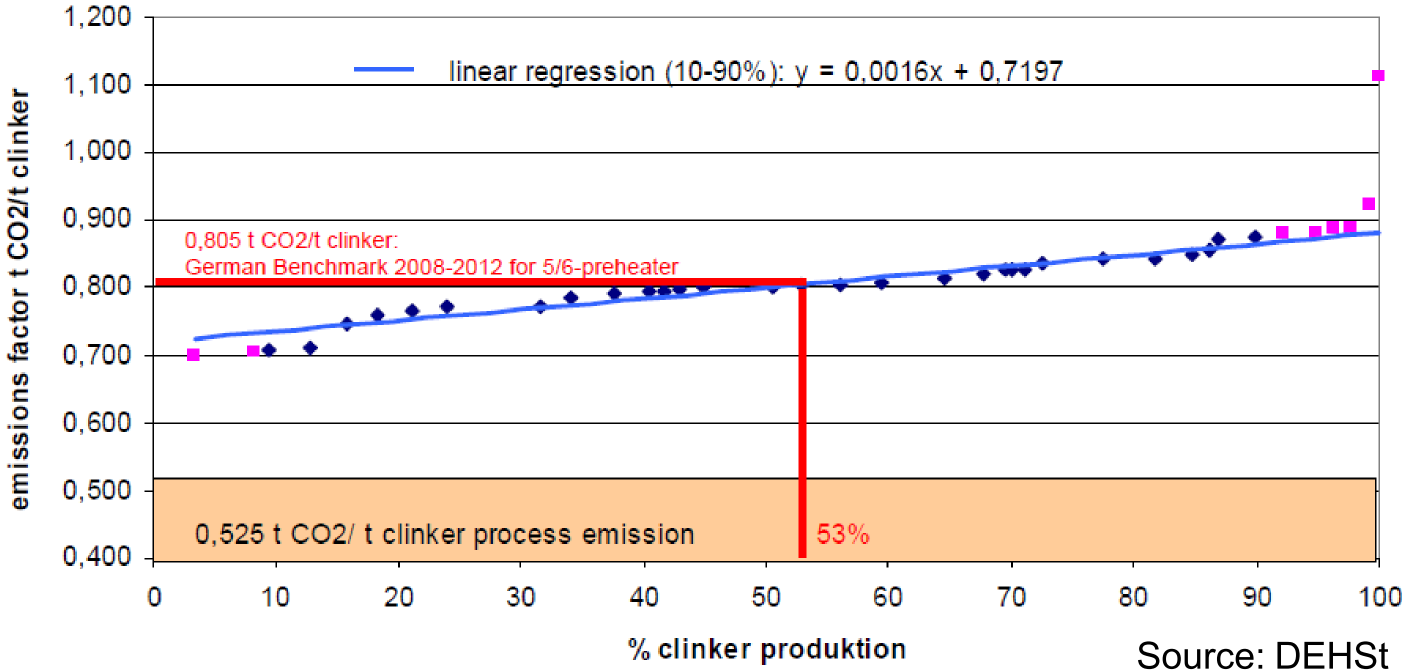

Source: DEHSt

- **Looking at real data:**
  - The BAT benchmark was not really BAT (high share of waste fuels used)
  - Perverse incentives due to the technology differentiation
  - Actual full load hours were only 5400 h and not 7500 h

Future: Cooperation with industry

- **Benchmarks for free allocation from 2013 onwards**
  - Benchmarks will be decided in the EU until end 2010
  - Benchmarks will be developed for all major industrial processes listed in the Annex of the ETS directive
  - Sector organisations were asked to construct benchmark curves based on the specific emissions in 2007-2008
  - Benchmarking curves are submitted (first via consultants and now directly) to the European Commission and externally verified

- **Number of Benchmarks**
  - Sector organisations were asked if they want to develop additional product benchmarks (e.g. sugar, starch, were under discussion)
  - No additional product benchmarks are developed in the EU, most sector organisations decided to go for the heat benchmark instead

Example: Benchmarking curve for cement clinker for the EU-27

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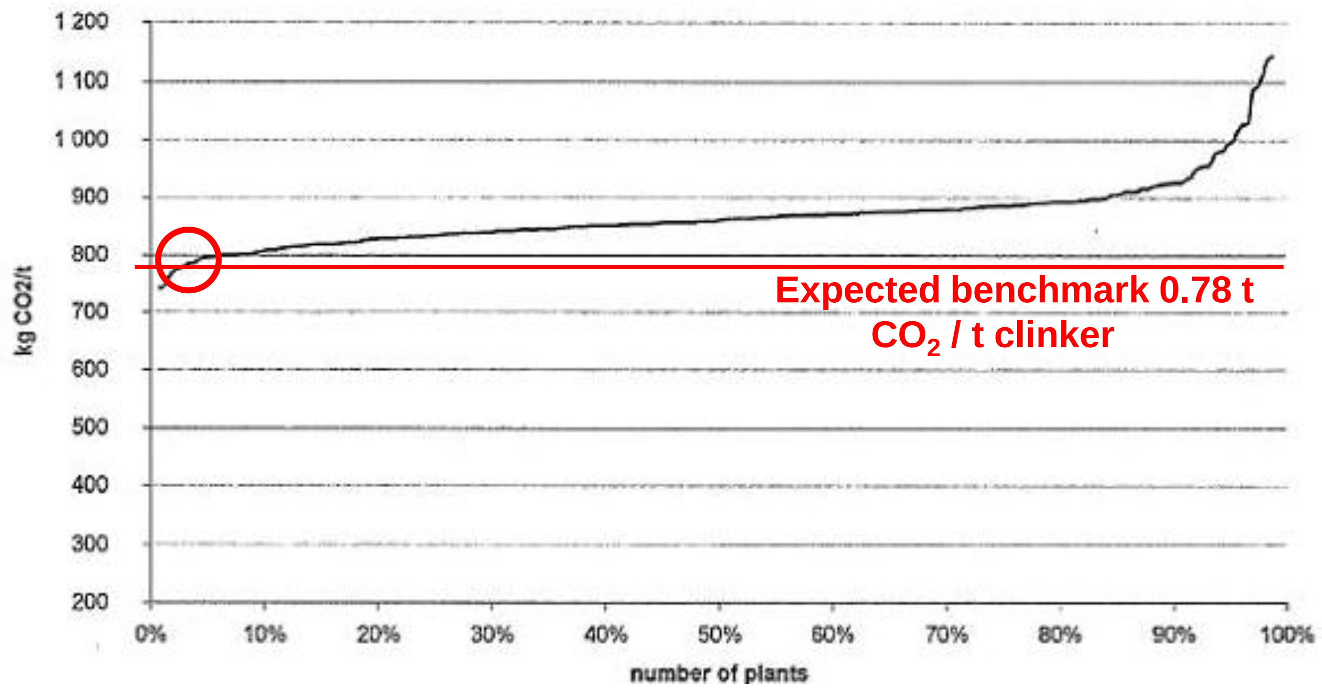
- **Improved approach from 2013 onwards:**
  - Construct benchmarking curve including all installations
  - Benchmark for free allocation is set at the efficiency of the average 10%



Source: Ecofys/ISI/Öko (2009), Preliminary graph based on data for 2006

How to set up benchmark curves

- **Benchmark curves**
  - Specific emissions are calculated by dividing emissions by production in a reference period (e.g. 2007-08)
  - No correction of the benchmarking curve for outliers, but
    - imports and exports of heat are corrected with the emission factor of natural gas (a paper mill with outsourced heat supply would have zero emission, this needs to be corrected in the benchmarking curve)
    - Imports and exports of waste gases (mainly relevant for iron and steel) are corrected with the emission factor of natural gas
  - The curve should consist of the specific emissions all installations in a region (e.g. US)

- **Data quality**
  - The same monitoring method should be used to set up benchmarking curves and to monitor emissions in an ETS

Conclusions (1)

- **Work with Industry, use real monitoring data for production and emissions to construct benchmarking curves**
- **Use an integrated assessment of CO_2 / t of product (and not energy efficiency and fuel mix separately)**
- **Use the 10% approach to determine the ambition of benchmarks (this lowers transactions costs for negotiations about availability of fuels and achievable efficiency)**
- **BM must maintain a non-distorted CO2 price signal and BM must avoid distortions within the EU**
  - one benchmarking curve per product (cement clinker, glasses, papers)
  - Focus on important basic processes (no benchmark for cars or planes)
  - No consideration of process, raw material, country, regional or other specifics
- **But, under regulatory / voluntary approaches benchmarking curves might be differentiated according to technology**

Conclusions (2)

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- **BM design must avoid perverse incentives with regard to carbon leakage**
  - Cement clinker facility vs. final product cement (output of grinding plant which is not regulated by the EU ETS – and possibly imports cement clinker)
  - → BM should be implemented at the point of regulation (e.g. based on clinker)

Thank you very much

Hauke Hermann
Energy & Climate Division
Berlin Office
Novalisstrasse 10
D-10115 Berlin
h.hermann@oeko.de
www.oeko.de

Further Reading (1)

Öko-Institut e.V.
Institut für angewandte Ökologie
Institute for Applied Ecology

- Matthes, F. Chr. et al:

  Pilot on Benchmarking in the EU ETS.

  Öko-Institut / Ecofys Report for the German Federal Ministry for the Environment, Nature Conservation and Nuclear Safety and the Dutch Ministry of Economic Affairs. November 2008. (http://www.dehst.de/cln_099/nn_719154/SharedDocs/Downloads/EN/ETS/Perspectives__EN/BM__Pilot__OekoInst__Ecofys__EN,templateId=raw,property=publicationFile.pdf/BM_Pilot_OekoInst_Ecofys_EN.pdf)

- Neuhoff, K., Matthes F. Chr. (Coord.):

  The Role of Auctions for Emissions Trading.

  Climate Strategies Report. October 2008.

  (http://http://www.climatestrategies.org/reportfiles/role_of_auctions_09_oct_08final.pdf)

Further Reading (2)

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Institute for Applied Ecology

- Neelis, M. et al:

  Developing benchmarking criteria for CO2 emissions.

  Ecofys / Fraunhofer ISI Report for the European Commission. February 2009. (http://ec.europa.eu/environment/climat/emission/pdf/benchm_co2emiss.pdf)

- **European Commission website on benchmarking**

  (http://ec.europa.eu/environment/climat/emission/benchmarking_en.htm

- **A series of forthcoming papers**

White Paper

Issues and Options for Benchmarking Industrial GHG Emissions

Submitted to: the Washington State Department of Ecology

PRELIMINARY DRAFT May 12, 2010

STOCKHOLM ENVIRONMENT INSTITUTE

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Washington Department of Ecology

Janice Adair
Justin Brant
Eli M. Levitt

SEI-US

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Öko-Institut

Hauke Hermann

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1. Introduction and Context

Industrial activity remains a cornerstone of modern economies, as well as a major source of emissions of heat-trapping greenhouse gases (GHGs). Industrial processes and energy use account for 20% of direct greenhouse gas emissions globally (Metz et al. 2007) and in Washington State (Center for Climate Strategies 2007). Many industries, such as aluminum production, are highly reliant on electricity use; when the emissions associated with generating electricity for industry are included, the share rises to a quarter of global emissions, and an even larger share of energy-related CO_2 emissions. A handful of energy-intensive industries – iron and steel, aluminum, chemicals, petroleum refining, minerals (e.g., cement, lime, and glass), and pulp and paper – account for over 80% of global industrial energy use, and a large majority of industrial GHG emissions (Metz et al. 2007).

These same industries could also play central roles in a transition to a low-carbon economy. Aluminum can reduce transportation energy needs by "lightweighting" vehicles. New low-carbon transportation and energy infrastructure, from public transit systems to wind turbines, may require significant amounts of steel and cement. Advanced low-emissivity ("low e") glass is a key component of ultra-low energy buildings. Sustainably harvested forest products offer the potential for carbon sequestration in the built environment as well as a low-carbon energy source. In short, a few key energy and GHG emissions intensive industries – most of which are represented here in Washington State and operate in a highly competitive international markets – are central to tackling climate change.

With these considerations in mind, state and federal policymakers are considering a range of approaches to address GHG emissions from industrial activity. Approaches under consideration for emissions-intensive industry sectors include voluntary agreements or incentives, inclusion of industry in an economy-wide cap-and-trade program, and direct regulation through performance standards. A common theme to all three such approaches is the use or development of GHG benchmarks, which enable the assessment of GHG emissions performance across facilities or against a common standard.

GHG benchmarks are typically expressed as a quantity of emissions per unit of output, as in the following simple equation, and may in some contexts be called *emissions intensity*. [1]

$$GHG\ Benchmark = \frac{Emissions\ (tons\ CO_2e)}{Unit\ of\ Output\ (tons, \$, or\ other\ metric)}$$

Policymakers can use GHG benchmarks in any of at least three policy approaches:

- **Voluntary performance goals,** in which participating companies commit to achieving a particular emissions benchmark by a particular year;
- **Allocation of allowances in a cap-and-trade program**, where emissions allowances are freely allocated to industry sectors based on a benchmark level of emissions performance and in proportion to the output of each facility;[2] and
- **Regulatory GHG performance standards,** where individual facilities are required to meet an emissions performance standard that may be set using a benchmark approach.[3]

With this range of possible purposes in mind, Washington Governor Gregoire issued Executive Order 09-05 in 2009, directing the Washington State Department of Ecology to develop emission benchmarks in consultation with industry and other interested stakeholders to be delivered to the Governor, per the Executive Order, by July 1, 2011. Specifically, the Executive Order calls for the Director of the Department of Ecology to:

[1] A common unit of emissions benchmarks is kilograms of carbon dioxide equivalent per ton of material processed or produced.
[2] For example, H.R, 2454 in the 111th Congress (the "Waxman-Markey" bill) included a rebate to certain energy intensive and trade-exposed sectors based on the average level of emissions per output of the sector.
[3] Other approaches to setting emissions performance standards also exist, such as defining particular technologies that must be installed.

"In consultation with business and other interested stakeholders, develop emission benchmarks, by industry sector, for facilities the Department of Ecology believes will be covered by a federal or regional cap-and-trade program. The Department of Ecology shall support the use of these emission benchmarks in any federal or regional cap-and-trade program as an appropriate basis for the distribution of emission allowances, and as a means to recognize and reward those businesses that have invested in achieving emission reductions. These benchmarks shall be based on industry best practices, reflecting emission levels from highly efficient, lower emitting facilities in each industry sector. The benchmarks shall be developed to allow their application as state-based emissions standards, should they be needed to complement the federal program, or in the absence of a federal program."

Benchmark Basics

Industry efforts to compare and track GHG emissions performance have been underway for several years. Many global and North American industry associations have collected data from member companies on greenhouse gas emissions and production and distributed corresponding greenhouse gas intensity statistics. For example, the petroleum industry has been engaged for more than 20 years in benchmarking the dozens of processes that occur in petroleum refineries. Petroleum industry actors have compiled a global database of energy use, and have developed a widely adopted benchmarking approach.[4] Other industry associations in other sectors – both globally and regionally – have also developed greenhouse gas intensity metrics, or benchmarks.[5]

Approaches to benchmarking can vary substantially by sector. Some sectors (e.g., cement) have processes and products that are relatively simple and uniform. In such sectors, the task of defining which emissions to include – and what products and/or processes to benchmark – can be relatively straightforward. In other sectors, the task can be much more difficult. For example, the presence of dozens of unique processes and wide variation between facilities in the petroleum refining sector can make the task of developing meaningful benchmarks much more challenging and time-consuming. Regardless, an important consideration in developing benchmarks is to balance the need to obtain emissions and production data from a large enough group of facilities to be representative against the need for each benchmark to be consistent with the circumstances of the facilities it is intended to help assess.[6]

Figure 1 below presents a hypothetical benchmarking curve of emissions intensity data for a fictional industry sector.[7] In this chart, each individual facility, knowing its emissions intensity, could compare its emissions performance (kg CO_2e/ton) to each other facility anonymously, as well as to the average intensity (displayed here as a red horizontal line). Facilities with emissions intensities below the red line are outperforming the average, while facilities with emissions above the red line are underperforming the average and emitting more emissions per each ton of product.

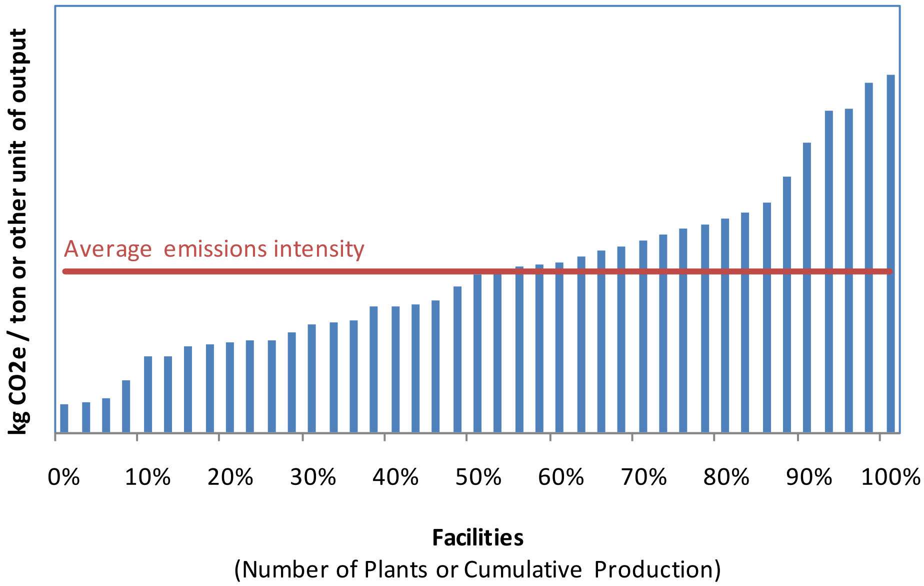
[4] The benchmarking approach developed for the refinery industry by Solomon Associates, Inc. has been widely adopted among the world's refineries and is also likely to form the basis for the European Union's approach to benchmarking refineries in the third phase of its Emissions Trading Scheme, discussed in greater detail later in this paper.

[5] Several industry efforts rely, and have contributed to, the Greenhouse Gas Protocol of the World Business Council for Sustainable Development and the World Resources Institute. In addition, the US EPA ENERGY STAR program for industry uses Census Bureau and industry-provided data to develop energy benchmarks called Energy Performance Indicators. Facilities that score in the top 25% energy efficiency are eligible to be awarded the ENERGY STAR label by EPA.

[6] Current industry efforts have tended to use kg CO_2e as the numerator of the benchmark (and participated in collaborative exercises to establish protocols, such as the GHG Protocol, for measuring such emissions) and tons of product (usually an output, but sometimes an input, as for refining) as the denominator. Industry associations are much less uniform, however, concerning the level of ambition of the benchmark. A common approach employed by several industry associations is to report average greenhouse gas intensity metrics for their respective members.

[7] Curves like that presented in Figure 1 are common in developing benchmarks for energy and emissions. For example, US EPA develops similar curves in its ENERGY STAR Energy Performance Indicators for Industry, including in spreadsheet tools made freely available on its website, www.energystar.gov.

Figure 1. Hypothetical Benchmark Curve: Comparing Facility Emission Intensities in a Given Sector or Subsector [8]



Benchmarks need not be set at the average emissions intensity, however. A benchmarking curve (and its underlying data) can also be used to develop more ambitious benchmarks. For example, a benchmarking curve can be used to understand the best achieved level of emissions performance (i.e., the column furthest to the left in the chart above), to set a goal for a specified improvement over the current average (e.g., a 20% improvement in emissions intensity by a certain year), or to select a definition of top-performing plants (e.g., the plants in the top 25th percentile of performers). As we discuss in Section 3, setting the ambition of a benchmark becomes particularly important in regulatory systems for reducing greenhouse gases, including both cap-and-trade and performance standards approaches.

Roadmap of the White Paper

In this *White Paper*, we discuss issues and options for developing emissions benchmarks, starting with a brief summary of the possible policy approaches in Section 2. We then provide an assessment of key issues and options for developing benchmarks in Section 3, including a discussion of how the issues and options may differ for three commonly applied policy approaches. We include a discussion of considerations specific to several industrial sectors (e.g., aluminum, cement, steel) in Section 4. In Section 5, we assess possible paths forward for Washington State in developing benchmarks to fulfill Governor Gregoire's Executive Order.

This *White Paper* and the associated GHG benchmarking symposium on May 19, 2010 mark the first phase of the Department of Ecology's research and stakeholder consultation on benchmarking. The second phase, starting in July 2010, will entail the development of recommendations on industry benchmarks and their appropriate use in achieving the state GHG emission reduction targets: to reduce emissions to 1990 levels by 2020, 25% below 1990 levels by 2035, and 50% below 1990 levels by 2050.[9]

---

[8] In this chart, each vertical bar represents an individual facility, with facilities organized from least emissions intensive on the left to most emissions intensive on the right. The horizontal (x-axis) can be defined simply as the cumulative number (or percent) of facilities, the cumulative production, the cumulative emissions, or the cumulative energy, depending on the intent of the benchmarking curve. The curve here is depicted as if the axis is cumulative share of facilities, which, if all the facilities produced the same quantity of output, would also equal cumulative production.

[9] As specified in Revised Code of Washington (RCW) 70.235.020 (2008): http://apps.leg.wa.gov/RCW/default.aspx?cite=70.235.020

We intend the primary audience for the *White Paper* to be policymakers, industries to which GHG benchmarks may apply, and other interested stakeholders. While we place a particular focus on the needs and opportunities with respect to Washington State, much of the discussion may also apply to broader policy dialogues and decisions in the Western Climate Initiative and U.S.

This *White Paper* is currently in draft form. We invite your comments on this draft by Friday, June 4, 2010. Please send comments via email to benchmarking.wa@sei-us.org. This document will be finalized by late June 2010.

2. Summary of Current Policy Approaches

Broadly speaking, greenhouse gas benchmarks are metrics that enable the assessment of GHG emissions performance across facilities or against a common standard. Benchmarks have been used in each of three leading policy approaches to reducing industrial GHG emissions: voluntary performance goals, cap-and-trade programs, and emission performance standards. This section describes these policy approaches and how benchmarks have been developed and applied in each approach.

Voluntary Performance Goals

Voluntary industry efforts to benchmark and reduce greenhouse gas emissions have been underway for several years at international, national, and local levels. For example, major players in the global cement industry, organized as the Cement Sustainability Initiative, share data on emissions released per ton of cement (or clinker, a key component) so that they may compare their performance against other plants, or against an average or high-performing plant (CSI 2009). Similarly, the international aluminum industry collects and shares data on emissions of perfluorocarbon (PFC), a highly potent greenhouse gas, and has recently pledge to reduce PFC emissions by at least 50% by 2020 as compared to 2006 (International Aluminum Institute 2009).

Voluntary programs may take one of several forms (Lyon 2003):

- initiatives undertaken by industry alone (e.g., self-regulation), such as the goals announced by the Cement Sustainability Initiative and the PFC reduction goals of the International Aluminum Institute;
- negotiated agreements between government and industry, such as the US EPA's Climate Leaders program; or
- public voluntary programs (e.g., ENERGY STAR) in which governments provide technical assistance and publicity to companies that adopt and meet certain goals.

Table 1 provides a summary of examples of the latter two types of voluntary programs recently active in the U.S. Benchmark methodologies in these programs have varied widely.

Table 1. U.S. Government Programs with Voluntary GHG or Energy Performance Goals

Program	Type of Goal	Sample of Participating Organizations with Facilities in Washington State	Benchmark Methodology
US DOE Climate VISION	Sector-wide improvement in energy or emissions intensity relative to value in some base year	▪ American Chemistry Council ▪ American Forest and Paper Association ▪ American Iron and Steel Institute ▪ Portland Cement Association	Unclear. Appears to be defined by each participating industry association.[10] Not a true benchmark since no comparison between facilities, though progress tracked in terms of emissions (or, in some cases, energy) per unit of physical or economic output.
US EPA Climate Leaders	Company-specific absolute GHG reduction that significantly outperforms a pre-defined sector benchmark[11]	▪ Alcoa ▪ Ash Grove Cement ▪ Boeing Company ▪ ConAgra ▪ Kimberly-Clark Corporation ▪ Lafarge North America ▪ Saint-Gobain Containers ▪ Tyson Foods ▪ Wafertech LLC	EPA calculates benchmark based on current and projected future GHG intensity of sector based on Department of Energy and Bureau of Labor Statistics data and models.
US EPA ENERGY STAR	Depends on individual facility. Facilities that are in the top 25th percentile nationally for energy performance receive the ENERGY STAR label / designation	▪ Ash Grove Cement ▪ ConAgra ▪ Simplot	EPA conducts a statistical analysis to determine energy use per normalized facility; specific benchmark value not available.
US EPA Performance Track (no longer active)[12]	Depends on individual facility. GHG reduction goals were common as are goals to reduce energy use by at least 10%.	▪ Wafertech LLC	Unclear. Appears to have been defined or negotiated by each participating facility.[13]
Northwest Food Processors Association and US DOE partnership	Reduce industry-wide energy intensity by 25% in 10 years and 50% in 20 years	49 facilities in Oregon and Washington (facility names and locations undisclosed)	Still under development. Completed energy audits and tested baseline methodologies in 2009.

Europe also has significant experience with voluntary GHG reduction goals particularly those agreements negotiated between governments and industries. For example, the German government and industrial sector organizations agreed to emission reduction targets in 2000.

Belgium and the Netherlands have also developed voluntary industrial covenants. These countries negotiated reduction targets with industry on a company level. By 2012, companies are to achieve an energy efficiency target comparable to the 10% most efficient installations worldwide. The companies must enact energy efficiency plans, which are subject to external verification, and report their progress annually. Table 2 summarizes the German, Dutch, and Flemish voluntary industry benchmarking programs.

[10] Per www.climatevision.gov.
[11] From 2002 to 2009, goals could be absolute or intensity-based.
[12] EPA's Performance Track program operated between 2000 and 2009.
[13] The EPA Performance Track program concluded in 2009. Methodology details could not be located on the EPA website.

Table 2. European Government Programs with Voluntary GHG or Energy Performance Goals

Program	Type of Goal	Sample of Participating Organizations	Benchmark Methodology
Voluntary commitment of German industry of 9th November 2000	Sector-wide improvement in emissions intensity relative to historic emissions / specific emissions depending on sectors	▪ Federation of German Industries ▪ Steel Industry ▪ Chemical Industry ▪ Power production	Not technically benchmarks, since sector-wide goal relative to historic emissions. Emission reductions are not reported on a company level, but by the sector organization.
Energy Efficiency Benchmarking Covenant (Dutch Benchmarking Committee 1999)	Company-should reach the energy efficiency of the best international standard (defined as energy efficiency of the top 10 %)	▪ Netherlands Chemical Industry Federation ▪ Netherlands Iron and Steel Producing Industry Association ▪ Non-Ferrous Industry Association ▪ Petroleum Industry Association	▪ Determination of the best international standard regarding energy efficiency. ▪ Companies draw up energy efficiency plans. ▪ Checked by independent authority. Annual reporting of companies to competent authority.
Flemish Energy Benchmarking Covenant (Flemish Benchmarking Commission 2010)	As in the Netherlands	As in the Netherlands	As in the Netherlands

Voluntary approaches have generally been perceived as being more acceptable to industry actors than regulatory or even market-based approaches to reducing greenhouse gases. Analyses of the success of voluntary environmental programs, however, have found that in general they have not and cannot attain levels of emissions reduction comparable to market-based or regulatory approaches (Lyon 2003; Morgenstern and Pizer 2007). When voluntary efforts have failed to meet their goals, some governments have pursued other policy approaches. For example, in the German voluntary program described above, when GHG reduction targets were not met in 2003 and 2004, Germany introduced a more ambitious cap into its cap-and-trade program in 2006 (German Federal Ministry of the Environment 2006). Despite their limitations, voluntary programs can help build technical capacity and early action towards eventual transition to a more comprehensive policy approach.

Market-Based Approaches

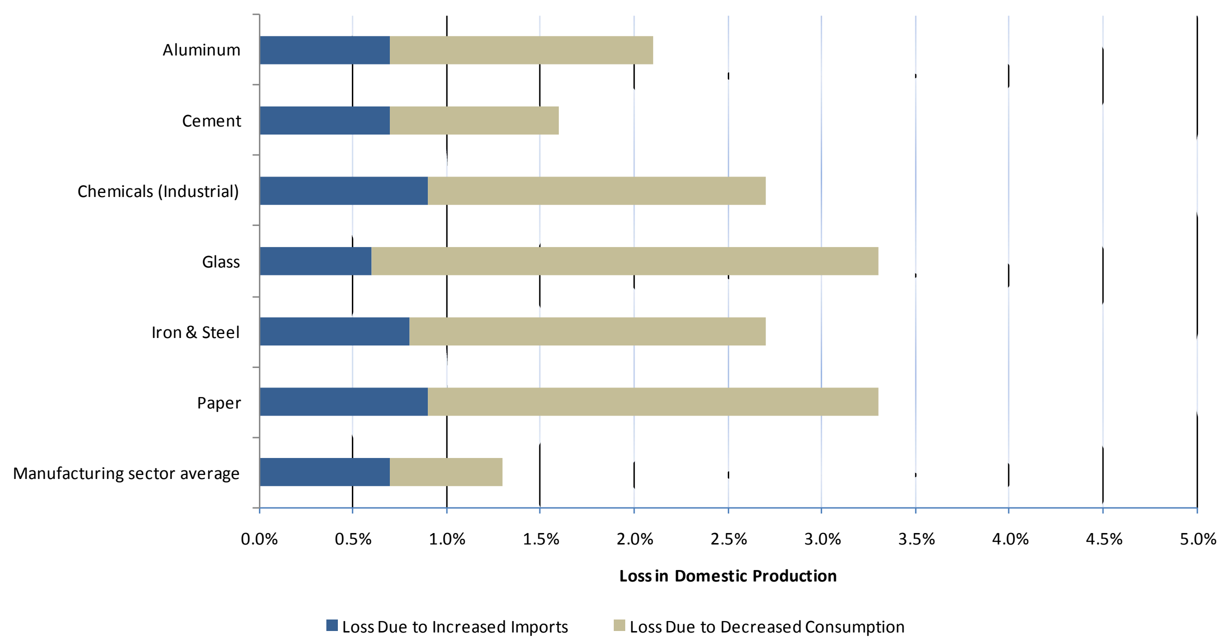
A cap-and-trade program is a market-based program to limit greenhouse gas emissions. These types of programs are being implemented in the U.S. East Coast and Mid-Atlantic states through the Regional Greenhouse Gas Initiative (RGGI), in Europe, through the EU Emission Trading System (EU ETS), and in the state of New South Wales, Australia through its Greenhouse Gas Abatement Scheme. The Western Climate Initiative, which comprises four Canadian provinces and seven U.S. states including Washington, is currently developing the detailed design for a regional cap-and-trade system, as are the states involved in the Midwest Greenhouse Gas Reduction Accord (MGGRA).

At the national level, proposed federal legislation that would establish a cap-and-trade system for large GHG emitters has been under consideration for many years, most recently in a Senate bill drafted by Senators Kerry, Graham, and Lieberman that is currently being evaluated by US EPA in preparation for possible debate on the Senate floor in late spring or early summer 2010. While the RGGI system currently covers only electric generators, most of the other GHG cap-and-trade programs proposed or underway also include large industrial sources.

Some industries – particularly those that are energy-intensive and sell their products in highly global markets – have raised concerns that a cap-and-trade program could disproportionately increase their costs and, in turn, potentially impact their competitiveness in the global marketplace. Furthermore, if implementation of a cap-and-trade program led industry to relocate its activities or investments to other regions or countries without comparable greenhouse gas regulations, emissions "leakage" could occur, compromising the environmental effectiveness of the greenhouse gas cap.[14] For example, recent economic modeling suggests that unless some counteracting policy was implemented, a cap-and-trade program on greenhouse gases in the U.S. could lead to declines in domestic production of between 0.5% and 1.0% for several industrial sectors due to international competition (Aldy and Pizer 2009). This shift of production to other countries would also result in increased emissions in those countries and possibly to increased global emissions if the emissions intensity of production in that other country was higher than in the U.S.

Economists have developed predictions of competitiveness impacts for several energy-intensive sectors. We display one such set of predictions in Figure 2, which indicates that a $15 carbon price in 2012 is predicted to lead to a 0.5-1.0% loss of domestic production in favor of foreign imports in some industry sectors. Economists also predict that a cap-and-trade program would decrease consumption of these energy-intensive goods, since some fraction of the carbon price could be expected to be passed on to consumers. As displayed in Figure 2, reduced consumption is expected to have a greater effect on industry production levels than is increased competition from foreign imports, with total impacts from both increased competition and decreased consumption less than 3% in most sectors.

Figure 2. Predicted Impacts on Industrial Production Resulting from a $15 per ton CO_2 Allowance Price in 2012 without Output-Based Rebates (Aldy and Pizer 2009)



As seen in Figure 2, economists expect the effects of increased costs on domestic production to vary by industry. Among the factors that help explain these differences are (US EPA, US EIA, and US Treasury 2009) are:

- Production cost advantages: differences among countries in terms of access to inexpensive raw materials, highly skilled or low-cost labor, or advanced technologies that may provide cost advantages greater than any increased cost of production resulting from the cap-and-trade program;

[14] Emissions "leakage" would occur if implementation of a greenhouse gas policy (e.g., cap-and-trade legislation) were to induce industry sectors to replace domestic production with imports or to relocate production to foreign countries. If that were to occur, emissions would increase in the other country, resulting in emissions "leaking" from the domestic to the foreign country (Dröge et al. 2009).

- Large, fixed, capital investments: the extent to which increased production costs in the US might influence where new manufacturing facilities are located; and
- Transportation costs: the degree to which transportation costs for inputs and outputs influence the competitive position of the industry.

Benchmark-based Allowance Allocation in Proposed U.S. Cap-and-trade Legislation

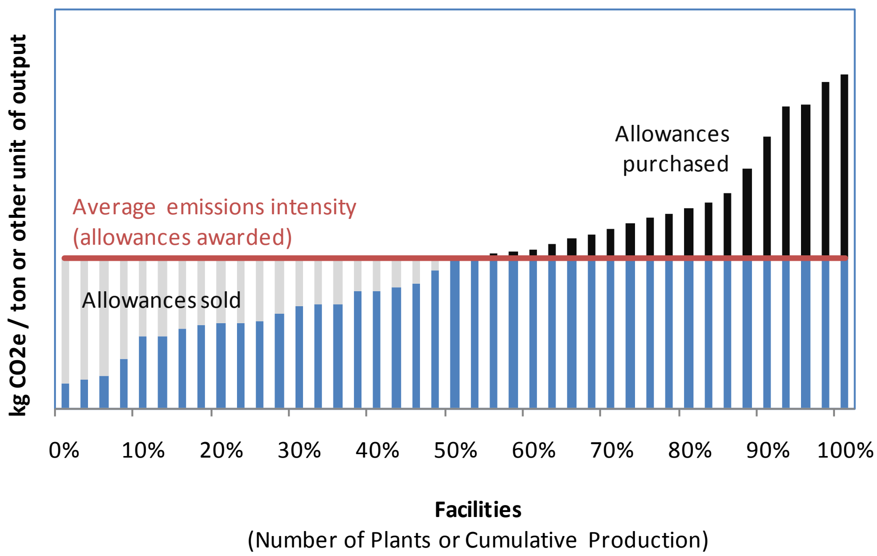
To help address concerns regarding industrial competitiveness, some observers have suggested that emissions allowances, the tradable commodity in a cap-and-trade system, be freely allocated to emissions-intensive, trade-exposed (EITE) industries. The *American Clean Energy and Security Act* (i.e., "Waxman-Markey"), which passed out of the U.S. House of Representatives as H.R. 2454 in June 2009, provides for allowances to EITE industries on the basis of a benchmark emissions level defined as the sector's average direct emissions per unit of production output.[15] Allowances are also rebated for indirect emissions (i.e., emissions released to produce purchased electricity or heat) based on a similar sector-average calculation.[16] The Senate bill drafted (but not introduced at the time of this writing) by Senators Kerry, Graham, and Lieberman is expected to include some similar provisions. Each individual facility in an EITE sector would receive free allowances based on the facility's output times the average emissions intensity of the sector (the benchmark).[17] Facilities with an emissions intensity below the average (more efficient or lower emitting facilities) would receive more allowances than they would need to cover their emissions and would therefore have extra allowances to sell. As shown in Figure 3, facilities with emissions above the average (less efficient or higher emitting facilities) would need to purchase allowances.

[15] See Section 761, page 1081, of H.R. 2454 as passed by the House of Representatives. In H.R. 2454, benchmarks are called "carbon factors." A similar approach to benchmarking was included in the Kerry-Boxer bill passed out of committee in the U.S. Senate in fall, 2009.

[16] Direct emissions are those released by sources owned or controlled by an entity, for example by the combustion of fossil fuels to fuel a boiler or the release of $CO_2$from limestone calcinations at a cement kiln. Indirect emissions are those released as a consequence of the activities of an entity but occur at sources not owned or controlled by the company (WBCSD and WRI 2004). The most commonly tracked source of indirect emissions is electricity production.

[17] The Waxman-Markey and Kerry-Boxer bills include allowance rebates to energy-intensive, trade-exposed (EITE) industry. EITE eligibility is determined according to criteria of energy or greenhouse gas intensity and trade intensity. Energy intensity is equal to a sector's energy expenditures divided by the dollar value of its shipments; GHG intensity is calculated the same way except that GHGs are monetized at $20/ton. Any sector that has an energy or GHG intensity of 20% or more is automatically an EITE industry. Otherwise, sectors that have an energy/carbon intensity greater than 5% and a trade intensity (defined as the sum of the value of imports and exports divided by sum of value of shipments and imports) greater than 15% are considered EITE. The actual benchmark value is calculated as the average direct and indirect emissions per unit of output (tons or a similar physical measure of output) for all entities in each eligible sector over the prior four years. Eligible entities are awarded allowances based on this benchmark multiplied by the average output in the two years preceding the allowance distribution. For further details on how EITE sectors are defined, benchmarks calculated, and allowances allocated, see EPA, EIA and Treasury (2009), Schneck, Murray, Mazurek and Boyd (2009), Tonkonogy (2009), or Bradbury (2009), or Section 764 of the final version of H.R. 2454 as passed by the House of Representatives in June 2009.

Figure 3. Simplified Diagram of Benchmark-based Allowance Allocation to EITE Industry Sectors in H.R. 2454 for a Given Sector or Subsector

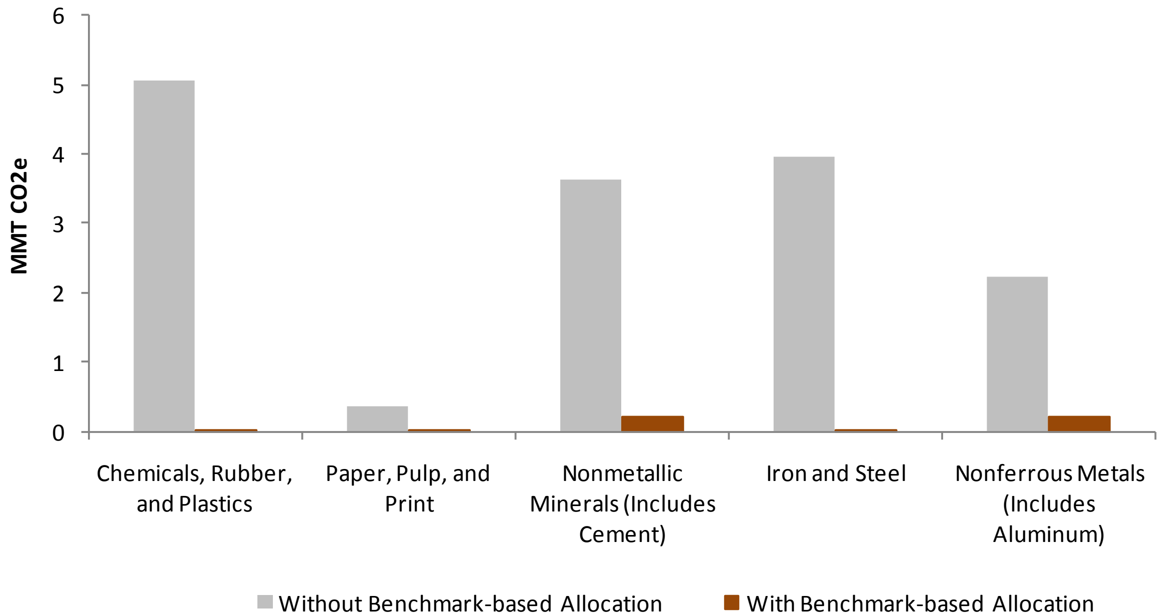


Economic modeling suggests that such output-based, or benchmarking, approaches to freely allocating allowances can effectively address industry competitiveness concerns, negating the potential impacts discussed above and summarized in Figure 2 (US EPA, US EIA, and US Treasury 2009; Fischer and Fox 2007; Fischer and Fox 2009). Analyzing the EITE provisions of H.R. 2454, a U.S. interagency report found that the free, output-based allocation of allowances "can eliminate almost all – and, in some cases, potentially more than all – of those cost impacts, as well as the resulting changes in net imports and emissions leakage"(EPA, EIA, and Treasury 2009).

Figure 4, below, displays results from the interagency study for five industrial sectors. Without the benchmark-based allocation (and companion free allowance allocation to electricity and natural gas local distribution companies), emissions leakage to developing countries is predicted to be many millions of tons of GHGs.[18] With the allocation, this leakage is predicted to be almost completely eliminated.

[18] The authors of the U.S. interagency report focused on leakage to developing countries based on the assumption that other major OECD trading partners (e.g., Canada, Mexico, Europe) would adopt comparable regulations, minimizing risks of leakage to and from these countries.

Figure 4. Estimated Emissions Leakage to Developing Countries from U.S. Energy-intensive Trade-Exposed Industries under H.R. 2454 without and with Benchmark-based Allowance Allocation (US EPA, US EIA, and US Treasury 2009)[19]



Despite the apparent benefits of free allocation of allowances via output-based benchmarks, tradeoffs do exist. In particular, freely allocating allowances to industry can substantially diminish the price signal to firms to reduce GHG emissions, the central goal of the cap-and-trade program (Schneck et al. 2009; Matthes et al. 2008). Freely allocating allowances also foregoes the opportunity to use that allowance value for "other uses, including support for low income consumers, clean energy technology, or deficit reduction" (US EPA, US EIA, and US Treasury 2009).

As an example of a benchmark-based allocation to an energy-intensive, trade-exposed industry, consider the cement sector. H.R. 2454 calls for emissions benchmarks to EITE sectors to be calculated "every 4 years, using an average of the four most recent years of the best available data" (Waxman and Markey 2009, 1111). Table 3, below, shows estimated emissions and production data for the U.S. cement industry for the four most recent years for which data are available as of the writing of this *White Paper*. The table includes both direct and indirect emissions for the cement sector as calculated by EPA, EIA, and Treasury in their Interagency Report (2009) from the national U.S. GHG inventory and the Energy Information Administration's Manufacturer Energy Consumption Survey. These underlying data sources – and the subsequent calculations in the Interagency Report – are calculated at an aggregate sector level and include significant assumptions and uncertainties. Nevertheless, we use these data here to provide a numerical example based on publicly available information. Actual benchmark development would likely require facility-level data to increase accuracy and enable construction of benchmark curves (as in Figure 1) or other statistics that would enable comparison across facilities.

Using the requirements in H.R. 2454 and these data, we estimate that the benchmark for direct emissions (i.e., process CO_2 and combustion-related GHGs) for the U.S. cement sector would therefore be approximately 0.78 tCO_2e per metric ton of cement produced.[20] The calculation of indirect emissions intensity would be a more

[19] The Waxman-Markey bill also includes free allocation to electricity and natural gas local distribution companies (LDCs) that would benefit energy-intensive and trade-exposed industries. In Figure 4, these LDC allocations are included in the results labeled "with benchmark-based allocation" and not in the results labeled "without benchmark-based allocation."

[20] Note that this benchmark calculation is denominated in metric tons of cement per the specifications of H.R. 2454 (page 1092). However, many stakeholders and analysts have recommended that benchmarks be based instead on clinker, the key, energy-intensive component of cement. Note also that data points in Table 3 are taken from public sources and in some cases are estimated. Since these may not be the exact same data sources or years ultimately used under any U.S. climate legislation, this calculation is approximate and for demonstration purposes only.

complicated calculation involving national average energy intensity multiplied by the GHG-intensity of each facility's electricity supply and is not displayed here.

Table 3. Sample Benchmark Calculation for Cement Sector under Waxman-Markey (H.R. 2454)

Year	GHG Emissions (MtCO2e)					Cement Production	Direct Emissions Intensity
	Process[21]	Combustion[22]	Total Direct	Indirect [22]	Total Direct + Indirect	Million Metric Tons[23]	tCO2e per ton of cement
2005	46	32	77	8	85	99	0.78
2006	47	31	78	8	85	98	0.79
2007	45	30	75	7	82	95	0.78
2008	41	27	68	7	74	86	0.78
						Direct Emissions Benchmark (Average over Four Years):	**0.78**

Under a cap-and-trade program with benchmark-based allocation similar to H.R. 2454, each individual facility would receive an allocation of allowances equal to its level of production (averaged over the two years preceding the distribution) multiplied by this direct emissions benchmark. For example, suppose that allowances were to be distributed in the year 2012,[24] that the benchmark value was 0.78 tCO_2e per ton of cement (as in Table 3), and cement production at a cement production facility averaged 400,000 metric tons in 2010 and 2011 (the two years preceding the distribution in 2012). This cement facility would therefore receive an allowance allocation as follows:

Benchmark value *(0.78 tCO_2e/ton cement) x* ***Production*** *(400,000 tons) =* ***Allocation*** *(312,000 allowances).*

The number of allowances allocated (312,000) may be more or less than the actual emissions released by the plant. If more, then the facility would have extra allowances to sell; if less, it would have to buy allowances. For example, suppose that this cement facility emitted 350,000 tCO_2e of emissions in 2012. With a free allocation of 312,000 allowances, the facility would need to purchase the remaining 38,000 allowances from the cap-and-trade market (or else reduce emissions by a corresponding amount). If, on the other hand, the facility emitted 300,000 tCO_2e, then the facility would have an extra 12,000 allowances to sell or bank for use in future years.[25]

The benchmark-based allocation for indirect emissions would be similar. Under H.R. 2454, the indirect emissions benchmark is calculated as the sector-wide average electricity intensity multiplied by an entity-specific electricity emissions factor. Using national (rather than facility-specific) data, this value would be expected to average about 0.08 tCO_2e per ton of cement (i.e., 7 $MtCO_2e$ divided by 86 million tons in 2008 per Table 3). The allocation is then calculated by multiplying by the production level (in this example, 400,000 tons).

In addition to proposed federal climate legislation, the State of California has proposed implementation of a cap-and-trade program. Its state-appointed Economic and Allocation Advisory Committee recently recommended output-based free allocation, which would require the development and use of benchmarks to the extent needed for the purpose of addressing emissions leakage associated with energy-intensive trade-exposed industries (EAAC 2010).[26]

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[21] Process emissions from cement production are taken from EPA's *Inventory of Greenhouse Gas Emissions and Sinks: 2000-2008* (2010c).
[22] Combustion and indirect emissions for the cement sector in 2006 are taken from US EPA, US EIA, and US Treasury (2009). Emissions for 2005, 2007, and 2008 are estimated here by SEI based on adjusting the 2006 values based on estimated annual energy intensity improvements for the U.S. cement industry reported in Dutrow et al (2010).
[23] Per the USGS Annual *Mineral Commodity Summary*: http://minerals.usgs.gov/minerals/pubs/commodity/cement/mcs-2010-cemen.pdf. Cement production here includes cement produced using imported clinker.
[24] The Waxman-Markey bill proposed to include most industrial sources beginning in 2014, but we use 2012 here for simplicity.
[25] Note that since the allocation is based on production in the two years prior to the distribution, an increase in production in the year of the distribution would not be figured into the allocation and could leave even the average producer with fewer allowances than emissions in that year. Similarly, a decline in production would result in too many allowances.
[26] In addition, the Portland Cement Association (PCA) has proposed that California adopt a "Cement Intensity Factor" as a tradable performance standard (Portland Cement Association 2009). Under a tradable performance standard, plants with performance less than the carbon intensity factor would generate a tradable credit, while plants with performance above the carbon intensity factor would have to purchase credits

Benchmark-based Allowance Allocation in the European Union

Benchmarks will be the basis for distributing free allowances to industry in the upcoming third phase of the European Union's Emissions Trading System, which begins in 2013. The EU-ETS Directive, adopted in late 2008, sets the broad framework for establishing these benchmarks. The Directive specifies that the benchmarks be based on "the average performance of the 10% most efficient installations in a sector or sub-sector" in the years 2007 and 2008 (European Union 2008).[27]

The EU will decide on final benchmark values for the EU-ETS in 2010. In order to facilitate the development of these benchmarks, the European Commission has developed a set of benchmarking criteria. For example, the criterion "one product, one benchmark" means that among facilities that produce the same product, there will be no disaggregation according to technology, process, fuel choice, or age of facilities. Prior to 2012, the EU will decide on the measure of physical output to use in conjunction with these benchmarks in order to determine the number of allowances each facility will receive.[28]

Emissions Performance Standards

While EPA and many stakeholders have expressed a preference for a market-based approach to reducing greenhouse gases (e.g., cap-and-trade), regulatory emissions performance standards continue to be considered and advanced as a "backstop" policy, should market-based approaches fail to be implemented (Alsalam 2009; Richardson, Fraas, and Burtraw 2010). In particular, EPA's December 2009 finding that greenhouse gases "endanger both the public health and the public welfare of current and future generations" may ultimately require EPA to regulate greenhouse gases from industrial facilities and other stationary sources under the Clean Air Act (Richardson, Fraas, and Burtraw 2010; US EPA 2009c). Accordingly, below we briefly describe possible means of developing and applying greenhouse gas emissions performance standards in a regulatory context.

Broadly speaking, regulations on GHG emissions from stationary, industrial facilities could be developed using one of two approaches. The first approach is to identify particular, sector-specific emissions benchmarks in terms, such as of tons CO_2e per unit of output, that must not be exceeded. This approach has already been taken in Washington State for baseload electric generation, per Senate Bill 6001 in 2007, which imposed an emissions performance standard (a benchmark of 1,100 pounds CO_2 per megawatt hour) that has to be met by all qualifying facilities. The second approach is to define a particular set of technological controls – such as best available control technology (BACT) – that must be implemented by a specific facility. These approaches are not mutually exclusive. For example, a BACT may be defined as a specific technology based on that technology's ability to meet a particular emissions benchmark. Below we discuss the possible development and application of the GHG benchmark-based approach under EPA's existing permitting systems. Box 1 describes the relationship of how this process could require a technology-specific approach under determinations of BACT.

Section 111 of the Clean Air Act authorizes EPA to set New Source Performance Standards (NSPS) for emissions from *new* or substantially modified sources based on best demonstrated technology (Alsalam 2009; Nordhaus 2007; Parker and McCarthy 2009). Section 111(d) also authorizes EPA to require states to regulate emissions from certain kinds of *existing* sources (covering non-criteria, non-hazardous air pollutants) for which it has promulgated an NSPS. In this case, EPA issues guidelines for these sources that are implemented by states. Accordingly, EPA and states could require both new and existing facilities, including power plants, refineries, and other industrial facilities, to achieve compliance with specific emissions limitations – for example, a benchmark quantity of GHG

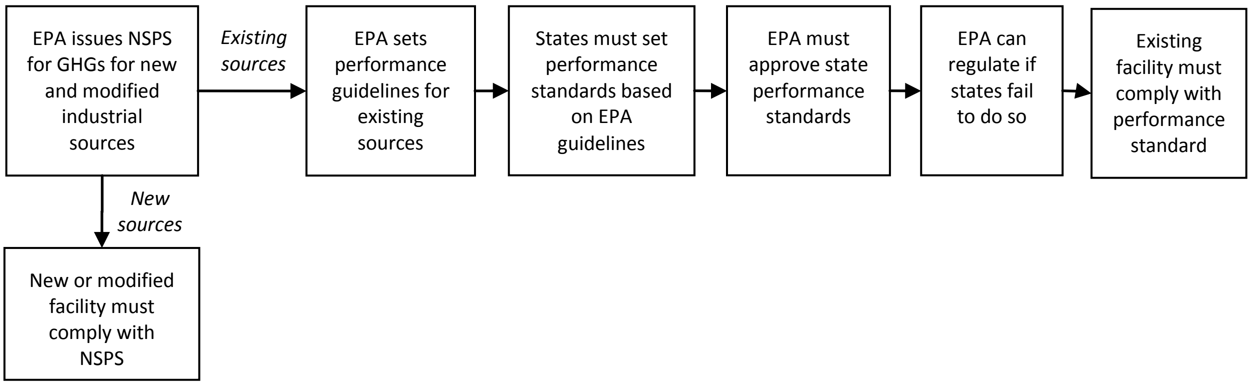
(Fischer 2003). In the absence of a cap, however, overall emissions could rise over time under a tradable intensity standard approach, if and as production increases.

[27] This level of ambition of the benchmark was agreed very early in the process. Since that time, the debate has focused on key methodological issues.

[28] In the EU, benchmarks will be in units of emissions per physical output (e.g., tons) and calculated based on performance of the 10% most efficient installations in 2007 and 2008 (European Union 2008). To translate this benchmark into an annual allocation of allowances, the benchmark must be multiplied by annual physical output. The rules for calculating physical output have not yet been agreed. The current proposal is use average production from 2005 to 2008 as the basis for "physical output."

emissions per unit of physical output of the facility (US EPA 2008b). Figure 5 displays the steps in the process of how the issuance of an NSPS for GHGs for an industrial source could translate into regulations on existing facilities.

Figure 5. Regulating GHGs from Industrial Facilities Under Section 111(d) of the Clean Air Act
Adapted from Richards, Fraas, and Burtraw (2010)



Section 111 of the Clean Air Act gives EPA significant flexibility in defining NSPS, including who is subject to the standards, when the regulations are phased in, the units and stringency of the standard, and, potentially, what emission-control systems are required. Accordingly, the process for developing greenhouse gas NSPS for industrial facilities is not immediately clear. EPA has stated that they "would need to consider how to develop a metric for measuring and benchmarking" GHG emissions "in terms of the facility's output production (e.g., amount of GHG per unit of production for a given facility)" (US EPA 2008b).[29] Whether EPA takes such an approach for greenhouse gases remains to be seen. EPA has shown a tendency to move towards more output-based standards under NSPS. For example, EPA has proposed, in its updates to the Portland cement NSPS, to switch the NSPS from being based on tons of input to tons of output (clinker): "Adopting an output-based standard avoids rewarding a source for becoming less efficient, i.e., requiring more feed to produce a unit of product, therefore promoting the most efficient production processes" (US EPA 2008c, p. 34076).

EPA is statutorily required to review NSPS every eight years. Development and inclusion of emissions performance standards for greenhouse gases would likely occur during these reviews (US EPA 2008d). In 2010, EPA is revising its NSPS for cement, expected in June. Some observers have speculated that EPA will include greenhouse gas emissions in the revisions (Bravender 2009). EPA has requested budget from Congress for funds to develop GHG NSPS for stationary sources, suggesting they do intend to develop NSPS for GHGs in the near future.[30] EPA staff have suggested that the June revisions to the Portland Cement NSPS will not include actual GHG standards for cement kilns, but instead will include some general statement about EPA's views on GHGs (EPA Office of Air and Radiation staff, personal communication, April 2010). If EPA does not include GHGs in the revised cement NSPS, some observers expect a legal challenge, as was the case in 2008 when EPA did not include GHGs in its updated NSPS for petroleum refineries (Richardson, Fraas, and Burtraw 2010).

Federal New Source Performance Standards set a performance floor for permitting in the New Source Review program under Section 111 of the Clean Air Act. Implementation of the New Source Review permitting program (involving case by case determination of best available control technology, or BACT) is carried out by state and local air pollution control agencies, such as the Washington State Department of Ecology and the Puget Sound Clean Air Agency. The Department of Ecology and most local air agencies in Washington have adopted most of the federal New Source Performance Standards covering other pollutants by reference. Washington State and local air

[29] EPA also discussed potential approaches in individual sectors. For example, regarding the petroleum refining sector, EPA states, "We are aware of proprietary metrics that exist that are used by refiners to benchmark their operations with respect to GHG emissions; however the use of a proprietary metric is problematic from a rulemaking perspective. We believe that a more transparent metric is desirable that could be used to describe the amount of GHG per unit of production for a given refinery" (US EPA 2008b, 21). For a list of existing NSPS for other pollutants, see: http://www.epa.gov/ttn/atw/nsps/nspstbl.html.
[30] See http://www.whitehouse.gov/omb/budget/fy2011/assets/environmental.pdf.

agencies in the state have adopted several output-based performance standards for other pollutants, as summarized in Table 4, indicating a precedent for such an approach in Washington.[31]

Table 4. Sample of Existing Output-based Emissions Performance Standards for Industrial Facilities in Washington
(Including examples from both State regulations and local permits)

Sector	Pollutant	Sub-sector or Process	Benchmark	Jurisdiction	Source of Regulation or Permit
Aluminum	Particulate matter (PM)	Primary aluminum	7.5 grams PM per kilogram of aluminum produced	Washington Department of Ecology	WAC 173-415-030
Electricity	Greenhouse gases ($CO2_e$)	Baseload thermal-electric generation facilities	1,100 lb CO_2e per MWh	Washington Department of Ecology	WAC 173-407-130
Glass	Particulate matter (PM)	Container glass (St. Gobain Containers)	0.5 lb PM_{10}/ton of glass produced	Puget Sound Clean Air Agency	Puget Sound Clean Air Agency Order of Approval No. 5193 and 5289
Iron & steel	Nitrous oxides	Electric arc furnace (Nucor Steel)	0.48 lb NO_x per ton of steel produced	Puget Sound Clean Air Agency	Puget Sound Clean Air Agency Order of Approval 9669
Pulp & paper	Sulfur dioxide (SO_2)	Sulfite pulping mills that incinerate spent sulfite liquor	10 g SO_2 / kg pulp produced[32]	Washington Department of Ecology	WAC 173-410-040

As discussed above, federal NSPS apply only to new and modified sources. Section 111(d) of the Clean Air Act also allows EPA to regulate *existing* sources under the NSPS program.[33] Under Section 111(d), the Clean Air Act would require EPA to set performance guidelines (similar to, but likely less stringent, than NSPS) for existing sources and then for the states (or EPA if a state were to fail to act) to create actual performance standards and submit plans to implement the standards (Richardson, Fraas, and Burtraw 2010). If as part of the NSPS proposal for cement plants, EPA were also to issue an emission guideline that addresses GHG emissions from existing facilities, then the state would have to adopt the guideline as a rule, develop a substitute state rule, or wait for EPA to issue the an EPA-implemented rule.

[31] Performance standards are not always based on output (i.e., benchmarks). Instead they can be in terms of concentration of pollutant from a stack. For example, WAC 173-415-030 specifies that SO_2 emissions from primary aluminum facilities must not exceed one thousand parts per million in any gas, in addition to specifying a benchmark-based standard of 30 g SO_2 per kg aluminum produced.
[32] Air dried, unbleached pulp.
[33] The authority to regulate existing sources using performance standards only applies if the pollutant is not regulated under the National Ambient Air Quality Standards (NAAQS) or as toxic pollutants under Section 112 of the Clean Air Act. Each of these has been discussed as an alternative or complementary pathway to regulating GHGs but are generally considered less feasible than NSPS. Nevertheless, this restriction on applying NSPS to existing sources may limit options for integrated approaches that combine regulation under different provisions of the. Clean Air Act (Richardson, Fraas, and Burtraw 2010).

Box 1. New Source Performance Standards and Best Available Control Technology (BACT)

New Source Review is the process for obtaining construction permits for new and modified stationary sources under the Clean Air Act and is sometimes also called Prevention of Significant Deterioration (PSD). Under the New Source Review (NSR) program:

1. **EPA establishes New Source Performance Standards (NSPS) for new and modified sources**.
2. **A new or modified facility emitting more than the pollutant threshold applies for a permit to a state or local air agency and must undergo preconstruction review and permitting.** EPA's proposed "tailoring rule" (US EPA 2009a) would raise the threshold to 25,000 tons CO_2e annually and shield small stationary sources. EPA Administrator Lisa Jackson has since proposed that this limit be raised to a "substantially higher" threshold and that the "smallest sources" not be subject to permitting before 2016 (Jackson 2010).
3. **The state or local air agency determines Best Available Control Technology (BACT) on a case-by-case basis**, taking into account energy, environmental, and economic impacts. Determinations of BACT must be at least as stringent as the NSPS.

Determination of BACT for GHGs will soon be required under the NSR program. In April 2010, EPA issued final rules that set GHG emissions and mileage standards for cars and light trucks (US EPA and US DOT 2010). These rules trigger regulation of GHGs for stationary sources under NSR and will require that major new or modified sources install BACT (Pew Center on Global Climate Change 2010). EPA has stated that limits (or related "work practice standards") for GHGs will be required in PSD permits for stationary sources on January 2, 2011 (US EPA 2010b).[1]

The definition of BACT for greenhouse gases at stationary sources is a major unknown, and defining what technologies qualify as BACT could be an enormous challenge. The normal process for determining BACT is to:

1. Identify all control options
2. Eliminate technically infeasible options
3. Rank remaining control options
4. Eliminate control options based on evaluation of collateral impacts
5. Select BACT

The difficulties of this task for GHGs were pointed out in a report from an EPA advisory committee. The interim report, by thirty-five representatives from industry, state and local governments, and environmental and public health non-profit organizations, identified several areas of contention on defining BACT for GHGs, including how tightly to draw the boundary around what emissions are regulated, criteria to use to determine whether a technology is feasible, and criteria for eliminating particular control technologies from consideration (Clean Air Act Advisory Committee 2010).

Some initial lessons may be drawn from the first facility in the U.S. to undergo a BACT determination for GHGs: the Russell City Energy Center, a combined cycle natural gas-fired power plant in Hayward, CA, which underwent the 5-step process above (Calpine 2010). In particular, that facility defined BACT as a net energy efficiency value expressed as a benchmark value of emissions (1100 lb CO_2/MWh, the California GHG emission performance standard for power plants). This value was not the maximum possible efficiency but was instead a level that could be consistently maintained under all operating conditions.

In addition, EPA is also considering means of providing incentives for continuous improvement and energy efficiency within definitions of BACT for greenhouse gases. These enhancements are being considered to help encourage performance beyond what is required by BACT and between upgrades to the definition of BACT.

Summary: Benchmarks in the Three Policy Approaches

Emissions benchmarks are used in each of the three policy approaches discussed above. For example,

- Member companies of the International Aluminum Institute (IAI) have committed to operate by 2020 with perfluorocarbons (PFC) emissions per ton of aluminum no higher than the 2006 global median level for their technology type. Alcoa, for example, is a member of the IAI, and its Washington facilities already exceed these targets. The IAI goals are an example of a voluntary, unilateral initiative undertaken by industry to reduce emissions of one highly potent GHG below a benchmark level.
- The Waxman-Markey bill, which passed out of the U.S. House of Representatives in June 2009, would allocate allowances to energy-intensive, trade-exposed industries at the level of a sector-average benchmark. For example, cement kilns would receive a number of allowances for each ton of cement produced to cover their direct emissions. This is an example of the use of benchmarks in a cap-and-trade program.
- Washington State has set a limit on the release of sulfur dioxide emissions from sulfite pulp mills of 10 grams of SO_2 per ton of pulp produced. This is an example of a mandatory performance standard on emissions.

The process for developing benchmarks such as these in the three different policy contexts share many common traits, issues, and options. In the following section, we describe several issues and options for constructing greenhouse gas benchmarks for industry and assess how these factors – and the process for constructing benchmarks – might differ according to the policy approach selected.

3. Benchmark Construction: Issues and Options

In this section, we discuss and assess several key issues and options for constructing GHG benchmarks for industry. These include:

- **Definition of product or sector being benchmarked**, including factors to consider in determining whether benchmarks are assigned at a sector-wide level (e.g. pulp and paper) or instead for particular products, processes (e.g., sulfite pulp), or other facility-specific factors;
- **Measurement protocol and boundaries**, such as whether to focus benchmarks on direct emissions only or all emissions (including the indirect emissions associated with purchased energy, such as electricity);
- **Units for normalizing the benchmark**, meaning alternative choices for benchmark denominator, such as tons of output, dollars of output, or tons of input;
- **Benchmark ambition**, or whether to make the benchmark based on an average across facilities or instead some better-than average value; and
- **Data sources** that may support development of benchmarks.

At the end of the section, we reflect on how the different policy approaches described in Section 2 – voluntary goals, output-based allocation in a cap-and-trade program, and emission performance standards – might affect how benchmarks are constructed. We also describe a potential alternative to benchmarking particular products or sectors: benchmarking heat production, an activity that extends across sectors.

Definition of Product or Activity Being Benchmarked

Benchmarks can be developed for entire industries (e.g., the global steel industry) or for individual plants with particular fuel choices and feedstocks (e.g., a steel plant with an electric arc furnace that uses 100% scrap steel). The choice of scale at which to define the benchmark – that is, the level of aggregation across subsectors, product types, technologies and other plant circumstances – is a critical design choice for ensuring that the benchmark provides an appropriate and effective incentive for reducing emissions.

Benchmarks based on an entire class of products (e.g., steel or cement) will tend to give the industry maximum long-term flexibility in reducing emissions. Under an industry-wide benchmark, industry actors could adapt by increasing the efficiency of existing plants, switching fuels from coal or oil to natural gas or low-carbon electricity, phasing out more GHG-intensive technologies in favor of less GHG-intensive technologies, or using a higher fraction of secondary (recovered) feedstock.

Consider the U.S. steel industry. The American Iron and Steel Institute reports that the U.S. steel industry emits an average of 1.24 tCO_2e per ton of steel produced (US EPA 2008a). Of the two primary types of steel mills, integrated (e.g., basic oxygen furnace or BOF) mills tend to produce much higher emissions than this average, in part because they must first convert iron to steel rather than rely on scrap steel. Electric arc furnaces (that rely on scrap steel as feedstock) produce much lower emissions (IEA 2008). Accordingly, implementing a policy approach based on a single industry-wide benchmark of 1.24 tCO_2e per ton of steel could provide a significant incentive to increase production at electric arc furnaces at the expense of production at integrated mills, provided that increased quantities of scrap steel were available to supply the electric arc furnaces.[34] Such an incentive – even as it allows maximum flexibility to the industry to make investments that cost-effectively reduce emissions – would not allow for site- or market-specific considerations and could lead to the closure of smaller, older manufacturers that cannot as readily upgrade, replace capital stock, or access supplies of alternative (e.g., recovered) feedstocks.

By contrast, a benchmark based on the specifics of individual plants may help recognize particular, site-specific conditions, but provides less incentive for larger-scale restructuring of the industry. For example, if individual benchmark-based regulatory performance standards were developed for each type of facility, each fuel choice, each type or quality of feedstock, and other site-specific parameters (such as the availability of recovered feedstocks), then the benchmark would provide relatively little (if any) incentive to alter these factors to reduce GHG emissions, leaving process efficiency improvements or minor retrofits as the only option. If site-specific benchmarks were developed in a cap-and-trade setting, then each facility would receive an allocation roughly equivalent to historic emissions, at least for the first allowance distribution period.[35] Allocating based on historic emissions ("grandfathering") has been criticized for not rewarding those facilities that have undertaken "early action" to reduce emissions before the start of the cap-and-trade program (EAAC 2010; Raymond 2003).

To address the tension between benchmark aggregation and specificity, one approach could be to develop individual benchmarks for each type of unique product produced by an industry. This approach has been employed in the European Union's cap-and-trade program, where it is has been called "one product, one benchmark." Under such an approach, only one benchmark would be developed for each product. Separate benchmarks would not be developed for different production technologies, fuel choices, type or quality of feedstock, local climate circumstances, product color, or other facility-specific factors.

For example, a benchmark on the production of writing paper would recognize the unique processes used to produce writing paper instead of another paper grade (e.g., newsprint). Separate benchmarks for different paper products would avoid incentivizing the production of one type of paper at the expense of another that could result if only one benchmark for all paper grades were applied. Even under a "one product, one benchmark" approach, however, many challenges would still remain in defining what constitutes a unique product. Although writing paper is clearly different from newspaper, cases could be made for distinguishing more specific grades of some types of paper (e.g., coated versus uncoated papers, or different types of containerboard). Similar decisions exist in most other sectors, including steel, aluminum, and chemical sectors. An additional challenge with the "one

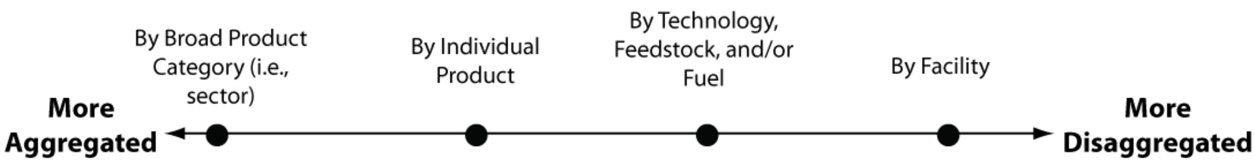
[34] The emissions benefits of an electric arc furnace (EAF) rely strongly on the use of scrap steel, of which supplies are limited. The alternative (virgin) feedstock for an EAF is direct reduced iron (DRI). According to the International Energy Agency, production of steel from DRI can be more or less emissions intensive than producing steel in a basic oxygen furnace depending on whether coal or natural gas, respectively, are used to produce the DRI (IEA 2008).

[35] Since still based on output, allocations in future years would depend on the facility to continue producing..

product, one benchmark" approach is how to develop benchmarks for facilities that produce many different products from the same process units.

Figure 6, below, displays the continuum of levels of benchmark disaggregation along with samples of the choices at each level.

Figure 6. Choices of Benchmark Disaggregation Lie along a Continuum
(With Sample Choices by Sector)



Aluminum	Cast aluminum, rolled aluminum	Anode type	e.g., Intalco, Ferndale
Cement	Clinker (white or grey)	Wet vs. dry kiln	e.g., Ash Grove Cement, Seattle
Glass	Flat, container, fiber glass	Fraction of recycled cullet used	e.g., Cardinal Glass, Winlock
Paper	Newsprint, writing paper, market pulp	Mechanical versus chemical pulp	e.g., Norpac, Longview
Steel	High-alloy steel, hot-rolled steel, cold-rolled steel	EAF vs. BOF, integrated versus rolling mill	e.g., Nucor Steel, Seattle

In a cap-and-trade program, a "one product, one benchmark" approach could help preserve a clear price signal to firms to make investments in reducing emissions. Under cap-and-trade programs like the EU-ETS and the program proposed in H.R. 2454, the program administrator would freely allocate or rebate emissions allowances to each firm according to the benchmark value. Facilities that emit more than the benchmark level would have the flexibility of purchasing allowances from the market to cover their additional emissions, while facilities that emit less than the benchmark value would have allowances to sell. Analysis conducted to support the EU's benchmark development process has found that benchmark-based allocation based on the "one product, one benchmark" concept (but not including consideration of technology or process type, fuels, or feedstock variations) best preserves the price signal to individual firms (Neelis et al. 2009).

Unlike in a cap-and-trade program, a "one product, one benchmark" approach may not be as applicable in a regulatory system using performance standards, however, unless some degree of trading or crediting was provided to the facilities to provide flexibility in meeting the benchmark.

Benchmark Disaggregation in the Three Policy Approaches

The type and extent of disaggregation for setting benchmarks can have important implications for how well the underlying policy can achieve its objectives. For example, in seeking to reduce GHG emissions, policymakers may also strive to maximize the economic efficiency of emission reductions attained, to avoid emissions leakage, and/or to manage cost burdens in an equitable manner. From an economic perspective, the rationale for disaggregating benchmarks by technology, feedstock, or fuel can differ by policy approach, as follows.

- **Cap-and-trade programs use benchmark-based allowance allocation to avoid carbon leakage while retaining an overall CO_2 price signal to incentivize lower-emissions production.** An aggregated benchmark (e.g., uniform across the industry sector) sends the same CO_2 price signal to all installations, irrespective of size, fuel, technology or age. If the benchmarks were instead highly differentiated by facility-specific factors, total economic costs of attaining a particular reduction in GHG emissions would **increase** total economic costs, since overall GHG abatement is determined by the emissions cap and awarding free allowances to facilities based on their individual circumstances diminishes the price signal to shift production from more GHG-intensive technologies, feedstocks, or fuels to less GHG-intensive technologies, feedstocks, or fuels. In other words, and in most cases, the benchmark value does not control the level of abatement. Rather, it helps avoid carbon leakage while attempting to preserve appropriate price signals to individual facilities.

- **In contrast to allowance allocation, regulatory performance standards directly determine the level of abatement. Since a performance standard also acts as a go/no-go threshold, the level of the benchmark will more directly determine whether new facilities are constructed or existing facilities continue to operate.** If the costs of abatement are different for different technologies, feedstocks, or fuels, it may be appropriate to consider more ambitious benchmarks for those with low abatement costs, and a less ambitious benchmark where abatement costs are higher. In this case, allowing for disaggregation by technology, feedstock, or fuel could **reduce** the total economic costs to achieve a given level of abatement. This outcome is more likely for existing facilities with long-lived capital investments and high switching costs. With new facilities the case for disaggregation may be less compelling.

- **In voluntary approach, the differentiating among technologies, feedstocks or fuels might encourage greater participation, especially by those companies with long-lived investments in technologies for which abatement options are more limited or costly.** Similar to regulatory performance standards, it may make sense to differentiate benchmarks if the costs of abatement are different between technologies. In this way, allowing for disaggregation can **reduce** total economic costs.

In summary, from an economic perspective, it may make more sense to disaggregated benchmarks by technology, feedstock, or fuel under voluntary and regulatory approaches, than for allowance distribution under a cap-and-trade system.

Considerations for Intermediate Products

Benchmarks are typically set on a measure of final product output, such as tons of steel or paper produced. Yet the choice of what constitutes a product is not always as easy as it seems. In some contexts, developing separate benchmarks for intermediate products (such as iron used to make steel, or pulp used to make paper) that are energy-intensive and commonly traded between firms and installations may help advance program goals.

In particular, in a cap-and-trade system, the primary motivations for free benchmark allocation is to avoid carbon leakage, while preserving the price signal and rewarding top performers that have undertaken “early action.” If the benchmark were based only on the final product, then companies could instead import the emission intensive intermediate product from non-regulated regions, therefore potentially increasing the risk of carbon leakage. To address this risk, benchmarks can be developed for emissions-intensive intermediate products that are traded between firms and internationally.

Such an approach could (but need not necessarily) be employed under a regulatory or voluntary approaches as well. Defining the benchmark on the final product only would help incentivize GHG emission reductions along the whole supply chain (including the intermediate products), allowing for greater flexibility (and, in turn, lower abatement costs) and potentially also for more ambitious benchmarks. On the other hand, calculating benchmarks for the full life-cycle emissions of an industry or facility’s products could introduce new extra methodological complexity for sectors where a significant fraction of an energy-intensive feedstock is traded between firms. For example, if paper mills were responsible for the emissions of the pulp they purchase from other facilities, new market data systems would be needed to allow pulp sellers to measure and communicate the emissions intensity of their pulp to paper makers purchasing this pulp on the market.

Table 5, below, summarizes the benefits and challenges of different levels of benchmark disaggregation discussed above.

Table 5. Benefits and Challenges of Benchmark Disaggregation

Level of Disaggregation	Benefits	Challenges
Broad product category (i.e., sector-wide) Benchmarks developed for an entire sector's output (e.g. pulp and paper)	Can be simpler than more disaggregated benchmarks. Provides maximum flexibility to industry in reducing emissions.	Smaller, older manufacturers performing far from the sector-wide average may be less able to upgrade, replace capital stock, or access alternative feedstocks. Does not recognize trade of intermediate products.
Product-specific Benchmarks developed for particular products (e.g., cardboard) but not for individual facilities	Provides greater flexibility and incentive to industry to reduce emissions than do facility-specific benchmarks, particularly in cap-and-trade context.	Determining what constitutes a unique product (including intermediate products) can be very challenging. Requires confidential data on product output. May not be as applicable in performance standard or voluntary context since does not recognize facility-specific conditions.
With consideration for technology, feedstock, and/or fuel	Can recognize long-lived investments or particular market conditions, possibly increasing flexibility in a voluntary program	Potentially large administrative burden. Distorts price signal.
Facility-specific Individual benchmarks developed for each facility (e.g., a particular paper mill)	Can tailor benchmarks to individual sites and set more ambitious benchmarks for facilities with greater GHG-reduction opportunities, thereby potentially increasing economic efficiency, at least in a regulatory or voluntary context	Potentially huge administrative burden to develop benchmarks for each individual facility. Erodes incentive for larger-scale restructuring of the industry (distorts price signal).

Measurement Protocol and Boundaries

To ensure that all relevant emission sources are included and produce effective benchmarks, policymakers and administrators need common guidelines, tools, and methods to measure or estimate greenhouse gas emissions and production at the facility level.[36] Fortunately, several GHG measurement protocols have already been established. For example, the World Business Council on Sustainable Development and World Resources Institute, working in partnership with industry groups, developed the GHG Protocol, which has been used widely for the past decade. Recently, US EPA established protocols to guide mandatory reporting of greenhouse gas emissions for all facilities in certain sectors (e.g., aluminum, cement) and for facilities that emit more than 25,000 tons CO_2e annually in most other sectors. The rule will also require reporting of production volumes for those industrial sectors required to report. Washington State will be harmonizing the reporting methodologies for its Greenhouse Gas Reporting Rule, which will cover facilities that emit at least 10,000 tons CO_2e, with those of EPA. Ideally, the same measurement protocol should be used for constructing benchmarks and for monitoring the emissions to which the benchmark will apply.

Include Indirect Emissions?

A critical question in developing GHG benchmarks will be whether and how to account for indirect emissions, in particular the emissions associated with electricity or heat purchased by industrial facilities.

The decision depends in part on the policy context of the benchmark development. In case of voluntary performance goals, including both direct and indirect emissions puts facilities on a more equal footing, and avoids meeting emission reduction goals simply by substituting purchased heat or electricity for on-site fuel combustion. While such a shift might reduce direct on-site emissions, it would increase emissions outside the facility boundary if fossil fuels were used to produce the purchased heat or electricity.

For cap-and-trade systems, however, the choice is less obvious. Under a cap-and-trade system that covers both electricity and industrial facilities, power producers would need to secure allowances for the emissions associated with electricity sold to industrial facilities. Therefore, there is no need to separately account for indirect emissions from electricity purchased by industrial facilities.

[36] Secure and robust data systems must be put in place to maintain confidence and, where needed, confidentiality.

However, industrial facilities could experience cost impacts due to any increase in the cost of electricity resulting from the price of allowances. Accordingly, some cap-and-trade program design (including of H.R. 2454 and Australia's proposed cap-and-trade system) provide further cost support to industry through benchmark-based allowance allocation for indirect emissions similar to the allocation for direct emissions.

For performance standards, the choice of whether to include direct and indirect emissions may be even yet more complex. The concern about a facility switching from fossil fuel to electricity with little or no reduction in overall (direct + indirect) emissions still exists, but is difficult to address given that NSPS and BACT are designed to address direct emissions, not indirect emissions or total energy use. Nevertheless, EPA has been exploring means of encouraging energy efficiency through provisions in BACT to potentially also address indirect emissions. Further research is necessary on means of addressing indirect emissions in a performance-standard approach.

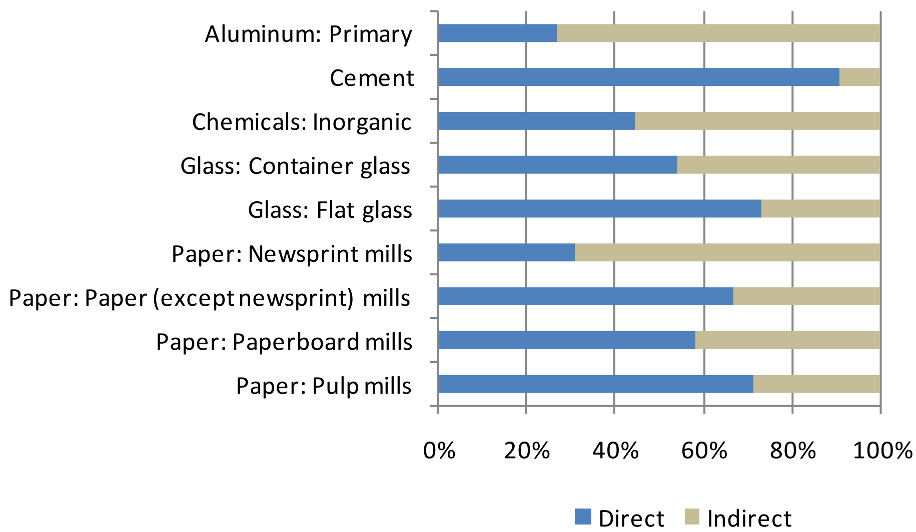
Table 6. Benefits and Challenges of Including Direct or All Emissions in Benchmark Construction

	Voluntary	Allowance Rebate in Cap-and-trade	Performance Standards
Direct only	▪ **Benefits**: simpler ▪ **Challenges**: might encourage emissions "leakage" to electricity sector	▪ **Benefits**: aligns well with basic structure of cap-and-trade ▪ **Challenges**: none	▪ **Benefits**: simpler ▪ **Challenges**: could encourage emissions "leakage" to electricity sector
All (Direct + Indirect)	▪ **Benefits**: includes more sources of emissions over which facility has control ▪ **Challenges**: greater data needs and methodological complexity	▪ **Benefits**: can help offset any added costs to industry from higher electricity prices ▪ **Challenges**: greater data needs and methodological complexity	▪ **Benefits**: includes all sources of emissions over which facility has control ▪ **Challenges**: BACT not designed to address indirect emissions; greater data needs and methodological complexity; might need to regulate electricity or heat purchases as a proxy for indirect emissions.

The relative importance of direct versus all (direct +indirect) emissions also varies by sector. Some sectors (particularly cement) release far more emissions directly than indirectly. For many others (e.g., aluminum), a significant fraction of the sector's emissions are released indirectly through electricity production. Figure 7 displays the overall fraction of direct versus indirect emissions for select industry sectors in the U.S. If a similar graph were produced for the northwestern U.S., the relative amount of direct and indirect emissions would change for many of the sectors, due to the region's relatively higher reliance on low-carbon hydroelectricity.

Even more critical than the balance of direct and indirect emissions is the relative substitutability of electricity and fossil fuels within a sector and the emissions-intensity of that electricity. For example, it could be argued that the electricity-dependent electric arc furnaces and the fossil-fuel-dependent (and more emissions-intensive) basic oxygen furnaces produce equivalent products and should be compared using the same benchmark. If that were the case, such a benchmark would be likely to incentivize the use of electric arc furnaces due to their lower emissions intensity, even considering the emissions used to produce the electricity.

Figure 7. Relative Overall U.S. Fraction of Direct and Indirect GHG Emissions in Select Energy-Intensive, Trade-exposed Sectors (US EPA, US EIA, and US Treasury 2009).



Another complicated issue is the use of combined heat and power (CHP), or cogeneration. With CHP, power and heat are produced by boilers or turbines at industrial facilities, and power or heat may be used internally, or sold to the grid or to other facilities. CHP requires approximately 25% less energy than separate heat and power systems and thus can help facilities meet emissions benchmarks (IEA 2008). Because CHP's two products – heat and electricity – may alternately be used internally or transferred to other facilities, the task of allocating emissions to the respective facilities can be difficult. As a result, how CHP is considered is an important consideration in developing and applying emissions benchmarks. [Research is ongoing; we will speak to options to address CHP in the subsequent version of this *White Paper*.]

Units for Normalizing

As described in the introduction to this paper, GHG benchmarks are typically expressed as a quantity of emissions per unit of output, as in the following simple equation:

$$GHG\ Benchmark = \frac{Emissions\ (tons\ CO_2e)}{Unit\ of\ Output\ (tons, \$, or\ other\ metric)}$$

The denominator of this equation – the *unit of output* – is often a physical unit of product output (e.g., a ton of cement, steel, or aluminum). However, the denominator could instead be a unit of input (e.g., a ton or barrel of crude oil refined), or some other metric, such as production capacity or a monetary output (e.g., net value added or revenue of product shipped). Benchmarking can also utilize a combination of factors, expressed in terms of an equation, as in the method of the US EPA ENERGY STAR program. This section discusses the rationale and tradeoffs with alternate choices of benchmark denominator, or the units for normalizing the benchmark.

Most, but not all, existing benchmarking efforts use physical product output as the benchmark denominator. For example, the formulas for constructing sector-average benchmarks in the U.S. Waxman-Markey bill (H.R. 2454), existing emissions performance standards in Washington State (e.g., NO_X from steel mills, SO_2 from sulfite pulp mills), and most of the voluntary efforts summarized in Section 2 of this White Paper all rely on a weight-based, physical unit of output. Physical units are not affected by cyclical variations in prices or other economic fluctuations and link more directly to technology performance and efficiency than do monetary denominators.

Furthermore, a physical unit of *output* (rather than input) will tend to better enable assessment of technology performance and efficiency. If a unit of *input* was used, the benchmark performance (emissions per ton or per unit of heat input) could provide a perverse incentive to use input feedstocks less efficiently, since using more input to produce the same unit of output would drive up the benchmark denominator and therefore improve the apparent GHG performance of the facility. By contrast, basing the benchmark on output provides an incentive to increase production – a goal that, while it may also have unintended consequences, does support manufacturing within the benchmark region and may help address industry competitiveness concerns, particularly in a cap-and-trade context. Still, for some industry sectors basing the benchmark on a unit of input may be desirable if defining and quantifying output-based benchmarks is too onerous. The petroleum refining industry is one sector where benchmarking based on inputs (e.g., barrels of crude oil) is commonly discussed and implemented.

Table 7, below, summarizes benefits and challenges associated with alternative choices of physical versus monetary and input versus output in selecting benchmark denominators.

Table 7. Benefits and Challenges of Alternative Choices of Benchmark Denominator

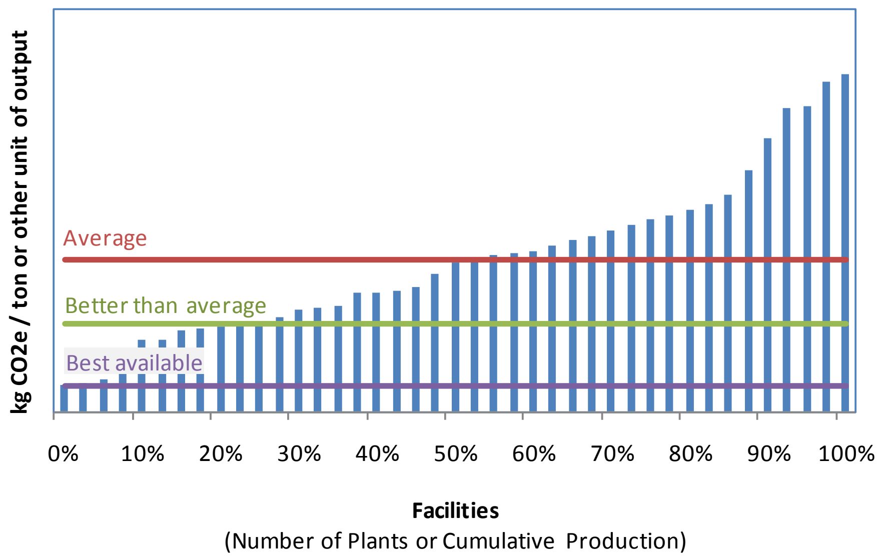
	Benefits	Challenges
Physical Input	Can be well-suited to industry sectors where the products are far more complicated than the inputs (e.g., petroleum refining)	Fails to reward efficient use of raw material feedstock in producing a product and can lead to perverse incentives
Physical Output	Links directly to technology performance and efficiency and therefore can more directly be used to help identify improvements possible through new technologies. Can enable comparisons between world regions regardless of the structure of each region's industry and economic data.	Requires data on product output, which is generally confidential, though will be supplied under mandatory GHG reporting in most instances
Monetary Input	None identified	Would require confidential information on each facility's expenditures on raw materials yet would not provide any physical unit (e.g., barrels of crude oil) on which to assess plant efficiency
Monetary Output	Some such data already exist, at least at the sector-wide level, through existing sources (e.g., U.S. Census Bureau). Can create a common denominator across sectors.	Using a monetary unit can introduce other types of variation (price or currency fluctuations) that would obscure the underlying technical performance of the plant

Benchmark Ambition

The choice of an emissions benchmark – whether average, better-than-average, or best available – depends on the intended use. If the goal is to assess performance relative to average emissions practices, a simple average can be sufficient, particularly when coupled with a curve such as was presented in Figure 1.

A benchmarking curve (and its underlying data) can also be used to assess potential benchmarks with ambitions other than a simple average performance. For example, a benchmarking curve can be used to understand the best achieved level of emissions performance, to set a goal for a specified improvement over the current average (e.g., a 20% improvement in emissions intensity by a certain year), or to select a definition of top-performing plants (e.g., the plants in the top 25th percentile of performers). In Figure 8, below, the green horizontal line depicts the emissions intensity of the top 25th percentile of plants and the purple horizontal line depicts the best-performing plant for a fictional industry sector.

Figure 8. Hypothetical Benchmark Curve: Choice of Benchmark Ambition



How ambitious to make the benchmark depends on the policy context and goals of the program. Under regulatory performance standards and voluntary programs, the level of benchmark ambition directly determines the level of greenhouse gas abatement and each sector's share of the costs of meeting a particular regional emissions target, as was discussed on page 18. When used for allowance allocation, on the other hand, the ambition of the benchmark does not itself determine the level of abatement but instead helps avoid carbon leakage while preserving price signals to individual facilities. Economic modeling, as in the U.S. Interagency Report (US EPA, US EIA, and US Treasury 2009), can be used to estimate the benchmark level that would be likely to avoid emissions leakage (as well as to avoid subsidizing domestic production if set too high) in individual industries.

Governor Gregoire's Executive Order 09-05 specifically calls for benchmarks developed by the Department of Ecology to "be based on industry best practices, reflecting emission levels from highly efficient, lower emitting facilities in each industry sector." This language suggests that benchmarks should be set at emission rate that lies below the average level.

Data Sources

Despite the potential for use of benchmarks to help address greenhouse gas emissions from industry, relatively few comprehensive data sources exist to develop and set benchmarks. In general, four types of data providers exist:

- **Industry groups and associations**, such as the Cement Sustainability Initiative, International Aluminum Institute, Northwest Food Processors Association, or National Council for Air and Stream Improvement. These organizations tend to have (or are developing) the most detailed and comprehensive data on production, energy use, and emissions at the level of individual facilities. However, none of these efforts are known to make their facility-level data publicly available.[37] Furthermore, comparable efforts do not exist in all sectors. Still, benchmarking curves with facility-level resolution have been published by the Cement Sustainability Initiative (CSI 2009) and the International Aluminum Institute (International Aluminum Institute 2009) and could serve as the basis for a benchmarking effort for these sectors.
- **Government surveys,** such as the Energy Information Administration's Manufacturing Energy Consumption Survey (MECS) or the US Census Bureau's Annual Survey of Manufactures and Economic

[37] In some cases, compiled information with facility identifiers removed can be acquired for a fee.

Census.[38] These sources cover some but not all applicable sectors or emissions sources. They also do not provide emissions estimates, but rather fuel use and production data that can be used, with standard emission factors, to estimate emission levels. Physical production data may be limited[39], and use of such data is typically restricted, even for government analysts (Schneck et al, 2009). Following strict procedures to maintain confidentiality, EPA uses Census Bureau data in developing energy benchmarks for industry in the agency's ENERGY STAR program. H.R. 2454 also lists these data as sources for determining industry eligibility for EITE provisions.[40]

- **Air permits held by state and local air agencies.** Air permits and other agency sources (e.g., information on fuel type) sometimes contain production levels and other data sufficient to perform reasonably accurate estimate of GHG emissions. For example, the Puget Sound Clean Air Agency has estimated process CO_2 emissions from both the Ash Grove and Lafarge cement kilns in Seattle based on clinker production data (Puget Sound Clean Air Agency 2008). Compiling data from air agencies around the country or region in order to develop benchmarking curves could be prohibitively difficult, given the sheer number of such agencies and potentially disparate and inconsistent data they may hold.[41]
- **Mandatory GHG reporting rules.** Data from state and federal mandatory reporting rules on GHGs are likely to provide the best source of data for benchmarking, however, these data are not yet available. US EPA's Mandatory Reporting of Greenhouse Gases rule will require all facilities that emit at least 25,000 tons CO_2e and all facilities in some sectors (e.g., aluminum, cement, several chemical industry sectors) to report greenhouse gas emissions and production volumes for year 2010 by March 31, 2011 (US EPA 2009b). Washington State's Mandatory Greenhouse Gas Reporting Rule takes effect in 2010 for facilities with at least 25,000 tons CO_2e of 2009 emissions. Facilities that emit at least 10,000 tons of GHGs must start reporting in 2011 for year 2010 emissions. The reporting methodologies for both the federal and Washington State rules will be harmonized.

The need for more comprehensive production, energy, and emissions data for developing greenhouse gas benchmarks –at least for benchmarks to be used in a cap-and-trade or performance standard setting – is clear. This need is recognized by national and regional policymakers. Notably, the recent interagency analysis of the competitiveness and leakage provisions of H.R. 2454 concluded that implementation of any mechanism to use output-based allocations would require "data from facilities on output levels, electricity use, and emissions associated with electricity use (in addition to data already planned via the Mandatory Reporting Rule)" and also require that "such data can be generated at a sufficiently disaggregated level for EPA to develop meaningful benchmarks for output-based allocations"(US EPA, US EIA, and US Treasury 2009). Facility-level data on physical production or sales is generally considered confidential information and not available to most analysts, regardless of whether the data are collected and held by industry groups (e.g., the Cement Sustainability Initiative) or government sources (e.g., the U.S. Census Bureau). Still, some industry groups (e.g., the international aluminum and cement industries) have voluntarily released GHG benchmarking curves or worked with government partners (e.g., the European Union) to develop and publicize GHG benchmarking curves which display, but do not identify, individual facility-level GHG intensity values. Lastly, monetary sales data are generally available in the U.S. at an aggregate industry level (e.g., six-digit NAICS code).

Table 8, below, displays an assessment of existing possible data sources for GHG benchmarking.

[38] An additional possible source of data is EPA's triennial national emission inventory (NEI), which includes company and state emission estimates for criteria and hazardous pollutants and production and fuel usage information that may be applicable for benchmark development.
[39] One potential source of production data is the US Geological Survey's (USGS) annual Minerals Yearbook, which reports some national and regional production volumes but facility-specific data are very limited (e.g., the USGS reports production capacity at Alcoa's Ferndale and Wenatchee facilities but not actual annual production) (USGS 2009).
[40] For the ENERGY STAR program, EPA relies on a sworn Census agent at the Triangle Research Data Center at Duke University to conduct these analyses.
[41] One potential source to facilitate such data collection is EPA's RACT/BACT/LAER Clearinghouse, which compiles facility-specific information on "best available" air pollution technologies. Since this system (http://cfpub.epa.gov/rblc/) is designed to collect permitting decision information rather than emissions and production information, it does not include the level of detail for the Ash Grove and Lafarge cement plants that is on the Puget Sound Clean Air Agency's own website, suggesting that the Clearinghouse may not an appropriate tool for consolidating relevant GHG benchmarking data. EPA does intend to modify the system to include permit limit data for greenhouse gases.

Table 8. Assessment of Possible Data Sources for GHG Benchmarking

Data Source	Level of Disaggregation (e.g., facility, product)	Types of Data	If Includes GHGs, Uses Accepted Protocol?	Geographic Coverage (& Country Resolution)	Threshold for Coverage	Scope (Direct / Indirect)	Publicly Available at Disaggregated Level	Years of Data Available	Other Considerations
Industry Groups and Associations									
Cement Sustainability Initiative	Facility	▪ CO_2 ▪ Energy ▪ Clinker and cement	Yes, WBCSD/CSI	Global down to North America; low coverage in developing countries (e.g., China)	CSI member companies only	Direct + Indirect	In benchmarking curve	1990-2007	
International Aluminum Institute	Facility	▪ PFCs ▪ Primary aluminum	Yes, IPCC	Global (60% of production);low coverage in China	All facilities	Direct	In benchmarking curve	1990-2008	
Government Surveys									
MECS	Facility	▪ Energy	N/A	U.S.	All but the smallest producers in each covered sector	Direct (fuels) + Indirect (electricity)	No	1991, 1994-2006 in 4-year increments	Does not cover all sectors; only sworn Census agents can access
Census Bureau Economic Census and ASM	Facility	▪ Value of shipments	N/A	U.S.	All facilities	N/A	No	Annual	Only sworn Census agents can access
USGS	Facility (for U.S. data)	▪ Production of metals and minerals	N/A	Global (175 countries) and U.S.	All facilities	N/A	No (country or region only)	1932-2008	
Air Permits From Local Air Agencies									
Puget Sound Clean Air Agency (as example)	Facility	Varies. May include GHGs and production	Varies	Limited to facilities in each individual air agency	Only those facilities required to be permitted for other (non-GHG) pollutants	Direct	Yes but data limited	Varies	Local air agencies may not use consistent methods for estimating GHGs
Mandatory GHG Reporting Rules									
WA GHG Reporting Rule	Facility	▪ 6 GHGs ▪ Production	Yes, US EPA	Washington State	Facilities that emit more than 10,000 tons CO_2e	Direct	Yes (emissions only)	2009 on	Data first reported in Oct. 2010
US GHG Reporting Rule	Facility	▪ 6 GHGs ▪ Production	Yes, US EPA	U.S.	All facilities in certain sectors (e.g., aluminum, cement); others if over 25,000 tCO_2e	Direct	Yes (emissions only)	2010 on	Data first reported in March, 2011

How Different Policy Approaches Might Affect Benchmark Construction

In the discussion above, we describe and assess several issues and options with benchmark construction and application. A few of these issues and options (e.g., what units to use for normalizing the benchmark) remain relatively consistent and apply equally regardless of policy approach. Several others, however, imply very different incentives or outcomes in different policy approaches. In Table 9 below, we summarize how different policy approaches – voluntary goals, output-based allocation in a cap-and-trade program, or emission performance standards – might affect how benchmarks are constructed and used. A key lesson is that disaggregating benchmarks by feedstock type, fuel, or technology distorts the price signal in a cap-and-trade program but may be necessary (or even desirable) in a regulator performance standard or voluntary framework.

Table 9. How Benchmark Application May Affect Benchmark Construction

	Allowance rebates in Cap-and-trade	**Regulatory Performance Standard**	**Voluntary**
Disaggregation by Feedstock type / fuel/ technology / other factors	Disaggregation should be minimized in order to provide the incentive to adopt to more efficient technologies and practices.	Some disaggregation might be necessary to consider cost-effectiveness and achievability, particularly for existing facilities	Some disaggregation might be necessary to distribute abatement costs between companies.
Disaggregation by specific product type	Disaggregation is desirable to extent that products are non-substitutable, and there is sufficient number of distinct facilities producing them to develop a meaningful benchmark	Similar to above	Similar to above
Consideration of indirect electricity emission factors	Indirect emissions do not have to be taken into account as the carbon price signal is part of the electricity price and automatically incentivizes an optimal use of fuel and electricity.	Indirect emissions should be taken into account in order to avoid perverse incentives to use more (carbon free) electricity instead of fuel.	Indirect emissions should be taken into account in order to avoid perverse incentives to use more (carbon free) electricity instead of fuel.
Point of regulation	In order to avoid carbon leakage the benchmark should be based on the point of regulation. This means that the benchmark should be set for the (intermediate) product leaving the installation.	In order to incentivize all abatement options the benchmark should be derived for the final product.	In order to incentivize all abatement options the benchmark should be derived for the final product.

Box 2. An Alternative to Product-specific Benchmarks: Benchmarking Heat Production

In several industries, the main source of emissions is the production of heat (as steam or hot water) in a boiler. That is, while many industrial sectors (e.g., aluminum, cement, glass, and steel) emit large quantities of greenhouse gas emissions directly from the a production process or from burning of fossil fuels to directly heat materials (e.g., in furnaces), others (e.g., food processors and some chemical industry companies) generate most of their emissions from the burning of fossil fuels to produce steam or hot water. Heat could therefore be considered as the product of the boiler and benchmarked accordingly, at least for facilities where other product-specific benchmarks are not applied. The EU has taken this approach in the development of its cap-and-trade program by developing a "fall-back" benchmark approach for sectors and facilities that generate and use heat but are not assigned product-specific benchmarks. The main advantage of applying a benchmark on heat is the simplicity and the potential application across sectors.

Three factors influence GHG emissions from combustion processes that generate heat as steam or hot water: the choice of fuels, the efficiency of the heat production, and the efficiency of heat end use (Ecofys, Fraunhofer Institute, and Öko Institut 2009a). A benchmark on heat production would account for the first two factors but not the third. As a result, one issue in benchmarking heat (at least relative to alternative approaches, such as benchmarking end products) is that a heat benchmark would not encouraged increased efficiency of the *use* of that heat in producing a final product such as paper, a food product, or chemicals.

An important question is whether a heat production benchmark should be differentiated by sector. Different industrial sectors may use different boiler technologies (with varying efficiencies) or rely historically on different fuels, factors that may suggest the use of differentiated benchmarks by sector, at least in a voluntary or regulatory approach. Under a cap-and-trade program, disaggregation by sector may be less appropriate as the goal is to encourage long-term technology and fuel transitions and facilities can purchase or sell allowances depending on whether they are emitting above or below the respective benchmarks.

Table 10 summarizes some benefits and challenges of benchmarking heat as opposed to developing individual product benchmarks.

Table 10. Benefits and Challenges of a GHG Benchmark on Heat Production

Benefits	Challenges
▪ Can be simpler than product-specific benchmarks for some sectors (e.g., food processing) ▪ Incentivizes low-GHG heat production through fuel choice and boiler efficiency ▪ Potentially applicable across a variety of industrial and commercial users, since many use boilers ▪ Does not require confidential production data (e.g., tons of frozen french fries, pulp, chemical product) other than steam/hot water production and fuel input data, which may be less sensitive	▪ Does not directly encourage efficient *use* of heat in producing a final product ▪ Differentiating heat production benchmarks by sector, may be desirable, which would limit the benefit of applying a single benchmark across multiple sectors ▪ Does not apply to process emissions, which are large in some sectors. ▪ Harder to apply to direct-heating applications (e.g., furnaces) than boilers

US EPA has conducted some initial research on possible GHG performance standards for heat production from industrial and commercial boilers. Federal New Source Performance Standards (NSPS) for other pollutants already exist for industrial boilers, and thus EPA may be required to develop GHG performance standards for boilers. [42]

[42] EPA reports that a first step in developing an NSPS for GHGs for industrial boilers would be to "consider how to develop a metric for measuring and benchmarking boiler GHG emissions in terms of the facility's output production" (US EPA 2008b). US EPA also has a GHG offset protocol for quantifying emission reductions from projects in industrial boilers: http://epa.gov/stateply/documents/resources/industrial_boiler_protocol.pdf

4. Focus on Particular Industry Sectors

This section provides a deeper dive into the particular issues and options for benchmarking in key industrial sectors: aluminum, cement, chemicals, food processing, glass, paper and pulp, and steel. We selected these sectors for further examination because they (or closely related sectors) are present in Washington State and are relatively energy-intensive and trade exposed. In addition, we discuss steam production as its own sector. Several other sectors generate most of their greenhouse gas emissions through the production of steam as an intermediate product in their operations, suggesting that a focus on steam could provide benefits to several industry sectors.

Research on each of the sectors has helped inform the issues and options discussed in Section 3, which generally apply across sectors. For example, the level of benchmark disaggregation and availability of comprehensive, facility-specific, publicly available data sources are key considerations in each sector. In this section, we instead focus primarily on key issues and options that are unique to each sector, such as the treatment of waste-derived fuels in the cement sector, availability and quality of recycled cullet in the glass sector, and whether separate benchmarks are needed for integrated versus non-integrated mills in the pulp and paper sector. In addition, this section also provides a review of the emission sources, production processes, and corresponding benchmarks already developed in each sector. For a review of upcoming mandatory GHG reporting data under federal and state rules, please see Appendix A.

As the Washington State Department of Ecology (Ecology) proceeds in the second phase of its work on industry GHG benchmarks under Executive Order 09-05, the agency may choose to focus to develop emission benchmarks for some subset of industries in the state. Accordingly, Ecology may choose to develop criteria to guide selection of sectors. Such criteria may include, for example, minimum thresholds of the following:

- **Energy-intensiveness and trade-exposure**. Industries that are particularly energy-intensive and exposed to global trade may have a greater risk of competitiveness impacts from domestic cap-and-trade legislation. Accordingly, such industry sectors may have a greater need for free allocation of allowances, potentially suggesting a benchmarking approach. For example, as discussed in Section 1, H.R. 2454 includes allowance rebates based on a sector being classified as an energy-intensive, trade-exposed (EITE) industry according to criteria of energy or greenhouse gas intensity and trade intensity. Since GHG benchmarks are often considered well suited to such energy-intensive and trade exposed industries in a cap-and-trade program, a criterion could be whether the industry sector in Washington is included as an EITE sector in federal legislation.
- **Contribution to Washington's annual GHG emissions**. The higher the industry's contribution to the state's total GHG releases, the greater the opportunity to develop approaches such as benchmarking for reducing those emissions. Accordingly, one criterion could be the fraction of the state's total annual GHG emissions (94.8 million metric tons CO_2e in 2005) contributed as direct emissions by the sector.
- **Experience with GHG benchmarking.** The process of developing benchmarks for use in a cap-and-trade system can be complex and time-consuming and may not be appropriate for all industry sectors. The process of assessing issues and options for benchmarks in Washington State may be facilitated by focusing on sectors where relevant data, or benchmarks themselves, have already been developed, and corresponding challenges addressed. For example, the international aluminum and cement industries have made significant strides in data collection and GHG benchmarking methodologies, and the Northwest Food Processors Association is embarking on an energy benchmarking effort. An additional source of research is the European Union, which is currently developing an approach to benchmark-based free allocation of emissions allowances, in coordination with industry associations, and where benchmarks are in their final stages of development, scheduled for release in mid- 2010.

Table 11. Potential Criteria for Selecting Industry Sectors to Benchmark, below, presents a preliminary assessment of industry sectors against these three criteria.

Table 11. Potential Criteria for Selecting Industry Sectors to Benchmark

Sector	NAICS Codes	**Energy-intensive, trade-exposed** (as covered by EITE Provisions in Federal Legislation) [43]	Estimated Contribution to Washington's Annual GHG Emissions [44]	Sector Experience with Benchmarking
Aerospace	336411	No	Low	
Aluminum (Primary)	331312	Yes	Medium	IAI*, EU
Aluminum (Secondary)	331314	No	Low	EU
Cement	327310	Yes	High	CSI*, EU
Chemical[45]	325188 325199	Yes	Low	EU
Electricity	221112	No	High	
Fertilizer	[Many]	Yes[46]	Low	EU
Food Processing	[Many]	Partial[47]	Medium	NWFPA*
Glass	327211 327212 327213	Yes	Low	EU
Gypsum	327420	No	Low	EU
Lime	327410	Yes	Low	EU
Natural Gas Transmission	486210	No	Medium	
Natural Gas Distribution	221210	No	High	
Oil refineries	324110	No[48]	High	EU
Pulp and Paper	322110 322121 322122 322130	Yes	High	EU
Semiconductors / solar	334413	No	Medium	
Steel	331111	Yes	Low	EU

* IAI = International Aluminum Institute
CSI = Cement Sustainability Initiative
NWFPA = Northwest Food Processors Association
EU – European Union Emissions Trading System

[43] For a comprehensive, national list of industrial sectors likely to be considered EITE under H.R. 2454, see EPA, EIA et al (2009).
[44] These categorizations are based on the Department of Ecology's estimates (Washington Dept. of Ecology 2009). A rating of *Low* indicates the sector is estimated to contribute 0.2% or less of the State's total GHG emissions, a rating of *Medium* indicates the sector is estimated to contribute between 0.2% and 1%, and a rating of *High* indicates an estimated contribution of more than 1%.
[45] The chemical industry is very diverse. Sectors listed here qualify for EITE rebates per EPA, EIA and Treasury (2009), but other sectors may not.
[46] Per EPA, EIA and Treasury (2009), "Nitrogenous fertilizer manufacturing" (NAICS 325311) is included.
[47] The only food processing subsectors that appear to be included are "malt manufacturing (NAICS 311213), "wet corn milling" (311221), and "rendering and meat byproduct processing" (311613) per EPA, EIA and Treasury (2009)
[48] Petroleum refining receives its own free allocation of allowances under Sections 782 (j) and 787of H.R. 2454 and so is explicitly excluded from the EITE provisions of H.R. 2454. Under the definition of EITE industries, petroleum refining may not have qualified as energy- or emissions-intensive. Because H.R. 2454's intensity criterion uses value of shipments in the denominator (instead of value added, as in the EU), and since the value of crude oil purchased is high, the denominator is great enough that the energy- or emissions-intensiveness of the petroleum refining may not meet the 5% (Bradbury 2009).

Aluminum

Aluminum is produced in one of two ways. In primary aluminum production, alumina is produced from bauxite and then processed to aluminum via electrolysis. In secondary aluminum production, aluminum is refined or remelted from scrap.

In the North America, over half of the aluminum supply is from primary production, about a third is from secondary production, and the remainder is imported as ingot or partially assembled components (Aluminum Association 2009). Historically, most aluminum production in Washington State has been primary and has benefited from relatively inexpensive, abundant hydroelectricity. In recent years, increases in energy prices and a drop in world aluminum markets have led to a decline in the state's aluminum industry, including the closing of primary aluminum smelters.

In Washington, aluminum-producing facilities include two primary aluminum smelters: Alcoa facilities in Ferndale and Wenatchee; and the Kaiser Aluminum secondary aluminum facility in Spokane.[49]

Overview of Production Process and Emissions Sources

Primary aluminum is produced in the following process:

- **Bauxite mining.** Most of the bauxite used in North American aluminum refineries is mined in other countries, with Jamaica, Guinea, Brazil, Guyana, and Sierra Leone being significant suppliers (USGS 2009).
- **Alumina refining.** Alumina (aluminum oxide) is produced from bauxite using the Bayer process in which bauxite is digested and then alumina is clarified, precipitated, and then dried and calcined. The bauxite digestion process uses significant quantities of (usually fossil fuel) energy to heat the caustic soda, as does the calcining of alumina (IEA 2009). The end product of alumina refining is a fine white powder.
- **Anode manufacturing**, in which coal tar pitch and petroleum coke is ground pressed into green anodes, and then baked[50] at high temperatures in gas-heated furnaces (Worrell et al. 2008). Anodes can either be made onsite at the smelter or in separate, specialized plants. The Alcoa facilities in Ferndale and Wenatchee both use pre-baked anodes made on-site. The Ferndale facility uses "side worked pre-bake" anodes and the Wenatchee facility uses "center work pre bake" anodes.
- **Aluminum smelting.** In aluminum smelting, known as the Hall-Héroult process, alumina is dissolved in an electrolyte bath under a strong electric current. The electric current separates the aluminum oxide molecules by pulling the oxygen ions towards the carbon anode, where they react with carbon, leaving molten aluminum behind. Smelting uses significant quantities of electricity.
- **Aluminum casting and forming.** Molten aluminum is shaped into forms and semi-finished products via casting of ingots, hot and cold rolling, extrusion, drawing, finishing, and cutting.

Producing secondary aluminum from scrap requires much less energy than primary production. Steps in the production of secondary aluminum include:

- **Scrap collection and processing.** Scrap aluminum needs to be collected, sorted, cleaned, and shredded. Sources of scrap aluminum include both post-consumer products (e.g., used beverage cans, old automobile parts, windows and doors) as well as post-industrial production scrap.
- **Remelting and refining,** which can occur via one of several processes, including reverbatory furnaces, rotary furnaces, or induction technology.
- **Aluminum casting and forming**, similar to that described above for primary aluminum.

The table below summarizes the major processes in aluminum production and sources of emissions.

[49]Per the Department of Ecology (2009) and http://www.ecy.wa.gov/programs/swfa/industrial/facilities.html.
[50] In a Soderburg aluminum smelter, the anodes are not pre-baked. Instead the heat from the aluminum reduction cell provides the heat to 'bake' the anodes at the same time it is being consumed in the smelting process.

Table 12. Summary of Aluminum Production Processes, Emission Sources, and Existing Benchmark Sources

Step	Dominant Emissions Sources	Proposed or Existing GHG Benchmarks under Cap-and-trade	Other Benchmarks or Best-Practice Values	Key Issues / Options
Primary				
Bauxite mining	▪ Fossil fuel burning for equipment	▪ None known	▪ None known	
Alumina refining	▪ Fossil fuel for heat generation	▪ Proposed EU benchmark on alumina ▪ H.R. 2454 (Waxman-Markey), passed in the US House of Representatives in 2009, included a formula for constructing an average benchmark for alumina refining	▪ Worrell et al (2008) list world best-practice energy benchmarks for alumina production	▪ Few installations produce alumina and with a wide spread of emissions, complicating benchmark development
Anode manufacture	▪ Fossil fuel for furnace ▪ Process CO_2 from anode baking	▪ Proposed EU benchmark on pre-baked anodes	▪ Worrell et al (2008) list world best-practice energy benchmarks for anode manufacture	
Aluminum smelting	▪ Fossil fuel for heat generation ▪ Process CO_2 from consumption of carbon anodes ▪ Perfluorocarbons (PFCs) from the anodes ▪ Electricity production for electrolysis	▪ Proposed EU benchmark on primary aluminum smelting ▪ H.R. 2454 (Waxman-Markey), passed in the US House of Representatives in 2009, included a formula for constructing an average benchmark for primary aluminum smelting	▪ Worrell et al (2008) list world best-practice energy benchmarks for aluminum smelting ▪ International Aluminum Institute has published benchmark curves for PFC emissions (International Aluminum Institute 2009)	▪ Choice of carbon anode type (e.g., pre-baked anodes versus Söderberg) can affect energy and process CO_2 emissions greatly ▪ In the EU, the aluminum industry has argued for a separate benchmark for primary cast houses with adjustment factors for degree of secondary remelting and homogenization
Aluminum casting and forming	▪ Fossil fuel for production machinery ▪ Electricity production to run machinery	▪ Proposed EU benchmark on primary cast aluminum ▪ EU has proposed using the separate "fall-back" approach for products from rolling plants, extrusion plants, and foil plants	▪ Worrell et al (2008) list world best-practice energy benchmarks for aluminum casting	
Secondary				
Scrap collection	▪ Fossil fuel and electricity to operate equipment	▪ None known	▪ None known	
Scrap processing	▪ Fossil fuel and electricity to operate equipment	▪ Proposed EU benchmark on secondary aluminum	▪ Worrell et al (2008) list world best-practice energy benchmarks for secondary aluminum	▪ See above if secondary aluminum remelting occurs in a primary cast house ▪ In EU, stakeholders have argued that production from low-quality scrap may be more energy-intensive than production of high-quality scrap and may deserve its own benchmark
Remelting and refining	▪ Fossil fuel for furnace ▪ Electricity production (if electric furnace used)			
Aluminum casting and forming	▪ Fossil fuel for production machinery ▪ Electricity production to run machinery			

Key Issues in Benchmarking Aluminum

As with all sectors, the data availability and level of benchmark disaggregation are key issues. This is discussed in detail in Section 3 of this *White Paper*. In addition, some stakeholders have suggested that quality of recovered scrap may be an issue for the secondary aluminum industry (Ecofys, Fraunhofer Institute, and Öko Institut 2009b). The quality of recovered scrap can affect energy required for production of secondary aluminum. However, under a cap-and-trade system on greenhouse gases, differentiating the benchmark based on aluminum scrap quality may be less appropriate, since the entity could use the savings realized from purchasing less expensive, lower-quality scrap to secure additional emissions allowances.

Cement

Cement is the binding agent in concrete and most mortars, and is generally produced from a feedstock of limestone, clay, and sand. In the United States, 118 cement plants produce about 85 million metric tons of cement annually.[51] In Washington State, the largest cement plants are Ash Grove Cement and Lafarge Cement, both located in Seattle. Together, these facilities emit about 900,000 tons CO_2e of GHGs annually in the course of producing about one million tons of cement (Washington Dept. of Ecology 2009).

Overview of Production Processes and Emission Sources

The production of cement involves four sequential production processes (Matthes et al. 2008):

- **Raw material extraction**, in which limestone and clay, sand, or other materials are quarried. Neither cement kiln in Washington State operates its own quarry; both import limestone from Texada Island in British Columbia, from which the limestone is transported by barge to the plants.
- **Raw material preparation,** in which a raw mixture of limestone (approximately 90%) and other materials (e.g., clay, sand) are crushed and ground into a mixture with a specific chemical composition. This step can occur either as a dry process, in which the product is a fine dry powder, or in a wet process, where the crushed material is mixed into a slurry prior to grinding. Over 75% of cement produced in the U.S. uses the dry process (Worrell and Christina Galitsky 2008).
- **Clinker production**, in which the fine powder or slurry is heated to over 2,500˚F in a kiln. The heating first transforms the ground limestone ($CaCO_3$) into lime (CaO), releasing CO_2, in a process called calcination, and then into solid pellets called clinker, the material which gives cement its binding properties. Two major kiln types exist: vertical shaft kilns, and the more-efficient rotary kilns. Few (if any) vertical shaft kilns remain in the U.S. Of rotary kilns, the wet kilns are less efficient because they require more energy to produce clinker due to the need to evaporate the slurry water prior to calcination. No new wet kilns have been built in the U.S. since the 1970s (US EPA 2008a). The Lafarge plant in Seattle (a wet kiln) has recently announced intentions to stop manufacturing clinker at the end of 2010.[52]
- **Cement grinding and blending**, in which clinker is mixed with other ingredients to produce cement. To make Portland cement, only about 5% gypsum is added. Other, “blended cements” can be made by mixing in other materials with cementitious properties, especially byproducts from other industries, such as fly ash from coal power plants or blast-furnace slags.

The table below summarizes the major processes and sources of emissions in cement production.

[51] Per USGS (2009) and the Portland Cement Association (www.cement.org).
[52] http://www.westseattleherald.com/2010/04/30/news/update-lafarge-cement-forced-make-changes-its-seattle-plant

Table 13. Summary of Cement Production Processes, Emission Sources, and Existing Benchmarks

Step	Dominant Emissions Sources	Proposed or Existing GHG Benchmarks under Cap-and-trade	Other Benchmarks or Best-Practice Values	Key Issues / Options
Raw material extraction	▪ Fossil fuel for extraction equipment and transport from mine to plant ▪ Electricity for conveyors	▪ None known	▪ None known	
Raw material Preparation	▪ Fossil fuel and/or electricity production for machinery to crush, grind, and dry (if necessary) the raw meal	▪ None known (emissions from this phase are included in clinker production phase in the EU benchmark)	▪ Worrell et al (2008) list world best-practice energy benchmark for raw materials preparation	▪ Higher moisture content and hardness of the limestone increase energy use.
Clinker production	▪ Process CO_2 released in the calcination reaction ▪ Fossil fuel burning for kiln heating ▪ Electricity production for machinery, including fans, kiln drive, cooler, and material transport	▪ EU has proposed benchmark on clinker production[53]	▪ Cement Sustainability Initiative (2009) lists global and regional average GHG intensities ▪ Worrell et al (2008) and IEA (2008) list world best-practice energy benchmark for clinker production ▪ US EPA ENERGY STAR has an energy benchmarking tool that compares energy per ton of clinker	▪ The choice of whether to benchmark based on clinker or cement is the most significant issue. Basing the benchmark on cement incentivizes blending with clinker substitutes (thereby reducing the emissions associated with clinker), but can create a perverse incentive to import clinker or else to restructure the industry to create companies that only grind clinker and do not make cement ▪ Treatment of biomass and wastes as heating fuels for the kiln can affect benchmark development ▪ Some have argued that different benchmarks should be created for grey versus white cement, but the possible applications (if not the aesthetics) are the same[54]. Both cement kilns in Washington produce grey cement.
Cement grinding and blending	▪ Fossil fuel needed for heat for drying of additives, if necessary ▪ Electricity for equipment for blending and grinding of additives and final product	▪ H.R. 2454 (Waxman-Markey), passed in the US House of Representatives in 2009, included a formula for constructing an average benchmark for cement (not clinker) production	▪ Cement Sustainability Initiative (2009) lists global and regional average GHG intensities ▪ Worrell et al (2008) list world best-practice energy benchmark for grinding and blending	

Key Issues in Benchmarking Cement

Based on review of benchmarking and related efforts in the cement sector, key questions to address in developing benchmarks for the cement sector would include:

- **Whether to benchmark based on cement or clinker.** A benchmark based on clinker helps drive kiln and process efficiency upgrades but fails to incentivize the use of clinker substitutes (such as fly ash and slag) in blending to reduce emissions. A benchmark based on cement provides incentive for blending of clinker substitutes but could lead to restructuring in the cement industry. In particular, if the benchmark were only applied to cement, cement facilities may choose to no longer make emissions-intensive clinker themselves, instead importing it or else purchasing it from facilities that only grind clinker and do not

[53] Information pertaining to benchmarking of cement from the EU is taken largely from Ecofys, Fraunhofer Institute, & Öko Institut (2009c). Final benchmarks are being developed in the EU in the first half of 2010.

[54] The EU has recommended that no separate benchmarks be developed for white versus grey cement (European Commission 2010). In Washington State, both cement kilns produce grey cement.

make cement (therefore potentially exempting themselves from the cement-based benchmark). Such a restructuring would provide little or no overall decrease in cement industry emissions.

- **Treatment of wastes and biomass as fuels,** in particular, how emissions from these fuels are calculated and included in the benchmark, including treatment of fuels such as used tires.

In addition, the cement system would also face issues similar to all sectors – such as what data are available and how many products to distinguish. Note that EPA is currently revising its NSPS for cement, expected in June 2010. Some observers have speculated that EPA will include greenhouse gas emissions in the revisions (Bravender 2009).

Chemicals

The chemical industry is a diverse, energy-intensive sector that generates products such as plastics, fertilizers, cleaners, pharmaceuticals, and numerous other products from feedstocks of natural gas, crude oil, and sometimes coal or other materials. The U.S. chemical industry is the largest in the world (Worrell et al. 2000). From an energy and emissions perspective, the three most significant subsectors of the chemical industry include (IEA 2008; Worrell et al. 2000):

- **Petrochemicals**, in which firms convert oil and natural gas feedstocks into chemical building blocks used to produce polymers, plastics, synthetic rubbers, solvents, and other organic chemicals. Petrochemical producers use large quantities of heat to power distillation columns and other processes, such as steam-cracking, the process used to produce ethylene (the most widely used petrochemical intermediate compound nationally and globally) and other chemicals.
- **Fertilizers** and related products, where the production of ammonia is the most energy-intensive production step. Ammonia is produced by a reaction of hydrogen and nitrogen. Most ammonia is converted to other compounds to be utilized as fertilizer.
- **Inorganic chemicals,** which include the energy-intensive chemicals chlorine, caustic soda (sodium hydroxide), carbon black, and soda ash, among others.

Major sources of greenhouse gas emissions from chemical manufacturers include direct combustion of fossil fuels to produce heat and non-combustion process emissions that occur from the use of fossil fuels as feedstocks and the use of other raw materials (US EPA 2008a).

In Washington State, the chemical industry includes numerous small companies that manufacture a variety of chemicals. Larger facilities include Solvay Chemicals and Emerald Kalama Chemicals. Solvay makes hydrogen peroxide (an inorganic chemical) from hydrogen it produces in a steam-methane reformer. The process of reforming methane (CH_4) to hydrogen (H_2) releases CO_2 as a process emission. Emerald Kalama Chemicals makes petrochemical additives for the food industry; the firm's primary source of emissions would likely be fuels used to heat the multiple boilers.

The huge diversity of the chemical industry, and many thousands of products made, complicate efforts to discuss production processes and greenhouse gas emission sources. A number of benchmarking efforts are underway globally, however, and may help inform possible benchmark development in other regions. These include efforts by the EU to develop benchmarks for the upcoming third phase of the EU Emissions Trading System (Ecofys, Fraunhofer Institute, and Öko Institut 2009d); development of a benchmarking approach for steam crackers (used to make ethylene and other petrochemicals) developed by the consulting firm Solomon Associates; documentation of world "best practice" energy intensity values for ammonia and ethylene production (Worrell et al. 2008); efforts to document best available techniques in the chemicals sector (European Commission 2003); and global average or typical energy and GHG emission intensities for production of several particular chemicals (IEA 2008). These efforts focus on the chemicals that comprise a large fraction of the worldwide chemical sector's energy consumption and emissions releases, and in most cases focus little attention on the chemicals produced at scale in Washington State: hydrogen (and then hydrogen peroxide) and food additives. The EU study (Ecofys, Fraunhofer Institute, and Öko Institut 2009d) does specifically address hydrogen and therefore may be relevant to Solvay Chemicals. That study includes a proposed benchmark value on hydrogen production that was developed in part through data provided by the European Industrial Gases Association (EIGA) as well as elements of the Solomon Associates approach.

In addition, H.R. 2454 ("Waxman-Markey"), passed out of the U.S. House of Representatives in June 2009, included a formula for constructing average, sector-wide benchmarks for several energy-intensive and trade-exposed subsectors of the chemical industry. The benchmarks were to be used to issue allowance rebates to these industry sectors.[55] Inorganic chemicals (NAICS 325188), a sector that includes Solvay Chemicals, and organic chemicals (NAICS 325199), a sector that includes Emerald Kalama chemicals, are both included in the proposed benchmarking approach to output-based rebates.

Key Issues in Benchmarking Chemicals

In general, key issues in developing GHG benchmarks in the chemicals industry include the large number of chemicals produced (which could, in theory, require hundreds of benchmarks), the rapidity by which come facilities can change the chemicals they produce in response to market demand, data availability (even for those chemicals that are dominant from an energy or emissions perspective, such as ammonia or ethylene), and the treatment of imported heat (generally in the form of steam) given that different types of facilities produce or import varying degrees of heat depending on individual plant needs and the product made.

Food Processing

Food processing facilities in Washington manufacture diverse products such as frozen french fries, juice, and dairy products. Together, large food processing facilities in Washington emit approximately 300,000 metric tons of greenhouse gases per year (Washington Dept. of Ecology 2009).

Overview of Production Processes and Emission Sources

Major sources of greenhouse gas emissions from food processing facilities include fossil fuel combustion for heating, cooking, drying, and other processes; non-combustion processes, such as methane emissions from onsite wastewater treatment plants and hydrofluorocarbon emissions from refrigeration; and purchased electricity (US EPA 2008a). Although difficult to generalize given the wide variety of food processing facilities, steps involved in food processing often include (Masanet et al. 2008):

- **Inspection, grading, and washing**, involving a variety of electrical equipment including motors, conveyors, and pumps;
- **Processing,** including any of a wide variety of activities that can include peeling, blanching, juice extraction, filtering, pasteurization, and others, depending on the particular product being made;
- **Freezing or canning**, in which the products are frozen (using large quantities of electricity) or canned (often using large quantities of heat); and
- **Packaging**, in which the products are placed in their final packaging for shipment.

Few efforts are known to benchmark greenhouse gas emissions in the food processing industry, although regional and national efforts are underway to benchmark energy performance. These include the US EPA's ENERGY STAR program for frozen french fry manufacturers and juice processing plants and a regional effort by the Northwest Food Processors Association. More specifically:

- **ENERGY STAR** released tools in 2009 to evaluate energy performance at frozen potato and juice processing plants. Two frozen fried potato facilities in Washington have since been awarded the ENERGY STAR: the JR Simplot plant in Quincy and the ConAgra plant in Othello. EPA estimates that these two plants are in the top 25th percentile in terms of energy efficiency performance and use about 20% less energy than similar plants throughout the nation (US EPA 2010a).
- **Northwest Food Processors Association (NWFPA)** members adopted a goal to reduce industry-wide energy intensity by 25% in 10 years and 50% in 20 years. In February 2009, NWFPA signed a

[55] For more information, see the discussion of benchmarking in the context of cap-and-trade legislation that begins on page 6.

Memorandum of Understanding (MOU) with the US Department of Energy supporting that goal. To date, 49 NWFPA-member facilities have documented energy intensities for 2006 through 2009. NWFPA is establishing an industry-wide baseline for 2009 against which industry progress toward achieving the energy intensity reduction goal can be tracked.[56] Other activities include expanding data collection to include the 180 or so member facilities, benchmarking energy intensities by subsectors (at the six digit NAICS level), and developing a "roadmap" to guide efforts to achieve the 2020 energy intensity goal.

The diversity of the food processing industry, and many products made, complicate efforts to provide a more detailed overview of production processes and greenhouse gas emission sources as provided in this report for other industries.

Glass

Broadly speaking, four types of glass are manufactured in the U.S.: flat glass (e.g., windows), container (hollow) glass, fiberglass, and specialty glass. Glass is made primarily from silica sand with lime, soda, cullet (recycled glass), and other ingredients added. In the United States, glass manufacturers produce approximately 20 million tons of glass annually (Worrell et al. 2008). In Washington State, the largest glass plants are Cardinal Glass, a flat glass manufacturer in Winlock (near Chehalis), and St. Gobain Containers, a glass bottle manufacturer in Seattle. Together these facilities emit approximately 150,000 metric tons of greenhouse gases annually (Washington Dept. of Ecology 2009). Accordingly, the container glass and flat glass segments of the industry will be the focus of this section. Several producers of fiberglass-reinforced plastics, as well as a variety of smaller specialty glass products, also exist in Washington State and are not addressed here.

Overview of Production Processes and Emission Sources

The production of glass involves four sequential steps (Worrell et al. 2008):

- **Batch preparation and mixing,** in which silica (sand), soda, potash, and (in some cases for container manufacture) cullet are combined with stabilizers lime, magnesium oxide, and aluminum oxide. Refining agents may be added to help remove air bubbles in the subsequent melting step. Other additives are included here to give the glass the desired color and other properties.
- **Melting and refining**, in which the raw materials are fired in a furnace (usually a "tank" furnace) heated either by combustion or electricity or a combination of both, and sometimes using oxygen instead of regular combustion air to increase efficiency and reduce nitrous oxide emissions. Refining, which involves removal of bubbles, and homogenization, also occur in the furnace. In the U.S., most glass furnaces are fired by natural gas and some use electric boosters, as glass is a conductor at high temperatures. In such cases, electricity can represent up to 30% of the energy input to the furnace.
- **Conditioning and forming**, in which glass is transferred out of the furnace into a forehearth, where it is conditioned to have the desired temperature distribution, and then delivered to the forming equipment, where it is either shaped continuously (e.g., the float or rolled glass processes used to make flat glass) or separated into individual portions ("gobs") for blowing or pressing into containers.
- **Finishing**, in which various processes and treatments may be applied to affect glass characteristics. These steps may include annealing (reheating and cooling of the glass to remove stresses), toughening (also accomplished by a reheating, followed by rapid cooling with air jets), and coatings (e.g., mirrors).

The table below summarizes the major processes and sources of emissions in glass production.

[56] Personal communication between Eli Levitt, Washington Department of Ecology and NWFPA staff, March 24, 2010.

Table 14. Summary of Flat and Container Glass Production Processes, Emission Sources, and Existing Benchmarks

Step	Dominant Emissions Sources	Proposed or Existing GHG Benchmarks under Cap-and-trade	Other Benchmarks or Best-Practice Values	Key Issues / Options
Batch preparation and mixing	▪ Electricity production or natural gas combustion for equipment operation	E.U. has proposed benchmarks on: ▪ Flat glass ▪ Hollow glass[57] H.R. 2454 (Waxman-Markey), passed in the US House of Representatives in 2009, included a formula for constructing a average benchmarks for: ▪ Flat glass ▪ Pressed / blown glass ▪ Glass containers	▪ IEA (2008) reports some average and best-practice energy-intensity values ▪ European Commission (2009) reports energy and CO_2 levels of typical and "best available techniques" for different types of glass production ▪ US EPA ENERGY STAR has an energy benchmarking tool that compares energy per ton of glass sand input (for flat glass) or glass sand plus cullet (for container glass)[58]	▪ Use of cullet can reduce energy use and process emissions in the manufacture of container glass, but availability and quality of cullet can vary substantially by region depending on local recycling programs, which can complicate assumptions about default rate of cullet use in development of benchmark ▪ The potential substitutability of natural gas and electricity can complicate a benchmark based on direct emissions only ▪ High degree of consolidation in the glass industry complicates data availability for benchmark development
Melting and refining	▪ Natural gas for firing the furnace ▪ Production of electricity used for boosting furnace, if applicable ▪ Process CO_2 emissions resulting from the decarbonization of soda ash and lime			
Conditioning and forming	▪ Natural gas burning or electricity production for heating of the forehearth ▪ Electricity production or natural gas combustion for equipment operation			
Finishing	▪ Electricity production or natural gas combustion for equipment operation	None known	▪ IEA (2008) reports some average and best-practice energy-intensity values	

Key Issues in Benchmarking Glass

As with all sectors, the data availability and number of products to distinguish (e.g., whether to develop separate benchmarks by container shape or color) may be key issues. In addition, two issues particular to the glass industry are:

- **How to treat use of cullet (recycled glass)**, particularly in container glass production. Use of cullet can reduce energy use and process emissions, but its availability and quality can vary substantially by region depending on local recycling programs, such that areas with more-developed recycled glass collection and processing infrastructures may have significant advantages in meeting a benchmark level. However, under a cap-and-trade system on greenhouse gases, differentiating the benchmark based on cullet usage or quality may be less appropriate, since the goal is to encourage the use of lowest-GHG processes and feedstocks and facilities have the flexibility to purchase allowances or offsets. Under a regulatory or voluntary framework, some level of accounting for cullet quality and availability may be desirable, assuming facilities are asked to meet a particular benchmark and do not have flexibility to purchase allowances or offsets to meet the benchmark.
- **Relative ease of substitution between electricity and natural gas** in many glass furnaces could complicate benchmark development and application. If the benchmark was based only on direct emissions, then the facilities that are more reliant on electricity would appear to fare much better, regardless of overall GHG intensity (including the emissions released in electricity production).

[57] The EU has also proposed a benchmark in continuous filament fibers that is not discussed here because the focus is on flat and container glass (Ecofys, Fraunhofer Institute, and Öko Institut 2009e)
[58] Cardinal Glass has been a participant in an EPA Work Group as part of the ENERGY STAR program: http://www.energystar.gov/index.cfm?c=in_focus.bus_glass_manuf_focus.

Pulp & Paper

With extensive forests, the Pacific Northwest (and Washington State in particular) has historically been a leader in the pulp and paper industry. In recent decades, the state's industry has contracted due to increased competition and decreased prices due to rising global production capacity (particularly in Asia), increased energy prices, and decreased supply of raw materials (e.g., wood chips). However, many pulp and paper mills remain in the state, with most being integrated mills, meaning they produce both pulp and paper. Together these large pulp and paper emitted approximately 850,000 metric tons of greenhouse gases in 2007 (Washington Dept. of Ecology 2009).

Table 15, below summarizes the active pulp and/or paper mills in Washington State.

Table 15. Active Pulp & Paper Mills in Washington State[59]

Facility	City	Mill Type	Pulp Type	Products
Boise*	Wallula	Integrated	▪ Kraft	▪ Bleached paper ▪ Coated paper ▪ Corrugating medium
Georgia Pacific*	Camas	Integrated	▪ Kraft	▪ Bleached kraft paper ▪ Tissue ▪ Paper towels
Grays Harbor Paper	Hoquiam	Non-integrated	▪ Recycled paper and Kraft (purchased)	▪ Writing paper
Inland Empire*	Spokane	Integrated	▪ Mechanical ▪ Deinked recycled	▪ Newsprint
Kimberly Clark*	Everett	Integrated	▪ Sulfite (ammonia-based)	▪ Tissue
Longview Fibre*	Longview	Integrated	▪ Kraft	▪ Container board
Nippon Paper	Port Angeles	Integrated	▪ Mechanical pulp and recycled paper	▪ Telephone directory paper
Ponderay Newsprint	Usk	Integrated	▪ Thermomechanical	▪ Newsprint
Port Townsend Paper*	Port Townsend	Integrated	▪ Kraft and recycled OCC	▪ Unbleached kraft pulp ▪ Lightweight linerboard ▪ Corrugating medium ▪ Unbleached converting grades
Simpson Tacoma Kraft*	Tacoma	Integrated	▪ Kraft	▪ Unbleached kraft pulp ▪ Bleached and unbleached packaging paper ▪ Linerboard
Sonoco	Sumner	Integrated	▪ Recycled cardboard and magazine-type papers	▪ Recycled paperboard
Weyerhaeuser Co.*	Longview	Integrated	▪ Kraft ▪ De-ink (recycled) ▪ Thermomechanical	▪ Paperboard ▪ Corrugating medium ▪ Newsprint ▪ Fine papers

*These facilities are estimated to emit at least 25,000 tons CO_2e annually (Washington Dept. of Ecology 2009)

One of the most significant distinctions between mills is the production process used to create pulp. The main pulp processes are chemical pulping (including the kraft and sulphite processes), mechanical pulping, or paper recycling, with mechanical pulping being the most greenhouse-gas intensive. The type of process used in each of Washington's mills is noted in Table 15 and described in more detail below.

[59] Summarized from the Department of Ecology's industrial section web page (http://www.ecy.wa.gov/programs/swfa/industrial/facilities.html) and individual company web pages.

Overview of Production Processes and Emission Sources

The production of pulp and paper involves four main processes:

- **Raw material harvest or collection**, in which either virgin wood is harvested and chipped or post-consumer or post-industrial paper feedstocks are collected and sorted.
- **Virgin pulp production**, in which the wood chips are broken down into their raw cellulose fibers by one of three dominant types of processes:
    - Kraft (sulfate) pulping, in which fibers are released by dissolving the wood chips in a high-temperature sulfate chemical solution (the cooking process) and which produces black liquor, a waste product that contains a significant quantity of lignin;
    - Sulfite pulping, in which the cooking process uses a bisulfate liquor in a pressurized vessel. Sulfite pulping is rare and is used mainly for specialty papers, and produces a byproduct called "green liquor."
    - Mechanical pulping, in which wood fibers are mechanically separated. One type of mechanical pulping is the groundwood process, in which wood is ground to produce relatively short fibres (e.g., for newsprint) in an electricity-intensive process. Mechanical pulping can also involve pre-softening with steam (thermo-mechanical pulping) or with chemicals (chemi-mechanical pulping), either of which can involve more use of fossil fuel than other mechanical-based pulps.

  Methods of recovering energy are possible in all three types of pulping. In the kraft process, black liquor can be combusted to recover substantial quantities of energy from the lignin, even producing more heat than is needed in the pulping process.[60] Similar energy recovery is possible from green liquor produced in sulfite pulping. In mechanical pulping, heat generated from the application of mechanical energy (only a fraction of which is used to separate the cellulose fibers) can also be recovered as hot water or steam.

  In all of the pulping processes, bleach may or may not be applied depending on the desired brightness of the finished product.
- **Recovered paper processing**, which involves collecting and sorting post-consumer and pre consumer waste as feedstocks, cleaning and de-inking. Use of recovered paper requires energy but tends to lower the overall energy and emissions intensity of paper production.
- **Paper production**, in which the pulp is fed into the paper making machine, screened, vacuumed of water, pressed by rollers, and dried. If necessary, sizing (to affect absorption and wear) and coatings are then applied.

Table 16 summarizes the major processes and sources of emissions in pulp and paper production.

[60] Lime can also be recovered from the kraft pulping process.

Table 16. Summary of Paper Production Processes, Emission Sources, and Existing Benchmarks

Step	Dominant Emissions Sources	Proposed or Existing GHG Benchmarks under Cap-and-trade	Other Benchmarks or Best-Practice Values	Key Issues / Options
Raw material harvest or collection	▪ Fossil fuel for extraction equipment	None known	None known	
Virgin pulp production	▪ Fossil fuel for heat or steam (particularly for start-up if recovering energy from waste liquors) and to power the lime kilns in the kraft process ▪ Process emissions from production of lime in the kraft process ▪ Electricity production (particularly for mechanical pulping)	▪ EU has proposed benchmark for kraft pulp (for lime kiln operation only)[61] ▪ H.R. 2454 (Waxman-Markey), passed in the US House of Representatives in 2009, included a formula for constructing an average benchmark for pulp production (NAICS 322110)	▪ Worrell et al (2008) and IEA (2008) list world best-practice energy and "best available technology" benchmarks, respectively, for virgin pulp production	Heat at the mill can be produced using feedstocks that are either: ▪ Inherent to the pulping process (e.g., black or green liquor recovery or from heat recovery from mechanical pulping), in which case heat recovery can exceed that needed for the pulping process and the facility can be a net exporter of heat; no benchmark may be needed (as in the EU) ▪ Unrelated to the pulping process (e.g., bark or wood residues, wastewater treatment, and short fiber sludges), which in the EU is left outside the pulp benchmark system boundary since it is not directly related to the performance of pulp making; this heat production may still receive a benchmark under the allocation for cross-facility heat flows
Recycled paper processing	▪ Fossil fuel and electricity for processing equipment, particularly for pulping and deinking	▪ EU has proposed a benchmark on processed recovered paper	▪ Worrell et al (2008) and IEA (2008) list world best-practice energy and "best available technology" benchmarks, respectively, for recovered pulp production	▪ Use of a separate benchmark for processed recovered paper avoids the need to derive an assumed ratio of recycled fibers to virgin pulp in paper benchmarks
Paper production	▪ Fossil fuel for dryers, heaters (for production of coated papers), and other equipment ▪ Electricity production for equipment, including rollers, presses, motors, and pumps	EU has proposed benchmarks on: ▪ Recycled paper ▪ Newsprint ▪ Uncoated fine paper ▪ Coated fine paper ▪ Tissue ▪ Container board ▪ Carton board ▪ Other papers H.R. 2454 (Waxman-Markey) included formulas for calculating benchmarks for: ▪ Newsprint, NAICS 322122 ▪ Paperboard, NAICS 322130 ▪ Other Paper, NAICS 322121	▪ Worrell et al (2008) and IEA (2008) list world best-practice energy and "best available technology" benchmarks, respectively, for numerous paper grades	▪ Benchmarks developed based on integrated mills may be too low for non-integrated mills that buy market pulp (and therefore don't have pulp residuals available as fuels), but splitting emissions in integrated mills between pulp and paper making is very difficult. ▪ The EU reports that containerboard, carton board, and other papers may need further disaggregation but that data are insufficient:[62]

[61] The EU has not proposed benchmarks for heat consumption for kraft, sulfite, or mechanical pulp because the recovery of waste products from these processes can produce more than enough heat to supply to the pulping process (Ecofys, Fraunhofer Institute, and Öko Institut 2009f) The allocation for lime production is for the fossil fuel use only, not for the process CO_2, because the process CO_2 here is from a biomass source, unlike in normal lime production (Neelis et al. 2009).

[62] A subsequent finding by the European Commission (European Commission 2010) suggests separate benchmarks for two types of containerboard: kraftliner and testliner/fluting.

Key Issues in Benchmarking Pulp & Paper

Three issues particular to the pulp and paper industry are:

- **How to treat use of recycled pulp or recovered paper**. Since use of recovered paper affects the GHG intensity of paper production, benchmark construction may need to either assume a default rate of recovered paper (or recycled pulp) use or else develop a separate benchmark for use of processed recovered paper, as is currently being explored in the EU.
- **Whether paper benchmarks based on integrated mills can be applied to non-integrated mills.** Integrated mills make paper from their own pulp and have pulping residuals (e.g., black liquor) left over to use as fuel in the boiler. Accordingly, non-integrated mills that buy market pulp or produce pulp by recycling papers may not be able to meet benchmarks based largely on emissions from integrated mills. Differentiating the benchmark for integrated and non-integrated mills may be particularly relevant for benchmarks in a regulatory or voluntary context. However, under a cap-and-trade system on greenhouse gases, such differentiating may be less appropriate, since the goal is to encourage the lowest-GHG processes and facilities have the flexibility to purchase allowances or offsets.
- **How to treat heat production and possibility for cross-facility heat flows**, especially since recovery of black liquor from the kraft pulping process can result in production of excess heat that could be sold to another facility or used to make electricity. In such case, some researchers (Ecofys, Fraunhofer Institute, and Öko Institut 2009f) have considered (but generally discarded due to methodological complexity) whether a *negative* benchmark might be considered to account for the heat that could be sold and exported as a separate product. Regardless, the question of how to account for cross-facility heat or power flows will need to be carefully considered.

Steam

Many industrial processes use heat (as hot water or steam) produced in boilers, many of which are fired using fossil fuels. Nationally, EPA estimates that the approximately 45,000 industrial boilers in use nationally emit 1,250 $MtCO_2e$ annually, or approximately 20% of the national U.S. greenhouse gas inventory (US EPA 2008b). Boilers are also used in commercial and institutional settings such as hospitals, schools, and shopping malls. Boiler sizes exist along a continuum from small residential-scale units to factory-built intermediate-sized units to large site-built units. While the differing boiler sizes can be subject to similar emission reduction options and benchmarking considerations, this *White Paper* addresses only boilers used at industrial sources.

The use of boilers and generation of steam applies across many of the industry sectors discussed in this *White Paper* (including pulp and paper, chemical, and food processing sectors), as well as many other sectors not discussed in detail (e.g., petroleum refining). More specifically, use of boilers is particularly common in the following sectors (Energy and Environmental Analysis, Inc. 2005; IEA 2008):

- **Pulp and paper**, with about 3,400 boilers nationally, and where the dominant fuel is black liquor, a byproduct of the chemical pulping process, and where bark, wood chips, and production wastes are other common feedstocks.
- **Chemicals**, with about 12,000 boilers nationally, many of them smaller than the 10 MMBtu/hour threshold for Clean Air Act standards, and where dominant fuels are natural gas, by-products, and coal or coke.
- **Petroleum refining**, with 1,200 (generally large) boilers nationally, and where the dominant fuels are crude oil, natural gas, and residual fuel oil.
- **Food processing,** where boilers are generally fueled by natural gas or residual fuel oil.
- **Wood products,** where the boilers are generally fueled by wood wastes.
- **Miscellaneous industrial products,** where the boilers are generally fueled by what fuel is available, was lowest cost at time of initial installation of the boiler, or is allowed in an air permit.

Accordingly, steam is not an industry *per se*,[63] but instead is an intermediate product produced and used by several industry sectors – a product that is usually generated and consumed in the same facility but is sometimes sold or transferred between facilities. Because many different types of facilities produce and use steam, some existing or proposed benchmarking efforts have considered developing separate benchmarks based on heat or steam production in addition to or instead of other benchmarks. These include the EU's effort to develop industry benchmarks for the third phase of its Emissions Trading System, where a heat production benchmark has been recommended as a "fall-back" approach for sectors or products where product-specific benchmarks are not developed and applied (Ecofys, Fraunhofer Institute, and Öko Institut 2009a). Additionally, US EPA has considered developing benchmark-based performance standards for industrial boilers as it has evaluated alternative possibilities for regulating greenhouse gases under the Clean Air Act (US EPA 2008b) and has also developed a protocol for measuring reductions in greenhouse gas emissions from industrial boilers (US EPA 2008e).

Overview of Production Processes and Emission Sources

The production and use of steam in industrial processes involves four sequential steps (LBNL and Resource Dynamics 2004):

- **Generation.** Steam is produced either in a boiler or in a system to recover heat from another industrial process. In either case, steam is produced by transferring heat to water, which when heated to the boiling point, produces steam. The temperature and pressure of the steam produced in a boiler is influenced by the boiler design and by the ultimate uses of the steam produced.
- **Distribution.** Under pressure, steam flows from the generator into distribution lines, which carry the steam to the points of end use and which involve various types of valves to regulate pressure.
- **End Use.** Steam can be used for process heating, mechanical drives via turbines, moderation of chemical reactions, drying of paper products, fractionation of hydrocarbons in petroleum refining, or used directly as a hydrogen feedstock in a steam-methane reformer (e.g., at Solvay Chemicals.)
- **Recovery.** Wet steam or condensed steam used in process heating is returned to the boiler area where it is cooled in a heat exchanger and collected in a boiler feedwater tank. From the collection tank, the water is pumped to a deaeretor, where it is stripped of oxygen and non-condensable gases and fed back into the boiler along with any makeup water needed to repeat the cycle.

Release of greenhouse gases occurs in the generation stage as a result of burning of fuels used to heat the boiler. Fuels used include the fossil fuels coal, oil, refiner gas (petroleum refining), and natural gas; waste products such as bark or wood chips, pulping liquors (pulp and paper sector), or landfill gas; plus other fuels. Boiler efficiency can vary tremendously by boiler age, size, and design. Coal and natural gas fired boilers are typically about 80 to 85% efficient, whereas a boiler fired by spent pulping liquors is approximately 70% efficient (Energy and Environmental Analysis, Inc. 2005). Significant losses of efficiency can also arise in the distribution system. According to the International Energy Agency, the best opportunity to increase efficiency of a steam system is through a combined heat and power (CHP) system (IEA 2008).

Key Issues in Benchmarking Steam

Three factors influence GHG emissions from combustion processes that generate steam: the choice of fuels, the efficiency of the heat production, and the efficiency of heat end use (Ecofys, Fraunhofer Institute, and Öko Institut 2009a). A benchmark on steam production would easily account for the first two factors, but the third would be harder to include. As a result, one issue in benchmarking steam (at least relative to alternative approaches, such as benchmarking end products) is that a steam benchmark would not account for the efficiency of the *use* of that steam in producing a final product such as paper, a food product, or chemicals, or heating buildings. To address this limitation, the EU has considered whether an adjustment factor may be applied to the benchmark to account for potential end-use efficiency improvements (Ecofys, Fraunhofer Institute, and Öko Institut 2009a). In other

[63] Unless the steam is the product of a specialized area heating/cooling facility that provides steam to heat office buildings in the area around the plant. The Seattle Steam plant in downtown Seattle is an example of such a facility.

words, for sectors with large end-use efficiency opportunities, the benchmark value could be adjusted to help encourage pursuit of the end-use efficiency opportunities.

The biggest issue with benchmarking steam, however, may be whether to differentiate a steam benchmark by sector. Different industrial sectors may use different boiler technologies (with varying efficiencies) or (as described above) rely historically on different fuels, factors which may suggest the use of differentiated benchmarks by sector or by fuel and boiler design, at least in a voluntary or regulatory approach. The U.S. Department of State, for example, has written "the efficiencies of industrial boiler applications in the U.S. are dictated by operational and emission requirements making no single emissions performance value applicable for the variety of industrial boilers in use in the U.S. (US Department of State 2010). Under a cap-and-trade program, developing different steam benchmarks for each sector may be less appropriate as the goal is to encourage long-term technology and fuel transitions and facilities can purchase or sell allowances depending on whether they are emitting above or below the respective benchmarks.

Finally, how emissions from biomass and waste fuels, as well as cross-boundary (versus within-facility) heat flows are treated in benchmark development and application is very important in ensuring that the benchmark sends the appropriate incentive. [Our research on cross boundary heat flows and combined heat and power (CHP) is ongoing.]

Steel

Crude steel is produced from both virgin materials (primary iron, which is made from iron ore) and secondary materials (scrap). The steel industry employs two distinct production technologies to make steel: the basic oxygen furnace (BOF), which is integrated with the production of pig iron, and the electric arc furnace (EAF), in which steel is produced by the melting of scrap or direct reduced iron with the help of electric arcs. Globally, about two-thirds of steel is produced via the first process, which uses mostly iron ore as its feedstock (with small amounts of scrap). In the U.S., more steel is produced in the electric arc furnaces, which is generally less greenhouse-gas intensive than production via basic oxygen furnace (IEA 2008).[64] Other technologies, including the outdated open-hearth furnaces, account for a very small fraction of steel making. The industry, in collaboration with researchers at the Massachusetts Institute of Technology, is also investigating new steelmaking technologies, such as molten oxide electrolysis, that would generate zero direct carbon emissions, but that would require large quantities of electricity (IEA 2009).

In Washington State, the only producer of crude steel is Nucor Steel in Seattle, an electric arc furnace that uses scrap (recycled) steel to make steel rebar, flat bar, channel, and other similar products. We cover both BOF and EAF technologies here, however, as basic oxygen furnaces have existed in Washington previously, and they continue to be major producers of steel in other parts of the country.

After crude steel is cast, additional processes convert the steel to finished products at forges. One forge, Jorgenson Forge, is based in Tukwila, WA. Together, Nucor Steel and Jorgensen Forge release an estimated 135,000 tons CO_2e of greenhouse gases each year(Washington Dept. of Ecology 2009).

Overview of Production Processes and Emission Sources

Production of steel occurs in five distinct steps (Ecofys, Fraunhofer Institute, and Öko Institut 2009g; Neelis and Patel 2006):

- **Mining and treatment of raw materials.** Two significant raw materials are used to make steel: iron ore and coal. Coal is converted to coke by heating in the absence of oxygen to remove the volatile components and tars. Iron ore is sintered, a process in which iron ores of different grain sizes (particularly finer-grained ore) are agglomerated together with additives (e.g., limestone) to make a consistent feedstock for the blast furnace.

[64] The exception would be if the electric arc furnace is fueled by direct reduced iron produced using coal, in which case total emissions per ton of steel can be higher than from a basic oxygen furnace (IEA 2008).

- **Iron making**, in which iron ore is smelted with coke in a blast furnace and iron oxides are reduced to liquid pig iron. Alternatively, iron ore can instead be reduced, below its melting point and retaining its original shape, into direct reduced iron (DRI) (also called "sponge iron") for use in an electric arc furnace.[65]
- **Steel making.** In the basic oxygen furnace, oxygen is blown through the molten pig iron, oxidizing the carbon, silicon, and phosphorus in the pig iron and producing steel. Some amount of scrap may be added at this stage to help control the reaction and aid in cooling. In an electric arc furnace, as in the Nucor facility in Seattle, melting of scrap (recycled steel) and direct reduced iron occurs in a bath at high temperatures attained with the help of an electric arc.
- **Casting**, in which liquid steel is cast into large ingots, billets, or, semi-finished products such as slabs. In the Nucor facility in Seattle, steel is cast into a billet.
- **Rolling and finishing,** in which the steel is converted to finished steel products via various foundry, rolling, pickling, annealing, welding, or other steps.

Table 17 summarizes the major processes and sources of emissions in iron and steel production. Note that the first two processes: raw material treatment and iron-making, do not occur in Washington State.

[65] Washington's only steel mill, Nucor Steel, an electric arc furnace, does not use direct reduced iron.

Table 17. Summary of Iron and Steel Production Processes, Emission Sources, and Existing Benchmark Sources

Step	Dominant Emissions Sources	Proposed or Existing GHG Benchmarks under Cap-and-trade	Other Benchmarks or Best-Practice Values	Key Issues / Options
Mining and treatment of raw materials	▪ Fossil fuel burning for coking and sintering ▪ Direct CO_2 emissions from residue materials and from limestone calcinations ▪ Direct CO_2 and CH_4 emissions from coke-making (usually transferred as a waste gas to the blast furnace) or sinter making	EU has proposed benchmarks for: ▪ Coke ▪ Sinter	▪ Worrell et al (2008) list world best-practice energy benchmarks for pellets	▪ Treatment of waste gases from the coke oven, blast furnace, and basic oxygen furnace can be used in internal processes or transferred to other installations. Benchmarks for these waste gases could be established and allowances allocated (if in a cap-and-trade setting) to either producer or consumer of them (or split between them).[66] ▪ EU states that a separate benchmark for iron ore pellets (an alternative to sinter) may be warranted if data are sufficient
Iron making	▪ Fossil fuel burning to fire blast furnaces ▪ Direct CO_2 emissions from use of coke as a reducing agent in a blast furnace	None known (In the EU, emissions for producing pig iron are included in the hot steel benchmark)	▪ Worrell et al (2008) list world best-practice energy benchmark for ironmaking, including direct reduced iron	Arguments exist both for and against having a separate benchmark for pig iron: ▪ For: it can be traded as its own intermediate product ▪ Against: Rarely is cooled and sold as its own product; could create perverse incentives for altering ratio or quality of pig iron use; separate pig iron and hot metal benchmarks would likely be impossible for an integrated facility to simultaneously attain.[67]
Steel making	▪ In a BOF, fossil fuel burning and direct CO_2 emissions from oxidizing the carbon in the pig iron ▪ In an EAF, direct, process CO_2 emissions from carbon from electrodes and scrap oxidizing, as well as emissions from production of electricity	EU has proposed benchmarks for: ▪ Hot steel ▪ EAF steel H.R. 2454 (Waxman-Markey), passed in the US House of Representatives in 2009, included a formula for constructing average benchmarks for: ▪ Steel from integrated mills ▪ EAF steel	IEA (2008) lists global averages for ▪ EAF steel from scrap ▪ EAF steel from direct reduced iron ▪ BOF steel Worrell et al (2008) list world best-practice energy benchmarks for steelmaking and casting US EPA (2008a) reports U.S. average 1.24 tons of CO_2 per ton of steel, including both direct and indirect emissions, based on AISI data	▪ Treatment of waste gases can be critical (see above under treatment of raw materials) ▪ EAF high-alloy steel may warrant its own benchmark as it may be considered a distinctly different product, but in the EU data were insufficient ▪ The substitutability of electricity and fossil fuel in EAFs may be debated ▪ A key decision may be in what casting steps to include in a steel benchmark versus to treat downstream with a separate benchmark (perhaps using a fall-back approach given limited data)
Casting	▪ Fossil fuel burning or electricity production			
Rolling and finishing	▪ Fossil fuel burning or electricity production for equipment	EU treats with a fall-back approach	▪ Worrell et al (2008) list world best-practice energy benchmarks for rolling and finishing	▪ EU considering separate benchmarks for foundry products and warm rolling if products are similar enough

[66] For a lengthy discussion of waste gases in the iron and steel sector, including stakeholder comments, see Ecofys, Fraunhofer Institute, and Öko Institut (2009g)
[67] For a full discussion, see Ecofys, Fraunhofer Institute, and Öko Institut (2009g).

Key Issues in Benchmarking Steel

As with all sectors, the data availability and number of products to distinguish may be key issues. In addition, three issues particular to the steel industry are:

- **Treatment of waste gases,** which can either be used internally as furnace fuel or to generate electricity. To what extent these waste gases are counted when the benchmark is constructed, and whether they are counted under the producer or consumer (if applicable) of these gases, can be important questions (Ecofys, Fraunhofer Institute, and Öko Institut 2009g).
- **Treatment of intermediate products.** Coke, sinter and hot metal are important intermediate products that can be traded between installations. How to account for these possible trades can be an important question. The EU proposed to develop benchmarks for these intermediate products (Ecofys, Fraunhofer Institute, and Öko Institut 2009g).
- **Substitutability of electricity and fossil fuel in an electric arc furnace.** In an electric arc furnace, oxy-fuel burners can also be used to provide heat to the furnace. Within certain limits, and depending on the product being made, the fraction of heat supplied by the oxy-fuel burner can be altered. Accordingly, a benchmark based only on direct emissions could tend to favor electric arc furnaces that use a lower fraction of heat from the oxy-fuel burner, regardless of overall (direct + indirect) GHG intensity. However, this issue would be less of a concern under a cap-and-trade program that also included electricity, since the cost of emissions from electricity production would be reflected in the price of the electricity.

5. Summary of Preliminary Findings and Potential Next Steps

Executive Order 09-05 directs the Department of Ecology to both to “develop emission benchmarks” and to deliver “recommendations on industry benchmarks, and the appropriate use of these benchmarks in achieving the state emission reduction targets” to the Governor by July 1, 2011.

Ecology has divided benchmarking work under the Executive Order into two phases. This report presents findings of the first, exploratory Phase I on key issues and options in benchmark development. Phase II could involve the development of benchmarks and will involve developing specific recommendations on their appropriate use. This section begins by reviewing our preliminary findings for Phase I, and then presents some possible paths forward under a Phase II.

Industries in Washington State and throughout the world use benchmarking to compare their performance to others in their own benchmarked industry sector using best practices and/or industry averages. Use of benchmarks to improve energy efficiency is well established, while benchmarking to reduce GHG emissions is increasingly explored and in some instances, practiced. Internationally, the cement and aluminum industries, for example, have made significant in-roads in developing GHG benchmarks and using these to set GHG performance targets.

As discussed in this paper, benchmarking is incorporated in most of the key efforts to address industrial GHGs :cap-and-trade programs, voluntary initiatives and agreements, and regulatory performance standards. From a climate policy perspective, industrial benchmarking is most advanced in the EU, where benchmarks have been used for voluntary agreements between national governments and industrial sectors or individual companies, and where detailed benchmark development is well underway for allowance distribution under the third phase of the EU’s Emission Trading System. However, as described in Section 2, GHG benchmarking is gaining ground in the U.S. as well. Benchmarking provides a tool for developing GHG performance standards under the Clean Air Act, and the possible basis for distributing allowances under a cap-and-trade system.

It is important to note that developing meaningful benchmarks will require collecting and comparing performance data across a significant proportion of product markets. The development of GHG benchmarks is thus most relevant at a regional, national, or international level, even as such benchmarks may be applied at more local (e.g., state) levels. This has implications for Ecology’s work in Phase II.

The construction of benchmarking presents a number of challenges, such as:

- The appropriate level of disaggregation by technology, feedstock, fuel or other facility-specific factors; The ability to differentiate by specific product type;
- Whether and how to include indirect emissions from purchased electricity and heat;
- How to address cogeneration (combined production of heat and power);
- Whether to develop and use a more generic heat production benchmark;
- What data sources to use, including how many facilities are needed to yield a meaningful data set for benchmarking; and
- The level of ambition to which the benchmark should be constructed to inform/motivate industry actors;

As described in Section 3, the policy context – cap-and-trade allowance distribution, regulatory performance standards, or voluntary targets – will influence how each of the challenges is resolved. Executive Order 09-05 calls for Ecology specifically to "develop emission benchmarks, by industry sector, for facilities the Department of Ecology believes will be covered by a federal or regional cap-and-trade program" and to "support the use of these emission benchmarks… as an appropriate basis for the distribution of emission allowances." At the same time, the Executive Order is also clear that benchmarks "shall be developed to allow their application as state-based emissions standards, should they be needed to complement the federal program, or in the absence of a federal program." Regardless of the ultimate policy approach – cap-and-trade or regulatory performance standards – there is some common work to do collect and analyze sectoral benchmarking data.

Indeed, benchmarking is a highly data-intensive exercise, and comprehensive and consistent facility-level greenhouse gas emissions data are only just now beginning to emerge, especially here in the U.S., through mandatory reporting rules and industry-led efforts. Benchmarking data can also be sensitive or difficult to procure, since the production data used to index performance are often considered confidential business or production information. As we note in Section 3, however, a number of sources can be utilized to analyze and gauge emissions, production, and other data needed to develop benchmarks. The timing of policies that will depend on benchmarks will determine the data sources that can be relied upon for benchmark construction, which in turn will influence how the benchmarks can be designed. If benchmarks are needed by July 1, 2011, for example, then they will be able to rely upon, at most, one year of comprehensive U.S.-wide mandatory reporting data.

In keeping with the Executive Order, and as reflected in this paper, Ecology is currently proceeding with an approach to benchmarking that leaves open how benchmarks might ultimately be used: for allowance distribution in a cap-and-trade system or for emissions performance standards. Such an approach enables Washington State agencies and industries to be prepared for, and be involved in shaping, a climate policy landscape that is currently highly uncertain. It allows Ecology to proceed with certain elements of benchmark development, such as data collection and analysis, that do not depend on policy context. However, as we illustrate in this paper, other elements of benchmark development, such as levels of ambition and disaggregation, are likely to depend upon whether benchmarks are used for allowance rebates, performance standards, or other applications.

As a path forward, Ecology could continue to cover all the bases with a comprehensive effort would involve developing benchmarking data and methodologies, and constructing proposed benchmarks, that are appropriate for each policy context. This path forward would require significant resources and would depend on finding ways to overcome possible data limitations, especially if all potentially relevant sectors are covered. Pursuing such an approach would maintain maximum flexibility and could include the greatest possible share of industrial GHG emitters in the state, but could forego the opportunity to use limited resources to develop a path forward tailored to policy approaches or industry sectors for which benefits are likely to be the greatest.

Alternatively, Ecology could choose more focused paths, for instance, by doing one or more of the following:

- Concentrate on one benchmark context alone, such as output-based allowance distribution. Doing so would allow Ecology to contribute to more detailed methodology development (with potential broader influence) yet would require the implementation of a national or regional cap-and-trade program to actually implement the use of benchmarks in this manner.

- Select one or more sectors for initial benchmark development. As a first step, Ecology could establish and use criteria upon which such a selection could be made. Section 4 of this report discussed particular industry sectors and how they might be evaluated under some potential criteria, such as energy-intensiveness or trade exposure, level of emissions in Washington State, data availability, and experience with benchmarking.
- Dive more deeply on a) resolving specific benchmarking questions, such as the feasible and desirable levels of product differentiation (e.g. writing paper, newspaper, or all paper within the pulp and paper sector) or technology or other differentiation in benchmarks for selected sectors, or b) collecting and analyzing performance data, rather than developing actual benchmark values.

The direction and extent of Phase II work will depend on a number of factors, from available resources at Ecology to policy developments occurring beyond the state's borders. With federal climate policy in considerable flux, and regional efforts (i.e., WCI) still under development, Ecology could take such an incremental approach, undertaking some of the steps noted above during the last half of 2010, and then re-evaluating whether and how to proceed with benchmark development in the first half of 2011.

Other steps that Ecology may consider, regardless of the path taken as outlined above, would be to:

- Partner with other interested jurisdictions in the WCI, MGGRA, or RGGI on data collection, analysis, and benchmark design;
- Establish a collaborative agreement with EPA and/or industry associations and facilities to gain better access to data and to pilot specific benchmarking methods; and/or
- Convene expert groups to review and evaluate benchmark methodologies for their relevancy to the Washington state context and the Governor's Executive Order.

As noted in the introduction, this report is a preliminary draft. Building on the insights gained from the benchmarking symposium (May 19, 2010) and stakeholder input, we will issue a final draft in late June. We invite your comments on this draft, submitted via email to benchmarking.wa@sei-us.org by Friday, June 4, 2010. Our recommendations on how Ecology might undertake Phase 2 will be detailed more fully in the final draft.

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Appendix A. Expected GHG Reporting Data

In Section 3 of this White Paper, we assess possible sources for emissions and production data that could enable construction of benchmark curves. One of the most promising – but as yet unavailable – sources of data will be mandatory greenhouse gas reporting rules. This appendix describes the data that will be submitted under the federal and Washington State reporting rules as well as other sector-specific data sources (e.g., the Cement Sustainability Initiative).

US EPA's Mandatory Reporting of Greenhouse Gases rule will require facilities to report greenhouse gas emissions for year 2010 by March 31, 2011 (US EPA 2009b). All facilities in the primary aluminum and cement sectors will need to report emissions, as will facilities in several other sectors without a significant presence in Washington State (e.g., chemical industry sectors adipic acid, ammonia, HCFC-22, nitric acid, phosphoric acid, and others). In most other sectors, all facilities that emit more than 25,000 ton CO_2e annually will be required to report. Emissions data will be public. Reporting of production data is also required. While a determination of the confidentiality of the production data is still forthcoming, these data are not expected to become public but may be used by agency staff (EPA staff, personal communication, April 2010).

The State of Washington's Mandatory Greenhouse Gas Reporting Rule takes effect in 2010 for facilities with at least 25,000 tons CO_2e of 2009 emissions. Facilities that emit at least 10,000 tons of GHGs must start reporting in 2011 for year 2010 emissions. The reporting methodologies for both the federal and Washington State rules have been harmonized.

Following is a discussion of reporting rule specifics for each sector that we addressed in Section 4 of the main body of this White Paper.

Aluminum

Reporting requirements for the aluminum sector are summarized in Table 18. Most of the emission sources below apply only to primary aluminum. For secondary aluminum, the major sources of direct emissions are fossil fuel combustion for the furnace (if applicable) and equipment.

Table 18. Summary of Required Federal GHG Reporting for the Aluminum Sector (US EPA 2009b)

Sources Addressed	▪ Aluminum smelting via electrolysis using either prebake or Söderberg anodes ▪ Baking of anodes for pre-bake anodes ▪ Stationary combustion of fossil fuel
GHGs Required to be Reported	▪ PFC – Perfluoromethane (CF_4) and perfluoroethane (C_2F_6) – emissions from anode effects ▪ Carbon dioxide (CO_2) emissions from anode consumption during electrolysis in all prebake and Søderberg cells. ▪ All CO_2 emissions from onsite anode baking ▪ CO_2, nitrous oxide (N_2O), and methane (CH_4) emissions from each stationary combustion unit
Methodology Highlights	▪ Perfluorocarbon emissions (CF_4) and perfluoroethane (C_2F_6) emissions calculated based on frequency and duration of anode effects, monthly aluminum production, and a pre-determined coefficient that estimates emissions from these parameters ▪ Process CO_2 emissions calculated based either on installing and operating a continuous emissions monitoring system (CEMS) or a mass-balance calculation ▪ Process CO_2 emissions during anode baking of prebake cells estimated based on mass balance calculation ▪ Carbon dioxide (CO_2) emissions from each fuel combustion unit calculated using one of the four tiered methods outlined in the rule, as well as methane (CH_4), and nitrous oxide (N_2O).
Required Reporting	▪ Annual GHG emissions ▪ Annual aluminum production in metric tons ▪ Type of smelter technology used ▪ Annual fuel use ▪ Various parameters used to support calculations of process emissions

Other Data Sources in the Aluminum Industry

Internationally, the International Aluminum Institute (IAI) collects data on the specific emissions of PFC emissions from primary aluminum production. The IAI publishes plant specific data for most of the aluminium production plants worldwide (International Aluminum Institute 2009). Unfortunately, only very few installations from China reported their emissions. With the data of the reporting installations (representing approximately 60% of all installations worldwide) a benchmarking curve can be constructed and is depicted below as Figure 9.

Figure 9. Benchmarking curve for PFC emissions from primary aluminum production
(X-axis is fraction of plants)

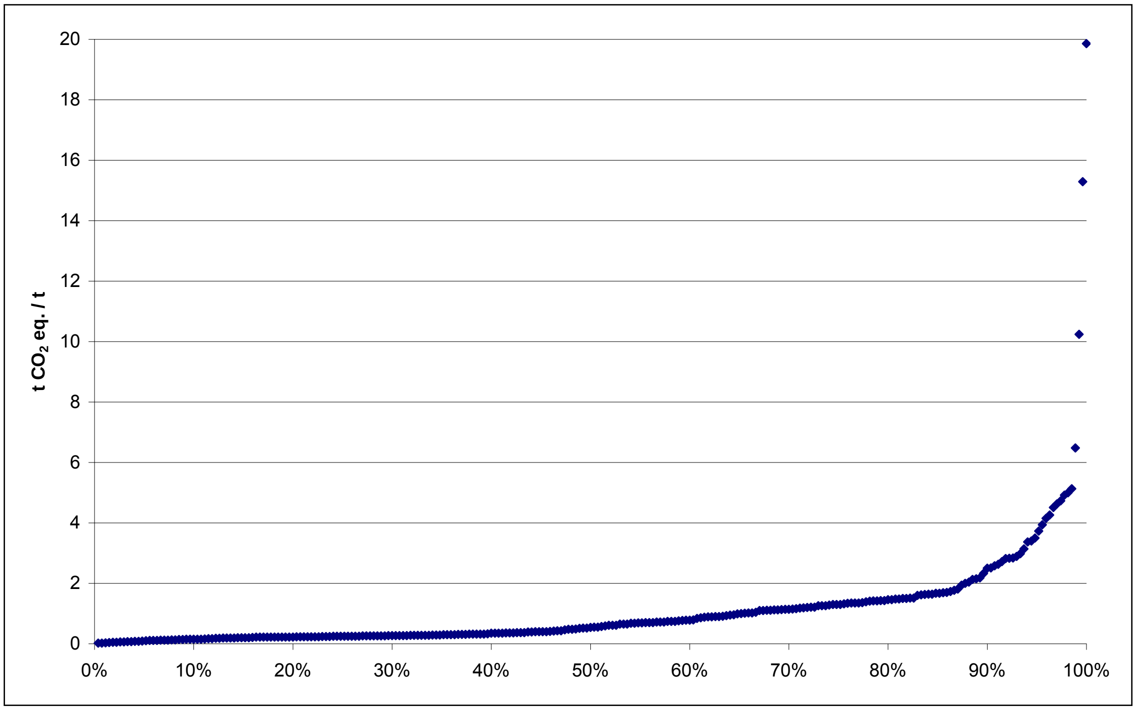


Figure Source: *Calculations by Öko-Institut based on specific emissions reported by 270 primary aluminium smelters published by IAI 2009*

In addition, the IAI's 2009 publication *Results of the 2008 Anode Effect Survey* includes additional detailed benchmarking data and curves that depict the performance of facilities with different anode technologies.

Cement

For the cement sector, the rules will require reporting of GHG emissions and clinker and cement production, as summarized in Table 19.

Table 19. Summary of Required Federal GHG Reporting for the Cement Sector (US EPA 2009b)

Sources Addressed	▪ Each kiln and each inline kiln / raw mill at any Portland cement manufacturing facility ▪ Stationary combustion of fossil fuel
GHGs Required to be Reported	▪ CO_2 process emissions from calcinations at each kiln ▪ CO_2, methane (CH_4), and nitrous oxide (N_2O) emissions from combustion at each kiln or combustion unit other than kilns
Methodology Highlights	▪ For process CO_2 emissions, either operate and maintain a continuous emissions monitoring system (CEMS, as in Tier 4) or calculate process CO_2 emissions based on clinker production and kiln-specific emission factors ▪ For fossil fuel combustion, calculate CO_2 emissions from each fuel combustion unit using one of the four tiered methods outlined in the rule and also report methane (CH_4), and nitrous oxide (N_2O) emissions
Required Reporting[68]	▪ Annual GHG emissions ▪ Monthly clinker and cement production ▪ Number of kilns and number of operating kilns ▪ Annual fuel use ▪ Additional, other data on cement kiln dust and raw material usage, as used to support calculations of process emissions if CEMS not used

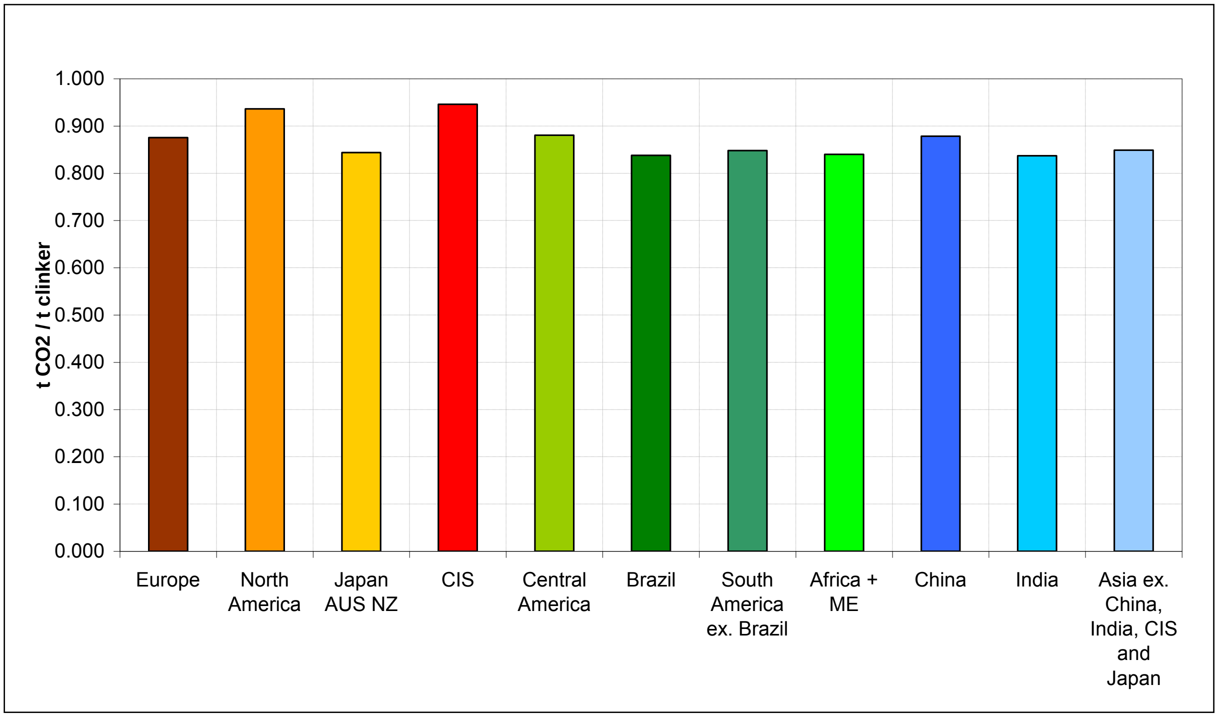
Other Data Sources in the Cement Industry

The Cement Sustainability Initiative (CSI) collects GHG benchmarking data for the global cement industry. To provide an example of possible benchmark curve construction based on these data, we calculated emissions for cement clinker production based on direct emissions and production using data from the Cement Sustainability Initiative (CSI 2009). These data include statistics from (mainly) multinational companies that represent 40% of the world's cement production. Direct emissions are influenced by the following two components: CO_2 intensity of the fuel used and specific fuel consumption per ton of product. Data on clinker production was used to calculate specific emissions from direct emissions from clinker production and illustrates how the CO_2 emissions associated with the production of a ton of clinker varied amongst the different countries. Figure 10 displays these results based on Cement Sustainability Initiative data.

The fact that for China and India relatively low specific emissions are reported can be explained by the fact that only the rather new and efficient plants of multinational companies are reporting under CSI.

[68] Additional data are required to support the methodology chosen.

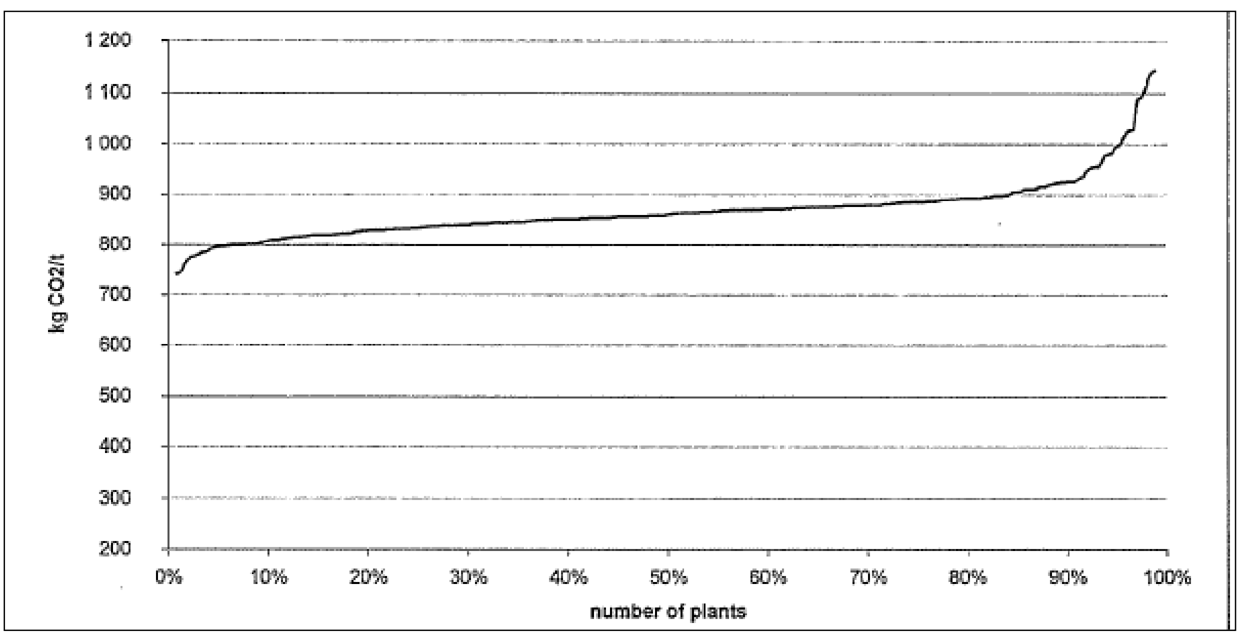
Figure 10. Average direct specific CO_2 emissions of clinker production in the year 2007 of those companies reporting under the CSI



Source: *Öko-Institute based on CSI (2009).*

In the EU, the preliminary benchmark for the third phase of the EU Emissions Trading System, derived from the average specific emissions of the 10 % most efficient installations, is about 0.78t CO_2 / ton of clinker (based on data in 2006, Figure 11). The final benchmark will be based on data for the years 2007 and 2008.

Figure 11. Benchmarking curve for cement clinker in the EU for the year 2006.



Source: *Ecofys, Fraunhofer Institute, and Öko-Institut (2009c)*

Chemicals

The federal GHG reporting rule requires facilities in several chemical industry sectors to report emissions regardless of size. Other sectors (including hydrogen production) must only report if emissions exceed 25,000 tons CO_2e annually. Since Solvay Chemicals produces hydrogen in Washington, Table 20, below, summarizes the reporting requirements for the hydrogen production sector. Emerald Kalama chemicals, which produces petrochemical food additives, would be required to report under the general requirements for facilities that emit at least 25,000 tons CO_2e from boilers and possibly also due to the petrochemical requirements.

Table 20. Summary of Required Federal GHG Reporting for the Hydrogen-production Sector (US EPA 2009b)

Sources Addressed	▪ Process units that produce hydrogen by reforming, gasification, oxidation, reaction, or other transformation of feedstock
GHGs Required to be Reported	▪ CO_2 process emissions from each hydrogen production process unit ▪ CO_2, methane (CH_4), and nitrous oxide (N_2O) emissions from combustion at each hydrogen production process unit ▪ CO_2 either collected and used on-site or transferred off site
Methodology Highlights	▪ For process CO_2 emissions, either operate and maintain a continuous emissions monitoring system (CEMS) or calculate process CO_2 emissions based on fuel and feedstock usage and fuel- and feedstock-specific emission factors
Required Reporting	▪ Annual GHG emissions ▪ Fuel and feedstock consumption ▪ Annual quantity of hydrogen produced (metric tons) ▪ Annual quantity of ammonia produced, if applicable (metric tons) ▪ Additional data to support other calculations, as specified in the rule

Food Processors

Food processors are not in an industry sector specifically addressed in the federal greenhouse gas reporting rule (US EPA 2009b) nor in federal legislation passed out of the U.S. House of Representatives in June 2009 (the Waxman-Markey bill, H.R. 2454, but with the exception of malt manufacturing, wet corn milling, and rendering and meat byproduct processing, which were included in the benchmark-based allowance rebates to energy-intensive, trade-exposed industry sectors). Nevertheless, where facilities emit more than the minimum thresholds for reporting (25,000 tons CO_2e in the federal reporting rule and 10,000 tons CO_2e in the State reporting rule, SB 6373), then food processing facilities will need to report GHG emissions.

Glass

For the glass sector, the federal rule will require reporting of GHG emissions from continuous glass melting furnaces, as summarized in Table 21.

Table 21. Summary of Required Federal GHG Reporting for the Glass Sector (US EPA 2009b)

Sources Addressed	▪ Continuous glass melting furnaces that manufacture flat, container, pressed or blown glass, or wool fiberglass
GHGs Required to be Reported	▪ CO_2 process emissions from each continuous glass melting furnace ▪ CO_2, methane (CH_4), and nitrous oxide (N_2O) emissions from combustion at continuous glass melting furnace or other fuel combustion units
Methodology Highlights	▪ For process CO_2 emissions, either operate and maintain a continuous emissions monitoring system (CEMS) or calculate process CO_2 emissions based on usage of carbonate raw material (e.g., lime), mass fraction of carbonate in the raw material, and fraction of calcinations achieved ▪ Carbon dioxide (CO_2) emissions from each fuel combustion unit calculated using one of the four tiered methods outlined in the rule, as well as methane (CH_4), and nitrous oxide (N_2O).
Required Reporting	▪ Annual GHG emissions ▪ Fuel and feedstock consumption ▪ Annual quantity of each carbonate-based material used (tons) ▪ Annual quantity of glass produced (tons) ▪ Number of continuous glass melting furnaces ▪ Additional data to support other calculations, as specified in the rule

Pulp and Paper

For the pulp and paper sector, the federal rule will require reporting of GHG emissions from facilities that produce market pulp, manufacture pulp and paper (i.e., integrated mills), produce paper from purchased pulp, produce secondary fiber from recovered paper, convert paper into paperboard products, or operate coating and laminating processes(US EPA 2009b). Reporting requirements for pulp and paper facilities are summarized in Table 22.

Table 22. Summary of Required Federal GHG Reporting for the Pulp and Paper Sector (US EPA 2009b)

Sources Addressed	▪ Chemical recovery furnaces at kraft and soda mills (including recovery furnaces that burn spent pulping liquor produced by both the kraft and co-located semichemical process). ▪ Chemical recovery combustion units at sulfite mills. ▪ Chemical recovery combustion units at stand-alone semichemical mills. ▪ Systems for adding makeup chemicals ▪ Lime kilns at kraft and soda pulp mills.
GHGs Required to be Reported	▪ CO_2, biogenic CO_2, methane (CH_4), and nitrous oxide (N_2O) emissions from each chemical recovery furnace at kraft and soda mills and from each chemical recovery combustion unit at sulfite or stand-alone semichemical mills ▪ CO_2, biogenic CO_2, methane (CH_4), and nitrous oxide (N_2O) emissions from combustion of fossil fuels in each kraft or soda pulp mill lime kiln ▪ CO_2 from stationary fuel combustion units calculated using one of the four tiered methods outlined in the rule, as well as methane (CH4), and nitrous oxide (N_2O).
Methodology Highlights	▪ Methods generally involve measurement of fossil fuels, spent liquor fuels, and makeup chemicals and application of default or site-specific emission factors
Required Reporting	▪ Annual GHG emissions ▪ Annual fuel consumption ▪ Annual mass of spent liquor solids fired at the facility (short tons) ▪ Annual steam purchases (pounds of steam per year) ▪ Annual quantity of makeup chemicals (metric tons) ▪ Annual production of pulp and/or paper products produced (metric tons)

Steam

US EPA's Mandatory Reporting of Greenhouse Gases rule will require facilities that emit at least 25,000 tons CO_2e from stationary fuel combustion sources (e.g., boilers) to report greenhouse gas emissions. Facilities that must report only because of stationary fuel combustion (for example, several food processing sectors but not other sectors that are specifically required to report) are required to also report) are not required to report production output, potentially limiting the utility of these data for benchmarking purposes.

Steel

For the iron and steel sector, the rule will require reporting of annual GHG emissions from both electric arc furnaces and basis oxygen furnaces (e.g., integrated mills), as summarized in Table 23. Note that to be consistent with the discussion above, this table addresses both integrated (BOF) and EAF steel. Only EAF steel is produced in Washington State.

Table 23. Summary of Required Federal GHG Reporting for the Steel Sector (US EPA 2009b)

Sources Addressed	▪ Taconite iron ore processing ▪ Integrated iron and steel manufacturing (production of steel from iron ore or iron ore pellets) ▪ Coke making not co-located with an integrated iron and steel manufacturing process. ▪ Electric arc furnace (EAF) steelmaking not co-located with an integrated iron and steel manufacturing process
GHGs Required to be Reported	▪ CO_2 process emissions from each taconite indurating furnace, basic oxygen furnace, nonrecovery coke oven battery combustion stack, coke pushing process; sinter process, EAF, argon-oxygen decarburization vessel, and direct reduction furnace. ▪ For fossil fuel combustion, calculate CO_2 emissions from each fuel combustion unit using one of the four tiered methods outlined in the rule and also report methane (CH_4), and nitrous oxide (N2O) emissions ▪ CO_2, CH_4, and N_2O emissions from flares (e.g., coke oven gas and blast furnace gas.)
Methodology Highlights	One of three methodologies: ▪ Operate and maintain a continuous emissions monitoring system (CEMS) for process and combustion CO_2 ▪ Calculate the mass emissions rate using a carbon balance method ▪ Use a site-specific emissions factor based on a performance test that measures CO2 emissions from all exhaust stacks and processes
Required Reporting[69]	▪ Annual GHG emissions ▪ Annual production quantity (metric tons) for taconite pellets, coke, sinter, iron, and raw steel. ▪ Annual fuel use

[69] Additional data are required to support the methodology chosen.

Statistical Energy Benchmarking for Manufacturing Plants: The Energy Star Energy Performance Indicators (EPI)

Gale Boyd, PhD

presented to the

Western Climate Initiative

Symposium on Understanding the Value of Benchmarking

Seattle WA, May 19, 2010

DUKE UNIVERSITY
DEPARTMENT of ECONOMICS

Philosophy of the EPI

Analysis of the range of actual performance

"Observed Best Practice"

Plant/System (fence boundary) rather than process level

"Bird's Eye View"

Statistical approach - stochastic frontier / linear regression

"Black Box"

"Is performance close (or far) from my competitors?"

Digging a Little Deeper..

- The Energy Star manufacturing plant EPI is a facility level comparison of energy use in "similar" manufacturing plants.
  - Plants are distinguished based on
    - The products produced for final shipment and
    - The materials used to produced those products
    - External factors (e.g. climate) that drive energy use
  - A statistical model is used to normalize for differences
- Since some activities may be "too different," the scope of the analysis is on plants in specific production sectors.
- How the model "works"
  - A statistical analysis computes weights applied to shares of products, materials, and other factors to compute MMBtu per ton for the plant.
    - Weights are computed so as to best represent (fit) the most energy efficient plant (lowest MMBtu/ton) producing that product (mix).
    - The difference between actual MMBtu/ton and the benchmark from the product weights is the EPI measure of inefficiency.

Plant level data is key

- Analysis typically uses confidential plant level data from two sources
  - Center for Economic Studies (CES), U.S. Bureau of the Census
  - Data provided by trade associations and (occasionally) directly from industry
- Data from CES includes the non-public, plant-level data which is the basis of the government statistics on manufacturing
  - Title 13 of the U.S. Code protects this data,
    - CES allows researchers with Special Sworn Status to access these confidential micro-data at a Research Data Center (RDC).
    - Confidentiality prevents the disclosure of any information that would allow for the identification of a specific plant or firm's activities.
  - Duke University is an institutional partner with CES which provides access to this research project to this confidential data and CES has reviewed and approved the use of the data for this purpose.
- Advantage of using available data
  - No new reporting requirements; all plants; confidentiality assured
- Disadvantage is that the data were not collected specifically for this purpose and may not have all the details we would like.

Approach considers four major factors

- Product mix
- Physical plant size or productive capacity
- Process inputs
- External variables, such as
  - weather and
  - utilization rates

Product mix

- Segment the industry into natural product categories.
  - No overlap between plants that produce the various products
  - Each sub-group is treated as a separate industry
  - The glass industry is a good example, since
    - flat, container, and fiberglass are distinct products and
    - each sector can be treated in a "stand alone" manner
- Specialty products may require different energy use
  - ASTM I is the most common, but masonry cement is more energy intensive
  - Corn refiners have a common process of separation of gluten from starch.
    - animal feed by-products result in similar energy demands
    - differences arise from the treatment of the cornstarch.

      It may be dried as a final product,
      further processed and "modified,"
      used as a feedstock for sugar (e.g. HFCS, glucose, etc) or
      ethanol production.
- Statistical modeling can measure these differences.

Plant size or capacity

- To include size in the EPI a meaningful measure of size or capacity is needed. This can be measured by
    - inputs (corn refining – tons of corn),
    - outputs (auto assembly – number of autos produced),
    - or physical size (pharmaceuticals – square feet).
- Possible advantages to larger scale of production, i.e. economies of scale with respect to energy use.
    - This was not found to be the case for auto assembly or pharmaceuticals.
    - For cement it was found that larger kilns are an advantage, but larger numbers of kilns are not.

Process Inputs

- Materials, labor, or production hours may be proxy measures of production when measures of output are not available
  - Corn refining is an example of a sector where the energy use per unit of material input, i.e. corn processed, is used.
  - When production data is not available, materials may be used, e.g. sand and cullet are common inputs to glass manufacturing.

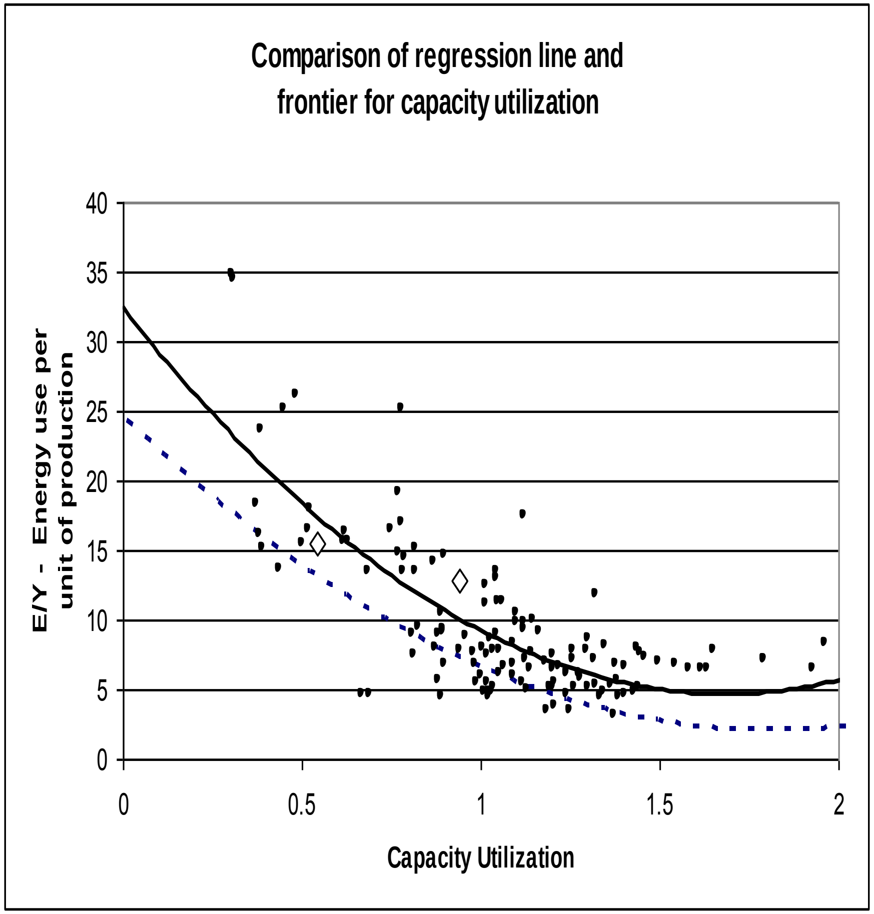
- When levels of materials or outputs are not available, production labor or hours of operation may be used to measure production activity and utilization
  - These alternatives are only used when they show a statistically significant relationship to energy, i.e. "when then work."

External Factors

- There are many things under the control of a plant or energy manager, but one they cannot control is "the weather."
- The approach that has been taken for all sectors is to include heating and cooling degree days (HDD and CDD) into the analysis to determine how much "weather" impact energy use.
  - For sectors like automobile, pharmaceutical, and some food manufacturing the approach finds statistically significant impacts of HDD and CDD on energy use.
  - For sectors like cement, glass, food processing, and corn refining we have not been able to estimate any impact so these factors are treated as de-minis for the purposed of annual, plant level benchmarks.

Stochastic Frontier is a Modified Regression

- Linear regression computes the "typical" performance by finding the line which "goes through the middle" of the data.
- Stochastic Frontier Regression (SFR) finds the best-performing by finding the line which "envelopes the frontier" of the data
- The frontier regression estimates the distribution of efficiency separately from the statistical error distribution and allows us to get a normalized percentile score for efficiency.



Statistical Frontier Model for Auto Assembly

- Stochastic frontier regression separates energy intensity into
  - Systematic effects,
  - Statistical (random) error
  - Inefficiency

$$E/Y_i = \beta_1 + \beta_2 Util + \beta_3 Util^2 + \beta_4 WB$$

$$\beta_5 HDD + \beta_6 HDD^2 + \beta_7 CDD \times AT + \beta_8 CDD^2 \times AT + u_i - v_i$$

E = total site energy use in mMBTU (1 kwh=3412 BTU)

Y = number of vehicles produced

Util = plant utilization rate, defined as output/capacity

HDD = heating degree days for the plant location and year

CDD = cooling degree days for the plant location and year

AT = dummy variable if plant is air-tempered is 1, otherwise 0

WB= wheelbase of the primary product

β is the vector of parameters to be estimated, $v \sim N(0, \sigma^2)$, and $u \sim \Gamma(\theta, P)$.

Why use SFR for benchmarking?

- The distribution of energy efficiency may not be "Bell shaped" curve, but may have a skewed distribution.
- We test whether a normalizing factor should be included
- The response of energy use to a factor, as measured by the estimated slope, may differ for average plants versus the best plants.
  - The best building may perform well in both cold and temperate climates, so it "less sensitive" to heating degree day differences.
  - The best plant may have better startup and shutdown procedures, so it "less sensitive" to differences in utilization.
- This method has 30 years of literature behind it used to measure productivity and other types of performance.

Benchmarking is an art, because...

- It is about developing tools that balance
  - Measures that are readily available
- Against
  - Information one can obtain from a particular approach
  - The specific needs of the application
  - The ability to meaningfully interpret the results
- Since there are often multiple needs for different types of information, a tool box is always better than any single tool

If the only tool you have is a hammer, then

everything looks like a nail…

Contact Information

- Gale A. Boyd, PhD
  Director, Triangle Census Research Data Center
  http://econ.duke.edu/tcrdc

  Duke University, Department of Economics
  Box 90097
  Durham NC 27708

  Office 919 660-6892
  email gale.boyd@duke.edu

DUKE UNIVERSITY DEPARTMENT of ECONOMICS

Benchmarking Industrial Plant Energy Efficiency

How EPA's ENERGY STAR® Program Helps Industry Improve Energy Efficiency

Elizabeth Dutrow
US Environmental Protection Agency
ENERGY STAR Industrial Partnership
May 19, 2010

ENERGY STAR

- Voluntary government partnership
  - ***Goal: reduce carbon dioxide emissions***
  - Introduced by EPA in 1992 to enable companies to improve in energy efficiency
- The national symbol of energy efficiency and environmental protection
  - Awareness exceeds 70% of U.S. households
  - A brand owned and managed solely by the government
- Focused on improving energy efficiency of:
  - Products
  - Homes
  - **Plants & buildings**
- For industrial businesses, EPA helps manufacturers improve strategic energy management.

ENERGY STAR & Industry

- EPA’s goals:
  - ***“Shift the curve” of energy performance for manufacturing industries***
  - Identify the transformative practices to achieve top energy performance
  - Help companies succeed in achieving top performance

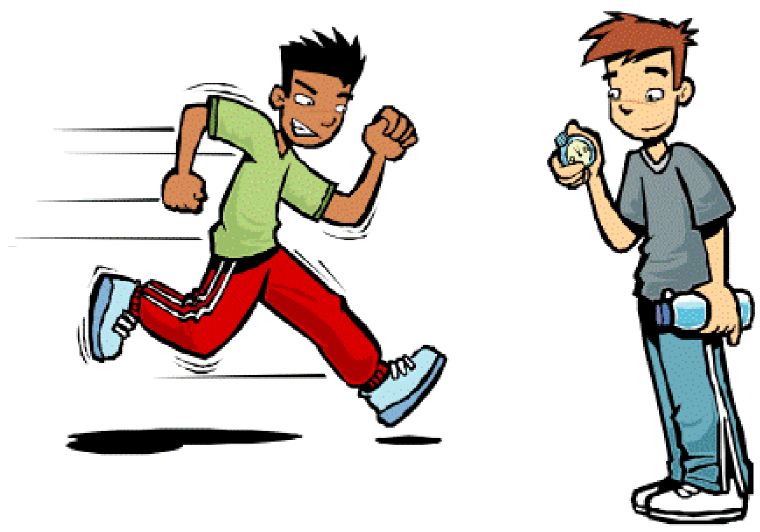
ENERGY STAR designed to address the barriers

Barrier

- Lack of a bearing on efficiency

Solution

- Benchmarking is an objective measurement method



ENERGY STAR provides business a clear pathway to succeed

1. Evaluate risks, prepare energy strategy with senior management

2. Build company-wide energy program, using ENERGY STAR

3. Look to suppliers and customers

Let's get on the same page

- Benchmarking
  - The process of comparing to something similar or the best
- ***Energy*** benchmarking
  - The process of comparing the energy performance of facilities, processes or equipment to something similar or the best

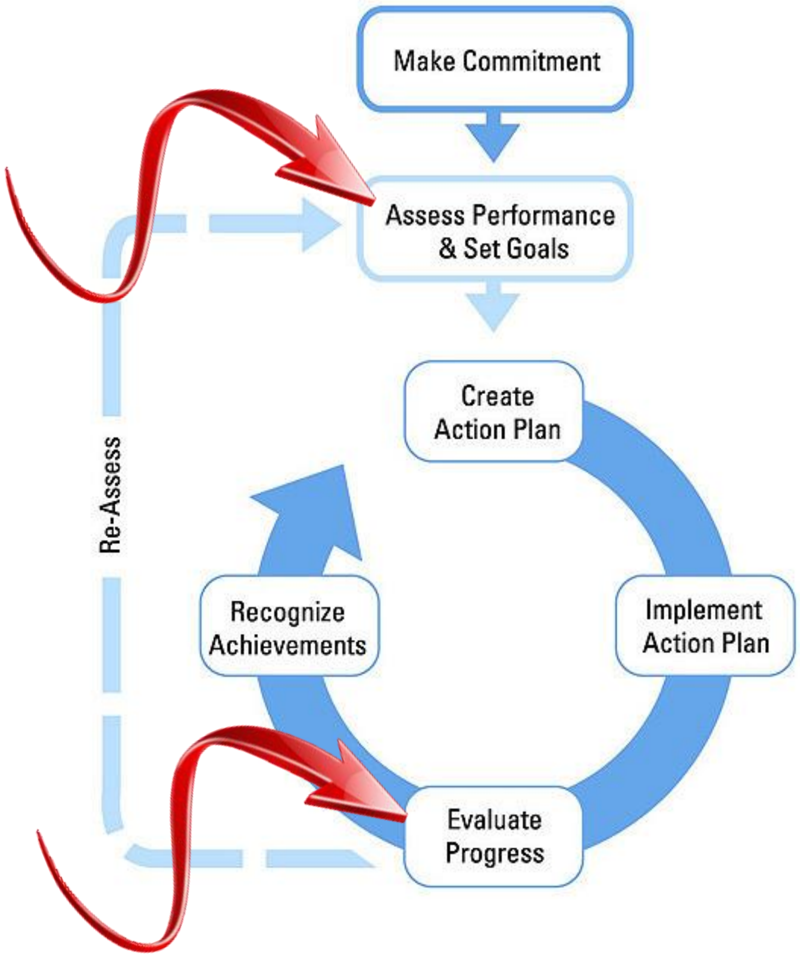
Types of benchmarking

- **Internal**
  – compares performance against internal baseline or benchmark
- **External**
  – compares performance against a metric “outside” of the organization
  – identifies “Best in Class” performance
- **Quantitative**
  – data-driven; compares actual numbers
- **Qualitative**
  – based on best practices; compares actions

Benchmarking's place in energy management

- Fundamental practice
- Energy reductions and project measurement are nice but only benchmarking proves improvements have had an effect
- Can be based on comparison of management practices or energy data
  - ***practice*** benchmarking gives an idea of where to improve by identifying best energy management practices
  - ***energy data*** benchmarking informs how well an entity might perform and improve and the position of that entity in terms of energy performance

ENERGY STAR Guidelines for Energy Management



Variety of benchmarking in energy management

Energy Management Objective	Scope		
	Scale	**Focus**	**Time Frame**
Assess equipment efficiency	Equipment or process	Internal – comparison against other owned equipment or process External – comparison to industry standard or cooperative study with other organizations	•Peak demand period •Three month sample •Weekly •Monthly •Annual •Continuous from baseline
Assess facility performance	Whole facility or sub-metered portion	Internal – comparison of single facility over time. Comparison of similar facilities within single organization External – comparison of facility against national performance rating	•Continuous from baseline •Monthly •Quarterly •Annual
Assess department or divisional energy use	Facilities or sub-metered portions of facilities	Internal – comparison against internal sub-divisions	•Continuous from baseline •Weekly •Monthly •Quarterly •Annual
Assess organizational performance	All facilities	Internal – comparison over time or towards goal. External – Comparison of portfolio average against a national performance rating	•Continuous from baseline •Monthly •Quarterly •Annual

ENERGY STAR benchmarks

- External
- Define “best in class” for an industry or building type
- Industry sector-specific at 6 digit NAICS code (or more refined)
- Energy data at the whole facility level
- Source energy intensity
- Normalized for key variables

ENERGY STAR Industrial Focuses

Developing specific industrial plant benchmarks

ENERGY STAR's industrial sector-specific focuses

Collaborative process to develop:

- ✓ **Energy Performance Indicator (EPI) to benchmark/rate plant energy performance**
- ✓ Energy Guide

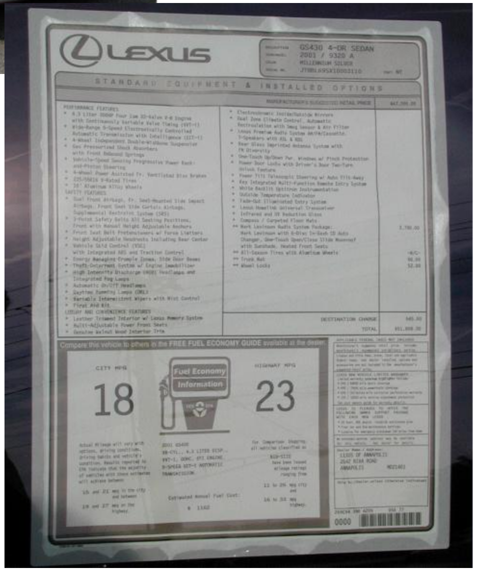
Facilitates:

- ✓ Sharing of best practices
- ✓ Networking
- ✓ Development of stronger company energy programs

Results in:

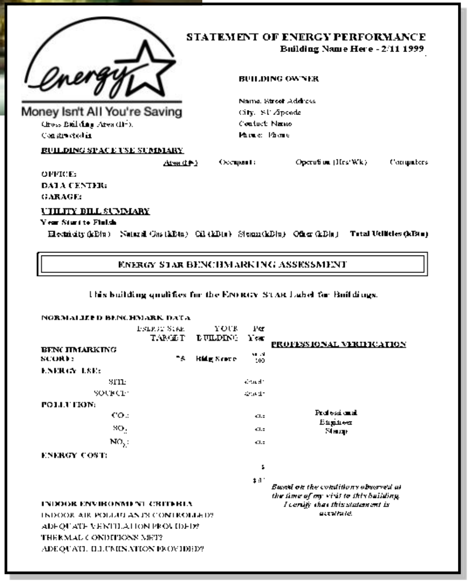
- ✓ **Sophisticated plant benchmarking tool**
- ✓ Recognition for energy-efficient plants with the ENERGY STAR
- ✓ Increased momentum for continued improvement
- ✓ Improved efficiency within an industry sector
- ✓ Prevention of carbon emissions

Benchmarking plant energy use:
Facility energy performance ratings



Fuel Efficiency:

MPG


STATEMENT OF ENERGY PERFORMANCE
Building Name Here - 2/11 1999

Money Isn't All You're Saving

BUILDING OWNER

BUILDING SPACE USE SUMMARY

OFFICE:
DATA CENTER:
GARAGE:

UTILITY BILL SUMMARY

ENERGY STAR BENCHMARKING ASSESSMENT

This building qualifies for the ENERGY STAR Label for Buildings.

NORMALIZED BENCHMARK DATA

PROFESSIONAL VERIFICATION

BENCHMARKING SCORE:
ENERGY USE:
POLLUTION:
ENERGY COST:

INDOOR ENVIRONMENT CRITERIA
INDOOR AIR POLLUTANTS CONTROLLED?
ADEQUATE VENTILATION PROVIDED?
THERMAL CONDITIONS MET?
ADEQUATE ILLUMINATION PROVIDED?

Energy Efficiency:

1 - 100

Benchmarking drives performance

Answers: *"If all plants in the industry use energy as this one, what percent of plants in the country would be better, and what percent would be worse?"*

Standardized measurement: the plant EPI

- Plant energy performance indicators (EPI)
  - Enable a higher level of energy management
    - Compare how efficiently a plant uses energy relative to those of its industry
    - Enable goal setting
    - Empower management to require greater energy performance from plants
    - Score plants on a **percentile basis (0-100),** normalized to a plant's unique configuration
      - ENERGY STAR defines score of 75 or above to be energy-efficient; 50 is average
  - www.energystar.gov/epis
  - www.energystar.gov/industrybenchmarkingtools

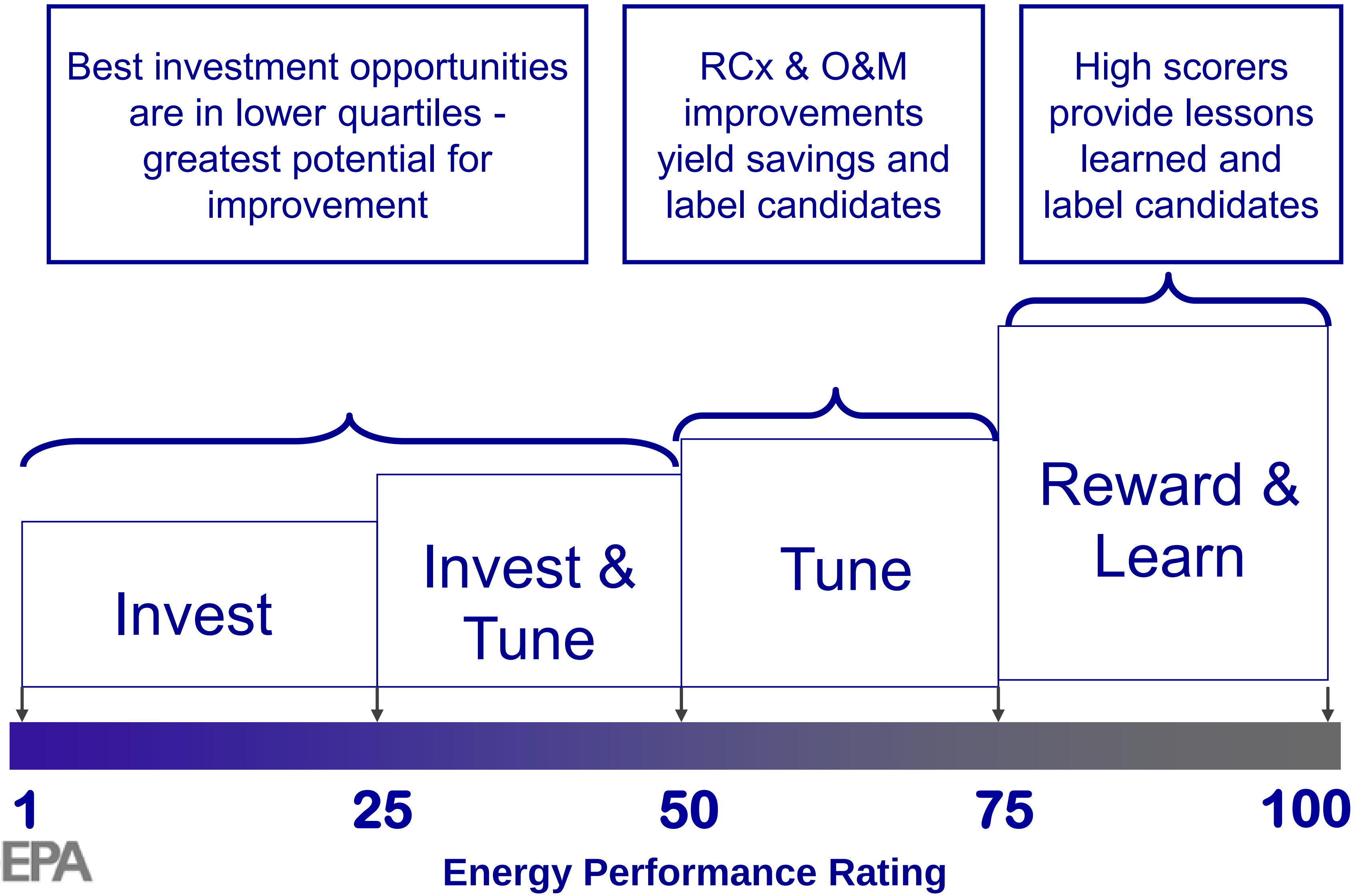
What EPA's national level plant energy benchmarking accomplishes

- Empowers industry to **shift the curve of energy performance**
  - For most companies, the ENERGY STAR EPI is the first time they are able to see how their plants' energy performance compares to that of their industry

- Enables companies in the benchmarked industry to **set competitive goals** for plant improvement

- Enables **EPA to gauge improvement** of an industry's energy performance over time

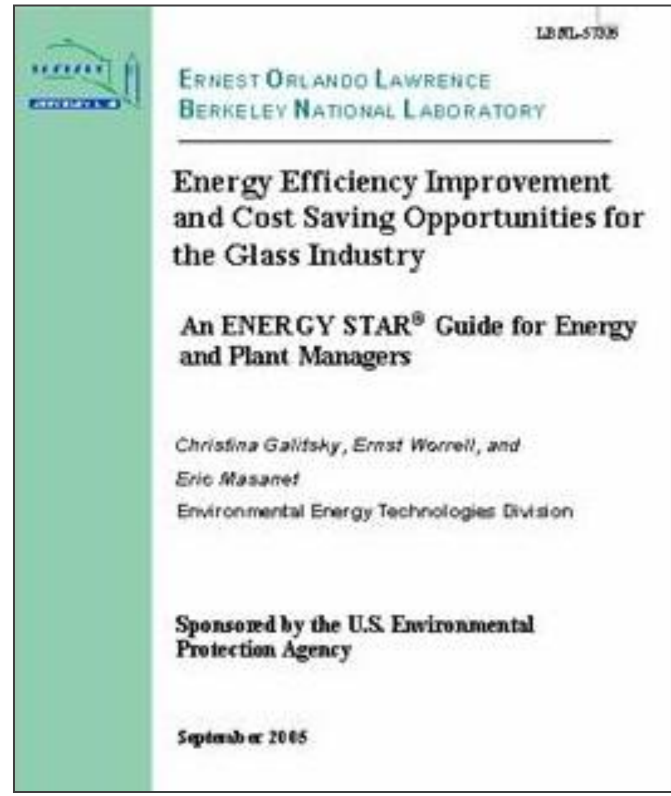
Enabling companies to make informed energy investment decisions



More help to improve: Energy Guides

Practices and technologies available now to improve energy efficiency in an industry

- **Identify existing & promising emerging technologies**
  - provide brief overview of technology or practice
    - review its limitations
    - quantify potential energy and cost savings
    - estimate payback periods
    - provide case study from application
    - highlight industry success stories


Ernest Orlando Lawrence Berkeley National Laboratory

Energy Efficiency Improvement and Cost Saving Opportunities for the Glass Industry

An ENERGY STAR® Guide for Energy and Plant Managers

Christina Galitsky, Ernst Worrell, and Eric Masanet

Environmental Energy Technologies Division

Sponsored by the U.S. Environmental Protection Agency

September 2005

Case study

- Example: U.S. cement plant
- Initial cement plant ENERGY STAR EPI score: **61**
- Upgraded in 2002, EPI verified energy reductions of 40%
  - Energy efficiency improved by 2.5 mmBtu/short ton of clinker
- Commercially available technologies employed (described in Energy Guide) :
  - Improved grinding mills
  - Roller mills
  - Improved preheaters
  - Indirect firing
- New ENERGY STAR EPI score: **98**
  - national energy efficiency scoring system demonstrated this plant is now one of the most efficient cement plants in the U.S.

Results – EPA experience with US auto assembly plants

- Based on ENERGY STAR benchmarking of auto assembly plants, EPA has seen fuel usage in the industry improve by 12 percent over a five year period.
- The level of inefficiency has also dropped by 1.0 mmBtu/vehicle.
- The range of performance has also narrowed.
  - This means that while the best auto assembly plants have improved, the others have more than "kept up" with this improvement.

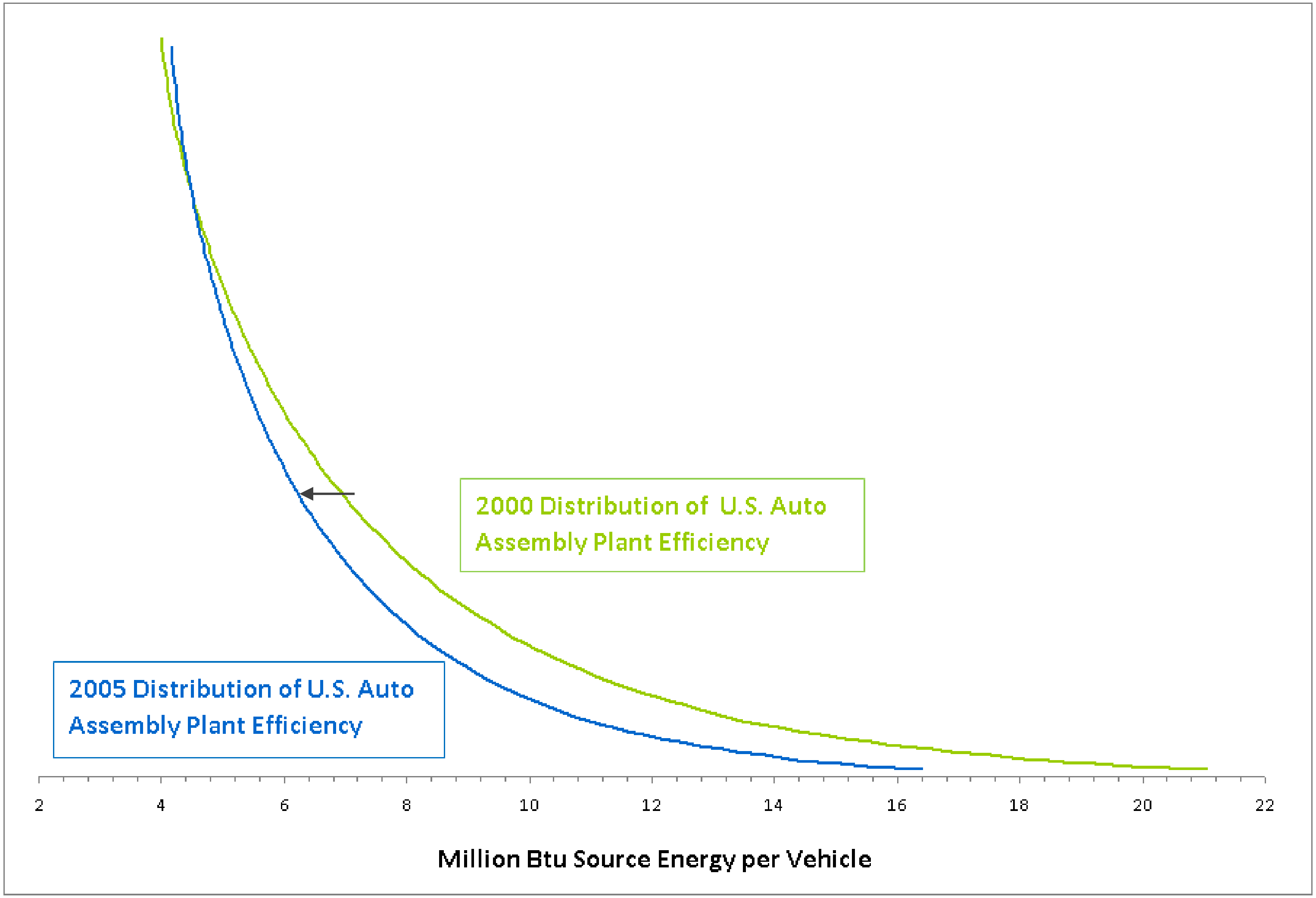
ENERGY STAR benchmarking resources

- **Plants** use ENERGY STAR's **Energy Performance Indicators** (EPIs)
- **Commercial Buildings** use ENERGY STAR's **Portfolio Manager**

Industrial EPIs
Motor Vehicle Assembly
Wet Corn Milling
Cement Manufacturing
Petroleum Refining (private system recognized)
Pharmaceuticals
Food Processing (variety)
Glass Manufacturing (variety)
Petrochemicals (draft)
Pulp and Paper
Steel

Portfolio Manager
Office Buildings
Hospitals
K-12 Schools
Hotels
Supermarkets
Retail Stores
Warehouses
Bank Branches
Residence Halls
Waste Water Treatment
Court houses
Medical Office Buildings

ENERGY STAR Benchmarking: Auto Assembly 2000-2005



EPA, Duke University

Lessons

- It is possible to benchmark plants and help industry improve
- Benchmarking takes data (lots of it) and time
- Benchmarked entity should be homogeneous.

Contact

Elizabeth Dutrow
Director, Industrial Sector Partnerships
ENERGY STAR Program
US EPA
(202) 343-9061
dutrow.elizabeth@epa.gov

All resources found at:
www.energystar.gov/industry

ALCOA

Key Issues for Industry GHG Benchmarking

Ken Martchek
Alcoa Inc.

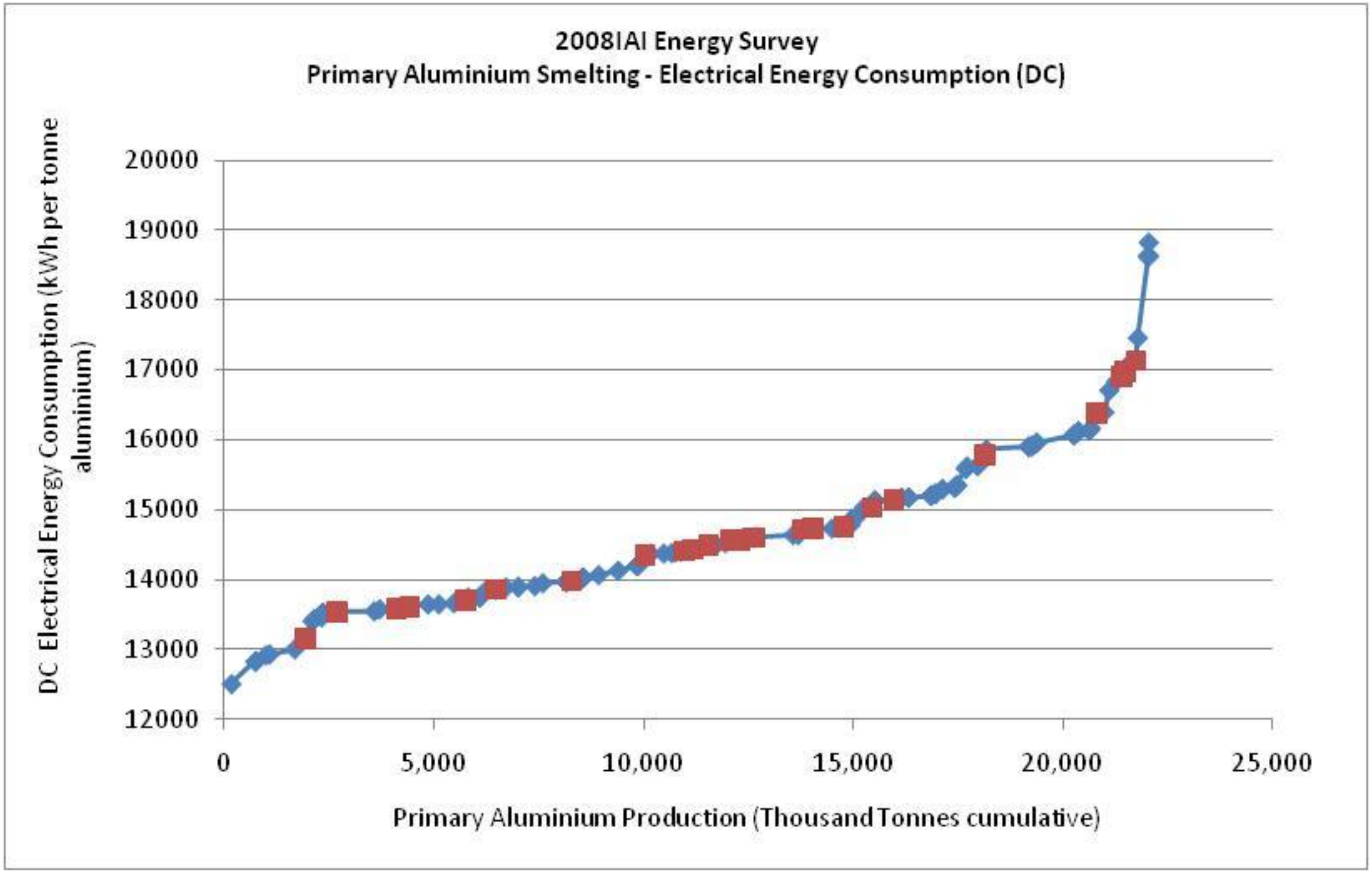
ALCOA

Afternoon Panel Objectives

<u>Address the following questions:</u>

- What are the benefits and challenges of developing and applying benchmarks for industry?
- What data constraints limit benchmarking and how might they be overcome?
- At what level of detail / disaggregation are benchmarks helpful or needed?
- How do responses to these questions differ depending on how benchmarks are used?
- What other information and perspectives are important for Washington State to consider in developing industry benchmarks?

Example of Industry Benchmarking



Benefits and Challenges to Industry

Benefits

- Drive process and energy improvements
- Set achievable objectives
- Etc.

Challenges

- Time and expense of data gathering, analysis, review, & communications
- “Apples” vs. “Oranges”

Clear Reporting Guidelines - Example

PFC EMISSIONS FROM PRIMARY ALUMINIUM SMELTING IAI FORM PFC001

Reporting Guidelines

1. Data are reported by technology category and, preferably, by potline. Data for different technology categories should not be mixed.

2. If anode effect data are not available then data for technology category, cell technology, feed type, primary aluminium production and average number of cells operating per day are still reported. Anode effect frequency data should be reported, if available, even though anode effect duration or overvoltage data are not available.

3. Technology category is reported as:
   a. PFPB - where cell technology is Centre Worked Prebake with a Point Feed System.
   b. CWPB - where cell technology is Centre Worked Prebake with a Bar Break Feed System.
   c. SWPB - where cell technology is Side Worked Prebake.
   d. HSS - where cell technology is Horizontal Stud Søderberg.
   e. VSS - where cell technology is Vertical Stud Søderberg.

4. Cell technology is the particular cell technology used (RA-300, SY300, AP18, Reynolds P19 etc.)

5. Potline number is the reference number or letter used to identify the potline. If data from two or more potlines are combined, then all relevant reference numbers or letters relating to the combined data are shown.

6. Feed type is reported as:
   a. PF - where a Point Feed System is applied to Prebake or Søderberg technologies.
   b. BF - where a Bar Break Feed System is used.
   c. SF - where a manual Side Feed System is used.

7. Primary aluminium production is molten (liquid) aluminium as tapped from the pots. It is reported in tonnes (metric tons) and is that production relevant to the anode effect and cell technology type data being reported.

8. Anode effect measurements are reported to two decimal places if possible. If the reported average anode effect duration is estimated, then this is indicated by adding the letter "E" against the reported figure. When data from two or more potlines are combined, the reported average anode effect frequency, average anode effect duration and averaged anode effect over-voltage are production-weighted averages.

9. Averaged anode effect over-voltage in millivolts is only reported for Alcan Pechiney cell technology types AP18, AP30, growth versions of these two cell technologies (e.g. AP33, AP35) and applicable Alcan Pechiney technology SWPB (Side Worked Prebake) potlines. Over-voltage can also be reported as integrated anode effect over-voltage in units of mv.day per cell day. Over-voltage is reported as either positive or algebraic according to the following definitions:
   a. Positive Anode Effect Over-voltage is the sum of the product of time and voltage above the pot target operating voltage (corresponding to the target resistance), divided by the time over which the data are collected (hour, shift, day, month etc.).
   b. Algebraic Anode Effect Over-voltage is the sum of the product of time and voltage above and below the pot target operating voltage (corresponding to the target resistance), divided by the time over which the data are collected (hour, shift, day, month etc.).

10. Section 3 is completed only if PFC emissions have been directly measured and the resulting CF_4 emissions coefficient and C_2F6/CF_4 weight fraction are applicable for production for the year being reported (in accordance with the USEPA/IAI *Protocol for Measurement of Tetrafluoromethane (CF4) and Hexafluoroethane (C2F6) Emissions from Primary Aluminum Production* - **http://www.epa.gov/aluminum-pfc/documents/measureprotocol.pdf**. The directly measured emissions, and hence also the calculated emission coefficients, are to take account of both duct and fugitive emissions. Emission rates and emission coefficients are reported to two decimal places.

11. If Anode Effect and PFC Emissions Measurement data (where appropriate) has been verified by a Third Party (e.g. auditor, regulatory authority) then please fill in details of the verifying body (fields a-d). If third party verification of the data has not occurred then please request internal verification of the data submitted by a senior manager and fill in their details in fields (a, b & d).

Enablers and Issues

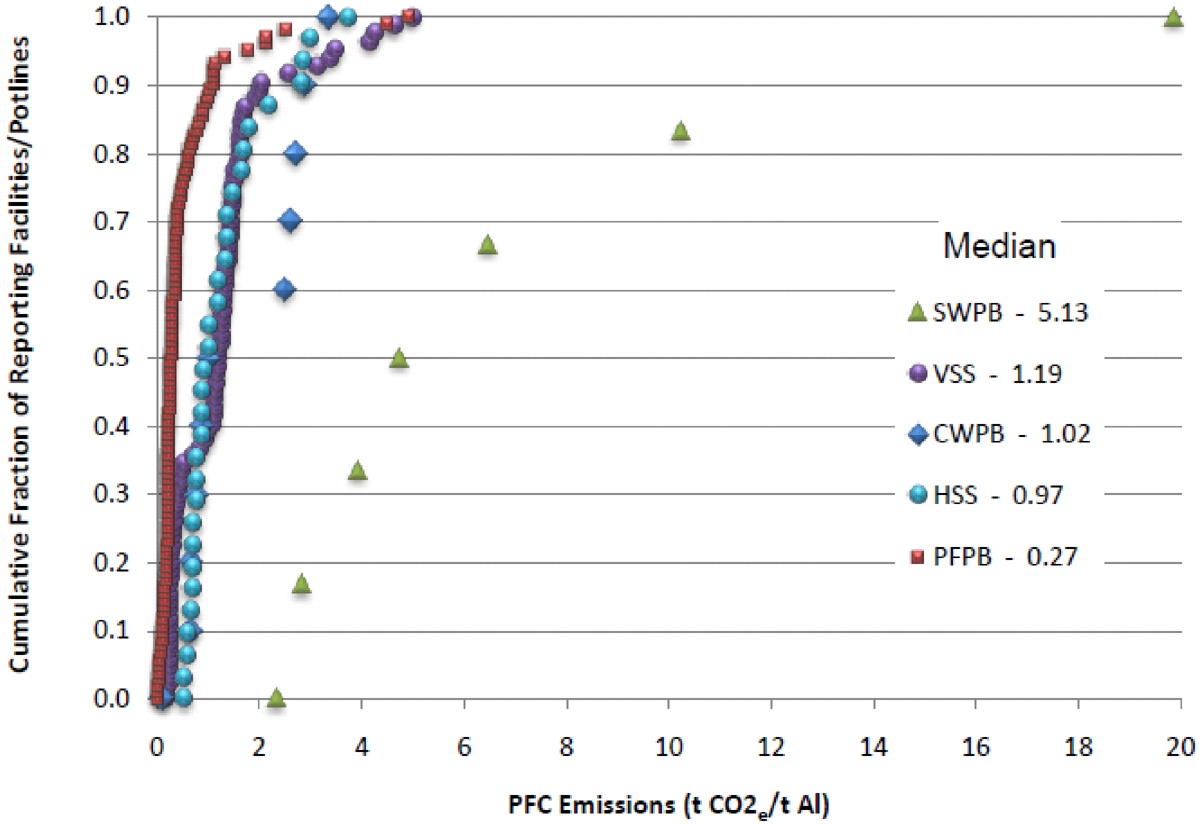
Enablers

- Reporting Guidelines
- Common Boundaries
- Written Industry Specific Protocols

Issues

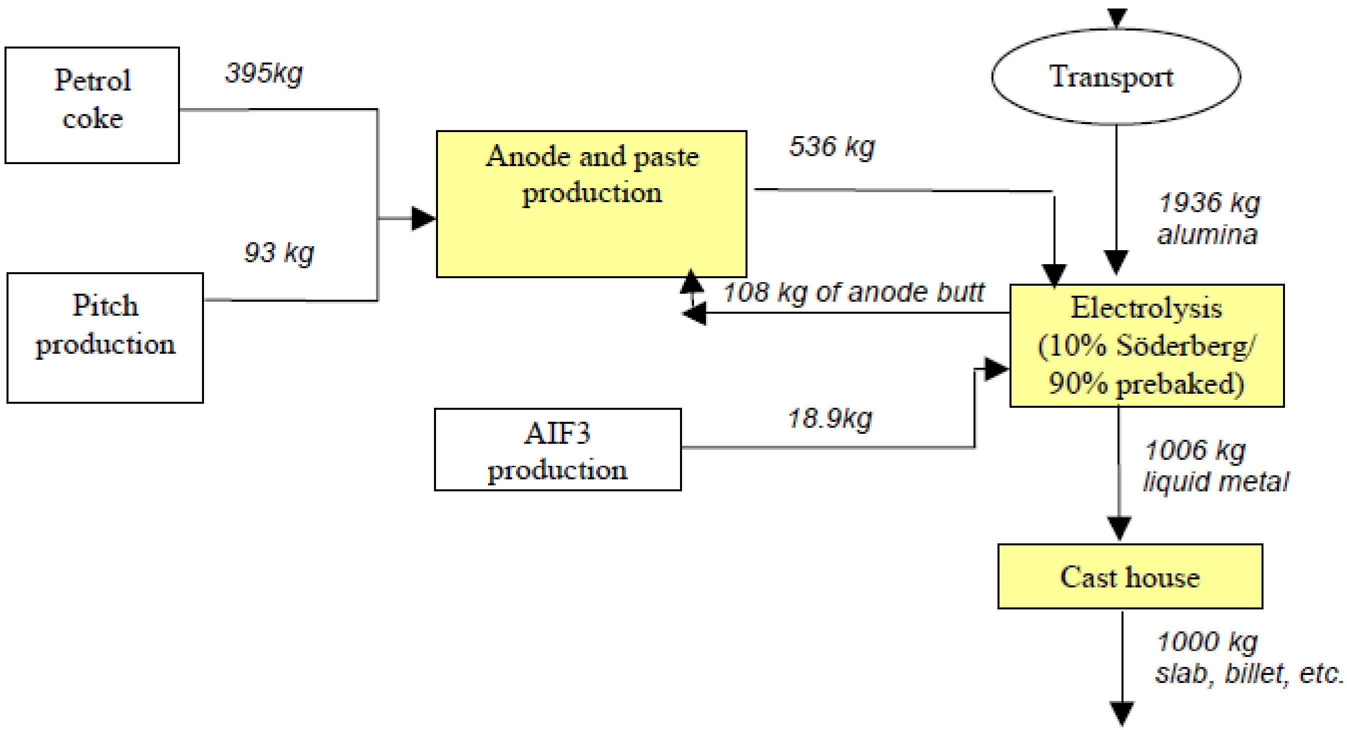
- What is appropriate benchmark subset?
  - World best practice (Worrell)
  - Best in North America? Europe?
  - Best in USA?
  - Best in Washington State?
- Best 10%?, Top quartile?
- Very small sub-sets
- Need to be technology specific

Different Technologies – Different Benchmarks



Level of Detail/ Disaggregation

- Each sub-process in a sector has different emissions
- Not all operators have all of the sub-processes



Conclusion

Also for Discussion Today

- How do responses to these questions differ depending on how benchmarks are used?
- What other information and perspectives are important for Washington State to consider in developing industry benchmarks?

Carbon Leakage Provisions Proposed in US Federal Climate Legislation

SYMPOSIUM ON UNDERSTANDING THE VALUE OF BENCHMARKING

Seattle, WA

May, 2010

James Bradbury

Senior Associate

Climate and Energy Program

World Resources Institute

jbradbury@wri.org

http://www.wri.org

W R I

Recent US Federal Policy History

- *Jun. 2008*, **Boxer-Lieberman-Warner**
  - letter from 10 Senate Democrats opposed bill, citing competitiveness concerns ("Gang of 10")
- *Sep. 2008*, **Inslee-Doyle** (HR 7146; HR 1759)
- *Jun. 2009*, **Waxman-Markey** (HR 2454)
  - passed US House (219-212)
- *Nov. 2009*, **Kerry-Boxer** (S. 1733)
  - passed Senate Committee (no Republicans present)
- *Dec. 2009*, **Interagency Report**
  - Responding to request from Sen. Bayh and colleagues
- *May 2010*, **Kerry-Lieberman**
  - Discussion-draft made public

Leakage Prevention & Transition Assistance

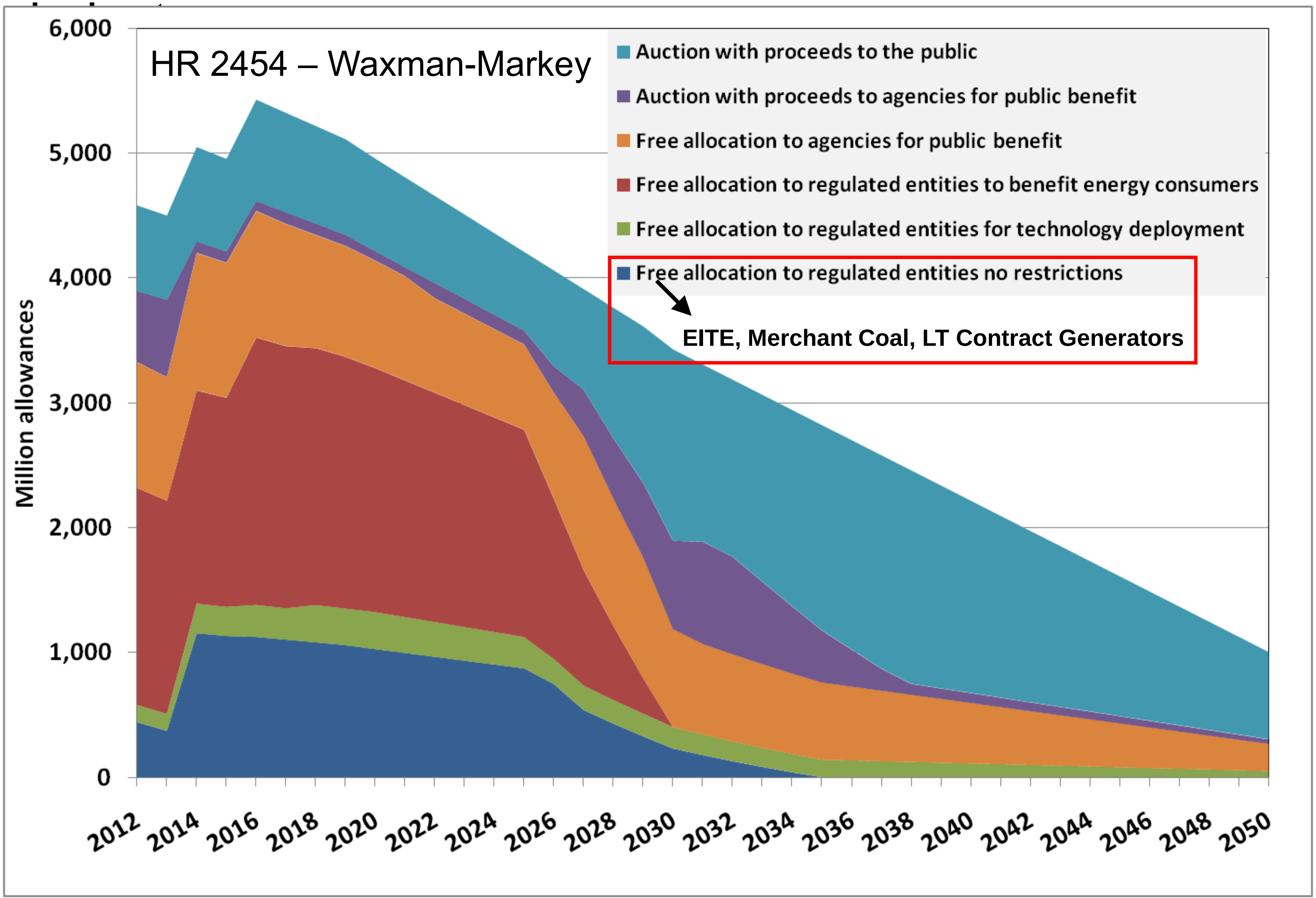
For *Energy-Intensive Trade Exposed* Industries:

- Allowance rebates for direct and indirect carbon costs
  - Up to 13.5% of the cap through 2025 (2% in 2012 & 2013)
  - Phased out by 2035 (w/ presidential discretion to persist)
- Border measures for EITEs in 2020

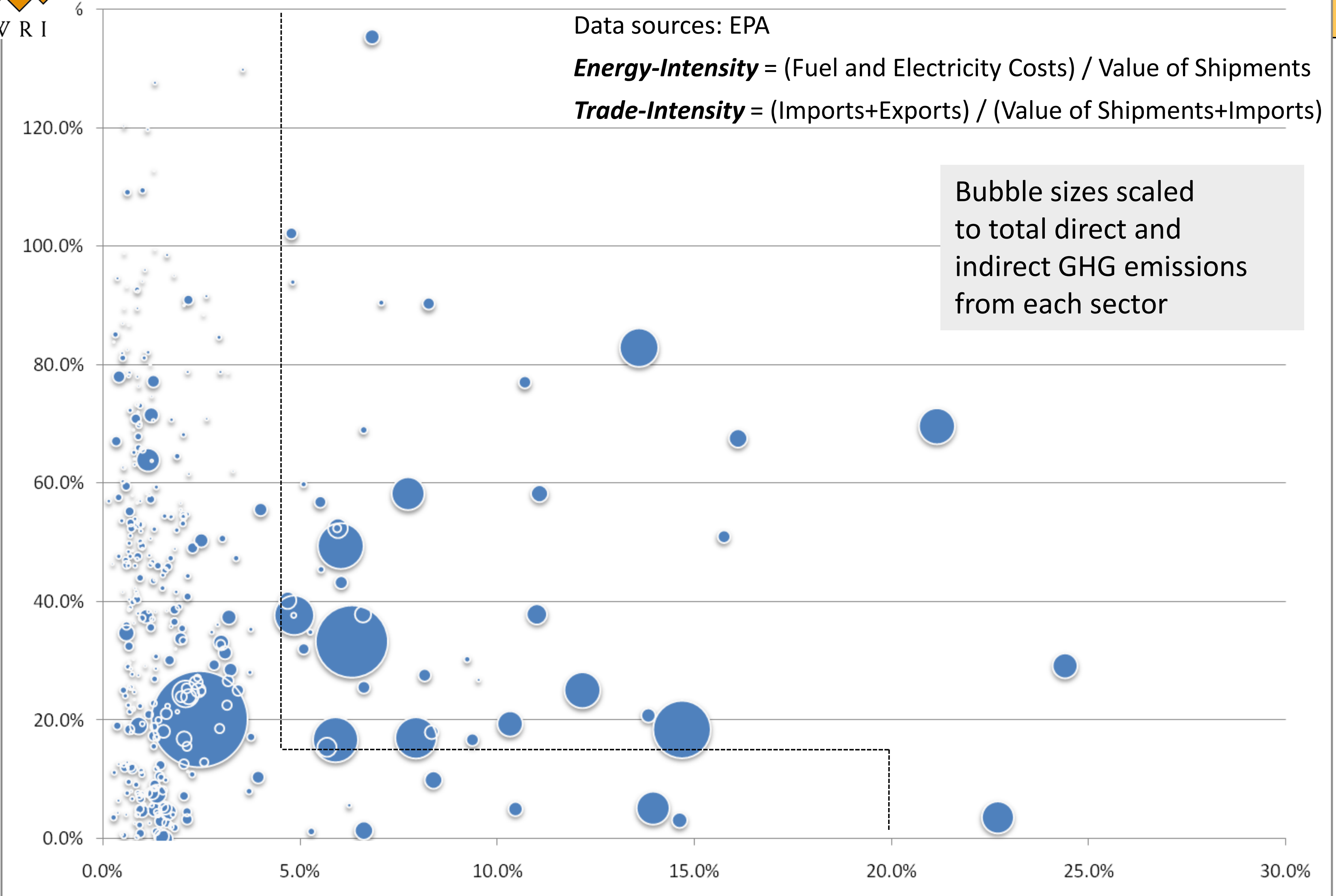
Other Assistance (through 2025, phased out by 2030):

- 40% of allowances to electric & nat. gas LDCs
  - "exclusively for the benefit of retail ratepayers"
  - >10% for industrial customers, including EITEs

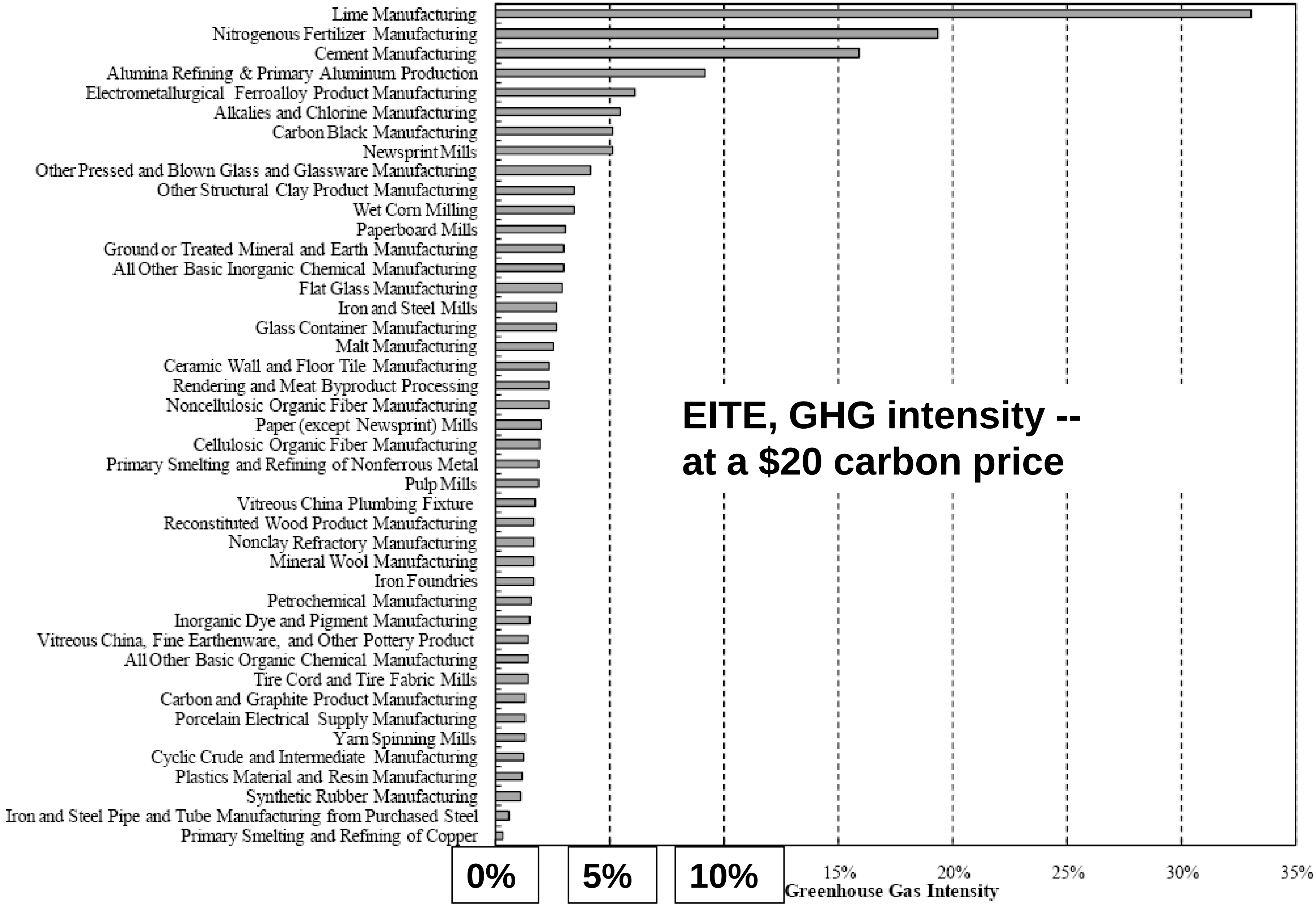
- Allowance value is targeted at public programs, consumer assistance and "transition assistance" for:



EITE Eligibility – Sectors by NAICS Code (6-digit level)



H.R. 2454's Greenhouse Gas Intensity Measure for the "Presumptively Eligible" Manufacturing Industries



Note: The H.R. 2454 greenhouse gas intensity measure is calculated by multiplying a sector's direct emissions and indirect emissions associated with electricity consumption by an allowance price of $20 per ton, and dividing by the sector's value of shipments.

Source: EPA analysis.

Which Costs Should be Compensated?

- Direct compliance costs
- Indirect compliance costs
  - Electricity
  - Purchased Steam

- Indirect, indirect

  (Costs of underlying climate policy)
  - Cost of utility investments in low carbon resources
  - Market dynamics that (may) cause fuel-switching and higher nat. gas prices

Output-Based Allocation Method and Level

- Allowances would be allocated to industry on a production *Output basis,* *based on:*
  - Each **facility's output** from 2 and 3 years prior

    and
  - 4-year **sector average,** updating benchmark
    - *The big (important) question is ability to pass-through costs (this assumes zero ability to pass-through)*
    - *HR 1759 included more stringent benchmark:*

      85% "allocation factor"

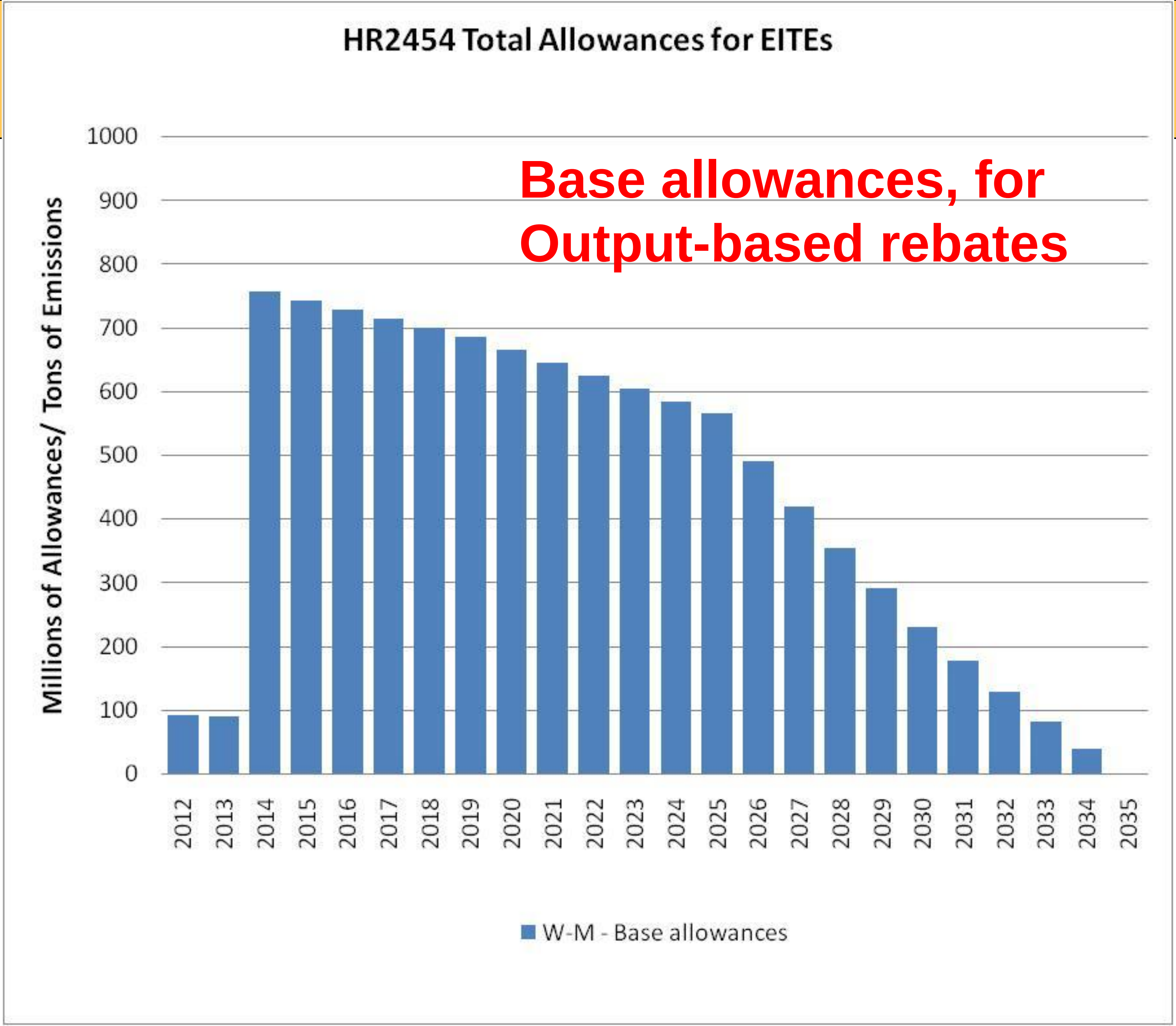
But how would the Benchmarks work?

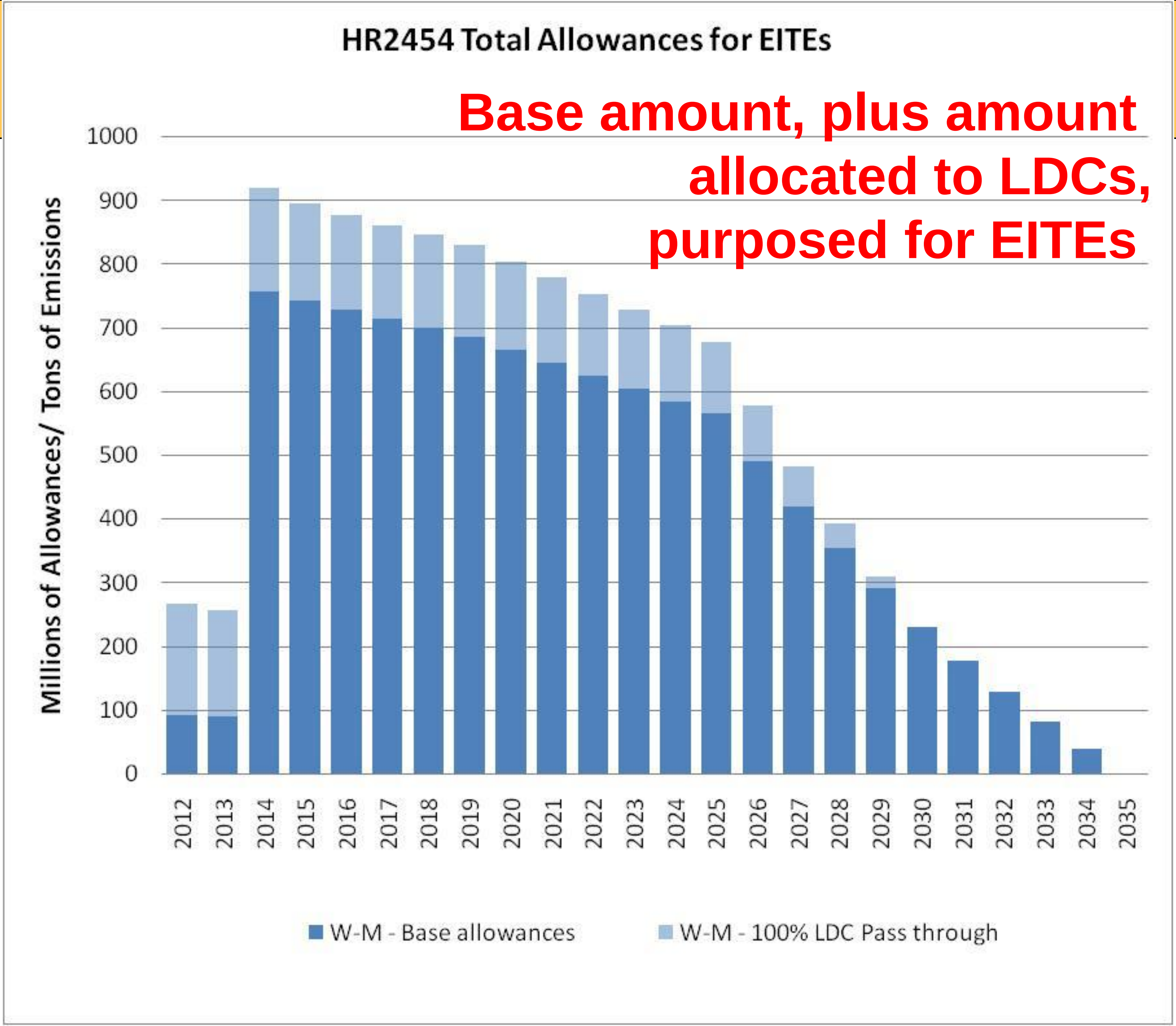
- In HR 2454, sectors defined at 6-digit level of NAICS-code (won’t work for benchmarks)
- In Kerry Lieberman, issue is getting more attention
  - EPA is given discretion to define subsectors, accounting for products and intermediate products, CHP (not processes)
  - Coverage under cap is delayed until 2016
- Growing discussion of applying 80-20 rule

However… there has not yet been a lot of attention to this at the Federal Level

Finally, phase down

- Recognizing that a harmonized international policy offers the best solution…
- At what point does domestic allowance allocation <u>phase down</u> or get replaced with an alternative policy mechanism?
  - Waxman-Markey (ACES)
    - Allowance pool reduces with the cap
    - Allocations reduced on a pro-rata basis, for any year in which demand exceeds supply
    - After 2025 (though 2035), allowances phase-down for all sectors, <u>unless exposure to leakage persists</u>


HR2454 Total Allowances for EITEs
Base allowances, for
Output-based rebates
Millions of Allowances/ Tons of Emissions
1000
900
800
700
600
500
400
300
200
100
0
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
W-M - Base allowances


HR2454 Total Allowances for EITEs
Base amount, plus amount allocated to LDCs, purposed for EITEs
Millions of Allowances/ Tons of Emissions
1000
900
800
700
600
500
400
300
200
100
0
2012
2013
2014
2015
2016
2017
2018
2019
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2021
2022
2023
2024
2025
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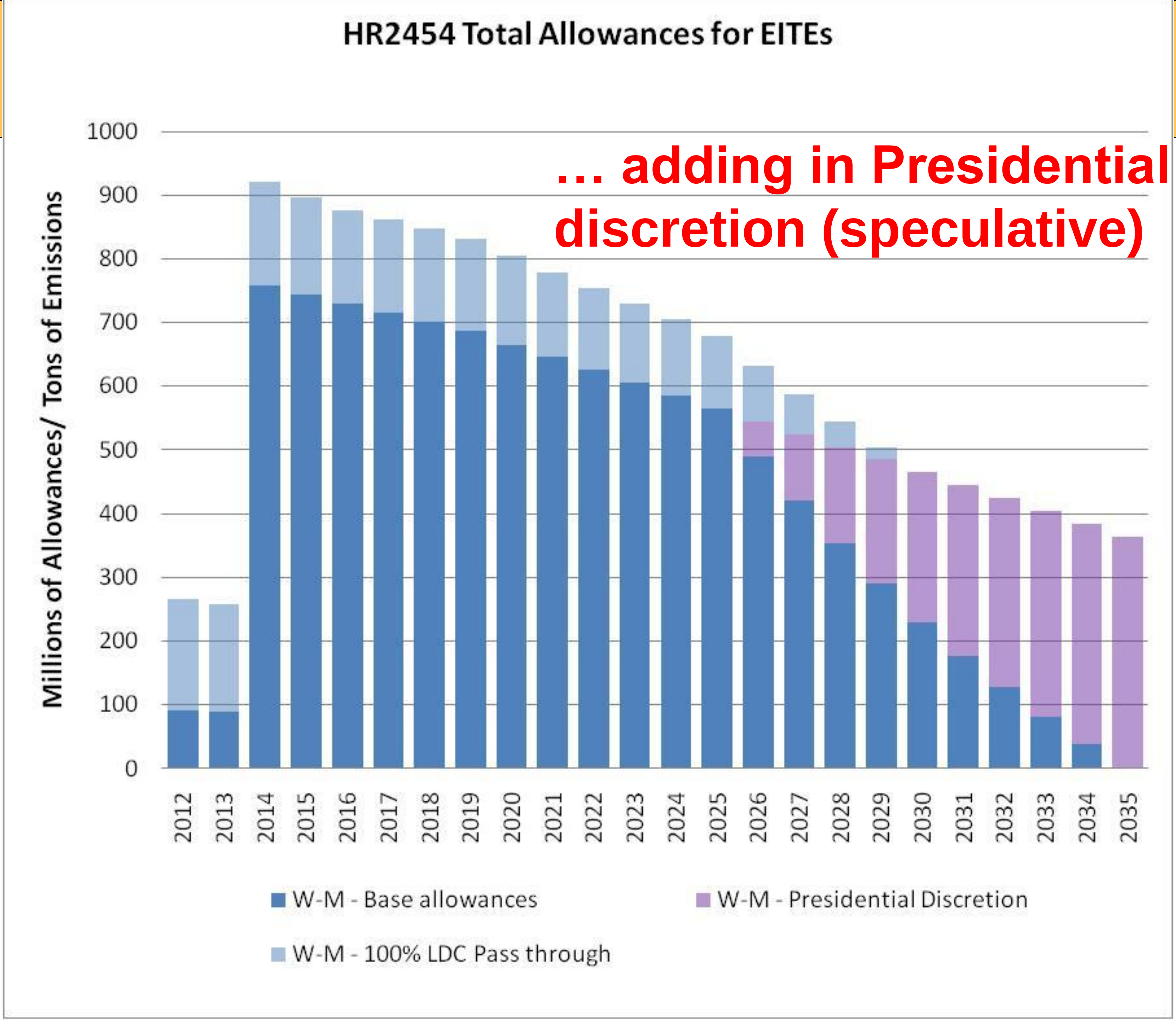
2032
2033
2034
2035
W-M - Base allowances
W-M - 100% LDC Pass through


HR2454 Total Allowances for EITEs
… adding in Presidential discretion (speculative)
Millions of Allowances/ Tons of Emissions
1000
900
800
700
600
500
400
300
200
100
0
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
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2025
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2027
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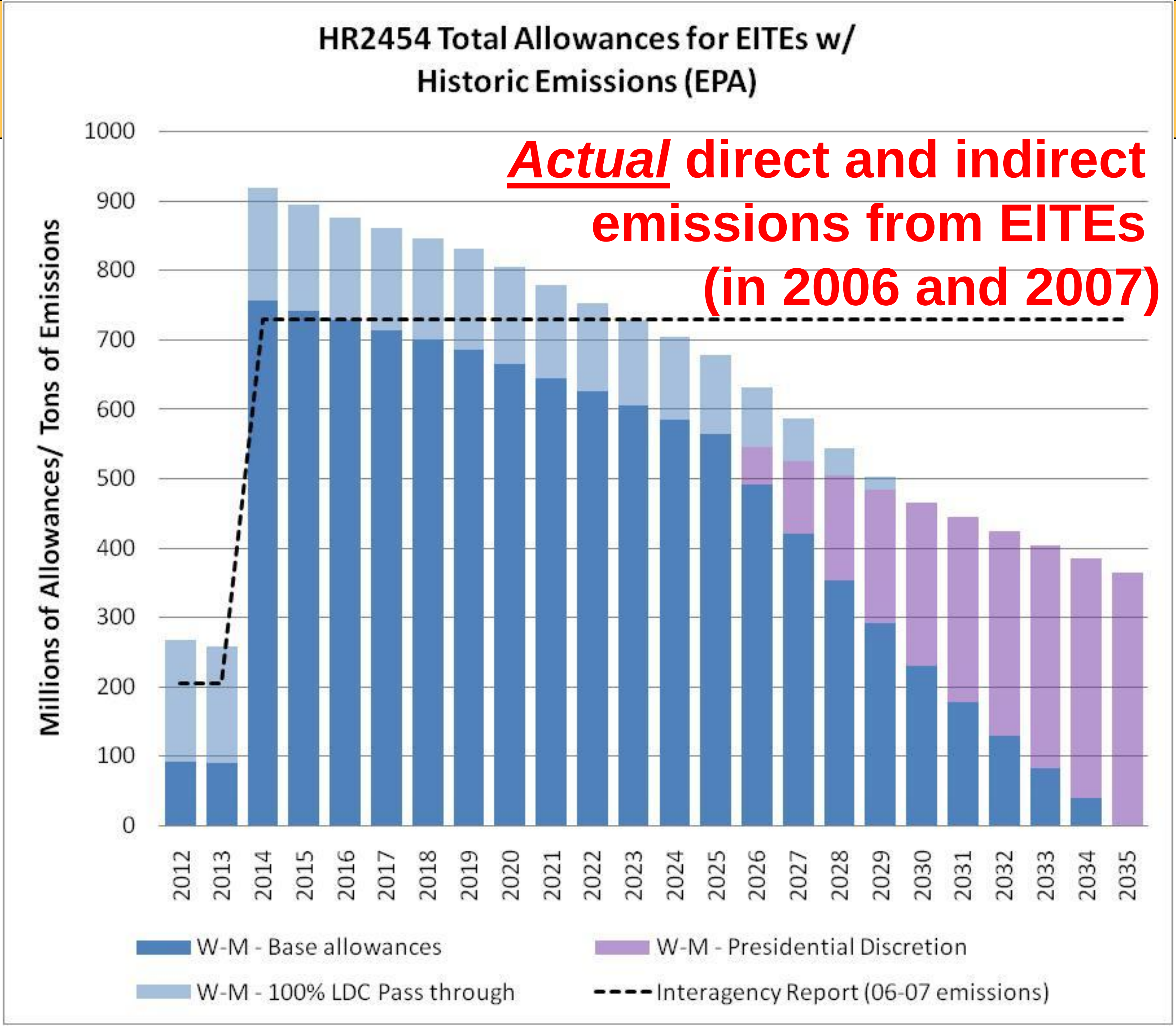
2034
2035
W-M - Base allowances
W-M - Presidential Discretion
W-M - 100% LDC Pass through


HR2454 Total Allowances for EITEs w/ Historic Emissions (EPA)
Actual direct and indirect emissions from EITEs (in 2006 and 2007)
Millions of Allowances/ Tons of Emissions
1000
900
800
700
600
500
400
300
200
100
0
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
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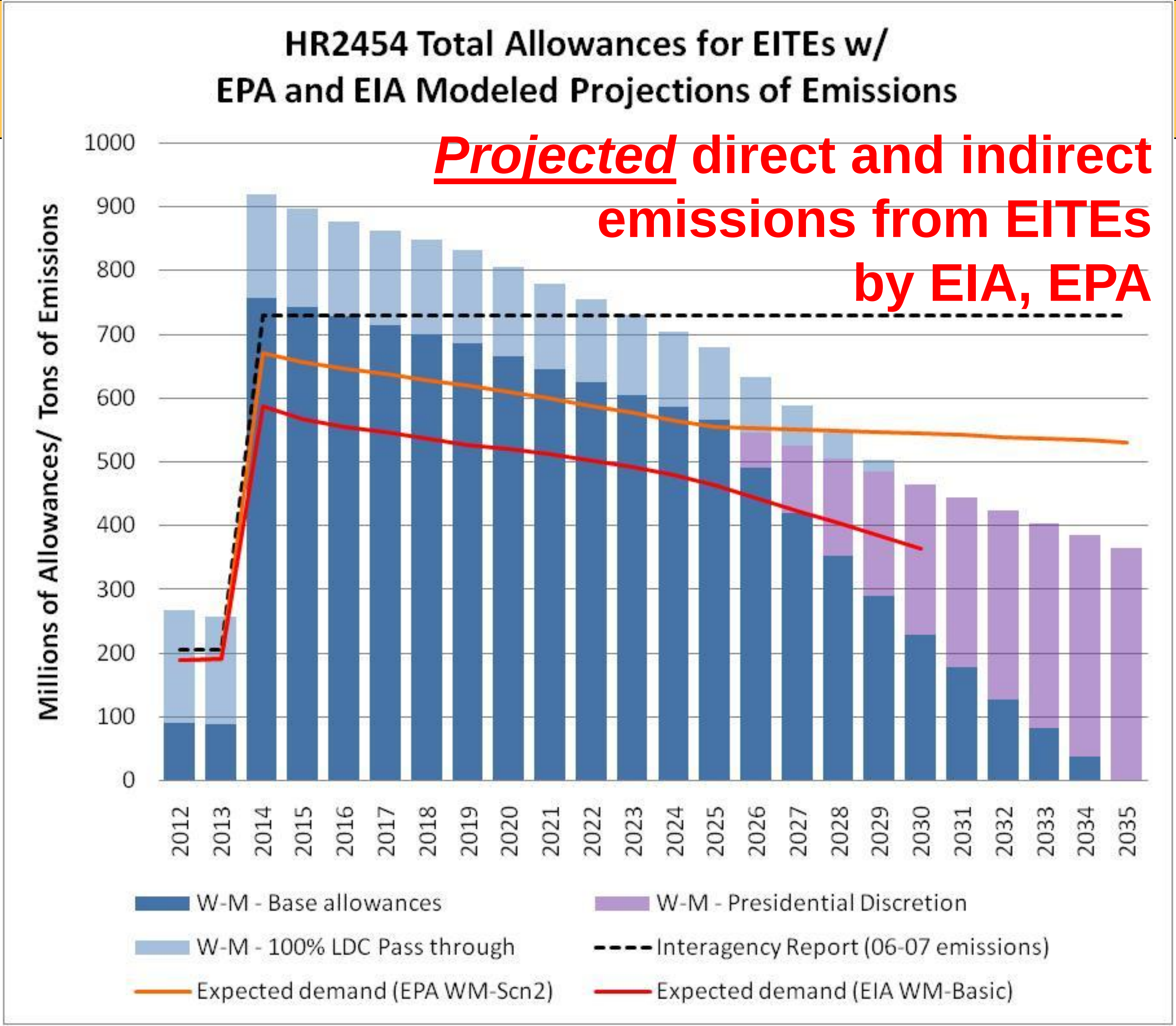
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
W-M - Base allowances
W-M - Presidential Discretion
W-M - 100% LDC Pass through
Interagency Report (06-07 emissions)


HR2454 Total Allowances for EITEs w/
EPA and EIA Modeled Projections of Emissions
Projected direct and indirect emissions from EITEs by EIA, EPA
Millions of Allowances/ Tons of Emissions
1000
900
800
700
600
500
400
300
200
100
0
2012
2013
2014
2015
2016
2017
2018
2019
2020
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2026
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2031
2032
2033
2034
2035
W-M - Base allowances
W-M - Presidential Discretion
W-M - 100% LDC Pass through
Interagency Report (06-07 emissions)
Expected demand (EPA WM-Scn2)
Expected demand (EIA WM-Basic)

Final Comments

- There is growing consensus around output-based allocation to EITEs to address leakage from economy-wide climate policy
- There is a critical unmet need for better data and analysis on how to conduct proper benchmarking, in the US
- In DC, too much focus on eliminating *all costs* for industries, not enough attention to:
  - Policies to improve efficiency of manufacturing through financing capital investments
  - R&D, other transition assistance

Thank you!

James Bradbury

Climate and Energy Program

World Resources Institute

jbradbury@wri.org

http://www.wri.org

WRI

Overview of Current Efforts in Industrial GHG Benchmarking

Michael Lazarus

Stockholm Environment Institute – US, Seattle

WA Ecology/WCI Symposium on Understanding the Value of Benchmarking, May 19, 2010, Seattle, WA

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Industry is a major source of greenhouse gas emissions

- One fifth of global GHG emissions
  - Fossil fuel combustion and process emissions
  - Over one quarter when electricity considered
- Also one fifth of Washington state GHG emissions
- Over a fifth of global emissions reduction potential (McKinsey)

A handful of sectors account for large majority of industrial GHG emissions

- Iron & steel
- Nonferrous metals (aluminum)
- Chemicals and fertilizers
- Petroleum refining
- Minerals (including cement and glass)
- Pulp and paper

… represent 85% of industrial energy use and most process GHG emissions (IPCC, 2007)

Energy and emissions intensive sectors

- Energy (carbon) costs represent a greater fraction of production cost and product value
- Many are subject to international competition, and
- Manufacture products that could be instrumental in a transition to low-carbon economy

Most energy and emissions intensive sectors are present in WA state

Sector	Contribution to WA Emissions	Major facilities in WA state (>25ktCO2e/yr)
Aluminum	High	Alcoa, Kaiser
Cement	High	Ash Grove, Lafarge
Chemical	Low	Solvay, Emerald Kalama
Food Processing	Medium	Many
Glass	Low	Cardinal, St. Gobain
Oil refineries	High	Several
Pulp and Paper	High	Many
Steel	Low	Nucor, Jorgenson

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The impetus for industry GHG benchmarking in WA state

- Executive Order 09-05 directs the Department of Ecology to develop greenhouse gas benchmarks
  - By industry for industry sectors that might be covered by federal or regional cap-and-trade program
  - To support use for allowance distribution and to recognize businesses that have made investments in emissions reduction
  - Based on best practices: highly efficient, low emitting facilities
  - For application as state-based emissions standards if needed to complement, or in absence of, federal program

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Ecology's process for moving forward

- Phase I (to June 2010): Benchmarking Issues and Options
  - White Paper and Symposium
- Phase II (July 2010 to June 2011): Development of Benchmarks for Some Sectors
- Focus on Washington State industries
- Engagement at regional and federal levels

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What is a GHG Benchmark?

- GHG emissions per unit of output

$$\text{Benchmark} = \frac{\text{Emissions}}{\text{Unit of Output}}$$

- Enables comparison across facilities against a common standard
- Used in a variety of industries and contexts worldwide

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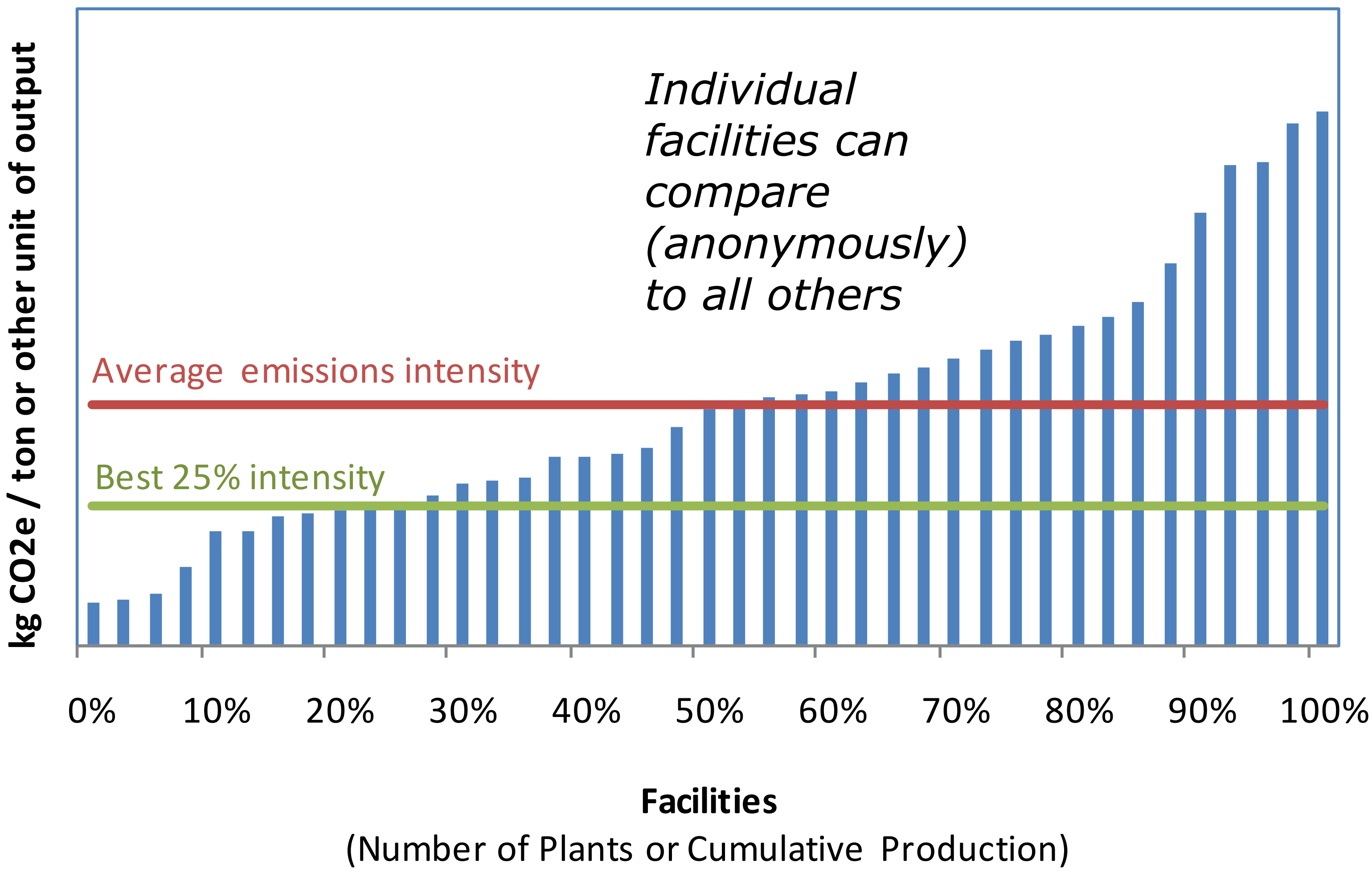
Comparison among facilities requires data and (often) confidentiality agreements

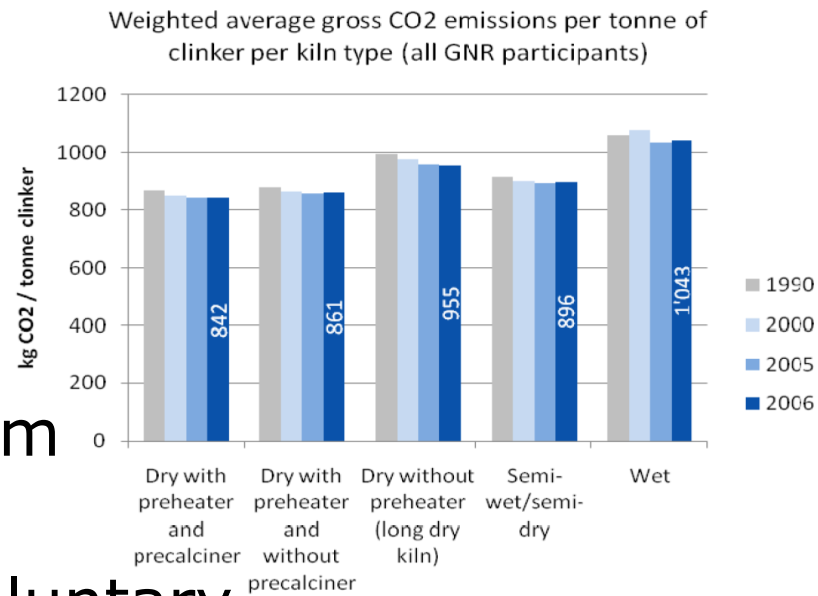
Hypothetical Benchmarking Curve



Voluntary industry and government efforts have relied on benchmarking

…to identify best practices and promote enhanced energy and emissions performance:

- US EPA's EnergyStar program
- Cement Sustainability Initiative
- International Aluminum Institute
- German and Dutch voluntary industry agreements



Source: Global data from Cement Sustainability Initiative, 2009. "Getting the Numbers Right".

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Cap-and-Trade programs may use benchmarks for allowance allocation

- Output-based rebates to emissions-intensive, trade-exposed industries can limit carbon leakage and maintain competitiveness of domestic industries…
  - Proposed US legislation (Kerry-Lieberman, Waxman-Markey)
  - European Union Emission Trading System (EU ETS)
  - Australian Carbon Pollution Reduction Scheme

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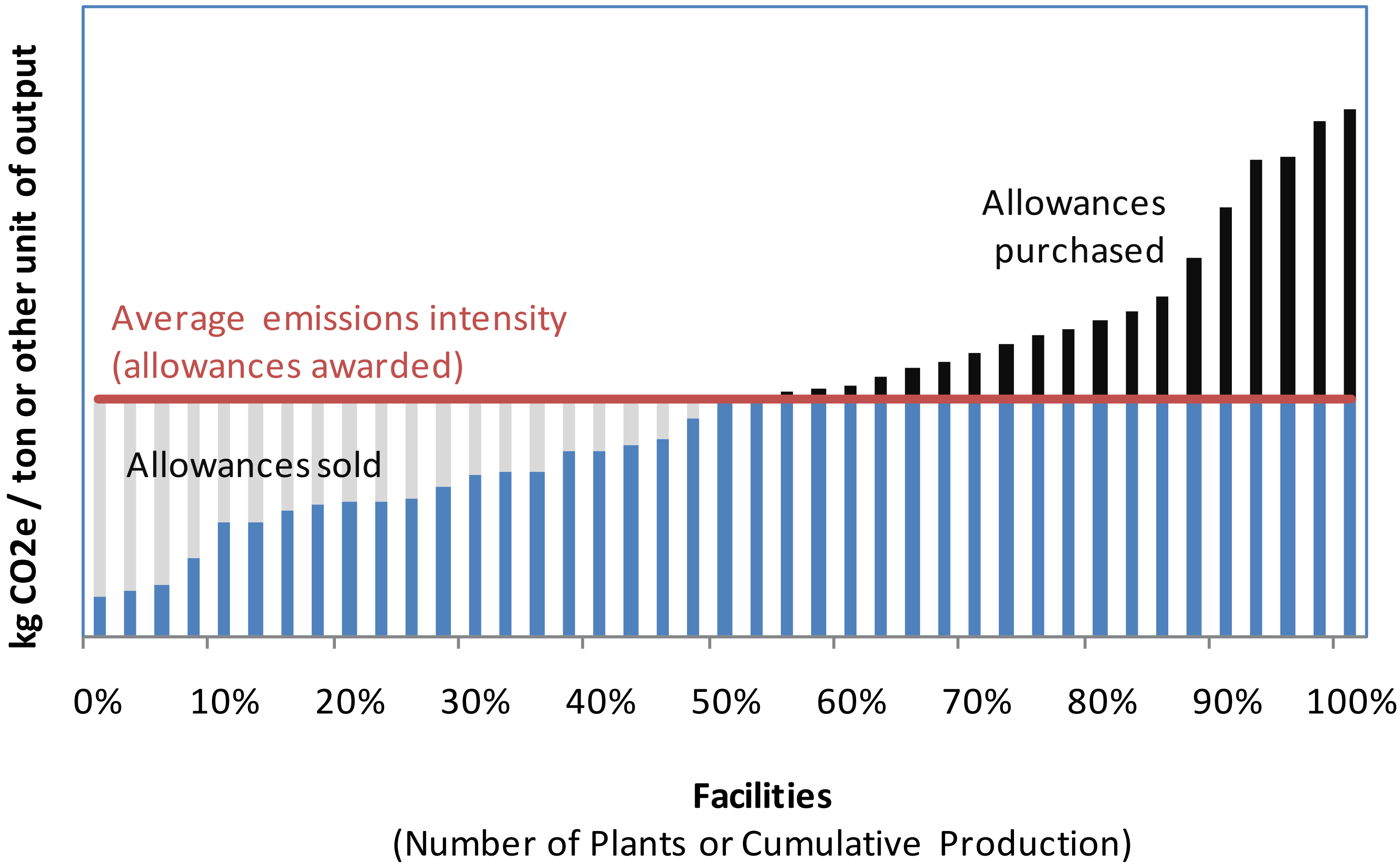
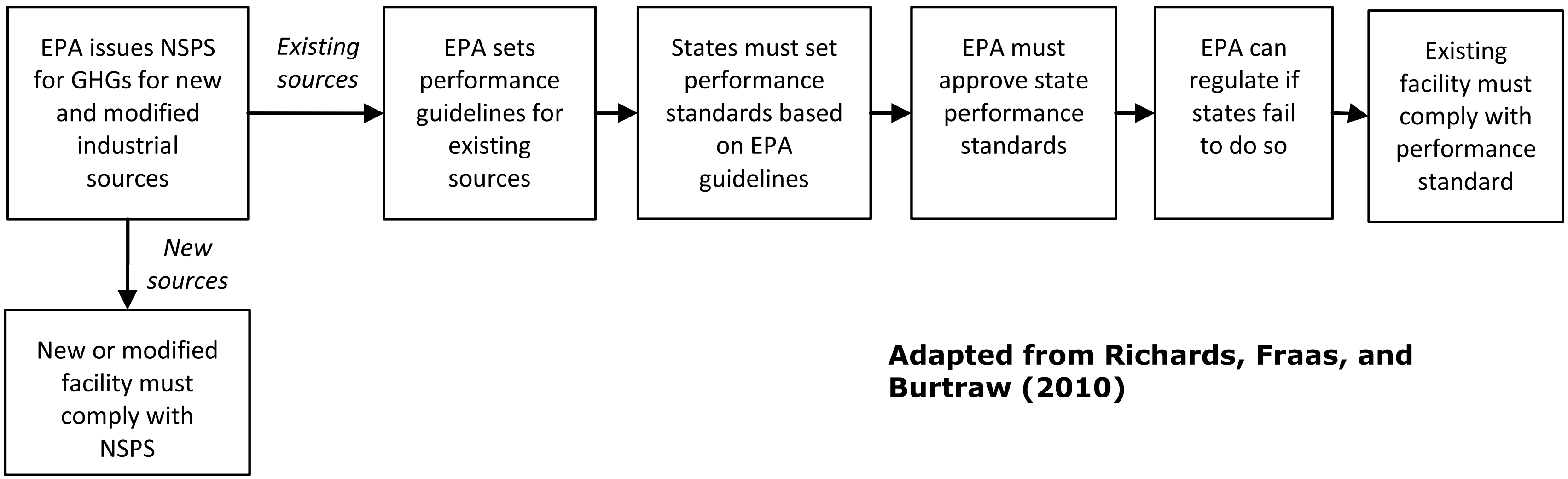
Waxman-Markey/Kerry-Lieberman bills use US average emission intensity as benchmark for allocation



Regulatory emissions performance standards can employ benchmarks

- Large stationary sources under the Clean Air Act:



Adapted from Richards, Fraas, and Burtraw (2010)

- WA already has a GHG performance standard (benchmark) for new power projects (ESSB 6001)
  - 1100 lbs CO2e/MWh for baseload generation or long-term contracts
  - And output-based performance standards for other pollutants

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Development of benchmarks poses several challenges

- **Ambition** – average, best available, top percentile?
- **Scope and boundaries** – direct only or total, including indirect?

$$\textbf{Benchmark} = \frac{\textbf{Emissions}}{\textbf{Unit of Output}}$$

- **Data** sources
- **Choice of unit and level of aggregation**: Sector, product, activity

All facets influenced by benchmark application

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Specific issues GHG benchmarking must address

- **Combined heat and power**, or use of waste gases (paper and pulp, steel, and others)
- **Feedstock quality and quantity**: Use and quality of recovered/recycled feedstock (glass, aluminum, steel)
- **Facilities that produce multiple products** (paper or steel mills)
- **Integrated vs. non-integrated facilities** (paper and pulp and steel)
- **Alternative definitions of the final product** (e.g. cement or clinker)

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Other key points

- Benchmarks should be based on facility performance at regional, national or international levels
  - WA state has leading industries in energy and environmental performance
- Benchmark design will depend upon the policy application

Questions to consider

- What are the benefits and challenges of developing and applying benchmarks?
- What approaches to benchmark development and use seem the most promising for managing GHG emissions?
- What would make a Phase II effort on benchmarking (July 2010-June 2011) most useful from your perspective?

For more information

- Website: http://www.ecy.wa.gov/climatechange/GHGbenchmarking.htm
- Draft White Paper Comment Period through June 4
- Contact us at benchmarking.wa@sei-us.org

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Using Benchmarks to Develop Regulatory Performance Standards

Judi Greenwald

Vice President for Innovative Solutions

Pew Center on Global Climate Change

SYMPOSIUM ON UNDERSTANDING THE VALUE OF BENCHMARKING

May 19, 2010

PEW CENTER ON Global CLIMATE CHANGE

Presentation Overview

- Setting Performance Standards Under the Clean Air Act and Other Environmental Statutes
- Role of Performance Standards as Benchmarks in Allowance Allocation under the U.S. Acid Rain Program
- Potential Application of CAA performance standards to GHGs

Setting Performance Standards Under the Clean Air Act and Other Environmental Statutes

(See Handout)

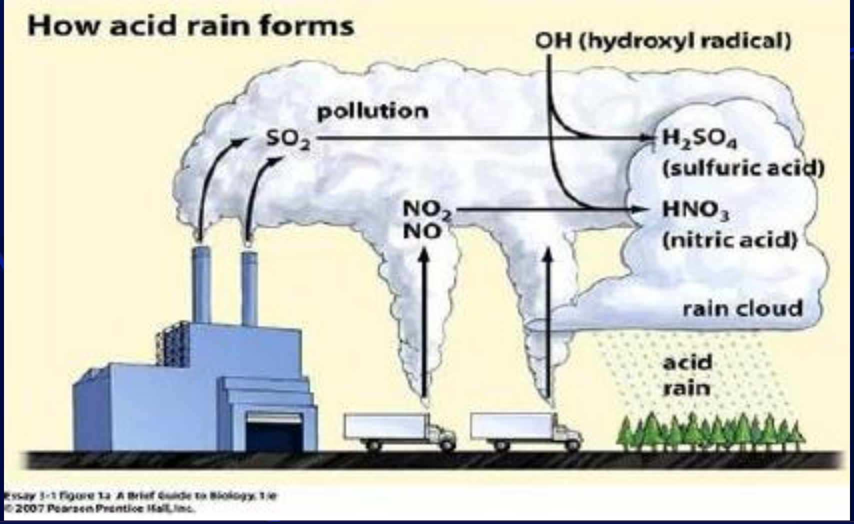
Setting Performance Standards: CAA

- Clean Air Act has several different technology-based, performance standard setting provisions
  - All are emission limits based on a technology
  - All consider feasibility, costs, co-benefits, etc.
  - All have some role for benchmarking
  - But different definitions, processes, and considerations
  - Alphabet soup: NSPS (BDT), NSR-PSD (BACT), NSR-NA (LAER), NAAQS SIP (RACT), Air Toxics (MACT and GACT)
  - MACT example

Other Environmental Statutes

- Clean Water Act: NPDES conventional (BCT); NPDES toxic and nonconventional (BAT); NPDES new sources (NSPS)
- RCRA LDR (BDAT)

Role of Performance Standards as Benchmarks in Allowance Allocation under the U.S. Acid Rain Program



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Key Allocation Formula Decisions

- ***Input* vs. output**
- Updating vs. ***fixed***
- ***Fuel-specific* vs. fuel-neutral benchmarks**
- Formula structure: Heat input x an emission rate for several classes of sources, plus some special cases

Some Specifics

- Heat input baseline: average of 1985-87; some adjustments possible for shutdowns or outages
- Emission rate varied by source category
  - .6 - 1.2, and 2.5 lbs/mmBtu were touchstones
- Bonus allowances for cleaner sources
- Alternative formula for cleaner states

What *were* we thinking?

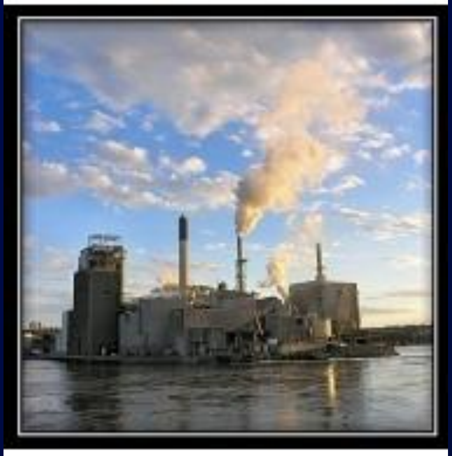
NSPS was frame of reference, touchstone or benchmark

- 1971: 1.2 lbs/mmBtu
- 1977/79: % reduction requirement; 0.6 to 1.2 lbs/mmBtu

Potential Application of CAA Performance Standards to GHGs

Challenges of Applying New Source Review to GHGs

- Timing
- Applicability
- What is BACT for GHGs?
- Role of states
- Innovation
- Energy Efficiency

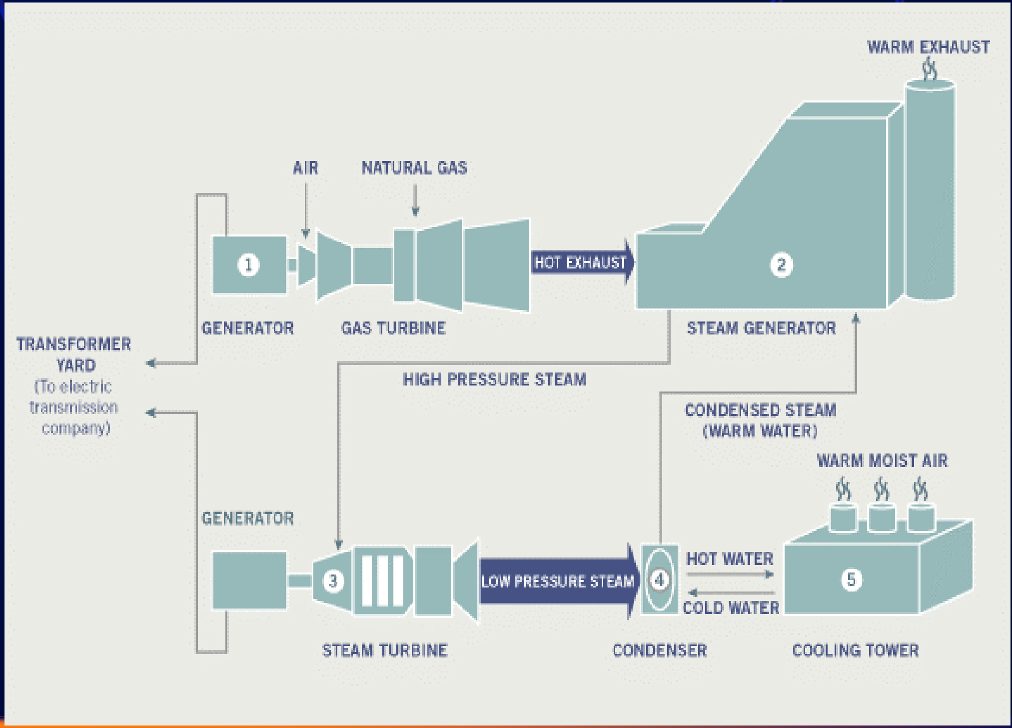


EPA Rising to the Challenge

- Timing
- Applicability
- Tailoring
- RACT/BACT/LAER Clearinghouse (benchmarking tool)
- Clean Air Act Advisory Committee Climate Change Work Group
  - Innovation
  - Energy Efficiency

Example: Russell City

- Bay Area Air Quality Management District and Calpine agreed to GHG BACT review and voluntary GHG limit as test case
- 612 MW natural gas fired combined cycle power plant in Hayward, CA
- Reviewed available technologies; concluded that high-efficiency power generation technology is the only available and feasible control technology
- BACT review resulted in slightly higher efficiency than originally proposed (56.45 vs. 55.8% efficiency)
- Tried to do an output based standard but wound up doing an input based standard plus an efficiency standard because GHGs per unit of output was too variable
- Covered all GHGs
- Also set BACT for fire pump and circuit breakers



Comparable Projects for Benchmarking

Facility	CEC Application Date	Facility Size (MW)	Thermal Efficiency (LHV)
Colusa Generation Station	11/6/2006	660	56%
Blythe Energy Project Phase II	2/19/2002	520	55-58% (est.)
Lodi Energy Center	9/10/2008	255	55.6%
CPV Vaca Station Power Plant	11/18/2008	660	55%
Victorville 2 Hybrid Power Project	2/28/2007	563	52.7% (w/ duct burn)
Avenal Energy Power Plant[44]	2/21/2008	600	50.5%
Palomar Energy Project	8/2003	550	55.3% (w/o duct firing) 54.2% (w/ duct firing)
SMUD Consumnes Phase I	9/13/2001	500	55.1%

Lessons from Russell City

- Can do GHG BACT like BACT for traditional air pollution, including benchmarking
- Modest impact on industry; modest impact on the environment
- Significant impact on permitting costs for first one; later ones should be more modest

New Source Performance Standards

- How to define source categories
- What is BDT for GHGs for new sources?
- What is cost-effective?
- How to drive innovation
- How to drive energy efficiency

?

Setting New Source Performance Standards

Section 111 defines NSPS as the “degree of emission limitation achievable through…the best system of emission reduction…taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements…adequately demonstrated” = Best Demonstrated Technology (BDT)

Applicability:

- Source category/stationary source category = industrial segment covered by standard
- Stationary source/affected facility = emission units subject to standard (affected facility means a discrete emitting unit, can be piece of equipment or whole plant)

EPA sets standards but states typically granted implementation, enforcement authority

NSPS: How is BDT Determined?

- "Degree of emission limitation" = maximum quantity of pollutant that may be emitted; meant to provide flexibility, but may be few practical means of achieving this

- EPA considers costs, but is not required to conduct a true CBA
  - Considers economic costs to the industry and ability to pass costs along to consumers without affecting demand
  - Incremental "cost-effectiveness" approach (costs of achieving incremental additional reductions under different controls)

- BDT may not be lowest emission standard achievable if it creates negative environmental/health consequences

NSPS: How is BDT Determined?

- Does not require commercial demonstration
  - EPA can rely on pilot projects, those in other industries or countries
  - Must be achievable under wide range of operating conditions
  - Can't be theoretical, but can result from technology forcing (projection based on existing technology, within reason)
- May be specific technologies based on their ability to meet a particular emissions benchmark
- Innovative technology waivers: for new sources with undemonstrated technology; intended to encourage innovation and reductions beyond NSPS, but it has been rarely used, if ever.

Control of existing sources under 111(d)

- EPA may issue guidelines to states for control of existing sources
  - NSPS must exist for source category; pollutant is not a criteria pollutant
  - To date, usually specialized sources that emit discrete types of pollutants
- Guidelines include information contained in NSPS:
  - Known/suspected health or welfare concerns
  - Control systems that reflect BDT
  - Information on costs
  - Time necessary for design, installation, and start-up of control systems
- States required to implement guidelines
  - States submit plan within 9 months, based on guidelines
  - If pollutant threatens public health, state standards must be ≥ guidelines, unless on a case-by-case basis the state shows controls are unreasonable

Section 111(d) issues

- How to define source categories
- What is BDT for GHGs for existing sources?
- What is cost-effective?
- How to drive innovation
- How to drive energy efficiency
- Is trading allowed?

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The EPA has issued Section 111(d) guidelines for:

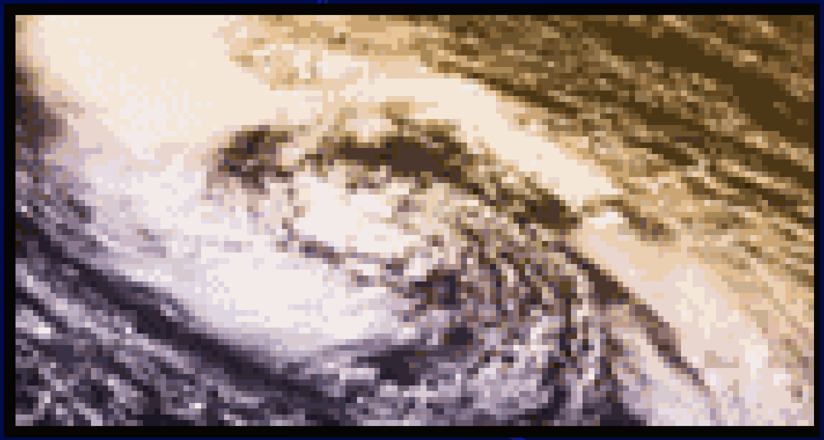
- sulfuric acid mist from sulfuric acid plants
- fluoride emissions from phosphate fertilizer plants
- total reduced sulfur (TRS) emissions from kraft pulp mills
- fluoride emissions from primary aluminum plants
- municipal waste combustion (MSW) emissions from solid waste incinerators (NOx trading is allowed)
- nonmethane organic emissions from landfills, hospital/medical infectious waste incinerators
- others

Some Takeaways

- Setting performance standards under the Clean Air Act and other environmental statutes utilizes benchmarking and provides some useful models.
- Performance standards played a role as benchmarks in allowance allocation under the U.S. acid rain program.
- Potential application of CAA performance standards to GHGs poses some special challenges; 111(d) may be applied to GHGs.

For More Information

www.pewclimate.org



Technology-Based Standards Under Different Federal Environmental Statutes

Statute	Technology Standard-setting Provision	Decision Rule	Comments
Clean Air Act	New Source Performance Standards (NSPS) (for new sources)	Best Demonstrated Technology (BDT)	Degree of emission limitation achievable through the application of the best system which (taking into account cost and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated. Technology may not be one that is purely theoretical but it can be a result of technology forcing. The EPA may make a projection based on existing technology, though that projection is subject to the restraints of reasonableness and cannot be based on crystal ball inquiry. Can do work practice standards if performance standard infeasible. Creates a floor for New Source Review.
Clean Air Act	Innovative Technology Waivers	Designed to allow testing of control systems that might prove to achieve greater reductions than the NSPS.	Not used very often or successfully.
Clean Air Act	111(d) ("NSPS" for existing sources)	Similar criteria to NSPS	EPA establishes emission guidelines for existing sources which must be implemented by states. Only applies to a limited set of sources (non-criteria, non-hazardous)

Statute	Technology Standard-setting Provision	Decision Rule	Comments
Clean Air Act	New Source Review (NAAQS[1] attainment areas)	Best Available Control Technology (BACT)	--Case by case review --Maximum degree of reduction achievable taking into account energy, environmental and economic impacts and other costs --EPA recommended top-down process for BACT determination: Step 1: Identify available pollution control options Step 2: Eliminate technically infeasible options Step 3: Rank remaining control technologies by control effectiveness Step 4: Evaluate the most effective controls (considering energy, environmental, and economic impacts) and document the results. Step 5: Make the BACT selection.
Clean Air Act	New Source Review (NAAQS non-attainment areas)	Lowest Available Emission Rate (LAER)	The most stringent emission limitation which is contained in the implementation plan of any State for such class or category of source, unless the owner or operator of the proposed source demonstrates that such limitations are not achievable; or the most stringent emission limitation which is achieved in practice by such class or category of source. Similar analysis to BACT, except no consideration of economic, energy or environmental factors.
Clean Air Act	State Implementation Plans (SIPs) for existing sources to meet NAAQS	Reasonably Available Control Technology (RACT) and Reasonably Available Control Measures (RACM)	Lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility.
Clean Air Act	RACT/BACT/LAER Clearinghouse	Database of state air permitting decisions	Essentially a benchmarking tool for state agencies and permit applicants

[1] National Ambient Air Quality Standards

Statute	Technology Standard-setting Provision	Decision Rule	Comments
Clean Air Act	Air Toxics Emission Standards for major sources	Maximally Available Control Technology (MACT)	Maximum degree of reductions and emissions deemed achievable for the source category or subcategory that, taking into consideration the cost of achieving the reduction, any non-air-quality health and environmental impacts and energy requirements, is achievable for new or existing sources. MACT floor for new sources is the emission control that is achieved in practice by the best controlled similar source. MACT floor for existing sources is the average emission limitation achieved by the best performing 12 percent of the existing sources; or if fewer than 30 sources, the best performing 5 sources. EPA says 94^{th} percentile (others say 88^{th}).
Clean Air Act	Air Toxics Emission Standards for some area sources	Generally Available Control Technology (GACT)	Agency has broad discretion. No floor analysis or minimum control requirement.
Clean Air Act	Vehicle and engine standards		Mostly federal, but CA allowed to continue to be laboratory. Generally Congress set specific limits for light duty vehicles but allowed for suspension if technology not available. More flexibility for heavy duty engines: the greatest degree of emission reduction achievable from available technology giving appropriate consideration to cost, energy and safety factors; manufacturers may bank and trade emission credits. The EPA generally follows international standards for aircraft emissions.
Clean Air Act	Fuel standards		EPA can regulate based on (1) public health impacts or (2) impacts on pollution control equipment. Under (1) can only consider health and other means of achieving standard. Under (2) must do cost-benefit analysis. Also Congress specified many rules.

Statute	Technology Standard-setting Provision	Decision Rule	Comments
Clean Water Act (CWA)	National Pollutant Discharge Elimination System (NPDES) permit (including both technology-based effluent standards and water quality-based standards)	Best practicable control technology currently available (BPT)	The first level of technology-based standards established by the CWA to control pollutants discharged to U.S. waters. This standard is used for conventional, toxic, and nonconventional pollutants and is applied to existing dischargers. BPT limit guidelines are generally set using the average of the best existing performance by plants within an industrial category or subcategory. EPA must conduct a cost-benefit analysis in setting BPT standards. All regulated industries have a BPT standard, and then industries may also have BAT and/or BCT standards set (see below).
Clean Water Act	National Pollutant Discharge Elimination System (NPDES) permit (including both technology-based effluent standards and water quality-based standards)[2]	Best conventional pollutant control technology (BCT)	Technology-based standard for conventional pollutants only and applicable to existing dischargers. Rather than a standard cost-benefit analysis, BCT is established using a two-part "cost reasonableness" test which compares the cost for an industry to reduce its discharges with the cost to a publicly owned treatment works (POTW) for similar levels of reduction. The second test examines the cost-effectiveness of additional treatment beyond the best practicable control technology (BPT; see above). EPA must find limits which are reasonable under both tests before establishing them as BCT. Generally, BCT represents the best existing treatment technologies that are economically achievable within an industrial category.

[2] Effluent limitations serve as the primary mechanism in NPDES permits for controlling discharges of pollutants. When developing effluent limitations for an NPDES permit, permit writers must consider limits based on both the technology available to control the pollutants (i.e., technology-based effluent limits) and limits that are protective of the water quality standards of the receiving water (i.e., water quality-based effluent limits).

The intent of technology-based effluent limits in NPDES permits is to require a minimum level of treatment of pollutants for point source discharges based on available treatment technologies, while allowing the discharger to use any available control technique to meet the limits. For industrial (and other non-municipal) facilities, technology-based effluent limits are derived by using national effluent limitations guidelines and standards established by EPA, and/or using best professional judgment (BPJ) on a case-by-case basis in the absence of national guidelines and standards.

Statute	Technology Standard-setting Provision	Decision Rule	Comments
Clean Water Act	National Pollutant Discharge Elimination System (NPDES) permit	Best available technology economically achievable (BAT)	Technology-based standard for toxic and nonconventional pollutants and applicable to existing dischargers; established as the most appropriate means available for controlling the direct discharge of toxic and nonconventional pollutants. BAT effluent limitations guidelines generally represent the best existing performance of treatment technologies that are economically achievable within an industrial category. EPA must consider costs in setting BAT, but does not have to weigh them against the benefits of effluent reduction.
Clean Water Act	National Pollutant Discharge Elimination System (NPDES) permit	New source performance standards (NSPS)	Technology-based standard for conventional pollutants and applicable to new sources. Standards consider that the new source facility has an opportunity to design operations to more effectively control pollutant discharges.
Resource Recovery and Conservation Act (RCRA) – Hazardous and Solid Waste Amendments (HSWA)	Land Disposal Restriction (LDR) treatment standards	Best Demonstrated Available Technologies (BDAT)	Technology-based treatment standards for hazardous waste. BDAT can be expressed either as a performance standard (based on a maximum allowable concentration of particular wastes) or as a specific technology or practice. These standards are determined through a process that involves dividing wastes into similar groups; assessing technologies based on availability, performance, and quality; and testing to determine the "best" technologies.

Regional Greenhouse Gas Initiative
an Initiative of the Northeast and Mid-Atlantic States of the U.S.

Midwestern Greenhouse Gas Reduction Accord

Western Climate Initiative

Ensuring Offset Quality: Design and Implementation Criteria for a High-Quality Offset Program

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<u>Working Group Members</u>

Midwestern Greenhouse Gas Reduction Accord
Ray Hammarlund (KS)

Regional Greenhouse Gas Initiative
Kristoffer Gontkovsky (DE)
Bill Lamkin (MA)
David Littell (ME)
John Marschilok (NY)
Christopher Sherry (NJ)
Michael Sullivan (RI)
Paul Ghosh-Roy (RGGI, Inc.)

Western Climate Initiative
Julia Altemus (MT)
Nick Baggs (ON)
Francis Béland-Plante (QB)
Justin Brant (WA)
Bill Drumheller (OR)
Lauren Faber (CA)
Jenny Gleeson (ON)
John Hutchison (ON)
Tim Lesiuk (BC)
Eli Levitt (WA)
Robert Noel de Tilly (QB)
Alex Rosenberg (ON)
Leslie R. Seffern (WA)
Stephen Shelby (CA)
Jessica Verhagen (BC)

Executive Summary

This whitepaper is a product of the Three-Regions collaborative process. The Three-Regions process includes member jurisdictions of the three sub-national greenhouse gas cap-and-trade initiatives in North America: the Midwestern Greenhouse Gas Reduction Accord (Midwestern Accord), the Northeastern and Mid-Atlantic Regional Greenhouse Gas Initiative (RGGI), and the Western Climate Initiative (WCI). It represents a consensus among the three regional programs on key offset policy design and implementation components that are necessary to ensure high quality offsets in a regulatory greenhouse gas cap-and-trade program.

Offsets provide a compliance flexibility mechanism that reduces the compliance cost of a cap-and-trade program, since more and varied emissions reduction opportunities may be used to meet a compliance obligation. Lower emissions abatement costs result in lower impacts on consumers, which allows for the pursuit of more aggressive emissions reduction targets. Examples of offset projects provided for in a number of programs include projects that capture and destroy methane from landfills, projects that avoid methane emissions from agricultural manure management, and afforestation and forestry management projects. Since offsets, if designed and implemented properly, maintain the integrity of the emissions cap while providing compliance flexibility, use of offsets avoids the implementation of flexibility mechanisms that undermine the emissions cap, such as a safety valve or price cap.

To be equivalent to an emissions reduction achieved at a regulated emissions source, an offset project, and the emissions reductions or removals achieved by the project, must be real, additional, verifiable, enforceable, and permanent.

Implementing a high-quality offset program also requires transparency, credible verification, and a degree of administrative flexibility over time. This includes clear and transparent project documentation requirements, high quality independent verification to support regulatory review, and regular program review and adjustment.

The three regional cap-and-trade initiatives have either implemented or intend to implement the offset component of their program through a standardized approach, to the extent possible. This approach, as outlined in this whitepaper, provides multiple benefits that improve both offset quality and program efficiency, compared to a project-by-project approach. These benefits include increased program transparency, a more objective project review process, reduced project transaction costs, reduced financial risk for project developers, a reduction in market uncertainty, and a more streamlined project regulatory review process.

This document discusses key offset quality concepts and presents the consensus of the three regional cap-and-trade programs on the following core offset quality criteria.

Real

For a greenhouse gas offset to be “real,” an offset compliance unit must represent one ton of CO_2-equivalent (CO_2e) greenhouse gas emissions reduction or removal (carbon sequestration) that results from an identified emissions reduction activity (i.e., a clearly identified action or decision). Offset project emissions reductions or removals must not be an artifact of incomplete or inaccurate accounting. Therefore, a project emissions or carbon sequestration baseline and project emissions reductions or removals must be quantified using accurate quantification methodologies and conservative assumptions where appropriate to account for measurement uncertainty. Quantification methodologies must appropriately account for all relevant greenhouse gas emissions sources and sinks and identified project leakage.

Additional

A greenhouse gas offset results from an emissions reduction or removal caused by a project specifically intended to compensate for emissions occurring elsewhere. A greenhouse gas emissions reduction or removal project is considered additional if the offset project activity would not have occurred in the absence of the offset program.[1] Because awarded offset compliance units allow a regulated entity to emit more than it otherwise would have been able to, the underlying offset project only provides a true emissions reduction benefit if the project would not have occurred absent the offset program—i.e., it is “additional” to activities that would have otherwise occurred in the absence of the offset program.

Verifiable

Offset projects and offset project emissions reductions or removals must be verifiable. Verification is necessary to ensure that an offset project is eligible and has met all program requirements and that the offset compliance units awarded are based on emissions reductions or removals that have actually occurred and been properly measured. As used here, the concept of verification applies to both evaluation of project eligibility (sometimes referred to as validation) and verification of periodic monitoring reports of greenhouse gas emissions reductions or removals achieved by a project (commonly referred to as verification).

[1] By extension, this also means that emission reductions, avoidance, or sequestration achieved by an offset project result in a lower level of net greenhouse gas emissions or atmospheric concentrations than would occur in the absence of the offset project.

Permanent
Greenhouse gas emissions reductions or removals achieved by offset projects must be permanent. Offset project emissions reductions or removals are considered permanent if they are not reversible or, if reductions or removals are reversible, certain programmatic requirements are met to ensure the permanence of the reductions or removals.

Enforceable
An offset is enforceable if the offset program has sufficient regulatory authority and enforcement mechanisms to compel compliance with its program requirements. To ensure that offsets are enforceable, any party submitting an offset project for regulatory review and that may receive an award of offset compliance units must already be subject to the jurisdiction of the appropriate regulatory agency or must voluntarily submit itself to the jurisdiction of the regulatory agency. The regulatory agency should also maintain authority related to the offset compliance unit itself, as it represents a limited authorization to emit a CO_2e ton of greenhouse gas issued by the regulatory agency.

I. Introduction

This whitepaper is a product of the Three-Regions collaborative process. The Three-Regions process includes member jurisdictions of the three sub-national greenhouse gas cap-and-trade initiatives in North America: the Midwest Greenhouse Gas Reduction Accord (Midwestern Accord), the Northeastern and Mid-Atlantic Regional Greenhouse Gas Initiative (RGGI), and the Western Climate Initiative (WCI). The Three-Regions process is a forum for each of the programs to share information related to the design and implementation of each of the regional cap-and-trade programs and to discuss issues related to potential future linking of the programs.

This whitepaper represents a consensus among the three regional programs on key offset policy design and implementation components that are necessary to ensure high-quality offsets in a regulatory greenhouse gas cap-and-trade program.

The whitepaper is intended to serve as both an internal policy document for use among the programs and as a public policy document to inform the development of comprehensive climate policy in North America. As an internal document, the whitepaper articulates key quality requirements for offsets and offset programs to facilitate potential future linking of regional cap-and-trade programs. Future linking of programs could include coordination of offset programs and offset reciprocity among programs, which would require that each program maintain minimum offset quality requirements and standards. As an external document, the whitepaper communicates common underlying offset quality concepts that are incorporated into the design and implementation of each of the regional cap-and-trade programs to inform the design and implementation of national cap-and-trade programs in the U.S. and Canada.

A. Introduction to offsets and the importance of offset quality

In a greenhouse gas cap-and-trade program, a greenhouse gas (GHG) offset ("offset") is a project-based greenhouse gas emissions reduction or removal that occurs outside the capped emissions sector or sectors regulated by the cap-and-trade program.[2] For each CO_2-equivalent (CO_2e) ton of greenhouse gas emissions reduction or carbon sequestration achieved by an offset project, the project is awarded an offset credit or allowance (a "compliance unit") that can be used by an emissions source in a capped sector to emit a CO_2e ton of greenhouse gas. Conceptually, an offset is used to allow a regulated emissions source to emit an additional ton of greenhouse gas in exchange for a ton of

[2] "Capped sector" as used in this whitepaper refers to the specific category or categories of emissions sources regulated through a cap-and-trade program (e.g., electricity generation facilities above a certain size threshold or industrial facilities above a certain annual emissions threshold). Capped sector may also refer to activities that indirectly reduce or increase emissions at a regulated source (e.g., electric end-use).

greenhouse gas emissions reduction or removal achieved outside of the capped sector(s) by an offset project activity (Figure 1). The regulated emissions source is allowed to emit more in exchange for achievement of an emissions reduction elsewhere.

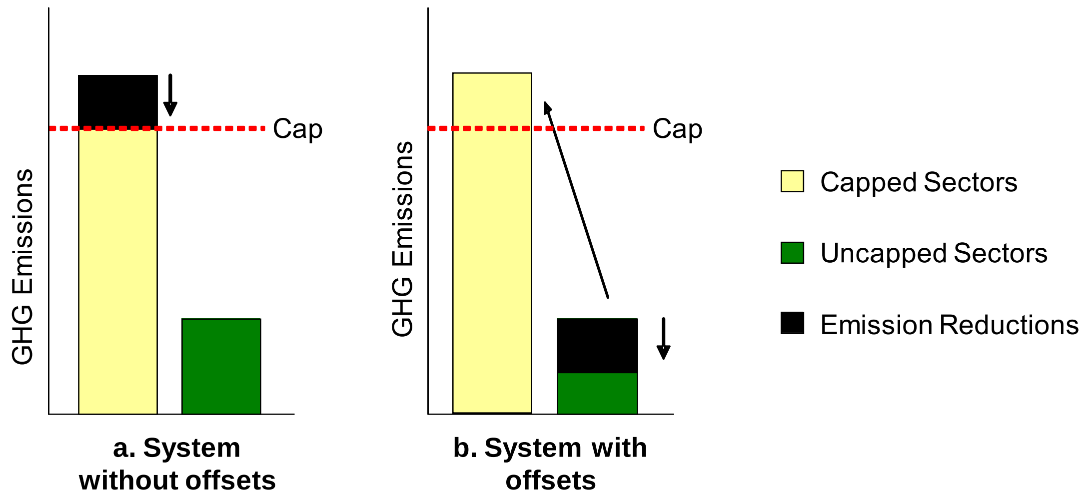

Figure 1. The Role of Offsets in Cap-and-Trade Programs[3]

Offsets provide a compliance flexibility mechanism that reduces the compliance cost of a cap-and-trade program, since more and varied emissions reduction opportunities may be used to meet a compliance obligation. Lower emissions abatement costs result in lower impacts on consumers, which allows for the pursuit of more aggressive emissions reduction targets. Since offsets, if designed and implemented properly, maintain the integrity of the emissions cap (the called for emissions reductions under the program) while providing compliance flexibility, use of offsets avoids the implementation of flexibility mechanisms that reduce the emissions reduction benefits achieved by the program, such as a safety valve or price cap.

Offsets result in the issuance of more compliance units in addition to the established emissions budget for a cap-and-trade program (the finite number of compliance units issued represents the emissions cap for regulated emissions sources). In order to maintain the integrity of the emissions cap, any offset compliance units that are issued must represent emissions reductions achieved outside capped sectors *as a result of the cap-and-trade program*. The premise is that rather than investing in more costly emissions abatement opportunities at regulated emissions sources, the owners or operators of a source (or a third party) are investing in lower-cost emissions abatement opportunities outside of the capped sectors.

[3] World Resources Institute, 2010

This basic premise means that the compliance obligation imposed by the cap-and-trade program is what drives investment in emissions reduction projects outside the capped sectors in order to generate offset compliance units.[4] Thus, there is a one-to-one relationship between emissions reductions achieved outside the capped sectors through an offset project and additional emissions permitted within the capped sectors. Net emissions to the atmosphere do not exceed the level of the established emissions cap because offsets represent equivalent emissions reductions or removals achieved elsewhere as a result of the cap-and-trade program. Absent this one-to-one relationship—the exchange of an emissions reduction elsewhere for an expansion of the emissions cap for regulated emissions sources—net emissions would exceed the level of the established emissions cap and the integrity of the emissions cap would be undermined. Simply put, the cap-and-trade program would not reduce the emissions it claims to.

B. Implications of offset quality

To maintain cap integrity, emissions reductions achieved through an offset should be functionally equivalent to emissions reductions achieved by a regulated emissions source. This has important implications for the quality requirements that an offset project must meet. In particular, emissions reductions or removals achieved through an offset project activity must meet functionally comparable standards to emissions reductions achieved by a regulated emissions source. An offset project must:

- be evaluated and verified (it must be eligible under the cap-and-trade program and implemented as claimed);
- achieve emissions reductions or removals that are properly quantified, monitored, and verified (as is required for regulated emissions sources); and
- achieve emissions reductions or removals that are permanent and enforceable (as is the case by default for regulated emissions sources).

In short, to be equivalent to an emissions reduction achieved at a regulated emissions source, an offset project, and the emissions reductions or removals achieved by the project, must be real, verifiable, permanent, and enforceable.

Perhaps most importantly, an offset project must occur *as a result of the offset component of the cap-and-trade program*, because more emissions from regulated emissions sources are being allowed in exchange for offset emissions reductions. This means that the offset project must be additional—it would not have happened anyway in the absence of the economic incentive created by the

[4] While this premise is straightforward, operationalizing this concept in order to evaluate offset project additionality is complex and requires workable, rigorous mechanisms, as discussed later in the whitepaper.

compliance obligation required by the cap-and-trade-program.[5] As discussed above, the concept of an offset rests on "exchanging" emissions reductions or removals that occur outside the capped sector(s) for allowing additional emissions from a regulated emissions source (Figure 1). In practice, this means that the compliance obligation of a cap-and-trade program is driving investment in emissions reduction opportunities outside the capped sector, in exchange for offset compliance units that can be used by a regulated emissions source for compliance. If an offset project that is awarded offset compliance units would have occurred anyway in the absence of the incentive provided by the offset component of the cap-and-trade program, then the award of offset compliance units would result in a net increase in atmospheric levels of greenhouse gases relative to those that would be achieved through the cap-and-trade program emissions cap (Figure 2). This outcome would undermine the cap-and-trade program's established emissions limitation and reduce the actual environmental benefits achieved by the program.

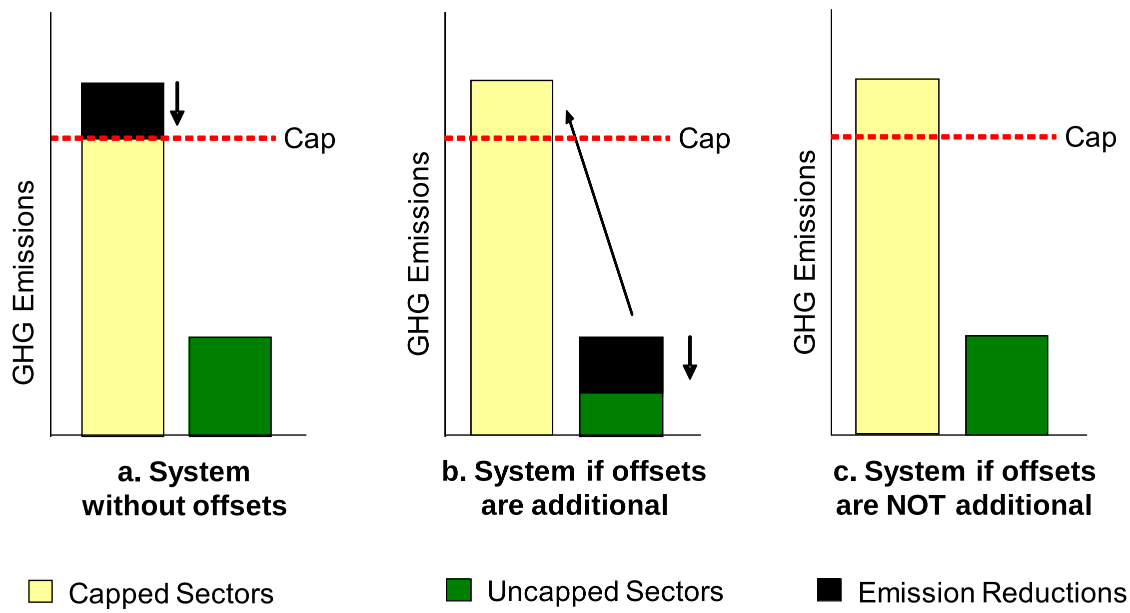

Figure 2. Impacts of Additional vs. Non-Additional Offsets on Emissions.[6]

In the absence of offsets (A), imposing a cap-and-trade program will result in emissions reductions in the capped sectors. Offsets provide regulated emissions sources with additional flexibility and allow them to meet a portion of their emissions obligations through reductions in an uncapped sector or sectors. When offsets are additional, the emissions reductions of the cap-and-trade program are preserved (B). However, if offset projects are not additional, and would have occurred in the absence of the program, then cap-and-trade program emissions benefits are

[5] Methods for operationalizing this concept and the complexities of evaluating offset project additionality are discussed in detail in Section II of the whitepaper.
[6] Bianco, Nicholas, "Stacking Payments for Ecosystem Services," WRI Fact Sheet, November 2009, World Resources Institute. Available at : http://pdf.wri.org/factsheets/factsheet_stacking_payments_for_ecosystem_services.pdf

lost (C), because the cap-and-trade program has not resulted in emissions reductions (either within the capped sector or through offsets).

To operationalize the additionality concept, assurance should be provided that an offset project was unlikely to occur absent the revenue stream provided by offset compliance units awarded through the offset component of the cap-and-trade program. Typically, this is done by evaluating an offset project in comparison to a “business-as-usual” baseline scenario that represents expected typical market activity that would have occurred in the absence of the project. To be eligible, the offset project must represent activity that is “in addition to” this expected typical market activity. This may involve a project-by-project assessment of financial data or market barriers, or the implementation of standardized criteria that represent activity that is significantly above standard market practice. Both types of evaluation strive to assure that the project would not have been implemented but for the anticipated revenue provided by the award of offset compliance units for project emissions reductions or removals.

The key offset quality criteria—real, additional, verifiable, permanent, and enforceable—are discussed in detail in the next section.

II. Key Offset Quality Criteria

This section provides an overview of the core attributes that ensure greenhouse gas emissions offsets are delivering their stated environmental benefits. These attributes are typically defined as real, additional, verifiable, permanent, and enforceable. The definitions and criteria presented here represent the consensus of the three regional greenhouse gas cap-and-trade programs, the Midwestern Accord, RGGI, and WCI.

Real

For a greenhouse gas offset to be real, an offset compliance unit must represent one ton of CO_2e greenhouse gas emissions reduction or removal (carbon sequestration) that results from an identified emissions reduction activity (i.e., a clearly identified action or decision). Offset project emissions reductions or removals must not be an artifact of incomplete or inaccurate accounting. Therefore, a project emissions or carbon sequestration baseline and project emissions reductions or removals must be quantified using accurate quantification methodologies and conservative assumptions where appropriate to account for measurement uncertainty. Quantification methodologies must appropriately account for all relevant greenhouse gas emissions sources and sinks and identified project leakage.[7] This includes adjusting project emissions

[7] Leakage occurs when greenhouse gas emissions or removals change outside the project boundary due to the implementation of the project. These changes in greenhouse gas emissions or removals may occur for a variety of reasons, including the shifting of emitting activities to other facilities or due to market forces indirectly impacted by the implementation of an offset project.

reductions or removals that are the basis for the award of offset compliance units to adequately account for leakage risk.

If offset compliance units are awarded in excess of the emissions reduction or carbon removal benefits that actually result from the offset project, then the integrity of the cap-and-trade program emissions cap will be compromised. This will result if the emissions reductions or removals claimed by a project are not in fact caused by the project, or if the emissions reductions or removals claimed do not actually occur. Projects may also be awarded excess offset compliance units if methodologies are employed that over-estimate the emissions reductions or removals achieved by the project. This can be avoided by employing conservative assumptions whenever there are uncertainties in quantifying emissions reductions or removals.

Meeting these goals also requires that an offset project and the offset compliance units awarded for the project be recorded in a transparent registry. This ensures that offset compliance units are only awarded once for each CO_2e ton of emissions reductions or removals occurring due to an offset project.

Additional

A greenhouse gas offset results from an emissions reduction or removal caused by a project specifically intended to compensate for emissions occurring elsewhere. A greenhouse gas emissions reduction or removal project is considered additional if the offset project activity (or activities) would not have occurred in the absence of the offset program.[8] Because awarded offset compliance units allow a regulated emissions source to emit more than it otherwise would have been able to, the underlying offset project only provides a true emissions reduction benefit if the project would not have occurred absent the offset program—i.e., it is “additional” to activities that would have otherwise occurred in the absence of the offset program.

While the concept of additionality is relatively straightforward, evaluating the additionality of an individual offset project can be complex. In practice, an offset project is considered additional if the project involves activities beyond standard market practice and the project is being implemented in response to economic incentives provided through the offset program (anticipated award of offset compliance units that have a market value). This does not necessarily preclude an offset project activity from receiving other economic incentives or providing other marketable ecosystem services or other economic products and services, provided it can be demonstrated that the offset program, alone or in combination with other incentives, is necessary to drive the implementation of the offset project (Figure 3).

[8] By extension, this also means that emission reductions, avoidance, or sequestration achieved by an offset project result in a lower level of net greenhouse gas emissions or atmospheric concentrations than would occur in the absence of the offset project.

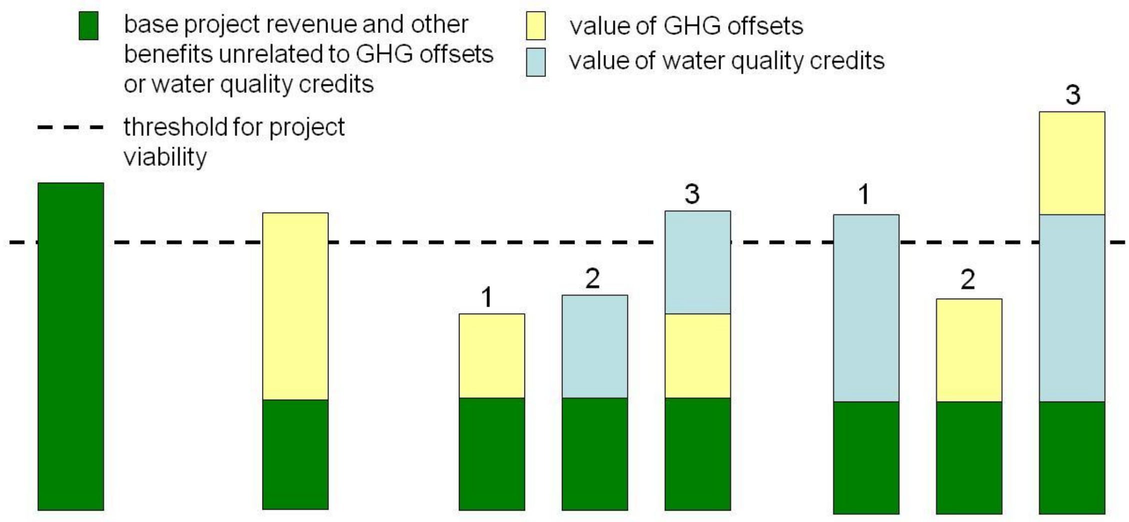

Figure 3. Additionality Evaluation, Considering Stacking of Multiple Project Incentives[9]

As shown in Figure 3a, some types of projects may be commonplace because they save the developer money or generate considerable revenue even without receiving offset compliance units ("GHG offsets"). Such projects are not additional. Figure 3b depicts a scenario where a project will not move forward without a carbon payment in the form of tradable offset compliance units. This project would be considered additional, and would be eligible for the award of offset compliance units. A project should be eligible for stacking of multiple project incentives if multiple incentives are necessary to drive project development. This scenario is depicted in Figure 3c, where neither offset compliance units (3c1) nor water quality credits (3c2) alone are sufficient to drive project development. However, when combined these two payments are sufficient to drive project development (3c3). However, if water quality credits alone are sufficient to drive project development without the need for carbon incentives in the form of offset compliance units (3d1), then offset compliance units do not drive project development, and therefore the project should not be eligible for stacking of multiple incentives under a cap-and-trade program.

An offset project should be evaluated to ensure that the project is not required by any local, state/provincial, or federal law, regulation, or administrative or judicial order. If a project or activity is required by regulation, law, or administrative or judicial order it is assumed to be implemented to achieve compliance with the law, and not to generate offset compliance units. Therefore, awarding offset compliance units for an offset project that involves mandated activities would

[9] Adapted from Bianco, Nicholas, "Stacking Payments for Ecosystem Services," WRI Fact Sheet, November 2009, World Resources Institute. Available at : http://pdf.wri.org/factsheets/factsheet_stacking_payments_for_ecosystem_services.pdf

undermine the emissions limitation of the cap-and-trade program. This concept is commonly referred to as “regulatory additionality”.

In addition to ensuring that a project is additional to regulation, the offset project activities must be shown to exceed a business-as-usual or “without-project” baseline scenario. The business-as-usual baseline scenario represents the expected activity that would occur in the absence of the offset program incentive.[10] Offset projects should only be awarded offset compliance units for greenhouse gas emissions reductions or removals if the project represents activities that exceed the activities under an approved business-as-usual baseline scenario.

Verifiable

Offset projects and offset project emissions reductions or removals must be verifiable. Verification is necessary to ensure that an offset project is eligible and has met all program requirements and that the offset compliance units awarded are based on emissions reductions or removals that have actually occurred and been properly measured. As used here, the concept of verification applies to both evaluation of project eligibility (sometimes referred to as validation) and verification of periodic monitoring reports of greenhouse gas emissions reductions or removals achieved by a project (commonly referred to as verification).

Prior to verification of project emissions reductions or removals, an offset project must be validated. Project validation confirms that the offset project either has been or will be implemented and that the project meets all program eligibility and other requirements. Typically, validation also includes a review of the adequacy of the project monitoring and reporting plan.

Emissions reductions or sequestration achieved through an offset project typically accrue over a multi-year period of time, which requires ongoing monitoring. As a result, robust monitoring and verification plans should be in place to ensure that project activities are monitored and project emissions reductions or removals are appropriately measured and recorded over time. Emissions reductions or removals should have occurred and been verified before the award of offset compliance units (sometimes referred to as *ex post* crediting). An emissions reduction or removal and the related offset compliance unit that is awarded can be verified if it results from a project for which the project activities and emissions reductions or removals can be readily monitored and quantified with reasonable precision and certainty, and the completeness and validity of project data underlying project assertions can be independently substantiated.

[10] This means that the proposed project activity could itself be considered to occur under a baseline scenario, and therefore would be non-additional. When considered as part of a “without project” scenario, this means that a valid claim could not be made that the project would not have occurred absent the incentive provided by offset compliance units; the without project scenario and project scenario would effectively be the same, and the project would be non-additional.

This requires that a given project's emissions reductions or removals are well documented and transparent, such that an objective ex-post review by a qualified verifier can be conducted.

Permanent
Greenhouse gas emissions reductions or removals achieved by offset projects must be permanent. Offset project emissions reductions or removals are considered permanent if they are not reversible or, if reductions or removals are reversible, certain programmatic requirements are met to ensure the permanence of the reductions or removals.

Offset project emissions reductions or removals should be comparable to emissions reductions by emissions sources regulated under the cap-and-trade program. Emissions reduced from a regulated emissions source during a specified period of time are permanent by default, since the absence of emissions during that past compliance period cannot be reversed. If the emissions reductions or removals provided by an offset project are not permanent, then the emissions limitation of the cap-and-trade program can be compromised if reversals occur.

For some offset project types, ensuring permanence is straightforward. For example, methane captured and destroyed through oxidation cannot reform into methane. As a result, the emissions reductions are permanent because they cannot be reversed. However, other offset project types face a risk of reversal. Specifically, the sequestration of carbon dioxide through biological means inherently bears the risk of reversal, as carbon can be released through a variety of causes, including fire, insect infestation, natural decay, and human caused reversals such as unsustainable harvesting. Therefore, if projects that sequester carbon through biological means are to be awarded offset compliance units, it is critical that programmatic safeguards be established to minimize the risk of reversal and that mechanisms be established to address and account for any reversals that may occur.

Enforceable
An offset compliance unit must be enforceable. An offset is enforceable if the offset program has sufficient regulatory authority and enforcement mechanisms to compel compliance with its program requirements. To ensure that offsets are enforceable, any party submitting an offset project for regulatory review and that may receive an award of offset compliance units must already be subject to the jurisdiction of the appropriate regulatory agency or must voluntarily submit itself to the jurisdiction of the regulatory agency. The regulatory agency should also maintain authority related to the offset compliance unit itself, as it represents a limited authorization to emit a CO_2e ton of greenhouse gas issued by the regulatory agency.

Offset compliance units must only be awarded after the project proponent demonstrates compliance with offset program requirements and protocols to the satisfaction of the issuing authority.

In the event of demonstrated non-compliance with any offset program requirement, enforcement measures may include: 1) mandated on-site changes to a project to bring it into compliance with program requirements; 2) administrative fines or penalties; 3) cancellation of awarded offset compliance units; and 4) mandated procurement and submittal to the regulatory agency of offset compliance units from the market to make up for awarded offset compliance units related to an offset project that is non-compliant with program requirements.

Failure to provide for the enforceability of offsets creates the potential for fraud and risks compromising the integrity of the cap-and-trade program emissions limitation. It could also undermine the establishment of a liquid offset market by creating potential uncertainty related to the market value of offset compliance units, both for regulated emissions sources using offsets for compliance and other market purchasers of offset compliance units.

III. Key Process Requirements Critical to Offset Quality

Implementing a high-quality offset program requires transparency and high-quality verification. Key process requirements that impact offset quality are discussed below.

A. Project documentation

Offset projects typically involve documentation of complex activities in diverse applications and locations. As a result, project documentation should be transparent and understandable, and readily accessible by the public. Transparency is key to assuring program integrity and maintaining public and market confidence in offset emissions reductions and removals, and by extension the market value of offset compliance units.

An offset program should have a secure yet transparent tracking system for offset projects and the award of offset compliance units (a project registry or tracking system). The offset tracking system and program regulatory requirements and administrative protocols should include measures to ensure against double counting of project emissions reductions and removals and double award of offset compliance units, and to assure that offset compliance units are properly assigned. At a minimum, offset project proponents should be required to attest that they hold the rights to project emissions reductions or removals, or have been assigned such rights, and also disclose any reporting related to a project to another voluntary or mandatory greenhouse gas reduction program.

B. High-quality independent verification to support regulatory review

High-quality, independent verification is critical to support regulatory agency review of offset projects and emissions reductions or removals achieved by offset projects.[11] Verification should be conducted by an independent party that does not have any financial interest or other interest in an offset project, or a relationship with an offset project developer or other party involved in an offset project that could cause a conflict of interest, which would undermine the objectivity of the verifier.

Verification should be conducted for both the evaluation of offset project eligibility and review of project monitoring reports that quantify periodic project emissions reductions or removals. In addition to evaluation of project eligibility, project validation should include a review of the project's monitoring and verification plan that will be used to monitor, quantify, and verify project emissions reductions or removals.

Project validation should include an on-site, or equivalent, review to ensure that projects will be or have been implemented as claimed and in accordance with program requirements. Verification of project monitoring reports of project emissions reductions or removals should also involve on-site review, or an equivalent review if appropriate for a specific offset project category. For example, in certain instances remote sensing technology may be adequate to demonstrate that a project is being implemented as claimed. Determinations about the appropriateness of various alternatives to on-site review should be based on well accepted methodologies.

The quality of verification services provided is dependent on the quality of the verifiers that provide such services. As a result, one of the keys to high-quality verification is the implementation of a robust verifier accreditation process. The focus of this process is three-fold: 1) to assure that verifiers have proper qualifications to provide verification services for specific types of offset projects; 2) to ensure that verification services are provided competently and ethically; and 3) to ensure that verifiers do not have any conflicts of interest with regard to offset projects for which they are providing verification services.

A verifier accreditation process should involve an initial assessment of prospective verifiers, including verifier competence and organizational protocols used to evaluate potential conflicts of interest. Verifier accreditation should also

[11] Verification as used here refers to both evaluation of project eligibility (sometimes referred to as validation) and verification of periodic monitoring reports of greenhouse gas emissions reductions or removals achieved by a project (commonly referred to as verification).

include ongoing requirements for maintenance of accreditation status, such as conflict of interest disclosure, and periodic evaluation of verifier performance.

C. Program review and adjustment

Regular review and adjustment of offset program requirements will allow an offset program to respond to changes in science, technology, regulations, market conditions, or other relevant factors. For example, global warming potentials may change and improved monitoring protocols may become available. There may also be changes in regulations or market dynamics that could affect project additionality. Regular review and adjustment of program requirements will help ensure that offsets are of high quality. Program revisions should be performed in a transparent manner to ensure public confidence in the offset program.

The need to revise program requirements over time should be balanced with the need to provide project developers with sufficient regulatory certainty to enable project development. This balance can be achieved by tying project approval to crediting periods of an appropriate length. Under this approach, projects would apply for offset program approval using the most current program requirements. If a project is qualified for the award of offset compliance units, then it is eligible for the award of offset compliance units throughout the approved crediting period, pursuant to the program requirements in effect at the time of project approval. During the crediting period, the regulatory agency may revise offset program requirements to accommodate changes in science, regulations, market conditions, or other relevant factors. New program requirements would be applied to all new projects submitted for approval. However, new program requirements would not retroactively be applied to an already approved offset project during its original crediting period.

IV. Importance of Standardized Implementation Approach

The three regional cap-and-trade initiatives have either implemented or intend to implement the offset component of their program through a standardized approach. This approach, as outlined below, provides multiple benefits that improve both offset quality and program efficiency, compared to a project-by-project approach. These benefits include increased program transparency, a more objective project review process, reduced project transaction costs, reduced financial risk for project developers, a reduction in market uncertainty, and a more streamlined project regulatory review process.

A. Introduction

As used here, a standardized approach to offset implementation sets program requirements up-front. This requires the relevant regulatory agency to develop a single set of program requirements for each offset project type (i.e., standardized for a category of projects). These requirements include mechanisms for evaluating project additionality, such as performance standards or benchmarks, and specified quantification, monitoring, reporting, and verification requirements. Standardized requirements need to address the five primary offset quality criteria discussed in Section II (real, additional, verifiable, permanent, and enforceable). For certain categories of offsets, standardized requirements may also address project permanence and project emissions leakage.

A standardized approach is distinct from a project-by-project approach. A project-by-project approach specifies certain process requirements for the evaluation of offset projects, but specific requirements are not set for project additionality, emissions quantification, monitoring, reporting, and verification. A project-by-project approach involves an offset project proponent proposing a customized set of evaluation criteria and other requirements for an individual offset project, including: (A) additionality evaluation process; and (B) quantification, monitoring, reporting, and verification criteria. The set of evaluation criteria and other project requirements proposed by the project proponent is then evaluated by the regulatory agency for sufficiency.

B. Examples of project-by-project and standardized approaches

Additionality

Project-by-project approach to evaluating additionality
The most notable program implementing the project-by-project approach is the Clean Development Mechanism (CDM). For example, the CDM specifies *process* requirements for evaluating project additionality, but does not specify additionality requirements for a category or type of project. The CDM evaluates project additionality through a process that typically involves the following:

- Identification of alternatives to the project
- Barriers analysis (market barriers, technology barriers, or financial barriers)
- Common practice analysis
- Investment analysis (project-by-project analysis, such as internal rate of return (IRR) or net present value (NPV)) with and without the projected revenue stream provided by the CDM offset compliance units; a determination is made as to whether the project, without offset revenue, is less financially attractive than other market options.

The overall goal is to provide reasonable assurance that the offset project would not have been implemented in the absence of the offset program. This process requires the creation by the project proponent of a project-specific baseline scenario of activities that are likely to occur in the absence of the offset project. A key component of this process is the evaluation of financial additionality – essentially an evaluation of the intent of the project developer, and whether the offset project would have been implemented absent the anticipated revenue stream from the market of value of offset compliance units awarded for the project.

Project-by-project evaluation of financial additionality requires a project-specific counterfactual assessment, which is by definition problematic. In particular, the outcome of a project-by-project evaluation of financial additionality is highly dependent on the selection by the project proponent of a project-specific business-as-usual scenario and other assumptions for threshold investment decision criteria, such as a project's benchmark internal rate of return or net present value required by the project developer to move forward with project implementation. These investment decision thresholds can vary significantly among individual investors. The project-specific nature of individual investment decisions makes it difficult for the regulatory agency to sufficiently evaluate project proponent assumptions.

Standardized approach to evaluating additionality
In contrast to the project-by-project approach, a standardized approach specifies a set of additionality criteria for a category of project types. The program administrator designs and specifies these criteria to provide reasonable assurance that an offset project eligible under a project category would not have been implemented absent the anticipated revenue stream from the market of value of offset compliance units awarded for the project. This is done by setting specific additionality requirements that provide reasonable assurance that an individual offset project significantly exceeds standard market practice. In practice, this typically involves conducting a market evaluation to develop and specify benchmarks and performance standards for a category of projects[12] that are used as proxies to infer the financial additionality of individual projects[13]:

- A benchmark is a qualitative eligibility criterion for a category of projects that ensures that a project is unlikely to occur under standard market practice. A benchmark could include a technology or practice standard and could also be a qualitative market evaluation criterion; for example, a criterion that addresses the stacking of multiple project incentives based on typical project economics for a category of projects, considering other available non-carbon economic incentives.

- A performance standard is a quantitative eligibility criterion that establishes a metric for determining if categories of projects are unlikely to occur under

[12] It should be noted that this process is more straightforward than a project-by-project analysis of financial additionality, as it involves evaluating actual market practices and project economics in a defined market, based on projects that have already occurred and evidenced trends, rather than a counterfactual assessment of future alternative project-level investments. It also reduces transaction costs for project proponents, as they do not need to conduct such an analysis to support the development of project-specific evaluation assumptions.
[13] If a project exceeds standard market practice, it is assumed to be financially additional and is assumed to be implemented in response to the financial incentive provided through the receipt of offset compliance units that have a market value.

standard market practice. The criterion is usually established in relation to the performance level achieved through standard market practice for the category of activities eligible under a certain offset category. Projects that meet or surpass the standard qualify as additional. Examples of performance standards include:

- Emission rate
- Energy efficiency criteria
- Market penetration rate

Quantification

There are many ways to determine the amount of greenhouse gas emissions reduced or sequestered by a given project. A project-by-project approach allows project proponents to propose their own quantification methods. This has lead to the development of methodologies that are highly tailored to specific projects, and thus not easily applied to a broad number of projects in a single category. This has increased the administrative burden of protocol and project review.[14] This problem can be avoided if quantification methods are initially standardized. Standardized quantification methodologies specify the quantification protocols that must be applied to a particular project type (e.g., anaerobic digesters).

Permanence

When a project type bears some risk of having its emissions benefits reversed, then administrative measures are necessary to ensure the permanence of the offset project emissions reductions or removals that are the basis for the award of offset compliance units. The purpose of these measures is to ensure that if an offset compliance unit is issued for an emissions reduction or removal that could be reversed, safeguards are in place to ensure that the integrity of the cap-and-trade program emissions cap is maintained, even if a reversal occurs. There are a number of potential approaches for addressing permanence, including: buyer liability for reversals, seller liability for reversals, insurance requirements, creation of project buffer pools or offset compliance unit reserves, discounting of project emissions reductions or removals used as the basis for awarding offset compliance units, and conservation easements, among others. A number of these approaches may be used individually or together to address potential project reversals.

Under a project-by-project approach to permanence, offset project proponents could propose which permanence mechanisms to employ, leading to the potential for considerable variation from project to project. Requiring regulatory agencies to evaluate the adequacy of the specifics of each proposed methodology would be labor intensive. Allowing for the adoption of a multitude of

[14] As a result, the CDM, which is administered through a project-by-project approach, has begun to develop consolidated methodologies that can be used for a wide range of project types.

approaches to address permanence could also introduce considerable uncertainty into the marketplace, thereby reducing the liquidity of the offset market.

A standardized approach specifies requirements for addressing permanence for a category of offset projects. Standardizing the approach to addressing project permanence provides more certainty to project developers, maximizes offset market liquidity, and reduces the administrative burden of implementing the program.

Monitoring and Reporting

A project-by-project approach to monitoring and reporting allows a project proponent to propose a monitoring and reporting plan for a specific offset project. The regulatory agency must then review the monitoring and reporting plan for sufficiency. A standardized approach specifies requirements for project monitoring and reporting for a category of offset projects. Standardizing the process for monitoring and reporting simplifies the verification process, and makes it easier to detect inconsistencies and errors.

Verification

Under a project-by-project approach to verification, the project proponent and independent verifier specify the verification protocol for an individual offset project and the required contents of verification reports, including the appropriate level of assurance to be provided. The regulatory agency must then evaluate the sufficiency of the proposed verification process. A standardized approach specifies verification requirements for a category of offset projects, which may include the required contents of verification reports and the minimum level of assurance that must be provided.

Providing standardized requirements for independent verifiers outlining what is expected of them during project review and the implications of failing to adequately review project details will help ensure that verified projects meet established regulatory standards. Moreover, ensuring that all non-governmental verifiers are accredited to a single standard of professional expertise and requirements ensures that professionals are trained in greenhouse gas emissions and carbon sequestration accounting and offset project verification, and are conducting objective verification activities with accuracy and competence.

C. Value of standardization in ensuring offset quality

The primary value of a standardized approach is that it sets program criteria up-front, through a regulatory process that provides for full technical, market, and policy evaluation, including full public participation. This approach increases program transparency and reduces the potential for the application of subjective project review criteria. However, a standardized approach can require more administrative resources during program design, but should reduce administrative resources required over the life of the program. It can also be difficult to establish standardized project evaluation criteria that are applicable across a wide range of regions and markets, which may require customizing standards for a respective region or regional market. Certain types of offset projects may not be amenable to a standardized approach if market data is lacking for development of additionality benchmarks and performance standards or quantification and monitoring protocols are not well developed.

The alternative is a case-law type approach, where program requirements evolve over time as project proponents submit proposed evaluation criteria and quantification, monitoring, and verification requirements for individual offset projects. This approach limits public participation by creating an administratively resource-intensive process that requires active ongoing participation from all affected stakeholders, some of which may lack the organizational capacity to fully participate in such a process. It also creates pressure to expedite technical and policy review in order to bring more offset projects to market.

If implemented properly, based on a robust market analysis, a standardized process avoids certain pitfalls of a project-by-project approach. In particular, the outcome of a project-by-project evaluation of financial additionality is highly dependent on the selection by the project proponent of project-specific business-as-usual scenarios and other assumptions for threshold investment decision criteria, such as a project's benchmark internal rate of return or net present value. These investment decision thresholds can vary significantly among individual investors. As a result, the evaluation criteria and key assumptions proposed by a project developer to evaluate project additionality must be validated by the relevant regulatory agency in order for the process to work as intended. To work properly, this could require significant additional market research, for which data might not be available, and would significantly slow the evaluation process. The end result is a potential for subjective evaluation results, an administrative overload that slows the project approval process, and pressure to expedite the regulatory agency review process without fully validating the project proponent's project evaluation criteria and other proposed project requirements.

A standardized process, in contrast, limits project eligibility to certain categories of projects for which sufficient market data is available and for which robust quantification, monitoring, and verification protocols already exist or can be readily developed. The market analysis is conducted up-front to develop standardized additionality criteria that can be applied to a group of like projects. If properly implemented, this ensures that the market analysis is objective and thorough.

A standardized process increases program transparency by allowing all parties to fully understand program requirements up-front. This reduces uncertainty for the project developer and decreases financial risk and market uncertainty. It also decreases project transaction costs by avoiding the need for project developers to develop their own complex project evaluation process and evaluation criteria. The complexity and potential subjectivity of the project review process is reduced, which should also reduce the time required to complete the regulatory review of a project.

D. Issues that need to be taken into account when using a standardized approach

A key offset quality issue that must be addressed when implementing a standardized approach is the need to update program requirements over time. For example, a standardized approach sets additionality requirements up-front, through regulation or other process, based on a market evaluation. However, while program requirements are specified up-front, program requirements should not be static. Since market conditions change over time, a program needs to build in a process for periodic market evaluation and the modification of program additionality requirements over time if warranted. Program administrators may also want to consider fine tuning standardized additionality criteria based on a project-specific evaluation of a subset of projects submitted for review under the program, in order to validate standardized program requirements.

Program administrators should also recognize that even with standardization of requirements, a number of project-specific assessments still need to be conducted. How these assessments are to be conducted may be specified in rule or protocol (i.e., standardized), but the project-specific evaluations still need to be conducted. An example is the determination of a project-specific emissions or sequestration baseline and monitoring and reporting of project performance and emissions reductions or removals.

For example, a standardized approach to evaluating additionality may employ default standards (referred to in pending U.S. federal legislation as “standardized activity baselines”), such as emissions performance standards, to determine project eligibility. When determining how many offset compliance units should be awarded for a project, it is important to consider not only such default values, but also project-specific baseline emissions (or carbon sequestration). Offset compliance units awarded should be calculated as the difference between project emissions reductions and either the standardized default emissions performance standard, or the project’s own emissions baseline, whichever produces a lower value.[15] If emissions reductions are credited directly against a standardized

[15] An example of the distinction between a baseline scenario that uses an emissions performance standard (a standardized activity baseline) and a project-specific emissions baseline is provided by the RGGI offset requirements for electricity-sector SF_6 offset projects. In RGGI, electricity transmission and distribution entities must meet an entity-wide SF_6 emissions performance

baseline scenario that is emissions-based, this could lead to over crediting of offset compliance units if the actual project emissions baseline differs from the default emissions baseline.

Applying default values for project emissions baselines and reporting period emissions reductions that do not involve project-specific evaluation could lead to the over-compensation of offset projects, and the award of offset compliance units for emissions reductions that are not real. An example is the potential for confusion of the concepts of a standardized baseline scenario and a project-specific emissions baseline.[16] A standardized baseline scenario evaluates a sector or subsector of similar activities, arriving at an average level of performance or establishing a typical common activity. It is in effect a scenario of what would have occurred in the absence of a project under common practice — in this case a standardized metric applicable to multiple, similar project activities. In contrast, a project emissions baseline should be project-specific, as it should represent the *lesser*[17] of actual emissions prior to implementation of a project or the emissions that result from application of a baseline scenario to the specific emissions sources within a project boundary. In practice, the baseline scenario must be applied to the specific greenhouse gas emissions sources and sinks addressed by an offset project in order to derive a project-specific emissions or sequestration baseline.

If offset compliance units are calculated directly against a standardized baseline scenario, the baseline scenario must be emissions based (e.g., tons of carbon sequestered per acre, or emissions per unit of output), which limits the types of activity metrics that could be used as an activity baseline. Furthermore, a qualifying project could potentially have actual baseline emissions above or below those that would be calculated through application of the baseline scenario to the specific emissions sources and sinks addressed by the project (e.g., a forestry management offset project, where actual carbon sequestered per acre prior to implementation of the project exceeds that which would be derived through application of the activity baseline to the number of acres of land within the project boundary). If emissions reductions are credited against the

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standard to qualify as eligible offset projects (the performance standard is an annual percentage emissions rate of total SF_6 used by the entity that is emitted per year). This emissions performance standard is one of the methods used to evaluate project additionality. However, while an emissions standard is used to evaluate additionality (the entity must have an emissions rate for its baseline year that is lower than the performance standard), actual baseline emissions as monitored for the entity are used as the basis against which emissions reductions are calculated and offset compliance units are awarded. This is because qualifying entities that meet the performance standard could have actual baseline year SF_6 emissions that are significantly lower than the performance standard. As a result, calculation of actual baseline emissions is necessary to ensure that a project is not over compensated with awarded offset compliance units.

[16] Activity baseline is a term used in current pending U.S. legislation, and is comparable to a baseline scenario.

[17] In the case of a sequestration offset project, the *greater* value of carbon sequestered would be used as the project baseline.

standardized baseline scenario, this would lead to over-crediting of offset compliance units for the project for the forestry management scenario above.

If emissions or sequestration baselines are not project-specific, the program could potentially issue offset compliance units for emissions reductions or removals that did not actually occur as a result of the project, due to the relative accuracy of the baseline scenario. This is because a standardized baseline scenario is a generalized proxy measure for evaluating project additionality for a category of projects and not necessarily a method for determining individual project baseline emissions. Avoiding this outcome requires quantification of baseline emissions or removals for all project emissions sources and sinks prior to the implementation of the project.

Western Climate Initiative

Auction Design Draft Recommendations

WCI Partners Meeting – Seattle, WA

May 20, 2010

Auction Design

- Released white paper on April 14, 2010
- Held stakeholder conference call on April 29, 2010
- Stakeholder comment period closed May 7, 2010
- Draft recommendations to be released Summer 2010

Auction Principles

- The following auction design principles inform decisions regarding the auction and guide the overall WCI market design effort.

The eight principles for auction design are:

Fairness	*Efficiency*
Effective Oversight	*Transparency & Openness*
Administrative Simplicity and Cost	*Accountability*
Compatibility with other markets	*Conflict of Interest*

Recommended Parameters

The following ten parameters were discussed in the white paper:

- *Auction Format*
- *Unsold Allowances*
- *Vintages*
- *Lot Size*
- *Avoiding Market Manipulation*
- *Timing and Frequency of Auctions*
- *Reserve Price*
- *Participant Access*
- *Financial Assurance*
- *Information and Transparency*

Draft Recommendations

Auction Format:

- Describes how participants can bid on allowances
- Majority stakeholder support for single round, sealed bid, uniform price auctions. Stakeholder suggestion to review the auction format after some time.

Draft Recommendations:

- *single round*
- *sealed bid*
- *uniform price*

Draft Recommendations

Reserve Price:

- Refers to the minimum allowance price that the seller will accept.
- Stakeholder comments indicate support as part of a price stability mechanism

Draft recommendation:

- *further analysis required*

Draft Recommendations

Unsold Allowances:

- Stakeholder support for use of unsold allowances for cost containment – unsold allowances released back into the market at certain prices.

Draft Recommendations:

- *partners will retire a fraction of the unsold allowances*
- *remaining fraction will be retained for use according to WCI partner direction.*

Draft Recommendations

Vintages:

- Vintage allowances refer to allowances sold prior to the compliance period for which they become valid.
- Stakeholder support for sale of vintages.

Draft Recommendations:

- *Include the sale of vintages.*
- *Separate auctions held for different vintages.*
- *Each auction day holds an auction for the current vintage year and a future vintage.*

Draft Recommendations

Lot Size:

- Refers to the number of allowances bundled together for offering as an auction unit.
- Stakeholder support for lot size of 1,000

Draft Recommendation:

- *lot size of 1,000*

Draft Recommendations

Timing and Frequency of Auctions:

- Stakeholder support for quarterly auctions, some support for auctions prior or post compliance period.

Draft Recommendation:

- *quarterly auctions*

Note: The last auction may be held at the end of the compliance period, prior to true-up.

Draft Recommendations

Participant Access:

- Stakeholders supported open access, and non-competitive bids. Limited support for consignment option.

Draft Recommendation:

- *auction open to anyone able to meet the qualification requirements.*

Note: Auction qualification requirements TBD.

Draft Recommendations

Financial Assurance:

- Stakeholders supported financial assurance

Draft Recommendation:

- *100% financial assurance*

Note: WCI will ensure a short time lag between the auction bid and settlement.

Draft Recommendations

Information and Transparency:

- Stakeholders supported information transparency but details varied.

Draft Recommendation:

- *public disclosure of auction results including:*
  - *the clearing price,*
  - *identity of winning bidders and*
  - *number of allowances awarded.*

Draft Recommendations

Avoiding Market Manipulation:

- Refers to options for minimizing collusion, manipulation and hoarding.

Draft Recommendation:

- *include auction monitoring, purchase limit (details TBD), and reserve price.*

Next Steps

- Finalize draft recommendations (May/June 2010)
- Brief partners on draft recommendations (June 2010)
- Post draft recommendations for stakeholder comment (June 2010)
- Incorporate stakeholder feedback
- Include final recommendations in the detailed program design document (Summer 2010)

Current Congressional Action on Climate

Judi Greenwald
Vice President of Innovative Solutions
Pew Center on Global Climate Change

Western Climate Initiative
May 20, 2010

Kerry-Lieberman Overview

- Result of several months of bipartisan negotiations
- Intended to be released April 26 as Kerry-Graham-Lieberman, though delayed after immigration controversy
- Eventually released on May 12 as Kerry-Lieberman
- Undergoing six-week EPA economic analysis, which should be finished in early June

Overview

- Coverage: 85% of U.S. GHG emissions under the cap
- Cap: 17% below 2005 levels by 2020; 83% below by 2050
- Threshold: Covers entities emitting >= 25K tons CO_2e; EPA may lower reporting threshold to 10K
- Offsets: 2 billion tons domestic & int'l
- Cost containment: Strategic reserve of 4 billion allowances available if allowance prices rise above trigger price
- Clean Air Act limitation: GHGs not regulated as criteria, hazardous, or international air pollutants under CAA
- State role: GHG cap-and-trade pre-empted; other state programs unaffected
- Allowance distribution: Multiple categories
- Bipartisan Senate Energy Committee ACELA bill may be incorporated in the future

Emissions Cap

- Reduction targets
  - 95.25% of 2005 levels by 2013
    - (slightly more aggressive than Waxman-Markey)
  - 83% of 2005 levels by 2020
  - 58% of 2005 levels by 2030
  - 17% of 2005 levels by 2050
- Mandatory reporting by 2011 for large sources with >25k tons/year of emissions; or lower at EPA's discretion
- EPA's discretion as to whether vehicle fleets with >25k tons/year must report

GHG Compliance Program

- Compliance begins in 2013 for:
  - Utilities
  - Refineries (onsite emissions)
  - Refined product providers (transportation fuel)

- Compliance begins in 2016 for:
  - Industrial sources
  - Natural gas local distribution companies

- Allowances are surrendered on an annual basis for all sources except for transportation fuels which is done on a quarterly basis.

- One-year compliance period with unlimited next year borrowing (similar in effect to two-year compliance period)

Transportation GHG Coverage

- 93% of GHG emissions from transportation are covered. Excludes ships and boats, pipelines, and lubricants.
- Transportation sector is covered under the cap but does not participate in the auction or trade with other sectors.
- EPA is ordered to set aside allowances from auctions by estimating the total need of the transport sector from existing data. Refined product providers don't compete with other sectors.
  - EPA can also borrow from one year ahead on a limited basis if needed.
- Refined product providers must pay the EPA quarterly for allowances as compliance
  - The amount is equal to the most recent auction clearing price for allowances in the cap-and-trade program for the other sectors X the attributable GHG emissions of the covered refined product during the previous quarter
  - Transportation sector may not trade, sell, bank or borrow allowances
  - The allowance price is announced at least 30 days before the beginning of the compliance quarter so that refined product providers can adjust future product prices accordingly

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Transportation GHG Coverage (cont'd)

- EPA will set the percentage of allowances from the general auction pool that can be set aside for transportation. If EPA estimates of allowances for the transportation sector are too low, they can borrow from the following year's pool of allowances. If EPA overestimates, then those allowances are returned to the auction pool for the following quarter's auction.
- It is unclear what happens if transportation needs more allowances than what is available in the auction pool throughout the life of the program

Allowance Markets for other Sectors

- Unlimited banking
- Unlimited one-year borrowing w no interest
- Borrowing up to 15% of compliance obligation with vintage years 1-5 beyond calendar year at 8% interest per year
- Trading restricted to compliance entities and regulated carbon market participants
  - Restrictions to prevent excessive speculation
  - All allowances must be bought and sold on an exchange

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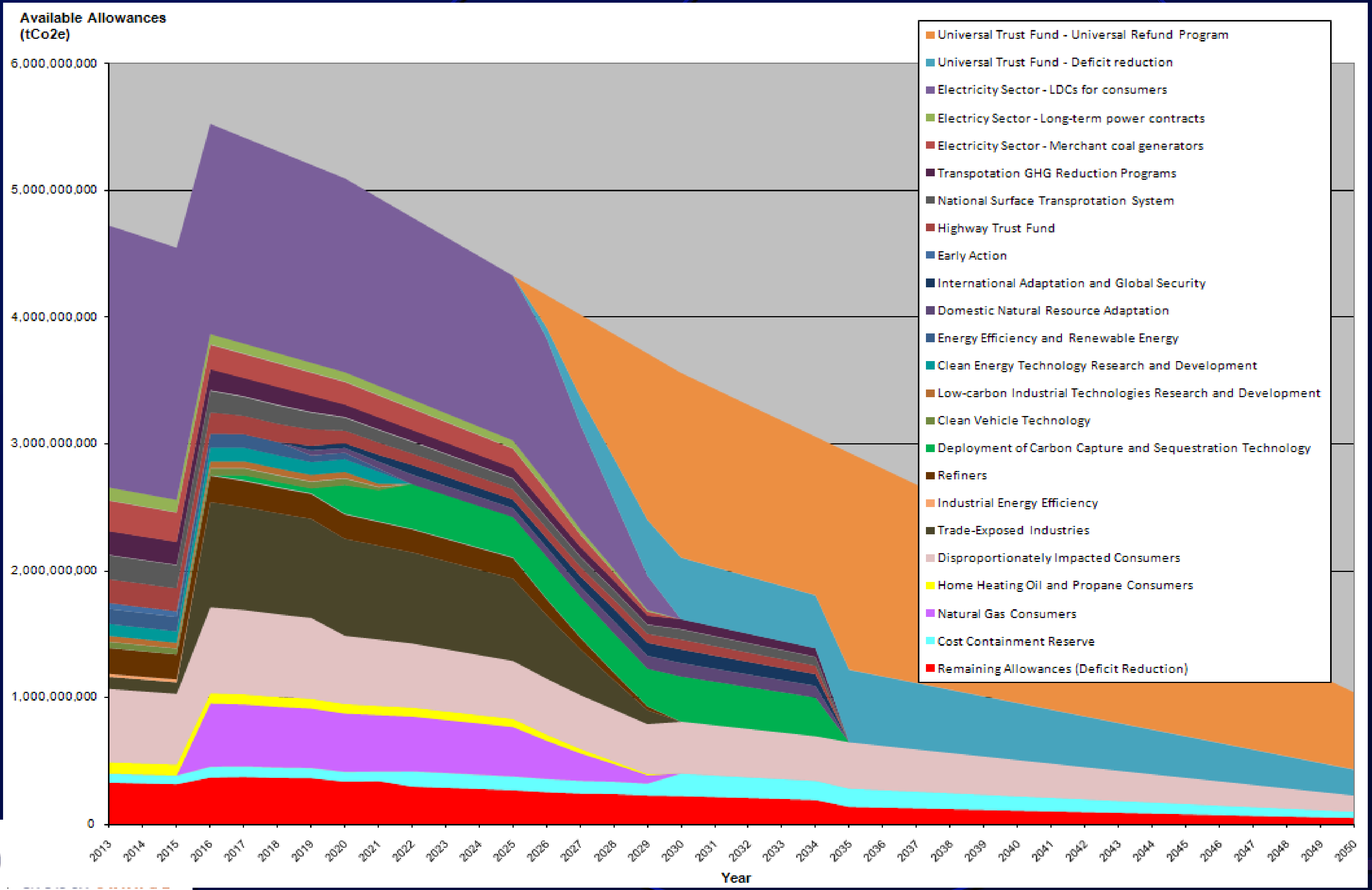
Allowance Distribution



EITE Provisions

- Allowance rebates for EITE ~ W-M
- Require surrender of allowances for imports in specified sectors, unless President determines otherwise

Credit for Early Action

- 1% of allowance value from 2013-2015 goes for early action
  - 2/3 of this amount goes to states with cap and trade programs
  - 1/3 of this amount goes to early action offset credits

Cost Containment

- Up to 2 billion tons of offsets system wide can be used for compliance (25% of which can come from international sources)
  - International limit may be increased up to 1 billion tons if the Administrator determines domestic supply is insufficient, but 2 billion ton overall limit still applies
- President may recommend to Congress to increase or decrease total number of offsets
- Domestic offset program similar to Stabenow bill

Cost Containment

- Price collar with a floor at $12/ton and a ceiling of $25/ton escalating respectively at 3% and 5% above inflation annually
- Strategic reserve contains 4 billion tons allowances over the life of the program pulled from future program years
  - Allowances are sold at the ceiling rate of that year
  - Covered entities can purchase reserve allowances up to 90 days before the date of compliance for up to 15% of their compliance obligation in that year
  - Must use strategic allowances within one year
  - Revenue from Strategic Reserve auction to be used to purchase REDD offsets which will be used to replenish the Reserve

Nuclear Provisions

- Increases nuclear loan guarantee funding to $54 billion (from $18.5 billion)
- Expands standby support regulatory risk insurance to cover up to 12 reactors (rather than 6)
- Includes provisions to expedite nuclear licensing
- Expands tax credits for nuclear power investments and generation

Offshore Oil and Gas

- Provides states with 37.5 percent of government revenue from drilling in offshore areas previously subject to drilling moratoria
- Allows states to prohibit offshore drilling within 75 miles of their coasts
  - Subject to Department of Interior impact analysis, any states directly impacted by potential oil spills in newly opened offshore areas can prevent leasing from proceeding

Coal Provisions

- Federal agencies to develop national CCS deployment strategy
- CCS trust fund to finance first 10 GW of commercial-scale demonstration projects
- Administrator to design legal framework for regulating geologic sequestration sites
- Authorizes bonus allowances in two phases
- Performance standards for new coal-fueled power plants. New facilities initially permitted after January 1, 2020 subject to a performance standard of a 65% reduction in CO_2 emissions. Plants permitted between 2009 and 2019 are subject to an annual CO_2 emission reduction of 50%
- Provides accelerated depreciation and investment tax credits for early replacement or retrofit of existing coal plants not subject to the CO_2 performance standard

Transportation Funding

- Most funds go to Highway Trust Fund and TIGER grant program;may or may not reduce GHG emissions
- Transportation Planning Program (up to $1.875 billion)
- Clean Vehicle Technology Fund (fixed % of allowances)
- Natural Gas Vehicle Support (separate funding mechanism)

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State Highlights

- Pre-empts state cap and trade programs; does not pre-empt other state actions
- Provides for exchange of state for federal allowances
- Less allowance value to states than under W-M
- States receive allowance value for consumer protection for home heating oil
- Offshore drilling: revenue sharing and veto power

State Highlights (cont'd)

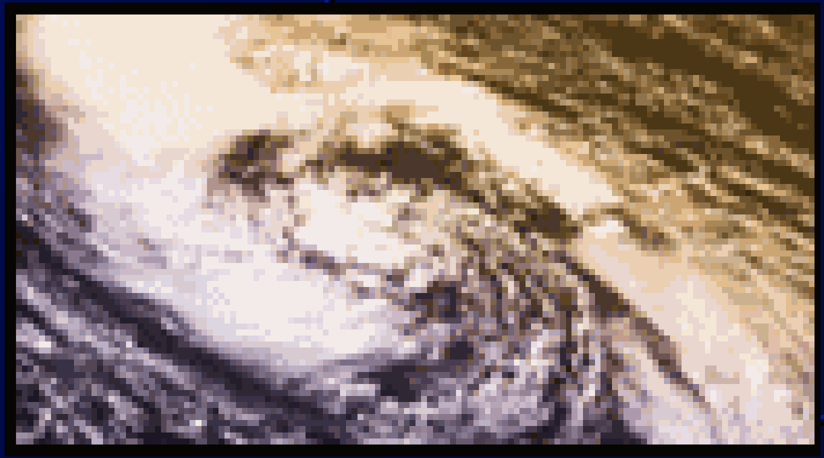
- Directs Administrator to consult with regional initiatives in developing regulations for implementation
- Early action allowances available for states who have enacted cap and trade programs
- No money for state adaptation programs

What happens next?

- Reading, digesting, summarizing and analyzing K-L
- Senate Majority Leader Reid decides how to proceed
- Conditions for legislative success
  - Administration engagement
  - Senate Republican engagement

For More Information

www.pewclimate.org



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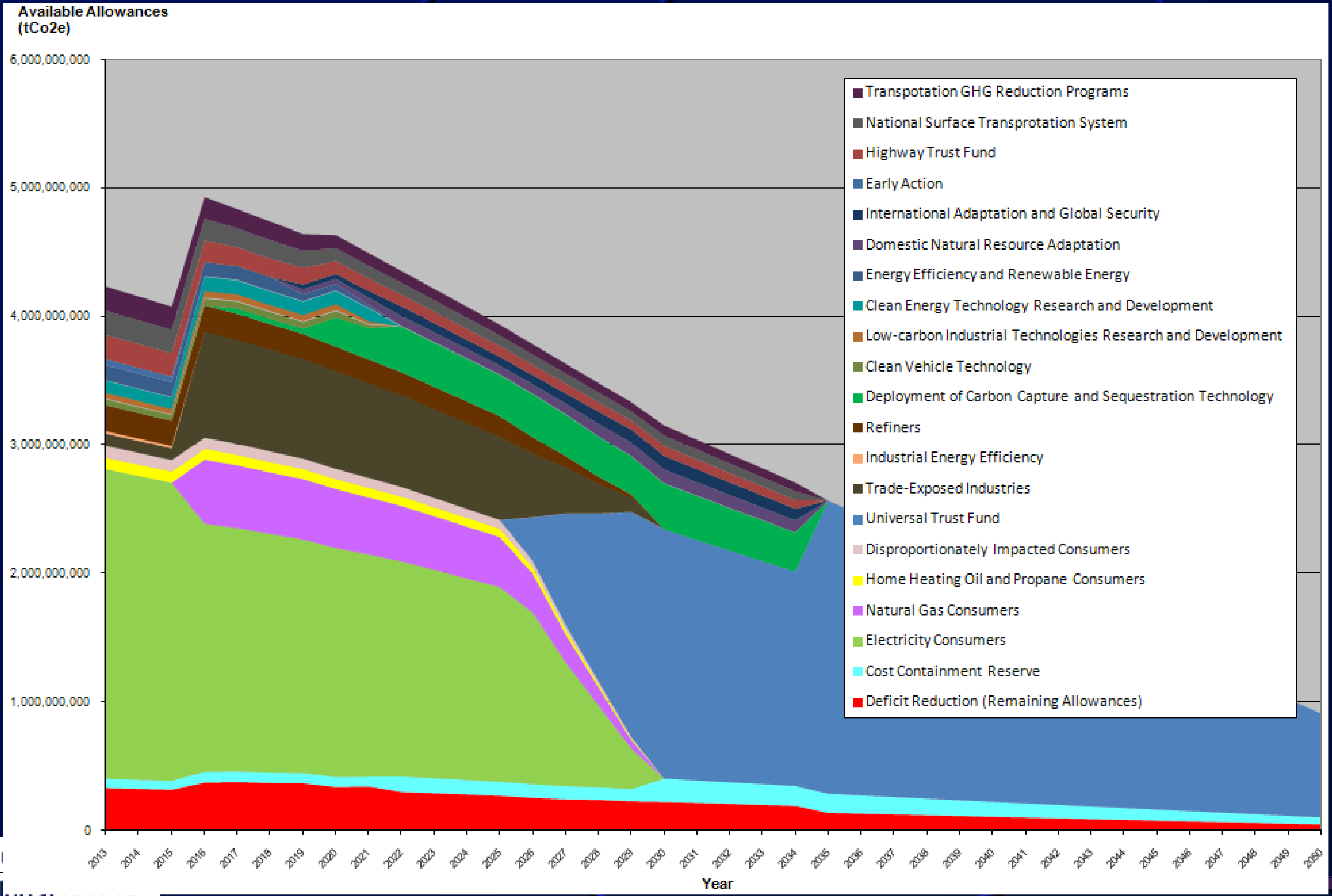
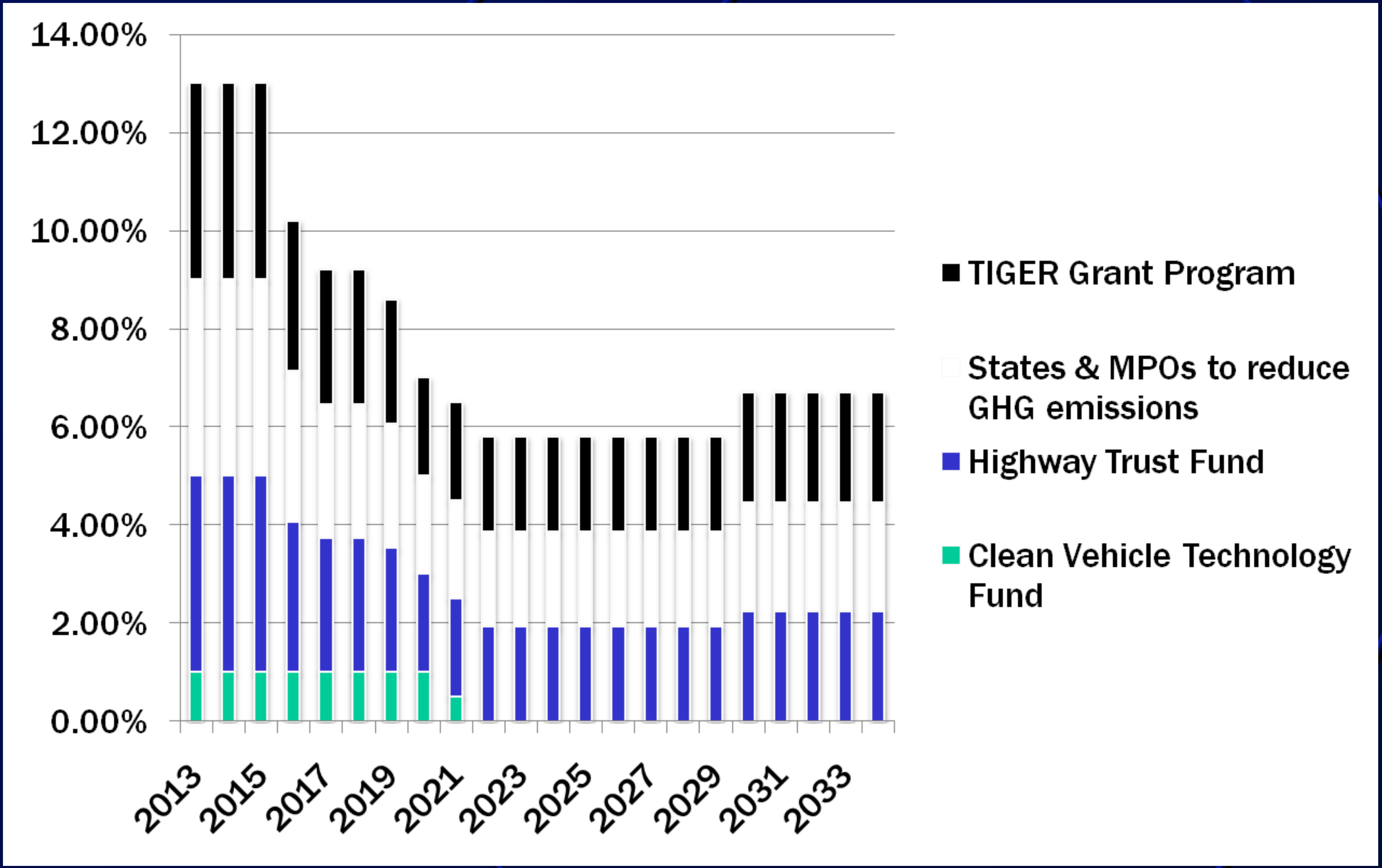
Allowance Allocation



Allowance Allocation for Transportation



PEW CENTER ON Global CLIMATE CHANGE

Western Climate Initiative

Market Oversight
Draft & Final Recommendations

Partner Meeting, Seattle, Washington

May 20, 2010

Market Oversight Objectives

- "The recommended design will provide opportunities to obtain low-cost emission reductions through emission trading, allowance banking, and inclusion of an offsets component."

WCI Design Recommendations, September 23, 2008

- "The WCI Partner jurisdictions and stakeholders want appropriate safeguards and oversight of the allowance and offset credit trading markets and want them to function efficiently."

Materials for Markets Workshop, April 9, 2009

Principles

- **Efficiency**: The market is designed to operate efficiently so that greenhouse gas (GHG) emission reductions can be achieved at the least cost. An efficient market means that allowance and offset credit prices reflect supply and demand, and accurately reveal the value of allowances and offset credits.

- **Effective Oversight**: The design and oversight of the market is effective in preventing or minimizing fraud, manipulation, and speculative excess.

Oversight Recommendations Process

- Public workshop April 9, 2009
- White Paper November 18, 2009
- Stakeholder call December 2, 2009
- Draft Recommendations paper April 1, 2010
- Stakeholder call April 20, 2010
- Holdings limit consultant’s report, May 14, 2010
- Stakeholder call May 25, 2010
- Final Recommendations paper
- Detailed Program Design Summary

Allowances, Offset Certificates, and Derivatives

- #1: Treat Compliance Instrument Derivatives as Commodity Derivatives for Market Oversight Purposes
- #2: Information on Derivatives Positions
- #3: Treat Allowances and Offset Certificates Identically for Market Oversight Purposes

Market Participants

- #4: Establish Legal Relationship with Market Participants Through Compliance Instrument Ownership Interest and Tracking System
- #5: Do Not Limit Market Participation to Compliance Entities
- #6: Do Not Require Registration of Intermediaries as Market Professionals

Holdings and Transfers

- #7: Holdings Limits
- #8: Require Use of a Central Limit Order Book for Secondary Market Transactions
- #9: Require Reporting of Beneficial Ownership
- #10: Information Required for Compliance Instrument Transfer
- #11: Holdings and Transfer Information Disclosed to Public
- #12 Market Monitoring

#2: Information on Derivatives Positions

- Mirror information to derivatives regulators for real-time monitoring
- Forensics
- Support for "providing appropriate technical and other compliance assistance" (Design Rec., §12.5)

- Data currently not collected
- Could not see whole market
- Infrastructure costs
- Debate over transparency benefits

#8 Central Limit Order Book

- Proposed as a way to get real-time transparency for prices, bids, and offers
- Stakeholder comment mixed, but largely unfavorable
- We have a refined proposal that addresses some concerns, but not all; still prescriptive in some ways
- Primary policy question is the value of real-time price transparency

Status

- Recommendations 1, 3 – 5, 6 (changed), 9 – 11 fairly solid
- #7 Holdings Limits: would need to work out details, but could likely be a final recommendation
- #12 Third-party market monitor: No final recommendation yet
- #2 Reporting to central derivatives repository: No final recommendation yet
- #8 Trading only on defined electronic platforms: No final recommendation yet

For More Information:

- Michael Gibbs, California, Markets Committee Co-Chair

  mgibbs@calepa.ca.gov

- Jim Whitestone, Ontario, Markets Committee Co-Chair

  jim.whitestone@ontario.ca

Western Climate Initiative

Public Comments
on
WCI Offset Criteria
Draft Recommendations

Seattle, Washington

May 20, 2010

Background

- May 12th, 2010 was the comment deadline for the WCI Offsets Criteria Draft Recommendations Paper
- Comments from 27 people/organizations were received
- This presentation summarizes the public comments by Offset Committee draft recommendation number

3.1 Offset Definition

- Add the term “avoidance” in the offsets definition.
- Include the notion that the reduction or removal is compensating for an emission elsewhere, and that the offset is a permit and does not create a new property right.
- Do not allow revoking a credit after certification otherwise you risk losing market confidence regarding the permanence and the value of a credit.

3.2.1 Offset Ownership

- Include guidance on who will have the authority to resolve ownership issues.
- Use a flexible approach to ownership based on the project proponent, similar to the approach used by CDM (“the focal point”) that does not have the program authority resolving issues of “ownership”.

3. 2.2. Use of Recommended Protocols

- Offset protocols should be fungible and harmonized across WCI.
- Provide further detail on the protocol review process.
- Create a central body to review and approve Partners' protocols.
- Have an open and timely process to adapt existing protocols and introduce new protocols.
- Protocols within sectors and within project types should use the same basic approaches to baseline determination, additionality, permanence, leakage, enforcement and environmental integrity.

3.2.3 Geographic Limits

- Allow WCI Partner jurisdictions to issue offset credits to qualified offset projects located outside of North America.
- Limit the geographic scope to just the WCI region.
- Clarify that offsets are fully fungible within the WCI structure

4.1 Real

- Consider recognizing reductions at sources not controlled by project developers under certain limited circumstances.
  - Indirect avoided deforestation
  - Electricity energy efficiency

4.2.1 Quantification

- Adopt only protocols with a high level of confidence that the reductions occurred can be establish.
- Develop procedures for re-evaluating quantification methodologies and publication of changes in advance
- Change the language in section 4.2.1.3 to "means erring on the side of caution, and it requires balancing of standards for accuracy with the need for cost-effective offset projects".
- Create an independent panel of scientists to review and make recommendations for updating each protocol. Accuracy should not be sacrificed in order to lower the cost of an offset.
- Clarify what is meant by "best available science".

4.2.2 Leakage

- Provide guidance to assess market leakage.
- Do not require leakage analysis for projects with no leakage risk.
- Provide clearly outlined policies and procedures for determining and quantifying leakage in each protocol.
- Qualify the use of “functional equivalence” evaluations in assessing leakage.

5.1 Additionality and Baseline

- Do not "reflect the most stringent regulatory requirements and legal requirements of any WCI Partner jurisdiction"; rather, evaluate on a case-by case basis the implications of using the most stringent legal requirements to set baselines and eligibility criteria.
- Do not rely exclusively on baselines as this would fail to comply with the rigorous definition of additionality.

5.2.1 Eligibility Date

- Move the eligibility date of September 23, 2008 to an earlier date, such as:
  - January 1st, 2000 to reward progressive companies
  - June 1st, 2005 Date of California Executive Order
  - January 1st, 2001 consistent with Waxman-Markey bill.
  - January 1st , 2006 as the proliferation of cap-and-trade opportunities reached a tipping point at that time
  - August 31, 2006 when California's AB 32 was signed into law
  - December 31, 2006 for consistency with the passage of California's Global Warming Solutions Act of 2006 (AB 32) and CARB preliminary draft regulations
  - Same as CAR or CCX
  - January 1, 2012

5.2.2 Crediting Period

- Do not limit the number of crediting period renewals.
- 15 years for sequestration projects.
- 50 year minimum for reforestation and improved forest management sequestration projects.
- 5 years for non-forestry projects.
- 10 years if project is subject to a comprehensive re-evaluation of additionality at the time of renewal
- Base the determination of crediting periods for certain project types on science and objective data.
- Allow an offset project to continue generating credits if a law is later enacted that makes the project activity mandatory.

6.1 Permanence

- intentional reversals should never be permitted and discounts or pro-rating should be consistent with this principle with strict penalties for reversals that are deemed intentional.
- Do not allow pro-rated short-term projects.
- Use measures that have proven to be successful in other areas to manage reversals and permanence, such as an assurance factor and a buffer reserve of credits.
- Have a shorter permanence requirement and investigate other means of achieving permanence that may be appropriate for some projects (e.g. a conservation easement).

7.1.1 Verification and 7.2.1 Validation

- Validation is absolutely necessary
- Do not require validation.
- Have consistent accreditation requirements across the WCI.
- Provide explicit guidance on what is a reasonable level of assurance down to the protocol level.

7.2.2 Enforcement

- Stringency of each jurisdiction's enforcement requirements should be designed to reduce opportunities for abuse.
- Apply penalties consistently across the WCI.

7.2.3.1 Material

- Errors in small projects may exceed materiality thresholds but only affect a small number of tons so could be exempted or subject to a different threshold.

8.1 Transparency

- A registry structure may facilitate disclosure for aggregated projects
- Timely public disclosure of project documents would allowing for public comments on proposed methodologies, projects, and credit issuance
- Regulators should explain why public comments were or were not taken into account.
- Establish registries that are ultimately linked to each other and contain standardized information.

8.2 Co-Benefits of Offsets

- Prioritize projects with positive co-benefits.
- Require a report on co-benefits as part of the offset registration and reporting process.

8.3 Assessment of Environmental or Social impacts

- Remove section 8.3.1
- Avoid additional assessment requirements to those already in place at the jurisdictional levels.
- Do not develop protocols that would require further analysis and mitigation of any negative environmental and socioeconomic impacts.
- Subject sequestration projects to further safeguards.
- Require offset projects to do no net harm

Other/General Comments

- Interest in how offsets/allowances from other systems are going to be considered
- Interest in the protocol and project approval processes
- Confusion over where WCI is including Market Oversight
- Establish a positive list (like the one included in the American Power Act).
- Include special program-wide provisions for small projects.

Next Steps

- WCI Offset Committee Task Team 1 will review and recommend where public comments should be incorporated into the revised recommendations for Partner Jurisdiction consideration

Western Climate Initiative

Proposed Harmonization of Essential Requirements for Mandatory Reporting with EPA Mandatory Reporting Rule

Partner Meeting, Seattle, Washington

May 20, 2010

Background

- July 16, 2009, Final ERs published
- As part of Summer 2009 re-prioritization, Partners directed Reporting Committee to harmonize ERs with EPA Mandatory Reporting Rule
- September 22, 2009, final EPA rule published

Principles

1. A U.S. facility should be able to comply with both the MRR and a WCI jurisdiction's reporting requirements by following a single set of monitoring, recordkeeping and reporting requirements.
2. The quantification methods included in the amended ERs must be sufficiently reliable and accurate to be employed in a (GHG) cap-and-trade program.
3. The amended ERs must remain suitable for use in Canadian WCI jurisdictions.

Process

- ERG prepared tables comparing each subpart of EPA rule to relevant ERs
- Committee reviewed each difference between the EPA rule and the ERs and decided whether:
  - The EPA approach could be adopted; or
  - The WCI approach need to be retained.

Process (cont'd)

- ERG and Committee prepared markup of EPA rules to conform to WCI requirements
- In most cases, the EPA rule could be modified without requiring a change to the EPA reporting system, e.g. by requiring a higher "tier" that is already available in and allowed by the EPA rule (next slide).
- During discussions of the GHG Data Exchange Integrated Project Team, EPA has indicated a willingness to augment its reporting system to accommodate additional data elements needed by state and regional programs.

Example Markup

(3) The Tier 3 Calculation Methodology:

(i) May be used for a unit of any size at any facility that combusts any type of fuel listed in Table C-1 of this subpart (except for MSW), unless the use of Tier 4 is required.

(ii) Shall be used for a unit ~~with~~ that has a maximum rated heat input capacity greater than 250 mmBtu/hr or is located at a facility subject to verification~~that combusts any type of fuel listed in Table C-1 of this subpart (except MSW)~~, unless either of the following conditions apply:

Subparts/Industries Covered

Subpart A—General Provisions
Subpart C—General Stationary Combustion
Subpart D—Electricity Generation
Subpart E—Adipic Acid Production
Subpart F—Aluminum Production
Subpart G—Ammonia Production
Subpart H—Cement Production
Subpart K—Ferroalloy Production
Subpart N—Glass Production
Subpart O—HCFC-22 Production and HFC-23 Destruction
Subpart P—Hydrogen Production

Subparts/Industries Covered (cont'd)

Subpart Q—Iron and Steel Production
Subpart R—Lead
Subpart V—Nitric Acid Production
Subpart X—Petrochemical Production
Subpart Y—Petroleum Refineries
Subpart Z—Phosphoric Acid Production
Subpart AA—Pulp and Paper
Subpart CC—Soda Ash Manufacturing
Subpart GG—Zinc Production

Next Steps

- U.S. jurisdictions to implement harmonized ERs by adopting incorporation-by-reference rules based on markup
- Canadian jurisdictions have determined that incorporation-by-reference of EPA rule or modified version of EPA rule is not feasible
- A version of the July 2009 ERs modified to conform in substance with the harmonized ERs is needed for the provinces

Western Climate Initiative

Final Complementary Policies White Paper

May 20, 2010

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1 Background and Purpose

The Western Climate Initiative (WCI) Partners have recommended a comprehensive regional effort to reduce emissions of global warming pollution, combining a broad cap-and-trade program with complementary policies to achieve the WCI 2020 regional emissions goal.[1] Complementary policies can address market barriers that would otherwise limit the use of low-cost greenhouse gas (GHG) emission-reduction options and reduce emissions from sources excluded from the cap-and-trade program. Thus, complementary policies can lower the overall cost of reducing GHG emissions. This view is supported by the 2008 economic analysis of WCI's cap-and-trade design, which incorporated complementary policies related to energy efficiency and tailpipe emission standards. The analysis found that the WCI 2020 reduction goals can be achieved with small overall net savings due to reduced energy expenditures exceeding the direct costs of greenhouse gas emission reductions.[2]

As part of the WCI 2009-2010 Workplan, the WCI Partner jurisdictions formed the Complementary Policies Committee. The charge of the Committee is to recommend to the WCI Partner jurisdictions those policies which, if harmonized across multiple states and provinces both within and outside the WCI Partner jurisdictions, would help achieve the regional emissions reduction goals and assist with the transition to a low-carbon economy. By harmonizing complementary policies, the WCI Partner jurisdictions intend to foster increased market certainty, encourage trade among participating jurisdictions, reduce administrative costs and streamline regulatory procedures.

As a first step, the Committee prepared this white paper to solicit input from stakeholders on:

- the policies it recommends for further evaluation as outlined in its workplan;
- the Committee's recommended evaluation criteria;
- key issues or barriers to harmonization; and
- benefits that could accrue to the Partner jurisdictions and businesses that operate in more than one jurisdiction, if implementation is harmonized.

The Committee submitted the draft white paper for public review on December 1, 2009. The Committee held a webinar on December 7, 2009 to present the paper to stakeholders and clarify any questions they might have. At the end of the 60-day comment period on January 29, 2010, a total of 17 comments had been received. WCI carefully considered all public comments and amended the initial draft to produce a final white paper. Appendix 2 discusses

[1] The WCI GHG reduction goals, established in 2007, call for an aggregate reduction in the region of 15 percent below 2005 levels by 2020 and, over the long term, a reduction that significantly lowers the risk of dangerous threats to the climate. *See* http://www.westernclimateinitiative.org/component/remository/general/Emission-Reduction-Goal-Aug-2007/.

[2] *See* WCI, Appendix B: Economic Modeling Results, Sept. 23, 2008, at: http://www.westernclimateinitiative.org/component/remository/Economic-Modeling-Team-Documents/.

the comments received and provides WCI's responses. The specific comments can be reviewed at http://www.westernclimateinitiative.org/public-comments/document/14.

This paper also discusses why and when policies complementary to a cap-and-trade program are useful, how complementary policies help achieve the WCI's GHG reduction goals, and which policies would affect emissions under the cap and which would affect emissions from sectors and sources outside the cap.

1.1 The Role of Complementary Policies

The WCI Partner jurisdictions have designed an economy-wide, cap-and-trade program to reduce emissions in accordance with the WCI GHG reduction goals, while maximizing market efficiency in achieving those reductions. Putting a price on GHG emissions will result in investments in technologies and other actions that will reduce emissions. However, some activities that reduce emissions cost-effectively do not respond to this price signal: so-called market barriers prevent or impede the diffusion of cost-effective technologies and practices that could mitigate GHG emissions. The distribution of the costs and benefits of improving a building's energy performance is an instructive example of a market barrier. In commercial buildings, the cost of improvements is typically borne by the owners, however, the benefits are enjoyed by the tenants through lower energy bills. Because building owners do not realize directly the financial benefit from their efficiency investments, they are less likely to make those investments. A well designed energy efficiency program can provide the needed incentive to make those investments.

Complementary policies achieve a variety of objectives in addition to reducing GHG emissions and removing market barriers. They can:[3]

- Achieve reductions outside (or below) the cap
- Encourage investments in low-carbon technologies
- Lower the cost per metric ton of reductions in GHG emissions covered by the cap-and-trade program
- Lower the cost of transitioning to a low carbon economy
- Prevent emissions and economic leakage
- Create and retain clean energy jobs

Given the role complementary policies play in the transition to a low-carbon economy, a comprehensive program that combines a cap-and-trade program with targeted complementary policies will deliver emissions reductions at a lower cost to consumers, measured as the cost per ton of avoided GHG emissions.[4]

[3] Western Climate Initiative 2009-10 Workplan, updated June 23, 2009, p, 36.
[4] *See* Testimony of Richard Cowart, Regulatory Assistance Project, Before the Committee on Energy and Commerce Subcommittee on Energy and Environment, U.S. House of Representatives, April 23, 2009, "The Consumer

Complementary policies will interact with the GHG emissions cap differently at the start of the program than after it has begun. Prior to the commencement of the cap-and-trade program, complementary policies may reduce emissions at sources covered by the program, decreasing the overall emissions reductions required to be achieved by the cap-and-trade mechanism. As the cap-and-trade program begins in 2012, each partner's allowance budget will effectively incorporate prior reductions achieved through complementary policies.[5] Following the start of the cap-and-trade program, complementary policies can play an important role in helping facilities operate under the program in a cost-effective manner while also moderating allowance prices. For example, energy efficiency programs can address barriers to cost-effective investments and include programs that offer the following types of assistance:

- Information, education, marketing and technical assistance to make consumers aware of energy efficiency opportunities and the technical means to achieve energy reductions
- Grants and rebates to reduce the cost to the consumer of investing in energy efficiency products and services
- Financing to provide consumers with positive cash flow and the means to retrofit buildings or replace inefficient equipment that achieve future reductions and associated savings

The WCI Partners would also like to consider the potential benefits of harmonizing complementary programs among not only WCI jurisdictions, but also states and provinces that are not part of the WCI. This would require having them participate with the WCI organization as it moves forward in its evaluation of selected complementary policies.

1.2 Evaluating and Prioritizing Policies

The Committee's next step will be to more fully evaluate selected policies based on the following criteria, which are intended to help the Committee determine whether and how each policy should be harmonized and how each policy will help achieve WCI's emissions reduction goals:[6]

- The policy will reduce GHG emissions.
- The policy is expected to reduce costs associated with achieving the WCI goals for covered facilities.
- Administrative costs are expected to be manageable.
- Impacts on low-income communities or small businesses can be mitigated.
- Meaningful benefits to harmonizing implementation have been identified.

Allocation for Efficiency: How Allowance Allocations Can Protect Consumers, Mobilize Efficiency, and Contain the Costs of GHG Reduction," at http://energycommerce.house.gov/Press_111/20090423/testimony_cowart.pdf.

[5]Each jurisdiction's allowance budget will be calculated by using the best estimate of expected emissions for sources covered in the cap-and-trade program considering both voluntary and mandatory emission reductions through 2011, thus reductions achieved due to complementary policies will be reflected in each jurisdiction's starting allowance budget.

[6] Refinement of criteria in Western Climate Initiative 2009-2010 Workplan, p. 38.

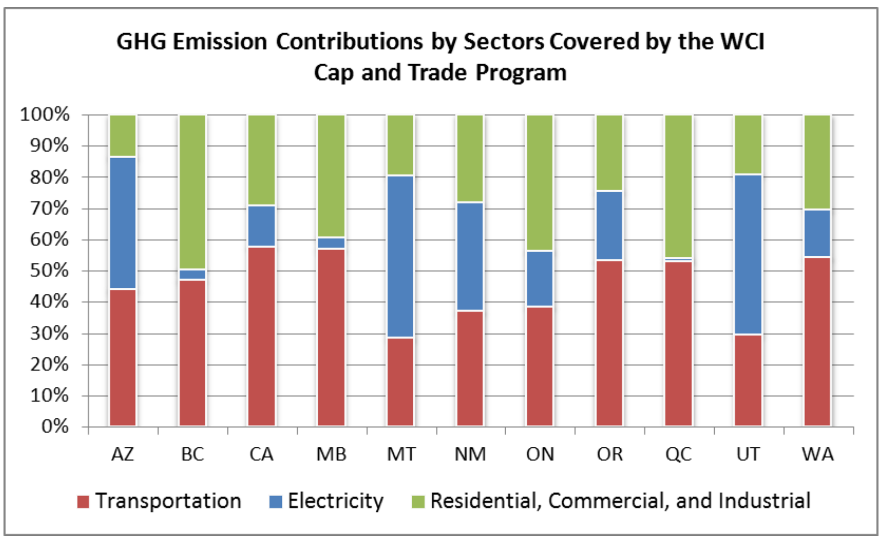
- Identified barriers to harmonizing implementation can be overcome.
- The policy addresses a perceived market failure.
- An opportunity to achieve collateral benefits (e.g., conserving water) has been identified.
- No collateral detriments (e.g., increased use of electricity that results in increased GHG emissions,[7] increased fine particulates or air toxics pollution) have been identified.
- The policy does not encourage leakage outside the cap.
- The policy has the potential to create or retain clean energy jobs or otherwise transition to a low-carbon economy.

These criteria are intended to help the Committee determine whether and how each policy should be harmonized and how each policy will help achieve WCI's emissions reduction goal.

After identifying an initial set of policies for further consideration, the Committee prioritized them using three tiers to assist with scheduling the Committee's work. Policies in the highest tier (Tier 1) will be evaluated first. The tiering of policies is based on the benefits of cross-jurisdictional harmonization, total GHG reduction benefits, and immediacy and ease of implementation (based on current or required efforts by jurisdictions). Tier 1 policies represent priority actions for the WCI Partners to consider because of their immediate impact in reducing GHG emissions and producing benefits from harmonization, and because they are currently underway or in development by multiple jurisdictions.

1.3 Policies Recommended for Evaluation

The accompanying graph shows for each WCI Partner jurisdiction the relative contribution of GHG emissions by each sector to be covered under the WCI cap-and-trade program.



Each of the WCI Partner jurisdictions has a climate action plan that delineates various policy instruments needed to achieve the jurisdiction's own emissions reduction goals or targets. The Committee used these plans to identify policies for consideration in this white paper. Listed below are the policies the Committee recommends for further evaluation.

[7] Where electricity substitutes for higher GHG-emitting transportation fuels, its increased use would be a benefit.

Energy Production

- Small-scale renewable energy resources (Tier 1)
- Combined heat and power (Tier 1)
- Hydropower (Tier 1)
- Emissions performance standards for electric generating units (Tier 1)
- Tradable renewable energy credits (Tier 2)
- Carbon capture and sequestration (Tier 2)

Energy Efficiency

- Energy efficiency targets (Tier 1)
- Energy efficiency programs and incentives (Tier 1)
- Energy savings credits (Tier 2)

Transportation

- Low-carbon fuel standard (Tier 1)
- Freight transportation infrastructure (Tier 1)
- Pay-as-you-drive insurance (Tier 2)
- Heavy-duty vehicle equipment (Tier 2)
- Electric and alternative fuel vehicle infrastructure (Tier 2)
- Vehicle emissions labeling (Tier 3)
- Medium- and heavy-duty vehicle hybridization (Tier 3)
- Transport refrigeration units (Tier 3)

Industrial Sector

- Emissions performance standards for major industrial sources (Tier 3)

High Global Warming Potential (GWP) Gases

- Regulatory measures for high GWP gases (Tier 1)

Agriculture

- Agricultural anaerobic digesters (Tier 2)

Waste Management

- Measures for landfill methane reduction (Tier 2)

Appendix A shows which of these complementary policies, if implemented, would reduce emissions from capped sources and sectors, and which policies would reduce emissions from uncapped sources and sectors.

It is important to note that many important complementary policy initiatives are not proposed to be evaluated by the Committee because they are being fully examined and developed in other venues. These other important policies are described briefly in Section 5 of this paper.

1.4 Next Steps

The Complementary Policies white paper was reviewed and approved by the WCI Partners on May 20, 2010 at their meeting in Seattle, Washington. The Complementary Policies Committee will next begin to evaluate the policies that are included in this paper to more fully identify the key issues and benefits. The Committee will evaluate necessary and available resources for next steps to address as many policies as practicable beginning with Tier 1 recommendations.

The Committee will also attempt to identify other related issues, such as needed jobs or skill sets to effectuate the policies. The outcome of the evaluation process will be design recommendations to facilitate regional harmonization of the policies.

The Committee will continue to engage stakeholders in future work and is currently developing an outreach plan to consider a number of options for doing so based on comments from stakeholders. The Committee also will produce reports that address two additional policy areas: 1) workforce transition, job creation, job retention and mitigation of community impacts associated with climate-related policies; and 2) climate change adaptation.

2 Tier 1 Policies

2.1 Energy Production

- Small-scale renewable energy resources
- Combined heat and power
- Hydropower
- Emissions performance standards for electric generating units

2.1.1 Small-Scale Renewable Energy Resources

Small-scale renewable resources include solar photovoltaic systems, solar water heating systems, community-scale wind turbines, geothermal systems, biomass digesters, micro-hydro systems, and generating systems that run on wood waste, agricultural waste, or waste gas from landfills or water treatment plants. These systems can help meet power and thermal energy needs and reduce GHG emissions. They can be installed at homes and businesses to supply on-site energy needs. In addition, utilities and third parties can build small-scale generating facilities as system resources for all customers.

Potential Policies. State/provincial policy options to address the barriers to small-scale renewable energy sources – many of which have been adopted in one or more WCI Partner jurisdictions – include the following:

Workforce training – Support for local and regional training programs may help ensure sufficient numbers of trained installers. Equipment and installer certification programs and random inspection of installations promote quality workmanship.

Public outreach and education – Public information can help consumers understand the benefits of small-scale renewable energy resources, how to undertake a project, and available assistance and funding options.

Uniform interconnection processes - Uniform technical standards, procedures and agreements can remove barriers and simplify the interconnection of small generators with utility systems, where appropriate. For projects with complex interconnection needs, reasonable timelines, fees and other requirements can be put in place for additional technical review and equipment that may be needed.

Power arrangements with the utility – Among the options:

- ‘‘Net metering” is a billing arrangement where the utility bills the customer only for the difference between the energy consumed at the premises and the energy produced by a qualifying system at the site. Any excess energy produced flows onto the utility grid for use by other customers, eliminating the need for the customer to have on-site storage or to to arrange for power sales to third parties. While net metering programs are widespread, many do not require all utilities in a state to participate or include all customer classes. Programs also may be constrained by low limits for individual project size and aggregate capacity, payment provisions for excess energy, insurance and equipment requirements, standby rates, and restrictions on third-party ownership of systems.[8]

- The Public Utility Regulatory Policies Act (PURPA)[9] requires utilities in the U.S. to interconnect with and purchase all capacity and energy from "Qualifying Facilities" up to 80 megawatts (MW) that use eligible renewable resources[10] at rates equal to the cost of the utility's avoided resource (for example, market purchases or a natural gas-fired power plant). States have broad discretion in implementing PURPA. Among the provisions for successful state programs are long-term contracts with fixed rates, standard avoided cost rates, commission-approved standard contract forms for small-scale projects, and methods for determining avoided costs that fully account for the value of the renewable energy to the utility system.
- Feed-in tariffs (FITs), also known as Advanced Renewable Tariffs, can provide rates that make it attractive for electricity to be produced by third parties (non-utilities) using renewable resources. Rates may vary by technology, geographic location and project size. FITs can encourage development of a variety of renewable energy projects. Like PURPA, FITs guarantee the right to interconnect and a buyer for the electricity, and payment is based on actual production. However, FIT rates are based on the cost of renewable energy generation, not the utility's avoided resource. Typically included in FIT rates is a return on investment sufficient to make the project worthwhile for investors.
- Targeted procurement of small-scale renewable energy resources that recognizes their unique benefits can incorporate many of the same features as a FIT, such as a must-take obligation and standard contract terms, but allow for market-based pricing through a reverse auction or similar mechanism.

Standby rates – Practices include cost-based rates, providing customer-generators choices for firm and non-firm service, including daily rates, allowing them to self-supply reserves and assure instantaneous load reductions to avoid standby charges, and providing supplemental power and maintenance service – with appropriate advance notice – at the customer's otherwise applicable tariff rate.

Utility resource planning and procurement – Utility resource planning and procurement often does not evaluate and include small-scale renewable resources for meeting generation and transmission needs. Similarly, the value of distributed generation typically is not considered in distribution system planning. Including distributed generation in utility

[8] A third party pays the upfront cost of the system; builds, installs and owns it for a specified term; takes advantage of tax, depreciation and other financial incentives; and sells the energy to the consumer hosting the system. The consumer reduces its bills through a net metering agreement with the utility. This financing model is especially important to local governments, schools, churches and others that cannot raise the capital for the project or take advantage of some government incentives.

[9] U.S. Public Utility Regulatory Policies Act, 16 U.S.C. § 824a-3.

[10] And qualifying cogeneration facilities of any size.

planning and acquisition processes helps states and provinces examine whether and how to use these resources to meet energy, capacity, distribution and transmission system needs.

Decouple utility sales from utility profits - "Decoupling" removes the link between utility sales and revenue so that the utility is indifferent to, rather than financially harmed by, customer-side distributed generation and efficiency measures.[11] Under decoupling, retail customer rates established to recover fixed utility costs are adjusted periodically to keep utility revenue at the level allowed by regulators.

Key issues to consider in developing small-scale renewable energy resources include:

- **Interconnection** – In the U.S., states generally have jurisdiction over interconnection (and sales) between customer-sited generation and retail electric utilities.[12] Utility interconnection processes may result in undue delays in gaining approval of applications, as well as undue costs associated with insurance and equipment which, upon closer examination, regulators may find unnecessary.

- **Power sales** – Utility procurement generally does not adequately consider small-scale distributed systems, despite their potential advantages, such as more rapid deployment and lower development risk compared to large projects. Small systems may not meet the minimum bid size for utility competitive bidding processes and wholesale markets, and the market for aggregation of small systems is immature. In addition, the prices utilities pay for renewable energy may be too low to drive significant development of small-scale systems.

- **Standby rates** – Unless prohibited by regulation, utilities may charge customer-generators special rates for back-up power when their on-site generator isn't running and for supplemental power to meet the customer's energy needs beyond the generator's capacity. Unless properly designed, standby rates can render a project uneconomic.

- **Utility planning** – Utility resource planning typically does not adequately evaluate and include small-scale renewable resources for meeting generation and transmission needs. Nor is the value of distributed generation typically considered in distribution system planning, where it could have especially high value in deferring costly upgrades to meet capacity needs in specific locations. Furthermore, those locations are not revealed to consumers or the marketplace.

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[11] *See* National Action Plan for Energy Efficiency, *Aligning Utility Incentives With Investment in Energy Efficiency*, November 2007, at http://www.epa.gov/cleanenergy/energyprograms/napee/resources/guides.html; Regulatory Assistance Project, *Revenue Decoupling Standards and Criteria: A Report to the Minnesota Public Utilities Commission*, June 2008, at http://www.raponline.org/Pubs/MN-RAP_Decoupling_Rpt_6-2008.pdf.

[12] The Federal Energy Regulatory Commission has jurisdiction over interconnection of generating facilities for wholesale sales.

- **Utility disincentives** – Utilities recover a large amount of their fixed costs through volumetric rates. When customers develop on-site generation, utility revenue declines. Because so many of the costs of providing utility service do not change in the short run, a small reduction in sales due to customer-side resources can result in a disproportionately large reduction in utility earnings. Also, utilities typically do not earn a return on non-utility resources, nor can they make profits on them through operational efficiencies.

- **Cost** – Homeowners, businesses, local governments and others may have difficulty securing financing at favorable terms. And without subsidies, it may take too long for the investment to pay back.

- **Trained workforce** – Successful programs require a trained workforce to properly size, select and install equipment. If installers are in short supply, the consumer's interest in developing a project may pass.

- **Consumer awareness** – Most consumers are not aware of the benefits of small-scale renewable energy resources, how to undertake a project, and available assistance and funding options.

Benefits to harmonizing. Harmonizing these policies could build a larger market for small-scale renewable energy resources. It also would allow manufacturers to build equipment to meet a uniform set of standards accepted across a large region, make it easier for installers operating in multiple jurisdictions to understand interconnection and program requirements, and facilitate regional marketing of renewable energy systems.

2.1.2 Combined Heat and Power

This section was added after review of stakeholder comments.

About two-thirds of the energy content of the fuel used to generate power in the U.S. is wasted through conversion and line losses.[13] Combined heat and power (CHP), or cogeneration, sequentially produces both electric power and thermal energy.[14] Compared to traditional thermal electricity production, CHP can be viewed as an energy production or energy efficiency measure to reduce GHG emissions. Located at customer sites, CHP improves energy efficiency in two ways:[15]

1. Increasing fuel-use efficiency – Heat produced in the electric generation process that otherwise would be wasted is used for process or other thermal needs.

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[13] Anna Shipley, Anne Hampson, Bruce Hedman, Patti Garland and Paul Bautista, *Combined Heat and Power: Effective Energy Solutions for a Sustainable Future*, Oak Ridge National Laboratory, Dec. 1, 2008, at http://www1.eere.energy.gov/industry/distributedenergy/pdfs/chp_report_12-08.pdf.

[14] Related, "waste energy recovery" generates additional electricity from waste heat from industrial processes.

[15] According to the U.S. Department of Energy, separately producing heat and power has a typical combined efficiency of 45 percent. CHP systems can operate at efficiency levels as high as 80 percent. *See* http://www1.eere.energy.gov/industry/distributedenergy/chp_basics.html.

2. Eliminating energy lost in delivering power – Electricity is produced on-site, so none is lost over transmission and distribution lines.

Compared to producing and delivering power from a remote power plant and separately producing steam or heat, overall energy required to produce the same amount of electric and thermal energy is reduced by about a third.[16] That efficiency savings translates into significant carbon savings.[17] Some states participating in the Regional Greenhouse Gas Initiative (RGGI) explicitly recognize the CO_2 emissions avoided by CHP units and reward them with allowances.[18]

CHP units are fueled by natural gas, other fossil fuels or local, renewable biomass resources. The units come in a wide range of sizes and technologies, including reciprocating engines, combustion or gas turbines, steam turbines, microturbines and fuel cells. The vast majority of CHP installations are in the industrial sector, but CHP also is used in commercial buildings and homes.

To advance CHP, WCI Partner jurisdictions can consider the policies discussed in this paper for small-scale renewable energy resources:

- Net metering programs can be applied to small-scale CHP.
- Federal PURPA law applies to CHP facilities of any size that meet efficiency requirements, as well as to renewable resources.
- Feed-in tariffs or targeted procurement could provide higher power purchase rates and long-term contracts for CHP, recognizing its energy efficiency and CO_2 benefits.
- Improvements in standby rates and interconnection processes are just as important for CHP as for renewable resources.
- CHP can be explicitly considered in utility planning and acquisition processes for energy, capacity, transmission and distribution.
- Decoupling can mitigate the disincentive for utilities to facilitate customer- or third party-owned CHP, which reduces utility sales and profits.

In addition, WCI Partner jurisdictions can consider including CHP as an eligible resource for meeting energy efficiency resource standards[19] and including waste energy recovery as an eligible resource for renewable portfolio standards – already the practice in some states.

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[16] *See* http://www.energy.ca.gov/distgen/equipment/chp/performance.html.

[17] One analysis found that a small, energy-efficient gas-turbine CHP unit could reduce CO_2 emissions by about half, compared to generating power at the average U.S. fuel mix plus and separately producing heat from a natural gas-fired boiler. *See* Shipley, *et al.*

[18] For example, a certain amount of allowances are directly awarded or sold at a fixed price in Connecticut (5 percent) and Maine (13 percent). *See* section 22a-174-31, Control of Carbon Dioxide Emissions, at http://www.ct.gov/dep/lib/dep/air/regulations/mainregs/22a-174-31.pdf, and Chapter 156: CO_2 Budget Trading Program, at http://www.maine.gov/dep/air/greenhouse/rggi.htm. The RGGI model rule contains no formula for quantifying useful steam from CHP systems. Instead, a showing to environmental regulators is made in accordance with section XX-8.8 of the model rule. *See* http://www.rggi.org/docs/model_rule_corrected_1_5_07.pdf.

[19] *See* page [31].

Key issues to consider in promoting CHP resources include the same issues for small-scale renewable resources, such as:

- Interconnection barriers
- Difficulty selling power to utilities
- Standby rate design
- Lack of consideration in utility planning
- Utility financial disincentives to facilitate CHP
- Compatibility with non-industrial land uses and zoning

A number of issues are somewhat unique to CHP applications in the industrial sector and point to the need for financial incentives:[20]

- Cost – Industrial projects generally require a very short payback, and upfront costs for CHP are high compared to short-term savings. Installing CHP interrupts industrial processes, another project cost.
- Competition with other capital needs - Corporate capital budgeting processes place CHP in direct competition with investments that expand production, increase throughput or maintain overall plant reliability.
- Financing – Industrial companies often cannot finance CHP investments in-house and have limited outside financing options.

Benefits to harmonizing. CHP-related policies are similar to those for small-scale renewable resources. In addition, because most CHP is installed in industrial facilities, improving uniformity of regulatory and incentive programs across jurisdictions would facilitate CHP adoption by companies operating in multiple states and reduce competitiveness issues among states and provinces.

2.1.3 Hydropower

This section was added after review of stakeholder comments.

Hydropower uses stream flows and gravity to propel water through a turbine to generate electricity. Hydropower is typically a very low-cost form of electricity because there are no fuel costs and low operating costs, and it produces low or no emissions. However, due to the nature of dam construction and the potential disruption of natural stream flows, there are challenges regarding impacts to local populations, fish, wildlife and ecosystems are and must continue to be considered.

Hydropower plays a prominent role in the energy portfolios of many of the WCI jurisdictions. Emissions and economic benefits can be increased by acquiring incremental capacity from existing dams, improving efficiency at current hydropower facilities and examining the potential for new, small-scale or low impact, run-of-the-river facilities. In response to stakeholder

[20] *See* Bob Hinkle and Steve Schiller, *New Business Models for Energy Efficiency*, CalCEF Innovations whitepaper, March 2009, at http://eec1.ucdavis.edu/techsummit2-0/NewBusinessModelsforEE-WhitePaper.

comments, the Committee felt that a recommendation on hydropower should be included in this white paper for further consideration.

Potential Policies. Potential state/provincial policy options to address barriers to increased efficiency and production from hydropower facilities in an environmentally responsible manner include the following:

- Evaluate expanding eligibility for low-impact hydropower for state/provincial renewable portfolio standards; for example, including installing generation capability at dams that do not produce power today, increasing electricity generation efficiency at current hydropower facilities and developing small-scale, run-of-the-river facilities.
- Enhance coordination between state resource agencies issuing certifications under Section 401 of the U.S. Clean Water Act and the Federal Energy Regulatory Commission's licensing/exemption proceedings. Licensing of Canadian hydroelectric facilities will continue under processes administered by the Provinces.
- Consider the climate change benefits of hydropower projects when permitting agencies evaluate or consult on such projects.
- Consider a task force of state/provincial agencies on licensing for certain low-impact hydropower projects. For example, the task force could make recommendations regarding the addition of power generation to an existing non-hydroelectric dam, closed-loop hydropower storage and other types of projects deemed low impact by the state or province. The task force could facilitate state/provincial agency participation in any applicable state permitting processes and the federal licensing process.

Key issues to consider in developing these policies include:

- Mitigating adverse impacts to ecosystems and wildlife
- Administrative or legislative changes that may be needed to expand hydropower eligibility for state/provincial RPS and other renewable energy programs
- A coordinated approach with federal permitting agencies to ensure a consistent and streamlined process
- The potential impacts to hydropower from increased or decreased water supply due to climate change
- Potential options for low-impact hydropower and the potential role for organizations that certify such projects

Benefits to harmonizing. Harmonizing state/provincial policies on hydropower will provide a consistent market signal to potential developers on its role in programs such as RPS and securing low carbon renewable electricity to meet GHG reduction targets. The streamlining and standardizing of permitting requirements will reduce barriers to projects and the overall time needed for project completion. Forming a state/provincial task force to develop parameters and expectations for low-impact hydropower projects can help to identify innovative and transferable solutions to increasing hydropower production and efficiency in a manner that minimizes environmental impact.

2.1.4 Emissions Performance Standards for Electric Generating Units

An emissions performance standard (EPS) sets a maximum level of GHG emissions per unit of output. An EPS for electric generating units is designed to “raise the bar” for the emissions performance of each power plant, analogous to efficiency standards for appliances. Through the use of an EPS requirement, the construction of high-emitting generating resources with long expected useful lifetimes may be avoided. Similarly, new long-term contracts with existing high-emitting generating resources may be prevented. As a consequence, an EPS may reduce ratepayers’ financial and reliability risks associated with plant retirements, retrofits and emission allowance and offset costs under future emission control regulations. An EPS can also promote technological innovation to advance new power generation systems and to modify existing facilities in order to meet the standard.

An EPS should be considered in conjunction with a cap-and-trade program if:

1. Market prices for electricity increase to an unacceptable level to change the generation dispatch order or to induce new investments and technological advancements in clean generation at a sufficient rate or magnitude to meet GHG emissions reduction goals.
2. The level of carbon “leakage” outside the cap-and-trade region is unacceptable.

Key issues to address in designing an EPS for electric generating units include:

- The appropriate EPS performance level (emissions rate)
- The point of regulation e,g, generators or distribution companies that serve load;
- How broadly the EPS should be applied, e.g. electricity produced within the jurisdiction only or imported power as well
- The type of facility or commitment that should be subject to the EPS
- Whether it applies to new construction only, and/or new investments in existing facilities that expand rated capacity for their effective useful life
- Whether it applies only to facilities underlying long-term contracts or also to short-term contracts
- Determining the facility threshold, i.e. MW size or capacity factor
- The state of technology and the degree to which it can be pushed
- Start date and implications of building current-technology power plants that will not qualify under the EPS
- Calculation of net emissions for combined heat and power and biomass facilities
- Potential for carbon capture and storage

Benefits to harmonizing. Harmonized EPS policies and standards design would promote consistent signals to the market across a broad geographic region concerning GHG emissions performance for generating units. This would drive technological advancement in low-carbon solutions within a specific timetable linked directly to the carbon reduction goals for the electricity sector.

This policy has already seen a great deal of harmonization in the Western jurisdictions of the WCI. The states of California, Oregon and Washington have enacted similar EPS laws.[21] In addition, Montana has adopted a law imposing restraints on emissions from new coal plants in certain cases.[22] British Columbia requires carbon capture and storage for any new coal-based generating facility.[23]

2.2 Energy Efficiency and Conservation

- Energy efficiency targets
- Energy efficiency programs and incentives

2.2.1 Energy Efficiency Targets

Energy efficiency targets are used by policy makers to set performance goals – binding or voluntary – for energy efficiency investments and savings. The targets may apply to states or provinces, utility companies or third-party administrators of programs.

Energy efficiency targets take various forms. Energy Efficiency Resource Standards (EERS) establish long-term efficiency targets that are typically expressed as a percentage reduction compared to retail energy sales over a baseline period. Both annual and cumulative energy savings targets may be included. Standards may apply to both electricity and natural gas, and they may target reductions in peak electricity demand as well as energy usage overall. EERS are already in place in many states and federal standards have been proposed.[24]

Energy savings generally are achieved through end-use efficiency programs. In some states, savings from building codes, appliance efficiency standards, combined heat and power facilities, and distribution system efficiency improvements also may count toward meeting the standard.

Instead of expressing savings targets as percentages or absolute (e.g., megawatt-hour) savings figures, some states and provinces have made a commitment to acquire all cost-effective

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[21] California SB 1368: http://www.energy.ca.gov/emission_standards/documents/sb_1368_bill_20060929_chaptered.pdf; Oregon SB 101: http://www.leg.state.or.us/09reg/measpdf/sb0100.dir/sb0101.en.pdf; and Washington SB 6001: http://apps.leg.wa.gov/billinfo/summary.aspx?year=2007&bill=6001.

[22] 69-8-421 MCA: http://data.opi.mt.gov/bills/mca/69/8/69-8-421.htm

[23] Bill 31: http://www.leg.bc.ca/38th4th/3rd_read/gov31-3.htm.

[24] In the U.S., for example, the American Council for an Energy-Efficient Economy (ACEEE) reports that 19 states have adopted an EERS requiring achievement of specified energy savings targets. In addition to strict EERS requirements, ACEEE includes states with Commission-ordered efficiency targets, states that allow efficiency to count toward renewable energy standards, and states with a rate cap triggering a relaxation of EERS requirements. *See* Laura A. Furrey, Steven Nadel, and John A. "Skip" Laitner, ACEEE, *Laying the Foundation for Implementing a Federal Energy Efficiency Resource Standard*, March 2009, at http://aceee.org/pubs/e091.htm. Bills pending in the 111th U.S. Congress would establish a national EERS. The United Kingdom and several Australian states are among jurisdictions outside the U.S. that have mechanisms similar to an EERS.

energy efficiency or achieve zero load growth through energy efficiency programs. Such efficiency targets can be articulated as part of a utility's integrated resource planning process and incorporated into applicable regulations. The suitability of subsequent utility acquisitions would be measured against that goal.

Energy efficiency targets also can be articulated in contracts or informal proceedings between the jurisdiction and a third-party efficiency provider. In some cases, the third-party provider is remunerated, in part, for achieving savings above the specified targets.

Key issues to consider in setting and achieving energy efficiency targets include:

- Savings potential (as assessed by a resource potential study)[25]
- Performance levels (e.g., percentage rate of savings)
- Baseline measurement (i.e., the starting point)
- Cost-effectiveness tests in screening individual efficiency programs or a portfolio of programs
- Utility disincentives to achieving stated goals[26]

Benefits to harmonizing. Energy efficiency targets include helping promote consistent signals to a broader market. Standardized requirements could be expected to reduce implementation barriers and costs for companies operating in multiple states.

2.2.2 Energy Efficiency Programs and Incentives

Energy efficiency programs are business plans or market mechanisms that address barriers to cost-effective investments. Programs can be run by the utility, the state or province, or a third-party administrator. Program costs can be integrated into the utility's cost of service, such as other resources, or be paid for through a separate charge on customer bills. The goal of a well-designed program is to motivate action by the targeted decision-makers – consumers, suppliers, stores or contractors – while minimizing program costs.

Energy efficiency investments can reduce total utility system costs[27] and avoid the use of fossil fuels and associated GHG emissions. Studies continue to find a vast potential of cost-effective

[25] A resource potential study assesses the technical and market potential for energy efficiency efforts and lays the foundation for developing appropriate savings targets. Results generally show achievable potential far in excess of current program scope.

[26] *See* decoupling discussion on page 7 and Regulatory Assistance Project, "The Role of Decoupling Where Energy Efficiency Is Required by Law," September 2009, at http://www.raponline.org/Pubs/RAP_Schwartz_IssuesletterSept09_2009_08_25.pdf.

[27] Preliminary research by ACEEE indicates average program costs of about 3 cents per kilowatt-hour saved and 29 cents per therm saved. (*See* Steven Nadel, ACEEE, Replies to Questions at the April 22, 2009, Hearing on Energy Efficiency Resource Standards, May 12, 2009, at http://aceee.org/tstimony/NadelQuestions04.22.09.pdf.) That's far less than the cost of new generating facilities. Efficiency investments also can avoid expensive upgrades to transmission and distribution systems.

efficiency remaining to be tapped.[28] Securing this potential could dramatically reduce electricity demand and significantly reduce the cost of meeting emissions reduction goals.

Policies include providing programs that offer the following types of assistance:[29]

- **Information, education, marketing and technical assistance** – Information on-line and at point of sale, branding (e.g., Energy Star), phone hotlines, workshops, multi-media advertising, on-site audits, field visits, training, certification and inspections are among the ways programs can increase awareness, knowledge and confidence among consumers, vendors and contractors.
- **Grants and rebates** – Financial incentives can reduce the cost to the consumer of investing in energy efficiency products and services. The incentive amounts are justified by a benefit-cost analysis and can be linked to the desired effect – for example, the number of targeted products installed by a certain date.
- **Financing** – Long-term financing of energy efficiency investments can provide consumers with positive cash flow. Financing strategies may focus on "lost opportunities," such as new buildings and new equipment, or they may provide consumers with the means to retrofit buildings or replace inefficient equipment. For example, some programs allow homeowners to add the cost of certain efficiency improvements to their mortgage, extending the repayment period.

Energy efficiency programs can include some form of "market transformation" – changing the way people make energy-related decisions or making efficient products and services widely available. Some programs are devoted exclusively to these purposes. Other programs focus on hard-to-reach sectors, such as multi-family housing and low-income households.

Programs to reduce energy consumption may be more compatible with a utility business structure that decouples utility sales from utility profits and includes performance incentives. Decoupling removes a utility's inherent *disincentive* to sell less of its product. Decoupling does not provide an *incentive* for the utility to acquire energy efficiency in lieu of supply-side alternatives that earn a return on investment. Where aggressive energy efficiency goals are in place, regulators may consider providing financial incentives to utilities for exceptional performance. Many utility commissions have adopted decoupling, incentive mechanisms, or both for electric and natural gas utilities.[30]

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[28] For example, the recent McKinsey study found the U.S. has the potential to cost-effectively reduce non-transportation energy consumption roughly 23 percent by 2020. *See* www.mckinsey.com/USenergyefficiency. The Northwest Power and Conservation Council recently estimated achievable, cost-effective conservation in the four-state region (Idaho, Montana, Oregon and Washington) at 21percent of 20-year forecasted (medium-case) electric load – an amount that would meet about 85 percent of load growth in the region while significantly reducing both system cost and risk. *See* http://www.nwcouncil.org/energy/crac/Default.htm.

[29] Building codes, appliance standards, and new energy efficiency technologies are addressed briefly at the end of this paper.

[30] For maps showing status of decoupling in the U.S., *see* http://www.raponline.org/docs/NRDC_Decoupling%20Maps%20US_2009_08.pdf. For examples of incentive mechanisms and modeled results, *see* Chuck Goldman, Peter Cappers, Michele Chait, George Edgar, Jeff Schlegel and Wayne Shirley, "Financial Analysis of Incentive Mechanisms to Promote Energy Efficiency: Case Study of a Prototypical Southwest Utility," report to the Ernest Orlando Lawrence Berkeley National Laboratory, March 2009, at http://eetd.lbl.gov/EA/EMP/ee-pubs.html.

Key issues to consider in developing these policies include:

- High upfront cost, long payback on investment, and limited financing options
- Short windows of investment decision-making opportunity are easy to miss
- Trained workforce may be in short supply
- Limited public awareness, information and knowledge
- "Split incentives" between builders/building owners and tenants who pay the utility bills
- Resource planning and acquisition processes that don't evaluate energy efficiency on a par with supply-side alternatives
- Utility disincentives to encouraging energy efficiency

Benefits to harmonizing. Energy efficiency programs among the WCI jurisdictions and other states and provinces include reducing costs, helping to transform markets for energy efficiency products, technologies and practices, and achieving greater energy savings and GHG reductions. Regional programs can achieve economies of scale that are not possible with isolated programs. Working together, utilities and other program administrators can leverage personnel and funds for resource potential studies, regional marketing and training, developing a broad supply chain of products and services, robust evaluation of programs, and verification of estimated energy savings. Consistent program features and requirements also make it easier for vendors and contractors to participate.

Many programs rely on a common set of product and service specifications developed by the ENERGY STAR program. Some states already coordinate on energy efficiency assessments, strategy, model standards, programs, and common protocols for evaluating, measuring and verifying program results through such organizations as the Northwest Power and Conservation Council[31] and Northwest Energy Efficiency Alliance[32]. These efforts could be expanded to include a broader set of jurisdictions. Multi-state utilities offer similar programs throughout their service areas.

2.3 Transportation

- Low-carbon fuel standard
- Freight transportation infrastructure

2.3.1 Low-Carbon Fuel Standard

A Low Carbon Fuel Standard (LCFS) is a GHG emissions standard for transportation fuels. An LCFS provides a method for calculating the carbon intensity of fuels and requires fuel providers to reduce over time the carbon intensity of the fuels they sell. The carbon intensity calculation is typically based on *life-cycle carbon emissions* for each fuel type. An LCFS is designed to be technology-neutral across alternative transportation fuels, including electricity, biofuels and hydrogen, provided that it facilitates a reduction in GHGs (relative to a baseline target). Fuel

[31] http://www.nwcouncil.org/Default.htm
[32] http://www.nwalliance.org/

providers have the flexibility to provide the lowest priced mix of low-carbon fuels that achieves the intensity standard. This approach differs from a renewable fuel standard, which mandates production volumes of certain renewable fuels instead of a specified carbon intensity reduction target.

The State of California has adopted an LCFS program. Oregon recently passed legislation directing the Department of Environmental Quality to develop an LCFS. British Columbia's Greenhouse Gas Reductions (Renewable and Low Carbon Fuel Requirements) Act will be implemented through two regulations: 1) the Renewable Fuel Requirement Regulation, which requires fuel suppliers to meet an annual, provincial average of 5 percent renewable content for gasoline and diesel fuels; and 2) the proposed Low Carbon Fuel Requirement Regulation (LCFRR), which would require that the carbon intensity of transportation fuel sold in the province be reduced 10 percent by 2020. The LCFRR would require suppliers to provide transportation fuels with average carbon intensity less than or equal to annual target values beginning in 2010. The State of Washington is evaluating whether a LCFS should be adopted there.

Key issues to consider in designing an LCFS include:

- Carbon intensity reduction goals and schedule
- Interaction of an LCFS with the regional cap-and-trade system, including issues such as consistency of signals to industry under the two systems, potential for double counting of emissions reductions, and within-region vs. outside-region emissions reductions;
- Point of regulation (for example, should fuel companies be held responsible for increasing use of electric vehicles?)
- Cost to the public and businesses
- Current and expected regional capacity to produce sufficient low-carbon alternative fuels and opportunities for increasing capacity[33]
- Potential for commercialization of vehicles that can use low- or no-carbon fuels
- Development of a regional low-carbon fuel credit program
- Consistency in estimating lifecycle carbon intensities, considering fuel mixes, land use issues and other factors
- Options for minimizing the cost of compliance
- Potential use of compliance deferrals to address issues such as fuel shortages, fuel quality problems and significant spikes in fuel costs
- Refueling infrastructure to support an LCFS
- Environmental and health impacts beyond GHG reductions
- Local needs and conditions
- Fuel standards, certification and other product fungibility issues
- International trade agreements
- Coordinating with national mandates such as the revised U.S. Renewable Fuel Standard

[33] Regional capacity may be important from an economic impact perspective.

Benefits to harmonizing. LCFS policies and program design include consistent requirements among states and provinces that participate in the same fuel markets. Looking at the future needs for regional low-carbon fuel capacity may promote coordinated investment and economic opportunities. Regional harmonization could also provide a useful model for any national LCFS program.

2.3.2 Freight Transportation Infrastructure and Heavy Duty Vehicles

West Coast ports are North America's links to the rapidly growing Asian economies. The amount of goods imported and exported through these ports will continue to grow. Similarly, transborder freight transportation is a significant component of the economies of the WCI jurisdictions as U.S.-Canada surface transportation trade totalled $29.2 billion in May 2009. The continued growth in marine, air, rail and road transport activity poses a challenge to policy makers seeking to reduce GHG emissions. In addition, overlapping jurisdictions among many levels of government results in regulatory challenges for operators.

Many transport sectors have agreed that the solution lies in coordinating, rather than competing, on environmental issues. This is particularly relevant for areas such as the West Coast, where shippers have a choice among numerous air and marine ports of entry and land-based carriers. Through coordinated improvements and standards, states, provinces, port authorities and private carriers can justify investment in environmental improvements, without the fear that business will be lost to a higher-emitting, but lower cost competitor.

Examples of potential regional coordination on freight transportation and heavy-duty vehicles include the following:

- Jurisdictions could adopt requirements such as the U.S. Environmental Protection Agency (EPA) model rule to reduce heavy-duty truck idling during rest stops to facilitate a uniform approach. Outreach and financial assistance programs could promote energy-efficient and cost-effective alternatives such as auxiliary power units and truck stop electrification. A viable electrification network requires action by multiple jurisdictions to be effective.
- Ocean- and river-going vessels at dock usually run onboard diesel generators for "hotel" power. Using power from the electric utility grid is less expensive, but it may be necessary for multiple ports to provide connection facilities on-shore to make it cost-effective for vessels to install capability to connect to those facilities. WCI members California, Washington and British Columbia have installed on-shore power facilities using the best available and most compatible technology. A regional approach also could help eliminate competitiveness concerns among ports providing on-shore power.
- Smaller engines to provide hotel power, new engine technologies, and electronic start/stop controls are available to reduce pollution from locomotives, which often idle for extended periods of time. A regional approach could coordinate incentives and address jurisdictional issues for cleaning up switchyards and long haul locomotives.

- Most trucks built during the last decade are equipped with a speed limiter – an integrated circuit that allows for regulating maximum vehicle speed. Policies could include the mandatory use of speed-limiting devices, equipment for aerodynamic efficiency, supporting the introduction of new energy-efficient and GHG-reducing technologies, and instituting an inspection and maintenance program for heavy-duty trucks in jurisdictions throughout the WCI jurisdictions and in other states and provinces.

Key issues to consider for freight transportation infrastructure and heavy-duty vehicles include:

- Competitiveness among ports for docking of ocean and river-going vessels
- Lack of consistent regulations, penalties and funding programs among states and provinces with respect to anti-idling to encourage investment while avoiding impacts on trade competitiveness
- Standards for port electrification under development by the International Maritime Organization and their broader use with increasing certainty regarding the final standards
- High upfront cost, long payback on investment, and limited financial resources and incentives to fund research, development and implementation of new technologies
- Need for public-private partnerships and investments to develop a network of low-carbon fuel and electrififcation instrastructure to support heavy-duty trucks and port operations
- Programs developed by the American Trucking Association to reduce GHG emissions from freight movement, which can be implemented and enhanced through coordinated action by states and provinces
- The burden posed by differing requirements on the majority of heavy-duty vehicles, which travel between states and provinces or issues that may raise interstate commerce concerns
- Cost impacts of potential policies on individuals and small companies that own heavy-duty vehicles

Benefits to harmonizing. Policies include improving uniformity of regulatory and incentive programs, reducing competitiveness issues among states and provinces, leveraging incentives, and addressing jurisdictional issues with interstate freight movement. Because many trucking companies, trains and marine vessels operate between WCI Partner jurisdictions, regional coordination could also help identify or prevent instances where one jurisdiction's compliance mechanism may cause emissions increases in other jurisdictions. A regional approach to on-shore power would allow for pricing strategies to encourage its use, without affecting the competitive balance. Regional strategies to reduce GHG emissions from the freight transportation sector would produce multi-pollutant benefits, reducing toxins, sulfur dioxide, nitrogen oxides and fine particulates.

2.4 High Global Warming Potential (GWP) Gases

2.4.1 Regulatory Measures for High GWP Gases

High GWP gases are of growing concern due to their increasing rate of emissions and persistence in the atmosphere. These gases from anthropogenic sources are released as byproducts of industrial operations, primarily from electric power transmission and distribution, aluminum smelters, semiconductor manufacturing, production of insulating foam, and magnesium smelters and die-casters. High GWP chemicals also are used in many applications such as refrigeration, air conditioning and fire suppression. Typically, emissions of high GWP gases from processes and products are individually too small to be covered by the WCI cap-and-trade program. Nevertheless, just a few pounds of these materials can have the equivalent effect on global warming as several *tons* of CO_2.

Voluntary partnerships between EPA and industry are substantially reducing emissions of high GWP gases. For example, 81 utilities are participating in a voluntary program to reduce emissions from SF_6 used for insulation of electric transmission and distribution equipment. EPA publishes lists of acceptable substitutes for high GWP gases.

Key issues to consider for reducing emissions of high GWP gases include:

- Long timeframe for transitioning to safe and acceptable substitutes that offer lower overall risks to the environment and human health
- Removal and disposal of high-GWP gases
- Voluntary nature of existing programs
- Sizable expansion that is occurring in many industries that emit high-GWP gases

Benefits to harmonizing. Measures to reduce high GWP gases include reducing burdens on consumers and manufacturers while encouraging a broader market for lower-emitting substitutes. Regional programs can achieve economies of scale that are not possible with isolated programs. Regional harmonization may promote coordinated investments for research and development of alternatives. Harmonized policies could include design and funding of programs for capturing and disposing of high GWP gases, incentives for upgrading to newer products in order to more rapidly remove products with high GWP gases from circulation, and establishing specifications for the use of high GWP gases in newly manufactured products.

3 Tier 2 Policies

3.1 Energy Production

3.1.1 Carbon Capture and Sequestration

Carbon capture and sequestration (CCS) is a key technology that may for sustained emissions reductions in the electricity sector.[34] It involves four five steps: 1) separating CO2 before or after combustion of fossil fuels; 2) compressing the CO2 stream; 3) transporting it to an injection site; and 4) pumping it into underground geologic formations in a manner that prevents its release into the atmosphere and 5) long term monitoring and insurance to certify the sequestration.

Given the technical, institutional and legal risks, putting a price solely on CO_2 emissions may be insufficient to advance CCS deployment. Additional policies for the capture, transport, injection, monitoring and liability of the sequestered CO_2 are needed. Utility resource policies that mandate or promote CCS may be appropriate – such as emissions performance standards[35] – as well as innovative policies for siting and permitting, financing and rate-making.[36] State and provincial policy options to advance CCS include the following:[37]

Managing transport and sequestration – Current rules for transport and injection of CO_2 are for enhanced oil recovery and CCS pilot projects, not large-scale CCS deployment. Existing pipeline laws must be adapted for CO_2 transport. A standard template, such as the one produced by the Interstate Oil and Gas Compact Commission,[38] may be useful for the development of rules for geologic sequestration of CO_2. Further options could accelerate CCS deployment, such as pre-screening and pre-qualifying the best CO_2 pipeline and injection sites and simultaneously reviewing permit applications for the power plant, CO_2 pipeline and injection infrastructure.

Limiting liability for CO_2 releases – Large-scale CCS may not be deployed unless companies are able to manage liability associated with the escape or migration of CO_2 from pipelines and storage sites following permanent capping of the site and decommissioning of the injection facilities.[39] Policies designed to address liability must balance the goals of shielding companies from excessive liability, while maintaining a strong incentive for companies to minimize the chances of CO_2 release after decommissioning. In the absence of national legislation, states and provinces are beginning to address this issue on their own.

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[34] Other strategies for sequestration also have been suggested, such as sequestration in biomass or in solid minerals.

[35] See pages 9-10.

[36] Jurisdictions also should consider whether any waivers may be warranted for power plant need determinations and competitive bidding requirements.

[37] For a complete discussion, see Richard Cowart and Shanna Vale, Regulatory Assistance Project, and Joshua Bushinsky and Pat Hogan, Pew Center on Global Climate Change, "Coal Initiative Reports: State Options for Low-Carbon Coal Policy," February 2008, at: http://www.pewclimate.org/docUploads/StateOptions-02-20-08.pdf.

[38] *See* http://iogcc.publishpath.com/Websites/iogcc/pdfs/Road-to-a-Greener-Energy-Future.pdf.

[39] Where those actions were taken in conformance with an approved plan for the cessation of operations.

Liability for releases during transport and injection (prior to decommissioning) also is an important issue. Insurance may adequately address liability during the operational period of a sequestration project, but clarifying legislation also could be beneficial. Other measures might be needed to compel the surrender of allowances for any CO_2 release.

Subsidies for CCS projects at fossil-fuel[40] plants – Among the options for funding are:

- A fee levied on generators or utilities on a per-megawatt-hour basis, or just on the portion attributable to fossil fuels
- A "feebate" system that charges fossil-fuel plants without CCS technology a per-megawatt-hour fee and distributes the funds collected for CCS equipment
- Direct expenditures or tax credits for CCS investments

Other financial incentives – Utilities could potentially receive higher rates of return or accelerated depreciation for CCS investments. Regulatory commissions or legislatures could grant bonding authority for CCS projects. Besides simply providing access to funds, such bonds could provide a lower interest rate.

Cost recovery support – Most regulatory commissions do not pre-approve power plants. Instead, they determine what costs may be included in a utility's retail rates only after the plant has reached commercial operation. Regulators can provide some type of cost recovery assurance for CCS projects even before construction begins, employing such strategies as:[41]

- Preapproval of CCS projects;
- Guaranteed buyer or must-take requirements for CCS-generated power;
- Cost recovery for power supply during unplanned outages of the CCS plant;
- Cost recovery even if the CCS plant is cancelled;
- Cost recovery for early retirement of existing coal plants if replaced with a CCS substitute.

Key issues to consider for CCS policies include the following:[42]

- *Acceleration:* Will it produce investment in CCS that would not otherwise occur?
- *Deterrence:* Will it deter investment in high-emitting technology options?
- *Prudence and accountability:* Will it promote prudent project management? Will those with responsibility be held accountable for performance?
- *Power supply costs:* Does it help to lower the cost premium for CCS power?
- *Administrative costs:* Does it help to lower administrative and regulatory costs for developers, government and other parties?
- *Risk and cost balance:* How well does it balance the interests of ratepayers and investors?

[40] Coal, natural gas, biomass, petroleum coke and other fossil fuel plants are candidates for CCS.
[41] State "used and useful" requirements (mandating that a plant be functioning and necessary to be included in the utility's revenue requirement) may need to be modified by statute to implement the last three options in this list.
[42] *See* Cowart, *et al.*

- *Innovation:* Will it promote further CCS research and technical innovation?
- *Standardization:* Will it promote CCS projects that could be replicated elsewhere?
- *Performance:* Does it secure significant carbon reductions? Are any incentives scaled to real-world performance, measured in tons of CO_2 permanently sequestered?

Benefits to harmonizing. Harmonizing CCS policies across jurisdictions might make sense for a number of reasons. First, successful CCS efforts require significant research, development and demonstration funding that is best spent in a coordinated manner. For example, coordinated mapping of potential sequestration sites and pipeline locations may reduce the need for redundant studies. Second, CCS projects may be developed by multi-state utilities, or developed jointly by utilities in multiple states and provinces, in order to achieve economies of scale and spread the costs and risks. Third, long-distance transmission lines for coal plants with CCS, as well as pipeline transport of CO_2 for sequestration at a remote location, may require cooperation among states and provinces.

In addition, consistent CCS policies could promote replicable CCS projects and reduce administrative costs for utilities and other project developers as well as stakeholders participating in regulatory processes. Further, absent a national policy, consistent policies across the region to address liability risks associated with potential CO_2 leakage could facilitate CCS projects where participating utilities, CO_2 pipeline transport and sequestration sites involve multiple jurisdictions.

3.1.2 Tradable Renewable Energy Certificates

This section was added after review of stakeholder comments.

To facilitate compliance with a Renewable Portfolio Standard (RPS), most jurisdictions allow renewable energy certificates[43] procured separately ("unbundled") from the associated electricity to satisfy at least a portion of the renewable resource obligation. These tradable certificates can reduce the cost of RPS compliance. However, differing requirements for certificates that may be used for RPS compliance hinder trading. Key differences across jurisdictions include:

- Eligible fuels and technologies
- The qualifying vintage of the generating unit (the date it began operation)
- Whether incremental power production at an existing unit qualifies
- Eligible project size
- Whether the power must be generated within – or delivered to – the jurisdiction
- Whether customer-sited resources are eligible
- Cost caps and alternative compliance mechanisms
- Limits on using certificates without also procuring the associated electricity
- The certificate definition itself, including any conveyed environmental attributes

[43] One certificate represents one megawatt-hour of electricity from a renewable energy generating unit.

Not all of these differences must be harmonized to make renewable energy certificates more fungible across WCI partner jurisdictions. And there are alternatives to developing common certificate requirements. Under multi-lateral agreements, for example, participating jurisdictions could accept certificates that qualify under each others' requirements on a reciprocal basis. A related approach would accept certificates that qualify in participating jurisdictions, but at a pre-determined discount instead of at par. In addition, jurisdictions could agree to expand geographic eligibility or relax energy delivery requirements under specified conditions indicating tight supplies of renewable resources.[44] Further, under any of these approaches, jurisdictions could limit the amount of otherwise non-qualifying certificates that may be used to meet renewable resource obligations.

States and provinces already have collaborated to establish a West-wide certificate tracking system. The Western Renewable Energy Generation Information System issues, registers and tracks all renewable energy certificates in the Western Interconnection. The system protects against multiple-counting and selling of certificates and verifies compliance with both RPS and voluntary renewable resource programs. The system can import (and export) certificates from (and to) other tracking systems in the U.S. and Canada. It provides the necessary infrastructure for certificate trading, but it is not a trading platform. Trading is generally through bilateral agreements.

Both of the major energy bills before Congress – the American Clean Energy and Security Act of 2009 (H.R. 2454) and the American Clean Energy Leadership Act of 2009 (S. 1462) – preserve the integrity of state renewable portfolio standards. Under both bills, federal renewable energy certificates would be entirely separate from state certificates and would have no purpose other than compliance with federal requirements. Federal certificates could be used nationwide for that purpose, but their use toward meeting state standards would be bound by individual state definitions and eligibility. H.R. 2454 includes explicit provisions for states to establish renewable energy certificate trading under higher state standards. Further, neither bill includes any apparent prohibitions against trading renewable energy certificates with Canadian provinces.

Key issues to consider in making renewable energy certificates more fungible include:

- Administrative or legislative changes that may be needed[45]
- Competing interests, e.g. renewable resource and economic development within the jurisdiction vs. lower RPS compliance costs through improved certificate trading
- Whether reducing climate change is among the jurisdiction's goals for its RPS program – CO_2 emissions reductions anywhere help meet that goal

[44] For a detailed review of potential approaches, *see* Edward A. Holt, *Increasing Coordination and Uniformity Among State Renewable Portfolio Standards,* prepared for Clean Energy States Alliance and the Northeast/Mid-Atlantic RPS Collaborative, December 2008, at http://www.cleanenergystates.org/Publications/CESA_Holt-RPS_Policy_Report_Dec2008.pdf.

[45] If an RPS was enacted through voter initiative, there may be restrictions on the legislature's ability to modify its provisions.

- Reduced local environmental benefits due to any reduction in local renewable energy development because the benefits of avoided air pollutants from a fossil-fuel power plant accrue primarily where *that* plant is located – except for for CO_2 – not necessarily in the vicinity of the renewable energy facilities that displace fossil-fuel generation
- The ability of jurisdictions to meet their highest RPS targets under today's differing certificate requirements
- In renewable-rich areas, the effect of increased use of unbundled certificates on the cost of balancing reserves, power prices, generation dispatch, and acquisition costs for RPS-qualifying resources[46]

Benefits to harmonizing. Trading renewable energy certificates across a broad region can increase competition and liquidity in the marketplace, lower prices for renewable resources and reduce the cost of RPS compliance.[47] In turn, lower prices may increase renewable energy development, leading to further reductions in greenhouse gas emissions. Because high-quality renewable resources are not dispersed evenly, trading among jurisdictions may increase the diversity of renewable resources that are developed. And tapping areas with better solar or wind potential, for example, may reduce acquisition costs. Renewable energy developers would benefit from increased certificate trading because their projects could comply with more RPS programs. Even if requirements for tradable certificates are not harmonized among WCI partner jurisdictions, the reciprocity approaches described above can provide significant benefits along these lines.

3.2 Energy Efficiency and Conservation

3.2.1 Tradable Energy Savings Credits

This section was added after review of stakeholder comments.

Energy savings credits[48] can be used like renewable energy credits.[49] They are issued, registered, tracked and retired. However, rather than representing one megawatt-hour (MWh) of renewable generation, an energy savings credit constitutes one MWh of energy not used. Energy savings credits present a greater challenge because their output cannot be metered. Instead, energy savings are estimated by comparing energy use after an energy savings

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[46] The Northwest Power and Conservation Council is undertaking a study to examine the implications of an unbundled certificate market in western North America for meeting renewable resource obligations, focusing on implications for the Northwest.

[47] For example, a study for the Western Electric Industry Leaders Group on the transmission that will be needed to meet RPS and carbon requirements in the Western Interconnection estimated that certificate trading could reduce renewable resource procurement costs in 2020 by $351 million. Study by Energy and Environmental Economics, Inc. at http://weilgroup.org/E3_WEIL_Complete_Study_2008_082508.pdf. A study by Lawrence Berkeley National Laboratory also found large savings from this approach. *See* http://eetd.lbl.gov/ea/EMP/reports/lbnl-3077e.pdf.

[48] Also called energy savings certificates or "white tags," a term trademarked by Sterling Planet.

[49] See page 29.

measure is taken with business-as-usual energy use — i.e., assuming the measure had not been taken.[50]

Energy savings credits generally are used in conjunction with energy efficiency requirements, such as energy efficiency resource standards.[51] A central reason for the adoption of energy savings credits is that they monetize savings from energy efficiency projects and allow those savings to be traded. Trading creates the opportunity to not only track compliance but also to lower its cost, because credits can migrate to the highest valued use and provide additional funding for efficiency programs.

To be effective, a trading program for energy savings credits should meet the following prerequisites:[52]

- **Measures, projects and programs** – Credits should be based on savings claimed by approved measures, projects and programs.
- **Measurement of energy savings** – Programs should have approved measurement protocols, typically established by a utility commission or other regulator.
- **Verification and certification** – Savings claims should be verified by an independent entity and be consistent with established protocols for measures, projects and programs. While not requiring the action of a single entity, the process must be credible.
- **Issuance of credits** – Energy savings credits (and the attributes they represent[53]) must be issued in a way that ensures they are not double-counted by another entity or in another place, and that they are issued to the lawful recipients – e.g., the home owner or program administrator.
- **Tracking** – Systems must be in place to track and account for traded and retired credits, including the degree to which attributes vary among jurisdictions.
- **Price determination** – Because pricing of energy savings credits is a key element in trading, the pricing process should be transparent.

Key issues to consider in developing energy savings credits include the following:

- Whether energy savings credits will help meet the goals of energy efficiency requirements – One of the purposes of trading is to lower the cost of compliance, because trading locates and mobilizes reductions from less expensive measures, practices and programs in order to sell them to places where reductions are more expensive. However, if the goal of state or provincial energy efficiency requirements is saving energy locally (and lowering local energy bills), reducing air pollution in the area, or relieving electric system congestion within the jurisdiction, using energy savings credits may not be effective in matching resources and desired benefits. To the degree that there is a closer connection between the region from which energy savings credits

[50] Joe Loper, Steve Capanna and Rodney Sobin, Alliance to Save Energy, "Energy Savings Credits: Shining a Light on the Measurement Challenge," 2009 draft.

[51] See page 18

[52] *See* Loper, *et al*.

[53] For example, carbon emissions reductions or demand reductions for a specified time period.

are purchased and the place where the benefits are being sought, this problem would be less pronounced.

- Costs associated with credit certification, tracking and trading – While these costs can be significant, the incremental costs would be limited to the degree that states and provinces already participate in tracking systems for renewable energy credits. Costs include upgrade of existing systems to certify and track energy savings credits and personnel training associated with regulatory oversight.
- Stringency of energy efficiency requirements – Trading energy savings credits can make weak energy efficiency requirements even weaker. To the degree that energy efficiency requirements produce more business-as-usual savings (and credits) than one utility requires, a second utility can purchase the credits in lieu of meeting the requirements with more stringent measures. The purchasing utility also complies with the requirements, but with weaker savings – i.e., savings that utility one would have made anyway. This problem is exacerbated to the degree that credits from a jurisdiction with a weaker program are sold to a jurisdiction with a more stringent program. However, where programs are equally stringent, energy savings within the jurisdictions would not necessarily be compromised by trading of energy savings credits.[54]
- Combining energy savings credits with renewable portfolio standards – Because energy efficiency is cheaper, if combined with renewable portfolio standards, energy savings credits could dilute renewable resource obligations. From a least-cost strategy point of view this would be beneficial for consumers. To the degree that a renewable energy policy is designed with additional goals, such as promoting the local renewable energy industry, this interaction should be considered. Regardless, if the renewable resource obligation is based on a percentage of overall sales to retail customers (MWh), *any* energy efficiency gains will reduce that obligation. Therefore, there is no need to explicitly combine renewable energy and energy efficiency obligations to get those least-cost benefits.

Benefits to harmonizing. Establishing a system of tradable energy savings credits across WCI Partner jurisdictions may reduce the cost of compliance with energy efficiency requirements. If such requirements are stringent and lead to deep reductions in energy use, energy savings credits also may reduce the cost of meeting renewable portfolio standards – if renewable resource obligations are based on a percentage of overall retail sales or combined with energy efficiency requirements.

[54] Loper, *et al.* at 24.

3.3 Transportation

3.3.1 Pay-as-You-Drive Insurance

This section was added after review of stakeholder comments.

Pay-as-you-drive insurance (PAYD) bases vehicle insurance rates on miles driven. PAYD is typically a voluntary program designed to offer lower rates to drivers that drive below a mileage target for a given period, which provides an economic incentive to drivers to reduce their vehicle miles traveled (VMT). Because the program is voluntary, high-mileage drivers have the option to purchase conventional insurance policies. If properly structured, a PAYD program provides insurance companies with a more accurate correlation between individual policies and risk.

Key issues to consider in developing programs:

- Identifying qualitative and quantitative metrics to accurately quantify risk
- Ensuring that privacy is not infringed upon in tracking or verifying driving habits

Benefits to harmonizing. By coordinating state/provincial efforts with insurance companies, standard policies and procedures can be developed to encourage large-scale availability of PAYD policies.

3.3.2 Electric and Alternative Fuel Vehicle Infrastructure

Development of electric and alternative fuel vehicle infrastructure can take a variety of forms including:

- Consumer outreach and education
- Direct purchases of charging stations and alternative-fuel refueling stations by businesses and local, state/provincial or regional governments
- Addressing utility system impacts
- Development and implementation of policies that streamline the permitting and installation of alternative fuel vehicle infrastructure
- Creation of grant, loan or loan guarantee programs to help finance infrastructure
- Enactment of tax incentives to reduce the cost to developers of installing infrastructure

Key issues to consider in developing programs to accelerate the deployment of alternative fuel vehicle infrastructure include:

- How to pay for infrastructure, including revenue-positive public and commercial cost models
- Electric system impacts
- Removing service provider disincentives to supplying additional electric load and alternative fuels through such means as providing additional emissions allowances
- Policies to ensure interoperability of refueling across utility service territories and jurisdictions

- Coordination of these programs with a regional low-carbon fuel standard, if implemented
- Whether public agencies should provide free electric vehicle charging
- Public and private partnerships
- Deployment simultaneously with (or in advance of) alternative-fuel vehicle sales
- Distance between stations for charging/fueling

Benefits to harmonizing. By coordinating the development of electric and alternative fuel vehicle infrastructure, the WCI jurisdictions could foster sufficient market penetration of electric and alternative fuel vehicles to attain significant reductions in GHG emissions, create jobs, foster economic growth, reduce reliance on foreign fuels and reduce air pollution.

3.4 Agriculture

3.4.1 Agricultural Anaerobic Digesters

Anaerobic digesters capture the gases created as agricultural waste materials break down into methane and CO_2. Anaerobic digesters:

- Capture methane, a potent GHG that would otherwise be released into the atmosphere
- Displace CO_2 emissions by producing carbon-neutral electricity, pipeline-quality natural gas, transportation and boiler fuels, feedstocks for commercial chemicals (such as ammonia and methanol), and digested fiber that can be used as a substitute for mined peat moss
- Provide a valuable economic resource to farmers through renewable energy production and cogeneration

Key issues to consider in harmonizing policies to facilitate on-farm anaerobic digesters are:

- The level of necessary capital investment and ongoing transaction costs as well as payback periods, which depend in part on:
    - The amount of financial assistance available
    - The rates available from electric and natural gas utilities for sale of digester-produced power and gas
- The ease with which small independent power producers are able to meet the interconnection requirements of electric and natural gas utilities
- The proportion of agricultural and non-agricultural wastes allowed on-farm by government agencies for the purpose of anaerobic digestion
- Environmental regulation by state and local governments
- Local government requirements on the movement of agricultural and non-agricultural waste
- The degree to which energy production is accepted as a normal farming practice by the public and relevant government agencies, including:
    - Whether there are special rules about what activities can take place on farmland

- Whether energy production will remain ancillary to other types of agricultural production.

Benefits to harmonizing. Anaerobic digestion offers significant potential for permanent, real, additional and verifiable GHG emissions reductions. Removing permitting barriers and providing clarity and consistency in regulations would increase accessibility for states and provinces to realize these reduction opportunities.

3.5 Waste

3.5.1 Landfill Methane Reduction

Methane gas from landfills is a significant source of GHG emissions due to its high global warming potential and the sheer number of landfills. According to Environment Canada, landfill emissions account for more than a quarter of the anthropogenic methane in the atmosphere.[55] Landfills generate methane as the anaerobic bacteria break down organic waste, a process that usually begins within the first year of landfill operation and can continue for 50 years after landfill closure.

The U.S. EPA defines "large" municipal solid waste landfills and requires that they collect landfill gas and combust it.[56] The regulations do not mandate secondary energy recovery processes. The B.C. Government passed a Landfill Gas Regulation under the Greenhouse Gas Reduction Statutes Amendment Act, which requires that by Jan. 1, 2016, all landfills that are above a certain size and methane threshold must install (and properly operate) landfill gas management facilities.[57]

Collected landfill gas can be used for electricity, heat production and other applications. Beneficial use of collected landfill gas offers potentially significant benefits, including further reductions of GHG emissions by offsetting fossil fuels and producing energy from a renewable source. The EPA estimates that more than 450 municipal solid waste landfills in the U.S. operate landfill gas-to-energy programs, and approximately 520 more landfills could effectively do so, providing enough electricity to power 700,000 homes.[58] Environment Canada estimates that 600,000 homes could be powered by electricity generated from Canadian landfill gas sources.

The EPA operates a voluntary Landfill Methane Outreach Program (LMOP) to facilitate and provide assistance for landfill methane capture and conversion to energy. Canada and the U.S.

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[55] *See* "Harnessing the Power of Landfill Gas" at http://www.ec.gc.ca/Science/sandemay99/article1_e.html.
[56] *See* 2006 Standards of Performance for New Stationary Sources and Guidelines for Control of Existing Sources, and 2003 National Emission Standards for Hazardous Air Pollutants.
[57] *See* http://www.bclaws.ca/Recon/document/freeside/--%20e%20--/environmental%20management%20act%20%20sbc%202003%20%20c.%2053/05_regulations/28_391_2008.xml.
[58] *See Landfill Methane Outreach Program: Benefits of LFG Energy* at http://www.epa.gov/lmop/benefits.htm.

participate in the Methane to Markets partnership with 28 other countries that have interest or expertise in developing methane projects.

Key issues to consider in developing programs to capture landfill methane include:

- Identifying the entire inventory of potential methane-generating landfills;
- Closed landfills may be difficult to identify, but still have emissions;
- The type of outreach and targeting needed to successfully maximize program participation and how to coordinate that effort regionally
  - Targeting larger landfills that may qualify to participate in the LMOP but aren't yet taking action
  - Targeting a different population of landfills than federal programs
  - Quantifying the amount of methane produced to select target landfills using consistent procedures
- Funding of methane recovery projects, particularly for closed landfills or small municipal landfills
- Availability of electrical infrastructure and proximity of landfills to transmission lines
- Establishing effective and timely monitoring of landfill gas to identify problems or potential problems, including in the area between waste disposal sites and neighboring properties
- Difficulty of determining the percentage of landfill gas captured through a collection of wells and headers, with many uncertainties and variables
- Additional considerations that may explicitly address:
  - Organic waste diversion programs
  - Emission credits
  - Non-methane organic compounds (odors and air quality)
  - Recycling programs to recover energy-intensive materials, such as aluminum
  - Methane management opportunities for non-landfill organic waste – from dairies and pig farms, for example

Benefits to harmonization. Reaching out to landfills not subject to U.S. or Canadian regulations could further reduce landfill methane emissions and encourage energy recovery. Guidance for outreach at the regional level – possibly modeled after EPA's Landfill Methane Outreach Program – would reduce the level of jurisdictional effort necessary and provide a consistent message for the goals, benefits and procedures for a program that reduces landfill methane emissions reduction and promotes electricity production from landfill gas.

4 Tier 3 Policies

4.1 Transportation

4.1.1 Vehicle Emissions Labeling

Emissions labels provide consumers with information on GHG emissions from vehicles. This approach has the potential to influence vehicle market decisions by providing information for consumers who might have a preference for purchasing vehicles with lower GHG emissions. Harmonizing the content of emissions labels would provide standardized information for consumers while reducing burdens for manufacturers and regulators.

4.1.2 Medium- and Heavy-duty Vehicle Hybridization

Medium- and heavy-duty vehicles account for a significant portion of GHG emissions from the transportation sector. Hybridization reduces GHG and other emissions from these vehicles through greater fuel efficiency. Hybrid trucks and buses would likely achieve the greatest benefits in urban, stop-and-go applications, such as parcel delivery, transit and other short-range travel. A harmonized program of standards and incentives could help encourage a broader market for medium- and heavy-duty vehicle technology.

4.1.3 Transport Refrigeration Units

Transport Refrigeration Units (TRUs) are gasoline- or diesel-powered cooling units that are installed on containers used to transport produce, meat, dairy and other perishable goods. TRUs are capable of both cooling and heating and are found on refrigerated vans, trucks, trailers, railcars and shipping containers. Although TRU engines are relatively small, ranging from 9 horsepower to 36 horsepower, significant numbers of these engines congregate at distribution centers, truck stops and other facilities. Some companies use TRUs for extended cold storage and store overflow goods in TRU-equipped trucks and trailers for several weeks before holiday periods, or for more than a 24-hour period throughout the year. Harmonized policies and standards design would encourage more energy-efficient operations that reduce GHG emissions from systems using internal combustion engines. Harmonization also would encourage advancements in electrically driven refrigeration systems and cryogenic systems.

4.2 Industrial Sector

4.2.1 Emissions Performance Standards for Major Industrial Sources

Emissions performance standards for industrial facilities would set a maximum level of GHG emissions per unit of product produced.[59] These standards would be established by sector, by product, or in some cases by industrial process within a sector.

[59] For example, tons of CO_2 equivalent emitted per unit of product produced at the facility. For energy-related emissions, both direct use of fossil fuels on-site as well as off-site production of electricity consumed at the plant would be included.

5 Important Policies Addressed in Other Venues

A comprehensive program to achieve significant GHG emissions reductions and transition to a low-carbon economy will require a broad range of actions and investments by business, consumers and all levels of government. In addition to the three tiers of policies discussed above, other important initiatives are being examined and developed in other venues. These policies are expected to make critical contributions to achieving the WCI Partner jurisdictions' goals for greenhouse gas reductions. These other polcies, not being evaluated by the Complementary Policies Committee, include the following:

- **Renewable portfolio standards in the electricity sector.** Already adopted by each of the WCI Partner jurisdictions, renewable portfolio standards direct retail electricity providers to generate or purchase a portion of their power from renewable sources. These requirements promote multiple objectives, including diversifying electricity supply and encouraging deployment of low-carbon technology in the electricity sector. Included in this paper for further consideration is improving the ability to trade renewable energy certificates across WCI Partner jurisdictions.

  This section was added after review of stakeholder comments.
- **Transmission for renewable and other low-carbon resources.** Several regional efforts are underway to identify and prioritize necessary transmission lines to facilitate increased electric generation from renewable resouces. A substantial amount of these resources are located in areas remote from load centers. The Federal Energy Regulatory Commission (FERC) has jurisdiction over transmission of electric power in the U.S., however, states retain authority over siting transmission facilities. The Western interconnection serves all or portions of 14 U.S. states; Alberta; British Columbia; and the northern portion of Baja California, Mexico. The Western Electricity Coordinating Council (WECC) is responsible for coordinating and promoting bulk electric system reliability and open and non-discriminatory transmission access, subject to oversight by FERC and Canadian authorities. Advisory groups to WECC, the Western Governors' Association (WGA) and its energy arm, the Western Interstate Energy Board, support cooperative reliability and transmission efforts. The Western Renewable Energy Zones initiative promotes the efficient development, procurement and delivery of energy from renewable-rich zones to population centers while balancing other state objectives. In addition, with funding from the U.S. Department of Energy, WECC is developing 10-year and 20-year regional transmission plans – due in 2011 and 2013, respectively – to provide guidance for decisionmakers and facilitate expansion of needed transmission infrastructure, including transmission to accelerate development of renewable and other low-carbon resources.

- **Energy efficiency standards for new buildings and appliances.** State and provincial building and appliance standards ensure that manufacturers and builders bring energy-saving products to market. These standards have proven to be highly effective for reducing energy consumption and GHG emissions. Moreover, their implementation in a similar manner across jurisdictions is key to building larger markets for energy-saving products and green building techniques. States and provinces regularly update building standards. Most of the WCI Partner jurisdictions have adopted residential and commercial building codes consistent with the 2006 model International Energy Conservation Code, which itself provides a degree of harmonization. Most appliance standards in the U.S. are set by the federal government, including recent updates under the Energy Independence and Security Act of 2007. Pending U.S. Congressional bills would raise energy efficiency standards in building codes and increase energy efficiency requirements for lighting and appliances. Depending on any federal preemption provision, building codes and appliance standards in WCI Partner states may exceed these requirements.

- **Smart grid.** Smart grid infrastructure is under development in several of the WCI Partner jurisdictions in order to facilitate the dynamic transfer of information and electricity between the electric grid and retail customers. The smart grid will enable greater integration of intermittent renewable generation, demand-side resources and energy efficiency into the grid while improving reliability. Using funding authorized under the American Recovery and Investment Act of 2009, the U.S. Department of Energy is awarding some $4.5 billion to utilities, equipment suppliers, regional transmission organizations, states and research organizations to jump-start smart grid on a massive scale.[60] The National Institute for Standards and Technology is developing a framework, including protocols and model standards for information management, to ensure smart grid devices and systems work effectively with the many interconnected elements of the electric power grid. The Western Electricity Coordinating Council is likely to have a role in developing harmonized standards for the western states and provinces.

- Light-duty vehicle emissions standards. Light-duty vehicle emissions standards. In June 2009, EPA granted a waiver to California to proceed with implementation of its GHG emission reduction standards for new passenger cars, pickup trucks and sport utility vehicles beginning with the 2009 model year. This opened the way for the other 13 states and the District of Columbia that have adopted those standards to also proceed. Shortly thereafter, the Obama Administration announced its intent to adopt these emission standards at the national level. The final joint rule between EPA and the Department of Transportation's National Highway Safety Administration (NHTSA) was announced on April 10, 2010. In Canada, 2 Provinces that participate in the WCI have adopted these standards and the national government has committed to developing national vehicle GHG standards for 2011 and subsequent model year light duty vehicles

[60] *See* http://www.energy.gov/recovery/smartgrid_maps/SGIGSelections_State.pdf and http://www.energy.gov/news2009/documents2009/SG_Demo_Project_List_11.24.09.pdf.

that will mirror the US federal standards to create a more harmonized regulatory environment for automakers.

- **Vehicle miles traveled reductions.** Several WCI Partner jurisdictions have undertaken initiatives to encourage reductions in vehicle miles traveled (VMT) by fostering transit-oriented development or integrating climate change into transportation and land use planning. Pay-as-you-drive insurance, which will be evaluated as a Tier 2 policy as noted in this document, may indirectly impact VMT. VMT reductions can be an effective strategy to enhance mobility efficiency while reducing GHG emissions from the transportation sector.

- **Government leading by example.** Each WCI Partner jurisdiction has adopted goals or policies to save energy and reduce GHG emissions in its own operations. These policies build markets for low-GHG materials and equipment and set an important example for the private sector. By demonstrating exceptional emissions reductions in various areas, WCI Partner jurisdictions provide a laboratory for the development of innovative approaches.

- **Assistance for low-income households.** Results from the WCI economic analysis released in September 2008 indicate that the WCI emissions targets can be met through a broad based cap-and-trade program and complementary policies with a net savings to the economy. However, the WCI Partner jurisdictions are committed to understanding and addressing potential impacts on low-income households that, for example, spend a relatively high portion of their income on energy. Each WCI Partner jurisdiction is examining how best to address this issue, relying on the programs and approaches most suitable to each Partner's circumstances.

Appendix 1: Complementary Policies: Capped vs. Uncapped Sources and Sectors[61]

Policies to Reduce Emissions From Sources and Sectors Capped in 2012 *Energy Production* • Small-scale renewable energy resources (Tier 1) • Combined heat and power (Tier 1) • Hydropower (Tier 1) • Emissions performance standards for electric generating units (Tier 1) • Carbon capture and sequestration (Tier 2) • Tradable renewable energy certificates (Tier 2)
Energy Efficiency • Energy efficiency targets (Tier 1) • Energy efficiency programs and incentives (Tier 1) • Tradable energy savings credits (Tier 2)
Industrial Sector • Emissions performance standards for major industrial sources (Tier 3)
Policies to Reduce Emissions From Sources and Sectors Capped in 2015 *Transportation* • Low-carbon fuel standard (Tier 1) • Freight transportation infrastructure and heavy-duty vehicles (Tier 1) • Electric and alternative fuel vehicle infrastructure (Tier 2) • Pay-as-you-drive insurance (Tier 2) • Vehicle emissions labeling (Tier 3) • Medium- and heavy-duty vehicle hybridization (Tier 3) • Transport refrigeration units (Tier 3)
Policies to Reduce Emissions From *Uncapped* Sources and Sectors *High-Global Warming Potential Gases* • Regulatory measures for high-global warming potential gases (Tier 1)
Agriculture • Agricultural anaerobic digesters (Tier 2)
Waste Management • Measures for landfill methane reduction (Tier 2)

[61] This table only includes policies the Committee will evaluate for further consideration; it does not include policy initiatives underway in other venues.

Appendix 2: Stakeholder Comments on Draft White Paper

The Complementary Policies Committee prepared a draft of this white paper to solicit input from stakeholders on:

- *Recommended Policies:* Which policies should be recommended for further evaluation, how those policies should be prioritized, key issues associated with the policies, and benefits to harmonizing policies across WCI Partner jurisdictions, as well as other states and provinces
- *Evaluation Criteria and Indicators:* How the Committee's recommended evaluation criteria and qualitative indicators can be used to verify that criteria have been met
- *Continued Stakeholder Engagement:* How the Committee can best engage with stakeholders as the evaluation process evolves

The Committee received 17 sets of written comments on its draft white paper during the 60-day public comment period. Some comments were submitted on behalf of numerous organizations. The Committee carefully reviewed all comments. Following is an overview of the public comments received and WCI's responses, including changes in this final paper.

Comments on Policy Recommendations

Energy Production

Renewable portfolio standards (RPS) and tradable renewable energy credits. One stakeholder recommended that WCI Partners procure out-of-state renewable resources – or renewable energy credits from out-of-state projects – to meet state RPS requirements. Another commenter recommended that WCI Partners establish a system of tradable energy efficiency credits, in combination with tradable renewable energy credits. Other stakeholders recommended that all WCI Partner jurisdictions have strong RPS requirements, or that WCI Partner jurisdictions harmonize RPS requirements. On RPS generally and treatment of out-of-state resources, each WCI Partner already has established an RPS that specifies renewable resource obligations, geographic or deliverability requirements, and other standards in accordance with state objectives. However, WCI agrees that the concept of improving trading of renewable energy credits should be further explored. A section on this topic has been added to the final paper. We discuss energy efficiency credits under "Energy Efficiency," below.

Hydropower. Several comments were received on the economic and GHG benefits of hydropower. WCI agrees that acquiring incremental capacity from existing dams and potentially new, small-scale, run-of-the-river facilities present a valuable opportunity. A section on this topic has been added to the final paper.

Emissions performance standards. Some stakeholders are opposed to emissions performance standards for electric generating units, maintaining that they do not comport with a cap-and-trade system and that low-carbon solutions may not exist for a number of generating technologies. In its white paper, the Committee notes several key issues related to implementation and technology availability. Further, this paper is the Committee's initial review of policies for consideration. As described in the "Next Steps" section, WCI will evaluate these policies in more depth in the future, beginning with tier 1 policies.

Transmission. Several stakeholders recommended that the Committee explore policies related to the expansion of interstate transmission to access low-carbon resources. WCI acknowledges that this is a priority action for consideration, however, several interjurisdictional efforts are already underway to address this need. A section describing these efforts has been added to the paper under "Important Policies Addressed in Other Venues."

Combined heat and power facilities. Several stakeholders recommended that WCI consider policies to promote combined heat and power (cogeneration) facilities. They noted that many of the policies considered in the white paper for small-scale renewable resources also could apply to combined heat and power. WCI agrees that policies to promote combined heat and power facilities should be a high priority. A section on such policies has been added to the final paper.

Energy Efficiency

Building codes and appliance standards. Some stakeholders recommended that WCI Partners coordinate on building energy codes and appliance standards that exceed national requirements. WCI agrees that these are important efforts, but notes that they are being addressed through other avenues. See revisions in this paper under "Important Policies Addressed in Other Venues."

Industrial efficiency measures. The Committee received a comment that the policies proposed for consideration put insufficient emphasis on industrial energy efficiency measures, noting in particular energy efficiency audits for large industrial emitters. In response, the Committee points out that the policies described under "Energy Efficiency Targets" and "Energy Efficiency Programs and Incentives" span all sectors of the economy, including industry. Regarding audits specifically, large industrial facilities typically have in-house energy expertise. For small- and medium-size manufacturers in the U.S., the Department of Energy provides free, in-depth assessments of facilities, services and manufacturing operations. The audits examine potential savings from energy efficiency improvements, waste minimization and pollution prevention, and productivity improvement.[62]

[62] *See* http://iac.rutgers.edu/.

Energy savings credits. As described above, one stakeholder recommended that WCI Partners establish a system of tradable energy efficiency credits. WCI agrees to further explore this concept. This potential policy has been added to the final paper.

Smart grid. The Committee was asked to address policies to develop a "smart grid." WCI recognizes that smart grid technologies can enable GHG emissions reductions, if the requisite complementary policies are in place, e.g., policies that promote energy efficiency, renewable energy and clean distributed resources. However, WCI believes its appropriate role in this area is education and outreach that supports the significant federal and regional efforts already underway. The "Important Policies Addressed in Other Venues" section has been revised to further describe these federal and regional efforts.

Transportation

Stakeholders noted significant opportunities for reducing GHG emissions in the transportation sector through a reduction in Vehicle Miles Traveled (VMT) and increased efficiencies in driving habits. The WCI economic analysis affirmed that these policies will be critical to meeting GHG reduction goals.

Pay-as-you-drive insurance. Several jurisdictions are pursuing policies that promote pay-as-you-drive insurance. WCI agrees to further consider this policy and has added an initial discussion to this paper.

Reduced speed limits. One stakeholder suggested reducing highway speed limits as a strategy to reduce GHG emissions. Lower speed limits and mandatory use of speed regulators for heavy duty trucks are among the possible policies included in this paper for further consideration by WCI.

Low-carbon fuel standard (LCFS). Some stakeholders recommended that transportation fuels be included in the WCI cap-and-trade program or that alternative policies, such as a federal renewable fuel standard, should be considered. When it approved its cap-and-trade program design, WCI determined that transportation fuels will come under the cap beginning in 2015. Other stakeholders stated their concerns about implementation and economic impacts of an LCFS. WCI will continue to explore these issues as it moves forward with evaluating an LCFS.

Vehicle efficiency. Stakeholders recommended WCI Partner jurisdictions adopt vehicle efficiency standards. On April 1, 2010, EPA and the Department of Transportation's National Highway Safety Administration (NHTSA) announced a joint final rule establishing a national program to reduce greenhouse gas emissions and improve fuel economy for new cars and trucks sold in the United States. These standards were simultaneously adopted by the Canadian national government.

Electrification of the transportation sector. Some stakeholders suggested that the white paper include the electrification of transportation as a tier 1 policy. There are a number of options for diversifying the transportation fuel mix in WCI Partner jurisdictions. The draft white paper included development of electric and alternative-fuel infrastructure for freight transportation and vehicles as Tier 2 policies for further evaluation. Several WCI Partner jurisdictions, particularly on the West Coast, already have efforts underway to develop infrastructure for electric vehicles.

Another stakeholder recommended that the Committee consider additional transportation policies such as replacement tire standards, feebates for highly efficient vehicles, and an accelerated vehicle retirement program. Several WCI jurisdictions currently offer incentives for high-efficiency or alternative-fuel vehicles and have other programs underway to reduce emissions from the transportation sector.

High-Global Warming Potential Gases

Some stakeholders suggested that ozone-depleting substance destruction should be eligible under the WCI cap-and-trade program as a GHG offset. Because this recommendation deals specifically with offsets under the program, the Complementary Policies Committee referred this recommendation to the Offsets Committee.

Waste Management

One stakeholder suggested that the Complementary Policies Committee should drop from further consideration policies on anaerobic digesters and landfill methane reductions, and that these policies instead be addressed by the WCI Offsets Committee as it develops offset protocols. The white paper has been amended to clarify that the proposed complementary policies for anaerobic digesters are targeted towards streamlining permitting processes and increasing the accessibility of this technology. In the case of landfills, the proposed policy is coordinated regional outreach to landfills that are not subject to U.S. or Canadian regulations for methane reduction. The Complementary Policies Committee will coordinate with the Offsets Committee in any further evaluation of such outreach.

Other stakeholders asked the Committee to explore *additional* policies that address emissions from the waste sector, including mandating landfill gas-to-electricity (or landfill gas-to-fuel) processes for large landfills; requiring small landfills to collect and combust waste gas; and flaring methane from other organic waste sources, such as dairies, pig farms and food processing facilities. To address large waste sources, some stakeholders recommended using waste gas to generate electricity and produce transportation fuels, and increasing recycling of aluminum and other discarded materials.

The white paper includes a variety of policy approaches to help coordinate and encourage broader adoption of methane management practices to reflect the diversity of landfills (e.g., size, construction and composition); the variability in methane yields among regions (e.g., wet vs. dry); and the various complex and, in some cases, novel technologies employed for methane capture and flaring/electricity generation. Such policy tools include funding of methane recovery projects, particularly for closed landfills or small municipal landfills; evaluation of requisite electrical infrastructure; outreach to maximize program participation; and improved inventorying.

Other Sectors

Forestry. Some stakeholders recommended that WCI Partners require standardized, sector-wide accounting of forest carbon, including flows between sectors and permanent conversion of forest land to other uses. Stakeholders also recommended that WCI use state and provincial inventory information to develop a regional forest carbon policy that includes no net loss or a "floor" for forest carbon and continued sequestration at or above current levels, with a goal of maintaining forest carbon stores in natural forests and increasing total terrestrial carbon stores in the forest sector over time. The Committee referred these recommendations to the WCI Partners for consideration. The Partners determined that these recommendations address areas beyond the Committee's scope, as outlined in its workplan.

Other land uses. WCI should consider developing a regional mitigation program, potentially implemented at the state or provincial level, for the net climate impact of emissions from other land uses (e.g., peat extraction) and conversion of natural and working landscapes to developed or other uses. While the Committee is aware of the potential impact of land use changes on greenhouse gas emissions, it also recognizes that land use is typically a local government decision.

Workforce strategies. The Committee received a comment that any strategy proposals to address workforce issues related to the cap-and-trade program should align state assets, such as community colleges and apprenticeship, rather than create new and perhaps duplicative programs. The Committee appreciates this advance comment for its future report in this area.

Evaluation Criteria

Stakeholders provided comments on the draft criteria for evaluating recommended policies for harmonization, suggesting either revisions to the criteria or additional criteria. The Committee has revised the criteria to include "The policy addresses a perceived market failure" and to clarify that the increased use of electricity is not a collateral detriment, unless it results in higher GHG emissions. Other revisions recommended by stakeholders were deemed to be similar to those already put forth by the Committee.

Stakeholders provided the following suggestions for how policies should be prioritized (tiered) and evaluated:

- The ranking of some policies, including small-scale renewable resources and development of algae biofuels, should be lowered. In the case of biofuels, a stakeholder commented that "supporting research of a single technology does not seem to be the proper role for the WCI complementary policies committee."

- Carbon capture and sequestration, transportation electrification, smart grid, and industrial emissions performance standards should be tier 1 policies.

The Committee agrees that barriers to algae biofuels fall under the purview of a broader policy, such as an LCFS. With regard to the other comments, the Committee re-evaluated the tiering of policies before publishing the final white paper to ensure consistency with the evaluation criteria.

Stakeholder Engagement

Stakeholders were asked to provide suggestions as to how the Complementary Policies Committee can better engage stakeholders and increase participation. The Committee sincerely appreciates these suggestions and will take them up as it continues its work.

General Comments

GHG reductions from complementary policies vs. cap-and-trade program. Some stakeholders maintain that GHG reductions from complementary policies should be counted towards the emissions cap under the cap-and-trade program. Additions to the white paper under "The Role of Complementary Policies" further clarify the interaction between GHG emission reductions from complementary policies and the cap-and-trade program.

Vehicle emissions labeling. The Committee received a comment that the benefits of vehicle emissions labeling would be nullified by combining that program with tradable credits for vehicle emissions. The purpose of vehicle emission labeling is to provide consumers with information about the particular vehicle. It does not purport to share information about overall greenhouse gas emissions. In an emissions trading program, emission reductions achieved in one sector may indeed be traded to another sector that is unable to make reductions. However, the declining cap will ensure the needed reductions are made.

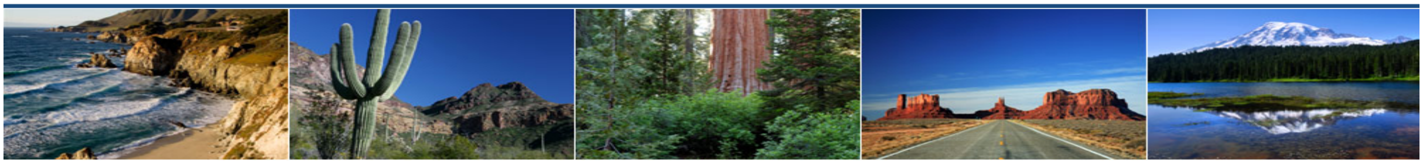
WCI focus. One stakeholder recommended that WCI focus its efforts on its core directives – particularly the implementation of the regional cap-and-trade program – and limit its engagement in complementary policies to those critical to the cap-and-trade program's success, at least until after the program's implementation in 2012. The section "The Role of Complementary Policies" explains the importance of both efforts to achieve WCI's GHG emissions reduction goals at least cost.

Regulatory and trade agreement conflicts. One commenter recommended that the Committee evaluate potential conflicts between complementary policies under consideration and regulations and trade agreements. That type of analysis is envisioned in the next phase of the Committee's work, as explained in further detail in the amended "Next Steps" section of this paper.

Appendix 3: List of Acronyms

CCS	Carbon capture and sequestration
CHP	Combined heat and power
EERS	Energy efficiency resource standard
EPA	U.S. Environmental Protection Agency
EPS	Emissions performance standard
FIT	Feed-in tariff
GHG	Greenhouse gas
GWP	Global warming potential
LCFRR	Low Carbon Fuel Requirement Regulation
LCFS	Low carbon fuel standard
LMOP	Landfill Methane Outreach Program
MW	Megawatt
MWh	Megawatt-hour
ODS	Ozone depleting substances
PAYD	Pay-as-you-drive
PURPA	Public Utility Regulatory Policies Act
RPS	Renewable portfolio standard
TRU	Transport Refrigeration Units
WCI	Western Climate Initiative
VMT	Vehicle miles traveled

Western Climate Initiative



Proposed Harmonization of Essential Requirements for Mandatory Reporting in U.S. Jurisdictions with EPA Mandatory Reporting Rule

May 28, 2010

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1 Introduction

On July 16, 2009, The WCI published the Final Essential Requirements for Mandatory Reporting (the "ERs") to be implemented by the WCI Partner jurisdictions. On September 22, 2009, U.S. EPA adopted its final Mandatory Reporting Rule (the "EPA rule") for greenhouse gas emissions. Many U.S. facilities in the WCI region will be subject to both reporting programs. Specifically, most facilities with emissions of CO_2e greater than or equal to 25,000 metric tons per year in WCI states will be subject to both programs.

The WCI Partners were concerned that the existence of two different reporting systems in a WCI state could result in the imposition of duplicative or conflicting reporting obligations on facilities subject to both programs. Unless steps were taken to reconcile the WCI ERs with the EPA rule, a facility in a WCI state and with CO_2e emissions of 25,000 metric tons per year or greater could be required to prepare and submit two reports containing different data values in different formats to two jurisdictions.

In order to avoid the imposition of this burden on reporting facilities, the Partners directed the WCI Reporting Committee to develop amended ERs that are harmonized with the EPA rule.

Both the EPA rule and the WCI ERs require the filing of initial reports for the 2010 reporting year by Spring 2011 (March 31, 2011, and April 1, 2011, respectively). The goal of the Reporting Committee is to issue amended ERs in time for implementation in the 2011 reporting year. The adoption and implementation of interim measures to harmonize existing reporting requirements with the EPA rule has been left to the discretion of individual WCI jurisdictions.

This document and its Appendices contain the WCI's proposal for harmonizing the ERs and the EPA rule in U.S. jurisdictions (the "harmonized ERs"). As explained below, the WCI is also working on the development of amended ERs that are methodologically consistent with the harmonized ERs but appropriate for use in the Canadian Partner jurisdictions.

WCI stakeholders are invited to submit written comments on this proposal by no later than June 28, 2010.

2 Harmonization Principles

2.1 For U.S. Jurisdictions

In developing harmonized ERs for use in U.S. jurisdictions, the WCI Reporting Committee adhered to the following principles:

1. A U.S. facility should be able to comply with both the MRR and a WCI jurisdiction's reporting requirements by following a single set of monitoring, recordkeeping and reporting requirements.

2. The quantification methods included in the harmonized ERs must be sufficiently reliable and accurate to be employed in a greenhouse gas (GHG) cap-and-trade program.

The most straightforward way to follow the first principle would be to adopt the EPA rule without change. Unfortunately, it is not possible to do so and also adhere to the second principle. As EPA has acknowledged, the EPA rule, unlike the WCI ERs, has not been specifically designed to meet the needs of a cap-and-trade program:

> A key difference between the Federal mandatory GHG reporting rule and the RGGI and WCI programs is that the Federal mandatory GHG rule is solely a reporting requirement. It does not in any way regulate GHG emissions or require any emissions reductions.

74 Fed. Reg. 16448, 16460 (2009); see also 74 Fed. Reg. 56260, 56369 (2009) (EPA rule designed to gather data needed to "inform future climate change policies").

Fortunately, in nearly all cases where the Reporting Committee determined that a modification to the EPA rule was necessary for implementation of a cap-and-trade program or to achieve other WCI objectives, the modification could be implemented without requiring any alteration to the EPA program. For example, Subpart C of EPA's general stationary combustion rule establishes essentially the same four-tiered approach as section WCI.20 of the ERs. In some cases, WCI.20 requires the use of a higher tier than the EPA rule. Because the EPA rule generally *allows* the use of higher tier for any facility, however, a facility may use the methodology required by WCI.20 and still submit a report conforming to the EPA rule.

In a few cases, the Reporting Committee identified additional data elements that the EPA rule does not require but that WCI jurisdictions will need for cap-and-trade or other purposes.[1] In order to avoid imposing a requirement to file a supplemental report addressing these data elements, the Reporting Committee has been working with EPA and the National Data Exchange to secure changes to the EPA GHG reporting schema that will allow submission of reports containing these data elements directly to EPA. In addition, EPA has indicated that it may be possible to make adjustments to the online reporting tool it is developing for the federal GHG reporting program to accommodate state and regional reporting requirements.

[1] For example, gathering data related to cogeneration.

WCI intends to follow the same principles with regard to future additions or amendments to the EPA rule, such as the recently re-proposed Subpart W for the oil and gas industry.

2.2 For Canadian Jurisdictions

In developing harmonized ERs for use in Canadian jurisdictions that modify the existing ERs, the WCI Reporting Committee is adhering to the following principles:

1. A Canadian facility should apply the same functions, equations, sampling protocols and measurement criteria as U.S. facilities subject to the U.S. version of the harmonized ERs. This means that the harmonized ERs will achieve the same level of reporting accuracy for Canadian and U.S. facilities, but the U.S. version may require more data elements to be reported to harmonize with the EPA rule.

2. The quantification methods included in the harmonized ERs must remain sufficiently reliable and accurate to be employed in a greenhouse gas (GHG) cap-and-trade program.

3. The WCI reporting system must remain suitable for use in Canadian jurisdictions. For example, it must allow reporting in metric as well as English units and must where necessary include Canada-specific emission factors.

4. The harmonized ERs should facilitate harmonization with Canadian federal reporting. Some Canadian jurisdictions are working with Environment Canada to develop a one-window reporting tool for provincial and national GHG reporting requirements.

3 Harmonization Approach

3.1 For U.S. Jurisdictions

The WCI proposes to achieve harmonization in U.S. jurisdictions by adopting incorporation-by-reference rules that modify the EPA rule in a manner consistent with the harmonization principles set forth in section 2.1. The new WCI ERs for U.S. jurisdictions, which are attached to this document as appendices, therefore take the form of a markup of the EPA rule. The partners anticipate that each U.S. Partner will adopt an incorporation-by-reference rule consistent with this markup.

The WCI chose this approach for U.S. jurisdictions, rather than attempting to amend the existing WCI ERs to achieve harmonization, for the following reasons:

- Although the WCI ERs and EPA rule for the most part follow similar approaches to GHG quantification, they vary widely in organization and formatting and in the details of the monitoring, recordkeeping and reporting requirements imposed. It would therefore be extraordinarily difficult to amend the ERs to conform to the EPA rule without inadvertently introducing inconsistencies between the two programs. Any inconsistency would subject U.S. facilities to the risk of noncompliance with one program or the other.

- An incorporation-by-reference rule will make it much easier for a facility subject to both WCI and EPA requirements to assure itself that it is complying with both programs.

3.2 For Canadian Jurisdictions

For the Canadian jurisdictions, the key requirement is that the WCI reporting system as a whole require the use of comparable methodologies and produce comparable results for facilities of the same type, so that a “ton is a ton” in both the U.S. and Canada. For Canadian jurisdictions it is not nearly as important to avoid small differences between the ERs and the EPA rule as it is for the U.S. jurisdictions, where differences create a risk of inadvertent non-compliance.

Canadian Partners have invested substantial resources in developing regulations to implement the existing WCI ERs. In addition, the provinces face technical and legal issues with the incorporation by reference of the EPA rule that do not apply to the states. The WCI is therefore working on the development of amendments to the existing WCI ERs to assure that they conform in substance with the U.S. version of the harmonized ERs. These amendments will also take into account the interest provinces have in harmonizing their reporting programs with Environment Canada’s.

The Reporting Committee is currently undertaking the Canadian ER harmonization work, and expects to have harmonized ERs prepared for stakeholder review in July.

3.3 Verification

Consistent with the Design Recommendations for the WCI Regional Cap-and-Trade Program, the harmonized ERs will continue to require third party verification of emission reports by entities and facilities included in the cap. A version of the verification rule, WCI.8, revised to cross reference the U.S. version of the harmonized ERs is included as an appendix.

Because the EPA rule does not require third-party verification, it generally requires reporting of substantially more data than the existing WCI ERs. In the absence of third-party verification, EPA must require the submission of sufficient data to enable the agency to implement its own audit program. In order to assure consistency with the first harmonization principle—allowing compliance with both programs through preparation of a single report—the WCI markup of the

EPA rule does not attempt to reduce the amount of data required in a report for U.S. jurisdictions.

The amount of data to be reported for Canadian jurisdictions will be modified to reflect that third party verification is required for emissions reports at a certain threshold of emissions, so less data is required to be reported to the Canadian jurisdictions as compared to that which is required to be reported to the EPA for their internal verification.

3.4 Missing Data Procedures

The EPA rule includes procedures in each subpart for replacing missing data resulting from monitoring failures. With the exception of methodologies for facilities subject to 40 C.F.R. Part 75 (the acid rain program), these missing data procedures do not appear to be sufficiently rigorous to support a cap-and-trade system. There is no limitation on the amount of data that may be missing, and replacement methods appear to be both inadequate (for example, many use only one or two available data points) and inequitable (for example, Part 75 power plants have to apply punitive methods, while other facilities do not).

In order to move forward with a harmonization proposal in time to allow implementation for the 2011 reporting year, the proposed harmonized ERs retain the EPA missing data procedures. Before implementation of the cap-and-trade program, however, the WCI intends to revisit this issue. The WCI will investigate whether the EPA missing data procedures can be modified to be more consistent with the needs of a cap-and-trade program while adhering to the harmonization principles in section 2.1.

As a partial measure to address the possibility of gaming, the harmonized ERs include a provision making it clear that the use of a missing data procedure does not excuse a facility's failure to follow the monitoring requirements of the rule.

4 Summary of Changes to EPA Rule

The following table summarizes the changes to the EPA rule that the WCI is proposing to implement in WCI jurisdictions. The specific language for the changes is set forth in the Appendices.

The table also identifies potential differences in approach that may be employed by the Canadian WCI jurisdictions.

§	Change to EPA Rule	Rationale
Subpart A—General Provisions		
98.1	Added new (c) substituting jurisdiction for EPA and EPA administrator throughout rule.	Clarifies who is responsible for administering the incorporated-by-reference version of the EPA rule. Since the EPA rule does not provide delegation, EPA will remain responsible for administering the original 40 C.F.R. Part 98 requirements.
98.1 and passim[2]	Added new (d) providing for identification of data that will be reported for informational purposes only and will not be subject to cap and trade. Added "reporting only" label to certain EPA subparts and specific quantification methods.	Not all quantification methods specified by the harmonized ERs are suitable for a cap-and-trade system. The "reporting only" label provides notice to stakeholders on WCI's current view on which emissions should not be subject to the cap-and-trade program.
98.1	Added new (e) to authorize a WCI jurisdiction to allow submission of a report to EPA to meet the requirements of the harmonized ERs.	As discussed above, WCI is working with EPA to allow reporting entities to use EPA's system to meet the requirements of both the EPA rule and the harmonized ERs.

[2] Occurring in various places.

§	Change to EPA Rule	Rationale
98.2 passim	Changed threshold for reporting from 25,000 metric tons to 10,000 metric tons.	Consistent with WCI design recommendation for reporting. EPA has indicated that it may be able to accommodate reports by facilities with emissions below the EPA rule threshold.
98.2(a)(3)(iii)	Changed heat input threshold for fuel combustion units from 30 mmBtu/hr to 12 mmBtu/hr.	The 30 mmBtu/hr threshold is designed to provide facilities whose only regulated GHG source is fuel combustion an easy method for determining whether they are above the 25,000 metric tons emission threshold. For WCI's 10,000 metric tons threshold, the equivalent heat input threshold is 12 mmBtu/hr.
98.2(b)(2)	Added exclusions from the applicability determination for certain emissions from the combustion of biomass.	Consistent with WCI Design Recommendations and existing WCI.1(b)(2).
98.2(i)	Added new (4) providing additional off-ramp for facilities required to report to WCI jurisdiction but not EPA (i.e. emissions between 10,000 and 25,000 metric tons per year) that subsequently fall below the 10,000- metric-tons-per-year threshold.	Consistent with existing WCI.1(e)(2).
98.3(g), 98.3(g)(5)(iv)	Added requirement to submit records within 10 days of a request from a WCI jurisdiction.	Consistent with existing WCI.4(b). Failure of EPA rule to specify a time period for responding may make enforcement difficult.
98.3(h)	Added a new (2) requiring facilities subject to WCI but not EPA reporting requirements to submit correction only if cumulative errors exceed 5 % of total CO_2e emissions.	Consistent with WCI.2(f). This change cannot be applied to facilities subject to the EPA rule, since EPA requires the correction of any errors.

§	Change to EPA Rule	Rationale
98.3(i) (6)	Modified to require calibration during any outage of sufficient duration to allow performance of the calibration procedure, not just during scheduled maintenance.	If outages occur for reasons other than scheduled maintenance (e.g. for repairs necessitated by unforeseen equipment failure), and the outages last long enough to complete a new calibration, there is no reason to put calibration off until the next schedule maintenance.
98.3	Added a method for calculating weighted averages as new (j).	In some cases, the harmonized ERs require more frequent sampling than the EPA rule. This subsection provides a method for reducing the data obtained from the additional samples to fit the EPA reporting system.
98.3	Added new (k) requiring a jurisdiction's approval before a facility may switch from a CEMS to a mass- or fuel-based monitoring method or vice versa.	This provision is designed to prevent facilities from using changes in monitoring methods to create an artificial reduction in GHG emissions.
98.3	Added a modified version of the de minimis provision in WCI.2(d) as new (l). Instead of allowing the use of any alternative method approved by the verifier, as in the current ERs, the modified version requires the use of a method permitted by 40 C.F.R. Part 98 for the facility. So, for example, a facility subject to verification could use Tiers 1 or 2, rather than Tier 3, for up to 3 percent of its combustion emissions.	The EPA rule does not include a de minimis provision. Allowing U.S. facilities to employ methods that are not specified by the EPA rule therefore would be inconsistent with harmonization. In some cases, however, the harmonized ERs require the use of a higher tier than would otherwise be required by the EPA rule. In these cases, it is consistent with harmonization to allow the use of the lower tier for emissions determined to be de minimis.

§	Change to EPA Rule	Rationale
98.3	Added new (m) to make it clear the missing data procedures included in the EPA rule (and therefore the harmonized ERs) do not excuse facilities from possible enforcement action for failure to conduct the monitoring required by the rule.	See section 3.4.
Subpart C—General Stationary Combustion		
98.32(b), 98.33(f)	Added requirement to report fugitive HFC emissions from cooling units.	Consistent with existing WCI.42(h) and WCI.42(d).
98.33(a)(2)(iii)	Limit availability of Equation C-2c (ratio of heat input to steam method) to municipal solid waste and solid biomass, rather than allowing its use for any other solid fuel listed in Table C-1.	Consistent with existing WCI.23(b)(2).
98.33(a)(4)(iv)	Require CEMS installed after beginning of first reporting year subject to rule to include a CO2 monitor, rather than an oxygen monitor.	Although it may make sense not to require the retrofit of grandfathered CEMS with a CO2 monitor, there is no reason for newly installed CEMS not to include such a monitor.
98.33(b)(1)	Limit use of Tier 1 (default emission factors and HHV) to units that are both (1) below both EPA's 250 mmBtu/hr heat input threshold and (2) located at facilities that are not subject to verification (i.e., emissions < 25,000 metric tons/yr).	Consistent with existing WCI.23(e)(1).
98.33(b)(1)(iv)	Require use of Tier 2 when a facility can obtain HHV from the fuel supplier, even if this information is not currently "routinely received."	If a facility is able to obtain this information, it should use the more accurate method.

§	Change to EPA Rule	Rationale
98.33(b)(2)	Limit use of Tier 2 (default emission factors and measured HHV) to units that are both (1) below both EPA's 250 mmBtu/hr heat input threshold and (2) located at facilities that are not subject to verification (i.e., emissions < 25,000 metric tons/yr), except for facilities that burn pipeline quality natural gas or distillate fuel oil.	Consistent with existing WCI.23(e)(2).
98.33(b)(3)	Require the use of Tier 3 (measured carbon content) for all units at a facility subject to verification (i.e. emissions > 25,000 metric tons/yr). Require Tier 3 for the combustion of *all* fuels that are not listed in Table C-1, not just for unlisted fuels that provide 10 % or more of a unit's annual heat input.	Consistent with existing WCI.23(e)(3). Exempting unlisted fuels that provide less than 10 % of a unit's heat input could result in a significant gap in a facility's reported emissions.
98.33(c)	Add new (6) to allow an operator use a source-specific emission factor to calculate CH4 and N2O emissions.	Consistent with existing WCI.24(d). Since this is optional, it does not conflict with harmonization principle 1.
98.33(e)(2)	Require the use of 98.33(e)(3) for the combustion of any fossil fuel/biomass mixture containing an undeterminable quantity of fossil fuels, not just MSW.	The method specified in 98.33(e)(2) assumes that the amount of fossil fuel in a fossil fuel/biomass mixture can be determined and that a mass balance approach is therefore possible. Its use therefore must be limited to fuels where the amount of fossil fuel in a mixture can in fact be determined. Other mixtures must as a practical matter be subject to 98.33(e)(3).

§	Change to EPA Rule	Rationale
98.34(b)(3)(ii)(E)	Require installation of equipment necessary to perform daily sampling and analysis of carbon content and molecular weight for refinery fuel gas by beginning of first reporting year subject to harmonized ERs.	Consistent with existing WCI.34.
98.36(b), (d)	Added provisions requiring reporting of nameplate capacity and net power generated for EGUs and cogeneration data, as well as certain fuel data if not reported under 40 C.F.R. Part 75.	Consistent with existing WCI.40.
Subpart D—Electricity Generation		
98.46	Corrected cross-reference.	Clarification.
Subpart E—Adipic Acid Production		
No change.		
Subpart F—Aluminum Production		
98.64(a)	Changed to require re-measurement of smelter-specific slope coefficients every 36 months, rather than every 10 years. Inserted additional conditions that would trigger the obligation to re-measure the coefficients before the expiration of the 36-month period.	Consistent with WCI.74(b).
98.64(a), (d)	Changed to require the use of smelter-specific measurements rather than the default values specified in table F-1.	Consistent with WCI.74.
98.64(b)	Changed minimum measurement frequency from annually to monthly for all parameters.	Consistent with WCI.74(a).
Subpart G—Ammonia Production		
No change.		

§	Change to EPA Rule	Rationale
Subpart H—Cement Production		
No change to EPA rule for U.S. jurisdictions. Unlike the EPA rule, existing WCI.090 allows emissions to be calculated on a facility-wide basis. The harmonized ERs for U.S. jurisdictions will retain the EPA requirement to calculate emissions for each kiln in order to assure harmonization. Canadian jurisdictions, however, may continue to allow facility-based calculations.		
Subpart K—Feroalloy Production		
No change.		
Subpart N—Glass Production		
Passim	Changed to apply to batch as well as continuous processes.	Consistent with draft WCI method. This change may require facilities not subject to the EPA rule to report but should not result in a facility subject to both the WCI and EPA programs being subject to inconsistent reporting obligations.
Subpart O—HCFC-22 Production and HFC-23 Destruction		
No change.		
Subpart P—Hydrogen Production		
98.160(a)	Changed to apply subpart to production of hydrogen for use on site as well as hydrogen sold as a product.	Consistent with WCI.131. This change may require facilities not subject to the EPA rule to report but should not result in a facility subject to both the WCI and EPA programs being subject to inconsistent reporting obligations.
98.163(b), 98.164(b)(2)-(4)	Require daily, rather than monthly or weekly, analysis of carbon feedstocks other than natural gas.	Consistent with WCI.134(b)(1). Higher frequency sampling required to insure accuracy adequate for a cap-and-trade program.

<table>
<tr><th>§</th><th>Change to EPA Rule</th><th>Rationale</th></tr>
<tr><td>98.166(b)</td><td>Added (7) requiring reporting of carbon in unconverted feedstock for which GHG emissions are calculated and reported by the facility using other methods.</td><td>In order to avoid possible double counting of emissions, WCI.133, Equation 130-1 allows subtraction of carbon “accounted for elsewhere” from the amount of feedstock, before calculation of the mass balance. EPA’s equations P-1, P-2 and P-3 do not allow for such a deduction. The equations themselves cannot be modified in the harmonized ERs, because that would require reporting different emissions to EPA and a U.S. WCI jurisdiction. The harmonized ERs therefore provide for the reporting of carbon accounted for elsewhere in bulk, which can then be subtracted from a facility’s total emissions by the WCI data system.</td></tr>
<tr><td colspan="3">Subpart Q—Iron and Steel Production</td></tr>
<tr><td colspan="3">No change to EPA rule for U.S. jurisdictions.

The EPA rule requires the reporting of CO2 from the combustion of coke oven gases at the point of combustion under Subpart C. Existing WCI.153 requires the reporting of emissions attributable to coke oven gases and blast furnace gases at the point of generation using a mass balance method. U.S. jurisdictions will employ the EPA method in order to assure harmonization. Canadian jurisdictions may continue to employ existing WCI.153. It is anticipated that the methods will produce substantially similar results.

Jurisdictions also may choose not to allow the use of the site-specific emission factor method established by 98.173(b)(2) for process emissions.</td></tr>
<tr><td colspan="3">Subpart R—Lead Production</td></tr>
<tr><td colspan="3">No change.</td></tr>
<tr><td colspan="3">Subpart S—Lime Production</td></tr>
<tr><td colspan="3">No change.</td></tr>
</table>

§	Change to EPA Rule	Rationale
Subpart V—Nitric Acid Production		
No change.		
Subpart X—Petrochemical Production		
No change.		
Subpart Y—Petroleum Refineries		
98.253(b)(1)(iii) 98.256(e)(8)	Amended to allow use of alternative equation Y-3 for flare emissions only during periods of startup, shutdown or malfunction.	The more accurate methods specified in equations Y-1 and Y-2 should be used for periods of normal operations.
98.253(c)(2) 98.256(f)(9)	Require calculation of emissions from catalytic cracking units that do not use CEMS and have rated capacities less than 10,000 barrels per stream day using this method (no less than hourly monitoring of O2, CO2 and CO), rather than 98.173(c)(3), which is deleted.	The EPA TSD for this sector states that the method specified in 98.173(c)(3) for units that do not have the necessary monitors is highly uncertain.
98.253(h), (l), (m), (n)	Identified as reporting only.	WCI does not believe the methods specified in these sections are sufficiently accurate to support a cap-and-trade program.
98.253(i)	Rather than allowing the use of default factors in Equation Y-18 for CO2 emissions from delayed coking units, require (1) the volumetric void fraction of the coking vessel prior to steaming to be based on engineering calculations and (2) the mole fraction of methane in coking vessel gas to be based on two samples per year.	Greater accuracy required for cap-and-trade.
98.253(k) 98.256(m)	Require the use the same method for process vents (paragraph (j)) and uncontrolled blowdown systems.	Consistent with WCI.200.

§	Change to EPA Rule	Rationale
98.254	New (m) added to require installation of equipment needed for daily sampling of carbon content and molecular weight of gaseous fuels (other than natural gas and biogas) by no later than first reporting year of harmonized ERs.	Needed to insure Tier 3 calculations of emissions from refinery gas are sufficiently accurate for cap-and-trade.
98.257(m)	New (b) added to require retention of records of the method used to demonstrate that the thresholds in §98.253(j) are not exceeded.	Needed for third-party verification.
Subpart Z—Phosphoric Acid Production		
No change.		
Subpart AA—Pulp and Paper		
98.273(a)(1), (b)(1), (c)(1)	Require use of applicable Subpart C methodology rather than specifying the use of Tier 1 for combustion at chemical recovery furnaces and pulp mill lime kilns.	Consistent with WCI.212(c). There does not appear to be any reason to treat combustion at these sources differently from combustion elsewhere. Note: Although Subpart C generally allows the use of higher tiers, even when a lower tier is specified for a particular unit or fuel, section 98.273 could be read as *requiring* the use of Tier 1. WCI is seeking clarification of the correct interpretation of section 98.273 in order to assure that the proposed changes are consistent with harmonization principle 1.
Subpart CC—Soda Ash Manufacturing		
98.294(d), 98.296(a)(5), (b)(12)	Added requirement to determine CO2 recycled to carbonation tower.	Consistent with WCI.232(f).

§	Change to EPA Rule	Rationale
Subpart GG—Zinc Production		
No change.		

Subpart A—General Provisions

§ 98.1 Purpose and scope.

(a) This part establishes mandatory greenhouse gas (GHG) reporting requirements for owners and operators of certain facilities that directly emit GHG as well as for certain fossil fuel suppliers and industrial GHG suppliers. For suppliers, the GHGs reported are the quantity that would be emitted from combustion or use of the products supplied.[1]

(b) Owners and operators of facilities and suppliers that are subject to this part must follow the requirements of subpart A and all applicable subparts of this part. If a conflict exists between a provision in subpart A and any other applicable subpart, the requirements of the subparts B through PP of this part shall take precedence.

(c) Except as otherwise specifically provided:

(1) Wherever the term "Administrator" is used in the rules incorporated by reference in this Article,[2] the term [director/secretary/administrator] of the [jurisdiction] shall be substituted.

(2) Wherever the term "EPA" is used in the rules incorporated by reference in this Article, the term [jurisdiction] shall be substituted.

(d) The following emissions data shall be submitted for information only and may not be subject to cap-and-trade requirements:[3]

(1) Data submitted by a source category designated as "reporting only." This provision does not apply to emissions from general stationary combustion at a source in a "reporting only" category.

(2) Emissions data calculated with a methodology identified as "reporting only."

(3) Data submitted by a facility not subject to verification under WCI.8.

[1] WCI jurisdictions will require reporting by fuel suppliers for reporting year 2012 and later and may in part rely on EPA methods

[2] "Article" is a placeholder for a jurisdiction-specific cross reference to whatever subdivision of its administrative code contains the WCI's Essential Requirements for Mandatory Reporting in their entirety. Any WCI methodologies that are not sufficiently accurate for cap-and-trade purposes, such as the coal storage method, should be designated "reporting only" in the jurisdiction's rules.

[3] The identification of data as "reporting only" will be subject to review possible revision before the adoption of a cap-and-trade program. On adoption of a cap-and-trade program, the jurisdiction will want to substitute a citation to the rules implementing the program for the words "cap-and-trade requirements." Any WCI methodologies that are not sufficiently accurate for cap-and-trade purposes, such as the coal storage method, should also be designated "reporting only" in the jurisdiction's rules.

(e) On approval by [jurisdiction], reports that conform to this Article and that are submitted to the EPA GHG reporting system shall be deemed to satisfy, in whole or in part,[4] the requirement to submit a report to [jurisdiction] under this Article.[5]

§ 98.2 Who must report?

(a) The GHG reporting requirements and related monitoring, recordkeeping, and reporting requirements of this part apply to the owners and operators of any facility that is located in the United States and that meets the requirements of either paragraph (a)(1), (a)(2), or (a)(3) of this section; and any supplier that meets the requirements of paragraph (a)(4) of this section:

(1) A facility that contains any source category (as defined in subparts C through JJ of this part) that is listed in this paragraph (a)(1) in any calendar year starting in ~~2010~~2011.[6] [7] For these facilities, the annual GHG report must cover all source categories and GHGs for which calculation methodologies are provided in subparts C through JJ of this part and sections – of this Article.

(i) Electricity generation (units that report CO2 emissions year-round through 40 CFR part 75).

(ii) Adipic acid production.

(iii) Aluminum production.

(iv) Ammonia manufacturing.

(v) Cement production.

(vi) HCFC–22 production.

(vii) HFC–23 destruction processes that are not collocated with a HCFC–22 production facility and that destroy more than 2.14 metric tons of HFC–23 per year.

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[4] Supplemental reports may be needed for facilities subject to both EPA reporting requirements and WCI-only quantification methodologies, e.g. facilities that include coal storage (subject to WCI.100).

[5] Applies in U.S. jurisdictions only. Procedures for approval will be established by the jurisdiction.

[6] Alternatively, the calendar year after adoption of these essential requirements for a WCI jurisdiction adopting them after 2011. The same change would be made to other instances below where an initial reporting year of 2011 is specified.

[7] No threshold is specified for these source categories, because EPA has determined that the overwhelming majority of facilities in these categories would have emissions greater than 25,000 metric tons per year. It is highly likely that all such facilities would have emissions greater than 10,000 metric tons per year. Thus, omitting a threshold simplifies the rule without departing from the WCI's policy of requiring reporting only for facilities with emissions exceeding 10,000 metric tons per year. Canadian jurisdictions may choose to impose the 10,000 metric tons per year threshold to some or all of these categories so long as the coverage is not altered.

(viii) Lime manufacturing.

(ix) Nitric acid production.

(x) Petrochemical production.

(xi) Petroleum refineries.

(xii) Phosphoric acid production.

(xiii) Silicon carbide production.

(xiv) Soda ash production.

(xv) Titanium dioxide production.

(xvi) Municipal solid waste landfills that generate CH4 in amounts equivalent to 25,000 metric tons CO2e or more per year, as determined according to subpart HH of this part [Reporting only].

(xvii) Manure management systems with combined CH4 and N2O emissions in amounts equivalent to metric tons CO2e or more per year, as determined according to subpart JJ of this part [Reporting only].

(2) A facility that contains any source category (as defined in subparts C through JJ of this part) that is listed in this paragraph (a)(2) in any calendar year starting in 2010 and that emits ~~25,000~~10,000 metric tons CO2e or more per year in combined emissions from stationary fuel combustion units, miscellaneous uses of carbonate, and all source categories that are listed in this paragraph. For these facilities, the annual GHG report must cover all source categories and GHGs for which calculation methodologies are provided in subparts C through JJ of this part and sections – of this Article.

(i) Ferroalloy Production.

(ii) Glass Production.

(iii) Hydrogen Production.

(iv) Iron and Steel Production.

(v) Lead Production.

(vi) Pulp and Paper Manufacturing.

(vii) Zinc Production.

(3) A facility that in any calendar year starting in 2010 meets all three of the conditions listed in this paragraph (a)(3). For these facilities, the annual GHG report must cover emissions from stationary fuel combustion sources only.

(i) The facility does not meet the requirements of either paragraph (a)(1) or (a)(2) of this section.

(ii) The aggregate maximum rated heat input capacity of the stationary fuel combustion units at the facility is ~~30~~ 12 mmBtu/hr or greater.[8]

(iii) The facility emits ~~25,000~~10,000 metric tons CO2e or more per year in combined emissions from all stationary fuel combustion sources.

(4) A supplier (as defined in subparts KK through PP of this part) that provides products listed in this paragraph (a)(4) in any calendar year starting in 2010. For these suppliers, the annual GHG report must cover all applicable products for which calculation methodologies are provided in subparts KK through PP of this part.

(i) Coal-to-liquids suppliers, as specified in this paragraph (a)(4)(i).

(A) All producers of coal-to-liquid products.

(B) Importers of an annual quantity of coal-to-liquid products that is equivalent to 25,000 metric tons CO2e or more.

(C) Exporters of an annual quantity of coal-to-liquid products is equivalent to 25,000 metric tons CO2e or more.

(ii) Petroleum product suppliers, as specified in this paragraph (a)(4)(ii):

(A) All petroleum refineries that distill crude oil.

(B) Importers of an annual quantity of petroleum products that is equivalent to 25,000 metric tons CO2e or more.

(C) Exporters of an annual quantity of petroleum products that is equivalent to 25,000 metric tons CO2e or more.

(iii) Natural gas and natural gas liquids suppliers, as specified in this paragraph (a)(4)(iii):

(A) All natural gas fractionators.

(B) All local natural gas distribution companies.

(iv) Industrial greenhouse gas suppliers, as specified in this paragraph (a)(4)(iv):

(A) All producers of industrial greenhouse gases.

(B) Importers of industrial greenhouse

[8] 30 mmBtu/hr * 10,000/25,000.

gases with annual bulk imports of N_2O, fluorinated GHG, and CO_2 that in combination are equivalent to 25,000 metric tons CO_2e or more.

(C) Exporters of industrial greenhouse gases with annual bulk exports of N_2O, fluorinated GHG, and CO_2 that in combination are equivalent to 25,000 metric tons CO_2e or more.

(v) Carbon dioxide suppliers, as specified in this paragraph (a)(4)(v).

(A) All producers of CO_2.

(B) Importers of CO_2 with annual bulk imports of N_2O, fluorinated GHG, and CO_2 that in combination are equivalent to 25,000 metric tons CO_2e or more.

(C) Exporters of CO_2 with annual bulk exports of N_2O, fluorinated GHG, and CO_2 that in combination are equivalent to 25,000 metric tons CO_2e or more.

(5) Research and development activities are not considered to be part of any source category defined in this part.

(b) To calculate GHG emissions for comparison to the ~~25,000~~10,000 metric ton CO_2e per year emission threshold in paragraph (a)(2) of this section, the owner or operator shall calculate annual CO_2e emissions, as described in paragraphs (b)(1) through (b)(4) of this section.

(1) Calculate the annual emissions of CO_2, CH_4, N_2O, and each fluorinated GHG in metric tons from all applicable source categories listed in paragraph (a)(2) of this section. The GHG emissions shall be calculated using the calculation methodologies specified in each applicable subpart and available company records. Include emissions from only those gases listed in Table A– 1 of this subpart.

(2) For each general stationary fuel combustion unit, calculate the annual CO_2 emissions in metric tons using any of the four calculation methodologies specified in § 98.33(a). Calculate the annual CH_4 and N_2O emissions from the stationary fuel combustion sources in metric tons using the appropriate equation in § 98.33(c). ~~Exclude carbon dioxide emissions from the combustion of biomass, but include emissions of CH4 and N2O from biomass combustion.~~

(i) For stationary combustion units, carbon dioxide emissions from the combustion of biomass fuels shall be included in determining whether a facility is subject to the reporting requirements of this Article with the following exceptions:

(1) Until such time as [jurisdiction] has made a determination regarding the carbon neutrality of any biomass fuels, a maximum of 15,000 metric tons of carbon dioxide emissions from the combustion of pure solid biomass fuel may be excluded from calculation of GHG emissions for comparison to the 10,000 metric ton CO2e per year emission threshold in paragraph (a)(2) of this section, provided that total GHG emissions including emissions from solid biomass fuel are less than 25,000 metric tons CO2e.

(2) After such time as [jurisdiction] has made a determination regarding the carbon neutrality of any biomass fuels, the carbon dioxide emissions from the combustion of those fuels may be excluded from calculation of GHG emissions for determining whether the 10,000 metric tons CO2e per year emission threshold in paragraph (a)(1) of this section has been met.

(ii) The exceptions in paragraphs (b)(2)(i) of this section shall not apply in determining whether a facility is subject to the reporting requirements of 40 C.F.R. Part 98.

(3) For miscellaneous uses of carbonate, calculate the annual CO2 emissions in metric tons using the procedures specified in subpart U of this part.

(4) Sum the emissions estimates from paragraphs (b)(1), (b)(2), and (b)(3) of this section for each GHG and calculate metric tons of CO2e using Equation A– 1 of this section.

$$CO_2e = \sum_{i=1}^{n} GHG_i \times GWP_i \qquad \text{(Eq. A-1)}$$

Where:

CO2e = Carbon dioxide equivalent, metric tons/year.

GHGi = Mass emissions of each greenhouse gas listed in Table A–1 of this subpart, metric tons/year.

GWPi = Global warming potential for each greenhouse gas from Table A–1 of this subpart.

n = The number of greenhouse gases emitted.

(5) For purpose of determining if an emission threshold has been exceeded, include in the emissions calculation any CO2 that is captured for transfer off site.

(c) To calculate GHG emissions for comparison to the ~~25,000~~10,000 metric ton CO_2e/year emission threshold for stationary fuel combustion under paragraph (a)(3) of this section, calculate CO_2, CH_4, and N_2O emissions from each stationary fuel combustion unit by following the methods specified in paragraph (b)(2) of this section. Then, convert the emissions of each GHG to metric tons CO_2e per year using Equation A–1 of this section, and sum the emissions for all units at the facility.

(d) To calculate GHG quantities for comparison to the 25,000 metric ton CO_2 per year threshold for importers and exporters of coal-to-liquid products under paragraph (a)(4)(i) of this section, calculate the mass in metric tons per year of CO_2 that would result from the complete combustion or oxidation of the quantity of coal-to-liquid products that are imported during the reporting year and that are exported during the reporting year. Calculate the emissions using the methodology specified in subpart LL of this part.

(e) To calculate GHG quantities for comparison to the 25,000 metric ton CO_2e per year threshold for importers and exporters of petroleum products under paragraph (a)(4)(ii) of this section, calculate the mass in metric tons per year of CO_2 that would result from the complete combustion or oxidation of the volume of petroleum products and natural gas liquids that are imported during the reporting year and that are exported during the reporting year. Calculate the emissions using the methodology specified in subpart MM of this part.

(f) To calculate GHG quantities for comparison to the 25,000 metric ton CO_2e per year threshold under paragraph (a)(4) of this section for importers and exporters of industrial greenhouse gases and for importers and exporters of CO_2, the owner or operator shall calculate the mass in metric tons per year of CO_2e imports and exports as described in paragraphs (f)(1) through (f)(3) of this section.

(1) Calculate the mass in metric tons per year of CO_2, N_2O, and each fluorinated GHG that is imported and the mass in metric tons per year of CO_2, N_2O, and each fluorinated GHG that is exported during the year. Include only those gases listed in Table A–1 of this subpart.

(2) Convert the mass of each imported and each GHG exported from paragraph (f)(1) of this section to metric tons of CO_2e using Equation A–1 of this section.

(3) Sum the total annual metric tons of CO_2e in paragraph (f)(2) of this section for all imported GHGs. Sum the total annual metric tons of CO_2e in paragraph (f)(2) of this section for all exported GHGs.

(g) If a capacity or generation reporting threshold in paragraph (a)(1) of this section applies, the owner or operator shall review the appropriate records and perform any necessary calculations to determine whether the threshold has been exceeded.

(h) An owner or operator of a facility or supplier that does not meet the applicability requirements of paragraph (a) of this section is not subject to this rule. Such owner or operator would become subject to the rule and reporting requirements § 98.3(b)(3), if a facility or supplier exceeds the applicability requirements of paragraph (a) of this section at a later time. Thus, the owner or operator should reevaluate the applicability to this part (including the revising of any relevant emissions calculations or other calculations) whenever there is any change that could cause a facility or supplier to meet the applicability requirements of paragraph (a) of this section. Such changes include but are not limited to process modifications, increases in operating hours, increases in production, changes in fuel or raw material use, addition of equipment, and facility expansion.

(i) Except as provided in this paragraph, once a facility or supplier is subject to the requirements of this part, the owner or operator must continue for each year thereafter to comply with all requirements of this part, including the requirement to submit annual GHG reports, even if the facility or supplier does not meet the applicability requirements in paragraph (a) of this section in a future year.

(1) If reported emissions are less than 25,000 metric tons CO2e per year for five consecutive years, then the owner or operator may discontinue complying with this part provided that the owner or operator submits a notification to the Administrator that announces the cessation of reporting and explains the reasons for the reduction in emissions. The notification shall be submitted no later than March 31 of the year immediately following the fifth consecutive year of emissions less than 25,000 tons CO2e per year. The owner or operator must maintain the corresponding records required under § 98.3(g) for each of the five consecutive years and retain such records for three years following the year that reporting was discontinued. The owner or operator must resume reporting if annual emissions in any future calendar year increase to 25,000 metric tons CO2e per year or more.

(2) If reported emissions are less than ~~15,000~~ 10,000 metric tons CO2e per year for three consecutive years, then the owner or operator may discontinue complying with this part provided that the owner or operator submits a notification to the Administrator that announces

the cessation of reporting and explains the reasons for the reduction in emissions. The notification shall be submitted no later than March 31 of the year immediately following the third consecutive year of emissions less than ~~15,000~~10,000 tons CO2e per year. The owner or operator must maintain the corresponding records required under § 98.3(g) for each of the three consecutive years and retain such records for three years following the year that reporting was discontinued. The owner or operator must resume reporting if annual emissions in any future calendar year increase to ~~25,000~~10,000 metric tons CO2e per year or more.

(3) If the operations of a facility or supplier are changed such that all applicable GHG-emitting processes and operations listed in paragraphs (a)(1) through (a)(4) of this section cease to operate, then the owner or operator is exempt from reporting in the years following the year in which cessation of such operations occurs, provided that the owner or operator submits a notification to the Administrator that announces the cessation of reporting and certifies to the closure of all GHG emitting processes and operations. This paragraph (i)(2) does not apply to seasonal or other temporary cessation of operations. This paragraph (i)(2) does not apply to facilities with municipal solid waste landfills. The owner or operator must resume reporting for any future calendar year during which any of the GHG-emitting processes or operations resume operation.[9]

(4) If in the prior year a facility was required to report under this Article but was not required to report under 40 C.F.R. Part 98, and the operations of the facility change such that emissions fall below 10,000 metric tons CO2e per year during the prior year, then in lieu of submitting a report under this Article the owner or operator shall submit to [jurisdiction] a signed statement certifying that emissions were less than 10,000 metric tons CO2e during the prior year. After certifying that emissions are below 10,000 metric tons CO2e per year for three consecutive years under this paragraph, the owner or operator shall be exempted from further reporting until CO2e emissions again exceed 10,000 metric tons in any future calendar year.

(j) Table A–2 of this subpart provides a conversion table for some of the common units of measure used in part 98.

[9] This provision may require modification to meet the needs of the cap-and-trade program.

§ 98.3 What are the general monitoring, reporting, recordkeeping and verification requirements of this part?

The owner or operator of a facility or supplier that is subject to the requirements of this part must submit GHG reports to the Administrator, as specified in this section.

(a) General. Except as provided in paragraph (d) of this section, follow the procedures for emission calculation, monitoring, quality assurance, missing data, recordkeeping, and reporting that are specified in each relevant subpart of this part.

(b) Schedule. The annual GHG report must be submitted no later than March 31 of each calendar year for GHG emissions in the previous calendar year.

(1) For an existing facility or supplier that began operation before January 1, 2010, report emissions for calendar year 2010 and each subsequent calendar year.

(2) For a new facility or supplier that begins operation on or after January 1, 2010, report emissions beginning with the first operating month and ending on December 31 of that year. Each subsequent annual report must cover emissions for the calendar year, beginning on January 1 and ending on December 31.

(3) For any facility or supplier that becomes subject to this rule because of a physical or operational change that is made after January 1, 2010, report emissions for the first calendar year in which the change occurs, beginning with the first month of the change and ending on December 31 of that year. For a facility or supplier that becomes subject to this rule solely because of an increase in hours of operation or level of production, the first month of the change is the month in which the increased hours of operation or level of production, if maintained for the remainder of the year, would cause the facility or supplier to exceed the applicable threshold. Each subsequent annual report must cover emissions for the calendar year, beginning on January 1 and ending on December 31.

(c) Content of the annual report. Except as provided in paragraph (d) of this section, each annual GHG report shall contain the following information:

(1) Facility name or supplier name (as appropriate) and physical street address including the city, state, and zip code.

(2) Year and months covered by the report.

(3) Date of submittal.

(4) For facilities, report annual emissions of CO_2, CH_4, N_2O, and each fluorinated GHG (as defined in § 98.6) as follows:

(i) Annual emissions (excluding biogenic CO_2) aggregated for all GHG from all applicable source categories in subparts C through JJ of this part and expressed in metric tons of CO_2e calculated using Equation A–1 of this subpart.

(ii) Annual emissions of biogenic CO_2 aggregated for all applicable source categories in subparts C through JJ of this part.

(iii) Annual emissions from each applicable source category in subparts C through JJ of this part, expressed in metric tons of each GHG listed in paragraphs (c)(4)(iii)(A) through (c)(4)(iii)(E) of this section.

(A) Biogenic CO_2.

(B) CO_2 (excluding biogenic CO_2).

(C) CH_4.

(D) N_2O.

(E) Each fluorinated GHG (including those not listed in Table A–1 of this subpart).

(iv) Emissions and other data for individual units. processes, activities, and operations as specified in the ‘‘Data reporting requirements’’ section of each applicable subpart of this part.

(5) For suppliers, report annual quantities of CO_2, CH_4, N_2O, and each fluorinated GHG (as defined in § 98.6) that would be emitted from combustion or use of the products supplied, imported, and exported during the year. Calculate and report quantities at the following levels:

(i) Total quantity of GHG aggregated for all GHG from all applicable supply categories in subparts KK through PP of this part and expressed in metric tons of CO_2e calculated using Equation A–1 of this subpart.

(ii) Quantity of each GHG from each applicable supply category in subparts KK through PP of this part, expressed in metric tons of each GHG. For fluorinated GHG, report emissions of all fluorinated GHG, including those not listed in Table A–1 of this subpart.

(iii) Any other data specified in the ‘‘Data reporting requirements’’ section of each applicable subpart of this part.

(6) A written explanation, as required under § 98.3(e), if you change emission calculation methodologies during the reporting period.

(7) A brief description of each ‘‘best available monitoring method’’ used according to paragraph (d) of this section, the parameter measured using the method, and the time period during which the ‘‘best available monitoring method’’ was used.

(8) Each data element for which a missing data procedure was used according to the procedures of an applicable subpart and the total number of hours in the year that a missing data procedure was used for each data element.

(9) A signed and dated certification statement provided by the designated representative of the owner or operator, according to the requirements of § 98.4(e)(1).

(d) Special provisions for reporting year 2010.

(1) Best available monitoring methods. During January 1, 2010 through March 31, 2010, owners or operators may use best available monitoring methods for any parameter (e.g., fuel use, daily carbon content of feedstock by process line) that cannot reasonably be measured according to the monitoring and QA/QC requirements of a relevant subpart. The owner or operator must use the calculation methodologies and equations in the ‘‘Calculating GHG Emissions’’ sections of each relevant subpart, but may use the best available monitoring method for any parameter for which it is not reasonably feasible to acquire, install, and operate a required piece of monitoring equipment by January 1, 2010. Starting no later than April 1, 2010, the owner or operator must discontinue using best available methods and begin following all applicable monitoring and QA/QC requirements of this part, except as provided in paragraphs (d)(2) and (d)(3) of this section. Best available monitoring methods means any of the following methods specified in this paragraph:

(i) Monitoring methods currently used by the facility that do not meet the specifications of an relevant subpart.

(ii) Supplier data.

(iii) Engineering calculations.

(iv) Other company records.

(2) Requests for extension of the use of best available monitoring methods. The owner or operator may submit a request to the Administrator to use one or more best available monitoring methods beyond March 31, 2010.

(i) Timing of request. The extension request must be submitted to EPA no later than 30 days after the effective date of the GHG reporting rule.

(ii) Content of request. Requests must contain the following information:

(A) A list of specific item of monitoring instrumentation for which the request is being made and the locations where each piece of monitoring instrumentation will be installed.

(B) Identification of the specific rule requirements (by rule subpart, section, and paragraph numbers) for which the instrumentation is needed.

(C) A description of the reasons why the needed equipment could not be obtained and installed before April 1, 2010.

(D) If the reason for the extension is that the equipment cannot be purchased and delivered by April 1, 2010, include supporting documentation such as the date the monitoring equipment was ordered, investigation of alternative suppliers and the dates by which alternative vendors promised delivery, backorder notices or unexpected delays, descriptions of actions taken to expedite delivery, and the current expected date of delivery.

(E) If the reason for the extension is that the equipment cannot be installed without a process unit shutdown, include supporting documentation demonstrating that it is not practicable to isolate the equipment and install the monitoring instrument without a full process unit shutdown. Include the date of the most recent process unit shutdown, the frequency of shutdowns for this process unit, and the date of the next planned shutdown during which the monitoring equipment can be installed. If there has been a shutdown or if there is a planned process unit shutdown between promulgation of this part and April 1, 2010, include a justification of why the equipment could not be obtained and installed during that shutdown.

(F) A description of the specific actions the facility will take to obtain and install the equipment as soon as reasonably feasible and the expected date by which the equipment will be installed and operating.

(iii) Approval criteria. To obtain approval, the owner or operator must demonstrate to the Administrator's satisfaction that it is not reasonably feasible to acquire, install, and operate a required piece of monitoring equipment by April 1, 2010. The use of best available methods will not be approved beyond December 31, 2010.

(3) Abbreviated emissions report for facilities containing only general stationary fuel combustion sources. In lieu of the report required by paragraph (c) of this section, the owner or operator of an existing facility that is in operation on January 1, 2010 and that meets the conditions of § 98.2 (a)(3) may submit an abbreviated GHG report for the facility for GHGs emitted in 2010. The abbreviated report must be submitted by March 31, 2011. An owner or operator that submits an abbreviated report must submit a full GHG report according to the requirements of paragraph (c) of this section beginning in calendar year 2011. The abbreviated facility report must include the following information:

(i) Facility name and physical street address including the city, state and zip code.

(ii) The year and months covered by the report.

(iii) Date of submittal.

(iv) Total facility GHG emissions aggregated for all stationary fuel combustion units calculated according to any method specified in § 98.33(a) and expressed in metric tons of CO2, CH4, N2O, and CO2e.

(v) Any facility operating data or process information used for the GHG emission calculations.

(vi) A signed and dated certification statement provided by the designated representative of the owner or operator, according to the requirements of paragraph (e)(1) of this section.

(e) Emission calculations. In preparing the GHG report, you must use the calculation methodologies specified in the relevant subparts, except as specified in paragraph (d) of this section. For each source category, you must use the same calculation methodology throughout a reporting period unless you provide a written explanation of why a change in methodology was required.

(f) Verification. To verify the completeness and accuracy of reported GHG emissions, the Administrator may review the certification statements described in paragraphs (c)(8) and (d)(3)(vi) of this section and any other credible evidence, in conjunction with a comprehensive review of the GHG reports and periodic audits of selected reporting facilities. Nothing in this section prohibits the Administrator from using additional information to verify the completeness and accuracy of the reports.

(g) Recordkeeping. An owner or operator that is required to report GHGs under this part must keep records as specified in this paragraph. Retain all required records for at least ~~3~~ 7 years. The records shall be kept in an electronic or hard-copy format (as appropriate) and recorded in a form that is suitable for expeditious inspection and review. Upon request by the Administrator, the records required under this section must be made available to EPA within 10 days after the request. Records may be retained off site if the records are readily available for expeditious inspection and review. For records that are electronically generated or maintained, the equipment or software necessary to read the records shall be made available, or, if requested by EPA, electronic records shall be converted to paper documents. You must retain the following records, in addition to those records prescribed in each applicable subpart of this part:

(1) A list of all units, operations, processes, and activities for which GHG emission were calculated.

(2) The data used to calculate the GHG emissions for each unit, operation, process, and activity, categorized by fuel or material type. These data include but are not limited to the following information in this paragraph (g)(2):

(i) The GHG emissions calculations and methods used.

(ii) Analytical results for the development of site-specific emissions factors.

(iii) The results of all required analyses for high heat value, carbon content, and other required fuel or feedstock parameters.

(iv) Any facility operating data or process information used for the GHG emission calculations.

(3) The annual GHG reports.

(4) Missing data computations. For each missing data event, also retain a record of the duration of the event, actions taken to restore malfunctioning monitoring equipment, the cause of the event, and the actions taken to prevent or minimize occurrence in the future.

(5) For sources subject to reporting under 40 C.F.R. Part 98, ~~A~~ a written GHG Monitoring Plan.[10]

[10] WCI jurisdictions may elect to require a GHG Monitoring Plan from all sources. This provision is optional for Canadian jurisdictions.

(i) At a minimum, the GHG Monitoring Plan shall include the elements listed in this paragraph (g)(5)(i).

(A) Identification of positions of responsibility (i.e., job titles) for collection of the emissions data.

(B) Explanation of the processes and methods used to collect the necessary data for the GHG calculations.

(C) Description of the procedures and methods that are used for quality assurance, maintenance, and repair of all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported under this part.

(ii) The GHG Monitoring Plan may rely on references to existing corporate documents (e.g., standard operating procedures, quality assurance programs under appendix F to 40 CFR part 60 or appendix B to 40 CFR part 75, and other documents) provided that the elements required by paragraph (g)(5)(i) of this section are easily recognizable.

(iii) The owner or operator shall revise the GHG Monitoring Plan as needed to reflect changes in production processes, monitoring instrumentation, and quality assurance procedures; or to improve procedures for the maintenance and repair of monitoring systems to reduce the frequency of monitoring equipment downtime.

(iv) Upon request by the Administrator, the owner or operator shall make all information that is collected in conformance with the GHG Monitoring Plan available for review during an audit within 10 days after the request. Electronic storage of the information in the plan is permissible, provided that the information can be made available in hard copy upon request during an audit.

(6) The results of all required certification and quality assurance tests of continuous monitoring systems, fuel flow meters, and other instrumentation used to provide data for the GHGs reported under this part.

(7) Maintenance records for all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported under this part.

(h) Annual GHG report revisions.

(1) The owner or operator of a facility subject to reporting under both this Article and 40 C.F.R. Part 98 shall submit a revised report within 45 days of discovering or being notified by EPA of errors in an annual GHG report. The revised report must correct all identified errors.

The owner or operator shall retain documentation for ~~3~~ 7 years to support any revisions made to an annual GHG report.

(2) The owner or operator of a facility subject to reporting under this Article but not 40 C.F.R. Part 98 shall submit a revised report within 30 days of finding that a report contains an error, or accumulation of errors, greater than 5 percent of the total CO_2e emissions reported. To the extent possible, the revised report must correct all identified errors. A revised report will be accepted only if approved by [jurisdiction]. The owner or operator shall retain documentation for 7 years to support any revisions made to an annual GHG report.

(i) Calibration accuracy requirements. The owner or operator of a facility or supplier that is subject to the requirements of this part must meet the calibration accuracy requirements of this paragraph (i).

(1) Except as provided paragraphs (i)(4) through (i)(6) of this section, flow meters and other devices (e.g., belt scales) that measure data used to calculate GHG emissions shall be calibrated prior to April 1, 2010 using the procedures specified in this paragraph and each relevant subpart of this part. All measurement devices must be calibrated according to the manufacturer's recommended procedures, an appropriate industry consensus standard, or a method specified in a relevant subpart of this part. All measurement devices shall be calibrated to an accuracy of 5 percent. For facilities and suppliers that become subject to this part after April 1, 2010, the initial calibration shall be conducted on the date that data collection is required to begin. Subsequent calibrations shall be performed at the frequency specified in each applicable subpart.[11]

(2) For flow meters, perform all calibrations at measurement points that are representative of normal operation of the meter. Except for the orifice, nozzle, and venturi flow meters described in paragraph (i)(3) of this section, calculate the calibration error at each measurement point using Equation A–2 of this section. The terms ''R'' and ''A'' in Equation A–2 must be expressed in consistent units of measure (e.g., gallons/minute, ft 3/min). The calibration error at each measurement point shall not exceed 5.0 percent of the reference value.

[11] Canadian jurisdictions may grant an exemption for the combustion of solid biomass or biomass fuels determined to be carbon neutral.

$$CE = \frac{R - A}{R} \times 100 \qquad \text{(Eq. A-2)}$$

Where:

CE = Calibration error (%)

R = Reference value

A = Flow meter response to the reference value

(3) For orifice, nozzle, and venturi flow meters, the initial quality assurance consists of in-situ calibration of the differential pressure (delta-P), total pressure, and temperature transmitters. Calibrate each transmitter at a zero point and at least one upscale point. Fixed reference points, such as the freezing point of water, may be used for temperature transmitter calibrations. Calculate the calibration error of each transmitter at each measurement point, using Equation A–3 of this subpart. The terms ‘‘R’’, ‘‘A’’, and ‘‘FS’’ in Equation A–3 of this subpart must be in consistent units of measure (e.g., milliamperes, inches of water, psi, degrees). For each transmitter, the CE value at each measurement point shall not exceed 2.0 percent of full-scale. Alternatively, the results are acceptable if the sum of the calculated CE values for the three transmitters at each calibration level (i.e., at the zero level and at each upscale level) does not exceed 5.0 percent.

$$CE = \frac{R - A}{FS} \times 100 \qquad \text{(Eq. A-3)}$$

Where:

CE = Calibration error (%)

R = Reference value

A = Transmitter response to the reference value

FS = Full-scale value of the transmitter

(4) Fuel billing meters are exempted from the calibration requirements of this section, provided that the fuel supplier and any unit combusting the fuel do not have any common owners and are not owned by subsidiaries or affiliates of the same company.

(5) For a flow meter or other measurement device that has been previously calibrated in accordance with this part, an initial calibration is not required by the date specified in paragraph (i)(1) of this section if, as of the date required for the initial calibration, the previous calibration is still active (i.e., the device is not yet due for recalibration because the time interval between successive calibrations, as required by this part, has not elapsed).

(6) For units and processes that operate continuously with infrequent outages, it may not be possible to meet the April 1, 2010 deadline for the initial calibration of a flow meter or other measurement device without removing the device from service and shipping it to a remote location, thereby disrupting normal process operation. In such cases, the owner or operator may postpone the initial calibration until the next scheduled maintenance outage or any other outage of sufficient duration to complete the calibration, and may similarly postpone the subsequent recalibrations. Such postponements shall be documented in the monitoring plan that is required under § 98.3(g)(5).

(j) Where a rule in this Article requires sampling of a parameter on a more frequent basis than the corresponding rule in 40 C.F.R. Part 98, the following shall apply:

(1) The samples must be spaced apart as evenly as possible over time, taking into account the operating schedule of the relevant unit or facility.

(2) You must calculate and report a weighted average of the values derived from the samples by using the following formula:

$$V_E = \frac{\sum_{j=1}^{n}(V_j \times M_j)}{\sum_{j=1}^{n} M_j}$$

Where:

V_E = The value of the parameter to be reported under 40 C.F.R. Part 98 for period E.

j = Each period during period E for which a sample is required by [jurisdiction] under the applicable rule in this Article.

n = The number of periods j in period E.

Vj = The value of the sample for period j.

Mj = The mass of the sampled material processed or otherwise used by the relevant unit or facility in period j.

(3) You must keep records of the date and result for each sample and mass measurement used in the equation in subsection (2) and of the calculation of each weighted average included in your report.

(k)Where this Article specifies a choice between use of a fuel-based or mass balance-based calculation or use of a continuous emissions monitoring system (CEMS) to calculate CO2 emissions, the operator shall make this choice and continue to use the method chosen for all future emissions data reports, unless the use of the alternative calculation method is approved in advance by [the jurisdiction].[12]

(l) The owner or operator may elect to designate as de minimis one or more sources or pollutants that collectively emit no more than 3 percent of the facility's total CO2e emissions, but not to exceed 20,000 metric tons CO2e. Where this Article otherwise requires the use of a more stringent method for monitoring and reporting emissions than the method required by 40 C.F.R. Part 98, the owner or operator may elect to use any other method allowed under 40 C.F.R. Part 98 for the sources or pollutants designated as de minimis.[13]

(m) Notwithstanding the missing data procedures specified in this Article, the failure to conduct monitoring in accordance with the schedules established in this Article shall constitute a violation.

§ 98.4 Authorization and responsibilities of the designated representative.[14]

(a) General. Except as provided under paragraph (f) of this section, each facility, and each supplier, that is subject to this part, shall have one and only one designated representative, who shall be responsible for certifying, signing, and submitting GHG emissions reports and any other submissions for such facility and supplier respectively to the Administrator under this part. If the

[12] Approval may be granted by rule or by other general authorization. A case-by-case approval process may not be required.
[13] Canadian jurisdictions may include de minimis provisions consistent with WCI.2(d).
[14] In Canadian jurisdictions, the responsibilities specified in this section will ordinarily fall on the "operator's representative" as defined in Canadian law.

facility is required under any other part of title 40 of the Code of Federal Regulations to submit to the Administrator any other emission report that is subject to any requirement in 40 CFR part 75, the same individual shall be the designated representative responsible for certifying, signing, and submitting the GHG emissions reports and all such other emissions reports under this part.

(b) Authorization of a designated representative. The designated representative of the facility or supplier shall be an individual selected by an agreement binding on the owners and operators of such facility or supplier and shall act in accordance with the certification statement in paragraph (i)(4)(iv) of this section.

(c) Responsibility of the designated representative. Upon receipt by the Administrator of a complete certificate of representation under this section for a facility or supplier, the designated representative identified in such certificate of representation shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator of such facility or supplier in all matters pertaining to this part, notwithstanding any agreement between the designated representative and such owners and operators. The owners and operators shall be bound by any decision or order issued to the designated representative by the Administrator or a court.

(d) Timing. No GHG emissions report or other submissions under this part for a facility or supplier will be accepted until the Administrator has received a complete certificate of representation under this section for a designated representative of the facility or supplier. Such certificate of representation shall be submitted at least 60 days before the deadline for submission of the facility's or supplier's initial emission report under this part.

(e) Certification of the GHG emissions report. Each GHG emission report and any other submission under this part for a facility or supplier shall be certified, signed, and submitted by the designated representative or any alternate designated representative of the facility or supplier in accordance with this section and § 3.10 of this chapter.

(1) Each such submission shall include the following certification statement signed by the designated representative or any alternate designated representative: ''I am authorized to make this submission on behalf of the owners and operators of the facility or supplier, as applicable, for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary

responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(2) The Administrator will accept a GHG emission report or other submission for a facility or supplier under this part only if the submission is certified, signed, and submitted in accordance with this section.

(f) Alternate designated representative. A certificate of representation under this section for a facility or supplier may designate one alternate designated representative, who shall be an individual selected by an agreement binding on the owners and operators, and may act on behalf of the designated representative, of such facility or supplier. The agreement by which the alternate designated representative is selected shall include a procedure for authorizing the alternate designated representative to act in lieu of the designated representative.

(1) Upon receipt by the Administrator of a complete certificate of representation under this section for a facility or supplier identifying an alternate designated representative.

(i) The alternate designated representative may act on behalf of the designated representative for such facility or supplier.

(ii) Any representation, action, inaction, or submission by the alternate designated representative shall be deemed to be a representation, action, inaction, or submission by the designated representative.

(2) Except in this section, whenever the term ‘‘designated representative’’ is used in this part, the term shall be construed to include the designated representative or any alternate designated representative.

(g) Changing a designated representative or alternate designated representative. The designated representative or alternate designated representative identified in a complete certificate of representation under this section for a facility or supplier received by the Administrator may be changed at any time upon receipt by the Administrator of another later signed, complete certificate of representation under this section for the facility or supplier. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous designated representative or the previous alternate designated representative of the facility or supplier before the time and date when the Administrator receives such later signed certificate of representation shall be binding on the new designated representative and the owners and operators of the facility or supplier.

(h) Changes in owners and operators. In the event an owner or operator of the facility or supplier is not included in the list of owners and operators in the certificate of representation under this section for the facility or supplier, such owner or operator shall be deemed to be subject to and bound by the certificate of representation, the representations, actions, inactions, and submissions of the designated representative and any alternate designated representative of the facility or supplier, as if the owner or operator were included in such list. Within 90 days after any change in the owners and operators of the facility or supplier (including the addition of a new owner or operator), the designated representative or any alternate designated representative shall submit a certificate of representation that is complete under this section except that such list shall be amended to reflect the change. If the designated representative or alternate designated representative determines at any time that an owner or operator of the facility or supplier is not included in such list and such exclusion is not the result of a change in the owners and operators, the designated representative or any alternate designated representative shall submit, within 90 days of making such determination, a certificate of representation that is complete under this section except that such list shall be amended to include such owner or operator.

(i) Certificate of representation. A certificate of representation shall be complete if it includes the following elements in a format prescribed by the Administrator in accordance with this section:

(1) Identification of the facility or supplier for which the certificate of representation is submitted.

(2) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the designated representative and any alternate designated representative.

(3) A list of the owners and operators of the facility or supplier identified in paragraph (i)(1) of this section, provided that, if the list includes the operators of the facility or supplier and the owners with control of the facility or supplier, the failure to include any other owners shall not make the certificate of representation incomplete.

(4) The following certification statements by the designated representative and any alternate designated representative:

(i) ‘‘I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of the facility or supplier, as applicable.’’

(ii) ‘‘I certify that I have all the necessary authority to carry out my duties and responsibilities under 40 CFR part 98 on behalf of the owners and operators of the facility or supplier, as applicable, and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions.’’

(iii) ‘‘I certify that the owners and operators of the facility or supplier, as applicable, shall be bound by any order issued to me by the Administrator or a court regarding the facility or supplier.’’

(iv) ‘‘If there are multiple owners and operators of the facility or supplier, as applicable, I certify that I have given a written notice of my selection as the ‘designated representative’ or ‘alternate designated representative’, as applicable, and of the agreement by which I was selected to each owner and operator of the facility or supplier.’’

(5) The signature of the designated representative and any alternate designated representative and the dates signed.

(j) Documents of agreement. Unless otherwise required by the Administrator, documents of agreement referred to in the certificate of representation shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(k) Binding nature of the certificate of representation. Once a complete certificate of representation under this section for a facility or supplier has been received, the Administrator will rely on the certificate of representation unless and until a later signed, complete certificate of representation under this section for the facility or supplier is received by the Administrator.

(l) Objections Concerning a Designated Representative

(1) Except as provided in paragraph (g) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission, of the designated representative or alternate designated representative shall affect any representation, action, inaction, or submission of the

designated representative or alternate designated representative, or the finality of any decision or order by the Administrator under this part.

(2) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any designated representative or alternate designated representative.

(m) Delegation by designated representative and alternate designated representative.

(1) A designated representative or an alternate designated representative may delegate his or her own authority, to one or more individuals, to submit an electronic submission to the Administrator provided for or required under this part, except for a submission under this paragraph.

(2) In order to delegate his or her own authority, to one or more individuals, to submit an electronic submission to the Administrator in accordance with paragraph (m)(1) of this section, the designated representative or alternate designated representative must submit electronically to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(i) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of such designated representative or alternate designated representative.

(ii) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such individual (referred to as an ‘‘agent’’).

(iii) For each such individual, a list of the type or types of electronic submissions under paragraph (m)(1) of this section for which authority is delegated to him or her.

(iv) For each type of electronic submission listed in accordance with paragraph (m)(2)(iii) of this section, the facility or supplier for which the electronic submission may be made.

(v) The following certification statements by such designated representative or alternate designated representative:

(A) ‘‘I agree that any electronic submission to the Administrator that is by an agent identified in this notice of delegation and of a type listed, and for a facility or supplier designated, for such agent in this notice of delegation and that is made when I am a designated representative or alternate designated representative, as applicable, and before this notice of delegation is superseded by another notice of delegation under § 98.4(m)(3) shall be deemed to be an electronic submission certified, signed, and submitted by me.''

(B) ''Until this notice of delegation is superseded by a later signed notice of delegation under § 98.4(m)(3), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under § 98.4(m) is terminated.''

(vi) The signature of such designated representative or alternate designated representative and the date signed.

(3) A notice of delegation submitted in accordance with paragraph (m)(2) of this section shall be effective, with regard to the designated representative or alternate designated representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of another such notice that was signed later by such designated representative or alternate designated representative, as applicable. The later signed notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(4) Any electronic submission covered by the certification in paragraph (m)(2)(iv)(A) of this section and made in accordance with a notice of delegation effective under paragraph (m)(3) of this section shall be deemed to be an electronic submission certified, signed, and submitted by the designated representative or alternate designated representative submitting such notice of delegation.

§ 98.5 How is the report submitted?

Each GHG report and certificate of representation for a facility or supplier must be submitted electronically in accordance with the requirements of § 98.4 and in a format specified by the Administrator.

98.6 Definitions.

[No change.]

98.7 What standardized methods are incorporated by reference into this part?

[No change.]

98.8 What are the compliance and enforcement provisions of this part?

[No change.]

98.9 Addresses.

[No change.]

Subpart C—General Stationary Combustion

§98.30 Definition of the source category.

(a) Stationary fuel combustion sources are devices that combust solid, liquid, or gaseous fuel, generally for the purposes of producing electricity, generating steam, or providing useful heat or energy for industrial, commercial, or institutional use, or reducing the volume of waste by removing combustible matter. Stationary fuel combustion sources include, but are not limited to, boilers, simple and combined-cycle combustion turbines, engines, incinerators, and process heaters.

(b) This source category does not include:

(1) Portable equipment, as defined in §98.6.

(2) Emergency generators and emergency equipment, as defined in §98.6.

(3) Irrigation pumps at agricultural operations.

(4) Flares, unless otherwise required by provisions of another subpart of 40 CFR part 98 to use methodologies in this subpart.

(5) Electricity generating units that are subject to subpart D of this part.

(c) For a unit that combusts hazardous waste (as defined in 40 CFR 261.3), reporting of GHG emissions is not required unless either of the following conditions apply:

(1) Continuous emission monitors (CEMS) are used to quantify CO_2 mass emissions.

(2) Any fuel listed in Table C-1 of this subpart is also combusted in the unit. In this case, report GHG emissions from combustion of all fuels listed in Table C-1 of this subpart.

§98.31 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains one or more stationary fuel combustion sources and the facility meets the applicability requirements of either §§98.2(a)(1), 98.2(a)(2), or 98.2(a)(3).

§98.32 GHGs to report.

(a) You must report CO_2, CH_4, and N_2O mass emissions from each stationary fuel combustion unit.

(b) [Reporting only] Units that generate electricity either for sale or for use onsite must also report fugitive HFC emissions from cooling units by following the requirements of §98.33(f).

§98.33 Calculating GHG emissions.

You must calculate CO_2 emissions according to paragraph (a) of this section, and calculate CH_4 and N_2O emissions according to paragraph (c) of this section.

Subpart C—General Stationary Combustion

(a) CO₂ emissions from fuel combustion. Calculate CO_2 emissions by using one of the four calculation methodologies in this paragraph (a) subject to the conditions, requirements, and restrictions set forth in paragraph (b) of this section. If you co-fire biomass fuels with fossil fuels, report CO_2 emissions from the combustion of biomass separately using the methods in paragraph (e) of this section.

(1) Tier 1 Calculation Methodology. Calculate the annual CO_2 mass emissions for each type of fuel by using Equation C-1 of this section.

$$CO_2 = 1 x 10^{-3} * Fuel * HHV * EF \qquad \text{(Eq. C-1)}$$

Where:

CO_2 = Annual CO_2 mass emissions for the specific fuel type (metric tons).

Fuel = Mass or volume of fuel combusted per year, from company records as defined in §98.6 (express mass in short tons for solid fuel, volume in standard cubic feet for gaseous fuel, and volume in gallons for liquid fuel).

HHV = Default high heat value of the fuel, from Table C-1 of this subpart (mmBtu per mass or mmBtu per volume, as applicable).

EF = Fuel-specific default CO_2 emission factor, from Table C-1 of this subpart (kg CO_2/mmBtu).

$1 \text{ x } 10^{-3}$ = Conversion factor from kilograms to metric tons.

(2) Tier 2 Calculation Methodology. Calculate the annual CO_2 mass emissions for each type of fuel by using either Equation C2a or C2c of this section, as appropriate.

(i) Equation C-2a of this section applies to any type of fuel listed in Table C-1 of the subpart, except for municipal solid waste (MSW). For MSW combustion, use Equation C-2c of this section.

$$CO_2 = 1x10^{-3} * Fuel * HHV * EF \qquad \text{(Eq. C-2a)}$$

Where:

CO_2 = Annual CO_2 mass emissions for a specific fuel type (metric tons).

Fuel = Mass or volume of the fuel combusted during the year, from company records as defined in §98.6 (express mass in short tons for solid fuel, volume in standard cubic feet for gaseous fuel, and volume in gallons for liquid fuel).

HHV = Annual average high heat value of the fuel from all valid samples for the year (mmBtu per mass or volume). The average HHV shall be calculated according to the requirements of paragraph (a)(2)(ii) of this section.

EF = Fuel-specific default CO_2 emission factor, from Table C-1 of this subpart (kg CO_2/mmBtu).

1×10^{-3} = Conversion factor from kilograms to metric tons.

(ii) The minimum number of HHV samples for determining annual average HHV is specified (e.g., monthly, quarterly, semi-annually, or by lot) in §98.34. The method for computing the annual average HHV is a function of how frequently you perform or receive from the fuel supplier the results of fuel sampling for HHV. The method is specified in paragraph (a)(2)(ii)(A) or (a)(2)(ii)(B) of this section, as applicable.

(A) If the results of fuel sampling are received monthly or more frequently, then the annual average HHV shall be calculated using Equation C-2b of this section. If multiple HHV determinations are made in any month, average the values for the month arithmetically.

$$(HHV)_{annual} = \frac{\sum_{i=1}^{n}(HHV)_i * (Fuel)_i}{\sum_{i=1}^{n}(Fuel)_i} \qquad \text{(Eq. C-2b)}$$

Where:

$(HHV)_{annual}$	=	Weighted annual average high heat value of the fuel (mmBtu per mass or volume).
$(HHV)_i$	=	High heat value of the fuel, for month "i" (mmBtu per mass or volume).
$(Fuel)_i$	=	Mass or volume of the fuel combusted during month "i" (express mass in short tons for solid fuel, volume in standard cubic feet for gaseous fuel, and volume in gallons for liquid fuel).
n	=	Number of months in the year that fuel is burned in the unit.

(B) If the results of fuel sampling are received less frequently than monthly, then the annual average HHV shall be computed as the arithmetic average HHV for all values for the year (including valid samples and substitute data values under 98.35).

(iii) For units that combust municipal solid waste (MSW) and that produce steam, use Equation C-2c of this section. Equation C-2c of this section may also be used for any ~~other~~ solid biomass fuel listed in Table C-1 of this subpart provided that steam is generated by the unit.

$$CO_2 = 1 \times 10^{-3} \text{ Steam} * B * EF \qquad \text{(Eq. C-2c)}$$

Where:

CO_2	=	Annual CO_2 mass emissions from MSW or solid fuel combustion (metric tons).
Steam	=	Total mass of steam generated by MSW or solid fuel combustion during the reporting year (lb steam).
B	=	Ratio of the boiler's maximum rated heat input capacity to its design rated steam output capacity (mmBtu/lb steam).
EF	=	Fuel-specific default CO_2 emission factor, from Table C-1 of this subpart (kg CO_2/mmBtu)[1].
1×10^{-3}	=	Conversion factor from kilograms to metric tons.

(3) Tier 3 Calculation Methodology. Calculate the annual CO_2 mass emissions for each fuel by using either Equation C3, C4, or C5 of this section, as appropriate.

(i) For a solid fuel, use Equation C-3 of this section.

[1] The ER required development of a site-specific emission factor for MSW. For harmonization with the MRR, this requirement was deleted. However, jurisdictions may allow or require testing to develop a site-specific emission factor as an alternative to the default emission factors in Table C-1.

$$CO_2 = \frac{44}{12} * Fuel * CC * 0.91 \qquad \text{(Eq. C-3)}$$

Where:

CO_2 = Annual CO_2 mass emissions from the combustion of the specific solid fuel (metric tons).

Fuel = Annual mass of the solid fuel combusted, from company records as defined in §98.6 (short tons).

CC = Annual average carbon content of the solid fuel (percent by weight, expressed as a decimal fraction, e.g., 95% = 0.95). The annual average carbon content shall be determined using the same procedures as specified for HHV in paragraph (a)(2)(ii) of this section.

44/12 = Ratio of molecular weights, CO_2 to carbon.

0.91 = Conversion factor from short tons to metric tons.

(ii) For a liquid fuel, use Equation C-4 of this section.

$$CO_2 = \frac{44}{12} * Fuel * CC * 0.001 \qquad \text{(Eq. C-4)}$$

Where:

CO_2 = Annual CO_2 mass emissions from the combustion of the specific liquid fuel (metric tons).

Fuel = Annual volume of the liquid fuel combusted (gallons). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to §98.3(i). Fuel billing meters may be used for this purpose. Tank drop measurements may also be used.

CC = Annual average carbon content of the liquid fuel (kg C per gallon of fuel). The annual average carbon content shall be determined using the same procedures as specified for HHV in paragraph (a)(2)(ii) of this section.

44/12 = Ratio of molecular weights, CO_2 to carbon.

0.001 = Conversion factor from kg to metric tons.

(iii) For a gaseous fuel, use Equation C-5 of this section.

$$CO_2 = \frac{44}{12} * Fuel * CC * \frac{MW}{MVC} * 0.001 \qquad \text{(Eq. C-5)}$$

Where:

CO_2	=	Annual CO_2 mass emissions from combustion of the specific gaseous fuel (metric tons).
Fuel	=	Annual volume of the gaseous fuel combusted (scf). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to §98.3(i). Fuel billing meters may be used for this purpose.
CC	=	Annual average carbon content of the liquid fuel (kg C per gallon of fuel). The annual average carbon content shall be determined using the same procedures as specified for HHV in paragraph (a)(2)(ii) of this section.
MW	=	Annual average molecular weight of the gaseous fuel (kg/kg-mole). The annual average carbon content shall be determined using the same procedures as specified for HHV in paragraph (a)(2)(ii) of this section.
MVC	=	Molar volume conversion factor (849.5 scf per kg-mole at standard conditions, as defined in §98.6).
44/12	=	Ratio of molecular weights, CO_2 to carbon.
0.001	=	Conversion factor from kg to metric tons.

(iv) Fuel flow meters that measure mass flow rates may be used for liquid fuels, provided that the fuel density is used to convert the readings to volumetric flow rates. The density shall be measured at the same frequency as the carbon content, using ASTM D1298-99 (Reapproved 2005) "Standard Test Method for Density, Relative Density (Specific Gravity), or API Gravity of Crude Petroleum and

Liquid Petroleum Products by Hydrometer Method” (incorporated by reference, see §98.7).

(v) The following default density values may be used for fuel oil, in lieu of using the ASTM method in paragraph (a)(3)(iv) of this section: 6.8 lb/gal for No. 1 oil; 7.2 lb/gal for No. 2 oil; 8.1 lb/gal for No. 6 oil.

(4) Tier 4 Calculation Methodology. Calculate the annual CO_2 mass emissions from all fuels combusted in a unit, by using quality-assured data from continuous emission monitoring systems (CEMS).

(i) This methodology requires a CO_2 concentration monitor and a stack gas volumetric flow rate monitor, except as otherwise provided in paragraph (a)(4)(iv) of this section. Hourly measurements of CO_2 concentration and stack gas flow rate are converted to CO_2 mass emission rates in metric tons per hour.

(ii) When the CO_2 concentration is measured on a wet basis, Equation C-6 of this section is used to calculate the hourly CO_2 emission rates:

$$CO_2 = 5.18x10^{-7} * C_{CO2} * Q \qquad \text{(Eq. C-6)}$$

Where:

CO_2 = CO_2 mass emission rate (metric tons/hr).
C_{CO2} = Hourly average CO_2 concentration (% CO_2).

Q = Hourly average stack gas volumetric flow rate (scfh).

5.18×10^{-7} = Conversion factor (metric tons/scf/% CO_2).

(iii) If the CO_2 concentration is measured on a dry basis, a correction for the stack gas moisture content is required. You shall either continuously monitor the stack gas moisture content as described in §75.11(b)(2) of this chapter or, for certain types of fuel, use a default moisture percentage from §75.11(b)(1) of this chapter. For each unit operating hour, a moisture correction must be applied to Equation C-6 of this section as follows:

$$CO_2^* = CO_2\left(\frac{100 - \%H_2O}{100}\right) \qquad \text{(Eq. C-7)}$$

Where:

CO_2^* = Hourly CO_2 mass emission rate, corrected for moisture (metric tons/hr).

CO_2 = Hourly CO_2 mass emission rate from Equation C-6 of this section, uncorrected (metric tons/hr).

$\%H_2O$ = Hourly moisture percentage in the stack gas (measured or default value, as appropriate).

(iv) An oxygen (O_2) concentration monitor may be used in lieu of a CO_2 concentration monitor in a CEMS installed before January 1, 2012,[2] to determine the hourly CO_2 concentrations, in accordance with Equation F-14a or F-14b (as applicable) in appendix F to 40 CFR part 75, if the

[2] A jurisdiction may want to modify this date depending on the effective date of the jurisdiction's reporting regulations.

effluent gas stream monitored by the CEMS consists solely of combustion products (i.e., no process CO_2 emissions are mixed with the combustion products) and if only fuels that are listed in Table 1 in section 3.3.5 of appendix F to 40 CFR part 75 are combusted in the unit. If the O_2 monitoring option is selected, the F-factors used in Equations F-14a and F-14b shall be determined according to section 3.3.5 or section 3.3.6 of appendix F to 40 CFR part 75, as applicable. If Equation F-14b is used, the hourly moisture percentage in the stack gas shall be either a measured value in accordance with §75.11(b)(2) of this chapter, or, for certain types of fuel, a default moisture value from §75.11(b)(1) of this chapter.

(v) Each hourly CO_2 mass emission rate from Equation C-6 or C-7 of this section is multiplied by the operating time to convert it from metric tons per hour to metric tons. The operating time is the fraction of the hour during which fuel is combusted (e.g., the unit operating time is 1.0 if the unit operates for the whole hour and is 0.5 if the unit operates for 30 minutes in the hour). For common stack configurations, the operating time is the fraction of the hour during which effluent gases flow through the common stack.

(vi) The hourly CO_2 mass emissions are then summed over each calendar quarter and the quarterly totals are summed to determine the annual CO_2 mass emissions.

(vii) If both biomass and fossil fuel are combusted during the year, determine and report the biogenic CO_2 mass emissions separately, as described in paragraph (e) of this section.

(5) Alternative methods for units with continuous monitoring systems. Units not subject to the Acid Rain Program that report data to EPA according to 40 CFR part 75 may use the alternative methods in this paragraph in lieu of using any of the four calculation methodology tiers.

(i) For a unit that combusts only natural gas and/or fuel oil, is not subject to the Acid Rain Program, monitors and reports heat input data year-round according to appendix D to 40 CFR part 75, but is not required by the applicable 40 CFR part 75 program to report CO_2 mass emissions data, calculate the annual CO_2 mass emissions for the purposes of this part as follows:

(A) Use the hourly heat input data from appendix D to 40 CFR part 75, together with Equation G-4 in appendix G to 40 CFR part 75 to determine the hourly CO_2 mass emission rates, in units of tons/hr;

(B) Use Equations F-12 and F-13 in appendix F to 40 CFR part 75 to calculate the quarterly and cumulative annual CO_2 mass emissions, respectively, in units of short tons; and

(C) Divide the cumulative annual CO_2 mass emissions value by 1.1 to convert it to metric tons.

(ii) For a unit that combusts only natural gas and/or fuel oil, is not subject to the Acid Rain Program, monitors and reports heat input data year-round according to 40 CFR 75.19 of this chapter but is not required by the applicable 40 CFR part 75 program to report CO_2 mass emissions data, calculate the annual CO_2 mass emissions for the purposes of this part as follows:

(A) Calculate the hourly CO_2 mass emissions, in units of short tons, using Equation LM-11 in 40 CFR 75.19(c)(4)(iii).

(B) Sum the hourly CO_2 mass emissions values over the entire reporting year to obtain the cumulative annual CO_2 mass emissions, in units of short tons.

(C) Divide the cumulative annual CO_2 mass emissions value by 1.1 to convert it to metric tons.

(iii) For a unit that is not subject to the Acid Rain Program, uses flow rate and CO_2 (or O_2) CEMS to report heat input data year-round according to 40 CFR part 75, but is not required by the applicable 40 CFR part 75 program to report CO_2 mass emissions data, calculate the annual CO_2 mass emissions as follows:

(A) Use Equation F-11 or F-2 (as applicable) in appendix F to 40 CFR part 75 to calculate the hourly CO_2 mass emission rates from the CEMS data. If an O_2 monitor is used, convert the hourly average O_2 readings to CO_2 using Equation F-14a or F-14b in appendix F to 40 CFR part 75 (as applicable), before applying Equation F-11 or F-2.

(B) Use Equations F-12 and F-13 in appendix F to 40 CFR part 75 to calculate the quarterly and cumulative annual CO_2 mass emissions, respectively, in units of short tons.

(C) Divide the cumulative annual CO_2 mass emissions value by 1.1 to convert it to metric tons.

(D) If both biomass and fossil fuel are combusted during the year, determine and report the biogenic CO_2 mass emissions separately, as described in paragraph (e) of this section.

(b) Use of the four tiers. Use of the four tiers of CO_2 emissions calculation methodologies described in paragraph (a) of this section is subject to the following conditions, requirements, and restrictions:

(1) The Tier 1 Calculation Methodology:

(i) May be used for any fuel listed in Table C-1 of this subpart that is combusted in a unit with a maximum rated heat input capacity of 250 mmBtu/hr or less at a facility that is not subject to verification.

(ii) ~~May be used for MSW in a unit of any size that does not produce steam, if the use of Tier 4 is not required.~~[Reserved]

(iii) ~~May be used for solid, gaseous, or liquid biomass fuels in a unit of any size provided that the fuel is listed in Table C-1 of this subpart.~~[Reserved]

(iv) May not be used if you routinely perform fuel sampling and analysis for the fuel high heat value (HHV) or ~~routinely receives~~can obtain the results of HHV sampling and analysis from the fuel supplier at the minimum frequency specified in §98.34(a), or at a greater frequency. In such cases, Tier 2 or higher shall be used.

(2) The Tier 2 Calculation Methodology:

(i) May be used for the combustion of any type of fuel in a unit with a maximum rated heat input capacity of 250 mmBtu/hr or less at a facility that is not subject to verification provided that the fuel is listed in Table C-1 of this subpart.

(ii) May be used in a unit with a maximum rated heat input capacity greater than 250 mmBtu/hr or that is located at a facility subject to verification for the combustion of pipeline quality natural gas and distillate fuel oil.

(iii) May be used for MSW or solid biomass fuel[3] in a unit of any size that produces steam, if Equation C-2c is employed and if the use of Tier 4 is not required.

(3) The Tier 3 Calculation Methodology:

(i) May be used for a unit of any size at any facility that combusts any type of fuel listed in Table C-1 of this subpart (except for MSW), unless the use of Tier 4 is required.

(ii) Shall be used for a unit ~~with~~ that has a maximum rated heat input capacity greater than 250 mmBtu/hr or is located at a facility subject to verification~~that combusts any type of fuel listed in Table C-1 of this subpart (except MSW)~~, unless either of the following conditions apply:

(A) The use of Tier ~~1 or~~ 2 is permitted, as described in paragraph~~s (b)(1)(iii) and~~ (b)(2)(ii) of this section.

(B) The use of Tier 4 is required.

~~(iii) Shall be used for a fuel not listed in Table C-1 of this subpart if the fuel is combusted in a unit with a maximum rated heat input capacity greater than 250 mmBtu/hr provided that both of the following conditions apply:~~

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[3] Consistent with 98.33(a)(2)(iii).

~~(A) The use of Tier 4 is not required.~~

~~(B) The fuel provides 10% or more of the annual heat input to the unit or, if §98.36(c)(3)applies, to a group of units served by common supply pipe.~~

(4) The Tier 4 Calculation Methodology:

(i) May be used for a unit of any size, combusting any type of fuel.

(ii) Shall be used if the unit meets all six of the conditions specified in paragraphs (b)(4)(ii)(A) through (b)(4)(ii)(F) of this section:

(A) The unit has a maximum rated heat input capacity greater than 250 mmBtu/hr, or if the unit combusts municipal solid waste and has a maximum rated input capacity greater than 250 tons per day of MSW.

(B) The unit combusts solid fossil fuel or MSW, either as a primary or secondary fuel.

(C) The unit has operated for more than 1,000 hours in any calendar year since 2005.

(D) The unit has installed CEMS that are required either by an applicable Federal or State regulation or the unit’s operating permit.

(E) The installed CEMS include a gas monitor of any kind or a stack gas volumetric flow rate monitor, or both and the monitors have been certified, either in accordance with the requirements of 40 CFR part 75, part 60 of this chapter, or an applicable State continuous monitoring program.

(F) The installed gas or stack gas volumetric flow rate monitors are required, either by an applicable Federal or State regulation or by the unit's operating permit, to undergo periodic quality assurance testing in accordance with either appendix B to 40 CFR part 75, appendix F to 40 CFR part 60, or an applicable State continuous monitoring program.

(iii) Shall be used for a unit with a maximum rated heat input capacity of 250 mmBtu/hr or less and for a unit that combusts municipal solid waste with a maximum rated input capacity of 250 tons of MSW per day or less, if the unit meets all of the following three conditions:

(A) The unit has both a stack gas volumetric flow rate monitor and a CO_2 concentration monitor.

(B) The unit meets the conditions specified in paragraphs (b)(4)(ii)(B) through (b)(4)(ii)(D) of this section.

(C) The CO_2 and stack gas volumetric flow rate monitors meet the conditions specified in paragraphs (b)(4)(ii)(E) and (b)(4)(ii)(F) of this section.

(5) The Tier 4 Calculation Methodology shall be used beginning on:

(i) January 1, 2010, for a unit that is required to report CO_2 mass emissions beginning on that date, if all of the monitors needed to measure CO_2 mass emissions have been installed and certified by that date.

(ii) January 1, 2011, for a unit that is required to report CO_2 mass emissions beginning on January 1, 2010, if all of the monitors needed to measure CO_2 mass emissions have not been installed and certified by January 1, 2010. In this case, you may use Tier 2 or Tier 3 to report GHG emissions for 2010.

(6) You may elect to use any applicable higher tier for one or more of the fuels combusted in a unit. For example, if a 100 mmBtu/hr unit combusts natural gas and distillate fuel oil, you may elect to use Tier 1 for natural gas and Tier 3 for the fuel oil, even though Tier 1 could have been used for both fuels. However, for units that use either the Tier 4 or the alternative calculation methodology specified in paragraph (a)(5) of this section, CO_2 emissions from the combustion of all fuels shall be based solely on CEMS measurements.

(c) Calculation of CH_4 and N_2O emissions from stationary combustion sources. You must calculate annual

CH_4 and N_2O mass emissions only for units that are required to report CO_2 emissions using the calculation methodologies of this subpart and for only those fuels that are listed in Table C-2 of this subpart.

(1) Use Equation C-8 of this section to estimate CH_4 and N_2O emissions for any fuels for which you use the Tier 1 or Tier 3 calculation methodologies for CO_2. Use the same values for fuel combustion that you use for the Tier 1 or Tier 3 calculation.

$$CH_4 \text{ or } N_2O = 1 \, x \, 10^{-3} * Fuel * HHV * EF \qquad \text{(Eq. C-8)}$$

Where:

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons).

Fuel = Mass or volume of the fuel combusted, either from company records or directly measured by a fuel flow meter, as applicable (mass or volume per year).

HHV = Default high heat value of the fuel from Table C-1 of this subpart (mmBtu per mass or volume).

EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 of this subpart (kg CH_4 or N_2O per mmBtu).

$1 \text{ x } 10^{-3}$ = Conversion factor from kilograms to metric tons.

(2) Use Equation C-9a of this section to estimate CH_4 and N_2O emissions for any fuels for which you use the Tier 2 Equation C-2a of this section to estimate CO_2 emissions.

Use the same values for fuel combustion and HHV that you use for the Tier 1 or Tier 3 calculation.

$$CH_4 \text{ or } N_2O = 1 \text{ x } 10^{-3} * HHV * EF * Fuel \qquad \text{(Eq. C-9a)}$$

Where:

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons).

Fuel = Mass or volume of the fuel combusted during the reporting year.

HHV = High heat value of the fuel, averaged for all valid measurements for the reporting year (mmBtu per mass or volume).

EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 of this subpart (kg CH_4 or N_2O per mmBtu).

1 x 10^{-3} = Conversion factor from kilograms to metric tons.

(3) Use Equation C-9b of this section to estimate CH_4 and N_2O emissions for any fuels for which you use Equation C-2c of this section to calculate the CO_2 emissions. Use the same values for steam generation and the ratio "B" that you use for Equation C-2c.

$$CH_4 \text{ or } N_2O = 1 \text{ x } 10^{-3} \text{ Steam} * B * EF \qquad \text{(Eq. C-9b)}$$

Where:

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a solid fuel (metric tons).

Steam = Total mass of steam generated by solid fuel combustion during the reporting year (lb steam).

B = Ratio of the boiler's maximum rated heat input capacity to its design rated steam output (mmBtu/lb steam).

EF = Fuel-specific emission factor for CH_4 or N_2O, from Table C-2 of this subpart (kg CH_4 or N_2O per mmBtu).

1×10^{-3} = Conversion factor from kilograms to metric tons.

(4) Use Equation C-10 of this section for units in the Acid Rain Program, units that monitor and report heat input on a year-round basis according to 40 CFR part 75, and units that use the Tier 4 Calculation Methodology.

$$CH_4 \text{ or } N_2O = 0.001 * (HI)_A * EF \qquad \text{(Eq. C-10)}$$

Where:

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons).

$(HI)_A$ = Cumulative annual heat input from the fuel, derived from the electronic data reports required under §75.64 of this chapter or, for Tier 4 units, from the best available information as described in paragraph (c)(4)(ii) of this section(mmBtu).

EF = Fuel-specific emission factor for CH_4 or N_2O, from Table C-2 of this section (kg CH_4 or N_2O per mmBtu).

0.001 = Conversion factor from kg to metric tons.

(i) If only one type of fuel listed in Table C-2 of this subpart is combusted during normal operation, substitute the cumulative annual heat input from combustion of the fuel into Equation C-10 of this section to calculate the annual CH_4 or N_2O emissions.

(ii) If more than one type of fuel listed in Table C-2 of this subpart is combusted during normal operation, use Equation C-10 of this section separately for each type of fuel. If flow rate and diluent gas monitors are used to measure the unit heat input, use the best available information (e.g., fuel feed rate measurements, fuel heating values, engineering analysis) to estimate the annual heat input from each type of fuel.

(5) When multiple fuels are combusted during the reporting year, sum the fuel-specific results from Equations C-8, C-9a, C-9b, or C-10 of this section (as applicable) to obtain the total annual CH_4 and N_2O emissions, in metric tons.

(6) The operator may elect to calculate CH_4 or N_2O emissions using source-specific emission factors derived from source tests conducted at least annually under the supervision of [jurisdiction]. Upon approval of a source test plan, the source test procedures in that plan shall be repeated in each future year to update the source specific emission factors annually.

(d) Calculation of CO_2 from sorbent.

(1) When a unit is a fluidized bed boiler, is equipped with a wet flue gas desulfurization system, or uses other acid gas emission controls with sorbent injection, use Equation C-11 of this section to calculate the CO_2 emissions from the sorbent, if those CO_2 emissions are not monitored by CEMS:

$$CO_2 = 0.91 * S * R * \left(\frac{MW_{CO2}}{MW_S}\right) \qquad \text{(Eq. C-11)}$$

Where:

CO_2 = CO_2 emitted from sorbent for the reporting year (metric tons).

S = Limestone or other sorbent used in the reporting year, from company records (short tons).

R = 1.00, the calcium-to-sulfur stoichiometric ratio.

MW_{CO2} = Molecular weight of carbon dioxide (44).

MW_S = Molecular weight of sorbent (100 if calcium carbonate).

0.91 = Conversion factor from short tons to metric tons

(2) The annual CO_2 mass emissions for the unit shall be the sum of the CO_2 emissions from the combustion process and the CO_2 emissions from the sorbent.

(e) <u>CO_2 emissions from combustion of biomass</u>. Use the procedures of this paragraph (e) to estimate biogenic CO_2 emissions from units that combust a combination of biomass and fossil fuels. Reporting of CO_2 emissions from combustion of biomass is required only for those biomass fuels listed in Table C-1 of this section, unless emissions are measured using CEMS.

(1) If CEMS are not used to measure CO_2, use Equation C-1 or C-2c of this subpart to calculate the annual CO_2 mass emissions from the combustion of biomass (except MSW) for a unit of any size. Determine the mass of biomass combusted using one of the following procedures in this paragraph (e)(1), as appropriate.

(i) Use company records.

(ii) Follow the procedures in paragraph (e)(5) of this section.

(iii) For premixed fuels that contain biomass and fossil fuels (e.g., mixtures containing biodiesel), use best available information to determine the mass of biomass fuels and document the procedure used in the GHG Monitoring Plan required by §98.3(g)(5).

(2) If a CO_2 CEMS (or a surrogate O_2 monitor) and a stack gas flow rate monitor are used to determine the annual CO_2 mass emissions either according to 40 CFR part 75, the Tier 4 Calculation Methodology, or the alternative calculation methodology specified in paragraph (a)(5)(iii); and if both fossil fuel and biomass (except for MSW) are combusted in the unit during the reporting year, you may use the following procedure to determine the annual

biogenic CO_2 mass emissions. If MSW or a fossil fuel/biomass mixture containing an undeterminable quantity of fossil fuels is combusted in the unit, follow the procedures in paragraph (e)(3) of this section.

(i) For each operating hour, use Equation C-12 of this section to determine the volume of CO_2 emitted.

$$V_{CO2h} = \frac{(\%CO_2)_h}{100} * Q_h * t_h \qquad \text{(Eq. C-12)}$$

Where:

V_{CO2h} = Hourly volume of CO_2 emitted (scf).

$(\%CO_2)_h$ = Hourly average CO_2 concentration, measured by the CO_2 concentration monitor, or, if applicable, calculated from the hourly average O_2 concentration ($\%CO_2$).

Q_h = Hourly average stack gas volumetric flow rate, measured by the stack gas volumetric flow rate monitor (scfh).

t_h = Source operating time (decimal fraction of the hour during which the source combusts fuel, i.e., 1.0 for a full operating hour, 0.5 for 30 minutes of operation, etc.).

100 = Conversion factor from percent to a decimal fraction.

(ii) Sum all of the hourly V_{CO2h} values for the reporting year, to obtain V_{total}, the total annual volume of CO_2 emitted.

(iii) Calculate the annual volume of CO_2 emitted from fossil fuel combustion using Equation C-13 of this section. If two or more types of fossil fuel are combusted during the year, perform a separate calculation with Equation C-13 of this section for each fuel and sum the results.

$$V_{ff} = \frac{Fuel * F_c * HHV}{10^6} \qquad \text{(Eq. C-13)}$$

Where:

V_{ff} = Annual volume of CO_2 emitted from combustion of a particular fossil fuel (scf).

Fuel = Total quantity of the fossil fuel combusted in the reporting year, from company records, as defined in §98.6 (lb for solid fuel, gallons for liquid fuel, and scf for gaseous fuel).

F_c = Fuel-specific carbon based F-factor, either a default value from Table 1 in section 3.3.5 of appendix F to 40 CFR part 75 or a site-specific value determined under section 3.3.6 of appendix F to 40 CFR part 75 (scf CO_2/mmBtu).

HHV = High heat value of the fossil fuel, from fuel sampling and analysis (annual average value in Btu/lb for solid fuel, Btu/gal for liquid fuel and Btu/scf for gaseous fuel, sampled as specified (e.g., monthly, quarterly, semi-annually, or by lot) in §98.34(a)(2)). The average HHV shall be calculated according to the requirements of paragraph (a)(2)(ii) of this section.

10^6 = Conversion factor, Btu per mmBtu.

(iv) Subtract V_{ff} from V_{total} to obtain V_{bio}, the annual volume of CO_2 from the combustion of biomass. If a CEMS is being used to measure the combined combustion and process emissions from a unit that is subject to another subpart of part 98, then also subtract CO_2 process emissions from V_{total} to determine V_{bio}. The CO_2 process emissions must be calculated according to the requirements of the applicable subpart.

(v) Calculate the biogenic percentage of the annual CO_2 emissions,expressed as a decimal fraction, using Equation C-14 of this section:

$$\% \, Biogenic = \frac{V_{bio}}{V_{total}} \qquad \text{(Eq. C-14)}$$

(vi) Calculate the annual biogenic CO_2 mass emissions, in metric tons, by multiplying the results obtained from Equation C-14 of this section by the annual CO_2 mass emissions in metric tons, as determined:

(A) Under paragraph (a)(4)(vi) of this section, for units using the Tier 4 Calculation Methodology.

(B) Under paragraph (a)(5)(iii)(B) of this section, for units using the alternative calculation methodology specified in paragraph (a)(5)(iii).

(C) From the electronic data report required under §75.64 of this chapter, for units in the Acid Rain Program and other units using CEMS to monitor and report CO_2 mass emissions according to 40 CFR part 75. However, before calculating the annual biogenic CO_2 mass emissions, multiply the cumulative annual CO_2 mass emissions by 0.91 to convert from short tons to metric tons.

(3) For a unit that combusts MSW, the annual biogenic CO_2 emissions shall be calculated using the procedures in this paragraph (3).

(i) If the Tier 1 or Tier 2 Calculation Methodology is used to quantify CO_2 mass emissions:

(A) Use Equation C-1 or C-2c of this subpart, as appropriate, to calculate the annual CO_2 mass emissions from MSW combustion.

(B) Determine the relative proportions of biogenic and non-biogenic CO_2 emissions on a quarterly basis using the method specified in §98.34(d).

(C) Determine the annual biogenic CO_2 mass emissions from MSW combustion by multiplying the annual CO_2 mass emissions by the annual average biogenic decimal fraction obtained from §98.34(d).

(ii) If the unit uses Tier 4 to quantify CO_2 emissions:

(A) Follow the procedures in paragraphs (e)(2)(i) and (ii) of this section, to determine V_{total}.

(B) If any fossil fuel was combusted during the year, follow the procedures in paragraph (e)(2)(iii) of this section, to determine V_{ff}.

(C) Subtract V_{ff} from V_{total}, to obtain V_{MSW} , the annual volume of CO_2 emissions from MSW combustion.

(D) Determine the annual volume of biogenic CO_2 emissions (V_{bio}) from MSW combustion as follows. Multiply the annual volume of CO_2 emissions from MSW combustion (V_{MSW})

by the annual average biogenic decimal fraction obtained from ASTM D6866-08 and ASTM D7459-08.

(E) Calculate the biogenic percentage of the annual CO_2 emissions from the unit, using Equation C-14 of this section. For the purposes of this calculation, the term "V_{bio}" in the numerator of Equation C-14 of this section shall be the results of the calculation performed under paragraph (e)(3)(ii)(D) of this section.

(F) Calculate the annual biogenic CO_2 mass emissions according to paragraph (e)(2)(vi)(A) of this section.

(4) As an alternative to the procedures in paragraph (e)(2) of this section, use ASTM Methods D7459-08 and D6866-08 to determine the biogenic portion of the annual CO_2 emissions, as described in §98.34(e). If this option is selected, the results of each determination shall be expressed as a decimal fraction (e.g., 0.30, if 30 percent of the CO_2 is biogenic), and the values shall be averaged over the reporting year. The annual biogenic CO_2 mass emissions shall be calculated by multiplying the the total annual CO_2 mass emissions by the annual average biogenic fraction obtained from ASTM D6866-08 and ASTM D7459-08.

(5) If Equation C-1 of this section is selected to calculate the annual biogenic mass emissions for wood, wood waste, or other solid biomass-derived fuel, Equation C-15

of this section may be used to quantify biogenic fuel consumption, provided that all of the required input parameters are accurately quantified. Similar equations and calculation methodologies based on steam generation and boiler efficiency may be used, provided that they are documented in the GHG Monitoring Plan required by §98.3(g)(5).

$$(Fuel)_p = \frac{[H * S] - (HI)_{nb}}{2000\,(HHV)_{bio}\,(Eff)_{bio}} \quad \text{(Eq. C-15)}$$

Where:

$(Fuel)_p$	=	Quantity of biomass consumed during the measurement period "p" (tons/year or tons/month, as applicable).
H	=	Average enthalpy of the boiler steam for the measurement period (Btu/lb).
S	=	Total boiler steam production for the measurement period (lb/month or lb/year, as applicable).
$(HI)_{nb}$	=	Heat input from co-fired fossil fuels and non-biomass-derived fuels for the measurement period, based on company records of fuel usage and default or measured HHV values (Btu/month or Btu/year, as applicable).
$(HHV)_{bio}$	=	Default or measured high heat value of the biomass fuel (Btu/lb).
$(Eff)_{bio}$	=	Percent efficiency of biomass-to-energy conversion, expressed as a decimal fraction.
2000	=	Conversion factor (lb/ton).

(f) [Reporting only] Calculating fugitive HFC emissions from cooling units.[4] Operators of electricity generating facilities shall calculate fugitive HFC emissions for each HFC compound used in cooling units that support power generation or are used in heat transfers to cool stack gases using either the methodology in paragraph (f)(1) or (f)(2). The Operator is not required to report GHG emissions from air or water cooling systems or condensers that do not contain HFCs.

(1) Use Equation C-16 to calculate annual HFC emissions:

$$HFC = HFC_{inventory} + HFC_{purchases/acquisitions} - HFC_{sales/disbursements} + HFC_{\Delta capacity} \qquad \text{Eqn. C-16}$$

Where:

HFC = Annual fugitive HFC emission, metric tons;

$HFC_{inventory}$ = The difference between the quantity of HFC in storage at the beginning of the year and the quantity in storage at the end of the year. Stored HFC includes HFC contained in cylinders (such as 115-pound storage cylinders), gas carts, and other storage containers. It does not include HFC gas held in operating equipment. The change in inventory will be negative if the quantity of HFC in storage increases over the course of the year.

$HFC_{purchases/acquisitions}$ = The sum of all HFC acquired from other entities during the year either in storage containers or in equipment.

$HFC_{sales/disbursements}$ = The sum of all the HFC sold or otherwise transferred offsite to other entities during the year either in storage containers or in equipment.

[4] Taken from WCI.43(d).

$HFC_{\Delta capacity}$ = The net change in the total nameplate capacity (i.e. the full and proper charge) of the cooling equipment). The net change in capacity will be negative if the total nameplate capacity at the end of the year is less than the total nameplate capacity at the beginning of the year.

(2) Use service logs to document HFC usage and emissions from each cooling unit. Service logs should document all maintenance and service performed on the unit during the report year, including the quantity of HFCs added to or removed from the unit, and include a record at the beginning and end of each report year. The operator may use service log information along with the following simplified material balance equations to quantify fugitive HFCs from unit installation, servicing, and retirement, as applicable. The operator shall include the sum of HFC emissions from the applicable equations in the greenhouse gas emissions data report.

$$HFC_{Install} = R_{new} - C_{new}$$

$$HFC_{Service} = R_{recharge} - R_{Recover}$$

$$HFC_{Retire} = C_{retire} - R_{retire}$$

Where:

$HFC_{Install}$ = HFC emitted during initial charging/installation of the unit, kilograms;

$HFC_{Service}$ = HFC emitted during use and servicing of the unit for the report year, kilograms;

HFC_{Retire} = HFC emitted during the removal from service/retirement of the unit, kilograms;

R_{new} = HFC used to fill new unit (omit if unit was pre-charged by the manufacturer), kilograms;

C_{new} = Nameplate capacity of new unit (omit if unit was pre-charged by the manufacturer), kilograms;

$R_{recharge}$ = HFC used to recharge the unit during maintenance and service, kilograms;

$R_{recover}$ = HFC recovered from the unit during maintenance and service, kilograms;

C_{retire} = Nameplate capacity of the retired unit, kilograms; and

R_{retire} = HFC recovered from the retired unit, kilograms.

§98.34 Monitoring and QA/QC requirements.

The CO_2 mass emissions data for stationary fuel combustion sources shall be monitored as follows:

(a) For the Tier 2 Calculation Methodology:

(1) All fuel samples shall be taken at a location in the fuel handling system that provides a sample representative of the fuel combusted. The fuel sampling and analysis may be performed by either the owner or operator or the supplier of the fuel.

(2) The minimum required frequency of the HHV sampling and analysis for each type of fuel is specified in this paragraph. When the specified frequency is based on a specified time period (i.e., weekly, monthly, quarterly, or semiannually), fuel sampling and analysis is required only for those periods in which the unit operates.

(i) For natural gas, semiannual sampling and analysis is required (i.e., twice in a calendar year, with consecutive samples taken at least four months apart).

(ii) For coal and fuel oil, analysis of at least one representative sample from each fuel lot is required. For the purposes of this section, a fuel lot is defined as a shipment or delivery of a single fuel (e.g., ship load, barge load, group of trucks, group of railroad cars, etc.).

(iii) For liquid fuels other than fuel oil, for fossil fuel-derived gaseous fuels, and for biogas; sampling and analysis is required at least once per calendar quarter. To the extent practicable, consecutive quarterly samples shall be taken at least 30 days apart.

(iv) For solid fuels other than coal and MSW, weekly sampling is required to obtain composite samples, which are then analyzed monthly.

(3) If different types of fuel (e.g., different ranks of coal or different grades of fuel oil) are blended prior to combustion, use one of the following procedures in this paragraph.

(i) Use a weighted HHV value in the emission calculations, based on the relative proportions of each fuel in the blend.

(ii) Take a representative sample of the blend and analyze it for HHV.

(4) If, for a particular type of fuel, HHV sampling and analysis is performed more often than the minimum frequency specified in paragraphs (a)(2)of this section, the results of all valid fuel analyses shall be used in the GHG emission calculations.

(5) If, for a particular type of fuel, valid HHV values are obtained at less than the minimum frequency specifed in paragraphs (a)(2) of this section, appropriate substitute data values shall be used in the emissions calculations, in accordance with missing data procedures of §98.35.

(6) Use any applicable fuel sampling and analysis methods in this paragraph (a)(6) to determine the high heat values. Alternatively, for gaseous fuels, the HHV may be calculated using chromatographic analysis together with standard heating values of the fuel constituents, provided that the gas chromatograph is operated, maintained, and calibrated according to the manufacturer's instructions.

(i) ASTM D4809-06 Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method) (incorporated by reference, see §98.7).

(ii) ASTM D240-02 (Reapproved 2007) Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (incorporated by reference, see §98.7).

(iii) ASTM D1826-94 (Reapproved 2003) Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter (incorporated by reference, see §98.7).

(iv) ASTM D3588-98 (Reapproved 2003) Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels (incorporated by reference, see §98.7).

(v) ASTM D4891-89 (Reapproved 2006) Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion (incorporated by reference, see §98.7).

(vi) GPA Standard 2172–09 Calculation of Gross Heating Value, Relative Density, Compressibility and Theoretical Hydrocarbon Liquid Content for Natural Gas Mixtures for Custody Transfer (incorporated by reference, see §98.7).

(vii) GPA Standard 2261–00, Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography (incorporated by reference, see §98.7).

(viii) ASTM D5865-07a, Standard Test Method for Gross Calorific Value of Coal and Coke (incorporated by reference, see §98.7).

(b) For the Tier 3 Calculation Methodology:

(1) Calibrate each oil and gas flow meter according to §98.3(i) and the provisions of paragraph (b).

(i) Perform calibrations using any of the test methods and procedures in this paragraph (b)(1)(i):

(A) An applicable flow meter test method listed in paragraphs (b)(4)(i) through (b)(4)(viii) of this section.

(B) The calibration procedures specified by the flow meter manufacturer.

(C) An industry-accepted or industry standard calibration practice.

(ii) In addition to the initial calibration required by §98.3(i), recalibrate each fuel flow meter (except for qualifying billing meters under paragraph (b)(1)(iii) of this section) either annually, at the minimum frequency specified by the manufacturer, or at the interval specified by the industry consensus standard practice used.

(iii) Fuel billing meters are exempted from the initial and ongoing calibration requirements of this paragraph, provided that the fuel supplier and the unit combusting the fuel do not have any common owners and are not owned by subsidiaries or affiliates of the same company.

(iv) For the initial calibration of an orifice, nozzle, or venturi meter; in-situ calibration of the transmitters is sufficient. A primary element inspection (PEI) shall be performed at least once every three years.

(v) For the continuously-operating units and processes described in §98.3(i)(6), the required flow meter recalibrations and, if necessary, the PEIs may be postponed until the next scheduled maintenance outage.

(vi) If a mixture of fuels is transported by a common pipe (e.g., still gas and supplementary natural gas), you must either separately meter each of the fuels prior to mixing using flow meters calibrated according to §98.3(i), or use flow meters calibrated according to §98.3(i) to measure the mixed fuel at the common pipe and to separately meter an appropriate subset of the fuels prior to mixing. If the latter option is chosen, quantify the fuels that are not measured prior to mixing by subtracting out the fuels measured prior to mixing from the fuel measured at the common pipe.

(2) Oil tank drop measurements (if used to determine liquid fuel use volume) shall be performed according to any an appropriate method published by a consensus-based standards organization (e.g., the American Petroleum Institute).

(3) The carbon content and, if applicable, molecular weight of the fuels shall be determined according to the procedures in paragraph (b)(3).

(i) All fuel samples shall be taken at a location in the fuel handling system that provides a sample representative of the fuel combusted. The fuel sampling and analysis may be performed by either the owner or operator or by the supplier of the fuel.

(ii) At a minimum, fuel samples shall be collected at the frequency specified in this paragraph. When sampling is required at a specified time interval (e.g., weekly, monthly, quarterly, or semiannually), fuel sampling and analysis is required for only those specified periods in which the unit operates.

(A) For natural gas, semiannual sampling and analysis is required (i.e., twice in a calendar year, with consecutive samples taken at least four months apart).

(B) For coal and fuel oil, analysis of at least one representative sample from each fuel lot is required. For the purposes of this section, a fuel lot is defined as a shipment or delivery of a single fuel (e.g., ship load, barge load, group of trucks, group of railroad cars, etc.).

(C) For other liquid fuels other than fuel oil, for fossil fuel-derived gaseous fuels, and for biogas; sampling and analysis is required at least once per calendar quarter. To the extent practicable, consecutive quarterly samples shall be taken at least 30 days apart.

(D) For solid fuels other than coal, weekly sampling is required to obtain composite samples, which are then analyzed monthly.

(E) For gaseous fuels other than natural gas and biogas (e.g., refinery gas), daily sampling and analysis to determine the carbon content and molecular weight of the fuel is required if the necessary equipment is in place to make these measurements. Otherwise, weekly sampling and analysis shall be performed. The equipment necessary to perform daily sampling and analysis of carbon content and molecular weight for refinery fuel gas must be installed no later than January 1, 2012.

(iii) If, for a particular type of fuel, sampling and analysis for carbon content and molecular weight is performed more often than the minimum frequency specified in paragraph (b)(3) of this section, the results of all valid fuel analyses shall be used in the GHG emission calculations.

(iv) If, for a particular type of fuel, sampling and analysis for carbon content and molecular weight is performed at less than the minimum frequency specifed in paragraph (b)(3) of this section, appropriate substitute data values shall be used in the emissions calculations, in accordance with the missing data procedures of §98.35.

(v) The procedures of paragraphs (a)(3) of this section apply to carbon content and molecular weight determinations.

(4) Use any applicable standard method from the following list to quality assure the data from each fuel flow meter.

(i) AGA Report No. 3, Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids, Part 1: General Equations and Uncertainty Guidelines (1990) and Part 2: Specification and Installation Requirements (2000)(incorporated by reference, see §98.7).

(ii) AGA Transmission Measurement Committee Report No. 7, Measurement of Gas by Turbine Meters (2006) (incorporated by reference, see §98.7).

(iii) ASME MFC-3M-2004 Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi (incorporated by reference, see §98.7).

(iv) ASME MFC-4M-1986 (Reaffirmed 1997), Measurement of Gas Flow by Turbine Meters (incorporated by reference, see §98.7).

(v) ASME MFC-5M-1985 (Reaffirmed 1994), Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters (incorporated by reference, see §98.7).

(vi) ASME MFC-6M-1998 Measurement of Fluid Flow in Pipes Using Vortex Flowmeters (incorporated by reference, see §98.7).

(vii) ASME MFC–7M–1987 (Reaffirmed 1992), Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles (incorporated by reference, see §98.7).

(viii) ASME MFC–9M–1988 (Reaffirmed 2001), Measurement of Liquid Flow in Closed Conduits by Weighing Method (incorporated by reference, see §98.7).

(5) Use any applicable methods from the following list to determine the carbon content and molecular weight (for gaseous fuel) of the fuel. Alternatively, the results of chromatographic analysis of the fuel may be used, provided that the gas chromatograph is operated, maintained, and calibrated according to the manufacturer's instructions.

(i) ASTM D1945-03 Standard Test Method for Analysis of Natural Gas by Gas Chromatography (incorporated by reference, see §98.7).

(ii) ASTM D1946-90 (Reapproved 2006) Standard Practice for Analysis of Reformed Gas by Gas Chromatography (incorporated by reference, see §98.7).

(iii) ASTM D2502-04 (Reapproved 2002) Standard Test Method for Estimation of Molecular Weight (Relative Molecular Mass) of Petroleum Oils from Viscosity Measurements (incorporated by reference, see §98.7).

(iv) ASTM D2503-92 (Reapproved 2007) Standard Test Method for Relative Molecular Mass (Relative Molecular Weight) of Hydrocarbons by Thermoelectric Measurement of Vapor Pressure (incorporated by reference, see §98.7).

(v) ASTM D3238-95 (Reapproved 2005) Standard Test Method for Calculation of Carbon Distribution and Structural Group Analysis of Petroleum Oils by the n-d-M Method (incorporated by reference, see §98.7).

(vi) ASTM D5291-02 (Reapproved 2007) Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants (incorporated by reference, see §98.7).

(vii) ASTM D5373-08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal (incorporated by reference, see §98.7).

(c) For the Tier 4 Calculation Methodology, the CO_2 and flow rate monitors must be certified prior to the applicable deadline specified in §98.33(b)(5).

(1) For initial certification, you may use any one of the following three procedures in this paragraph.

(i) §75.20(c)(2) and (4) and appendix A to 40 CFR part 75.

(ii) The calibration drift test and relative accuracy test audit (RATA) procedures of Performance Specification 3 in appendix B to part 60 (for the CO_2 concentration monitor) and Performance Specification 6 in appendix B to part 60 (for the continuous emission rate monitoring system (CERMS)).

(iii) The provisions of an applicable State continuous monitoring program.

(2) If an O_2 concentration monitor is used to determine CO_2 concentrations, the applicable provisions of 40 CFR part 75, 40 CFR part 60, or an applicable State continuous monitoring program shall be followed for initial certification and on-going quality assurance, and all required RATAs of the monitor shall be done on a percent CO_2 basis.

(3) For ongoing quality assurance, follow the applicable procedures in either appendix B to 40 CFR part 75, appendix F to 40 CFR part 60, or an applicable State continuous monitoring program. If appendix F to 40 CFR part 60 is selected for on-going quality assurance, perform daily calibration drift assessments for both the CO_2 monitor (or surrogate O_2 monitor) and the flow rate monitor, conduct cylinder gas audits of the CO_2 concentration monitor in three of the four quarters of each year (except for non-

operating quarters), and perform annual RATAs of the CO_2 concentration monitor and the CERMS.

(4) For the purposes of this part, the stack gas volumetric flow rate monitor RATAs required by appendix B to 40 CFR part 75 and the annual RATAs of the CERMS required by appendix F to 40 CFR part 60 need only be done at one operating level, representing normal load or normal process operating conditions, both for initial certification and for ongoing quality assurance.

(5) If, for any source operating hour, quality assured data are not obtained with a CO_2 monitor (or surrogate O_2 monitor), flow rate monitor, or (if applicable) moisture monitor, use appropriate substitute data values in accordance with the missing data provisions of §98.35.

(d) When municipal solid waste (MSW) is combusted in a unit, determine the biogenic portion of the CO_2 emissions from MSW combustion using ASTM D6866-08 Standard Test Methods for Determining the Biobased Content of Solid, Liquid, and Gaseous Samples Using Radiocarbon Analysis (incorporated by reference, see §98.7) and ASTM D7459-08 Standard Practice for Collection of Integrated Samples for the Speciation of Biomass (Biogenic) and Fossil-Derived Carbon Dioxide Emitted from Stationary Emissions Sources (incorporated by reference, see §98.7). Perform the ASTM

D7459-08 sampling and the ASTM D6866-08 analysis at least once in every calendar quarter in which MSW is combusted in the unit. Collect each gas sample during normal unit operating conditions while MSW is the only fuel being combusted for at least 24 consecutive hours or for as long as is necessary to obtain a sample large enough to meet the specifications of ASTM D6866-08. Separate CO_2 emissions into the biogenic and non-biogenic fraction using the average proportion of biogenic emissions of all samples analyzed during the reporting year. Express the results as a decimal fraction (e.g., 0.30, if 30 percent of the CO_2 from MSW combustion is biogenic). If there is a common fuel source of MSW that feeds multiple units at the facility, performing the testing at only one of the units is sufficient.

(e) For units that use CEMS to measure the total CO_2 mass emissions and combust a combination of biogenic fuels (other than MSW) with a fossil fuel, ASTM D6866-08 and ASTM D7459-08 may be used to determine the biogenic portion of the CO_2 emissions. Perform the ASTM D7459-08 sampling and the ASTM D6866-08 analysis at least once in every calendar quarter in which biogenic and non-biogenic fuels are co-fired in the unit. The relative proportions of the biogenic and non-biogenic fuels during the sampling shall be representative of the average fuel blend for a typical operating year. Collect each gas sample using ASTM D7459-08 during normal unit operation for at least 24 consecutive hours or for as long as is necessary to obtain a sample large enough to meet the specifications of ASTM D6866-08.

(f) Whenever company records are used in the calculation of CO_2 emissions, the records required under §98.3(g) shall include both the company records and an explanation of how those records are used to estimate the following parameters:

(1) Fuel consumption, when the Tier 1 and Tier 2 Calculation Methodologies are used.

(2) Fuel consumption, when solid fuel is combusted and the Tier 3 Calculation Methodology is used.

(3) Fossil fuel consumption when §98.33(e) applies to a unit that uses CEMS to quantify CO_2 emissions and that combusts both fossil and biomass fuels.

(4) Sorbent usage, when §98.33(d) applies.

(5) Quantity of steam generated by a unit when §98.33(a)(2) applies.

(6) Biogenic fuel consumption under §98.33(e)(5).

(g) As part of the GHG Monitoring Plan required under §98.3(g)(5), you must document the procedures used to ensure the accuracy of the estimates of fuel usage, sorbent usage, steam production, and boiler efficiency (as applicable) in paragraph (f) of this section, including but not limited to calibration of weighing equipment, fuel flow meters, steam flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices shall also be recorded, and the technical basis for these estimates shall be provided.

§98.35 Procedures for estimating missing data.

Required in U.S. jurisdictions only. Canadian jurisdictions may impose data substitution procedures that differ from the following.

Whenever a quality-assured value of a required parameter is unavailable (e.g., if a CEMS malfunctions during unit operation or if a required fuel sample is not taken), a substitute data value for the missing parameter shall be used in the calculations.

(a) For all units subject to the requirements of the Acid Rain Program, and all other stationary combustion units subject to the requirements of this part that monitor and report emissions and heat input data in accordance with 40 CFR part 75, the missing data substitution procedures in 40 CFR part 75 shall be followed for CO_2 concentration, stack gas flow rate, fuel flow rate, high heating value, and fuel carbon content.

(b) For units that use the Tier 1, Tier 2, Tier 3, and Tier 4 Calculation Methodologies, perform missing data substitution as follows for each parameter:

(1) For each missing value of the high heating value, carbon content, or molecular weight of the fuel, substitute the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If the “after” value has not been obtained by the time that the GHG emissions report is due, you may use the “before” value for missing data substitution or the best available estimate of the parameter, based on all available process data (e.g., electrical load, steam production, operating hours). If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.

(2) For missing records of CO_2 concentration, stack gas flow rate, percent moisture, fuel usage, and sorbent usage, the substitute data value shall be the best available estimate of the parameter, based on all available process data (e.g., electrical load, steam production,

operating hours, etc.). You must document and retain records of the procedures used for all such estimates.

§98.36 Data reporting requirements.

Canadian jurisdictions may allow or require aggregation of emissions data up to the facility level.

(a) In addition to the facility-level information required under §98.3, the annual GHG emissions report shall contain the unit-level or process-level emissions data in paragraphs (b) through (d) of this section (as applicable) and the emissions verification data in paragraph (e) of this section.

(b) Units that use the four tiers. You shall report the following information for stationary combustion units that use the Tier 1, Tier 2, Tier 3, or Tier 4 methodology in §98.33(a) to calculate CO_2 emissions, except as otherwise provided in paragraphs (c) and (d) of this section:

(1) The unit ID number.

(2) A code representing the type of unit.

(3) Maximum rated heat input capacity of the unit, in mmBtu/hr for boilers and process heaters only and relevant units of measure for other combustion sources.

(4) Each type of fuel combusted in the unit during the report year.

(5) The tier used to calculate the CO_2 emissions for each type of fuel combusted (i.e., Tier 1, 2, 3, or 4).

(6) For a unit that uses Tiers 1, 2, and 3; the CO_2, CH_4, and N_2O emissions for each type of fuel combusted, expressed in metric tons of each gas and in metric tons of CO_2e.

(7) For a unit that uses Tier 4:

(i) For units that burn fossil fuels only, the annual CO_2 emissions for all fuels combined. Reporting CO_2 emissions by type of fuel is not required.

(ii) For units that burn both fossil fuels and biomass, the annual CO_2 emissions from combustion of all fossil fuels combined and the annual CO_2 emissions from combustion of all biomass fuels combined. Reporting CO_2 emissions by type of fuel is not required.

(iii) Annual CH_4 and N_2O emissions for each type of fuel combusted expressed in metric tons of each gas and in metric tons of CO_2e.

(8) Annual CO_2 emissions from sorbent (if calculated using Equation C-11 of this subpart), expressed in metric tons.

(9) Annual GHG emissions from all fossil fuels burned in the unit (i.e., the sum of the CO_2 , CH_4, and N_2O emissions), expressed in metric tons of CO_2e.

(10) Customer meter number for units that combust natural gas.

(11) For units that generate electricity, nameplate generating capacity (MW) and net power generated (MWh) during the reporting year.

(12) For each cogeneration unit, indicate whether topping or bottoming cycle and provide useful thermal output as applicable, in mmBtu. Where steam or heat is acquired from another facility for the generation of electricity, report the provider and amount of acquired steam or heat in mmBtu. Where supplemental firing has been applied to support electricity generation or industrial output, report this purpose and fuel consumption by fuel type using the following units:[5]

(i) For gases, report in units of million standard cubic feet.
(ii) For liquids, report in units of gallons.
(iii) For non-biomass solids, report in units of short tons.
(iv) For biomass-derived solid fuels, report in units of bone dry short tons.

(c) Reporting alternatives for units using the four Tiers. You may use any of the applicable reporting alternatives of this paragraph to simplify the unit-level reporting required under paragraph (b) of this section:

[5] Taken from WCI.42(b).

Subpart C—General Stationary Combustion

(1) Aggregation of units. If a facility contains two or more units (e.g., boilers or combustion turbines), each of which has a maximum rated heat input capacity of 250 mmBtu/hr or less, you may report the combined GHG emissions for the group of units in lieu of reporting GHG emissions from the individual units, provided that the use of Tier 4 is not required or elected for any of the units and the units use the same tier for any common fuels combusted. If this option is selected, the following information shall be reported instead of the information in paragraph (b) of this section:

(i) Group ID number, beginning with the prefix "GP".

(ii) An identification number for each unit in the group.

(iii) Cumulative maximum rated heat input capacity of the group (mmBtu/hr).

(iv) The highest maximum rated heat input capacity of any unit in the group (mmBtu/hr).

(v) Each type of fuel combusted in the group of units during the reporting year.

(vi) Annual CO_2, CH_4, and N_2O mass emissions aggregated for each type of fuel combusted in the group of units during the year, expressed in metric tons of each gas and in metric tons of CO_2e. If any of the units burn both fossil fuels and biomass, report also the annual CO_2 emissions from combustion of all fossil fuels combined and annual CO_2 emissions from combustion of all biomass fuels combined, expressed in metric tons.

(vii) The tier used to calculate the CO_2 mass emissions for each type of fuel combusted in the units (i.e., Tier 1, Tier 2, or Tier 3).

(viii) The calculated CO_2 mass emissions (if any) from sorbent.

(ix) Annual GHG emissions from all fossil fuels burned in the group (i.e., the sum of the CO_2 , CH_4, and N_2O emissions), expressed in metric tons of CO2e.

(2) Monitored common stack or duct configurations. When the flue gases from two or more stationary combustion units at a facility are discharged through a common stack or duct before exiting to the atmosphere and if CEMS are used to continuously monitor CO_2 mass emissions at the common stack or duct according to the Tier 4 Calculation Methodology, you may report the combined emissions from the units sharing the common stack or duct, in lieu of separately reporting the GHG emissions from the individual units. The following information shall be reported instead of the information in paragraph (b) of this section:

(i) Common stack or duct identification number, beginning with the prefix "CS".

(ii) Identification numbers of the units sharing the common stack or duct.

(iii) Maximum rated heat input capacity of each unit sharing the common stack or duct (mmBtu/hr).

(iv) Each type of fuel combusted in the units during the year.

(v) The methodology used to calculate the CO_2 mass emissions, i.e., Tier 4.

(vi) If the any of the units burn both fossil fuels and biomass, annual CO_2 mass emissions, annual CO_2 emissions from combustion of fossil fuels, and annual CO_2 emissions from combustion of biomass measured at the common stack or duct, expressed in metric tons.

(vii) The annual CH_4 and N_2O emissions from the units sharing the common stack or duct, expressed in metric tons of each gas and in metric tons of CO_2e.

(viii) Annual GHG emissions from all fossil fuels burned in the group (i.e., the sum of the CO_2 , CH_4, and N_2O emissions), expressed in metric tons of CO2e.

(3) <u>Common pipe configurations</u>. When two or more liquid-fired or gaseous-fired stationary combustion units at a facility combust the same type of fuel and the fuel is

fed to the individual units through a common supply line or pipe, you may report the combined emissions from the units served by the common supply line, in lieu of separately reporting the GHG emissions from the individual units, provided that the total amount of fuel combusted by the units is accurately measured at the common pipe or supply line using a fuel flow meter that is calibrated in accordance with §98.34(a). If a portion of the fuel measured at the common pipe is diverted to a chemical or industrial process where it is used but not combusted, you may subtract the diverted fuel from the fuel measured at the common pipe prior to performing the GHG emissions calculations, provided that the amount of fuel diverted is also measured with a calibrated flow meter per §98.3(i). If the common pipe option is selected, the applicable tier shall be used based on the maximum rated heat input capacity of the largest unit served by the common pipe configuration. The following information shall be reported instead of the information in paragraph (b) of this section:

(i) Common pipe identification number, beginning with the prefix "CP".

(ii) The identification numbers of the units served by the common pipe.

(iii) Maximum rated heat input capacity of each unit served by the common pipe (mmBtu/hr).

(iv) The fuels combusted in the units during the reporting year.

(v) The methodology used to calculate the CO_2 mass emissions (i.e., Tier 1, Tier 2, or Tier 3).

(vi) If the any of the units burns both fossil fuels and biomass, the annual CO_2 mass emissions from combustion of all fossil fuels and annual CO_2 emissions from combustion of all biomass fuels from the units served by the common pipe, expressed in metric tons.

(vii) Annual CH_4 and N_2O emissions from the units served by the common pipe, expressed in metric tons of each gas and in metric tons of CO_2e.

(viii) Annual GHG emissions from all fossil fuels burned in units served by the common pipe (i.e., the sum of the CO_2, CH_4, and N_2O emissions), expressed in metric tons of CO_2e.

(d) Units subject to 40 CFR part 75.

(1) For stationary combustion units that are either subject to the Acid Rain Program or not in the Acid Rain Program but monitor and report CO_2 mass emissions year-round according to 40 CFR part 75, you shall report the following unit-level information:

(i) Unit or stack identification numbers. Use exact same unit, common stack, or multiple stack identification numbers that represent the monitored locations (e.g., 1, 2, CS001, MS1A, etc.) that are reported under §75.64 of this chapter.

(ii) Annual CO_2, CH_4, and N_2O emissions at each monitored location, expressed in metric tons of CO_2e.

(iii) Identification of the Part 75 methodology used to determine the CO_2 mass emissions.

(iv) Annual fuel consumption, if not reported under 40 CFR part 75.

(A) For gases, report in units of thousands of standard cubic feet.

(B) For liquids, report in units of gallons.

(C) For non-biomass solids, report in units of short tons.

(D) For biomass solid fuels, report in units of bone dry short tons or bone dry metric tons.

(v) Average carbon content of each fuel, if used to compute CO_2 emissions but not reported under 40 CFR part 75.

(vi) Average high heating value of each fuel, if used to compute CO_2 emissions but not reported under 40 CFR part 75.

(vii) For units that burn both fossil fuels and biomass, the annual CO2 emissions from combustion of all fossil fuels combined and the annual CO2 emissions from combustion of all biomass fuels combined. Reporting CO2 emissions by type of fuel is not required.

(viii) For units that generate electricity, nameplate generating capacity (MW) and net power generated (MWh) during the reporting year.

(ix) For each cogeneration unit, indicate whether topping or bottoming cycle and provide useful thermal output as applicable, in mmBtu. Where steam or heat is acquired from another facility for the generation of electricity, report the provider and amount of acquired steam or heat in mmBtu. Where supplemental firing has been applied to support electricity generation or industrial output, report this purpose and fuel consumption by fuel type using the units in WCI.42(b).

(2) For units that use the alternative CO_2 mass emissions calculation methods for units with continuous monitoring systems provided in §98.33(a)(5), you shall report the following unit-level information:

(i) Unit, stack, or pipe ID numbers. Use exact same unit, common stack, or multiple stack identification numbers that represent the monitored locations (e.g., 1, 2, CS001, MS1A, etc.) that are reported under §75.64 of this chapter.

(ii) For units that use the alternative methods specified in §98.33(a)(5)(i) and (ii) to monitor and report heat input data year-round according to appendix D to 40 CFR part 75 or 40 CFR 75.19:

(A) Each type of fuel combusted in the unit during the reporting year.

(B) The methodology used to calculate the CO_2 mass emissions for each fuel type.

(C) A code or flag to indicate whether heat input is calculated according to appendix D to 40 CFR part 75 or 40 CFR 75.19.

(D) Annual CO_2, CH_4, and N_2O emissions at each monitored location, across all fuel types, expressed in metric tons of CO_2e.

(iii) For units with continuous monitoring systems that use the alternative method for units with continuous monitoring systems in §98.33(a)(5)(iii) to monitor heat input year-round according to 40 CFR part 75:

(A) Fuel combusted during the reporting year.

(B) Methodology used to calculate the CO_2 mass emissions.

(C) A code or flag to indicate that the heat input data is derived from CEMS measurements.

(D) The total annual CO_2, CH_4, and N_2O emissions at each monitored location, expressed in metric tons of CO_2e.

(iv) The information required in paragraphs (d)(1)(iv) through (d)(1)(ix) of this section, as applicable.

(e) Verification data. You must keep on file, in a format suitable for inspection and auditing, sufficient data to verify the reported GHG emissions. This data and information must, where indicated in this paragraph (e), be included in the annual GHG emissions report.

(1) The applicable verification data specified in this paragraph (e) are not required to be kept on file or reported for units that meet any one of the three following conditions:

(i) Are subject to the Acid Rain Program.

(ii) Use the alternative methods for units with continuous monitoring systems provided in §98.33(a)(5).

(iii) Are not in the Acid Rain Program, but are required monitor and report CO_2 mass emissions and heat input data year-round, in accordance with 40 CFR part 75.

(2) For stationary combustion sources using the Tier 1, Tier 2, Tier 3, and Tier 4 Calculation Methodologies in

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§98.33(a) to quantify CO_2 emissions, the following additional information shall be kept on file and included in the GHG emissions report, where indicated:

(i) For the Tier 1 Calculation Methodology, report the total quantity of each type of fuel combusted in the unit or group of aggregated units (as applicable) during the reporting year, in short tons for solid fuels, gallons for liquid fuels and standard cubic feet for gaseous fuels.

(ii) For the Tier 2 Calculation Methodology, report:

(A) The total quantity of each type of fuel combusted in the unit or group of aggregated units (as applicable) during each month of the reporting year. Express the quantity of each fuel combusted during the measurement period in short tons for solid fuels, gallons for liquid fuels, and scf for gaseous fuels.

(B) The frequency of the HHV determinations (e.g., once a month, once per fuel lot).

(C) The high heat values used in the CO_2 emissions calculations for each type of fuel combusted, in mmBtu per short ton for solid fuels, mmBtu per gallon for liquid fuels, and mmBtu per scf for gaseous fuels. Specify the date on which each fuel sample was taken. Indicate whether each HHV is a measured value of a substitute data value.

(D) If Equation C-2c of this subpart is used to calculate CO_2 mass emissions, report the total quantity (i.e., pounds) of steam produced from MSW or solid fuel combustion during the year, and the ratio of the maximum rate heat input capacity to the design rated steam output capacity of the unit, in mmBtu per lb of steam.

(iii) For the Tier 2 Calculation Methodology, keep records of the methods used to determine the HHV for each type of fuel combusted and the date on which each fuel sample was taken.

(iv) For the Tier 3 Calculation Methodology, report:

(A) The quantity of each type of fuel combusted in the unit or group of units (as applicable) during the year, in short tons for solid fuels, gallons for liquid fuels, and scf for gaseous fuels.

(B) The frequency of carbon content and, if applicable, molecular weight determinations for each type of fuel for the reporting year (e.g., daily, weekly, monthly, semiannually, once per fuel lot).

(C) The carbon content and, if applicable, gas molecular weight values used in the emission calculations (including both valid and substitute data values). Report all measured values if the fuel is sampled monthly or less frequently. Otherwise, for daily and weekly sampling, report monthly average values determined using the calculation procedures in Equation C-2b for each variable. Express carbon content as a decimal fraction for solid fuels, kg C per gallon for liquid fuels, and kg C per kg of fuel for gaseous fuels. Express the gas molecular weights in units of kg per kg-mole.

(D) The total number of valid carbon content determinations and, if applicable, molecular weight determinations made during the reporting year, for each fuel type.

(E) The number of substitute data values used for carbon content and, if applicable, molecular weight used in the annual GHG emissions calculations.

(v) For the Tier 3 Calculation Methodology, keep records of the following:

(A) For liquid and gaseous fuel combustion, the dates and results of the initial calibrations and periodic recalibrations of the required fuel flow meters.

(B) For fuel oil combustion, the method from §98.34(b) used to make tank drop measurements (if applicable).

(C) The methods used to determine the carbon content for each type of fuel combusted.

(D) The methods used to calibrate the fuel flow meters).

(vi) For the Tier 4 Calculation Methodology, report:

(A) The total number of source operating hours in the reporting year.

(B) The cumulative CO_2 mass emissions in each quarter of the reporting year, i.e., the sum of the hourly values calculated from Equation C-6 or C-7 of this subpart (as applicable), in metric tons.

(C) For CO_2 concentration, stack gas flow rate, and (if applicable) stack gas moisture content, the percentage of source operating hours in which a substitute data value of each parameter was used in the emissions calculations.

(vii) For the Tier 4 Calculation Methodology, keep records of:

(A) Whether the CEMS certification and quality assurance procedures of 40 CFR part 75, 40 CFR part 60, or an applicable State continuous monitoring program were used.

(B) The dates and results of the initial certification tests of the CEMS.

(C) The dates and results of the major quality assurance tests performed on the CEMS during the reporting year, i.e., linearity checks, cylinder gas audits, and relative accuracy test audits (RATAs).

(viii) If CO_2 emissions that are generated from acid gas scrubbing with sorbent injection are not captured using CEMS, report:

(A) The total amount of sorbent used during the report year, in short tons.

(B) The molecular weight of the sorbent.

(C) The ratio ("R") in Equation C-11 of this subpart.

(ix) For units that combust both fossil fuel and biomass, when CEMS are used to quantify the annual CO_2 emissions and biogenic CO_2 is determined according to §98.33(e)(2), you shall report the following additional information, as applicable:

(A) The annual volume of CO_2 emitted from the combustion of all fuels, i.e., V_{total}, in scf.

(B) The annual volume of CO_2 emitted from the combustion of fossil fuels, i.e., V_{ff}, in scf. If more than one type of fossil fuel was combusted, report the combustion volume of CO_2 for each fuel separately as well as the total.

(C) The annual volume of CO_2 emitted from the combustion of biomass, i.e., V_{bio}, in scf.

(D) The carbon-based F-factor used in Equation C-13 of this subpart, for each type of fossil fuel combusted, in scf CO_2 per mmBtu.

(E) The annual average HHV value used in Equation C-13 of this subpart, for each type of fossil fuel combusted, in Btu/lb, Btu/gal, or Btu/scf, as appropriate.

(F) The total quantity of each type of fossil fuel combusted during the reporting year, in lb, gallons, or scf, as appropriate.

(G) Annual biogenic CO_2 mass emissions, in metric tons.

(x) When ASTM methods D7459-08 and D6866-08 are used to determine the biogenic portion of the annual CO_2 emissions from MSW combustion, report:

(A) The results of each quarterly sample analysis, expressed as a decimal fraction (e.g., if the biogenic fraction of the CO_2 emissions from MSW combustion is 30 percent, report 0.30).

(B) Annual combined biomass and fossil fuel CO_2 emissions from MSW combustion, in metric tons of CO_2e.

(C) The quantities V_{ff}, V_{total}, and V_{MSW} from §98.33(e)(4)(ii), if CEMS are used to measure CO_2 emissions.

(D) The annual volume of biogenic CO_2 emissions from MSW combustion, in metric tons.

(xi) When ASTM methods D7459-08 and D6866-08 are used to determine the biogenic portion of the annual CO_2 emissions from a unit that co-fires biogenic (other than MSW) and non-biogenic fuels, you shall report the results of each quarterly sample analysis, expressed as a decimal fraction (e.g., if the biogenic fraction of the CO_2 emissions is 30 percent, report 0.30).

(3) Within 30 days of receipt of a written request from the Administrator, you shall submit explanations of the following:

(i) An explanation of how company records are used to quantify fuel consumption, if the Tier 1 or Tier 2 Calculation Methodology is used to calculate CO_2 emissions.

(ii) An explanation of how company records are used to quantify fuel consumption, if solid fuel is combusted and the Tier 3 Calculation Methodology is used to calculate CO_2 emissions.

(iii) An explanation of how sorbent usage is quantified.

(iv) An explanation of how company records are used to quantify fossil fuel consumption in units that uses CEMS to quantify CO_2 emissions and combusts both fossil fuel and biomass.

(v) An explanation of how company records are used to measure steam production, when it is used to calculate CO_2 mass emissions under §98.33(a)(2)(iii) or to quantify solid fuel usage under §98.33(c)(3).

(4) Within 30 days of receipt of a written request from the Administrator, you shall submit the verification data and information described in paragraphs (e)(2)(iii), (e)(2)(v), and (e)(2)(vii) of this section.

§98.37 Records That Must be Retained.

In addition to the requirements of §98.3(g), you must retain the applicable records specified in §§98.34(f) and (g), 98.35(b), and 98.36(e).

§98.38 Definitions.

Except as specified in this section, all~~All~~ terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

"Bottoming cycle plant" means a cogeneration plant in which the energy input to the system is first applied to a useful thermal energy application or process, and at least some of the reject heat emerging from the application or process is then used for electricity production.

"Cogeneration unit" means a stationary fuel combustion device which simultaneously generates electrical and thermal energy that is (i) used by the operator of the facility where the cogeneration unit is located; or (ii) transferred to another facility for use by that facility.

"Cogeneration system" means individual cogeneration components including the prime mover (heat engine), generator, heat recovery, and electrical interconnection, configured into an integrated system that provides sequential generation of multiple forms of useful energy (usually electrical and thermal), at least one form of which the facility consumes on-site or makes available to other users for an end-use other than electricity generation.

"Topping cycle plant" means a cogeneration plant in which the energy input to the plant is first used to produce electricity, and at least some of the reject heat from the electricity production process is then used to provide useful thermal output.

Canadian jurisdictions will substitute tables that contain Canada-specific emission factors for Tables C-1 and C-2 below:

Table C-1 of Subpart C—Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel

Fuel Type	Default High Heat Value	Default CO_2 Emission Factor
Coal and Coke	**mmBtu/short ton**	**kg CO_2 /mmBtu**
Anthracite	25.09	103.54

Subpart C—General Stationary Combustion

Table C-1 of Subpart C—Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel

Fuel Type	Default High Heat Value	Default CO_2 Emission Factor
Bituminous	24.93	93.40
Subbituminous	17.25	97.02
Lignite	14.21	96.36
Coke	24.80	102.04
Mixed (Commercial sector)	21.39	95.26
Mixed (Industrial coking)	26.28	93.65
Mixed (Industrial sector)	22.35	93.91
Mixed (Electric Power sector)	19.73	94.38
Natural Gas	**mmBtu/scf**	**kg CO_2 /mmBtu**
Pipeline (Weighted U.S. Average)	1.028×10^{-3}	53.02
Petroleum Products	**mmBtu/gallon**	**kg CO_2 /mmBtu**
Distillate Fuel Oil No. 1	0.139	73.25
Distillate Fuel Oil No. 2	0.138	73.96
Distillate Fuel Oil No. 4	0.146	75.04
Residual Fuel Oil No. 5	0.140	72.93
Residual Fuel Oil No. 6	0.150	75.10
Still Gas	0.143	66.72
Kerosene	0.135	75.20
Liquefied petroleum gases (LPG)	0.092	62.98
Propane	0.091	61.46
Propylene	0.091	65.95
Ethane	0.096	62.64
Ethylene	0.100	67.43
Isobutane	0.097	64.91
Isobutylene	0.103	67.74
Butane	0.101	65.15
Butylene	0.103	67.73
Naphtha (<401 deg F)	0.125	68.02
Natural Gasoline	0.110	66.83
Other Oil (>401 deg F)	0.139	76.22
Pentanes Plus	0.110	70.02
Petrochemical Feedstocks	0.129	70.97
Petroleum Coke	0.143	102.41
Special Naphtha	0.125	72.34
Unfinished Oils	0.139	74.49
Heavy Gas Oils	0.148	74.92
Lubricants	0.144	74.27
Motor Gasoline	0.125	70.22
Aviation Gasoline	0.120	69.25
Kerosene-Type Jet Fuel	0.135	72.22
Asphalt and Road Oil	0.158	75.36
Crude Oil	0.138	74.49
Fossil Fuel-derived Fuels (Solid)	**mmBtu/short ton**	**kg CO_2 /mmBtu**
Municipal Solid Waste[1]	9.95	90.7
Tires	26.87	85.97
Fossil Fuel-derived Fuels (Gaseous)	**mmBtu/scf**	**kg CO_2 /mmBtu**

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Table C-1 of Subpart C—Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel

Fuel Type	Default High Heat Value	Default CO_2 Emission Factor
Blast Furnace Gas	0.092×10^{-3}	274.32
Coke Oven Gas	0.599×10^{-3}	46.85
Biomass Fuels - Solid	**mmBtu/short Ton**	**kg CO_2 /mmBtu**
Wood and Wood Residuals	15.38	93.80
Agricultural Byproducts	8.25	118.17
Peat	8.00	111.84
Solid Byproducts	25.83	105.51
Biomass Fuels - Gaseous	**mmBtu/scf**	**kg CO_2 /mmBtu**
Biogas (Captured methane)	0.841×10^{-3}	52.07
Biomass Fuels - Liquid	**mmBtu/gallon**	**kg CO_2 /mmBtu**
Ethanol (100%)	0.084	68.44
Biodiesel (100%)	0.128	73.84
Rendered Animal Fat	0.125	71.06
Vegetable Oil	0.120	81.55

[1]Allowed only for units that do not generate steam and use Tier 1.

Table C-2 of Subpart C—Default CH_4 and N_2O Emission Factors for Various Types of Fuel.

Fuel Type	Default CH_4 Emission Factor (kg CH_4 /mmBtu)	Default N_2O Emission Factor (kg N_2O/mmBtu)
Coal and Coke (All fuel types in Table C-1)	1.1×10^{-2}	1.6×10^{-03}
Natural Gas	1.0×10^{-03}	1.0×10^{-04}
Petroleum (All fuel types in Table C-1)	3.0×10^{-03}	6.0×10^{-04}
Municipal Solid Waste	3.2×10^{-02}	4.2×10^{-03}
Tires	3.2×10^{-02}	4.2×10^{-03}
Blast Furnace Gas	2.2 x 10-05	1.0×10^{-04}
Coke Oven Gas	4.8 x 10-04	1.0×10^{-04}
Biomass Fuels - Solid (All fuel types in Table C-1)	3.2×10^{-02}	4.2×10^{-03}
Biogas	3.2×10^{-03}	6.3×10^{-04}
Biomass Fuels - Liquid (All fuel types in Table C-1)	1.1×10^{-03}	1.1×10^{-04}

Note: Those employing this table are assumed to fall under the IPCC definitions of the "Energy Industry" or "Manufacturing Industries and Construction". In all fuels except for coal the values for these two categories are identical. For coal combustion, those who fall within the IPCC "Energy Industry" category may employ a value of 1 g of CH_4/MMBtu.

[1]Allowed only for units that do not generate steam and use Tier 1.

Table C-2 of Subpart C—Default CH_4 and N_2O Emission Factors for Various Types of Fuel.

Fuel Type	Default CH_4 Emission Factor (kg CH_4 /mmBtu)	Default N_2O Emission Factor (kg N_2O/mmBtu)
Coal and Coke (All fuel types in Table C-1)	1.1×10^{-2}	1.6×10^{-03}
Natural Gas	1.0×10^{-03}	1.0×10^{-04}
Petroleum (All fuel types in Table C-1)	3.0×10^{-03}	6.0×10^{-04}
Municipal Solid Waste	3.2×10^{-02}	4.2×10^{-03}
Tires	3.2×10^{-02}	4.2×10^{-03}
Blast Furnace Gas	2.2×10^{-05}	1.0×10^{-04}
Coke Oven Gas	4.8×10^{-04}	1.0×10^{-04}
Biomass Fuels - Solid (All fuel types in Table C-1)	3.2×10^{-02}	4.2×10^{-03}
Biogas	3.2×10^{-03}	6.3×10^{-04}
Biomass Fuels – Liquid (All fuel types in Table C-1)	1.1×10^{-03}	1.1×10^{-04}

Note: Those employing this table are assumed to fall under the IPCC definitions of the "Energy Industry" or "Manufacturing Industries and Construction". In all fuels except for coal the values for these two categories are identical. For coal combustion, those who fall within the IPCC "Energy Industry" category may employ a value of 1 g of CH_4/MMBtu.

Subpart D—Electricity Generation

§98.40 Definition of the source category.

(a) The electricity generation source category comprises electricity generating units that are subject to the requirements of the Acid Rain Program and any other electricity generating units that are required to monitor and report to EPA CO_2 emissions year-round according to 40 CFR part 75.

(b) This source category does not include portable equipment, emergency equipment, or emergency generators, as defined in §98.6.[1]

§98.41 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains one or more electricity generating units and the facility meets the requirements of §98.2(a)(1).

§98.42 GHGs to report[2].

(a) For each electricity generating unit that is subject to the requirements of the Acid Rain Program or is otherwise required to monitor and report to EPA CO_2 emissions year-round according to 40 CFR part 75, you must

[1] Retain for U.S. rules. Canadians will decide whether or not to retain for their jurisdictions.

[2] Reporting of fugitive CO2 by geothermal facilities is in the ERMRs but not in the MRR. Flag for Partners decision on whether or not to retain reporting by geothermal facilities. If geothermal is retained, it may be clearer to publish the requirement as a separate WCI subpart rather than be included in MRR subpart D.

report under this subpart the annual mass emissions of CO_2, N_2O, and CH_4 by following the requirements of this subpart.

(b) For each electricity generating unit that is not subject to the Acid Rain Program or otherwise required to monitor and report to EPA CO_2 emissions year-round according to 40 CFR part 75, you must report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO_2, CH_4, and N_2O by following the requirements of subpart C.

(c) For each stationary fuel combustion unit that does not generate electricity, you must report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO_2, CH_4, and N_2O by following the requirements of subpart C of this part.

§98.43 Calculating GHG emissions.

Continue to monitor and report CO_2 mass emissions as required under §75.13 or section 2.3 of apppendix G to 40 CFR part 75, and §75.64. Calculate CO_2, CH_4, and N_2O emissions as follows:

(a) Convert the cumulative annual CO_2 mass emissions reported in the fourth quarter electronic data report required under §75.64 from units of short tons to metric tons. To convert tons to metric tons, divide by 1.1023.

(b) Calculate and report annual CH_4 and N_2O mass emissions under this subpart by following the applicable method specified in §98.33(c).

§98.44 Monitoring and QA/QC requirements

Follow the applicable quality assurance procedures for CO_2 emissions in appendices B, D, and G to 40 CFR part 75.

§98.45 Procedures for estimating missing data.

Follow the applicable missing data substitution procedures in 40 CFR part 75 for CO_2 concentration, stack gas flow rate, fuel flow rate, high heating value, and fuel carbon content.

§98.46 Data reporting requirements.

The annual report shall comply with the data reporting requirements specified in §98.36(d~~b~~)[3] and, if applicable, §98.36(c)(2) or (c)(3).

§98.47 Records that must be retained.

You shall comply with the recordkeeping requirements of §§98.3(g) and 98.37.

§98.48 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

[3] This corrects an error in the MRR that EPA is in the process of correcting.

Subpart F—Aluminum Production

§98.60 Definition of the source category.

(a) A primary aluminum production facility manufactures primary aluminum using the Hall-Héroult manufacturing process. The primary aluminum manufacturing process comprises the following operations:

(1) Electrolysis in prebake and Søderberg cells.

(2) Anode baking for prebake cells.

(b) This source category does not include experimental cells or research and development process units.

§98.61 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains an aluminum production process and the facility meets the requirements of either §98.2(a)(1) or (a)(2).

§98.62 GHGs to report.

You must report:

(a) Perfluoromethane (CF_4), and perfluoroethane (C_2F_6) emissions from anode effects in all prebake and Søderberg electolysis cells.

(b) CO_2 emissions from anode consumption during electrolysis in all prebake and Søderberg electolysis cells.

(c) CO_2 emissions from on-site anode baking.

(d) You must report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO_2, N_2O, and CH_4 emissions from each stationary fuel combustion unit by following the requirements of subpart C.

§98.63 Calculating GHG emissions.

(a) The annual value for PFC emissions shall be estimated from the sum of monthly values using Equation F-1 of this section:

$$E_{PFC} = \sum_{m=1}^{m=12} E_m \qquad \text{(Eq. F-1)}$$

Where:

E_{PFC} = Annual PFC emissions from aluminum production (metric tons PFC).

E_m = PFC emissions from aluminum production for the month "m" (metric tons PFC).

(b) Use Equation F-2 of this section to estimate CF_4 emissions from anode effect duration or Equation F-3 of this section to estimate CF_4 emissions from overvoltage, and use Equation F-4 of this section to estimate C_2F_6 emissions from anode effects from each prebake and Søderberg electolysis cell.

$$E_{CF4} = S_{CF4} \times AEM \times MP \times 0.001 \qquad \text{(Eq. F-2)}$$

Where:

E_{CF4} = Monthly CF_4 emissions from aluminum production (metric tons CF_4).

S_{CF4} = The slope coefficient ((kg CF_4/metric ton Al)/(AE-Mins/cell-day)).

AEM = The anode effect minutes per cell-day (AE-Mins/cell-day).

MP = Metal production (metric tons Al), where AEM and MP are calculated monthly.

$$E_{CF4} = EF_{CF4} \times MP \times 0.001 \qquad \text{(Eq. F-3)}$$

Where:

E_{CF4} = Monthly CF_4 emissions from aluminum production (metric tons CF_4).

EF_{CF4} = The overvoltage emission factor (kg CF_4/metric ton Al).

MP = Metal production (metric tons Al), where MP is calculated monthly.

$$E_{C2F6} = E_{CF4} \times F_{C2F6/CF4} \times 0.001 \qquad \text{(Eq. F-4)}$$

Where:

E_{C2F6} = Monthly C_2F_6 emissions from aluminum production (metric tons C_2F_6).

E_{CF4} = CF_4 emissions from aluminum production(kg CF_4).

$F_{C2F6/CF4}$ = The weight fraction of C_2F_6/CF_4 (kg C_2F_6/kg CF_4).

0.001 = Conversion factor from kg to metric tons, where E_{CF4} is calculated monthly.

(c) You must calculate and report the annual process CO_2 emissions from anode consumption during electrolysis and anode baking of prebake cells using either the procedures in paragraph (d) of this section or the procedures in paragraphs (e) and (f) of this section.

(d) Calculate and report under this subpart the process CO_2 emissions by operating and maintaining CEMS according to the Tier 4 Calculation Methodology in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(e) Use the following procedures to calculate CO_2 emissions from anode consumption during electrolysis:

(1) For Prebake cells: you must calculate CO_2 emissions from anode consumption using Equation F-5 of this section:[1]

$$E_{CO2} = NAC \times MP \times ([100 - S_a - Ash_a] / 100) \times (44/12) \quad \text{(Eq. F-5)}$$

Where:

E_{CO2} = Annual CO_2 emissions from prebaked anode consumption (metric tons CO_2).

NAC = Net annual prebaked anode consumption per metric ton Al (metric tons C/metric tons Al).

MP = Annual metal production (metric tons Al).

S_a = Sulfur content in baked anode (percent weight).

Ash_a = Ash content in baked anode(percent weight).

44/12 = Ratio of molecular weights, CO_2 to carbon.

(2) For Søderberg cells you must calculate CO_2 emissions using Equation F-6 of this section:[2]

$$E_{CO2} = (PC \times MP - [CSM \times MP] / 1000 - BC / 100 \times PC \times MP \times [S_p + Ash_p + H_p] / 100 - [100 - BC] / 100 \times PC \times MP \times [S_c + Ash_c] / 100 - MP \times CD) \times (44/12) \quad \text{(Eq. F-6)}$$

Where:

E_{CO2} = Annual CO_2 emissions from paste consumption (metric ton CO_2).

PC = Annual paste consumption (metric ton/metric ton Al).

MP = Annual metal production (metric ton Al).

[1]The WCI equivalents for equations F-5, F-6 and F-8 in the existing ERs for aluminum production include a deduction for impurities in the baked anode, pitch and packing coke respectively. Allowing such a deduction, however, would be inconsistent with harmonization, since it would require reporting different amounts for these processes to EPA and the WCI. WCI solicits stakeholder input on the significance of this omission.

[2]WCI discussed removing the factor for carbon removed as skimmed dust (CD) since it is not included in the WCI methodology. It has been retained to assure harmonization.

CSM = Annual emissions of cyclohexane soluble matter (kg/metric ton Al).

BC = Binder content of paste (percent weight).

S_p = Sulfur content of pitch (percent weight).

Ash_p = Ash content of pitch (percent weight).

H_p = Hydrogen content of pitch (percent weight).

S_c = Sulfur content in calcined coke (percent weight).

Ash_c = Ash content in calcined coke (percent weight).

CD = Carbon in skimmed dust from Søderberg cells (metric ton C/metric ton Al).

44/12 = Ratio of molecular weights, CO_2 to carbon.

(e) Use the following procedures to calculate CO_2 emissions from anode baking of prebake cells:

(1) Use Equation F-7 of this section to calculate emissions from pitch volatiles combustion.

$$E_{CO2PV} = (GA - H_w - BA - WT) \times (44/12) \qquad \text{(Eq. F-7)}$$

Where:

E_{CO2PV} = Annual CO_2 emissions from pitch volatiles combustion (metric tons CO_2).

GA = Initial weight of green anodes (metric tons).

H_w = Annual hydrogen content in green anodes (metric tons).

BA = Annual baked anode production (metric tons).

WT = Annual waste tar collected (metric tons).

44/12 = Ratio of molecular weights, CO_2 to carbon.

(2) Use Equation F-8 of this section to calculate emissions from bake furnace packing material.

$$E_{CO2PC} = PCC \times BA \times ([100 - S_{pc} - Ash_{pc}] / 100) \times (44/12) \qquad \text{(Eq. F-8)}$$

Where:

E_{CO2PC} = Annual CO_2 emissions from bake furnace packing material (metric tons CO_2).

PCC = Annual packing coke consumption (metric tons/metric ton baked anode).

BA = Annual baked anode production (metric tons).
S_{pc} = Sulfur content in packing coke (percent weight).
Ash_{pc} = Ash content in packing coke (percent weight).
44/12 = Ratio of molecular weights, CO_2 to carbon.

(f) If process CO_2 emissions from anode consumption during electrolysis or anode baking of prebake cells are vented through the same stack as any combustion unit or process equipment that reports CO_2 emissions using a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Fuel Combustion Sources), then the calculation methodology in paragraphs (d) and (e) of this section shall not be used to calculate those process emissions. The owner or operation shall report under this subpart the combined stack emissions according to the Tier 4 Calculation Methodology in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

§98.64 Monitoring and QA/QC requirements.

(a) Effective one year after publication of the rule for smelters with no prior measurement or effective three years after publication for facilities with historic measurements, the smelter-specific slope coefficients used in Equations F-2, F-3, and F-4 of this subpart must be measured in accordance with the recommendations of the

EPA/IAI Protocol for Measurement of Tetrafluoromethane (CF_4) and Hexafluoroethane (C_2F_6) Emissions from Primary Aluminum Production (2008), except the minimum frequency of measurement shall be every ~~10 years~~ 36 months ~~unless~~ and when a change occurs in the control algorithm that affects the mix of types of anode effects or the nature of the anode effect termination routine or when changes occur in the distribution or duration of anode effects (i.e., when the percentage of manual kills changes or if the number of anode effects decreases and results in a fewer number of longer anode effects) or for Rio Tinto Alcan control technology (i.e., when the algorithm for bridge movements and anode effect overvoltage accounting changes). Facilities which operate at less than 0.2 anode effect minutes per cell day or operate with less than 1.4mV anode effect overvoltage ~~can~~ must use ~~either~~ smelter-specific slope coefficients ~~or the technology specific default values in Table F-1 of this subpart~~.

(b) The minimum frequency of the measurement and analysis is ~~annually except as follows: Monthly – anode effect minutes per cell day (or anode effect overvoltage and current efficiency), production~~monthly.

(c) Sources ~~may~~ must use ~~either~~ smelter-specific values from annual measurements of parameters needed to complete the equations in §98.63 (e.g., sulfur, ash, and hydrogen contents)~~ or the default values shown in Table F-2 of this subpart~~.

§98.65 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation or if a required sample measurement is not taken), a substitute data value for the missing parameter shall be used in the calculations, according to the following requirements:

(a) Where anode or paste consumption data are missing, CO_2 emissions can be estimated from aluminum production using Tier 1 method per Equation F-8 of this section.

$$ECO_2 = EF_p \times MP_p + EF_s \times MP_s \qquad \text{(Eq. F-8)}$$

Where:

ECO_2 = CO_2 emissions from anode and/or paste consumption, metric tons CO_2.

EF_p = Prebake technology specific emission factor (1.6 metric tons CO_2/metric ton aluminum produced).

MP_p = Metal production from prebake process (metric tons Al).

EF_s = Søderberg technology specific emission factor (1.7 metric tons CO_2/metric ton Al produced).

MP_s = Metal production from Søderberg process (metric tons Al).

(b) For other parameters, use the average of the two most recent data points after the missing data.

§98.66 Data reporting requirements.

In addition to the information required by §98.3(c), you must report the following information at the facility level:

(a) Annual aluminum production in metric tons.

(b) Type of smelter technology used.

(c) The following PFC-specific information on an annual basis:

(1) Perfluoromethane emissions and perfluoroethane emissions from anode effects in all prebake and all Søderberg electolysis cells combined.

(2) Anode effect minutes per cell-day (AE-mins/cell-day), anode effect frequency (AE/cell-day), anode effect duration (minutes). (Or anode effect overvoltage factor ((kg CF_4/metric ton Al)/(mV/cell day)), potline overvoltage (mV/cell day), current efficiency (%).)

(3) Smelter-specific slope coefficients (or overvoltage emission factors) and the last date when the smelter-specific-slope coefficients (or overvoltage emission factors) were measured.

(d) Method used to measure the frequency and duration of anode effects (or overvoltage).

(e) The following CO_2-specific information for prebake cells:

(1) Annual anode consumption.

(2) Annual CO_2 emissions from the smelter.

(f) The following CO_2-specific information for Søderberg cells:

(1) Annual paste consumption.

(2) Annual CO_2 emissions from the smelter.

(g) Smelter-specific inputs to the CO_2 process equations (e.g., levels of sulfur and ash) that were used in the calculation, on an annual basis.

(h) Exact data elements required will vary depending on smelter technology (e.g., point-feed prebake or Søderberg) and process control technology (e.g., Pechiney or other).

§98.67 Records that must be retained.

In addition to the information required by §98.3(g), you must retain the following records:

(a) Monthly aluminum production in metric tons.

(b) Type of smelter technology used.

(c) The following PFC-specific information on a monthly basis:

(1) Perfluoromethane and perfluoroethane emissions from anode effects in prebake and Søderberg electolysis cells.

(2) Anode effect minutes per cell-day (AE-mins/cell-day), anode effect frequency (AE/cell-day), anode effect duration (minutes). (Or anode effect overvoltage factor ((kg CF_4/metric ton Al)/(mV/cell day)), potline overvoltage (mV/cell day), current efficiency (%).))

(3) Smelter-specific slope coefficients and the last date when the smelter-specific-slope coefficients were measured.

(d) Method used to measure the frequency and duration of anode effects (or to measure anode effect overvoltage and current efficiency).

(e) The following CO_2-specific information for prebake cells:

(1) Annual anode consumption.

(2) Annual CO_2 emissions from the smelter.

(f) The following CO_2-specific information for Søderberg cells:

(1) Annual paste consumption.

(2) Annual CO_2 emissions from the smelter.

(g) Smelter-specific inputs to the CO_2 process equations (e.g., levels of sulfur and ash) that were used in the calculation, on an annual basis.

(h) Exact data elements required will vary depending on smelter technology (e.g., point-feed prebake or Søderberg) and process control technology (e.g., Pechiney or other).

§98.68 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Table F-1 of Subpart F—Slope and Overvoltage Coefficients for the Calculation of PFC Emissions from Aluminum Production

Technology	**CF_4 Slope Coefficient [(kg CF_4/metric ton Al)/(AE-Mins/cell-day)]**	**CF_4 Overvoltage Coefficient [(kg CF_4/metric ton Al)/(mV)]**	**Weight Fraction C_2F_6/CF_4 [(kg C_2F_6/kg CF_4)]**
CWPB	0.143	1.16	0.121
SWPB	0.272	3.65	0.252
VSS	0.092	NA	0.053
HSS	0.099	NA	0.085

Table F-2 of Subpart F—Default Data Sources for Parameters Used for CO_2 Emissions

CO_2 Emissions from Prebake Cells (CWPB and SWPB)	
Parameter	Data Source
MP: metal production (metric tons Al)	Individual facility records
NAC: net annual prebaked anode consumption per metric ton Al (metric tons C/metric tons Al)	Individual facility records
S_a: sulfur content in baked	2.0

anode (percent weight)	
Ash_a: ash content in baked anode(percent weight)	0.4
CO_2 Emissions from Søderberg Cells (VSS and HSS)	
Parameter	Data Source
MP: metal production (metric tons Al)	Individual facility records
PC: annual paste consumption (metric ton/metric ton Al)	Individual facility records
CSM: annual emissions of cyclohexane soluble matter (kg/metric ton Al)	HSS: 4.0 VSS: 0.5
BC: binder content of paste (percent weight)	Dry Paste: 24 Wet Paste: 27
S_p: sulfur content of pitch (percent weight)	0.6
Ash_p: ash content of pitch (percent weight)	0.2
H_p: hydrogen content of pitch (percent weight)	3.3
S_c: sulfur content in calcined coke (percent weight)	1.9
Ash_c: ash content in calcined coke (percent weight)	0.2
CD: carbon in skimmed dust from Søderberg cells (metric ton C/metric ton Al)	0.01
CO_2 Emissions from Pitch Volatiles Combustion (VSS and HSS)	
Parameter	Data Source
GA: initial weight of green anodes (metric tons)	Individual facility records
H_w: annual hydrogen content in green anodes (metric tons)	0.005 × GA
BA: annual baked anode production (metric tons)	Individual facility records
WT: annual waste tar collected (metric tons) (a) Riedhammer furnaces (b) all other furnaces	(a) 0.005 × GA (b) insignificant
CO_2 Emissions from Bake Furnace Packing Materials (CWPB	

and SWPB)	
Parameter	Data Source
PCC: annual packing coke consumption (metric tons/metric ton baked anode)	0.015
BA: annual baked anode production (metric tons)	Individual facility records
S_{pc}: sulfur content in packing coke (percent weight)	2
Ash_{pc}: ash content in packing coke (percent weight)	2.5

Subpart N—Glass Production

§98.140 Definition of the source category.

(a) A glass manufacturing facility manufactures flat glass, container glass, pressed and blown glass, or wool fiberglass by melting a mixture of raw materials to produce molten glass and form the molten glass into sheets, containers, fibers, or other shapes. A glass manufacturing facility uses one or more continuous or batch glass melting furnaces to produce glass.[1]

(b) A glass melting furnace that is an experimental furnace or a research and development process unit is not subject to this subpart.

§98.141 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a glass production process and the facility meets the requirements of either §98.2(a)(1) or (2).

§98.142 GHGs to report.

You must report:

(a) CO_2 process emissions from each continuous or batch glass melting furnace.

[1]EPA's definition of a glass manufacturing facility is limited to only continuous glass melting furnaces. WCI has requested that batch furnaces be included as well. Expanded definition included in §98.140(a). All references in Subpart N to "continuous glass melting furnace" have been changed to "continuous or batch glass melting furnace" or "continuous and batch glass melting furnace", depending upon the specific text.

(b) CO_2 combustion emissions from each continuous or batch glass melting furnace.

(c) CH_4 and N_2O combustion emissions from each continuous or batch glass melting furnace. You must calculate and report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

(d) CO_2, CH_4, and N_2O emissions from each stationary fuel combustion unit other than continuous or batch glass melting furnaces. You must report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

§98.143 Calculating GHG emissions.

You must calculate and report the annual process CO_2 emissions from each continuous or batch glass melting furnace using the procedure in paragraphs (a) and (b) of this section.

(a) For each continuous or batch glass melting furnace that meets the conditions specified in §98.33(b)(4)(ii) or (iii), you must calculate and report under this subpart the combined process and combustion CO_2 emissions by operating and maintaining a CEMS to measure CO_2 emissions according to the Tier 4 Calculation Methodology specified in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(b) For each continuous or batch glass melting furnace that is not subject to the requirements in paragraph (a) of this section, calculate and report the process and combustion CO_2 emissions from the glass melting furnace by using either the procedure in paragraph (b)(1) of this section or the procedure in paragraphs (b)(2) through (b)(7) of this section, except as specified in paragraph (c) of this section.

(1) Calculate and report under this subpart the combined process and combustion CO_2 emissions by operating and maintaining a CEMS to measure CO_2 emissions according to the Tier 4 Calculation Methodology specified in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(2) Calculate and report the process and combustion CO_2 emissions separately using the procedures specified in paragraphs (b)(2)(i) through (b)(2)(vi) of this section.

(i) For each carbonate-based raw material charged to the furnace, obtain from the supplier of the raw material the carbonate-based mineral mass fraction.

(ii) Determine the quantity of each carbonate-based raw material charged to the furnace.

(iii) Apply the appropriate emission factor for each carbonate-based raw material charged to the furnace, as shown in Table N-1 to this subpart.

(iv) Use Equation N-1 of this section to calculate process mass emissions of CO_2 for each furnace:

$$E_{CO2} = \sum_{i=1}^{n} MF_i \bullet (M_i \bullet \frac{2000}{2205}) \bullet EF_i \bullet F_i \qquad \text{(Eq. N-1)}$$

Where:

E_{CO2}	=	Process emissions of CO_2 from the furnace (metric tons).
n	=	Number of carbonate-based raw materials charged to furnace.
MF_i	=	Annual average mass fraction of carbonate-based mineral i in carbonate-based raw material i (percentage, expressed as a decimal).
M_i	=	Annual amount of carbonate-based raw material i charged to furnace (tons).
2000/2205	=	Conversion factor to convert tons to metric tons.
EF_i	=	Emission factor for carbonate-based raw material i (metric ton CO_2 per metric ton carbonate-based raw material as shown in Table N-1 to this subpart).
F_i	=	Fraction of calcination achieved for carbonate-based raw material i, assumed to be equal to 1.0 (percentage, expressed as a decimal).

(v) You must calculate the total process CO_2 emissions from continuous and batch glass melting furnaces at the facility using Equation N-2 of this section:

$$CO_2 = \sum_{i=1}^{k} E_{CO_2 i} \qquad \text{(Eq. N-2)}$$

Where:

CO_2	=	Annual process CO_2 emissions from glass manufacturing facility (metric tons).
E_{CO2i}	=	Annual CO_2 emissions from glass melting furnace i (metric tons).
k	=	Number of continuous and batch glass melting furnaces.

(vi) Calculate and report under subpart C of this part (General Stationary Fuel Combustion Sources) the combustion CO_2 emissions in the glass furnace according to the applicable requirements in subpart C.

(c) As an alternative to data provided by the raw material supplier, a value of 1.0 can be used for the mass fraction (MF_i) of carbonate-based mineral i in Equation N-1 of this section.

§98.144 Monitoring and QA/QC requirements.

(a) You must measure annual amounts of carbonate-based raw materials charged to each continuous or batch glass melting furnace from monthly measurements using plant instruments used for accounting purposes, such as calibrated scales or weigh hoppers. Total annual mass charged to glass melting furnaces at the facility shall be compared to records of raw material purchases for the year.

(b) You must measure carbonate-based mineral mass fractions at least annually to verify the mass fraction data provided by the supplier of the raw material; such measurements shall be based on sampling and chemical analysis conducted by a certified laboratory using ASTM D3682-01 (Reapproved 2006) Standard Test Method for Major and Minor Elements in Combustion Residues from Coal Utilization Processes (incorporated by reference, see §98.7).

(c) You must determine the annual average mass fraction for the carbonate-based mineral in each carbonate-based raw material by calculating an arithmetic average of the monthly data obtained from raw material suppliers or sampling and chemical analysis.

(d) You must determine on an annual basis the calcination fraction for each carbonate consumed based on sampling and chemical analysis using an industry consensus standard. This chemical analysis must be conducted using an x-ray fluorescence test or other enhanced testing method published by an industry consensus standards organization (e.g., ASTM, ASME, API, etc.).

§98.145 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required (e.g., carbonate raw materials consumed, etc.). If the monitoring and quality assurance procedures in §98.144 cannot be followed and data is missing, you must use the most appropriate of the missing data procedures in paragraphs (a) and (b) of this section. You must document and keep records of the procedures used for all such missing value estimates.

(a) For missing data on the monthly amounts of carbonate-based raw materials charged to any continuous or batch glass melting furnace use the best available estimate(s) of the parameter(s), based on all available process data or data used for accounting purposes, such as purchase records.

(b) For missing data on the mass fractions of carbonate-based minerals in the carbonate-based raw materials assume that the mass fraction of each carbonate based mineral is 1.0.

§98.146 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) and (b) of this section, as applicable.

Subpart N—Glass Production

(a) If a CEMS is used to measure CO_2 emissions, then you must report under this subpart the relevant information required under §98.37 for the Tier 4 Calculation Methodology and the following information specified in paragraphs (a)(1) and (a)(2) of this section:

(1) Annual quantity of each carbonate-based raw material charged to each continuous or batch glass melting furnace and for all furnaces combined (tons).

(2) Annual quantity of glass produced (tons).

(b) If a CEMS is not used to determine CO_2 emissions from continuous or batch glass melting furnaces, and process CO_2 emissions are calculated according to the procedures specified in §98.143(b), then you must report the following information as specified in paragraphs (b)(1) through (b)(9) of this section:

(1) Annual process emissions of CO_2 (metric tons) for each continuous or batch glass melting furnace and for all furnaces combined.

(2) Annual quantity of each carbonate-based raw material charged (tons) to each continuous or batch glass melting furnace and for all furnaces combined.

(3) Annual quantity of glass produced (tons) from each continuous or batch glass melting furnace and from all furnaces combined.

(4) Carbonate-based mineral mass fraction (percentage, expressed as a decimal) for each carbonate-based raw material charged to a continuous or batch glass melting furnace.

(5) Results of all tests used to verify the carbonate-based mineral mass fraction for each carbonate-based raw material charged to a continuous or batch glass melting furnace, as specified in paragraphs (b)(5)(i) through (b)(5)(iii) of this section.

(i) Date of test.

(ii) Method(s) and any variations used in the analyses.

(iii) Mass fraction of each sample analyzed.

(6) The fraction of calcination achieved for each carbonate-based raw material, if a value other than 1.0 is used to calculate process mass emissions of CO_2.

(7) Method used to determine fraction of calcination (percentage, expressed as a decimal).

(8) Total number of continuous or batch glass melting furnaces.

(9) The number of times in the reporting year that missing data procedures were followed to measure monthly quantities of carbonate-based raw materials any continuous

or batch glass melting furnace or mass fraction of the carbonate-based minerals (months).

§98.147 Records that must be retained.

In addition to the information required by §98.3(g), you must retain the records listed in paragraphs (a), (b), and (c) of this section.

(a) If a CEMS is used to measure emissions, then you must retain the records required under §98.37 for the Tier 4 Calculation Methodology and the following information specified in paragraphs (a)(1) and (a)(2) of this section:

(1) Monthly glass production rate for each continuous or batch glass melting furnace (tons).

(2) Monthly amount of each carbonate-based raw material charged to each continuous or batch glass melting furnace (tons).

(b) If process CO_2 emissions are calculated according to the procedures specified in §98.143(b), you must retain the records in paragraphs (b)(1) through (b)(5) of this section.

(1) Monthly glass production rate for each continuous or batch glass melting furnace (metric tons).

(2) Monthly amount of each carbonate-based raw material charged to each continuous or batch glass melting furnace (metric tons).

(3) Data on carbonate-based mineral mass fractions provided by the raw material supplier for all raw materials consumed annually and included in calculating process emissions in Equation N-1 of this subpart.

(4) Results of all tests used to verify the carbonate-based mineral mass fraction for each carbonate-based raw material charged to a continuous or batch glass melting furnace, including the data specified in paragraphs (b)(4)(i) through (b)(4)(v) of this section.

(i) Date of test.

(ii) Method(s), and any variations of the methods, used in the analyses.

(iii) Mass fraction of each sample analyzed.

(iv) Relevant calibration data for the instrument(s) used in the analyses.

(v) Name and address of laboratory that conducted the tests.

(5) The fraction of calcination achieved for each carbonate-based raw material (percentage, expressed as a decimal), if a value other than 1.0 is used to calculate process mass emissions of CO_2.

(c) All other documentation used to support the reported GHG emissions.

§98.148 Definitions.

Subpart N—Glass Production

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Table N-1 of Subpart N—CO_2 Emission Factors for Carbonate-Based Raw Materials

Carbonate-Based Raw Material – Mineral	CO_2 Emission Factor[a]
Limestone – $CaCO_3$	0.440
Dolomite – $CaMg(CO_3)_2$	0.477
Sodium carbonate/soda ash – Na_2CO_3	0.415

[a] Emission factors in units of metric tons of CO_2 emitted per metric ton of carbonate-based raw material charged to the furnace.

Subpart P—Hydrogen Production

§98.160 Definition of the source category.

(a) A hydrogen production source category consists of facilities that produce hydrogen gas for use onsite or sold as a product to other entities.

(b) This source category comprises process units that produce hydrogen by reforming, gasification, oxidation, reaction, or other transformations of feedstocks.

(c) This source category includes merchant hydrogen production facilities located within a petroleum refinery if they are not owned by, or under the direct control of, the refinery owner and operator.

§98.161 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a hydrogen production process and the facility meets the requirements of either §98.2(a)(1) or (a)(2).

§98.162 GHGs to report.

You must report:

(a) CO_2 process emissions from each hydrogen production process unit.

(b) CO_2, CH_4 and N_2O combustion emissions from each hydrogen production process unit. You must calculate and report these combustion emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

(c) CO_2, CH_4, and N_2O emissions from each stationary combustion unit other than hydrogen production process units. You must calculate and report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

(d) For CO_2 collected and transferred off site, you must follow the requirements of subpart PP of this part.

§98.163 Calculating GHG emissions.

You must calculate and report the annual process CO_2 emissions from each hydrogen production process unit using the procedures specified in either paragraph (a) or (b) of this section.

(a) Continuous Emissions Montoring Systems (CEMS). Calculate and report under this subpart the process CO_2 emissions by operating and maintaining CEMS according to the Tier 4 Calculation Methodology specified in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(b) Fuel and feedstock material balance approach. Calculate and report process CO_2 emissions as the sum of the annual emissions associated with each fuel and feedstock used for hydrogen production by following paragraphs (b)(1) through (b)(3) of this section.

(1) Gaseous fuel and feedstock. You must calculate the annual CO_2 process emissions from gaseous fuel and feedstock according to Equation P-1 of this section:

$$CO_2 = (\sum_{n=1}^{k} \frac{44}{12} * Fdstk_n * CC_n * \frac{MW}{MVC}) * 0.001 \qquad \text{(Eq. P-1)}$$

Where:

CO_2	=	Annual CO_2 process emissions arising from fuel and feedstock consumption (metric tons/yr).
$Fdstk_n$	=	Volume of the gaseous fuel and feedstock used in month n(scf (at standard conditions of 68 °F and atmospheric pressure) of fuel and feedstock).
CC_n	=	Weighted ~~A~~average carbon content of the gaseous fuel and feedstock, from the results of one or more analyses for month n for natural gas or from daily analysis for gasseous feedstocks other than natural gas(kg carbon per kg of fuel and feedstock).
MW	=	Molecular weight of the gaseous fuel and feedstock (kg/kg-mole).
MVC	=	Molar volume conversion factor (849.5 scf per kg-mole at standard conditions).
k	=	Months in the year.
44/12	=	Ratio of molecular weights, CO_2 to carbon.
0.001	=	Conversion factor from kg to metric tons.

(2) Liquid fuel and feedstock. You must calculate the annual CO_2 process emissions from liquid fuel and feedstock according to Equation P-2 of this section:

$$CO_2 = (\sum_{n=1}^{k} \frac{44}{12} * Fdstk_n * CC_n) * 0.001 \qquad \text{(Eq. P-2)}$$

Where:

CO_2 = Annual CO_2 emissions arising from fuel and feedstock consumption (metric tons/yr).

$Fdstk_n$ = Volume of the liquid fuel and feedstock used in month n (gallons of fuel and feedstock).

CC_n = Weighted Average carbon content of the liquid fuel and feedstock, from the results of daily ~~one or more~~ analyses for month n (kg carbon per gallon of fuel and feedstock).

k = Months in the year.

44/12 = Ratio of molecular weights, CO_2 to carbon.

0.001 = Conversion factor from kg to metric tons.

(3) Solid fuel and feedstock. You must calculate the annual CO_2 process emissions from solid fuel and feedstock according to Equation P-3 of this section:

$$CO_2 = \sum_{n=1}^{k} \frac{44}{12} * (Fdstk_n * CC_n) * 0.001 \qquad \text{(Eq.P-3)}$$

Where:

CO_2 = Annual CO_2 emissions from fuel and feedstock consumption in metric tons per year ~~month~~ ~~(~~(metric tons/yr).

$Fdstk_n$ = Mass of solid fuel and feedstock used in month n (kg of fuel and feedstock).

CC_n = Weighted ~~A~~average carbon content of the solid fuel and feedstock, from the results of daily~~one or more~~ analyses for month n (kg carbon per kg of fuel and feedstock).

k = Months in the year.

44/12 = Ratio of molecular weights, CO_2 to carbon.

0.001 = Conversion factor from kg to metric tons.

(c) If GHG emissions from a hydrogen production process unit are vented through the same stack as any combustion unit or process equipment that reports CO_2 emissions using a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Fuel Combustion Sources), then the calculation methodology in paragraph (b) of this section shall not be used to calculate process emissions. The owner or operator shall report under this subpart the combined stack emissions according to the Tier 4 Calculation Methodology in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

§98.164 Monitoring and QA/QC requirements.

The GHG emissions data for hydrogen production process units must be quality-assured as specified in paragraphs (a) or (b) of this section, as appropriate for each process unit:

(a) If a CEMS is used to measure GHG emissions, then the facility must comply with the monitoring and QA/QC procedures specified in §98.34(c).

(b) If a CEMS is not used to measure GHG emissions, then you must:

(1) Calibrate all oil and gas flow meters (except for gas billing meters), solids weighing equipment, and oil tank drop measurements (if used to determine liquid fuel and feedstock use volume) according to the calibration accuracy requirements in §98.3(i) of this part .

(2) Determine the carbon content and the molecular weight monthly ~~annually~~ for ~~of standard gaseous hydrocarbon fuels and feedstocks having consistent composition (e.g.,~~ natural gas~~)~~. For other gaseous fuels and feedstocks (e.g., biogas, refinery gas, or process gas), daily ~~weekly~~ sampling and analysis is required to determine the carbon content and molecular weight of the fuel and feedstock.

(3) Determine the carbon content of fuel oil, naphtha, and other liquid fuels and feedstocks at least ~~monthly~~daily~~,~~. ~~except annually for standard liquid hydrocarbon fuels and feedstocks having consistent composition, or upon delivery for liquid fuels delivered by bulk transport (e.g., by truck or rail).~~

(4) Determine the carbon content of coal, coke, and other solid fuels and feedstocks at least ~~monthly,~~daily ~~except annually for standard solid hydrocarbon fuels and feedstocks having consistent composition, or upon delivery for solid fuels delivered by bulk transport (e.g., by truck or rail)~~.

(5) You must use the following applicable methods to determine the carbon content for all fuels and feedstocks, and molecular weight of gaseous fuels and feedstocks.

(i) ASTM D1945-03 Standard Test Method for Analysis of Natural Gas by Gas Chromatography (incorporated by reference, see §98.7).

(ii) ASTM D1946-90 (Reapproved 2006), Standard Practice for Analysis of Reformed Gas by Gas Chromatography (incorporated by reference, see §98.7).

(iii) ASTM D2013-07 Standard Practice of Preparing Coal Samples for Analysis (incorporated by reference, see §98.7).

(iv) ASTM D2234/D2234M-07 Standard Practice for Collection of a Gross Sample of Coal (incorporated by reference, see §98.7).

(v) ASTM D2597-94 (Reapproved 2004) Standard Test Method for Analysis of Demethanized Hydrocarbon Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography (incorporated by reference, see §98.7).

(vi) ASTM D3176-89 (Reapproved 2002), Standard Practice for Ultimate Analysis of Coal and Coke (incorporated by reference, see §98.7).

(vii) ASTM D3238-95 (Reapproved 2005), Standard Test Method for Calculation of Carbon Distribution and

Structural Group Analysis of Petroleum Oils by the n-d-M Method (incorporated by reference, see §98.7).

(viii) ASTM D4057-06 Standard Practice for Manual Sampling of Petroleum and Petroleum Products (incorporated by reference, see §98.7).

(ix) ASTM D4177-95 (Reapproved 2005) Standard Practice for Automatic Sampling of Petroleum and Petroleum Products (incorporated by reference, see §98.7).

(x) ASTM D5291-02 (Reapproved 2007), Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants (incorporated by reference, see §98.7).

(xi) ASTM D5373-08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal (incorporated by reference, see §98.7).

(xii) ASTM D6609-08 Standard Guide for Part-Stream Sampling of Coal (incorporated by reference, see §98.7).

(xiii) ASTM D6883-04 Standard Practice for Manual Sampling of Stationary Coal from Railroad Cars, Barges, Trucks, or Stockpiles (incorporated by reference, see §98.7).

(xiv) ASTM D7430-08ae1 Standard Practice for Mechanical Sampling of Coal (incorporated by reference, see §98.7).

(xv) ASTM UOP539-97 Refinery Gas Analysis by Gas Chromatography (incorporated by reference, see §98.7).

(xvi) GPA 2261–00 Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography (incorporated by reference, see §98.7).

(xvii) ISO 3170: Petroleum Liquids -- Manual sampling – Third Edition (incorporated by reference, see §98.7).

(xviii) ISO 3171: Petroleum Liquids -- Automatic pipeline sampling – Second Edition (incorporated by reference, see §98.7).

(c) For units using the calculation methodologies described in this section, the records required under §98.3(g) must include both the company records and a detailed explanation of how company records are used to estimate the following:

(1) Fuel and feedstock consumption, when solid fuel and feedstock is combusted and a CEMS is not used to measure GHG emissions.

(2) Fossil fuel consumption, when, pursuant to §98.33(e), the owner or operator of a unit that uses CEMS to quantify CO_2 emissions and that combusts both fossil and

biogenic fuels separately reports the biogenic portion of the total annual CO_2 emissions.

(3) Sorbent usage, if the methodology in §98.33(d) is used to calculate CO_2 emissions from sorbent.

(d) The owner or operator must document the procedures used to ensure the accuracy of the estimates of fuel and feedstock usage and sorbent usage (as applicable) in paragraph (b) of this section, including, but not limited to, calibration of weighing equipment, fuel and feedstock flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.

§98.165 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation), a substitute data value for the missing parameter must be used in the calculations as specified in paragraphs (a), (b), and (c) of this section:

(a) For each missing value of the monthly fuel and feedstock consumption, the substitute data value must be the best available estimate of the fuel and feedstock consumption, based on all available process data (e.g., hydrogen production, electrical load, and operating hours). You must document and keep records of the procedures used for all such estimates.

(b) For each missing value of the carbon content or molecular weight of the fuel and feedstock, the substitute data value must be the arithmetic average of the quality-assured values of carbon contents or molecular weight of the fuel and feedstock immediately preceding and immediately following the missing data incident. If no quality-assured data on carbon contents or molecular weight of the fuel and feedstock are available prior to the missing data incident, the substitute data value must be the first quality-assured value for carbon contents or molecular weight of the fuel and feedstock obtained after the missing data period. You must document and keep records of the procedures used for all such estimates.

(c) For missing CEMS data, you must use the missing data procedures in §98.35.

§98.166 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) or (b) of this section, as appropriate:

Subpart P—Hydrogen Production

(a) If a CEMS is used to measure CO_2 emissions, then you must report the relevant information required under §98.36 for the Tier 4 Calculation Methodology and the following information in this paragraph (a):

(1) Unit identification number and annual CO_2 process emissions.

(2) Annual quantity of hydrogen produced (metric tons) for each process unit and for all units combined.

(3) Annual quantity of ammonia produced (metric tons), if applicable, for each process unit and for all units combined.

(b) If a CEMS is not used to measure CO_2 emissions, then you must report the following information for each hydrogen production process unit:

(1) Unit identification number and annual CO_2 process emissions (2) Monthly consumption of each fuel and feedstock used for hydrogen production and its type (scf of gaseous fuels and feedstocks, gallons of liquid fuels and feedstocks, kg of solid fuels and feedstocks).

(3) Annual quantity of hydrogen produced (metric tons).

(4) Annual quantity of ammonia produced, if applicable (metric tons).

(5) Monthly or daily analyses of carbon content for each fuel and feedstock used in hydrogen production (kg carbon/kg of gaseous and solid fuels and feedstocks, (kg carbon per gallon of liquid fuels and feedstocks).

(6) Monthly or daily analyses of the molecular weight of gaseous fuels and feedstocks (kg/kg-mole) used, if any.

(7) Amount of carbon in unconverted feedstock for which GHG emissions are calculated and reported by your facility using other calculation methods provided in this regulation. For example, carbon in waste diverted to a fuel system or flare, where the CO_2 and CH_4 emissions are calculated and reported using other methods provided in this regulation. (metric tons CO_2e/year).

(c) Quarterly quantity of CO_2 collected and transferred off site in either gas, liquid, or solid forms (kg), following the requirements of subpart PP of this part.

(d) Annual quantity of carbon other than CO_2 collected and transferred off site in either gas, liquid, or solid forms (kg carbon).

§98.167 Records that must be retained.

In addition to the information required by §98.3(g), you must retain the records specified in paragraphs (a) through (b) of this section for each hydrogen production facility.

(a) If a CEMS is used to measure CO_2 emissions, then you must retain under this subpart the records required for the Tier 4 Calculation Methodology in §98.37.

(b) If a CEMS is not used to measure CO_2 emissions, then you must retain records of all analyses and calculations conducted as listed in §§98.166(b), (c), and (d).

§98.168 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart Y—Petroleum Refineries

§98.250 Definition of Source Category.

(a) A petroleum refinery is any facility engaged in producing gasoline, gasoline blending stocks, naphtha, kerosene, distillate fuel oils, residual fuel oils, lubricants, or asphalt (bitumen) through distillation of petroleum or through redistillation, cracking, or reforming of unfinished petroleum derivatives, except as provided in paragraph (b) of this section.

(b) For the purposes of this subpart, facilities that distill only pipeline transmix (off-spec material created when different specification products mix during pipeline transportation) are not petroleum refineries, regardless of the products produced.

(c) This source category consists of the following sources at petroleum refineries: catalytic cracking units; fluid coking units; delayed coking units; catalytic reforming units; coke calcining units; asphalt blowing operations; blowdown systems; storage tanks; process equipment components (compressors, pumps, valves, pressure relief devices, flanges, and connectors) in gas service; marine vessel, barge, tanker truck, and similar loading operations; flares; sulfur recovery plants; and non-merchant hydrogen plants (i.e., hydrogen plants that are owned or under the direct control of the refinery owner and operator).

Subpart Y—Petroleum Refineries

§98.251 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a petroleum refineries process and the facility meets the requirements of either §98.2(a)(1) or (a)(2).

§98.252 GHGs to report.

You must report:

(a) CO_2, CH_4, and N_2O combustion emissions from stationary combustion units and from each flare. Calculate and report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C, except for CO_2 emissions from combustion of refinery fuel gas. For CO_2 emissions from combustion of fuel gas, use either equation C-5 in subpart C of this part or the Tier 4 methodology in subpart C of this part. You may aggregate units, monitor common stacks, or monitor common (fuel) pipes as provided in §98.36(c) when calculating and reporting emissions from stationary combustion units.

(b) CO_2, CH_4, and N_2O coke burn-off emissions from each catalytic cracking unit, fluid coking unit, and catalytic reforming unit under this subpart.

(c) CO_2 emissions from sour gas sent off site for sulfur recovery operations under this subpart. You must follow the calculation methodologies from §98.253(f)and the monitoring and

QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of this subpart.

(d) CO_2 process emissions from each on-site sulfur recovery plant under this subpart.

(e) CO_2, CH_4, and N_2O emissions from each coke calcining unit under this subpart.

(f) CO_2 and CH_4 emissions from asphalt blowing operations under this subpart.

(g) CH_4 emissions from equipment leaks, storage tanks, loading operations, delayed coking units, and uncontrolled blowdown systems under this subpart.

(h) CO_2, CH_4, and N_2O emissions from each process vent not specifically included in paragraphs (a) through (g) of this section under this subpart.

(i) CO_2 and CH_4 emissions from non-merchant hydrogen production under this subpart. You must follow the calculation methodologies, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of subpart P of this part.

§98.253 Calculating GHG emissions.

(a) Calculate GHG emissions required to be reported in §98.252(b) through (i) using the applicable methods in paragraphs (b) through (n) of this section.

(b) For flares, calculate GHG emissions according to the requirements in paragraphs (b)(1) through (b)(3) of this section.

(1) Calculate the CO_2 emissions according to the applicable requirements in paragraphs (b)(1)(i) through (b)(1)(iii) of this section.

(i) Flow measurement. If you have a continuous flow monitor on the flare, you must use the measured flow rates when the monitor is operational and the flow rate is within the calibrated range of the measurement device to calculate the flare gas flow. If you do not have a continuous flow monitor on the flare and for periods when the monitor is not operational or the flow rate is outside the calibrated range of the measurement device, you must use engineering calculations, company records, or similar estimates of volumetric flare gas flow.

(ii) Heat value or carbon content measurement. If you have a continuous higher heating value monitor or gas composition monitor on the flare or if you monitor these parameters at least weekly, you must use the measured heat value or carbon content value in calculating the CO_2 emissions from the flare using the applicable methods in paragraphs (b)(1)(ii)(A) and (b)(1)(ii)(B).

(A) If you monitor gas composition, calculate the CO_2 emissions from the flare using Equation Y-1 of this section. If daily or more frequent measurement data are available, you must use daily values when using Equation Y-1 of this section; otherwise, use weekly values.

$$CO_2 = 0.98 \times 0.001 \times \left(\sum_{p=1}^{n} \left[\frac{44}{12} \times (Flare)_p \times \frac{(MW)_p}{MVC} \times (CC)_p \right] \right) \qquad \text{(Eq.Y-1)}$$

Where:

CO_2	=	Annual CO_2 emissions for a specific fuel type (metric tons/year).
0.98	=	Assumed combustion efficiency of a flare.
0.001	=	Unit conversion factor (metric tons per kilogram, mt/kg).
n	=	Number of measurement periods. The minimum value for n is 52 (for weekly measurements); the maximum value for n is 366 (for daily measurements during a leap year).
p	=	Measurement period index.
44	=	Molecular weight of CO_2 (kg/kg-mole).
12	=	Atomic weight of C (kg/kg-mole).
$(Flare)_p$	=	Volume of flare gas combusted during measurement period (standard cubic feet per period, scf/period). If a mass flow meter is used, measure flare gas flow rate in kg/period and replace the term "$(MW)_p$/MVC" with "1".
$(MW)_p$	=	Average molecular weight of the flare gas combusted during measurement period (kg/kg-mole). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.
MVC	=	Molar volume conversion factor (849.5 scf/kg-mole).
$(CC)_p$	=	Average carbon content of the flare gas combusted during measurement period (kg C per kg flare gas). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.

(B) If you monitor heat content but do not monitor gas composition, calculate the CO_2 emissions from the flare using Equation Y-2 of this section. If daily or more frequent measurement data are available, you must use daily values when using Equation Y-2 of this section; otherwise, use weekly values.

$$CO_2 = 0.98 \times 0.001 \times \sum_{p=1}^{n} \left[(Flare)_p \times (HHV)_p \times EmF \right] \qquad \text{(Eq.Y-2)}$$

Where:

CO_2	=	Annual CO_2 emissions for a specific fuel type (metric tons/year).
0.98	=	Assumed combustion efficiency of a flare.
0.001	=	Unit conversion factor (metric tons per kilogram, mt/kg).
n	=	Number of measurement periods. The minimum value for n is 52 (for weekly measurements); the maximum value for n is 366 (for daily measurements during a leap year).
p	=	Measurement period index.
$(Flare)_p$	=	Volume of flare gas combusted during measurement period (million (MM) scf/period). If a mass flow meter is used, you must also measure molecular weight and convert the mass flow to a volumetric flow as follows: Flare[MMscf] = 0.000001 × Flare[kg] × MVC/$(MW)_p$, where MVC is the molar volume conversion factor (849.5 scf/kg-mole) and $(MW)_p$ is the average molecular weight of the flare gas combusted during measurement period (kg/kg-mole).
$(HHV)_p$	=	Higher heating value for the flare gas combusted during measurement period (British thermal units per scf, Btu/scf = MMBtu/MMscf). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.
EmF	=	Default CO_2 emission factor of 60 kilograms CO_2/MMBtu (HHV basis).

(iii) Alternative Method for Startup, Shutdown, and Malfunctions~~to heat value or carbon content measurements~~. For startup, shutdown, and malfunctions during which you were unable to measure the parameters required by Equations Y-1 and Y-2 of this section, ~~If you do not measure the~~ you must ~~higher heating value or carbon content of the flare gas at least weekly,~~ determine the quantity of gas discharged to the flare separately for each ~~periods of routine flare operation and for periods of~~ start-up, shutdown, or malfunction, and calculate the CO_2 emissions as specified in paragraphs (b)(1)(iii)(A) ~~through~~ and (b)(1)(iii)(C) of this section.

(A) For periods of start-up, shutdown, or malfunction, use engineering calculations and process knowledge to estimate the carbon content of the flared gas for each start-up, shutdown, or malfunction event. ~~exceeding 500,000 scf/day.~~

(B) ~~For periods of normal operation, use the average heating value measured for the fuel gas for the heating value of the flare gas. If heating value is not measured, the heating value may be estimated from historic data or engineering calculations.~~

Reserved.

(C) Calculate the CO_2 emissions using Equation Y-3 of this section.

$$\cancel{CO_2 = 0.98 \times 0.001 \times \left(Flare_{Norm} \times HHV \times EmF + \sum_{p=1}^{n} \left[\frac{44}{12} \times (Flare_{SSM})_p \times \frac{(MW)_p}{MVC} \times (CC)_p \right] \right)}$$ ~~(Eq.Y-3)~~

$$CO_2 = 0.98 \times 0.001 \times \left(\sum_{p=1}^{n} \left[\frac{44}{12} \times (Flare_{SSM})_p \times \frac{(MW)_p}{MVC} \times (CC)_p \right] \right) \quad \text{(Eq.Y-3)}$$ [1]

Where:

CO_2	=	Annual CO_2 emissions for a specific fuel type (metric tons/year).
0.98	=	Assumed combustion efficiency of a flare.
0.001	=	Unit conversion factor (metric tons per kilogram, mt/kg).
~~$Flare_{Norm}$~~	~~=~~	~~Annual volume of flare gas combusted during normal operations from company records, (million (MM) standard cubic feet per year, MMscf/year).~~
~~HHV~~	~~=~~	~~Higher heating value for fuel gas or flare gas from company records (British thermal units per scf, Btu/scf = MMBtu/MMscf).~~
~~EmF~~	~~=~~	~~Default CO_2 emission factor for flare gas of 60 kilograms CO_2/MMBtu (HHV basis).~~
n	=	Number of start-up, shutdown, and malfunction events during the reporting year exceeding 500,000 scf/day.
p	=	Start-up, shutdown, and malfunction event index.
44	=	Molecular weight of CO_2 (kg/kg-mole).
12	=	Atomic weight of C (kg/kg-mole).
$(Flare_{SSM})_p$	=	Volume of flare gas combusted during indexed start-up, shutdown, or malfunction event from engineering calculations, (scf/event).
$(MW)_p$	=	Average molecular weight of the flare gas, from the analysis results or engineering calculations for the event (kg/kg-mole).
MVC	=	Molar volume conversion factor (849.5 scf/kg-mole).

[1] Equation Y-3 was revised to delete the factors used to calculate CO_2 emissions during normal operation of the flare. For normal operation of flares, ERMR proposes that CO_2 emissions be calcualted using either Equation Y-1 or Y-2.

$(CC)_p$ = Average carbon content of the flare gas, from analysis results or engineering calculations for the event (kg C per kg flare gas).

(2) Calculate CH_4 using Equation Y-4 of this section.

$$CH_4 = \left(CO_2 \times \frac{EmF_{CH4}}{EmF} \right) + CO_2 \times \frac{0.02}{0.98} \times \frac{16}{44} \times f_{CH4} \qquad \text{(Eq. Y-4)}$$

Where:

CH_4 = Annual methane emissions from flared gas (metric tons CH_4/year).

CO_2 = Emission rate of CO_2 from flared gas calculated in paragraph (b)(1) of this section (metric tons/year).

EmF_{CH4} = Default CH_4 emission factor for "PetroleumProducts" from Table C-2 of subpart C of this part (General Stationary Fuel Combustion Sources) (kg CH_4/MMBtu).

EmF = Default CO_2 emission factor for flare gas of 60 kg CO_2/MMBtu (HHV basis).

0.02/0.98 = correction factor for flare combustion efficiency.

16/44 = correction factor ratio of the molecular weight of CH_4 to CO_2

f_{CH4} = Weight fraction of carbon in the flare gas prior to combustion that is contributed by methane from measurement values or engineering calculations (kg C in methane in flare gas/kg C in flare gas); default is 0.4.

(3) Calculate N_2O emissions using Equation Y-5 of this section.

$$N_2O = \left(CO_2 \times \frac{EmF_{N2O}}{EmF} \right) \qquad \text{(Eq. Y-5)}$$

Where:

N_2O = Annual nitrous oxide emissions from flared gas (metric tons N_2O/year).

CO_2 = Emission rate of CO_2 from flared gas calculated in paragraph (b)(1) of this section (metric tons/year).
EmF_{N2O} = Default N_2O emission factor for "PetroleumProducts" from Table C-2 of subpart C of this part (General Stationary Fuel Combustion Sources)(kg N_2O/MMBtu).
EmF = Default CO_2 emission factor for flare gas of 60 kg CO_2/MMBtu (HHV basis).

(c) For catalytic cracking units and traditional fluid coking units, calculate the GHG emissions using the applicable methods described in paragraphs (c)(1) through (c)(5) of this section.

(1) If you operate and maintain a CEMS that measures CO_2 emissions according to subpart C of this part (General Stationary Fuel Combustion Sources), you must calculate and report CO_2 emissions as provided in paragraphs (c)(1)(i) and (c)(1)(ii) of this section. Other catalytic cracking units and traditional fluid coking units must either install a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Combustion Souces), or follow the requirements of paragraphs (c)(2) or (3) of this section.

(i) Calculate CO_2 emissions by following the Tier 4 Calculation Methodology specified in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(ii) If a CO boiler or other post-combustion device is used, you must also calculate the CO_2 emissions from the fuel fired to the CO boiler or post-combustion device using the applicable methods for stationary combustion units in subpart C of this part. Calculate the process emissions from the catalytic cracking unit or fluid coking unit as the difference in the CO_2 CEMS emissions and the calculated combustion emissions associated with the CO boiler.

(2) For catalytic cracking units and fluid coking units ~~with rated capacities greater than 10,000 barrels per stream day (bbls/sd)~~ that do not use a continuous CO_2 CEMS for the final exhaust stack, you must continuously or no less frequently than hourly monitor the O_2, CO_2, and (if necessary) CO concentrations in the exhaust stack from the catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels and calculate the CO_2 emissions according to the requirements of paragraphs (c)(2)(i) through (c)(2)(iii) of this section:

(i) Calculate the CO_2 emissions from each catalytic cracking unit and fluid coking unit using Equation Y-6 of this section.

$$CO_2 = \sum_{p=1}^{n}\left[\left(Q_r\right)_p \times \frac{\left(\%CO_2 + \%CO\right)_p}{100\%} \times \frac{44}{MVC} \times 0.001\right] \qquad \text{(Eq. Y-6)}$$

Where:

CO_2 = Annual CO_2 mass emissions (metric tons/year).

Q_r = Volumetric flow rate of exhaust gas from the fluid catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels (dry standard cubic feet per hour, dscfh).

$\%CO_2$ = Hourly average percent CO_2 concentration in the exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume – dry basis).

$\%CO$ = Hourly average percent CO concentration in the exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume – dry basis). When there is no post-combustion device, assume %CO to be zero.

44 = Molecular weight of CO_2 (kg/kg-mole).

MVC = Molar volume conversion factor (849.5 scf/kg-mole).

0.001 = Conversion factor (metric ton/kg).

n = Number of hours in calendar year.

(ii) Either continuously monitor the volumetric flow rate of exhaust gas from the fluid catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels or calculate the volumetric flow rate of this exhaust gas stream using Equation Y-7 of this section.

$$Q_r = \frac{\left(79 * Q_a + (100 - \%O_{oxy}) * Q_{oxy}\right)}{100 - \%CO_2 - \%CO - \%O_2} \quad \text{(Eq. Y-7)}$$

Where:

Q_r = Volumetric flow rate of exhaust gas from the fluid catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels (dscfh).

Q_a = Volumetric flow rate of air to the fluid catalytic cracking unit regenerator or fluid coking unit burner, as determined from control room instrumentation (dscfh).

Q_{oxy} = Volumetric flow rate of oxygen enriched air to the fluid catalytic cracking unit regenerator or fluid coking unit burner as determined from control room instrumentation (dscfh).

$\%O_2$	=	Hourly average percent oxygen concentration in exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume – dry basis).
$\%O_{oxy}$	=	O_2 concentration in oxygen enriched gas stream inlet to the fluid catalytic cracking unit regenerator or fluid coking unit burner based on oxygen purity specifications of the oxygen supply used for enrichment (percent by volume – dry basis).
$\%CO_2$	=	Hourly average percent CO_2 concentration in the exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume – dry basis).
%CO	=	Hourly average percent CO concentration in the exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume – dry basis). When no auxiliary fuel is burned and a continuous CO monitor is not required under 40 CFR part 63 subpart UUU, assume %CO to be zero.

(iii) If you have a CO boiler that uses auxiliary fuels or combusts materials other than catalytic cracking unit or fluid coking unit exhaust gas, you must determine the CO_2 emissions resulting from the combustion of these fuels or other materials following the requirements in subpart C and report those emissions by following the requirements of subpart C of this part.

(3) ~~For catalytic cracking units and fluid coking units with rated capacities of 10,000 barrels per stream day (bbls/sd) or less that do not use a continuous CO_2 CEMS for the final exhaust stack, comply with the requirements in paragraphs (c)(3)(i) of this section or paragraphs (c)(3)(ii) and (c)(3)(iii) of this section, as applicable.~~

Reserved.

~~(i) If you continuously or no less frequently than daily monitor the O_2, CO_2, and (if necessary) CO concentrations in the exhaust stack from the catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels, you must calculate the CO_2 emissions according to the requirements of paragraphs (c)(2)(i) through (c)(2)(iii) of this section, except that daily averages are allowed and the summation can be performed on a daily basis.~~

~~(ii) If you do not monitor at least daily the O_2, CO_2, and (if necessary) CO concentrations in the exhaust stack from the catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels, calculate the CO_2 emissions from each catalytic cracking unit and fluid coking unit using Equation Y-8 of this section.~~

$$\cancel{CO_2 = Q_{unit} \times (CBF \times 0.001) \times CC \times \frac{44}{12}} \qquad \text{(Eq. Y-8)}$$

~~Where:~~

~~CO_2 = Annual CO_2 mass emissions (metric tons/year).~~

~~Q_{unit} = Annual throughput of unit from company records (barrels (bbls) per year, bbl/yr).~~

~~CBF = Coke burn-off factor from engineering calculations (kg coke per barrel of feed); default for catalytic cracking units = 7.3; default for fluid coking units = 11.~~

~~0.001 = Conversion factor (metric ton/kg).~~

~~CC = Carbon content of coke based on measurement or engineering estimate (kg C per kg coke); default = 0.94.~~

~~44/12 = Ratio of molecular weight of CO_2 to C (kg CO_2 per kg C).~~

~~(iii) If you have a CO boiler that uses auxiliary fuels or combusts materials other than catalytic cracking unit or fluid coking unit exhaust gas, you must determine the CO_2 emissions resulting from the combustion of these fuels or other materials following the requirements in subpart C of this part (General Stationary Fuel Combustion Sources) and report those emissions by following the requirements of subpart C of this part.~~

(4) Calculate CH_4 emissions using either unit specific measurement data, a unit-specific emission factor based on a source test of the unit, or Equation Y-9 of this section.

$$CH_4 = \left(CO_2 * \frac{EmF_2}{EmF_1} \right) \qquad \text{(Eq. Y-9)}$$

Where:

CH_4 = Annual methane emissions from coke burn-off (metric tons CH_4/year).

CO_2 = Emission rate of CO_2 from coke burn-off calculated in paragraphs (c)(1), (c)(2), (e)(1), (e)(2), (g)(1), or (g)(2) of this section, as applicable (metric tons/year).

EmF_1 = Default CO_2 emission factor for petroleum coke from Table C-1 of subpart C of this part (General Stationary Fuel Combustion Sources) (kg CO_2/MMBtu).

EmF_2 = Default CH_4 emission factor for "PetroleumProducts" from Table C-2 of subpart C of this part (General Stationary Fuel Combustion Sources) (kg CH_4/MMBtu).

(5) Calculate N_2O emissions using either unit specific measurement data, a unit-specific emission factor based on a source test of the unit, or Equation Y-10 of this section.

$$N_2O = \left(CO_2 * \frac{EmF_3}{EmF_1} \right) \quad \text{(Eq. Y-10)}$$

Where:

N_2O = Annual nitrous oxide emissions from coke burn-off (mt N_2O/year).

CO_2 = Emission rate of CO_2 from coke burn-off calculated in paragraphs (c)(1), (c)(2), (e)(1), (e)(2), (g)(1), or (g)(2) of this section, as applicable (metric tons/year).

EmF_1 = Default CO_2 emission factor for petroleum coke from Table C-1 of subpart C of this part (General Stationary Fuel Combustion Sources) (kg CO_2/MMBtu).

EmF_3 = Default N_2O emission factor for ”PetroleumProducts” from Table C-2 of subpart C of this part (kg N_2O/MMBtu).

(d) For fluid coking units that use the flexicoking design, the GHG emissions from the resulting use of the low value fuel gas must be accounted for only once. Typically, these emissions will be accounted for using the methods described in subpart C of this part (General Stationary Fuel Combustion Sources). Alternatively, you may use the methods in paragraph (c) of this section provided that you do not otherwise account for the subsequent combustion of this low value fuel gas.

(e) For catalytic reforming units, calculate the CO_2 emissions using the applicable methods described in paragraphs (e)(1) through (e)(3) of this section and calculate the CH_4 and N_2O emissions using the methods described in paragraphs (c)(4) and (c)(5) of this section, respectively.

(1) If you operate and maintain a CEMS that measures CO_2 emissions according to subpart C of this part (General Stationary Fuel Combustion Sources), you must calculate CO_2 emissions as provided in paragraphs (c)(1)(i) and (c)(1)(ii) of this section. Other catalytic reforming units must either install a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part, or follow the requirements of paragraph (e)(2) or (e)(3) of this section.

(2) If you continuously or no less frequently than daily monitor the O_2, CO_2, and (if necessary) CO concentrations in the exhaust stack from the catalytic reforming unit catalyst regenerator prior to the combustion of other fossil fuels, you must calculate the CO_2 emissions according to the requirements of paragraphs (c)(2)(i) through (c)(2)(iii) of this section.

(3) Calculate CO_2 emissions from the catalytic reforming unit catalyst regenerator using Equation Y-11 of this section.

$$CO_2 = \sum_{1}^{n} \left[\left(CB_Q\right)_n \times CC \times \frac{44}{12} \times 0.001 \right] \qquad \text{(Eq. Y-11)}$$

Where:

CO_2	=	Annual CO_2 emissions (metric tons/year).
CB_Q	=	Coke burn-off quantity per regeneration cycle from engineering estimates (kg coke/cycle).
n	=	Number of regeneration cycles in the calendar year.
CC	=	Carbon content of coke based on measurement or engineering estimate (kg C per kg coke); default = 0.94.
44/12	=	Ratio of molecular weight of CO_2 to C (kg CO_2 per kg C).
0.001	=	Conversion factor (metric ton/kg).

(f) For on-site sulfur recovery plants, calculate and report CO_2 process emissions from sulfur recovery plants according to the requirements in paragraphs (f)(1) through (f)(5) of this section. Combustion emissions from the sulfur recovery plant (e.g., from fuel combustion in the Claus burner or the tail gas treatment incinerator) must be reported under subpart C of this part (General Stationary Fuel Combustion Sources). For the purposes of this subpart, the sour gas stream for which monitoring is required according to paragraphs (f)(2) through (f)(5) of this section is not considered a fuel.

(1) If you operate and maintain a CEMS that measures CO_2 emissions according to subpart C of this part, you must calculate CO_2 emissions under this subpart by following the Tier 4 Calculation Methodology specified in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources). You must monitor fuel use in the Claus burner, tail gas incinerator, or other

combustion sources that discharge via the final exhaust stack from the sulfur recovery plant and calculate the combustion emissions from the fuel use according to subpart C of this part. Calculate the process emissions from the sulfur recovery plant as the difference in the CO_2 CEMS emissions and the calculated combustion emissions associated with the sulfur recovery plant final exhaust stack. Other sulfur recovery plants must either install a CEMS that complies with the Tier 4 Calculation Methodology in subpart C, or follow the requirements of paragraphs (f)(2) through (f)(5) of this section.

(2) Flow measurement. If you have a continuous flow monitor on the sour gas feed to the sulfur recovery plant, you must use the measured flow rates when the monitor is operational to calculate the sour gas flow rate. If you do not have a continuous flow monitor on the sour gas feed to the sulfur recovery plant, you must use engineering calculations, company records, or similar estimates of volumetric sour gas flow.

(3) Carbon content. If you have a continuous gas composition monitor capable of measuring carbon content on the sour gas feed to the sulfur recovery plant or if you monitor gas composition for carbon content on a routine basis, you must use the measured carbon content value. Alternatively, you may develop a site-specific carbon content factor using limited

measurement data or engineering estimates or use the default factor of 0.20.

(4) Calculate the CO_2 emissions from each sulfur recovery plant using Equation Y-12 of this section.

$$CO_2 = F_{SG} * \frac{44}{MVC} * MF_C * 0.001 \quad \text{(Eq. Y-12)}$$

Where:

CO_2 = Annual CO_2 emissions (metric tons/year).

F_{SG} = Volumetric flow rate of sour gas feed (including sour water stripper gas) to the sulfur recovery plant (scf/year).

44 = Molecular weight of CO_2 (kg/kg-mole).

MVC = Molar volume conversion factor (849.5 scf/kg-mole).

MF_C = Mole fraction of carbon in the sour gas to the sulfur recovery plant (kg-mole C/kg-mole gas); default = 0.20.

0.001 = Conversion factor, kg to metric tons

(5) If tail gas is recycled to the front of the sulfur recovery plant and the recycled flow rate and carbon content is included in the measured data under paragraphs (f)(2) and (f)(3) of this section, respectively, then the annual CO_2 emissions calculated in paragraph (f)(4) of this section must be corrected to avoid double counting these emissions. You may use engineering estimates to perform this correction or assume that the corrected CO_2 emissions are 95 percent of the uncorrected value calculated using Equation Y-12 of this section.

(g) For coke calcining units, calculate GHG emissions according to the applicable provisions in paragraphs (g)(1) through (g)(3) of this section.

(1) If you operate and maintain a CEMS that measures CO_2 emissions according to subpart C of this part, you must calculate and report CO_2 emissions under this subpart by following the Tier 4 Calculation Methodology specified in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources). You must monitor fuel use in the coke calcining unit that discharges via the final exhaust stack from the coke calcining unit and calculate the combustion emissions from the fuel use according to subpart C of this part. Calculate the process emissions from the coke calcining unit as the difference in the CO_2 CEMS emissions and the calculated combustion emissions associated with the coke calcining unit final exhaust stack. Other coke calcining units must either install a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part, or follow the requirements of paragraph (g)(2) of this section.

(2) Calculate the CO_2 emissions from the coke calcining unit using Equation Y-13 of this section.

$$CO_2 = \frac{44}{12} * \left(M_{in} * CC_{GC} - \left(M_{out} + M_{dust}\right) * CC_{MPC}\right) \quad \text{(Eq. Y-13)}$$

Where:

CO_2	=	Annual CO_2 emissions (metric tons/year).
M_{in}	=	Annual mass of green coke fed to the coke calcining unit from facility records (metric tons/year).
CC_{GC}	=	Average mass fraction carbon content of green coke from facility measurement data (metric ton carbon/metric ton green coke).
M_{out}	=	Annual mass of marketable petroleum coke produced by the coke calcining unit from facility records (metric tons petroleum coke/year).
M_{dust}	=	Annual mass of petroleum coke dust collected in the dust collection system of the coke calcining unit from facility records (metric ton petroleum coke dust/year)
CC_{MPC}	=	Average mass fraction carbon content of marketable petroleum coke produced by the coke calcining unit from facility measurement data (metric ton carbon/metric ton petroleum coke).
44	=	Molecular weight of CO_2 (kg/kg-mole).
12	=	Atomic weight of C (kg/kg-mole).

(3) For all coke calcining units, use the CO_2 emissions from the coke calcining unit calculated in paragraphs (g)(1) or (g)(2), as applicable, and calculate CH_4 using the methods described in paragraph (c)(4) of this section and N_2O emissions using the methods described in paragraph (c)(5) of this section.

(h) [Reporting only.] For asphalt blowing operations, calculate GHG emissions according to the requirements in paragraph (j) of this section or according to the applicable provisions in paragraphs (h)(1) and (h)(2) of this section.

(1) For uncontrolled asphalt blowing operations or asphalt blowing operations controlled by vapor scrubbing, calculate CO_2

and CH_4 emissions using Equations Y-14 and Y-15 of this section, respectively.

$$CO_2 = (Q_{AB} \times EF_{AB.CO2}) \quad \text{(Eq. Y-14)}$$

Where:

CO_2 = Annual CO_2 emissions from uncontrolled asphalt blowing (metric tons CO_2/year).

Q_{AB} = Quantity of asphalt blown (million barrels per year, MMbbl/year).

$EF_{AB,CO2}$ = Emission factor for CO_2 from uncontrolled asphalt blowing from facility-specific test data (metric tons CO_2/MMbbl asphalt blown); default = 1,100.

$$CH_4 = (Q_{AB} \times EF_{AB,CH4}) \quad \text{(Eq. Y-15)}$$

Where:

CH_4 = Annual methane emissions from uncontrolled asphalt blowing (metric tons CH_4/year).

Q_{AB} = Quantity of asphalt blown (million barrels per year, MMbbl/year).

$EF_{AB,CH4}$ = Emission factor for CH_4 from uncontrolled asphalt blowing from facility-specific test data (metric tons CH_4/MMbbl asphalt blown); default = 580.

(2) For asphalt blowing operations controlled by thermal oxidizer or flare, calculate CO_2 and CH_4 emissions using Equations Y-16 and Y-17 of this section, respectively, provided these emissions are not already included in the flare emissions calculated in paragraph (b) of this section or in the stationary combustion unit emissions required under subpart C of this part (General Stationary Fuel Combustion Sources).

$$CO_2 = 0.98 \times \left(Q_{AB} \times CEF_{AB} \times \frac{44}{12} \right) \quad \text{(Eq. Y-16)}$$

Where:

CO_2 = Annual CO_2 emissions from controlled asphalt blowing (metric tons CO_2/year).

0.98 = Assumed combustion efficiency of thermal oxidizer or flare.

Q_{AB} = Quantity of asphalt blown (MMbbl/year).

CEF_{AB} = Carbon emission factor from asphalt blowing from facility-specific test data (metric tons C/MMbbl asphalt blown); default = 2,750.

44 = Molecular weight of CO_2 (kg/kg-mole).

12 = Atomic weight of C (kg/kg-mole).

$$CH_4 = 0.02 \times (Q_{AB} \times EF_{AB,CH4}) \qquad \text{(Eq. Y-17)}$$

Where:

CH_4 = Annual methane emissions from controlled asphalt blowing (metric tons CH_4/year).

0.02 = Fraction of methane uncombusted in thermal oxidizer or flare based on assumed 98% combustion efficiency.

Q_{AB} = Quantity of asphalt blown (million barrels per year, MMbbl/year).

$EF_{AB,CH4}$ = Emission factor for CH_4 from uncontrolled asphalt blowing from facility-specific test data (metric tons CH_4/MMbbl asphalt blown); default = 580.

(i) For delayed coking units, calculate the CH_4 emissions from the depressurization of the coking unit vessel (i.e., the "coke drum") to atmosphere using either of the methods provided in paragraphs (i)(1) or (i)(2), provided no water or steam is added to the vessel once it is vented to the atmosphere. You must use the method in paragraph (i)(1) of this section if you add water or steam to the vessel after it is vented to the atmosphere.

(1) Use the process vent method in paragraph (j) of this section and also calculate the CH_4 emissions from the subsequent opening of the vessel for coke cutting operations using Equation Y-18 of this section. If you have coke drums or vessels of different dimensions, use Equation Y-18 for each set of coke drums or vessels of the same size and sum the resultant emissions across each set of coke drums or vessels to calculate the CH_4 emissions for all delayed coking units.

$$CH_4 = \left(N \times H \times \frac{(P_{CV} + 14.7)}{14.7} \times f_{void} \times \frac{\pi \times D^2}{4} \times \frac{16}{MVC} \times MF_{CH4} \times 0.001 \right) \quad \text{(Eq. Y-18)}$$

Where:

CH_4	=	Annual methane emissions from the delayed coking unit vessel opening (metric ton/year).
N	=	Cumulative number of vessel openings for all delayed coking unit vessels of the same dimensions during the year.
H	=	Height of coking unit vessel (feet).
P_{CV}	=	Gauge pressure of the coking vessel when opened to the atmosphere prior to coke cutting or, if the alternative method provided in paragraph (i)(2) of this section is used, gauge pressure of the coking vessel when depressurization gases are first routed to the atmosphere (pounds per square inch gauge, psig)
14.7	=	Assumed atmospheric pressure (pounds per square inch, psi)
f_{void}	=	Volumetric void fraction of coking vessel prior to steaming based on engineering calculations(cf gas/cf of vessel)~~; default = 0.6~~.
D	=	Diameter of coking unit vessel (feet).
16	=	Molecular weight of CH_4 (kg/kg-mole).
MVC	=	Molar volume conversion factor (849.5 scf/ kg-mole).
MF_{CH4}	=	Average ~~M~~mole fraction of methane in coking vessel gas based on the analysis of at least two samples per

year, collected at least four months a part (kg-mole CH_4/kg-mole gas, wet basis)~~; default value is 0.01~~.

0.001 = Conversion factor (metric ton/kg).

(2) Calculate the CH_4 emissions from the depressurization vent and subsequent opening of the vessel for coke cutting operations using Equation Y-18 of this section and the pressure of the coking vessel when the depressurization gases are first routed to the atmosphere. If you have coke drums or vessels of different dimensions, use Equation Y-18 for each set of coke drums or vessels of the same size and sum the resultant emissions across each set of coke drums or vessels to calculate the CH_4 emissions for all delayed coking units.

(j) For each process vent not covered in paragraphs (a) through (i) of this section that can be reasonably expected to contain greater than 2 percent by volume CO_2 or greater than 0.5 percent by volume of CH_4 or greater than 0.01 percent by volume (100 parts per million) of N_2O, calculate GHG emissions using the Equation Y-19 of this section. You must use Equation Y-19 of this section for catalytic reforming unit depressurization and purge vents when methane is used as the purge gas or if you elected this method as an alternative to the methods in paragraphs (h)(1) or (h)(2) of this section.

$$E_x = \sum_{p=1}^{N}\left((VR)_p \times (MF_x)_p \times \frac{MW_x}{MVC} \times (VT)_p \times 0.001\right) \qquad \text{(Eq. Y-19)}$$

Where:

E_x = Annual emissions of each GHG from process vent (metric ton/yr).

N = Number of venting events per year.

P = Index of venting events.

$(VR)_p$ = Average volumetric flow rate of process gas during the event (scf per hour).

$(MF_x)_p$ = Mole fraction of GHG x in process vent during the event (kg-mol of GHG x/kg-mol vent gas).

MW_x = Molecular weight of GHG x (kg/kg-mole); use 44 for CO_2 or N_2O and 16 for CH_4.

MVC = Molar volume conversion factor (849.5 scf/kg-mole).

$(VT)_p$ = Venting time for the event, (hours).

0.001 = Conversion factor (metric ton/kg)

(k) For uncontrolled blowdown systems, you must ~~either~~ use the methods for process vents in paragraph (j) of this section. ~~or calculate CH_4 emissions using Equation Y-20 of this section. Blowdown systems where the uncondensed gas stream is routed to a flare or similar control device is considered to be controlled and is not required to estimate emissions under this paragraph (k).~~

$$CH_4 = \left(Q_{Ref} \times EF_{BD} \times \frac{16}{MVC} \times 0.001 \right) \qquad \text{(Eq. Y-20)}$$

~~Where:~~

~~CH_4 = Methane emission rate from blowdown systems (mt CH_4/year).~~

~~Q_{Ref} = Quantity of crude oil plus the quantity of intermediate products received from off site that are processed at the facility (MMbbl/year).~~

~~EF_{BD} = Methane emission factor for uncontrolled blown systems (scf CH_4/MMbbl); default is 137,000.~~

~~16 = Molecular weight of CH_4 (kg/kg-mole).~~

~~MVC = Molar volume conversion factor (849.5 scf/kg-mole).~~
~~0.001 = Conversion factor (metric ton/kg).~~

(l) [Reporting only.] For equipment leaks, calculate CH_4 emissions using the method specified in either paragraph (l)(1) or (l)(2) of this section.

(1) Use process-specific methane composition data (from measurement data or process knowledge) and any of the emission estimation procedures provided in the Protocol for Equipment Leak Emissions Estimates (EPA-453/R-95-017, NTIS PB96-175401).

(2) Use Equation Y-21 of this section.

$$CH_4 = \left(0.4 \times N_{CD} + 0.2 \times N_{PU1} + 0.1 \times N_{PU2} + 4.3 \times N_{H2} + 6 \times N_{FGS}\right) \quad \text{(Eq. Y-21)}$$

Where:

CH_4 = Annual methane emissions from equipment leaks (metric tons/year)

N_{CD} = Number of atmospheric crude oil distillation columns at the facility.

N_{PU1} = Cumulative number of catalytic cracking units, coking units (delayed or fluid), hydrocracking, and full-range distillation columns (including depropanizer and debutanizer distillation columns) at the facility.

N_{PU2} = Cumulative number of hydrotreating/hydrorefining units, catalytic reforming units, and visbreaking units at the facility.

N_{H2} = Total number of hydrogen plants at the facility.

N_{FGS} = Total number of fuel gas systems at the facility.

(m) [Reporting only.] For storage tanks, except as provided in paragraph (m)(3) of this section, calculate CH_4 emissions using the applicable methods in paragraphs (m)(1) and (m)(2) of this section.

(1) For storage tanks other than those processing unstabilized crude oil, you must either calculate CH_4 emissions from storage tanks that have a vapor-phase methane concentration of 0.5 volume percent or more using tank-specific methane composition data (from measurement data or product knowledge) and the AP-42 emission estimation methods provided in Section 7.1 of the AP-42: "Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources", including TANKS Model (Version 4.09D) or similar programs, or estimate CH_4 emissions from storage tanks using Equation Y-22 of this section.

$$CH_4 = \left(0.1 \times Q_{Ref}\right) \qquad \text{(Eq. Y-22)}$$

Where:

CH_4 = Annual methane emissions from storage tanks (metric tons/year).

0.1 = Default emission factor for storage tanks (metric ton CH_4/MMbbl).

Q_{Ref} = Quantity of crude oil plus the quantity of intermediate products received from off site that are processed at the facility (MMbbl/year).

(2) For storage tanks that process unstabilized crude oil, calculate CH_4 emissions from the storage of unstabilized crude oil using either tank-specific methane composition data (from measurement data or product knowledge) and direct measurement of the gas generation rate or by using Equation Y-23 of this section.

$$CH_4 = (995{,}000 \times Q_{un} \times \Delta P) \times MF_{CH4} \times \frac{16}{MVC} \times 0.001 \qquad \text{(Eq. Y-23)}$$

Where:

CH_4 = Annual methane emissions from storage tanks (metric tons/year).

Q_{un} = Quantity of unstabilized crude oil received at the facility (MMbbl/year).

ΔP = Pressure differential from the previous storage pressure to atmospheric pressure (pounds per square inch, psi).

MF_{CH4} = Mole fraction of CH_4 in vent gas from the unstabilized crude oil storage tank from facility measurements (kg-mole CH_4/kg-mole gas); use 0.27 as a default if measurement data are not available.

995,000 = Correlation Equation factor (scf gas per MMbbl per psi)

16 = Molecular weight of CH_4 (kg/kg-mole).

MVC = Molar volume conversion factor (849.5 scf/kg-mole).

0.001 = Conversion factor (metric ton/kg).

(3) You do not need to calculate CH_4 emissions from storage tanks that meet any of the following descriptions:

(i) Units permanently attached to conveyances such as trucks, trailers, rail cars, barges, or ships;

(ii) Pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere;

(iii) Bottoms receivers or sumps;

(iv) Vessels storing wastewater; or

(v) Reactor vessels associated with a manufacturing process unit.

(n) [Reporting only.] For crude oil, intermediate, or product loading operations for which the equilibrium vapor-phase concentration of methane is 0.5 volume percent or more, calculate CH_4 emissions from loading operations using product-specific, vapor-phase methane composition data (from measurement data or process knowledge) and the emission estimation procedures provided in Section 5.2 of the AP-42: "Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources." For loading operations in which the equilibrium vapor-phase concentration of methane is less than 0.5 volume percent, you may assume zero methane emissions.

§98.254 Monitoring and QA/QC requirements.

(a) Fuel flow meters, gas composition monitors, and heating value monitors associated with stationary combustion sources must follow the monitoring and QA/QC requirements in §98.34.

(b) All flow meters, gas composition monitors, and heating value monitors that are used to provide data for the GHG emissions calculations in this subpart for sources other than stationary combustion sources shall be calibrated according to the procedures in the applicable methods specified in paragraphs (c) through (e) of this section, the procedures specified by the manufacturer, or §§98.3(i). Recalibrate each flow meter either biennially (every two years) or at the minimum frequency specified by the manufacturer. Recalibrate each gas composition monitor and heating value monitor either annually or at the minimum frequency specified by the manufacturer.

(c) For flare or sour gas flow meters, operate and maintain the flow meter using any of the following methods, a method published by a consensus-based standards organization (e.g., ASTM, API, etc.) or follow the procedures specified by the flow meter manufacturer. Flow meters must have a rated accuracy of ±5 percent or lower.

(1) ASME MFC–3M–2004 Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi (incorporated by reference, see §98.7).

(2) ASME MFC–4M–1986 (Reaffirmed 1997) Measurement of Gas Flow by Turbine Meters (incorporated by reference, see §98.7).

(3) ASME MFC–6M–1998 Measurement of Fluid Flow in Pipes Using Vortex Flowmeters (incorporated by reference, see §98.7).

(4) ASME MFC–7M–1987 (Reaffirmed 1992) Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles (incorporated by reference, see §98.7).

(5) ASME MFC-11M-2006 Measurement of Fluid Flow by Means of Coriolis Mass Flowmeters (incorporated by reference, see §98.7).

(6) ASME MFC-14M-2003 Measurement of Fluid Flow Using Small Bore Precision Orifice Meters (incorporated by reference, see §98.7).

(7) ASME MFC-18M-2001 Measurement of Fluid Flow Using Variable Area Meters (incorporated by reference, see §98.7).

(8) AGA Report No. 11 Measurement of Natural Gas by Coriolis Meter (2003) (incorporated by reference, see §98.7).

(d) Determine flare gas composition using any of the following methods.

(1) Method 18 at 40 CFR part 60, appendix A-6.

(2) ASTM D1945-03 Standard Test Method for Analysis of Natural Gas by Gas Chromatography (incorporated by reference, see §98.7).

(3) ASTM D1946-90 (Reapproved 2006) Standard Practice for Analysis of Reformed Gas by Gas Chromatography (incorporated by reference, see §98.7).

(4) GPA 2261–00 Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography (incorporated by reference, see §98.7).

(5) UOP539-97 Refinery Gas Analysis by Gas Chromatography (incorporated by reference, see §98.7).

(e) Determine flare gas higher heating value using any of the following methods.

(1) ASTM D4809-06 Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method) (incorporated by reference, see §98.7).

(2) ASTM D240-02 (Reapproved 2007) Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (incorporated by reference, see §98.7).

(3) ASTM D1826-94 (Reapproved 2003) Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter (incorporated by reference, see §98.7).

(4) ASTM D3588-98 (Reapproved 2003) Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels (incorporated by reference, see §98.7).

(5) ASTM D4891-89 (Reapproved 2006) Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion (incorporated by reference, see §98.7).

(f) For exhaust gas flow meters used to comply with the requirements in §98.253(c)(2)(ii), install, operate, calibrate, and maintain exhaust gas flow meter according to the requirements in 40 CFR 63.1572(c) or according to the following requirements.

(1) Locate the flow meter(s) and other necessary equipment such as straightening vanes in a position that provides representative flow; reduce swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.

(2) Use a flow rate meter with an accuracy within ±5 percent.

(3) Use a continuous monitoring system capable of correcting for the temperature, pressure, and moisture content to output flow in dry standard cubic feet (standard conditions as defined in §98.6).

(4) Install, operate, and maintain each continuous monitoring system according to the manufacturer's specifications and requirements.

(g) For exhaust gas CO_2/CO/O_2 composition monitors used to comply with the requirements in §98.253(c)(2), install, operate, calibrate, and maintain exhaust gas composition monitors according to the the requirements in 40 CFR 60.105a(b)(2) or 40 CFR 63.1572(a) or according to the manufacturer's specifications and requirements.

(h) Determine the mass of petroleum coke as required by Equation Y-13 of this subpart using mass measurement equipment meeting the requirements for commercial weighing equipment as described in Specifications, Tolerances, and Other Technical Requirements For Weighing and Measuring Devices, NIST Handbook 44 (2009) (incorporated by reference, see §98.7). Calibrate the measurement device according to the procedures specified by the method, the procedures specified by the manufacturer, or

§98.3(i). Recalibrate either biennially or at the minimum frequency specified by the manufacturer.

(i) Determine the carbon content of petroleum coke as required by Equation Y-13 of this subpart using any one of the following methods. Calibrate the measurement device according to procedures specified by the method or procedures specified by the measurement device manufacturer.

(1) ASTM D3176-89 (Reapproved 2002) Standard Practice for Ultimate Analysis of Coal and Coke (incorporated by reference, see §98.7).

(2) ASTM D5291-02 (Reapproved 2007) Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants (incorporated by reference, see §98.7).

(3) ASTM D5373-08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal (incorporated by reference, see §98.7).

(j) Determine the quantity of petroleum process streams using company records. These quantities include the quantity of asphalt blown, quantity of crude oil plus the quantity of intermediate products received from off site, and the quantity of unstabilized crude oil received at the facility.

(k) The owner or operator shall document the procedures used to ensure the accuracy of the estimates of fuel usage, gas composition, and heating value including but not limited to calibration of weighing equipment, fuel flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices shall also be recorded, and the technical basis for these estimates shall be provided.

(l) All CO_2 CEMS and flow rate monitors used for direct measurement of GHG emissions must comply with the QA procedures in §98.34(c).

(m) For purposes of §98.34(b)(3)(ii)(E), the equipment necessary to take daily measurements of carbon content and molecular weight shall be in place for refinery fuel gas, and daily sampling and analysis shall therefore be required, by no later than January 1, 2012.

§98.255 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required (e.g., concentrations, flow rates, fuel heating values, carbon content values). Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a CEMS malfunctions during unit operation or if a required fuel sample is not taken), a substitute data value for the missing parameter shall be used in the calculations.

(a) For stationary combustion sources, use the missing data procedures in subpart C of this part.

(b) For each missing value of the heat content, carbon content, or molecular weight of the fuel, substitute the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If the "after" value is not obtained by the end of the reporting year, you may use the "before" value for the missing data substitution. If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.

(c) For missing CO_2, CO, O_2, CH_4, or N_2O concentrations, gas flow rate, and percent moisture, the substitute data values shall be the best available estimate(s) of the parameter(s), based on all available process data (e.g., processing rates, operating hours, etc.). The owner or operator shall document and keep records of the procedures used for all such estimates.

(d) For hydrogen plants, use the missing data procedures in subpart P of this part.

§98.256 Data reporting requirements.

In addition to the reporting requirements of §98.3(c), you must report the information specified in paragraphs (a) through (q) of this section.

Subpart Y—Petroleum Refineries

(a) For combustion sources, follow the data reporting requirements under subpart C of this part (General Stationary Fuel Combustion Sources).

(b) For hydrogen plants, follow the data reporting requirements under subpart P of this part (Hydrogen Production).

(c) [RESERVED].

(d) [RESERVED].

(e) For flares, owners and operators shall report:

(1) The flare ID number (if applicable).

(2) A description of the type of flare (steam assisted, air-assisted).

(3) A description of the flare service (general facility flare, unit flare, emergency only or back-up flare).

(4) The calculated CO_2, CH_4, and N_2O annual emissions for each flare, expressed in metric tons of each pollutant emitted.

(5) A description of the method used to calculate the CO_2 emissions for each flare (e.g., reference section and equation number).

(6) If you use Equation Y-1 of this subpart, the annual volume of flare gas combusted (in scf/year) and the annual average molecular weight (in kg/kg-mole) and carbon content of the flare gas (in kg carbon per kg flare gas).

(7) If you use Equation Y-2 of this subpart, the annual volume of flare gas combusted (in million (MM) scf/year) and the

annual average higher heating value of the flare gas (in MMBtu per MMscf).

(8) If you use Equation Y-3 of this subpart, ~~the annual volume of flare gas combusted (in MMscf/year) during normal operations, the annual average higher heating value of the flare gas (in MMBtu/MMscf),~~ the number of SSM events, and ~~exceeding 500,000 scf/day, and~~ the volume of gas flared (in scf/event) and the average molecular weight (in kg/kg-mole) and carbon content of the flare gas (in kg carbon per kg flare) for each SSM event ~~over 500,000 scf/day~~.

(9) The fraction of carbon in the flare gas contributed by methane used in Equation Y-4 of this subpart and the basis for its value.

(f) For catalytic cracking units, traditional fluid coking units, and catalytic reforming units, owners and operators shall report:

(1) The unit ID number (if applicable).

(2) A description of the type of unit (fluid catalytic cracking unit, thermal catalytic cracking unit, traditional fluid coking unit, or catalytic reforming unit).

(3) Maximum rated throughput of the unit, in bbl/stream day.

(4) The calculated CO_2, CH_4, and N_2O annual emissions for each unit, expressed in metric tons of each pollutant emitted.

(5) A description of the method used to calculate the CO_2 emissions for each unit (e.g., reference section and equation number).

(6) If you use a CEMS, the relevant information required under §98.36(e)(2)(vi) for the Tier 4 Calculation Methodology, the CO_2 annual emissions as measured by the CEMS (unadjusted to remove CO_2 combustion emissions associated with a CO boiler, if present) and the process CO_2 emissions as calculated according to §98.253(c)(1)(ii). Report the CO_2 annual emissions associated with fuel combustion under subpart C of this part (General Stationary Fuel Combustion Sources).

(7) If you use Equation Y-6 of this subpart, the annual average exhaust gas flow rate, $\%CO_2$, and %CO.

(8) If you use Equation Y-7 of this subpart, the annual average flow rate of inlet air and oxygen-enriched air, $\%O_2$, $\%O_{oxy}$, $\%CO_2$, and %CO.

(9) ~~If you use Equation Y-8 of this subpart, the coke burn-off factor, annual throughput of unit, and the average carbon content of coke and the basis for the value.~~

Reserved.

(10) ~~Indicate whether you use a measured value, a unit-specific emission factor, or a default emission factor for CH_4 emissions. If you use a unit-specific emission factor for CH_4, report the units of measure for the unit-specific factor, the~~

~~activity data for calculating emissions (e.g., if the emission factor is based on coke burn-off rate, the annual quantity of coke burned), and the basis for the factor.~~

Reserved.

(11) Indicate whether you use a measured value, a unit-specific emission factor, or a default emission factor for N_2O emissions. If you use a unit-specific emission factor for N_2O, report the units of measure for the unit-specific factor, the activity data for calculating emissions (e.g., if the emission factor is based on coke burn-off rate, the annual quantity of coke burned), and the basis for the factor.

(12) If you use Equation Y-11 of this subpart, the number of regeneration cycles during the reporting year, the average coke burn-off quantity per cycle, and the average carbon content of the coke.

(g) For fluid coking unit of the flexicoking type, the owner or operator shall report:

(1) The unit ID number (if applicable).

(2) A description of the type of unit.

(3) Maximum rated throughput of the unit, in bbl/stream day.

(4) Indicate whether the GHG emissions from the low heat value gas are accounted for in subpart C of this part or §98.253(c).

(5) If the GHG emissions for the low heat value gas are calculated at the flexicoking unit, also report the calculated annual CO_2, CH_4, and N_2O emissions for each unit, expressed in metric tons of each pollutant emitted, and the applicable equation input parameters specified in paragraphs (f)(7) through (f)(11) of this section.

(h) For sulfur recovery plants and for emissions from sour gas sent off-site for sulfur recovery, the owner and operator shall report:

(1) The plant ID number (if applicable).

(2) Maximum rated throughput of each independent sulfur recovery plant, in metric tons sulfur produced/stream day.

(3) The calculated CO_2 annual emissions for each sulfur recovery plant, expressed in metric tons. The calculated annual CO_2 emissions from sour gas sent off-site for sulfur recovery, expressed in metric tons.

(4) If you use Equation Y-12 of this subpart, the annual volumetric flow to the sulfur recovery plant (in scf/year) and the annual average mole fraction of carbon in the sour gas (in kg-mole C/kg-mole gas).

(5) If you recycle tail gas to the front of the sulfur recovery plant, indicate whether the recycled flow rate and carbon content are included in the measured data under §98.253(f)(2) and (3). Indicate whether a correction for CO_2

emissions in the tail gas was used in Equation Y-12. If so, then report the value of the correction, the annual volume of recycled tail gas (in scf/year) and the annual average mole fraction of carbon in the tail gas (in kg-mole C/kg-mole gas). Indicate whether you used the default (95%) or a unit specific correction, and if used, report the approach used.

(6) If you use a CEMS, the relevant information required under §98.36(e)(2)(vi) for the Tier 4 Calculation Methodology, the CO_2 annual emissions as measured by the CEMS and the annual process CO_2 emissions calculated according to §98.253(f)(1). Report the CO_2 annual emissions associated with fuel combustion subpart C of this part (General Stationary Fuel Combustion Sources).

(i) For coke calcining units, the owner and operator shall report:

(1) The unit ID number (if applicable).

(2) Maximum rated throughput of the unit, in metric tons coke calcined/stream day.

(3) The calculated CO_2, CH_4, and N_2O annual emissions for each unit, expressed in metric tons of each pollutant emitted.

(4) A description of the method used to calculate the CO_2 emissions for each unit (e.g., reference section and equation number).

(5) If you use Equation Y-13 of this subpart, annual mass and carbon content of green coke fed to the unit, the annual mass and carbon content of marketable coke produced, and the annual mass of coke dust collected in dust collection systems.

(6) If you use a CEMS, the relevant information required under §98.36(e)(2)(vi) for the Tier 4 Calculation Methodology, the CO_2 annual emissions as measured by the CEMS and the annual process CO_2 emissions calculated according to §98.253(g)(1). Report the CO_2 annual emissions associated with fuel combustion under subpart C of this part (General Stationary Fuel Combustion Sources).

(7) Indicate whether you use a measured value, a unit-specific emission factor or a default for CH_4 emissions. If you use a unit-specific emission factor for CH_4, the unit-specific emission factor for CH_4, the units of measure for the unit-specific factor, the activity data for calculating emissions (e.g., if the emission factor is based on coke burn-off rate, the annual quantity of coke burned), and the basis for the factor.

(8) If you use a site-specific emission factor in Equation Y-10 of this subpart, the site-specific emission factor and the basis of the factor.

(j) For asphalt blowing operations, the owner or operator shall report:

(1) The unit ID number (if applicable).

(2) The quantity of asphalt blown (in Million bbl) at the facility in the reporting year.

(3) The type of control device used to reduce methane (and other organic) emissions from the unit.

(4) The calculated annual CO_2 and CH_4 emissions for each unit, expressed in metric tons of each pollutant emitted.

(5) If you use Equation Y-14 of this subpart, the CO_2 emission factor used and the basis for the value.

(6) If you use Equation Y-15 of this subpart, the CH_4 emission factor used and the basis for the value.

(7) If you use Equation Y-16 of this subpart, the carbon emission factor used and the basis for the value.

(8) If you use Equation Y-17 of this subpart, the CH_4 emission factor used and the basis for the value.

(k) For delayed coking units, the owner or operator shall report:

(1) The cumulative annual CH_4 emissions (in metric tons of each pollutant emitted) for all delayed coking units at the facility.

(2) A description of the method used to calculate the CH_4 emissions for each unit (e.g., reference section and equation number).

(3) The total number of delayed coking units at the facility, the total number of delayed coking drums at the facility, and for each coke drum or vessel: the dimensions, the typical gauge pressure of the coking drum when first vented to the atmosphere, typical void fraction, the typical drum outage (i.e. the unfilled distance from the top of the drum, in feet), and annual number of coke-cutting cycles.

(4) For each set of coking drums that are the same dimensions: the number of coking drums in the set, the height and diameter of the coke drums (in feet), the cumulative number of vessel openings for all delayed coking drums in the set, the typical venting pressure (in psig), void fraction (in cf gas/cf of vessel), and the mole fraction of methane in coking gas (in kg-mole CF_4/kg-mole gas, wet basis).

(5) The basis for the volumetric void fraction of the coke vessel prior to steaming and the basis for the mole fraction of methane in the coking gas.

(l) For process vents subject to §98.253(j), the owner or operator shall report:

(1) The vent ID number (if applicable).

(2) The unit or operation associated with the emissions.

(3) The type of control device used to reduce methane (and other organic) emissions from the unit, if applicable.

(4) The calculated annual CO_2, CH_4, and N_2O emissions for each vent, expressed in metric tons of each pollutant emitted.

(5) The annual volumetric flow discharged to the atmosphere (in scf), mole fraction of each GHG above the concentration threshold, and for intermittent vents, the number of venting events and the cumulative venting time.

(m) For uncontrolled blowdown systems, the owner or operator shall report:

(1) The cumulative annual CH_4 emissions (in metric tons of each pollutant emitted) for uncontrolled blowdown systems.

(2) ~~The total quantity (in Million bbl) of crude oil plus the quantity of intermediate products received from off-site that are processed at the facility in the reporting year.~~The information required for process vents in paragraph (l) of this section.

(3) ~~The methane emission factor used for uncontrolled blowdown systems and the basis for the value.~~

Reserved.

(n) For equipment leaks, the owner or operator shall report:

(1) The cumulative CH_4 emissions (in metric tons of each pollutant emitted) for all equipment leak sources.

(2) The method used to calculate the reported equipment leak emissions.

(3) The number of each type of emission source listed in Equation Y-21 of this subpart at the facility.

(o) For storage tanks, the owner or operator shall report:

(1) The cumulative annual CH_4 emissions (in metric tons of each pollutant emitted) for all storage tanks, except for those used to process unstabilized crude oil.

(2) The method used to calculate the reported storage tank emissions for storage tanks other than those processing unstabilized crude (AP-42, TANKS 4.09D, Equation Y-22 of this subpart, other).

(3) The total quantity (in MMbbl) of crude oil plus the quantity of intermediate products received from off-site that are processed at the facility in the reporting year.

(4) The cumulative CH_4 emissions (in metric tons of each pollutant emitted) for storage tanks used to process unstabilized crude oil.

(5) The method used to calculate the reported storage tank emissions for storage tanks processing unstabilized crude oil.

(6) The quantity of unstabilized crude oil received during the calendar year (in MMbbl), the average pressure differential (in psi), and the mole fraction of CH_4 in vent gas from the unstabilized crude oil storage tank, and the basis for the mole fraction.

(7) The tank-specific methane composition data and the gas generation rate data, if you did not use Equation Y-23.

(p) For loading operations, the owner or operator shall report:

(1) The cumulative annual CH_4 emissions (in metric tons of each pollutant emitted) for loading operations.

(2) The quantity and types of materials loaded by vessel type (barge, tanker, marine vessel, etc.) that have an equilibrium vapor-phase concentration of methane of 0.5 volume percent or greater, and the type of vessels in which the material is loaded.

(3) The type of control system used to reduce emissions from the loading of material with an equilibrium vapor-phase concentration of methane of 0.5 volume percent or greater, if any (submerged loading, vapor balancing, etc.).

(q) Name of each method listed in §98.254 or a description of manufacturer's recommended method used to determine a measured parameter.

§98.257 Records that must be retained.

(a) In addition to the records required by §98.3(g), you must retain the records of all parameters monitored under §98.255.

(b) For each process vent for which the concentration of CO_2, N_2O and CH_4 are determined to be below the thresholds in

§98.253(j), the owner or operator shall maintain records of the method used to determine the CO_2, N_2O, and CH_4 concentration and all supporting documentation necessary to demonstrate the thresholds in §98.253(j) are not exceeded during the reporting year.

§98.258 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart AA—Pulp and Paper Manufacturing

§98.270 Definition of Source Category.

(a) The pulp and paper manufacturing source category consists of facilities that produce market pulp (i.e., stand-alone pulp facilities), manufacture pulp and paper (i.e., integrated facilities), produce paper products from purchased pulp, produce secondary fiber from recycled paper, convert paper into paperboard products (e.g., containers), or operate coating and laminating processes.

(b) The emission units for which GHG emissions must be reported are listed in paragraphs (b)(1) through (b)(5) of this section:

(1) Chemical recovery furnaces at kraft and soda mills (including recovery furnaces that burn spent pulping liquor produced by both the kraft and semichemical process).

(2) Chemical recovery combustion units at sulfite facilities.

(3) Chemical recovery combustion units at stand-alone semichemical facilities.

(4) Pulp mill lime kilns at kraft and soda facilities.

(5) Systems for adding makeup chemicals ($CaCO_3$, Na_2CO_3) in the chemical recovery areas of chemical pulp mills.

Subpart AA—Pulp and Paper Manufacturing

§98.271 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a pulp and paper manufacturing process and the facility meets the requirements of either §98.2(a)(1) or (a)(2).

§98.272 GHGs to report.

You must report the emissions listed in paragraphs (a) through (f) of this section:[1]

(a) CO_2, biogenic CO_2, CH_4, and N_2O emissions from each kraft or soda chemical recovery furnace.

(b) CO_2, biogenic CO_2, CH_4, and N_2O emissions from each sulfite chemical recovery combustion unit.

(c) CO_2, biogenic CO_2, CH_4, and N_2O emissions from each stand-alone semichemical chemical recovery combustion unit.

(d) CO_2, biogenic CO_2, CH_4, and N_2O emissions from each kraft or soda pulp mill lime kiln.

(e) CO_2 emissions from addition of makeup chemicals ($CaCO_3$, Na_2CO_3) in the chemical recovery areas of chemical pulp mills.

(f) CO_2, CH_4, and N_2O combustion emissions from each stationary combustion unit. You must calculate and report these emissions under subpart C of this part (General

[1] WCI ERs previously included methodologies for calculating CH_4 and N_2O emissions from wastewater treatment plants at this source category. Coverage of these facilities will now be left to the discretion of the jurisdiction.

Stationary Fuel Combustion Sources) by following the requirements of subpart C.

§98.273 Calculating GHG emissions.

(a) For each chemical recovery furnace located at a kraft or soda facility, you must determine CO_2, biogenic CO_2, CH_4, and N_2O emissions using the procedures in paragraphs (a)(1) through (a)(3) of this section. CH_4 and N_2O emissions must be calculated as the sum of emissions from combustion of fossil fuels and combustion of biomass in spent liquor solids.

(1) Calculate fossil fuel-based CO_2 emissions from direct measurement of fossil fuels consumed and the methodology for stationary combustion sources specified by §98.33(a) (as modified by this Article) for the appropriate fuel type ~~default emissions factors according to the Tier 1 methodology for stationary combustion sources in §98.33(a)(1)~~.[2]

(2) Calculate fossil fuel-based CH_4 and N_2O emissions from direct measurement of fossil fuels consumed, default HHV, and default emissions factors and convert to metric tons of CO_2 equivalent according to the methodology for stationary combustion sources in §98.33(c).

[2] Although Subpart C generally allows the use of higher tiers, even when a lower tier is specified for a particular unit or fuel, section 98.273 could be read as *requiring* the use of Tier 1. WCI is seeking clarification of the correct interpretation of section 98.273 in order to assure that the proposed changes are consistent with harmonization.

(3) Calculate biogenic CO_2 emissions and emissions of CH_4 and N_2O from biomass using measured quantities of spent liquor solids fired, site-specific HHV, and default or site-specific emissions factors[3], according to Equation AA-1 of this section:

$$CO_2, CH_4, or\ N_2O\ from\ biomass = (0.907.18) * \text{Solids} * \text{HHV} * \text{EF} \quad \text{(Eq.AA-1)}$$

Where:

CO_2, CH_4, or N_2O, from Biomass	=	Biogenic CO_2 emissions or emissions of CH_4 or N_2O from spent liquor solids combustion (metric tons per year).
Solids	=	Mass of spent liquor solids combusted (short tons per year) determined according to §98.274(b).
HHV	=	Annual high heat value of the spent liquor solids (mmBtu per kilogram) determined according to 98.274(b).
EF	=	Default emission factor for CO_2, CH_4, or N_2O, from Table AA-1 of this subpart (kg CO_2, CH_4, or N_2O per mmBtu).
0.90718	=	Conversion factor from short tons to metric tons.

(b) For each chemical recovery combustion unit located at a sulfite or stand-alone semichemical facility, you must determine CO_2, CH_4, and N_2O emissions using the procedures in paragraphs (b)(1) through (b)(4) of this section:

(1) Calculate fossil CO_2 emissions from fossil fuels from direct measurement of fossil fuels consumed and the

methodology for stationary combustion sources specified by §98.33(a) (as modified by this Article) for the appropriate fuel type ~~default emissions factors according to the Tier 1 Calculation Methodology for stationary combustion sources in §98.33(a)(1)~~.

(2) Calculate CH_4 and N_2O emissions from fossil fuels from direct measurement of fossil fuels consumed, default HHV, and default emissions factors and convert to metric tons of CO_2 equivalent according to the methodology for stationary combustion sources in §98.33(c).

(3) Calculate biogenic CO_2 emissions using measured quantities of spent liquor solids fired and the carbon content of the spent liquor solids, according to Equation AA-2 of this section:

$$Biogenic\,CO_2 = \frac{44}{12} * \mathrm{Solids} * \mathrm{CC} * (0.90718) \qquad \text{(Eq. AA-2)}$$

Where:

Biogenic CO_2	=	Annual CO_2 mass emissions for spent liquor solids combustion (metric tons per year).
Solids	=	Mass of the spent liquor solids combusted (short tons per year) determined according to §98.274(b).
CC	=	Annual carbon content of the spent liquor solids, determined according to §98.274(b) (percent by weight, expressed as a decimal fraction, e.g., 95% = 0.95).
44/12	=	Ratio of molecular weights, CO_2 to carbon.
0.90718	=	Conversion from short tons to metric tons

(4) Calculate CH_4 and N_2O emissions from biomass using Equation AA-1 of this section and the default CH_4 and N_2O emissions factors for kraft facilities in Table AA-1 of this subpart and convert the CH_4 or N_2O emissions to metric tons of CO_2 equivalent by multiplying each annual CH_4 and N_2O emissions total by the appropriate global warming potential (GWP) factor from Table A-1 of subpart A of this part.

(c) For each pulp mill lime kiln located at a kraft or soda facility, you must determine CO_2, CH_4, and N_2O emissions using the procedures in paragraphs (c)(1) through (c)(3) of this section:

(1) Calculate CO_2 emissions from fossil fuels from direct measurement of fossil fuels consumed and the methodology for stationary combustion sources specified by §98.33(a) (as modified by this Article) for the appropriate fuel type. ~~and default HHV and default emissions factors, according to the Tier 1 Calculation Methodology for stationary combustion sources in §98.33(a)(1); use the default HHV listed in Table C-1 of subpart C and~~ Where the applicable method specified by § 98.33(a) allows the use of a default emission factor, use the default CO_2 emissions factors listed in Table AA-2 of this subpart.

(2) Calculate CH_4 and N_2O emissions from fossil fuel from direct measurement of fossil fuels consumed, default HHV, and default emissions factors and convert to metric tons of CO_2 equivalent according to the methodology for stationary combustion sources in §98.33(c); use the default HHV listed in Table C-1 of subpart C and the default CH_4 and N_2O emissions factors listed in Table AA-2 of this subpart.

(3) Biogenic CO_2 emissions from conversion of $CaCO_3$ to CaO are included in the biogenic CO_2 estimates calculated for the chemical recovery furnace in paragraph (a)(3) of this section.

(d) For makeup chemical use, you must calculate CO_2 emissions by using direct or indirect measurement of the quantity of chemicals added and ratios of the molecular weights of CO_2 and the makeup chemicals, according to Equation AA-3 of this section:

$$CO_2 = \left[M_{(CaCO_3)} * \frac{44}{100} + M_{(Na_2CO_3)} \frac{44}{105.99} \right] * 1000\, kg / metric\, ton \qquad \text{(Eq. AA-3)}$$

Where:

CO_2	=	CO_2 mass emissions from makeup chemicals (kilograms/yr).
M ($CaCO_3$)	=	Make-up quantity of $CaCO_3$ used for the reporting year (metric tons per year).
M ($NaCO_3$)	=	Make-up quantity of Na_2CO_3 used for the reporting year (metric tons per year).
44	=	Molecular weight of CO_2.
100	=	Molecular weight of $CaCO_3$.
105.99	=	Molecular weight of Na_2CO_3.

§98.274 Monitoring and QA/QC requirements.

(a) Each facility subject to this subpart must quality assure the GHG emissions data according to the applicable requirements in §98.34. All QA/QC data must be available for inspection upon request.

(b) Fuel properties needed to perform the calculations in Equations AA-1 and AA-2 of this subpart must be determined according to paragraphs (b)(1) through (b)(3) of this section.

(1) High heat values of black liquor must be determined no less than annually using T684 om–06 Gross Heating Value of Black Liquor, TAPPI (incorporated by reference, see §98.7). If measurements are performed more frequently than annually, then the high heat value used in Equation AA-1 of this subpart must be based on the average of the representative measurements made during the year.

(2) The annual mass of spent liquor solids must be determined using either of the methods specified in paragraph (b)(2)(i) or (b)(2)(ii).

(i) Measure the mass of spent liquor solids annually (or more frequently) using T-650 om–05 Solids Content of Black Liquor, TAPPI (incorporated by reference in §98.7). If measurements are performed more frequently than annually, then the mass of spent liquor solids used in

Equation AA-1 of this subpart must be based on the average of the representative measurements made during the year.

(ii) Determine the annual mass of spent liquor solids based on records of measurements made with an online measurement system that determines the mass of spent liquor solids fired in a chemical recovery furnace or chemical recovery combustion unit.

(3) Carbon analyses for spent pulping liquor must be determined no less than annually using ASTM D5373-08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal (incorporated by reference, see §98.7). If measurements using ASTM D5373-08 are performed more frequently than annually, then the spent pulping liquor carbon content used in Equation AA-2 of this subpart must be based on the average of the representative measurements made during the year.

(c) Each facility must keep records that include a detailed explanation of how company records of measurements are used to estimate GHG emissions. The owner or operator must also document the procedures used to ensure the accuracy of the measurements of fuel, spent liquor solids, and makeup chemical usage, including, but not limited to calibration of weighing equipment, fuel flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices must be recorded and the technical basis for these estimates must be provided. The procedures used to convert spent pulping liquor flow rates to units of mass (i.e., spent liquor solids firing rates) also must be documented.

(d) Records must be made available upon request for verification of the calculations and measurements.

§98.275 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation or if a required sample is not taken), a substitute data value for the missing parameter shall be used in the calculations, according to the requirements of paragraphs (a) through (c) of this section:

(a) There are no missing data procedures for measurements of heat content and carbon content of spent pulping liquor. A re-test must be performed if the data from any annual measurements are determined to be invalid.

(b) For missing measurements of the mass of spent liquor solids or spent pulping liquor flow rates, use the lesser value of either the maximum mass or fuel flow rate for the combustion unit, or the maximum mass or flow rate that the fuel meter can measure.

(c) For the use of makeup chemicals (carbonates), the substitute data value shall be the best available estimate of makeup chemical consumption, based on available data (e.g., past accounting records, production rates). The owner or operator shall document and keep records of the procedures used for all such estimates.

§98.276 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the information in paragraphs (a) through (K) of this section as applicable:

(a) Annual emissions of CO_2, biogenic CO_2, CH_4, biogenic CH_4 N_2O, and biogenic N_2O (metric tons per year).

(b) Annual quantities fossil fuels by type used in chemical recovery furnaces and chemical recovery combustion units in short tons for solid fuels, gallons for liquid fuels and scf for gaseous fuels.

(c) Annual mass of the spent liquor solids combusted (short tons per year), and basis for determining the annual mass of the spent liquor solids combusted (whether based on T650 om-05 Solids Content of Black Liquor, TAPPI (incorporated by reference, see §98.7) or an online measurement system).

(d) The high heat value (HHV) of the spent liquor solids used in Equation AA-1 of this subpart (mmBtu per kilogram).

(e) The default emission factor for CO_2, CH_4, or N_2O, used in Equation AA-1 of this subpart (kg CO_2, CH_4, or N_2O per mmBtu).

(f) The carbon content (CC) of the spent liquor solids, used in Equation AA-2 of this subpart (percent by weight, expressed as a decimal fraction, e.g., 95% = 0.95).

(g) Annual quantities of fossil fuels by type used in pulp mill lime kilns in short tons for solid fuels, gallons for liquid fuels and scf for gaseous fuels.

(h) Make-up quantity of $CaCO_3$ used for the reporting year (metric tons per year) used in Equation AA-3 of this subpart.

(i) Make-up quantity of Na_2CO_3 used for the reporting year (metric tons per year) used in Equation AA-3 of this subpart.

(j) Annual steam purchases(pounds of steam per year).

(k) Annual production of pulp and/or paper products produced (metric tons).

§98.277 Records that must be retained.

Subpart AA—Pulp and Paper Manufacturing

In addition to the information required by §98.3(g), you must retain the records in paragraphs (a) through (f) of this section.

(a) GHG emission estimates (including separate estimates of biogenic CO_2) for each emissions source listed under §98.270(b).

(b) Annual analyses of spent pulping liquor HHV for each chemical recovery furnace at kraft and soda facilities.

(c) Annual analyses of spent pulping liquor carbon content for each chemical recovery combustion unit at a sulfite or semichemical pulp facility.

(d) Annual quantity of spent liquor solids combusted in each chemical recovery furnace and chemical recovery combustion unit, and the basis for detemining the annual quantity of the spent liquor solids combusted (whether based on T650 om–05 Solids Content of Black Liquor, TAPPI (incorporated by reference, see §98.7) or an online measurement system). If an online measurement system is used, you must retain records of the calaulations used to determine the annual quantity of spent liquor solids combusted from the continuous measurements.

(e) Annual steam purchases.

(f) Annual quantities of makeup chemicals used.

Subpart AA—Pulp and Paper Manufacturing

§98.278 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Table AA-1 of Subpart AA—Kraft Pulping Liquor Emissions Factors for Biomass-Based CO_2, CH_4, and N_2O.

Wood Furnish	Biomass-Based Emissions Factors (kg/mmBtu HHV)		
	CO_2[a]	CH_4	N_2O
North American Softwood	94.4	0.030	0.005
North American Hardwood	93.7		
Bagasse	95.5		
Bamboo	93.7		
Straw	95.1		

[a] Includes emissions from both the recovery furnace and pulp mill lime kiln.

Table AA-2 of Subpart AA—Kraft Lime Kiln and Calciner Emissions Factors for Fossil Fuel-Based CO_2, CH_4, and N_2O

Fuel	Fossil Fuel-Based Emissions Factors (kg/mmBtu HHV)					
	Kraft Lime Kilns			Kraft Calciners		
	CO_2	CH_4	N_2O	CO_2	CH_4	N_2O
Residual Oil	76.7	0.0027	0	76.7	0.0027	0.0003
Distillate Oil	73.5			73.5		0.0004
Natural Gas	56.0			56.0		0.0001
Biogas	0			0		0.0001

Subpart CC—Soda Ash Manufacturing

§98.290 Definition of the source category.

A soda ash manufacturing facility is any facility with a manufacturing line that produces soda ash by one of the methods in paragraphs (a) through (c) of this section:

(a) Calcining trona.

(b) Calcining sodium sesquicarbonate.

(c) Using a liquid alkaline feedstock process that directly produces CO_2.

In the context of the soda ash manufacturing sector, “calcining” means the thermal/chemical conversion of the bicarbonate fraction of the feedstock to sodium carbonate.

§98.291 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a soda ash manufacturing process and the facility meets the requirements of either §98.2(a)(1) or (a)(2).

§98.292 GHGs to report.

You must report:

(a) CO_2 process emissions from each soda ash manufacturing line combined.[1]

(b) CO_2 combustion emissions from each soda ash manufacturing line.

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[1]Clarification – if CO_2 generated during calcination is recycled to carbonation towers, these calculated process emissions will be adjusted by the measured quantity of recycled CO_2 determined by the method identified in §98.293(d).

(c) CH_4 and N_2O combustion emissions from each soda ash manufacturing line. You must calculate and report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

(d) CO_2, CH_4, and N_2O emissions from each stationary combustion unit other than soda ash manufacturing lines. You must calculate and report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

§98.293 Calculating GHG emissions.

You must calculate and report the annual process CO_2 emissions from each soda ash manufacturing line using the procedures specified in paragraph (a) or (b) of this section.

(a) For each soda ash manufacturing line that meets the conditions specified in §98.33(b)(4)(ii) or (b)(4)(iii), you must calculate and report under this subpart the combined process and combustion CO_2 emissions by operating and maintaining a CEMS to measure CO_2 emissions according to the Tier 4 Calculation Methodology specified in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(b) For each soda ash manufacturing line that is not subject to the requirements in paragraph (a) of this section, calculate and report the process CO_2 emissions from the soda ash manufacturing line by using the procedure in either paragraphs (b)(1), (b)(2), or (b)(3) of this section; and the combustion CO_2 emissions using the procedure in paragraph (b)(4) of this section.

(1) Calculate and report under this subpart the combined process and combustion CO_2 emissions by operating and maintaining a CEMS to measure CO_2 emissions according to the Tier 4 Calculation Methodology specified in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(2) Use either Equation CC-1 or Equation CC-2 of this section to calculate annual CO_2 process emissions from each manufacturing line that calcines trona to produce soda ash:

$$E_k = \sum_{n=1}^{12} [(IC_T)_n * (T_t)_n] * \frac{2000}{2205} * \frac{0.097}{1} \qquad \text{(Eq. CC-1)}$$

$$E_k = \sum_{n=1}^{12} [(IC_{sa})_n * (T_{sa})_n] * \frac{2000}{2205} * \frac{0.138}{1} \qquad \text{(Eq. CC-2)}$$

Where:

E_k = Annual CO_2 process emissions from each manufacturing line, k (metric tons).

$(IC_T)_n$ = Inorganic carbon content (percent by weight, expressed as a decimal fraction) in trona input, from the carbon analysis results for

		month n. This represents the ratio of trona to trona ore.
$(IC_{sa})_n$	=	Inorganic carbon content(percent by weight, expressed as a decimal fraction) in soda ash output, from the carbon analysis results for month n. This represents the purity of the soda ash produced.
$(T_t)_n$	=	Mass of trona input in month n (tons).
$(T_{sa})_n$	=	Mass of soda ash output in month n (tons).
2000/2205	=	Conversion factor to convert tons to metric tons.
0.097/1	=	Ratio of ton of CO_2 emitted for each ton of trona.
0.138/1	=	Ratio of ton of CO_2 emitted for each ton of soda ash produced.

(3) Site-specific emission factor method. Use Equations CC-3, CC-4, and CC-5 of this section to determine annual CO_2 process emissions from manufacturing lines that use the liquid alkaline feedstock process to produce soda ash. You must conduct an annual performance test and measure CO_2 emissions and flow rates at all process vents from the mine water stripper/evaporator for each manufacturing line and calculate CO_2 emissions as described in paragraphs (b)(3)(i) through (b)(3)(iv) of this section.

(i) During the performance test, you must measure the process vent flow from each process vent during the test and calculate the average rate for the test period in metric tons per hour.

(ii) Using the test data, you must calculate the hourly CO_2 emission rate using Equation CC-3 of this section:

$$ER_{CO2} = [(C_{co2} * 10000) * 2.59x10^{-9} * 44] * (Q * 60) * 4.53x10^{-4} \quad \text{(Eq. CC-3)}$$

Where:

ER_{CO2}	=	CO_2 mass emission rate (metric tons/hour).
C_{CO2}	=	Hourly CO_2 concentration (percent CO_2) as determined by §98.294(c).
10000	=	Parts per million per percent
2.59×10^{-9}	=	Conversion factor (pounds-mole/dscf/ppm).
44	=	Pounds per pound-mole of carbon dioxide.
Q	=	Stack gas volumetric flow rate per minute (dscfm).
60	=	Minutes per hour
4.53×10^{-4}	=	Conversion factor (metric tons/pound)

(iii) Using the test data, you must calculate a CO_2 emission factor for the process using Equation CC-4 of this section:

$$EF_{CO2} = \frac{ER_{CO2}}{(V_t * 4.53x10^{-4})} \quad \text{(Eq. CC-4)}$$

Where:

EF_{CO2}	=	CO_2 emission factor (metric tons CO_2/metric ton of process vent flow from mine water stripper/evaporator).
ER_{CO2}	=	CO_2 mass emission rate (metric tons/hour).
V_t	=	Process vent flow rate from mine water stripper/evaporator during annual performance test (pounds/hour).
4.53×10^{-4}	=	Conversion factor (metric tons/pound)

(iv) You must calculate annual CO_2 process emissions from each manufacturing line using Equation CC-5 of this section:

$$E_k = EF_{CO2} * (V_a * 0.453) * H \qquad \text{(Eq. CC-5)}$$

Where:

E_k	=	Annual CO_2 process emissions for each manufacturing line, k (metric tons).
EF_{CO2}	=	CO_2 emission factor (metric tons CO_2/metric ton of process vent flow from mine water stripper/evaporator).
V_a	=	Annual process vent flow rate from mine water stripper/evaporator (thousand pounds/hour).
H	=	Annual operating hours for the each manufacturing line.
0.453	=	Conversion factor (metric tons/thousand pounds).

(4) Calculate and report under subpart C of this part (General Stationary Fuel Combustion Sources) the combustion CO_2, CH_4, and N_2O emissions in the soda ash manufacturing line according to the applicable requirements in subpart C.

§98.294 Monitoring and QA/QC requirements.

Section 98.293 provides ~~three~~ four different procedures for emission calculations. The appropriate paragraphs (a) through (~~c~~d) of this section should be used for the procedure chosen.[2]

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[2]For plants that recycle CO_2 generated during calcination to carbonation towers, WCI requested that CEMS be installed in the recycle loop to measure the quantity of recycled CO_2. As a result, an additional method was added to §98.293(d). The resulting measurement of the quantity of recycled CO_2 was also added to §98.296(a)(5) and §98.296(b)(12).

Subpart CC—Soda Ash Manufacturing

(a) If you determine your emissions using §98.293(b)(2) (Equation CC-1 of this subpart) you must:

(1) Determine the monthly inorganic carbon content of the trona from a weekly composite analysis for each soda ash manufacturing line, using a modified version of ASTM E359-00(Reapproved 2005)e1, Standard Test Methods for Analysis of Soda Ash (Sodium Carbonate) (incorporated by reference, see §98.7). ASTM E359-00(Reapproved 2005)e1 is designed to measure the total alkalinity in soda ash not in trona. The modified method of ASTM E359-00 adjusts the regular ASTM method to expresse the results in terms of trona. Although ASTM E359-00(Reapproved 2005)e1 uses manual titration, suitable autotitrators may also be used for this determination.

(2) Measure the mass of trona input produced by each soda ash manufacturing line on a monthly basis using belt scales or methods used for accounting purposes.

(3) Document the procedures used to ensure the accuracy of the monthly measurements of trona consumed.

(b) If you calculate CO_2 process emissions based on soda ash production (§98.293(b)(2)Equation CC-2 of this subpart), you must:

(1) Determine the inorganic carbon content of the soda ash (i.e., soda ash purity) using ASTM E359-

00(Reapproved 2005)e1 Standard Test Methods for Analysis of Soda Ash (Sodium Carbonate) (incorporated by reference, see §98.7). Although ASTM E359-00(Reapproved 2005)e1 uses manual titration, suitable autotitrators may also be used for this determination.

(2) Measure the mass of soda ash produced by each soda ash manufacturing line on a monthly basis using belt scales, by weighing the soda ash at the truck or rail loadout points of your facility, or methods used for accounting purposes.

(3) Document the procedures used to ensure the accuracy of the monthly measurements of soda ash produced.

(c) If you calculate CO_2 emissions using the site-specific emission factor method in §98.293(b)(3), you must:

(1) Conduct an annual performance test that is based on representative performance (i.e., performance based on normal operating conditions) of the affected process.

(2) Sample the stack gas and conduct three emissions test runs of 1 hour each.

(3) Conduct the stack test using EPA Method 3A at 40 CFR part 60, appendix A-2 to measure the CO_2 concentration, Method 2, 2A, 2C, 2D, or 2F at 40 CFR part 60, appendix A-1 or Method 26 at 40 CFR part 60, appendix A-2 to determine the stack gas volumetric flow rate. All QA/QC procedures

specified in the reference test methods and any associated performance specifications apply. For each test, the facility must prepare an emission factor determination report that must include the items in paragraphs (c)(3)(i) through (c)(3)(iii) of this section.

(i) Analysis of samples, determination of emissions, and raw data.

(ii) All information and data used to derive the emissions factor(s).

(iii) You must determine the average process vent flow rate from the mine water stripper/evaporater during each test and document how it was determined.

(4) You must also determine the the annual vent flow rate from the mine water stripper/evaporater from monthly information using the same plant instruments or procedures used for accounting purposes (i.e., volumetric flow meter).

(d) If you recycle CO_2 generated during calcination to carbonation towers, then you must install a CEMS in the recycle loop and measure this quantity of CO_2.

§98.295 Procedures for estimating missing data.

For the emission calculation methodologies in §98.293(b)(2)and (b)(3), a complete record of all measured parameters used in the GHG emissions calculations is required (e.g., inorganic carbon content values, etc.).

Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in the paragraphs (a) through (d) of this section. You must document and keep records of the procedures used for all such missing value estimates.

(a) For each missing value of the weekly composite of inorganic carbon content of either soda ash or trona, the substitute data value shall be the arithmetic average of the quality-assured values of inorganic carbon contents from the week immediately preceding and the week immediately following the missing data incident. If no quality-assured data on inorganic carbon contents are available prior to the missing data incident, the substitute data value shall be the first quality-assured value for carbon contents obtained after the missing data period.

(b) For each missing value of either the monthly soda ash production or the trona consumption, the substitute data value shall shall be the best available estimate(s) of the parameter(s), based on all available process data or data used for accounting purposes.

(c) For each missing value collected during the performance test (hourly CO_2 concentration, stack gas volumetric flow rate, or average process vent flow from mine water stripper/evaporator during performance test), you must repeat the annual performance test following the calculation and monitoring and QA/QC requirements under §§98.293(b)(3) and 98.294(c).

(d) For each missing value of the monthly process vent flow rate from mine water stripper/evaporator, the subsititute data value shall be the best available estimate(s) of the parameter(s), based on all available process data or the lesser of the maximum capacity of the system or the maximum rate the meter can measure.

§98.296 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) or (b) of this section, as appropriate for each soda ash manufacturing facility.

(a) If a CEMS is used to measure CO_2 emissions, then you must report under this subpart the relevant information required under §98.36 and the following information in this paragraph (a):

(1) Annual consumption of trona or liquid alkaline feedstock for each manufacturing line (metric tons).

(2) Annual production of soda ash for each manufacturing line (tons).

(3) Annual production capacity of soda ash for each manufacturing line (tons).

(4) Identification number of each manufacturing line.

(5) Annual quantity of generated CO_2 recycled to carbonation towers (tons), if applicable.

(b) If a CEMS is not used to measure CO_2 emissions, then you must report the information listed in this paragraph (b):

(1) Identification number of each manufacturing line.

(2) Annual process CO_2 emissions from each soda ash manufacturing line (metric tons).

(3) Annual production of soda ash (tons).

(4) Annual production capacity of soda ash for each manufacturing line (tons).

(5) Monthly consumption of trona or liquid alkaline feedstock for each manufacturing line (tons).

(6) Monthly production of soda ash for each manufacturing line (metric tons).

(7) Inorganic carbon content factor of trona or soda ash (depending on use of Equations CC-1 or CC-2 of this subpart) as measured by the applicable method in §98.294(b) or (c) for each month (percent by weight expressed as a decimal fraction).

(8) Whether CO_2 emissions for each manufacturing line were calculated using a trona input method as described in Equation CC-1 of this subpart, a soda ash output method as described in Equation CC-2 of this subpart, or a site-specific emission factor method as described in Equations CC-3 through CC-5 of this subpart.

(9) Number of manufacturing lines located used to produce soda ash.

(10) If you produce soda ash using the liquid alkaline feedstock process and use the site-specific emission factor method (§98.293(b)(3)) to estimate emissions then you must report the following relevant information:

(i) Stack gas volumetric flow rate per minute (dscfm)

(ii) Hourly CO_2 concentration (percent CO_2)

(iii) CO_2 emission factor (metric tons CO_2/metric tons of process vent flow from mine water stripper/evaporator).

(iv) CO_2 mass emission rate (metric tons/hour).

(v) Average process vent flow from mine water stripper/evaporater during performance test (pounds/hour).

(vi) Annual process vent flow rate from mine stripper/evaporator (thousand pounds/hour).

(vii) Annual operating hours for each manufacturing line used to produce soda ash using liquid alkaline feedstock (hours).

(11) Number of times missing data procedures were used and for which parameter as specified in this paragraph (b)(11):

(i) Trona or soda ash (number of months).

(ii) Inorganic carbon contents of trona or soda ash (weeks).

(iii) Process vent flow rate from mine water stripper/evaporator (number of months).

(iv) Stack gas volumetric flow rate during performance test(number of times).

(v) Hourly CO_2 concentration (number of times).

(vi) Average vent process vent flow rate from mine stripper/evaporator during performance test (number of times).

(12) Annual quantity of generated CO_2 recycled to carbonation towers (tons), if applicable.

§98.297 Records that must be retained.

In addition to the records required by §98.3(g), you must retain the records specified in paragraphs (a) and (b) of this section for each soda ash manufacturing line.

Subpart CC—Soda Ash Manufacturing

(a) If a CEMS is used to measure CO_2 emissions, then you must retain under this subpart the records required for the Tier 4 Calculation Methodology specified in subpart C of this part and the information listed in this paragraph (a):

(1) Monthly production of soda ash (tons)

(2) Monthly consumption of trona or liquid alkaline feedstock (tons)

(3) Annual operating hours (hours).

(b) If a CEMS is not used to measure emissions, then you must retain records for the information listed in this paragraph (b):

(1) Records of all analyses and calculations conducted for determining all reported data as listed in §98.296(b).

(2) If using Equation CC-1 or CC-2 of this subpart, weekly inorganic carbon content factor of trona or soda ash, depending on method chosen, as measured by the applicable method in §98.294(b)(percent by weight expressed as a decimal fraction).

(3) Annual operating hours for each manufacturing line used to produce soda ash (hours).

(4) You must document the procedures used to ensure the accuracy of the monthly trona consumption or soda ash

prodcution measurements including, but not limited to, calibration of weighing equipment and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.

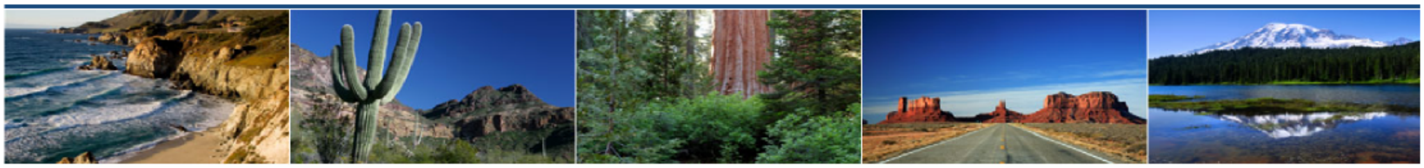
(5) If you produce soda ash using the liquid alkaline feedstock process and use the site-specific emission factor method to estimate emissions (§98.293(b)(3)) then you must also retain the following relevant information:

(i) Records of performance test results.

(ii) You must document the procedures used to ensure the accuracy of the annual average vent flow measurements including, but not limited to, calibration of flow rate meters and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.

§98.298 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.



§WCI.8 REQUIREMENTS FOR VERIFICATION OF GREENHOUSE GAS EMISSIONS DATA REPORTS AND REQUIREMENTS APPLICABLE TO EMISSIONS DATA VERIFIERS (UPDATED FOR USE IN U.S. JURISDICTIONS TO CONFORM TO HARMONIZED ERS)

Note: The verification requirements laid out in this section strive for consistency with ISO 14064-3[1] requirements and set forth a high standard for verification that will ultimately support a WCI cap and trade program. Due to differences in rulemaking procedures between jurisdictions, Supplement 1 provides supplemental text that jurisdictions must incorporate into either the jurisdiction's prescriptive rule language, replacing more general procedural language in Section WCI.8, or into enforceable guidance documents. There are notes in WCI.8 that direct readers to appropriate text in Verification Supplement 1 when applicable.

It would be ideal for all jurisdictions to enforce the same requirements and have the same implementation processes for accreditation and verification to ensure that consistent accurate data exists throughout the WCI regional program. Reporters and verifiers with operations throughout the WCI region will benefit from a consistent approach and such an approach would facilitate administration of the verification requirements by a central body or designee.

(a) Applicability and Scope.

(1) Except as provided in WCI.8(a)(2) through (4) owners or operators [Each jurisdiction will select the specific terminology for the regulated persons in accordance with their customary rule-writing practices] are required to obtain annual verification for a facility that emits 25,000 metric tons CO_2e or more per year in combined emissions from one or more of the source categories listed in ~~WCI.1~~section 98.2 in any calendar year starting on or after 2010.

(2) When the operation of a facility, fuel supplier, or electricity importer subject to the requirements of this section is changed such that the operator has reported less than 25,000 metric tons of CO_2e emissions for a calendar year, the operator shall obtain verification of annual emissions reports for the lesser of three subsequent calendar years or for those years remaining in the current compliance period. If CO_2e emissions of a facility, fuel supplier, or electricity importer subject to the requirements of this section

1 ISO (2006) ISO 14064-3: Greenhouse Gases-Part 3: Specification with guidance for the validation and verification of greenhouse gas assertions, March, 2006, International Organization for Standardization, Switzerland.

again exceed 25,000 metric tons in any calendar year the provisions of WCI.8(a)(1) apply.

(3) Carbon dioxide emissions from the combustion of biomass fuels shall be included in the determination regarding verification applicability, with the following exceptions:

(A) Until such time as [the jurisdiction] has made a determination regarding the carbon neutrality of any biomass fuels, a maximum of 15,000 metric tons of carbon dioxide emissions from the combustion of pure solid biomass fuel may be excluded from calculation of GHG emissions for comparison to the 25,000 metric ton CO_2e per year verification threshold in paragraph (a) of this section.

(B) After such time as [the jurisdiction] has made a determination regarding the carbon neutrality of any biomass fuels, the carbon dioxide emissions from the combustion of those fuels may be excluded from calculation of GHG emissions for determining whether the 25,000 metric tons CO_2e per year verification threshold in paragraph (a)(1) of this section has been met.

[Under Design Recommendation 1.3, carbon neutral biomass will be excluded from the cap-and-trade program. A WCI Partner jurisdiction, however, may, in its discretion, choose to require carbon dioxide emissions from the combustion of biomass fuel to be included in the determination of the verification threshold in order to obtain a complete inventory of the fuels being combusted in the jurisdiction.]

(4) Owners or operators may exclude carbon dioxide emissions from the combustion of biomass fuels that [jurisdiction] has deemed carbon neutral from the scope of verification.

[A WCI Partner jurisdiction may, in its discretion, choose to require carbon dioxide emissions from the combustion of biomass fuel to be included in the scope of verification.]

(5) Notwithstanding WCI.8(a)(2) and (3), any facility, fuel supplier or electricity importer subject to a cap-and-trade program for CO_2e emissions established by [the jurisdiction] shall obtain verification of reported annual emissions.

(b) Requirements for Annual Verification of Emissions Data Reports.

(1) Verification bodies shall conduct verification processes and design verification procedures to determine whether there is a reasonable level of assurance for each separate emissions data report every year of the verification cycle. The verification team shall find that there is a reasonable level of assurance for an emissions data report if the report

(A) contains no material misstatement; and

(B) conforms to the requirements of this article.

(2) The verification body must provide verification services in compliance with WCI.8.

(3) Facility owners or operators, fuel suppliers, and electricity importers required to obtain annual verification shall be subject to full verification requirements in the first year that verification is required for an emissions data report. Upon completion of a positive verification statement under full verification requirements, the facility owner or operator, fuel supplier, or electricity importer may be eligible for two years of less

intensive verification services as ~~described~~ defined in section WCI.8(x)~~9~~. This cycle may be repeated in subsequent three-year cycles; however, full verification requirements shall apply at least once every three years.

(4) Facility owners or operators, fuel suppliers, and electricity importers required to obtain annual verification will be required to obtain full verification services if any of the following apply:

(A) There has been a change in the verification body from the previous year; or

(B) A verification body issued an adverse verification statement for that facility's previous year's emissions data report.

(c) Accreditation Requirements for Verification Bodies.

(1) The accreditation requirements specified in this subsection shall apply to all verification bodies that wish to provide verification services under this rule.

(2) A verification body is qualified to conduct verification services for the WCI if

(A) it has demonstrated knowledge of the WCI reporting requirements; and

(B) it is accredited to ISO 14065 through a program developed under ISO 17011 by an accreditation body that is a member of the International Accreditation Forum.

[Note the details of the WCI's specific accreditation process for verification bodies (which has yet to be developed) will be consistent with ISO 14065 through an accreditation program that will developed under ISO 17011 and will include demonstrated knowledge of the WCI reporting requirements. The WCI will explore additional accreditation requirements and/or other criteria for individual lead verifiers, general verifiers, and/or sector specialists.]

(3) Prior to January 1, 2013, accreditation by the California Air Resources Board under Title 17, California Code of Regulation, section 95132, may be substituted for the accreditation required under WCI.8(c)(2)(B).

(d) Requirements for Verification Services. The following verification services must be provided for each emissions data report.

(1) As part of the verification services, the verification team shall review documents submitted, assess risks of a material misstatement, develop a verification plan (that includes a sampling plan), evaluate the emissions data report against the verification requirements, and assess the materiality of errors, omissions and misstatements identified.

(2) The verification team shall request any information and documents needed for verification services. Such information shall include, but is not limited to original records and supporting data for the emissions data report.

(e) A verification team must include the following:

(1) a Lead Verifier;

(2) an Independent Peer Reviewer;

(3) any subcontractor elected to provide verification services under WCI.8(f).

(f) Subcontracting. The following requirements shall apply to any verification body that elects to subcontract verification services.

(1) The primary verification body must assume full legal responsibility for verification services performed by subcontracted verifiers or verification bodies.

(2) A verification body or verifier acting as a subcontractor to the primary verification body will not further subcontract that same work to another firm or individual.

(3) A verification body or verifier acting as a subcontractor is subject to all Conflict of Interest requirements in Section WCI.8(g).

(4) A verification body or verifier acting as a subcontractor must be identified by the primary verification body as part of the verification team.

(g) Conflict of Interest Requirements for Verification Bodies. The conflict of interest provisions of this section shall apply to the verification body, entities related to the verification body, and the verification team accredited according to the requirements of the WCI to perform verification services for the WCI program. Member for purposes of this section means any employee or subcontractor of the verification body or entities related to the verification body. Member also includes any individual with a majority equity share in the verification body or entities related to the verification body.

(1) Prior to a jurisdiction accepting a verification statement, and prior to a jurisdiction accepting the associated emissions report for consideration for approval, the AVA must determine that the verification body has a low potential for conflict of interest as described under WCI.8(g)(6). To inform this determination by the AVA, a self-evaluation of the potential for any conflict of interest that the verification body, entities related to the verification body, and members of the verification team, including subcontractors, may have with the owner or operator or their related entities for which verification services will be or have been provided shall be submitted to the AVA. This self-evaluation must include an evaluation of any threats to the verification body's independence including: [*note: a standardized Conflict of Interest Assessment form will be developed for the WCI*]

[To facilitate timely determinations of conflict-of-interest potential, and to reduce the risk of finding medium or high conflict-of-interest potential after verification services have been initiated, it is recommended that jurisdictions require that the self evaluations be submitted and evaluated by the AVA prior to the initiation of verification services. A jurisdiction may elect to allow verification services to commence prior to the determination of the conflict-of-interest potential by the AVA.]

(A) Threats created by the reporting operation offering inducements to the verification body, subcontractors or verification team members for a positive opinion;

(B) Threats created by members of the verification body, verification team members, subcontractors, or family of subcontractors or team members having a financial interest in the reporting operation or its operator;

(C) Threats created by members of the verification body reviewing work of the verification body, subcontractors, members of the verification team, or related companies, including but not limited to any situation where the body, subcontractors, team members or companies have provided services related to greenhouse gases;

(D) Threats created by members of the verification body, verification team members, or subcontractors having a close relationship with the reporting operation, such that they might become too sympathetic to the interests of the reporting operation; and

(E) Threats created by members of the verification body, verification team members, or subcontractors being deterred from acting objectively or exercising professional skepticism by threats, actual or perceived, from the reporting operation.

(2) The verification body shall deem the potential for conflict of interest to be low if

(A) No threats as listed in WCI.8(g)(1) exist, and

(B) Any non-verification services provided by the verification body to the owner or operator within the last three years are valued at less than five percent of the verification body's annual revenue in each of those years.

(3) The verification body shall deem the potential for conflict of interest to be high if threats as listed in WCI.8(g)(1)(A) or (E) exist.

[A jurisdiction may expand the list of high threats (i.e. un-mitigatable conflicts) with the items included in paragraph 2 of the Conflict of Interest section of Supplement 1 below.]

(4) The verification body shall deem the potential for a conflict of interest to be medium if the potential for a conflict of interest is not deemed to be either low or high as specified in sections WCI.8(g)(2)-(3).

(5) If a verification body deems the potential for conflict of interest to be medium and wishes to provide verification services for the owner or operator, then the verification body shall submit, in addition to the self-evaluation, a plan to avoid, neutralize, or mitigate the potential conflict of interest situation.

(6) Conflict of Interest Determinations. The AVA shall review the self-evaluation submitted by the verification body and determine the verification body's potential conflict of interest in performing verification services for the owner or operator.

[In addition to the AVA determination, a jurisdiction may elect to conduct audits of conflict of interest submissions for compliance verification and enforcement purposes.]

(A) The AVA shall notify the verification body in writing when the conflict of interest evaluation information submitted under section WCI.8(g)(1) is deemed complete. Within 45 days after deeming the evaluation information complete, the AVA shall determine the conflict-of-interest potential and shall notify the verification body or owner or operator if the potential conflict of interest is determined to be medium or high.

(B) If the AVA determines the verification body or any member of the verification team has any threats specified in section WCI.8(g)(1), the AVA shall find a high potential conflict of interest and verification services may not proceed.

(C) If the AVA determines that there is a low potential conflict of interest prior to the verification services being provided, verification services may proceed.

(D) If the AVA determines that the verification body and verification team have a medium potential for a conflict of interest, the AVA shall evaluate the conflict of interest mitigation plan and may request additional information from the applicant to complete the determination. In determining potential conflict of interest, the AVA may consider factors including, but not limited to, the nature of previous work performed, the current and past relationships between the verification body and its subcontractors with the owner or operator, and the cost of the verification services to be performed. The AVA will determine whether these factors when considered in combination with the mitigation plan demonstrate a low level of potential conflict of interest or a high level. If the AVA determines that there is a low potential conflict of interest prior to the verification services being initiated, verification services may proceed. If a high potential is determined prior to verification services being initiated, verification services may not proceed. If a high potential is determined after verification services have been initiated, the verification statement shall not be accepted..

(7) Monitoring Conflict of Interest Situations.

(A) After commencement of verification services, the verification body shall monitor and immediately make full disclosure in writing to the AVA regarding any potential for a conflict of interest situation that arises. This disclosure shall include a description of actions that the verification body has taken or proposes to take to avoid, neutralize, or mitigate the potential for a conflict of interest.

(B) The verification body shall monitor arrangements or relationships that may be present for a period of one year after the completion of verification services. During that period, within 30 calendar days of any change in arrangements or relationships with the owner or operator for which the verification body has provided verification services that may create a medium or high threat of conflict of interest, the verification body shall notify the AVA of the change and provide a description of the nature of the change. The AVA will make a conflict of interest determination under WCI.8(g)(6).

(C) The verification body shall report to the AVA any changes in its organizational structure, including mergers, acquisitions, or divestitures that may have created a medium or high threat of conflict of interest for one year after completion of verification services within 30 days and submit an evaluation of how the change(s) impacts the potential for conflict of interest.

(D) The AVA may invalidate a verification finding if a medium or high threat of a conflict of interest has arisen for the verification body or any member of the verification team and, in the case of a medium threat, the threat has not been adequately mitigated. In such a case, the owner or operator shall be provided 180 calendar days to have their emissions report verified by a different verification body.

(E) If the verification body or its subcontractor(s) are found to have violated the conflict of interest requirements of this section, the AVA may rescind its accreditation for any appropriate period of time . Additionally, the AVA may separately revoke its recognition of an accredited Verification Body under WCI.8(w). *[The WCI intends to develop more detailed accreditation requirements in the future.]*

(h) Notice of Verification Services. Prior to commencing verification services for a facility owner or operator, fuel supplier, and electricity importer, the verification body shall submit a notice of verification services to the AVA. Verification activities shall not proceed for 15 business days or until the verification body receives written approval to proceed from the AVA, whichever is earlier. If the AVA does not respond to the verification body within 15 business days, the verification body may begin to conduct verification activities.

[The NOVS form will be standardized across WCI and developed later.]

(i) Verification Plan.

(1) Accounting for requirements set by WCI.8, the verification plan shall document:

(A) the scope of the verification;

(B) the level of assurance;

(C) the verification standard;

(D) the verification criteria;

(E) the objectives of the verification;

(F) the timing of the verification, including site visits;

(G) the nature of the communications required;

(H) the resources required to conduct the verification, including the role of verification team members; and

(I) the nature, timing and extent of the verification procedures, including the sampling plan.

(2) The verification body shall retain the verification plan in paper, electronic, or other format for a period of not less than seven years following the submission of each verification statement.

(j) Site visits. In years for which full verification services are required under WCI.8(b)(3), at least one member of the verification team shall at a minimum make one onsite site visit to each facility or fuel supply location *[Note that exact location of fuel supplier site visits remains TBD]* for which an emissions data report is submitted. The verification team member(s) shall also conduct an onsite visit of the headquarters or other location of central data management, if different from the facility or fuel supply location, when the owner or operator is an electricity importer.

(k) Owners or operators shall make available to the verification team all information and documentation used to calculate and report emissions, electricity transactions, and other information required under this rule, as applicable.

(l) As applicable for electricity importers, the verification team shall review electricity transaction records, including receipts of power attributed to the Northwest or Southwest region as verifiable via North American Electric Reliability Corporation (NERC) E-Tags, settlements data, or other information as confirmation of the region of origin. [*Note that this procedure is subject to change pending WCI Electricity Committee review.*]

(m) Data Checks. To determine the reliability of the submitted emissions data report, the verification team shall use data checks as defined in WCI.~~9~~98(x). Verifiers will use their professional judgment in determining how many data checks are needed to provide a reasonable level of assurance.

(n) Emissions Data Report Modifications. If as a result of review by the verification team and prior to completion of a verification statement the owner or operator chooses to make improvements or corrections to the submitted emissions data report, a revised emissions data report must be submitted to [the jurisdiction] as specified by section WCI.8(q). The owner or operator shall maintain documentation to support any revisions made to the initial emissions data report. Documentation for all emissions data report submittals shall be retained by the operator for seven years pursuant to section ~~WCI.4~~ 98.3(g).

(o) Materiality and Conformance Assessment Criteria. The verifier shall determine if the annual emissions report is prepared in such a way that it satisfies WCI.8(b)(1).

(1) A verification team shall determine that an emission data report contains a material misstatement, if either of the following is true:

(A) Based on the verification team's own determination of the level of emissions subject to verification based on the sampling plan, the verification team concludes that total reported emissions are less than 95 percent accurate using the following equation:

$$PA = 100 - [(SOU/TRE) \cancel{*}\times 100)]$$

Where:

PA	=	Percent accuracy
SOU	=	The net result of summing overstatements and understatements resulting from errors, omissions and misreporting
TRE	=	Total reported emissions

(B) The individual or aggregate effect of one or more errors, omissions or misstatements identified in the course of verification make it probable that the judgment of a reasonable person regarding the total reported emissions would have been changed or influenced by the error, omission or misrepresentation.

(2) To assess conformance with this rule the verification team shall review the methods and factors used to develop the emissions data report for adherence to the requirements of this rule.

(3) The verification team shall keep a log of any issues identified in the course of verification activities that may affect determinations of material misstatement and nonconformance, and how those issues were resolved.

(p) Completion of verification services shall include:

(1) Verification Statement. Upon completion of the verification services required by WCI.8, the verification body shall prepare either a positive or adverse verification statement, for each emissions data report, based on its findings during the verification process. The verification body shall provide the verification statement(s) to the reporter and to the AVA [alternatively, this could be the reporter's responsibility to submit the statement to the AVA], according to the schedule specified in section WCI.2(b). Before each statement is completed, the verification body shall have the verification services and findings of the verification team independently reviewed and approved by an Independent Peer Reviewer.

~~Verification Statement. Upon completion of the verification services required by WCI.8, the verification body shall complete a verification statement for each emissions data report, and provide that statement to the owner or operator and [the jurisdiction or other body] according to the schedule specified in section WCI.2(b). Before that statement is completed, the verification body shall have the verification services and findings of the verification team independently reviewed and approved by an Independent Peer Reviewer.~~

~~The verification body shall provide either a positive or adverse verification statement to the reporter and to the AVA *[alternatively, this could be the reporter's responsibility to submit the statement to the AVA]* based on its findings during the verification process.~~

(2) The lead verifier in the verification team shall attest on the verification statement that the verification team has carried out all verification services as required by this rule, and the Independent Peer Reviewer shall attest to his or her independent review on behalf of the verification body and his or her concurrence with the verification findings. If the Independent Peer Reviewer does not determine that the verification team has carried out all verification services as required by the rule or if the Independent Peer Reviewer rejects the verification team's findings, then the verification body cannot issue a positive verification statement.

(3) The verification body shall provide to the owner or operator a detailed verification report. The verification report shall at minimum include the detailed comparison of the data checks with the submitted emissions data report, errors, omissions and misstatements identified during the course of the verification, any corrections made to the original annual emissions report as a result of the verification, and observations about the data management systems that are connected to the errors, omissions and misstatements identified, as well as any qualifying comments on findings during verification services. The detailed verification report shall be made available to [the jurisdiction] upon request.

(q) Prior to the verification body providing an adverse verification statement pursuant to WCI.8(p)(2), the owner or operator shall be provided at least 14 working days to modify the emissions data report to correct any material misstatement or nonconformance found by the verification team. The modified report and verification statement must be submitted to [the jurisdiction] before the applicable verification deadline, unless the operator makes a request to [the jurisidiction*]* as follows:

(1) If the owner or operator and the verification body cannot reach agreement on modifications to the emissions data report that result in a positive verification statement, the operator may petition the AVA to make a final decision as to the verifiability of the submitted emissions data report.

(2) If the AVA determines that the emissions data report does not meet the standards and requirements specified in this article, the owner or operator shall have the opportunity to submit within 60 calendar days of the date of this decision *[Note that this time frame may need to be changed pending details of cap-and-trade system design and needs.]* any emissions data report revisions that address the AVA's determination, for re-verification of the emissions data report. In re-verifying a revised emissions data report, the verification body and verification team shall be subject to the requirements in section WCI.8(q)-(s).

(3) Upon provision of the verification statement to [the jurisdiction], the emissions data report shall be considered final and no changes shall be made except as provided in section WCI.8(n) or (q). All verification requirements of this rule shall be considered complete upon provision of the verification statement.

(r) In addition to initiating WCI's dispute resolution process, the operator and verification body must inform the applicable accreditation body of the dispute.

(s) The AVA may make void the positive verification statement submitted by the verification body if:

(1) The AVA finds a high level of conflict of interest existed between a verification body and an owner or operator; or,

(2) An emissions data report that received a positive verification statement fails an audit by the AVA.

(t) Upon request by the AVA, the owner or operator shall provide the data used to generate an emissions data report, including all data available to a verification body. The AVA may also review the full verification report given by the verification body to the owner or operator. The full verification report shall be provided to the AVA upon request.

(u) Upon written notification by the AVA, the verification body shall make itself available for a verification services audit.

(v) Duration of verification services by one verification body. Facility owners or operators, fuel suppliers, or electricity importers subject to annual verification shall not use the same verification body for a period of more than six consecutive years. If a facility owner or operator, fuel supplier, or electricity importer is required or elects to contract with another verification body, they may contract verification services from the previous verification body only after not using the previous verification body for at least three years. If a verification body or verification team member has been providing verification services for an owner or operator in a greenhouse gas reporting or reductions program other than [the jurisdiction's] within the previous three years, those years of services will count towards the six consecutive year limit in this section.

(w) Revocation of Recognition. A jurisdiction may review, and for good cause, work to revoke or modify the accreditation status of a recognized verification body. If a recognized verification body is suspended in any other mandatory or voluntary GHG reporting or trading program, that verification body will not be allowed to provide any verification services until that suspension ends. If a recognized verification body has its accreditation revoked under any other mandatory or voluntary GHG reporting or trading program, that verification body will no longer be allowed to provide verification services under WCI.8 until it is reaccredited.

(x) Definitions. The following definitions shall apply to terms used in this section:

"Accreditation and Verification Authority" or "AVA" means [the jurisdiction] or any entity or entities to which [the jurisdiction] assigns any of the responsibilities for oversight and execution of the accreditation and verification program established in WCI.8.

"Adverse verification statement" means a verification statement rendered by a verification body stating that the verification body cannot conclude that there is a reasonable level of assurance for an emissions data report.

"Conflict of interest" means a situation in which, because of financial or other activities or relationships with other persons or organizations, a person or body is unable or potentially unable to render an impartial verification opinion of a potential client's greenhouse gas emissions, or the person or body's objectivity in performing verification services is or might be otherwise compromised.

"Data check" means an independent calculation or checking of data conducted by a verifier to recreate the emissions for a discreet source included in an emissions data report.

"Full verification" means all verification services as provided in section WCI.8(b).

"Less Intensive Verification" means the verification services provided in interim years between full verifications; less intensive verification only requires risk assessment and data checks on an owner or operator's emissions data report based on the most current sampling plan developed as part of the most current full verification services. This level of verification may only be used if the verifier can provide findings with a reasonable level of assurance.

"Material misstatement" means an error or omission, or a collection of errors or omissions, that results in a determination that a verification statement contains a material misstatement under WCI.8(o)(1)(A) or (B).

"Positive verification statement" means a verification statement rendered by a verification body stating that the verification body can say with reasonable assurance that the submitted emissions data report is free of material misstatement and that the emissions data report conforms to the requirements of this article.

"Verification" means a systematic, independent and documented process for the evaluation of an operator's emissions data report against the WCI's reporting procedures and methods for calculating and reporting GHG emissions.

"Verification body" means a firm accredited by the [Accreditation Body TBD] and recognized by the jurisdiction or its designee, that is able to render a verification statement and provide verification services for operators subject to reporting under this article.

“Verification cycle” means three years of verification activities. Each verification cycle must include at least one year of full verification, and may include two years of less intensive verification, if eligible.

“Verification statement” means the final written declaration rendered by a verification body attesting whether an operator’s emissions data report is free of material misstatement and whether the emissions data report conforms to the requirements of this article.

“Verification services” means services provided during verification as specified in WCI.8, including but not limited to reviewing an operator’s emissions data report, verifying its accuracy according to the standards specified in this article, assessing the operator’s compliance with this rule, and submitting a verification opinion to the *[jurisdiction or its agent]*.

“Verification team” means all of those working for a verification body, including all subcontractors, to provide verification services for an operator.

“Verifier” means an individual employed or contracted by an accredited verification body who has been deemed competent by the verification body to carry out verification services as specified in section WCI.8.

Verification Supplement 1

Note: the additional content in this Supplement must either be included in regulatory text in the appropriate subsections of WCI.8 or enforceable guidance documents by jurisdictions. The language in this section provides further explanation of items required in WCI.8 or alternative, more prescriptive language of those requirements.

Preliminary Activities and Verification Plan

The verification team shall discuss with the owner or operator the scope and objective of the verification services and obtain information from the owner or operator necessary to develop a verification plan. Such information shall include but is not limited to:

- Information to allow the verification team to develop a general understanding of facility or entity boundaries, operations, emissions sources, electricity transactions, as applicable;
- Information about the data management system used to track GHG emissions, electricity transactions, and other required measurement data as applicable;
- Information regarding the training or qualifications of personnel involved in developing the GHG emissions data report;
- Description of the specific methodologies used to quantify and report GHG emissions, electricity transactions, and other required data as applicable;
- Records of measured data related to emissions and operations for the prior and current period;
- Inventory of sources and their associated emissions for the reporting period, and
- Any prior verification reports, if applicable.

In developing the verification plan, the verifier shall:

- Gain an understanding of the organization and the process that emit greenhouse gases;
- Conduct a risk assessment to evaluate inherent, control and detection risk;
- Conduct preliminary analytical testing to identify anomalies in the data;
- Conduct a sensitivity analysis to assess the relative contribution of each source in the inventory to the reported annual emissions, and
- Consider any other relevant developments at the facility, in the regulations, or legal environment.

Sampling Plan

As part of the verification procedures, the verification team shall develop a sampling plan that, when combined with the other verification procedures, provides sufficient and appropriate evidence to allow the verifier to arrive at a conclusion. The sampling plan shall be designed to achieve the specified verification objective. The sample plan shall consider:

- Statistical versus non-statistical approaches
- Design of the sample, including the population characteristics
- Stratification (categorization of population into subgroups)
- Emission weighted selection
- Sample size

- Sample selection

As relevant information becomes available during the course of verification activities, the verification team must modify the sampling plan as necessary to address potential issues emerge of material misstatement or nonconformance with the requirements of this rule.

Data Checks

The verification team conducts data checks throughout the verification process and shall focus first on the largest and most uncertain estimates of emissions and electricity transactions.

- In establishing the verification plan, the verification team shall use professional judgment to determine the number of data checks required for the team to conclude with reasonable assurance whether the reported emissions and transactions are free of material misstatement and the emissions data report otherwise conforms to the requirements of this rule.
- The verification team shall choose emissions sources, and electricity transactions data as applicable, for data checks based on their relative sizes and risks of material misstatement as indicated in the verification plan;
- The verification team, through the conformance assessment, shall ensure that the appropriate methodologies and emission factors have been applied for the emissions sources and electricity transactions for sampled data covered under sections WCI.20 through WCI.XX;

Site Visits

During the site visit, the verification team member(s) shall conduct the following:

- Observe whether all sources at the site are represented in the emissions report as specified in sections WCI.20 to WCI.XX as applicable to the owner or operator.
- Assess whether the source inventory is identified, categorized, and reported appropriately. Collect evidence as to explanations for data anomalies identified in the verification plan.
- Understand the data trail used by the owner or operator to measure, quantify, and report greenhouse gas emissions and, when applicable, electricity transactions.
- Understand and evaluate the associated data controls used by the owner to ensure the completeness and accuracy of the data

Materiality Assessment

In assessing whether misstatements are material, the verification team shall determine whether the total reported emissions are at least 95 percent accurate using the following equation:

Percent accuracy = 100 **–** (sum of (errors, omissions, misreporting) * 100 / (total reported emissions))

To assess conformance with this rule the verification team shall review the methods and factors used to develop the emissions data report for adherence to the requirement of this rule. The verification team shall keep a record of any errors, omissions or misstatements identified in the course of verification activities that may affect determinations of material misstatement and nonconformance, and how those issues were resolved.

Conflict of Interest (*could replace more general procedural language in Section WCI.8*)

(1) Conflict of Interest Submittal Requirements for Accredited Verification Bodies.

(A) Before the start of any work related to providing verification services to an owner or operator, a verification body must first be authorized in writing by *the AVA* to provide verification services. To obtain authorization the verification body shall submit to *the AVA* a self-evaluation of the potential for any conflict of interest that the verification body, entities related to the verification body, and members of the verification team including, subcontractors may have with the owner or operator or their related entities for which it will perform verification services. For the purposes of this section, the term member refers to staff on the verification team, in the verification body and any subcontractors. The submittal shall include the following:

(i) Identification of whether the potential for conflict of interest is high, low, or medium based on factors specified in this section;

(ii) An organizational chart of the business structure of the verification body, including its related entities and brief description of the primary work done by the verification body and related entities;

(iii) iii. Identification of whether any member of the verification body, entities related to the verification body, or the verification team including subcontractors has previously provided verification services for the owner or operator or its related entities and, if so, the years in which such verification services were provided;

(iv) Identification of whether any member of the verification body, entities related to the verification body, or the verification team or including subcontractors has engaged in any non-verification services of any nature with the owner or operator or related entities either within or outside the WCI region during the previous three years. The verification body must also disclose any services listed under section (high COI list) it has provided to the owner or operator, regardless of when these services occurred. If non-verification services have previously been provided, the following information shall also be submitted:

(v) Identification of the nature and location of the work performed for the owner or operator and whether the work is similar to the type of work to be performed during verification, such as emissions inventory auditing, energy efficiency, renewable energy, or other work with implications for the operator's greenhouse gas emissions or the accounting of greenhouse gas emissions or electricity transactions;

(vi) The nature of past, present or future relationships the verification body, entities related to the verification body, and members of the verification team including subcontractors have with the owner or operator or related entity including:

- Instances when any member has performed or intends to perform work for the owner or operator;
- Identification of whether work is currently being performed for the owner or operator and, if so, the nature of the work;

- Whether any member has any contracts or other arrangements to perform work for the owner or operator or a related entity;
- Identify how much work was performed in each of the last three years, as a percentage of the verification body's total gross income for each of the last three years;
- Identify how much work related to greenhouse gases or electricity transactions was has performed for the owner or operator or related entities in each of the last three years, as a percentage of the verification body's income for each of the last three years;
- Identify how much work was performed by each subcontractor for the operator in each of the last three years, as a percentage of each subcontractor's total gross income for each of the last three years.

(vii) Explanation of how the amount and nature of work previously performed is such that any member of the verification team's credibility and lack of bias should not be under question.

(viii) A list of names of the verification team members that will perform verification services for the owner or operator and a description of any instances of personal or family relationships with management or employees of the owner or operator that potentially represent a conflict of interest; and,

(ix) Identification of any other circumstances or relevant information known to the verification body or owner or operator that could result in a conflict of interest, or any situation where the appearance of impartiality could undermine confidence in the verification body's ability to assess the reported emissions.

(2) The potential for a conflict of interest shall be deemed to be high where:

(A) The verification body and owner or operator share any management staff or board of directors membership, or any of the management staff of the owner or operator have been employed by the verification body, or vice versa, within the previous three years; or

(B) Within the previous three years, any member of the verification body, any entity related to the verification body, and the verification team has provided to the owner or operator any of the following non-verification services:

(i) Designing, developing, implementing, or maintaining an inventory or information or data management system for facility greenhouse gases, or, where applicable, electricity transactions;

(ii) Developing greenhouse gas emission factors or other greenhouse gas-related engineering analysis;

(iii) Designing energy efficiency, renewable power, or other projects which explicitly identify greenhouse gas reductions as a benefit;

(iv) Preparing or producing greenhouse gas-related manuals, handbooks, or procedures specifically for the reporting facility;

(v) Appraisal services of carbon or greenhouse gas liabilities or assets;

(vi) Brokering in, advising on, or assisting in any way in carbon or greenhouse gas-related markets;

(vii) Managing any health, environment or safety functions which explicitly identify greenhouse gas reductions as a benefit;

(viii) Bookkeeping or other services related to the accounting records or financial statements, unless those services limited to financial auditing;

(ix) Any service related to information systems, unless those systems will not be part of the verification process and excluding third-party auditor or registration services;

(x) Appraisal and valuation services, both tangible and intangible related to GHG emissions or reductions inventories;

(xi) Fairness opinions and contribution-in-kind reports in which the verification body has provided its opinion on the adequacy of consideration in a transaction, unless the resulting services shall not be part of the verification process;

(xii) Any actuarially oriented advisory service involving the determination of amounts recorded in financial statements and related accounts;

(xiii) Any internal audit service as provided under section (GHG plan) that has been outsourced by the operator that relates to the owner's or operator's internal accounting controls, financial systems or financial statements, unless no consulting or advice was provided as part of the audit;

(xiv) Acting as a broker-dealer (registered or unregistered), promoter or underwriter on behalf of the owner or operator;

(xv) Any legal services related to GHG emissions;

(xvi) Expert services to the owner or operator or his or her legal representative for the purpose of advocating his or her's interests in litigation or in a regulatory or administrative proceeding or investigation involving GHG emissions, unless providing factual testimony.

(C) The potential for a conflict of interest shall also be deemed to be high where any staff member of the verification body, entity related to the verification body, or the verification team has provided verification services for the owner or operator for six consecutive years or within three years of the termination of a previous GHG verification contract with the owner or operator. If a verification body or verification team member has been providing verification services for a [operator/owner] in a greenhouse gas reporting or reductions program other than WCI within the past three years, those years of services will count towards the six consecutive year limit in the WCI.

(D) The potential for a conflict of interest shall be deemed high where the Independent Peer Reviewer for the verification team has provided verification or non-verification services for the operator during the current reporting year.

(3) The potential for a conflict of interest shall be deemed to be low where no potential for a conflict of interest is found under section WCI.8(g) *[may need to be updated, depending upon final version of WCI.8)* and any non-verification services provided by all members of the verification body and the verification team to the owner or operator within the last three years are valued at less than five percent of the verification body's revenue.

****

WCI.8 OPTIONAL GUIDANCE

Note: This text is supporting material and not intended as part of the essential requirements.

Collection of Evidence

The verification body shall obtain sufficient and appropriate evidence to be able to draw reasonable conclusions on which to base the verification statement. The verification body obtains evidence by performing verification procedures. Verification procedures are classified as:

- **Computation (or Recalculation)** is the checking of mathematical accuracy of documents or records
- **Observation** of a process or procedure
- **Confirmation** is obtaining representations from a third party
- **Enquiry** is seeking information from a knowledgeable person
- **Inspection** of Records or Documents/Assets
- **Re-performance** is the verifiers independent execution of procedures or controls
- **Analysis** is the evaluation of information made by studying the plausible relationships among different types of data

Some or all of these techniques can be used to obtain sufficient and appropriate evidence. Site visits are used to obtain evidence that is readily available at that location.

June 2, 2010 Proposed Harmonization of Essential Requirements for Mandatory Reporting in U.S. Jurisdictions with EPA Mandatory Reporting Rule

List of Commenters

Canadian Steel Producers Association

George, Margaret

George-Zieser, Shalomi

Holly Corporation

Kloepper, John

Pacific Gas and Electric Company

Runyan, Kim

Smith, Beverley A.

Southern California Public Power Authority

Spectra Energy

Utah Business Climate Change Coalition

Western Climate Advocates Network

Western Climate Initiative

Notice regarding *Electricity Imports, Exports and Leakage in the Eastern WCI Partners: Quebec, Ontario and Manitoba*

The WCI Partners note that, as with any detailed modeling analysis, specific results depend on the assumptions and the characteristics of the model. In particular, as noted by Navigant, while the assumptions around generation represent one of many scenarios, they cannot and do not entirely reflect current reality or the actual future. For example, the model includes new natural gas power plants in Quebec, while Quebec has made clear it has no intention to build new natural gas power plants, as described in the Quebec 2006-2015 Energy Strategy and the Hydro-Quebec Strategic Development Plan. Also, again as noted by Navigant, the model uses fixed demand and generation assets, which in reality would change in response to a cap and trade program.

The results of the study should be taken as indicative of trends and impacts of cap and trade and specifically the potential for leakage in the electricity sector, and do not constitute a forecast of generation or demand for the Partner jurisdictions. The release of this study by the Partner jurisdictions does not represent an endorsement of the specific projections on generation, demand, or trade of electricity.

NAVIGANT
CONSULTING

Electricity Imports, Exports and Leakage in the Eastern WCI Partners: Quebec, Ontario and Manitoba

Prepared for:

Western Climate Initiative

Prepared by:

Navigant Consulting, Inc.
One Adelaide Street East
Suite 3000
Toronto, ON M5C 2V9

+1 647 288 5204
www.navigantconsulting.com

May 2010

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EXECUTIVE SUMMARY

This report summarizes the results of a study carried out by Navigant Consulting Inc. (NCI) on behalf of the Western Climate Initiative (WCI) from October 2009 – January 2010.

The intention of the study was to address the concern that reductions in fossil-fired generation within WCI Partner jurisdictions resulting from proposed WCI greenhouse gas regulation might be offset by increases in fossil-fired generation in non-WCI jurisdictions that would then be imported into WCI jurisdictions.

The study was designed to quantify the likely level of "leakage" – the ratio of emission increases in non-WCI jurisdictions to emission reductions in WCI Partner jurisdictions – at various levels of allowance costs and deemed emissions rates within the WCI. The study also considered the impact of other existing and proposed greenhouse gas regulations - RGGI (Regional Greenhouse Gas Initiative) and MGGRA (Midwestern Greenhouse Gas Reduction Accord) - to understand how these regulations could affect the potential for leakage.

The analysis required by the WCI was carried out by NCI using PROMOD IV, a commercial electricity market model, to simulate the hourly operation of the regions of the Canadian and US electricity system known as the 'Eastern Interconnect'. The Eastern Interconnect extends from eastern Canada to Florida to the U.S. Midwest and includes the three WCI partners – Manitoba, Ontario, Quebec – relevant for this study. The core of the study was a series of power system market simulations, for 2012 and 2020, with various levels of WCI allowance costs, import charges and regulatory assumptions for CO_2 emissions.

The starting point for the analysis was the definition of a 'Base Case' for 2012 and 2020 which represented a plausible evolution of the Eastern Interconnect – in terms of demand forecasts, fuel price assumptions, generation capacity, and environmental regulations – in the absence of WCI legislation.

Starting with this Base Case, a number of scenarios were defined to examine the effect on generation and emissions in the three Eastern WCI members – Manitoba, Ontario, Quebec – that might result as a consequence of imposing WCI CO_2 allowance charges, import ('First Jurisdictional Deliverer' or FJD) charges, and permitting "contract shuffling" (the ability to apply a zero 'import' charge to non-WCI generation that is sourced from non CO_2-emitting generation). In these scenarios, WCI CO_2 allowance prices ranged from $15 - $60/tonne, and import (FJD) charges were 500 kg/MWh or 1000 kg/MWh, which translated into $7.50 - $30/MWh[1] depending on the scenario. Some scenarios also considered the effect of additional

[1] The maximum FJD charge was $30/MWh, as the combination of $60/tonne CO_2 allowance charge and an FJD charge of 1000 kg/MWh was not in considered in any scenario.

greenhouse regulations, notably RGGI and MGGRA, in neighboring regions, and this involved defining allowance prices and FJD charges appropriate to those regions.

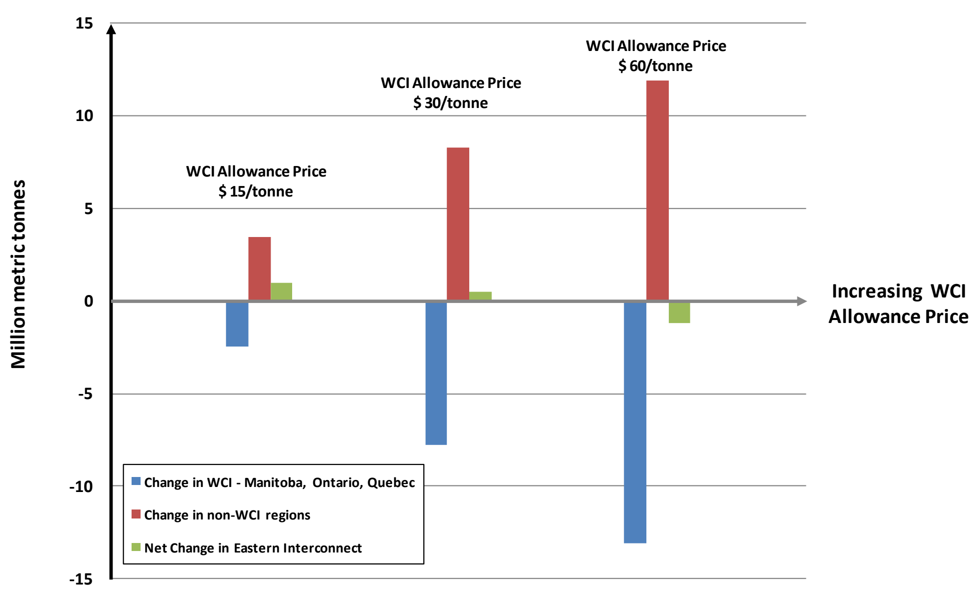
The modeling results showed a large (as much as 48%) decrease in the CO_2 emissions of the three WCI provinces as a result of introducing allowance prices. For scenarios with no corresponding regulation in MGGRA, the decrease in WCI emissions was offset by an increase in non-WCI emissions in every case, resulting in almost no net change in total emissions.

WCI emissions decrease because fossil generation (primarily from coal and gas plants in Ontario) falls when allowance prices are applied. This decrease in WCI generation leads to reduced exports from (or increased imports into) WCI. Non-WCI generation therefore needs to increase, and since only fossil generation has variable output, this means an increase in non-WCI fossil generation and CO_2 emissions. The small changes in total emissions that result are from replacing one type of generation (e.g., gas in Ontario) with another (e.g., coal in Ohio).

Import (FJD) charges reduce the attractiveness of importing power from non-WCI regions. The higher the FJD charge, the lower the imports into WCI, and the greater are the corresponding WCI generation and emissions. However, WCI generation and emissions are much less sensitive to the level of the FJD charge than they are to the WCI allowance price, and less sensitive to FJD charges in 2012 than in 2020.

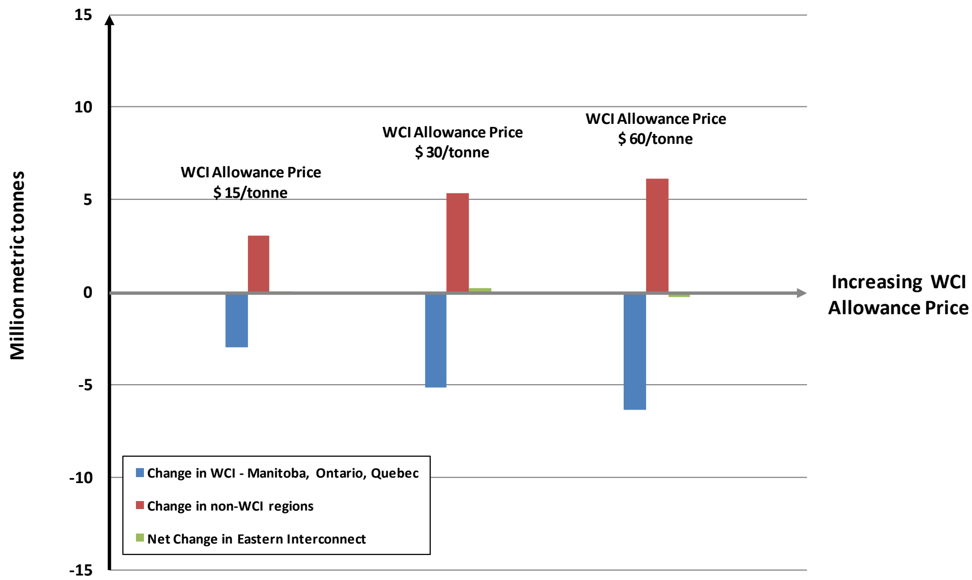
Figures ES-1 and ES-2 show the change in CO_2 emissions for 2012 and 2020 compared to the corresponding Base Case emissions. For clarity, the changes in CO_2 emissions indicated in these figures are averaged across the scenarios with the same WCI allowance prices but different FJD charges.

Figure ES-1: Changes in CO_2 Emissions in 2012 in Response to Allowance Costs



The results for 2020 and 2012 were similar, but the net changes in emissions in 2020 were generally lower across the scenarios. Much of the reduction in WCI emissions in 2012 comes from reductions in Ontario coal generation, as coal generation with a high carbon content is particularly affected by carbon charges. By 2020, all of Ontario's coal plants will have been shut down, making Ontario generation less sensitive to carbon charges.

Figure ES-2: Changes in CO_2 Emissions in 2020 in Response to Allowance Costs



Allowing "contract shuffling" led to a greater reduction in WCI generation and emissions, and a greater increase in non-WCI generation and emissions – i.e., more leakage. The scenarios with "contract shuffling" distinguished between imports from non CO_2-emitting sources and imports from CO_2-emitting sources, and applied a zero charge for imports from non CO_2-emitting sources. This reduced the impact of any given level of FJD charges compared to the simple scenarios where this distinction between imports from different sources was not made.

The scenarios that combined regulation in WCI with regulation in MGGRA and RGGI gave somewhat different results. Firstly, reductions in WCI generation and emissions were much smaller. This is because coordination of price allowances with RGGI and/or MGGRA reduces the incentive to import electricity from non-WCI jurisdictions (the main sources of these imports are RGGI and MGGRA).

The overall CO_2 emissions from the Eastern Interconnect were reduced when there was combined regulation across WCI, MGGRA and RGGI. This was because of a change in generation from coal to gas in MGGRA, and was not directly related to the WCI assumptions. It is a consequence of the effect of the additional allowance cost on the coal and gas MGGRA units.

NAVIGANT CONSULTING

This report for the Western Climate Initiative was prepared by staff from the Toronto and Washington D.C. offices of Navigant Consulting Inc. (NCI).

Navigant Consulting is a specialized independent consulting firm providing professional services to assist clients in identifying practical solutions to the challenges of uncertainty, risk and distress, and has over 1800 professionals in 30 cities.

The Energy Practice, hired by the WCI for this analysis, consists of more than 250 professionals and provides a full range of advisory services for energy sector clients, with particular expertise in clean energy, renewable generation and greenhouse gas issues.

The principal authors of the report were:

- Simon Carr, Director (Washington D.C.)
- Wesley Stevens, Associate Director (Toronto)
- Todd Williams, Director (Toronto)

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1. INTRODUCTION

1.1 Background

This report summarizes the results of a study carried out by Navigant Consulting on behalf of the Western Climate Initiative (WCI) from October 2009 – January 2010.

The intention of the study was to address the concern that reductions in fossil-fired generation within WCI Partner jurisdictions resulting from proposed WCI greenhouse gas regulation might be offset by increases in fossil-fired generation in non-WCI jurisdictions that would then be imported into WCI jurisdictions.

The study was designed to quantify the likely level of "leakage" – the ratio of emission increases in non-WCI jurisdictions to emission reductions in WCI Partner jurisdictions – at various levels of allowance costs and deemed emissions rates within the WCI.

The study also considered the possible impact of other existing and proposed greenhouse gas regulations[2], notably RGGI (Regional Greenhouse Gas Initiative) and MGGRA (Midwestern Greenhouse Gas Reduction Accord), to understand how the existence of other greenhouse gas regulations could affect the potential for leakage.

The study, and the associated modeling of Canadian and U.S. electricity markets carried out by Navigant Consulting, was focused on the WCI members in Eastern Canada – Manitoba, Ontario and Quebec.

The report is structured as follows:

- **Introduction**, covering the background and objectives of the study
- **Modeling Methodology for WCI Study**, describing the PROMOD IV software and the demand, fuel price, generation and other assumptions used in the analysis
- **WCI Scenarios without Contract Shuffling**, which covers scenarios that do not involve contract shuffling or the effects of RGGI and MGGRA CO_2 regulation
- **WCI Scenarios with Contract Shuffling**, which covers the scenarios that involve contract shuffling and/or the effects of RGGI and MGGRA CO_2 regulation
- **Conclusions,** which summarizes Navigant's conclusions from the analysis of the various scenarios

[2] WCI – http://www.westernclimateinitiative.org/
MGGRA - http://www.midwesternaccord.org/
RGGI - http://www.rggi.org/home

- **Appendices**, which contain tables with more detailed results than shown in the body of the report

1.2 Scope of the Study

The Scope of Work defined by WCI stated:

"Under the Western Climate Initiative (WCI) Cap and Trade program, generators that emit greenhouse gases (GHG) in the eastern WCI Partner jurisdictions will need to acquire allowances or offsets in order to produce electricity. The cost of carbon for these generators becomes an additional marginal cost of production and will generally be added to the offer price of fossil-fired units in that jurisdiction. As the market clearing price rises, non-WCI fossil-fired generators that are not subject to the same emissions measures and requirements in nearby interconnected power markets may well find their units becoming more competitive. To discourage substitution of more carbon-intensive imports from non-WCI markets for WCI generation (an increase in emissions in uncapped areas known as leakage), the WCI market design includes emissions from electricity imports in the emissions of the WCI partners and holds the "First Jurisdictional Deliverer" (FJD) responsible for the emissions associated with imported electricity.

Efforts to regulate the emissions associated with imported electricity require the attribution of emissions on either a specified basis, using the emission rate of specified power plants, or an unspecified basis, using a default emission rate. The integrity of emission attribution may be undermined by a reallocation of generation resources on paper for the purposes of reducing compliance obligations. Importers of electricity generated by GHG-emitting sources in uncapped areas can use such a reallocation (sometimes called contract shuffling) to reduce GHG compliance obligations either by reporting the source as "unspecified" when the default rate is lower than the true emission rate, or by reporting the power as having originated at specified zero- or low-GHG plants. The existence of the Regional Greenhouse Gas Initiative (RGGI) and possible implementation of the Midwestern Greenhouse Gas Reduction Accord (MGGRA) may reduce the potential for both leakage and contract shuffling.

Objectives:

The purpose of this study is to simulate the impact of the proposed WCI caps in the three Eastern WCI Partners on power imports and exports, to estimate the GHG emission content of the power imports, and to estimate the potentials for leakage and contract shuffling. Results for both 2012 and 2020 are expected. The study should:
Estimate the quantity of electricity imported from non-WCI jurisdictions and the emissions associated with those imports in a business-as-usual (BAU) scenario without WCI.

Quantify the leakage potential by modeling the imposition of pure source-based cap and trade in WCI, with no attempt to account for emissions of imports, taking into account current and projected transmission constraints, RGGI, and MGGRA."

1.3 Overview of Navigant Consulting's Approach

The analysis required by the WCI was carried out by NCI using PROMOD IV, a commercial electricity market model, to simulate the hourly operation of the regions of the Canadian and US electricity system that is known as the 'Eastern Interconnect'. The Eastern Interconnect extends from eastern Canada to Florida to the U.S. Midwest and includes the three WCI partners – Manitoba, Ontario, Quebec – relevant for this study.

The core of the study was a series of power system market simulations, for 2012 and 2020, with various levels of WCI allowance costs[3], import charges[4] and regulatory assumptions for CO_2 emissions.

The starting point for the analysis was the definition of a 'Base Case' for 2012 and 2020 which represented a plausible evolution of the Eastern Interconnect – in terms of demand forecasts, fuel price assumptions, generation capacity, and environmental regulations – in the absence of WCI legislation. The assumptions for this Base Case were reviewed with the Eastern WCI partners in advance of the PROMOD market simulations.

Starting with this Base Case, a number of scenarios were defined to examine the effect on generation and emissions in the three Eastern WCI members – Manitoba, Ontario, Quebec – that might result as a consequence of imposing WCI CO_2 allowance charges, import ('First Jurisdictional Deliverer' or FJD) charges, and permitting contract shuffling. Some scenarios also considered the effect of additional greenhouse regulations, notably RGGI and MGGRA, in neighboring regions. The scenarios examined in the course of the study are outlined in detail in Chapters 3 and 4.

The analysis of the scenarios focused on the "deltas" – the differences between emissions, generation, imports in these scenarios - from the corresponding emissions, generation, and imports in the Base Case.

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[3] The proposed WCI legislation would establish a 'cap and trade' system for CO_2 in the WCI jurisdictions. In modeling this with PROMOD, NCI assumed various levels of CO_2 allowance costs for emissions from CO_2-emitting plants in the WCI regions. This is analogous to modeling the CAIR SO_2 and NO_x regulation in PROMOD and is necessary because PROMOD (and similar models) do not usually simulate the emissions cap as such, except through the mechanism of allowance prices.

[4] Import charges are discussed in Chapter 2. Import charges are applied to electricity imports from non-WCI regions into WCI regions. In WCI terminology this is referred to as 'First Jurisdictional Deliverer' [FJD).

A key aspect of the analysis was that the definition of scenarios did not allow for changes in electricity demand, fuel prices, or the type of new generation that could result because of the imposition of allowance prices and import (FJD) charges:

- It is recognized that a significant part of the reduction in CO_2 emissions that would result from the introduction of WCI caps would probably come about through long-term changes in the generation mix or through price-induced conservation, rather than through short-term shifts in generation from existing and planned plants
- However, modeling such changes is very complex and it was agreed with the Eastern WCI partners that this was beyond the scope of the current project. In particular, the gas price was fixed for all scenarios, although in reality any CO_2 emission caps or cost allowances would change the demand for, and therefore the price of, natural gas

Power system simulation modeling can provide a great deal of insight into how WCI caps would affect electricity flows and generation in non-WCI jurisdictions, but it cannot capture all aspects. In particular, it is difficult for power system models to dynamically simulate contractual relationships that bypass the deemed emissions rates. PROMOD IV is capable of modeling specific detailed contracts, but it was agreed with WCI that this would not be feasible within the scope of this project.

In terms of PROMOD modeling, the commitment and dispatch of generation was based on minimizing the overall system cost, with plants 'bidding in 'at their marginal operating cost. The market modeling performed by PROMOD does not include any impacts on commitment and dispatch that would result from contractual arrangements, or from generators bidding into markets above or below marginal production cost.

The commitment and dispatch of generating plants does take into account the major transmission constraints that apply in the Eastern Interconnect, including those between WCI provinces and between the WCI provinces and the U.S.

1.4 Units

Unless otherwise indicated, in this report cost estimates are reported in real $US 2008. Emission allowance prices for WCI, MGGRA and RGGI are reported as $/tonne, i.e. metric units.

PROMOD uses imperial units – short tons – and the input data was adjusted were necessary to be consistent with the designated allowance costs in metric tons.

2. Modeling Methodology for WCI Study

2.1 PROMOD Software

PROMOD IV is a commercially-available software package[5] that simulates the hourly operation of electricity markets. It is widely used in the U.S. by a large number of utilities, energy consulting firms and ISOs including WECC, PJM and MISO.

PROMOD IV is typically used to forecast future electricity prices for various regions and unit revenues for various generators. It is often used to analyze the impact on prices of changes in the physical power system and changes in fuel prices.

PROMOD can also be used to study transmission planning and operations issues, including the effects of transmission line construction or enhancement, e.g., for siting studies.

PROMOD is supplied with three databases:

- WECC, the Western Electricity Coordinating Council, which covers the western U.S.
- ERCOT, the Electricity Reliability Council of Texas, which primarily covers Texas
- Eastern Interconnect, which is the electricity generation and transmission system that extends from Maine to Florida into the mid West. It includes Eastern Canada, ISO NE, NYISO, PJM, MISO markets and also regulated areas such as SPP, SERC and Florida in the southeastern U.S.

2.1.1 PROMOD IV Methodology

PROMOD IV is an optimization model that simulates the hourly operation of generation and transmission resources in market and non-market regions. For each hour, PROMOD commits and dispatches units in order of increasing generation cost until hourly demand is met, while taking into account unit operating constraints and transmission limits. The unit operating constraints represent system parameters such as planned and forced outages, unit minimum up and down times, ramp rates, and heat rate structures.

The transmission line limits and interface limits represent the operating restrictions that apply to the physical transmission system that links generators to demand.

PROMOD can be operated either as a zonal or a nodal model. As a nodal model, PROMOD contains a detailed representation of the transmission system in the form of a load flow and takes into account loss and congestion costs. As a nodal model, PROMOD can provide bus-

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[5] Developed by Ventyx http://www.ventyx.com/about.asp

specific prices rather than the average zonal prices provided by PROMOD when run as a zonal model.

PROMOD capabilities include:

- Detailed and flexible unit commitment and dispatch modeling
- Chronological hourly modeling of loads and resource operation
- Individual transmission line modeling and modeling of operational transmission constraints [nodal model]
- Loss modeling, including marginal loss calculations [nodal model]
- Calculation of security constrained dispatch schedules [nodal model]

2.1.2 Locational Marginal Pricing – Nodal Simulation

When run as a nodal model, PROMOD IV contains an explicit load flow representation of the transmission system. This means that PROMOD can calculate locational marginal prices (LMPs) at each bus. Pricing mechanisms based on nodal prices are used in the PJM, ISO NE, NYISO, MISO and CAISO markets, and will be implemented in ERCOT in late 2010.

The LMP at a bus represents the value of supplying the next MW of load at a specific location, assuming that the system is being dispatched economically. Where there is no congestion, the LMPs at each bus are identical and equal to the cost of the most expensive generator that has been dispatched.

However, where there is transmission congestion, LMPs at different buses will differ. This difference in LMP prices directly reflects congestion and the cost of losses across the grid.

In addition to bus prices, PROMOD can provide load- or generation-weighted average LMPs across a region; this is analogous to the zonal average prices reported in zonal simulations.

2.1.3 Loss Modeling in PROMOD – Nodal Simulation

PROMOD IV can be run with a number of loss options:

- No losses
- Marginal losses
- Single pass losses

'No losses' assumes that losses are incorporated in the demand forecasts. It effectively assumes average losses across the system.

‘Marginal losses’ approximates the AC quadratic loss function through an iterative procedure, starting from a demand forecast that does not include losses. This option is computationally intensive and can significantly increase the run time for a PROMOD simulation.

‘Single pass losses’ is a linearized approximation to the quadratic loss calculation that is computationally much less intensive. In single pass losses, the demand forecast includes losses, but PROMOD uses the characteristics of the transmission system to apportion losses across the system and calculate LMPs with loss and congestion components.

In Navigant’s experience, the single pass loss calculation is the most appropriate choice for the majority of PROMOD nodal analyses.

2.1.4 PROMOD Setup for WCI Analysis

For the WCI analysis, PROMOD IV was operated as a nodal model with single pass losses. Although the run time for a nodal simulation is far greater than the run time for a zonal simulation, the requirements of the WCI analysis meant that a nodal analysis was required in order to accommodate certain specific requirements of the WCI analysis - particularly import (FJD) charges from generation in non-WCI regions serving load in WCI regions.

2.1.5 PROMOD Data Requirements

PROMOD IV is a data intensive model, and the Eastern Interconnect includes over 5000 existing units.

To run a PROMOD simulation, the user must provide, for any year that is to be studied:

- Expected annual peak demand, annual energy demand for each geographical region – 146 load areas - in the model
- Monthly fuel prices – coal, gas, oil, renewables such as biomass – for each unit
- Monthly emission allowance prices for each environmental regulation that is applicable
- Details of all existing generation, with their operating characteristics such as summer/winter capacity, heat rate, variable operating cost, emission rates, start costs etc
- Details of planned new generation and the relevant operating characteristics
- Expected monthly generation from renewable sources such as hydro, wind, solar, geothermal, biomass
- For a nodal analysis, load flows representing the transmission system linking generators to demand
- Transmission limits on individual lines (nodal simulations), and interface limits between regions

In creating a Base Case simulation for the WCI analysis, Navigant Consulting extensively modified the original Ventyx - supplied Eastern Interconnect database to include details of new transmission lines, new generators, revised demand forecasts, different fuel prices, and the WCI/MGGRA/RGGI regulatory structure.

2.2 WCI Analysis Requirements in PROMOD

The scope of the WCI analysis, as outlined above in Chapter 1, implied that PROMOD modeling would need to take into account the following requirements for the scenarios:

- The ability to selectively apply CO_2 emission cost adders to specific thermal units, based on their inclusion in particular regulatory schemes – notably WCI, MGGRA and RGGI
- Applying 'import' (FJD) charges to power sourced from generation in non-WCI regions that is serving load in WCI regions
- To investigate contract shuffling, the ability to apply a zero 'import' charge to non-WCI generation that is sourced from non CO_2-emitting generation[6]
- The ability to track electricity imports and exports into the WCI provinces

These requirements, and specifically import charges, required that PROMOD be operated as a nodal model. The only method of applying 'import' charges in PROMOD is through the PROMOD mechanism of 'pool-to-pool' charges, which is only available in PROMOD nodal modeling.

2.2.1 Simulation Years

The WCI analyses were conducted for two years, 2012 and 2020. For each year, PROMOD simulated the Eastern Interconnect for each hour in the year.

2.2.2 CO_2 Regulation and Emission Costs

Assigning particular units to regulatory groups, and applying emission costs to the units in those groups, is straightforward in PROMOD IV. This involves:

- Defining for the appropriate units an emission rate (by month) for the pollutant – for this analysis, CO_2
- Defining a monthly allowance price for CO_2 for the relevant regulation

[6] Contract shuffling presumes that (conceptually) the non CO_2-emitting generation in non-WCI regions is serving WCI load, and that the CO_2-emitting generation in non-WCI regions is serving non-WCI load. With that conceptual assignment, there is no import charge on power sourced from the non CO_2-emitting plants even though they are outside WCI regions

In the WCI analysis, the CO_2 regulations of interest were those proposed or implemented by WCI, MGGRA and RGGI. In PROMOD, CO_2-emitting units in the appropriate geographical areas were assigned to the appropriate regulation, and CO_2 allowance price series for WCI, MGGRA and RGGI were defined according to the individual scenario assumptions.

The criteria used to classify CO_2-emitting units as exempt or non-exempt in terms of the appropriate CO_2 regulation are listed in Table 1.

Table 1: CO_2 Regulations in WCI Analysis

Greenhouse Gas Regulation	Location of Generating Units	Criteria for Inclusion in Regulation	Notes
Eastern WCI[7]	Quebec Ontario Manitoba	Units/plants emitting more than 25,000 tons of CO_2 annually	Biomass units exempt
MGGRA	Iowa Illinois Kansas Manitoba Michigan Minnesota Wisconsin	Units producing more than 25,000 tons of CO_2 annually, and CO_2-emitting units >25 MW in size	Biomass units exempt To simplify modeling, units in Kansas were not included in MGGRA as they do not border the WCI provinces and FJD charges would not apply
RGGI	Connecticut Delaware Maine Maryland Massachusetts New Hampshire New Jersey New York Rhode Island Vermont	CO_2-emitting units > 25 MW in size	Biomass units exempt

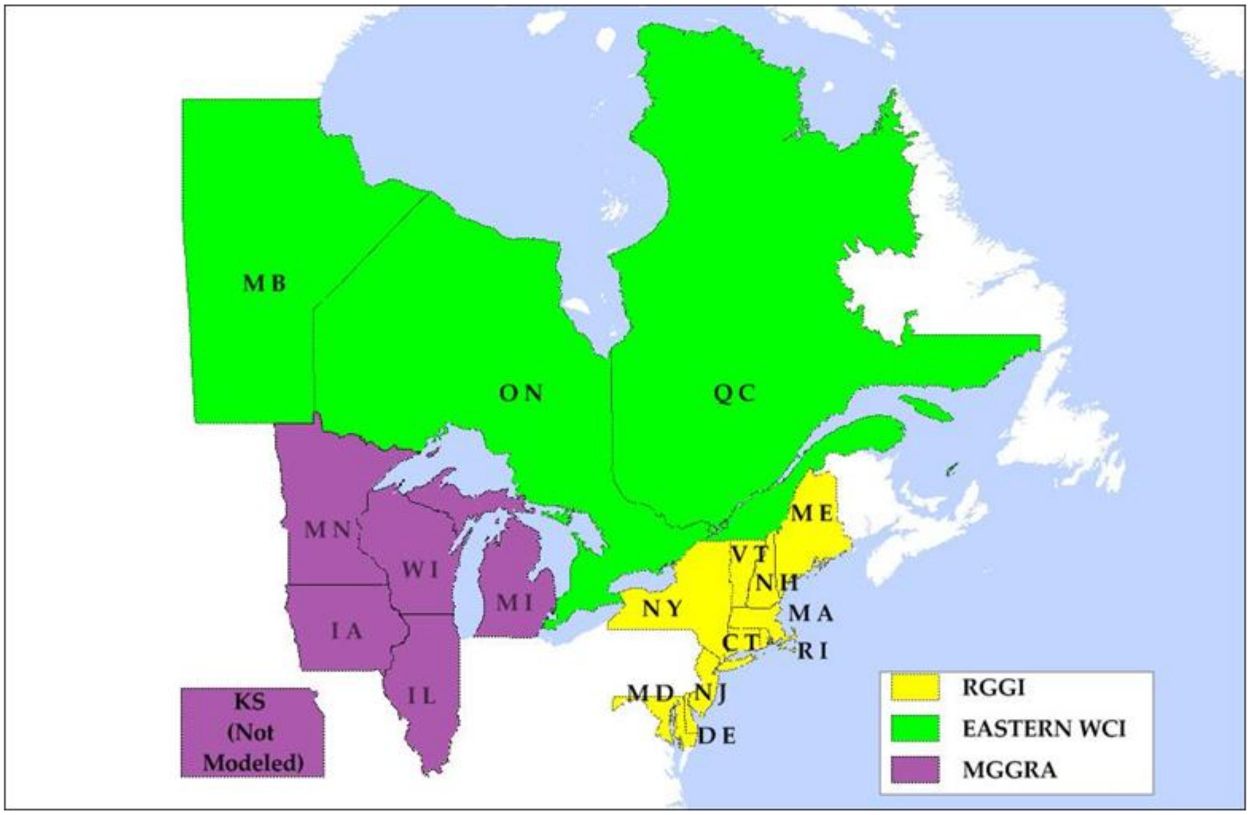
CO_2-emitting units in other regions – such as SERC, SPP, Florida – were not linked to any carbon regulation, because the WCI Base Case assumed no national U.S. carbon regulation.

[7] Western WCI members – not relevant for this study – are Arizona, British Columbia, California, Montana, New Mexico, Oregon, Utah, Washington

The CO_2 emission costs associated with RGGI, WCI or MGGRA regulation are additional to the SO_2 or NO_X emission costs associated with the CAIR SO_2 and NO_X regulations.

Figure 1 indicates the relationship between WCI, MGGRA and RGGI member province/states.

Figure 1: Eastern Interconnect Regions Surrounding WCI Footprint



2.2.3 Import (FJD) Charges in PROMOD

In the WCI analysis, import (FJD) charges are defined in terms of the assumed carbon intensity of the imports. In PROMOD, this is translated into an incremental[8] pool-to-pool tariff as shown in Table 2.

[8] The WCI Base Case has non-zero tariffs between pools in the Eastern Interconnect. These tariffs are defined in ISO schedules, based on FERC Order 888 - Open Access Transmission Tariffs. Typical tariffs are ~ $1-6/MWh, and thus much smaller than the import tariffs considered for the WCI scenarios, which are up to $60/MWh

For imports into the WCI region, the pool-to-pool tariffs were modified between the appropriate combinations of:

- Non-WCI regions: Saskatchewan and the Maritime provinces, ISO NE, NYISO, MGGRA, MRO
- WCI provinces: Manitoba, Ontario, Quebec

For the more complex scenarios, where WCI and MGGRA were considered under a common regulatory framework, the same principles were applied. In that case, there were no import charges between MGGRA and the WCI provinces, but there were import charges into MGGRA from MISO, MRO, and SPP.

Table 2: FJD Import Charges - Incremental Pool-to-Pool Transmission Tariff

FJD Charge	WCI CO_2 Allowance Price *$/tonne*	Incremental Transmission Tariff - Applied to Imports *$/MWh*
500 kg/MWh	0	0
	15	7.5
	30	15
	60	30
1000 kg/MWh	0	0
	15	15
	30	30
	60	60

Note

1 Allowance price and transmission tariff are $US real 2008

As regards RGGI, for scenarios where the WCI allowance prices and RGGI prices were not aligned (i.e., RGGI = $2.06/tonne), FJD charges were applied. For the scenarios where the WCI allowance price and the RGGI allowance prices were aligned, we presumed there would be no FJD charges.

Pool-to-pool tariffs are defined in PROMOD in both directions. So, for example, in a scenario where FJD charges are to be applied for imports into WCI provinces, the pool-to-pool tariffs from ISO NE into Quebec were increased according to the above table, but the pool-to-pool tariffs from Quebec to ISO NE were left unchanged. Similarly, the tariffs from NYISO into Quebec and Ontario were increased and those from Quebec and Ontario to NYISO were left unchanged.

FJD charges have to be implemented in terms of the import of electricity from non-WCI regions to WCI regions. They cannot be represented by increasing the cost of the generation as this also affects the cost of that unit as seen from non-WCI regions.

2.2.4 Contract Shuffling

Under WCI rules, non-fossil generation outside WCI can be exempt from import (FJD) charges if it is specified as no- or low-carbon. This can lead to "contract shuffling", as non-fossil generation is deemed to serve WCI load and fossil generation is deemed to serve local (non-WCI) load, with no change in total generation, fossil generation, flows, or emissions.

WCI rules regarding renewable attributes have not been finalized. For this analysis, it was assumed that renewables can "double-dip":

- Sell renewable attributes to U.S. states – count toward meeting Renewable Portfolio Standards AND
- Sell electricity to WCI provinces exempt from FJD charges

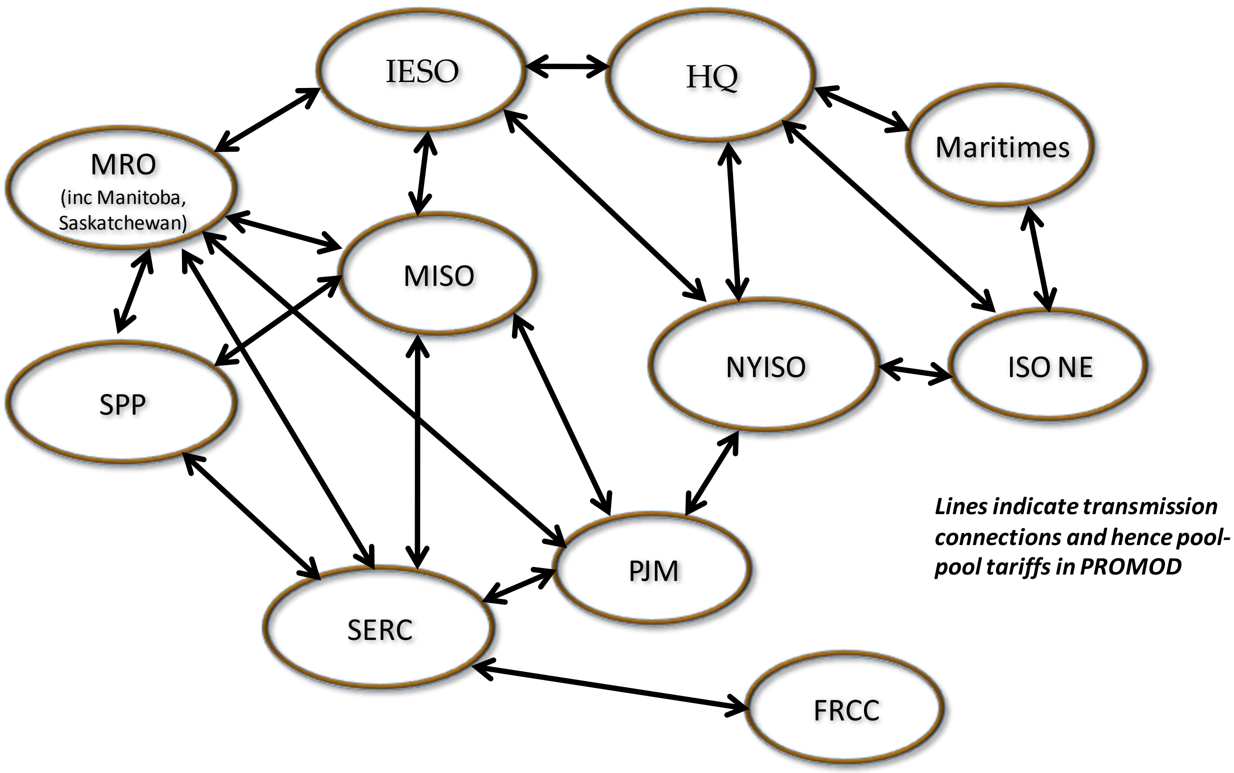
The impact of contract shuffling would be slightly less if renewable generation cannot double-dip, because most wind (but not nuclear or hydro) is tied to Renewable Portfolio Standards.

In PROMOD, in a region this can be represented by separating out the non-CO_2-emitting generation from the CO_2-emitting generation and placing this in a separate 'other' (non-fossil) pool, with a zero incremental transmission tariff for the pool with the non-CO_2-emitting generation. This requires a more complex pool structure which is described in Section 2.3.

2.3 Eastern Interconnect Pool Structure

The Eastern Interconnect Pool Structure, as usually represented, is shown in Figure 2. For the WCI analysis, this pool structure was modified to permit FJD charges and to allow contract shuffling.

Figure 2: Default Pool Representation in Eastern Interconnect



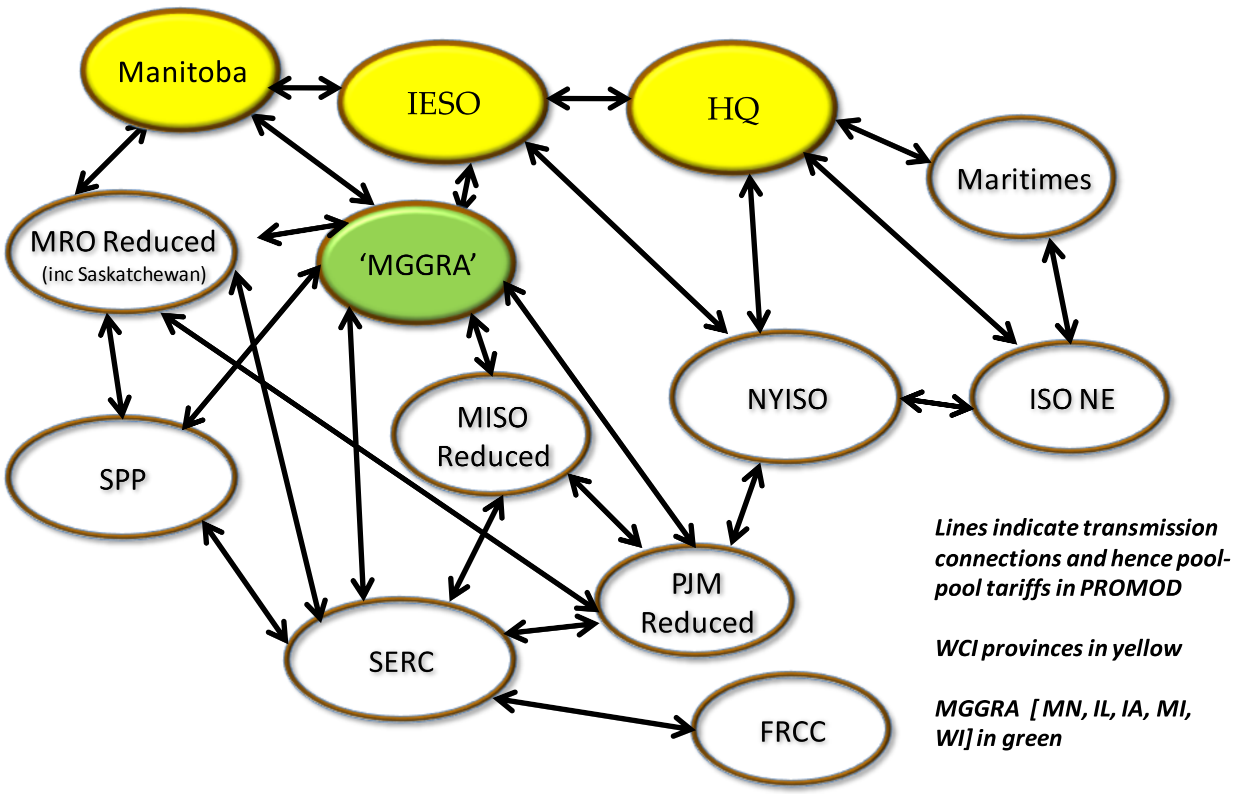
The changes to the pool structure for the WCI analysis were made in two steps.

For the 'simple scenarios' which did not involve contract shuffling, the existing pool structure in PROMOD was rearranged as shown in Figure 3.

- Manitoba was separated out from MRO
- Units in PJM, MISO and MRO that were located in Wisconsin, Minnesota, Michigan, Iowa and Illinois were removed from those pools and assigned to a new 'MGGRA'[9] pool

[9] For modeling simplicity, Kansas was not included as it is not geographically contiguous to the other MGGRA states. Also, Manitoba is in both MGGRA and WCI but was located in WCI for this study.

Figure 3: Modified Pool Representation in Eastern Interconnect - 'Simple' Scenarios



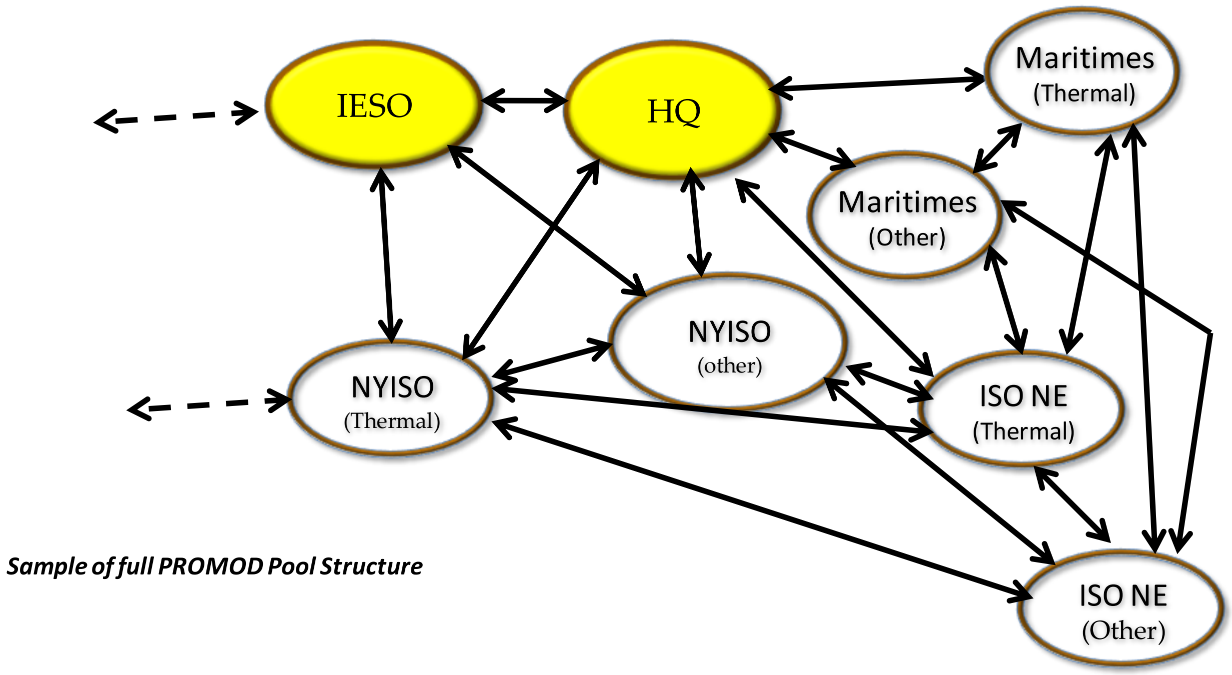
For the more complex scenarios, which involved contract shuffling, further modifications were needed, as shown in Figure 4, to allow import tariffs to apply only to power imported from non-WCI regions that was generated by CO_2-emitting units.

This was achieved by splitting each non-WCI pool – and MGGRA for some analyses – into a 'Fossil 'pool and an 'Other' pool. Thermal (except nuclear) units were located in the 'Fossil' pool, remaining units in the 'Other' pool. This is a conceptual split that does not affect the load distribution, physical location of plants, or transmission; there are minor effects on commitment and dispatch of units.

Splitting each non-WCI pool allows the incremental pool-to-pool tariff for a 'Fossil' pool to a WCI province to be set at the level appropriate for the scenario, and the incremental tariff for the corresponding 'Other' pool to be zero. This mimics contract shuffling in that particular non-CO_2 emitting renewable resources in non WCI regions are meeting WCI load, with no import charge.

This construction is only necessary for non-WCI pools that are contiguous to the WCI provinces, and similarly for the scenarios with consistent WCI-MGGRA CO_2 regulation.

Figure 4: Modified Pool Representation in Eastern Interconnect - 'Complex' Scenarios



The PROMOD modifications necessary to handle contract shuffling have a very significant effect on the simulation time, and this limited the number of complex scenarios that could be examined.

2.4 WCI Base Case Assumptions

The following sections summarize the key assumptions used in the WCI Base Case analysis. For the various WCI scenarios derived from the Base Case, fuel prices, demand forecasts and generation were unchanged in all scenarios.

WCI, RGGI and MGGRA CO_2 allowance prices and import (FJD) charges varied depending on the particular scenario, and these are described in Chapters 3 and 4.

2.4.1 WCI Demand Forecasts

Tables 3 - 4 summarize the 2010 – 2020 demand forecasts used for the WCI provinces in this study.

Table 3: Annual Peak Demand - Eastern WCI Provinces

Year	Manitoba *MW*	Quebec *MW*	Ontario *MW*
2010	4,487	36,547	23,779
2011	4,607	37,042	23,589
2012	4,715	37,402	23,426
2013	4,807	38,229	23,390
2014	4,852	38,574	23,342
2015	4,896	38,916	23,316
2016	4,941	39,218	23,250
2017	4,977	39,537	23,503
2018	5,030	40,087	23,604
2019	5,090	40,644	23,759
2020	5,150	41,209	23,781

Table 4: Annual Energy Demand - Eastern WCI Provinces

Year	Manitoba *GWh*	Quebec *GWh*	Ontario *GWh*
2010	24,937	186,923	143,634
2011	25,713	189,341	142,172
2012	26,362	193,894	141,814
2013	26,922	196,967	141,272
2014	27,241	198,806	140,642
2015	27,531	200,777	140,116
2016	27,827	203,163	140,769
2017	28,078	204,132	141,732
2018	28,418	206,663	142,718
2019	28,757	209,226	143,727
2020	29,095	211,820	144,760

2.4.2 WCI Fuel Prices

Tables 5 - 8 and Figures 5 – 6 summarize the 2010 – 2020 price forecasts for gas and oil for used for Eastern Canada in the WCI study. These forecasts are based on NCI's Fall 2009 fuel price forecast.

Table 5: WCI Analysis Gas Price Forecast – Henry Hub

Year	Henry Hub - NCI Monthly Gas Price Forecast ($US 2008 Real/mmBtu)											
	Jan	*Feb*	*Mar*	*Apr*	*May*	*Jun*	*Jul*	*Aug*	*Sep*	*Oct*	*Nov*	*Dec*
2010	5.06	5.12	5.11	5.11	5.17	5.31	5.42	5.51	5.58	5.72	6.16	6.56
2011	6.77	6.77	6.59	6.11	6.07	6.15	6.23	6.30	6.32	6.25	6.31	6.40
2012	6.38	6.20	5.92	5.46	5.37	5.32	5.26	5.19	5.11	5.18	5.27	5.50
2013	5.57	5.61	5.44	5.28	5.34	5.38	5.42	5.46	5.50	5.55	5.68	5.89
2014	5.95	6.00	5.84	5.68	5.75	5.80	5.84	5.88	5.92	5.98	6.15	6.33
2015	6.39	6.42	6.23	6.08	6.15	6.20	6.24	6.28	6.33	6.38	6.57	6.71
2016	6.77	6.80	6.75	6.60	6.66	6.71	6.76	6.80	6.85	6.97	7.17	7.35
2017	7.43	7.47	7.25	7.06	7.12	7.17	7.22	7.26	7.32	7.38	7.59	7.75
2018	7.82	7.87	7.44	7.24	7.29	7.34	7.39	7.44	7.49	7.55	7.79	7.93
2019	8.00	8.05	7.63	7.47	7.54	7.59	7.64	7.70	7.75	7.81	8.08	8.18
2020	8.25	8.23	8.08	7.95	8.03	8.09	8.15	8.20	8.25	8.31	8.56	8.74

Table 6: WCI Analysis Gas Price Forecast – Dawn Hub

Year	Dawn, Ontario - NCI Monthly Gas Price Forecast ($US 2008 Real/mmBtu)											
	Jan	*Feb*	*Mar*	*Apr*	*May*	*Jun*	*Jul*	*Aug*	*Sep*	*Oct*	*Nov*	*Dec*
2010	5.41	5.47	5.46	5.51	5.56	5.65	5.74	5.83	5.91	6.07	6.68	6.97
2011	7.18	7.18	6.99	6.54	6.45	6.51	6.56	6.62	6.66	6.59	6.81	6.80
2012	6.76	6.56	6.25	5.80	5.67	5.59	5.51	5.42	5.35	5.42	5.64	5.76
2013	5.83	5.88	5.72	5.58	5.60	5.64	5.66	5.70	5.74	5.80	6.07	6.16
2014	6.24	6.29	6.14	6.00	6.01	6.05	6.08	6.11	6.17	6.24	6.54	6.62
2015	6.67	6.72	6.55	6.42	6.42	6.45	6.47	6.51	6.56	6.62	6.95	7.02
2016	7.07	7.10	7.07	6.94	6.93	6.97	6.99	7.03	7.09	7.24	7.57	7.67
2017	7.72	7.78	7.60	7.42	7.40	7.45	7.47	7.51	7.57	7.64	7.99	8.09
2018	8.14	8.18	7.80	7.60	7.57	7.62	7.64	7.68	7.75	7.81	8.18	8.26
2019	8.32	8.36	7.99	7.84	7.81	7.85	7.88	7.93	8.00	8.05	8.44	8.51
2020	8.57	8.48	8.45	8.31	8.29	8.33	8.37	8.42	8.49	8.55	8.95	9.05

Figure 5: WCI Analysis - Monthly Gas Price Forecast

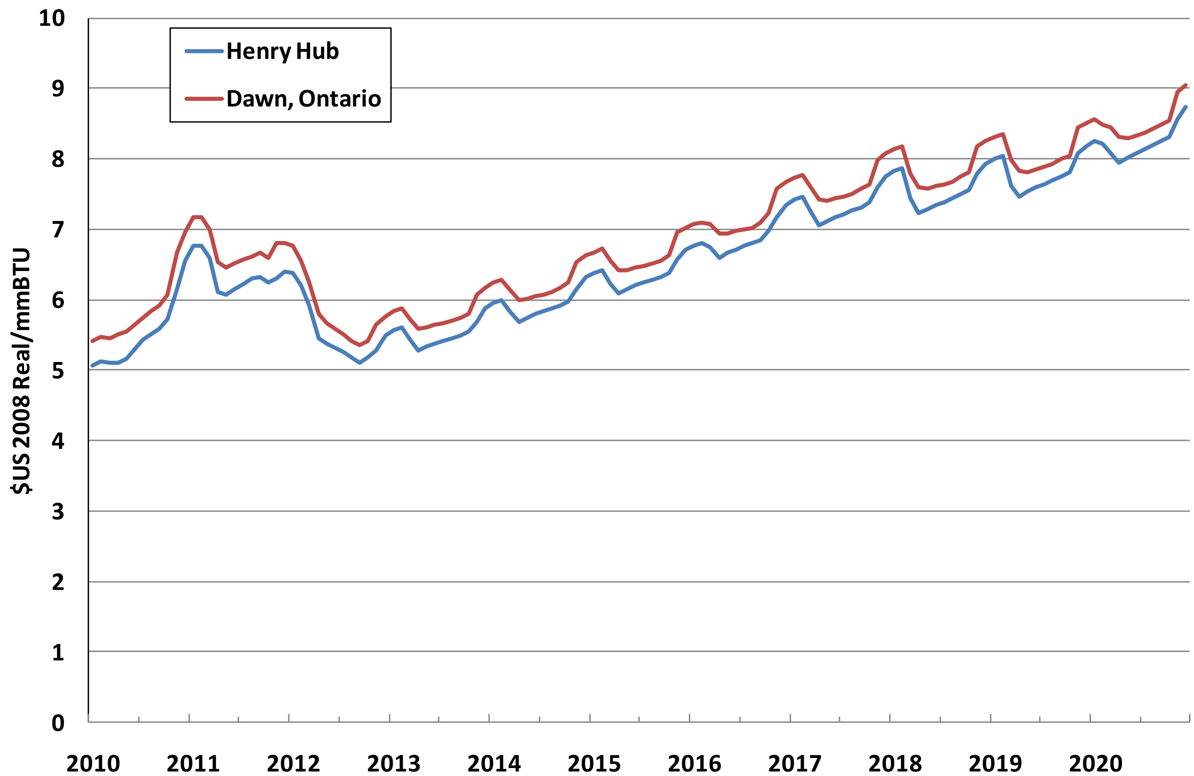


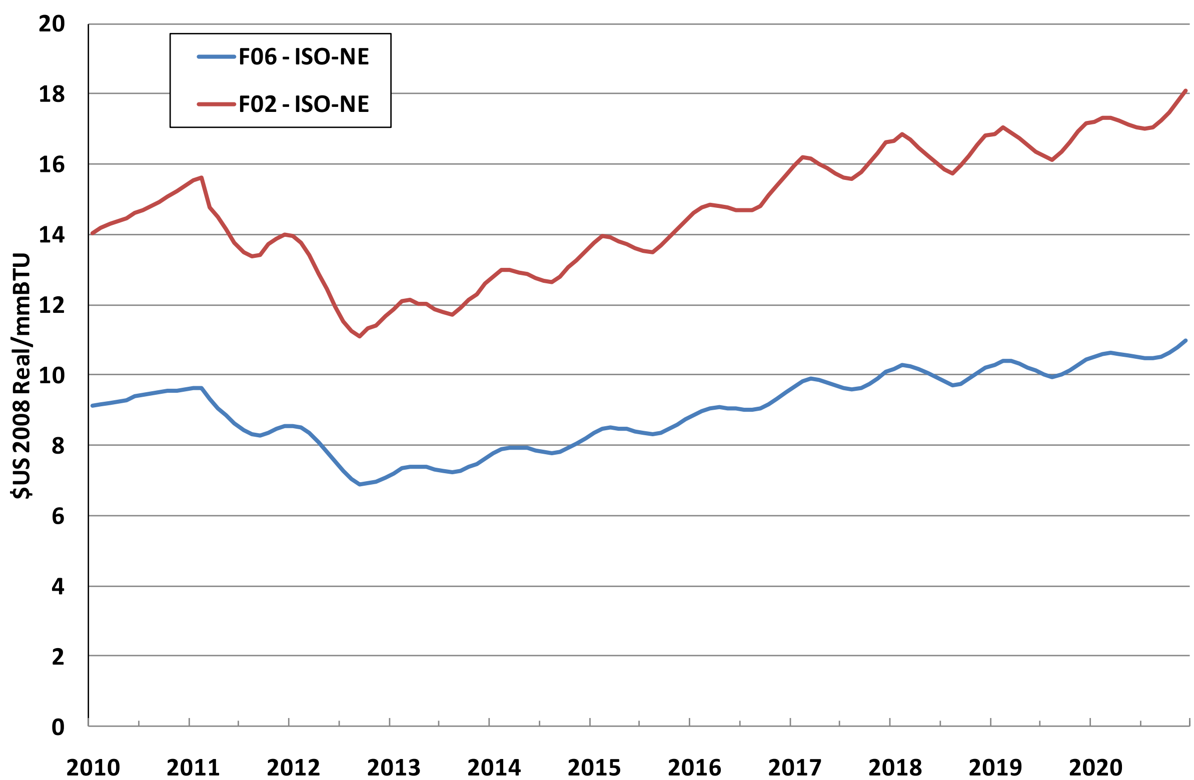
Table 7: WCI Analysis Oil Price Forecast – Fuel Oil

Year	FO6 - ISO NE - NCI Monthly Oil Price Forecast ($US 2008 Real/mmBtu)											
	Jan	*Feb*	*Mar*	*Apr*	*May*	*Jun*	*Jul*	*Aug*	*Sep*	*Oct*	*Nov*	*Dec*
2010	9.12	9.15	9.19	9.24	9.28	9.39	9.44	9.47	9.50	9.53	9.57	9.60
2011	9.62	9.63	9.30	9.07	8.84	8.62	8.42	8.30	8.26	8.36	8.45	8.53
2012	8.56	8.50	8.35	8.09	7.83	7.54	7.27	7.05	6.90	6.93	6.97	7.08
2013	7.20	7.33	7.40	7.39	7.38	7.32	7.27	7.23	7.27	7.37	7.47	7.62
2014	7.76	7.89	7.94	7.92	7.91	7.86	7.81	7.78	7.82	7.93	8.05	8.20
2015	8.34	8.47	8.50	8.48	8.45	8.39	8.34	8.30	8.35	8.46	8.59	8.73
2016	8.86	8.98	9.06	9.08	9.06	9.04	9.02	9.02	9.05	9.18	9.33	9.51
2017	9.68	9.83	9.88	9.84	9.78	9.70	9.64	9.59	9.64	9.76	9.91	10.07
2018	10.16	10.27	10.26	10.17	10.05	9.93	9.82	9.72	9.76	9.88	10.04	10.20
2019	10.28	10.39	10.38	10.32	10.22	10.11	10.02	9.94	10.00	10.11	10.28	10.43
2020	10.51	10.59	10.61	10.60	10.54	10.50	10.46	10.46	10.53	10.64	10.80	10.97

Table 8: WCI Analysis Oil Price Forecast – Distillate

Year	FO2 - ISO NE - NCI Monthly Oil Price Forecast ($US 2008 Real/mmBtu)											
	Jan	*Feb*	*Mar*	*Apr*	*May*	*Jun*	*Jul*	*Aug*	*Sep*	*Oct*	*Nov*	*Dec*
2010	14.03	14.19	14.30	14.37	14.45	14.61	14.71	14.81	14.93	15.08	15.24	15.39
2011	15.54	15.61	14.78	14.49	14.15	13.78	13.50	13.38	13.41	13.74	13.89	13.99
2012	13.98	13.78	13.43	12.88	12.44	11.96	11.53	11.24	11.08	11.33	11.42	11.67
2013	11.87	12.10	12.15	12.04	12.03	11.87	11.79	11.73	11.90	12.14	12.31	12.60
2014	12.81	13.01	12.99	12.90	12.88	12.75	12.69	12.64	12.81	13.06	13.27	13.55
2015	13.76	13.95	13.91	13.80	13.74	13.60	13.53	13.49	13.68	13.92	14.15	14.40
2016	14.60	14.78	14.87	14.81	14.76	14.70	14.69	14.70	14.80	15.11	15.39	15.71
2017	15.97	16.20	16.17	15.99	15.88	15.72	15.63	15.56	15.77	16.05	16.33	16.61
2018	16.66	16.87	16.70	16.47	16.25	16.04	15.87	15.72	15.96	16.25	16.55	16.81
2019	16.85	17.07	16.91	16.73	16.53	16.36	16.23	16.11	16.36	16.62	16.94	17.18
2020	17.21	17.34	17.33	17.26	17.12	17.05	17.01	17.05	17.24	17.48	17.77	18.08

Figure 6: WCI Analysis - Monthly Oil Price Forecast



2.4.3 WCI Allowance Prices

In the WCI Base Case, the following environmental regulations[10] were assumed to be in place for units in the Eastern Interconnect:

- CAIR SO_2 and CAIR NO_X, both annual and seasonal
- RGGI CO_2
- The Base Case assumed no national U.S. carbon legislation
- The Base Case (and all other scenarios) assumed no national U.S. mercury legislation to replace CAMR

The allowance price values for CAIR SO_2 and NO_X reflect Ventyx - supplied PROMOD data, and the RGGI allowance prices are based on the September 2009 auction results.

Table 9: WCI Base Case Allowance Price Forecast

Year	CAIR SO_2 $/tonne[2,3]	CAIR Annual NO_X $/tonne[2,3]	CAIR Seasonal[1] NO_X $/tonne[2,3]	CAMR Hg $/tonne[2,3]	RGGI CO_2 $/tonne[2,3]	US National CO_2 $/tonne[2,3]
2010	79	661	165	0	2.29	0
2011	422	1,021	504	0	2.18	0
2012	764	1,380	843	0	2.06	0
2013	798	1,099	827	0	2.06	0
2014	854	789	812	0	2.06	0
2015	841	721	822	0	2.06	0
2016	780	711	770	0	2.06	0
2017	665	710	756	0	2.06	0
2018	607	680	767	0	2.06	0
2019	579	622	720	0	2.06	0
2020	556	601	750	0	2.06	0

Notes

1. CAIR Seasonal NO_X applies only in summer months (May - Sep)

2. In this table, PROMOD Allowance Prices are shown in metric units for consistency with scenario definitions, although data is in imperial units in PROMOD. 1 Metric Tonne = 1.102 Short Ton

3. Allowance prices are in $US 2008 Real

4.WCI analysis also had allowance prices for Ontario - $100/tonne SO_2, $300/tonne NO_X

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[10] CAIR – Clean Air Interstate Rule

CAMR – Clean Air Mercury Rule

2.4.4 WCI Generation Assumptions

The generation assumed for Ontario, Quebec[11] and Manitoba is based on a Ventyx database for the Eastern Interconnect, updated to take into account unit changes, retirements and planned new developments. As part of this project, the details of existing generation were reviewed with the WCI partners. Planned new units were based on published data and a variety of previous planning studies for the various WCI provinces.

Throughout this report and in the tables following, "CC", "CT" and "ST" are conventional shorthand for combined cycle, combustion turbine and steam turbine respectively.

Table 10: Ontario Generating Capacity

Generation Type	Installed Capacity at Year End	
	2012 *MW*	**2020** *MW*
Wind	3,855	4,352
Hydro	7,925	8,720
Solar/Biomass	973	2,596
Nuclear	12,473	6,729
CC	7,019	7,674
CT Gas	794	1,669
ST Gas	2,110	1,060
ST Coal	3,785	0
Other	104	104
Total Ontario Generation	**39,038**	**32,905**

[11] In the WCI analysis, to reflect Hydro Quebec's intention to continue to export to the north-eastern U.S., NCI set up the Quebec hydro dispatch to generate more in the peak hours than is required to meet Quebec load. This encourages PROMOD to export power to the U.S. in those periods. As hydro generation is limited annually by inflows, this has the result that Quebec then needs additional power in off-peak periods to meet load, i.e. imports from Ontario. This can be seen in the Appendix in the tables that summarize flows at a provincial level.

Table 11: Quebec Generating Capacity

Generation Type	Installed Capacity at Year End	
	2012 **MW**	**2020** **MW**
Wind	1,565	5,339
Hydro	39,756	41,361
Solar/Biomass	277	897
Nuclear	675	675
CC	507	1,537
CT Gas	510	1,020
ST Gas	0	0
ST Coal	0	0
Other	1,373	2,198
Total Quebec Generation	**44,663**	**53,027**

Table 12: Manitoba Generating Capacity

Generation Type	Installed Capacity at Year End	
	2012 *MW*	**2020** *MW*
Wind	242	242
Hydro	5,304	5,991
Solar/Biomass	0	0
Nuclear	0	0
CC	0	0
CT Gas	274	274
ST Gas	140	140
ST Coal	97	0
Other	0	0
Total Manitoba Generation	**6,057**	**6,647**

2.4.5 Transmission Assumptions

The PROMOD simulations were run with load flows representing the transmission system in the Eastern Interconnect for 2012 and 2020 respectively. The load flows were based on the FERC 2007 release and were modified by Navigant Consulting to include various planned transmission enhancements in ISO NE, NYISO, PJM and in Eastern Canada.

Manitoba and Quebec are connected to various sections of the U.S. electricity system primarily by a number of asynchronous DC lines, and Ontario is similarly connected by AC lines. The results of the WCI analysis are affected by the import and export of electricity across these interfaces, and this creates the possibility for leakage, where U.S. generation and CO_2 emissions increase in response to WCI CO_2 regulation.

Also, Quebec and Manitoba have substantial hydro generation and generation in excess of demand. Hydro Quebec has indicated intentions to increase exports to the northeast US to reach ~15-20 TWh annually. This may be affected by the WCI CO_2 proposals if they lead to a reduction in thermal generation inside the WCI provinces.

Table 13 indicates the assumed interface capability between the WCI provinces and other sections of the Eastern Interconnect.

Table 13: Transmission Interfaces for Manitoba, Ontario, Quebec

Transmission Interfaces *WCI – non WCI Regions*	**Limit** *MW*
Quebec – New Brunswick	1,080
Quebec – ISO NE	1,670
Quebec – NYISO	1,625
Ontario – NYISO	1,825
Ontario – MISO	2,540
Manitoba – MISO	2,175

The Quebec – ISO NE interface does not include the expected increase that will result from development of the proposed 1200 MW NU/NSTAR DC line in 2015. This line was included in the 2020 simulations.

3. Initial WCI Scenarios Without Contract Shuffling

3.1 Scenario Definitions

The initial PROMOD simulations analyzed by Navigant Consulting were based on the Eastern Interconnect pool structure shown above in Figure 3, where a MGGRA pool was created and Manitoba was separated from MRO. Key aspects of this group of scenarios were:

- CO_2 regulation for generating units in the eastern WCI provinces – Quebec, Ontario, Manitoba
- No corresponding CO_2 regulation in MGGRA states
- RGGI regulation in NE US not aligned with WCI regulation in terms of CO_2 allowance price, but CO_2-emitting units in the 10 RGGI states were subject to an allowance cost of $2.06/tonne
- Non-WCI, non-RGGI generation was not subject to any CO_2 emission charges
- Import (FJD) charges applied to all imports into Quebec, Ontario, Manitoba from non-WCI provinces/states – no distinction made on basis of the carbon content of imported power
- As all imported power attracted the same FJD charge, contract shuffling was not possible

Within this common structure, a number of scenarios were run for 2012 and 2020 with different combinations of WCI allowance prices and import charges, as shown in Table 14.

Table 14: Allowance Prices and FJD Charges – Simple Scenarios

Scenario	Years	WCI CO_2 Allowance Price *$/tonne*	MGGRA CO_2 Allowance Price *$/tonne*	RGGI CO_2 Allowance Price *$/tonne*	FJD Charge *kg/MWh*	FJD Charge *$/MWh*
Scenario 1 *[Base Case]*	2012, 2020	0	0	2.06	0	0
Scenario 2	2012, 2020	30	0	2.06	0	0
Scenario 3	2012, 2020	30	0	2.06	500	15
Scenario 3a	2020	60	0	2.06	500	30
Scenario 4	2012, 2020	30	0	2.06	1000	30
Scenario 5	2012, 2020	15	0	2.06	0	0
Scenario 6	2012, 2020	15	0	2.06	500	7.5
Scenario 7	2012, 2020	15	0	2.06	1000	15
Scenario 8	2012, 2020	15	0	15	500	7.5

Notes

1. In this table, the RGGI allowance prices from the auction result - $US 1.87/short ton - has been converted to metric tonnes

2. In these scenarios the FJD charge applies to all imports from non-WCI regions regardless of the presumed type of generation

3.2 Scenario Results

3.2.1 WCI Generation, Emissions and Imports/Exports

Figures 7 - 8 show total WCI generation and emissions for these scenarios[12] in 2012.

With no import charge, both generation and emissions within WCI decline significantly as allowance prices increase from zero (Scenario 1), to $15/tonne (Scenario 5), to $30/tonne (Scenario 2). For a given WCI allowance price, WCI generation and emissions progressively increase as import charges increase, to $7.50/MWh (Scenario 6), $15/MWh (Scenarios 3 and 7) and $30/MWh (Scenario 4), though they remain well below the Base Case with no allowance price. From these results, it is clear that the WCI allowance price has a more significant effect than the FJD charge, and this remains true at the highest allowance prices investigated (Scenario 3a - $60/MWh).

[12] Tables corresponding to these figures, with WCI totals and breakdowns by province, are included in the Appendix

Figure 7: Eastern WCI Generation in 2012 – Simple Scenarios

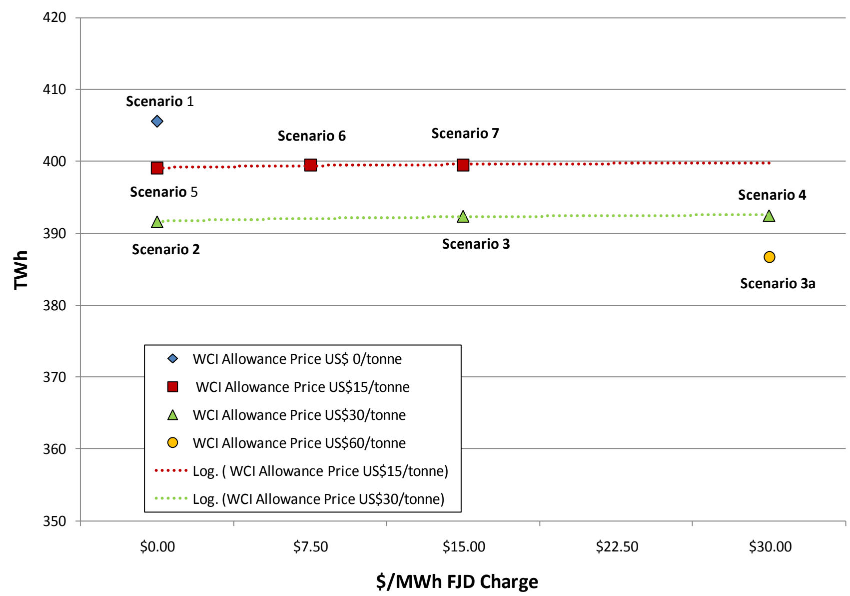
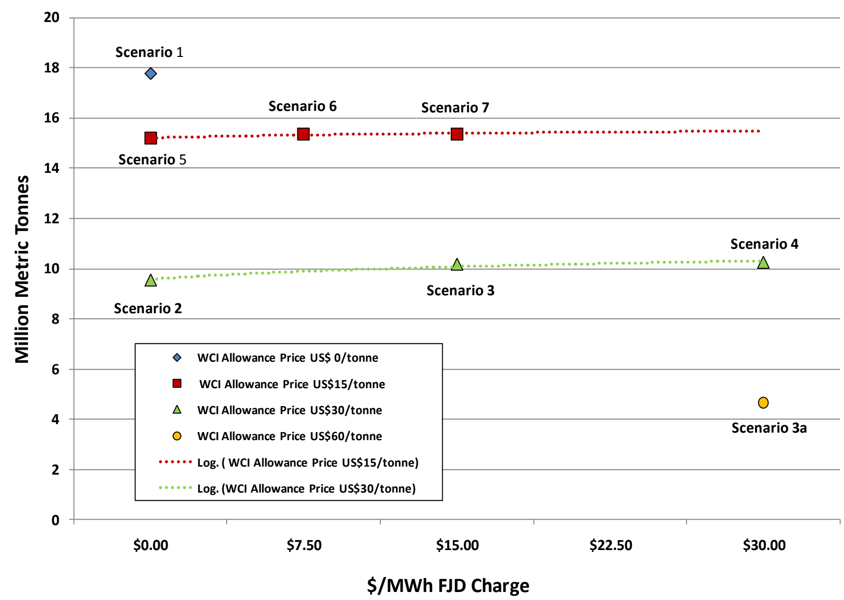


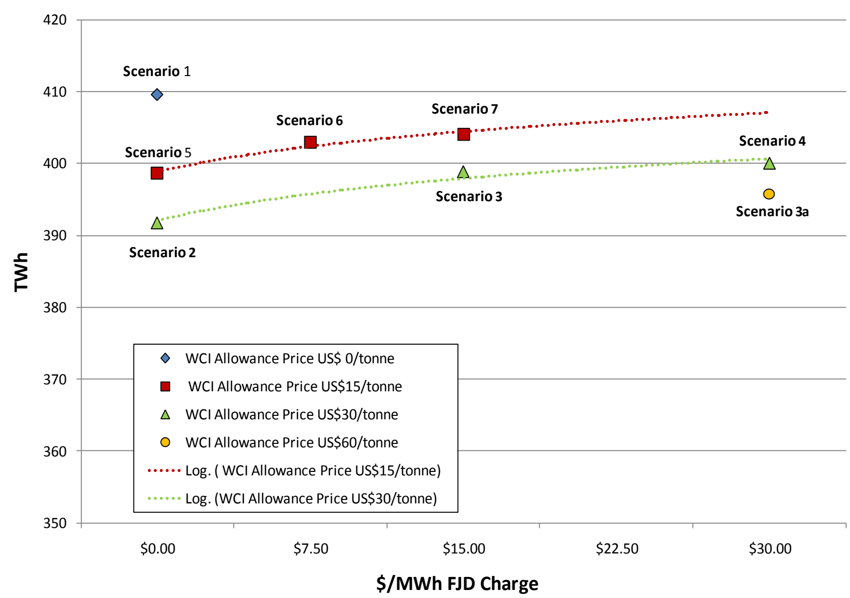
Figure 8: Eastern WCI CO_2 Emissions in 2012 – Simple Scenarios



Figures 9 - 10 show generation and emissions for 2020. Base case WCI emissions are significantly lower in 2020 than in 2012 (14.8 instead of 17.8 million tonnes), primarily because Ontario coal plants will all have been shut down by then. The emission reductions are lower in absolute terms in most of the scenarios, but similar in percentage terms. For example, Scenario 2 shows a reduction of 8.2 million tonnes, or 54% of Base Case reductions, in 2012. In 2020, the reduction is only 7.1 million tonnes, but the percentage reduction (52%) is almost the same.

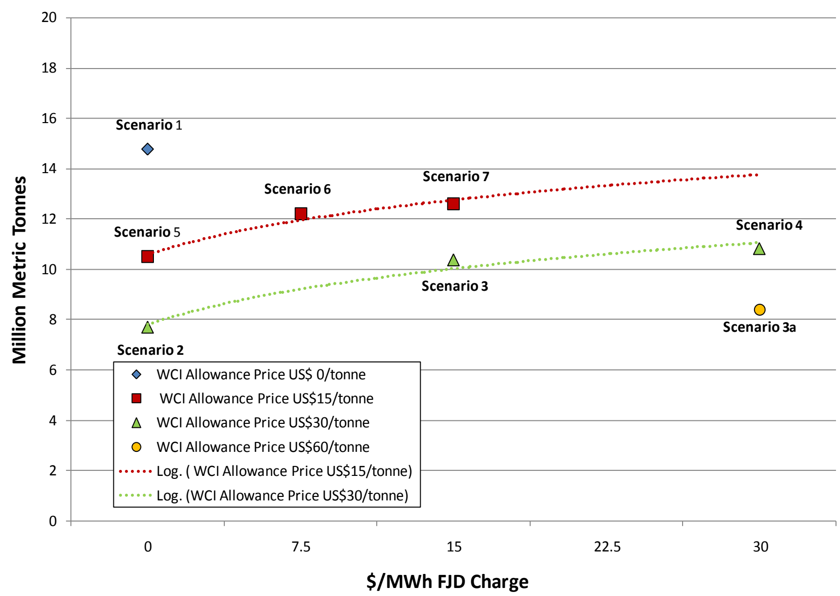
The reason for the decreases in WCI emissions shown in Figures 7 - 10 is that WCI fossil generation - gas and coal plants - is reduced as the WCI allowance cost increases. As the tables in the Appendix show, almost all of the decrease in emissions by the Eastern WCI provinces is due to changes in Ontario-based generation, rather than to changes in Manitoba or Quebec. This is to be expected since Ontario has the majority of the coal-fired generation in 2012[13], and most of the gas-fired generation in the Eastern WCI provinces in both 2012 and 2020.

Figure 9: Eastern WCI Generation in 2020 – Simple Scenarios



[13] Ontario fossil generation in 2020 is primarily gas as the Ontario coal plants are expected to be retired by the end of 2014

Figure 10: Eastern WCI CO_2 Emissions in 2020 – Simple Scenarios



These decreases in generation are offset by a decrease in net exports, as shown in Figures 11 - 12. Net exports from the WCI are substantially lowered by the imposition of a WCI CO_2 allowance price. The Appendix provides detailed tables of imports and exports by province. These show that in 2012, the reduction in net exports is primarily due to Ontario, which both imports more and exports less. In 2020, the reduction in net exports to non-WCI areas is due both to increases in imports into Ontario and decreases in exports out of Quebec. This reduction in Quebec's exports to non-WCI areas is offset by a change in net imports from Ontario (both less imports to, and more exports from, Quebec).

WCI Emissions are significantly more sensitive to FJD charges in 2020 than in 2012. This is because the WCI provinces are much more dependent on imports in 2020. In the 2012 Base Case, the WCI provinces export 50 TWh to non-WCI areas, and import only 8 TWh. In the 2020 Base Case, exports have fallen to 38 TWh and, more importantly for FJD charges, imports have doubled, to 16 TWh. The FJD charges therefore have a greater impact.

Figure 11: Eastern WCI CO_2 Net Exports in 2012 – Simple Scenarios

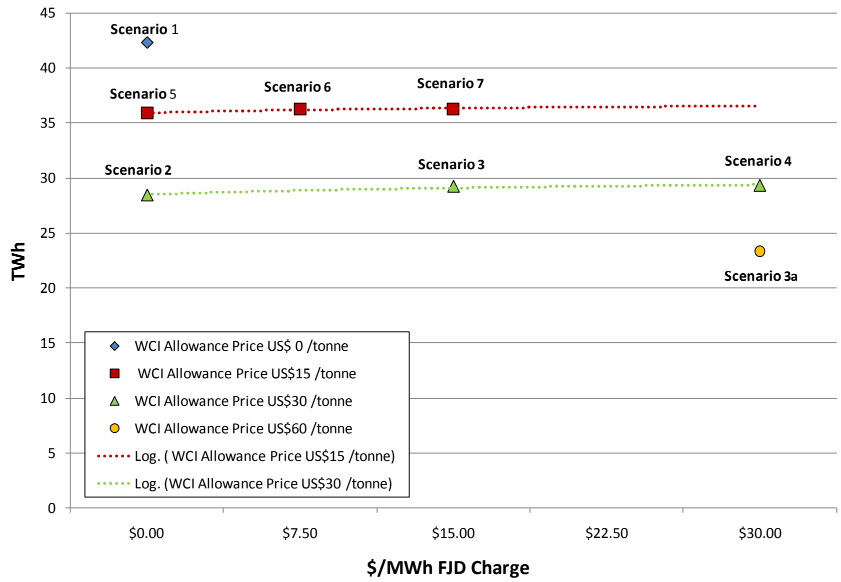
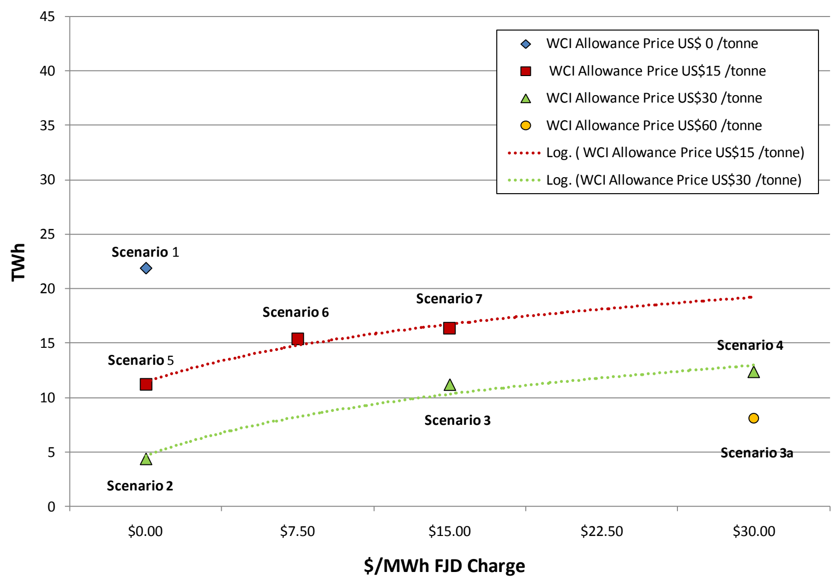


Figure 12: Eastern WCI CO_2 Net Exports in 2020 – Simple Scenarios



Tables 15 - 16 summarize the imports and exports into the Eastern WCI region – Manitoba, Ontario, Quebec – for the various scenarios.

Table 15: Summary of WCI Imports and Exports in 2012 – Simple Scenarios

Scenario	WCI Allowance Price	FJD Adder	RGGI Allowance Price	MGGRA Allowance Price	Imports Into WCI	Exports From WCI	Net Exports	Change in Net Exports	
	$/tonne	*$/MWh*	*$/tonne*	*$/tonne*	*TWh*	*TWh*	*TWh*	*TWh*	*%*
Scenario 1 (Base Case)	0	0	2.06	0	7.9	50.3	42.4		
Scenario 2	30	0	2.06	0	11.9	40.3	28.4	-13.9	-33%
Scenario 3	30	15	2.06	0	11.5	40.7	29.2	-13.1	-31%
Scenario 3a	60	30	2.06	0	14.4	37.7	23.3	-19.0	-45%
Scenario 4	30	30	2.06	0	11.4	40.7	29.3	-13.0	-31%
Scenario 5	15	0	2.06	0	8.9	44.8	35.9	-6.5	-15%
Scenario 6	15	7.5	2.06	0	8.8	45.1	36.3	-6.1	-14%
Scenario 7	15	15	2.06	0	8.9	45.1	36.3	-6.1	-14%
Scenario 8	15	7.5	15	0	8.4	47.7	39.3	-3.1	-7%

Table 16: Summary of WCI Imports and Exports in 2020 – Simple Scenarios

Scenario	WCI Allowance Price	FJD Adder	RGGI Allowance Price	MGGRA Allowance Price	Imports Into WCI	Exports From WCI	Net Exports	Change in Net Exports	
	$/tonne	*$/MWh*	*$/tonne*	*$/tonne*	*TWh*	*TWh*	*TWh*	*TWh*	*%*
Scenario 1 (Base Case)	0	0	2.06	0	16.3	38.1	21.9		
Scenario 2	30	0	2.06	0	24.6	29.0	4.4	-17.5	-80%
Scenario 3	30	15	2.06	0	20.6	31.8	11.2	-10.7	-49%
Scenario 3a	60	30	2.06	0	22.3	30.4	8.1	-13.8	-63%
Scenario 4	30	30	2.06	0	20.1	32.5	12.4	-9.5	-43%
Scenario 5	15	0	2.06	0	20.9	32.1	11.2	-10.7	-49%
Scenario 6	15	7.5	2.06	0	18.8	34.2	15.4	-6.5	-30%
Scenario 7	15	15	2.06	0	18.3	34.7	16.4	-5.5	-25%
Scenario 8	15	7.5	15	0	17.5	37.0	19.5	-2.3	-11%

Figure 13 summarizes the net WCI exports for the base case and the scenarios with a WCI allowance price of $30/tonne. This shows that at a particular WCI allowance price level, as FJD charges increase, net WCI exports tend to return to the level of the Base Case. This is most noticeable in 2020, but also occurs in 2012.

Similar results can be seen for the scenarios with an allowance price of $15/tonne.

FJD charges can consequently provide a means of reducing leakage resulting from the imposition of WCI allowance charges.

Figure 13: Example of Effect of FJD charges on WCI Exports – Simple Scenarios

3.2.2 Changes in WCI Generation and Emissions

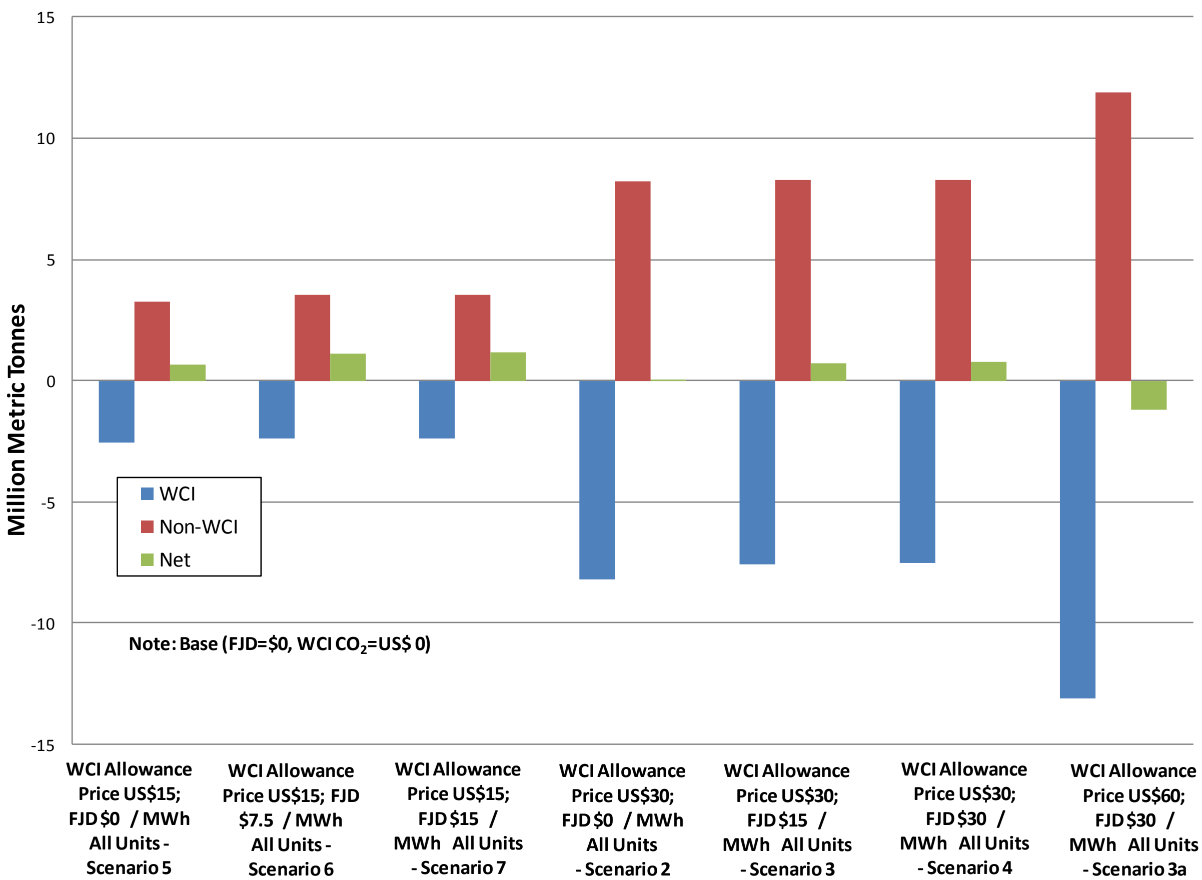
A decrease in net exports from WCI provinces means an increase in non-WCI generation, as total system demand is fixed. The annual output of all types of non-fossil generation – primarily hydro, wind – does not change and the reduction in exports from WCI is made up by increased non-WCI fossil generation, accompanied by an increase in CO_2 emissions. The net change in total emissions (WCI plus non-WCI) is very small, as shown in Figures 14 and 15 and Tables 17 and 18.

The overall result of introducing allowance prices - with or without import charges - in WCI, but not in the rest of the Eastern Interconnect, is in most cases a small increase in overall CO_2 emissions.

However, this is a consequence of assuming no change in demand and no change in the future generation mix in any of the scenarios. Since the annual output of total non-fossil generation is fixed, any reduction in fossil generation in one jurisdiction will be offset by an increase in fossil generation in another jurisdiction. To the extent that gas-fired generation in WCI is offset by coal-fired generation in non-WCI jurisdictions, total emissions will increase[14].

In reality, the introduction of allowance prices in WCI would increase prices and therefore reduce consumption. As well, higher prices for fossil-generation would lead to the development of more non-fossil generation, thus changing the future generation mix. As noted in the introduction, quantifying such the effects of such changes - in fossil generation at existing plants in WCI and non-WCI jurisdictions, in demand, and in capacity development - is a much more involved analysis, beyond the scope of this study.

Figure 14: Change in WCI, Non-WCI and Total CO_2 Emissions in 2012 – Simple Scenarios



[14] Differences in transmission losses may also have a small impact on generation and emissions. Note that an increase in non-WCI CO_2 is not inevitable – for example, the difference in generation could be made up by non-WCI gas fired capacity. The overall result depends on the availability and economics of coal generation vs. gas generation in the non-WCI regions.

Figure 15: Change in WCI, Non-WCI and Total CO_2 Emissions in 2020 – Simple Scenarios

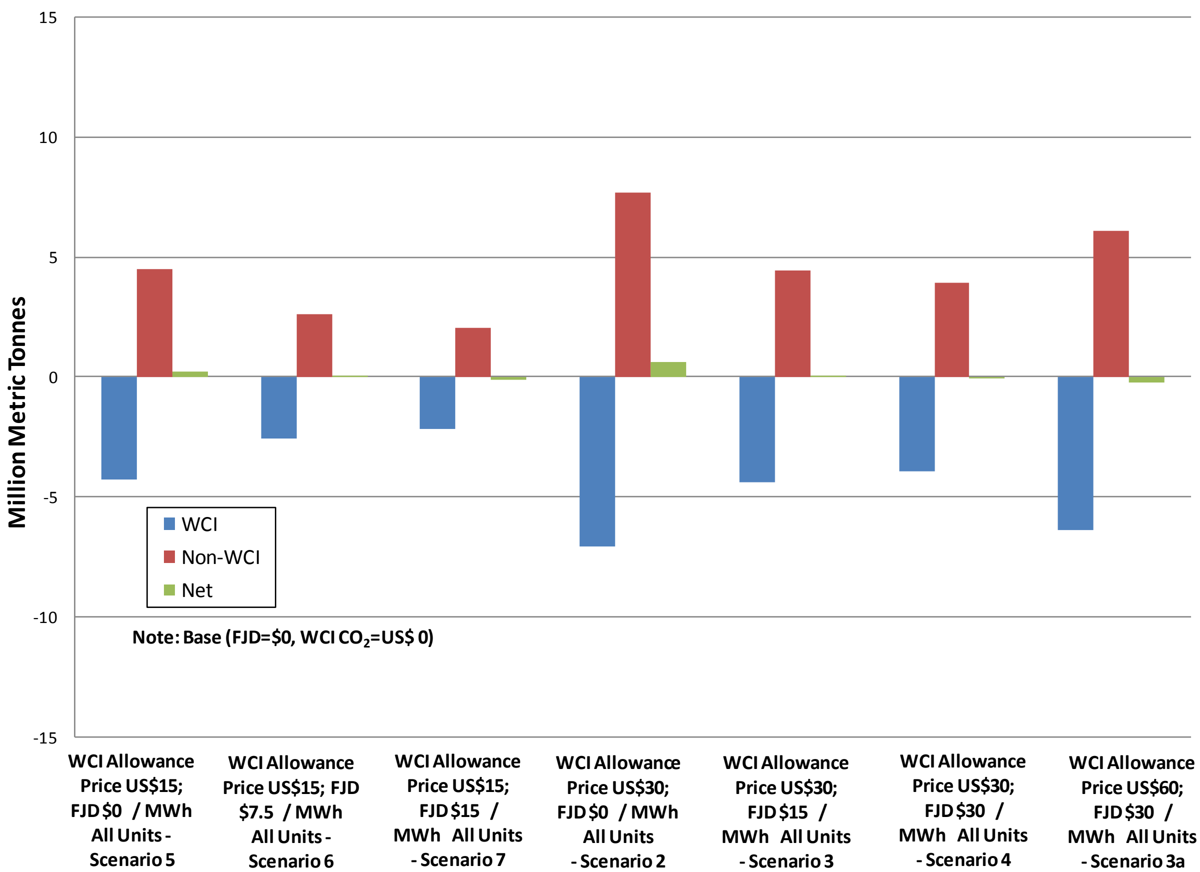


Table 17: Change in WCI, Non-WCI and Total CO_2 Emissions in 2012 – Simple Scenarios

	Gross 2012 CO_2 Emissions			Change in Gross 2012 CO_2 Emissions from 2012 Base Case		
Scenario	**WCI** *Million Tonnes*	**Non-WCI** *Million Tonnes*	**Total** *Million Tonnes*	**WCI** *Million Tonnes*	**Non-WCI** *Million Tonnes*	**Net** *Million Tonnes*
Scenario 1 *[Base Case]*	17.8	1,771.6	1,789.4	-	-	-
Scenario 2	9.5	1,779.8	1,789.4	-8.2	8.2	0.0
Scenario 3	10.2	1,779.9	1,790.1	-7.6	8.3	0.7
Scenario 3a	4.7	1,783.5	1,788.2	-13.1	11.9	-1.2
Scenario 4	10.2	1,779.9	1,790.2	-7.5	8.3	0.8
Scenario 5	15.2	1,774.9	1,790.1	-2.6	3.2	0.7
Scenario 6	15.4	1,775.1	1,790.5	-2.4	3.5	1.1
Scenario 7	15.4	1,775.2	1,790.5	-2.4	3.5	1.2
Scenario 8	16.5	1,764.7	1,781.2	-1.2	-6.9	-8.2

Table 18: Change in WCI, Non-WCI and Total CO_2 Emissions in 2020 – Simple Scenarios

	Gross 2020 CO_2 Emissions			Change in Gross 2020 CO_2 Emissions from 2020 Base Case		
Scenario	**WCI** *Million Tonnes*	**Non-WCI** *Million Tonnes*	**Total** *Million Tonnes*	**WCI** *Million Tonnes*	**Non-WCI** *Million Tonnes*	**Net** *Million Tonnes*
Scenario 1 *[Base Case]*	14.8	1,910.3	1,925.1	-	-	-
Scenario 2	7.7	1,918.0	1,925.7	-7.1	7.7	0.6
Scenario 3	10.4	1,914.8	1,925.2	-4.4	4.5	0.1
Scenario 3a	8.4	1,916.4	1,924.8	-6.4	6.1	-0.3
Scenario 4	10.8	1,914.2	1,925.1	-3.9	3.9	0.0
Scenario 5	10.5	1,914.8	1,925.3	-4.3	4.5	0.2
Scenario 6	12.2	1,912.9	1,925.1	-2.6	2.6	0.0
Scenario 7	12.6	1,912.4	1,925.0	-2.2	2.1	-0.1
Scenario 8	13.7	1,910.9	1,924.6	-1.0	0.5	-0.5

3.2.3 Carbon Content of WCI Imports

As a final step in the analysis of the initial scenarios, the carbon content of non-WCI generation was estimated, as an indicator of an appropriate default level of import charges. This was done by dividing the increase in non-WCI emissions by the decrease in net exports, as shown in Table 19 and Figure 16. The results are clustered around 600 kg/MWh in 2012 and 400 kg/MWh in 2020. The difference is due to the fact that coal (which emits more CO_2 per MWh than gas) is on the margin less in 2020 than in 2012, so the decrease in WCI exports is offset by an increase in gas generation more often than coal generation.

Table 19: Average Carbon Content of Non-WCI Generation

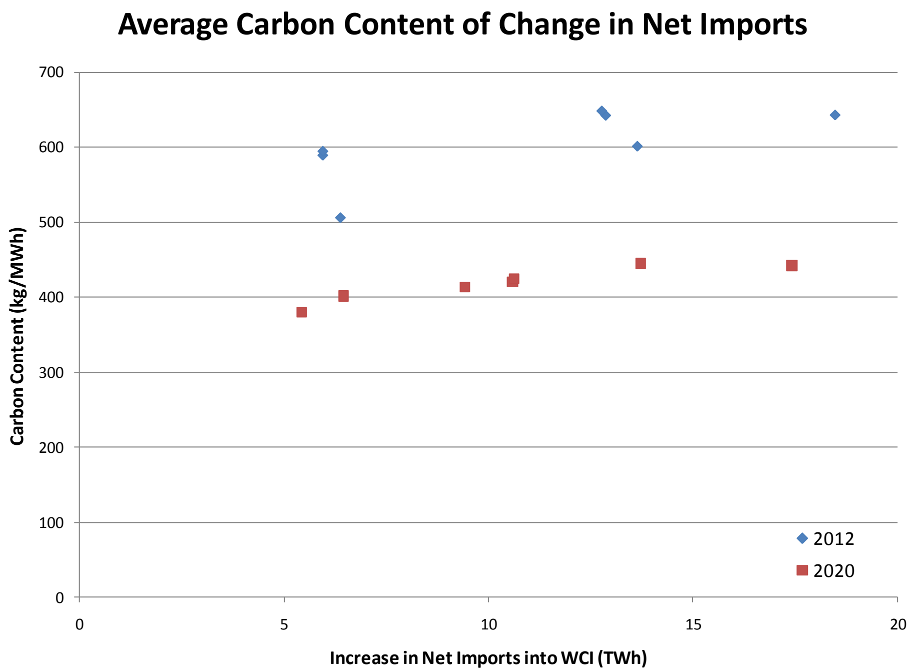
	Change from 2012 Base Case			Change from 2020 Base Case		
Scenario	**Change in Non-WCI CO_2 Emissions** *Million Tonnes*	**Change in WCI Net Imports** *TWh*	**Average CO_2 Content of Import** *kg/MWh*	**Change in Non-WCI CO_2 Emissions** *Million Tonnes*	**Change in WCI Net Imports** *TWh*	**Average CO_2 Content of Import** *kg/MWh*
Scenario 1 *[Base Case]*	n/a	n/a	n/a	n/a	n/a	n/a
Scenario 2	8.2	13.9	590	7.7	17.5	441
Scenario 3	8.3	13.1	631	4.5	10.7	418
Scenario 3a	11.9	19.0	625	6.1	13.8	444
Scenario 4	8.3	13.0	636	3.9	9.5	411
Scenario 5	3.2	6.5	499	4.5	10.7	423
Scenario 6	3.5	6.1	580	2.6	6.5	398
Scenario 7	3.5	6.1	584	2.1	5.5	376

Notes

1 Scenario 8 has different RGGI allowance price from Base Case and CO_2 calculation is not appropriate

2 Average CO_2 content of imports = (change in non-WCI CO_2 emissions)/(Change in WCI imports)

Figure 16: Average Carbon Content of Non-WCI Generation



3.2.4 Changes in Generation and Emissions by Province

Tables 20 - 23 summarize the breakdown of generation and CO_2 emissions by province for the simple scenarios. In both 2012 and 2020, the changes in generation and emissions compared to the Base Case occur primarily in Ontario, primarily in response to the WCI allowance price. Changes in Quebec and Manitoba are limited as there is relative little thermal generation in those regions.

Overall emissions in 2020 are lower than those in 2012 because of the expected retirement of coal units in Ontario and Manitoba.

Table 20: Provincial Generation in 2012 – Simple Scenarios

Scenario	WCI Allowance Price	FJD Adder		Quebec Generation	Ontario Generation	Manitoba Generation	Total WCI Generation
	$/tonne	*kg/MWh*	*$/MWh*	*TWh*	*TWh*	*TWh*	*TWh*
Scenario 1 *[Base Case]*	0	0	0	200.9	173.3	31.5	405.6
Scenario 2	30	0	0	200.8	159.3	31.5	391.6
Scenario 3	30	500	15	200.8	160.1	31.5	392.4
Scenario 3a	60	500	30	200.8	154.5	31.4	386.7
Scenario 4	30	1000	30	200.8	160.2	31.5	392.5
Scenario 5	15	0	0	200.8	166.7	31.5	399.1
Scenario 6	15	500	7.5	200.8	167.1	31.5	399.5
Scenario 7	15	1000	15	200.8	167.1	31.5	399.5
Scenario 8	15	500	7.5	200.9	170.1	31.5	402.5

Notes

1. Allowance price and FJD adder are $US 2008 Real

Table 21: Provincial CO_2 Emissions in 2012 – Simple Scenarios

Scenario	WCI Allowance Price	FJD Adder		Quebec CO_2 Emissions	Ontario CO_2 Emissions	Manitoba CO_2 Emissions	Total WCI CO_2 Emissions
	$/tonne	*kg/MWh*	*$/MWh*	*Million tonnes*	*Million tonnes*	*Million tonnes*	*Million tonnes*
Scenario 1 *[Base Case]*	0	0	0	0.4	17.2	0.1	17.8
Scenario 2	30	0	0	0.4	9.1	0.0	9.5
Scenario 3	30	500	15	0.4	9.7	0.1	10.2
Scenario 3a	60	500	30	0.4	4.3	0.0	4.7
Scenario 4	30	1000	30	0.4	9.8	0.1	10.2
Scenario 5	15	0	0	0.4	14.7	0.1	15.2
Scenario 6	15	500	7.5	0.4	14.8	0.1	15.4
Scenario 7	15	1000	15	0.4	14.9	0.1	15.4
Scenario 8	15	500	7.5	0.4	16.0	0.1	16.5

Notes

1. Allowance price and FJD adder are $US 2008 Real

Table 22: Provincial Generation in 2020 – Simple Scenarios

Scenario	WCI Allowance Price	FJD Adder		Quebec Generation	Ontario Generation	Manitoba Generation	Total WCI Generation
	$/tonne	*kg/MWh*	*$/MWh*	*TWh*	*TWh*	*TWh*	*TWh*
Scenario 1 *[Base Case]*	0	0	0	232.2	140.7	36.7	409.6
Scenario 2	30	0	0	229.6	125.5	36.7	391.8
Scenario 3	30	500	15	230.3	131.9	36.7	398.9
Scenario 3a	60	500	30	229.9	129.2	36.7	395.8
Scenario 4	30	1000	30	230.9	132.5	36.7	400.1
Scenario 5	15	0	0	230.4	131.6	36.7	398.6
Scenario 6	15	500	7.5	231.1	135.3	36.7	403.0
Scenario 7	15	1000	15	231.6	135.8	36.7	404.1
Scenario 8	15	500	7.5	231.9	138.4	36.7	407.0

Notes

1. Allowance price and FJD adder are $US 2008 Real

Table 23: Provincial CO_2 Emissions in 2020 – Simple Scenarios

Scenario	WCI Allowance Price	FJD Adder		Quebec CO_2 Emissions	Ontario CO_2 Emissions	Manitoba CO_2 Emissions	Total WCI CO_2 Emissions
	$/tonne	*kg/MWh*	*$/MWh*	*Million tonnes*	*Million tonnes*	*Million tonnes*	*Million tonnes*
Scenario 1 *[Base Case]*	0	0	0	1.3	13.5	0.0	14.8
Scenario 2	30	0	0	0.4	7.3	0.0	7.7
Scenario 3	30	500	15	0.6	9.7	0.0	10.4
Scenario 3a	60	500	30	0.5	7.9	0.0	8.4
Scenario 4	30	1000	30	0.8	10.0	0.0	10.8
Scenario 5	15	0	0	0.6	9.9	0.0	10.5
Scenario 6	15	500	7.5	0.9	11.3	0.0	12.2
Scenario 7	15	1000	15	1.1	11.5	0.0	12.6
Scenario 8	15	500	7.5	1.2	12.5	0.0	13.7

Notes

1. Allowance price and FJD adder are $US 2008 Real

A more detailed breakdown by individual province is included in the Appendix.

3.3 Comparison of WCI Study with E3 Study

In March 2009, Energy and Environmental Economics ("E3") produced a report for the Electricity Sub-committee of the Western Climate Initiative titled "Electricity Leakage Analysis Summary Report" ("The E3 report"). The E3 report addressed many of the same questions as the current report, but for the Western WCI members, i.e., excluding Manitoba, Ontario and Quebec. However, the analysis is primarily qualitative. The main findings on the potential for leakage were that there is little potential for increased coal generation in neighboring jurisdictions, as the coal plants already have high capacity factors, but there is potential for increased generation from non-WCI gas plants. The current report takes a quantitative approach to this question, finding that the increase in non-WCI generation induced by WCI allowance prices will be a mix of coal and gas in 2012, and primarily gas in 2020.

The E3 report addressed the question of power plant investment incentives, considering whether WCI regulation of GHG emissions could create an incentive to build coal-fired plants in non-WCI areas. The approach was largely qualitative. The E3 report found the answer depends on WCI allowance prices, transmission costs and import charges (called "deemed emission rates" in the E3 report).

The current report does not address any issues related to power plant development in non-WCI regions.

4 WCI SCENARIOS WITH CONTRACT SHUFFLING

4.1 Scenario Definitions

The second set of PROMOD simulations analyzed by Navigant Consulting were based on the Eastern Interconnect pool structure shown earlier in Figure 4. Key aspects of this group of scenarios were:

- CO_2 regulation for generating units in the eastern WCI provinces – Quebec, Ontario, Manitoba – through the WCI CO_2 allowance cost as in the simple scenarios
- Some scenarios aligned CO_2 regulation in MGGRA states and RGGI regulation in NE US with WCI regulation in terms of a common CO_2 allowance price
- FJD charges applied to all flows into Quebec, Ontario, Manitoba from other provinces/states, but only applied to power sourced from CO_2-emitting plants
- For scenarios with aligned CO_2 regulation in WCI and MGGRA/RGGI, import (FJD) charges between WCI and MGGRA/RGGI were set to zero and import charges were applied for imports into MGGRA, but not into RGGI as that is existing legislation which currently does not include import charges
- These scenarios, with zero incremental transmission tariffs applied to imports from non-CO_2 emitting units outside the WCI (and MGGRA as appropriate), permit the examination of the effects of contract shuffling

For these more complex scenarios, because of the increased simulation time resulting from the more complex pool structure, the scenarios were run for 2020 only, as shown in Table 24.

Table 24: WCI Scenarios with Contract Shuffling

Scenario	Years	WCI Allowance Price	MGGRA Allowance Price	RGGI Allowance Price	FJD Charge	
		$/tonne	*$/tonne*	*$/tonne*	*kg/MWh*	*$/MWh*
Scenario 9 *[Base Case]*	2020	0	0	2.06	0	0
Scenario 10	2020	30	0	2.06	1000	30
Scenario 10a	2020	30	0	2.06	500	15
Scenario 12	2020	30	30	30	1000	30

Notes

1. RGGI allowance prices from the auction result - $1.87/short ton - have been converted to metric tonnes

2. Allowance prices and FJD charges are $US 2008 real

3. In these scenarios the FJD charge applies only to imports from carbon producing units

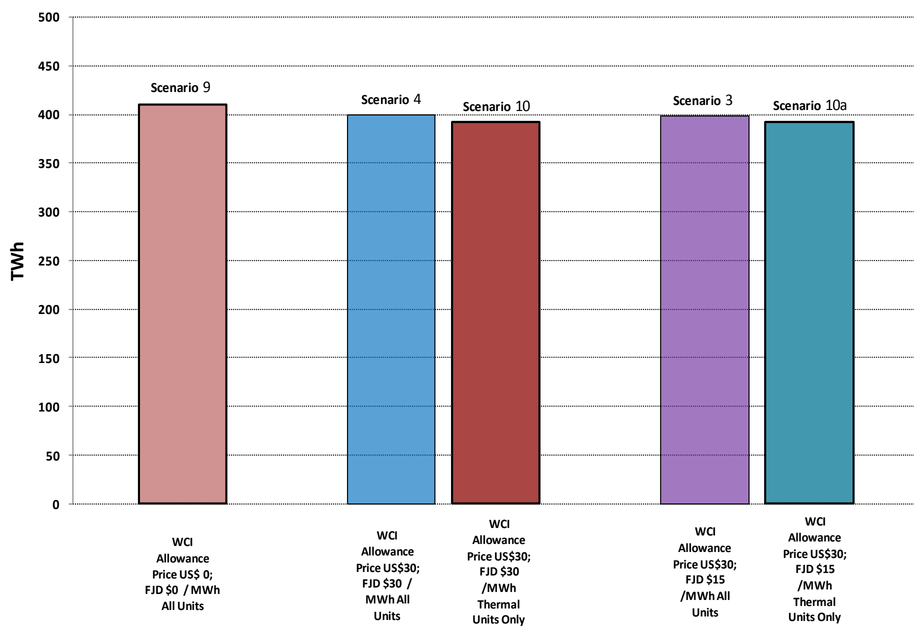
Scenario 9 represents the Base Case in the more complex pool structure. This was rerun to allow differences between scenarios to be evaluated without concerns arising from different pool structures.

4.2 Scenario Results

4.2.1 Changes in Generation and Emissions for Complex Scenarios

Figures 17 – 19 summarize the results from the PROMOD simulations for the more complex scenarios, where contract shuffling has been permitted. Although not run with the same pool structure as the simple scenarios, for reference the figures include comparable results from the earlier simple scenarios – no contract shuffling.

Figure 17: WCI Generation in 2020 – Complex Scenarios



Generally, permitting contract shuffling – with no import tariffs for imports sourced from non CO_2-emitting plants – leads to a reduction in WCI generation and in WCI emissions compared to the equivalent simulations where contract shuffling was not permitted. This is to be expected, as encouraging imports into the WCI from non CO_2-emitting sources requires additional thermal generation in non-WCI regions to meet load in those regions. The overall result, as shown in Figure 19, is an increase in total CO_2 emissions in the Eastern Interconnect, and the increase for scenarios with contract shuffling (Scenarios 10a, 10) is greater than that for the simple scenarios with no contract shuffling (Scenarios 3, 4). Effectively, allowing contract shuffling leads to an increase in leakage.

Figure 18: WCI CO_2 Emissions in 2020 – Complex Scenarios

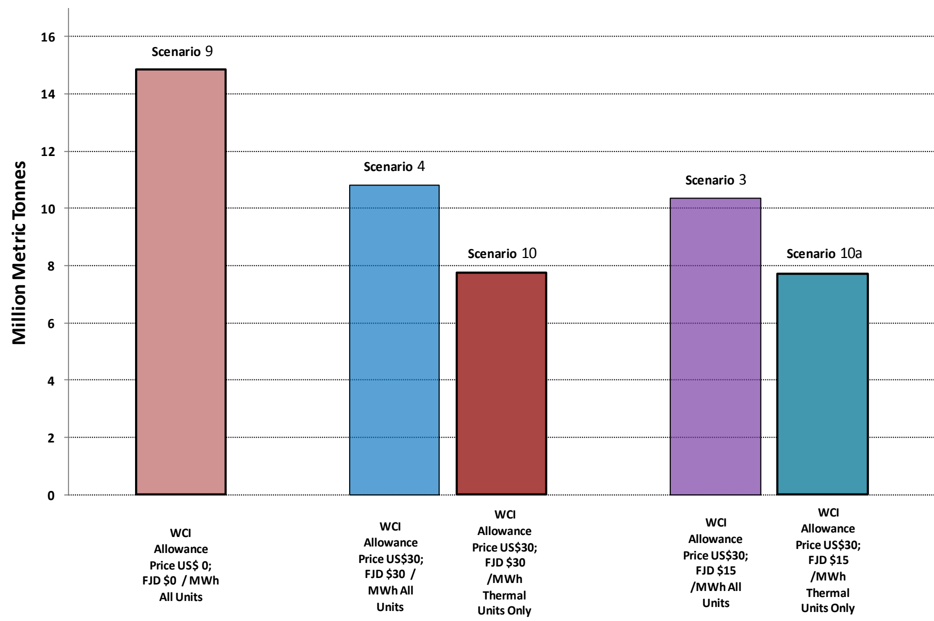
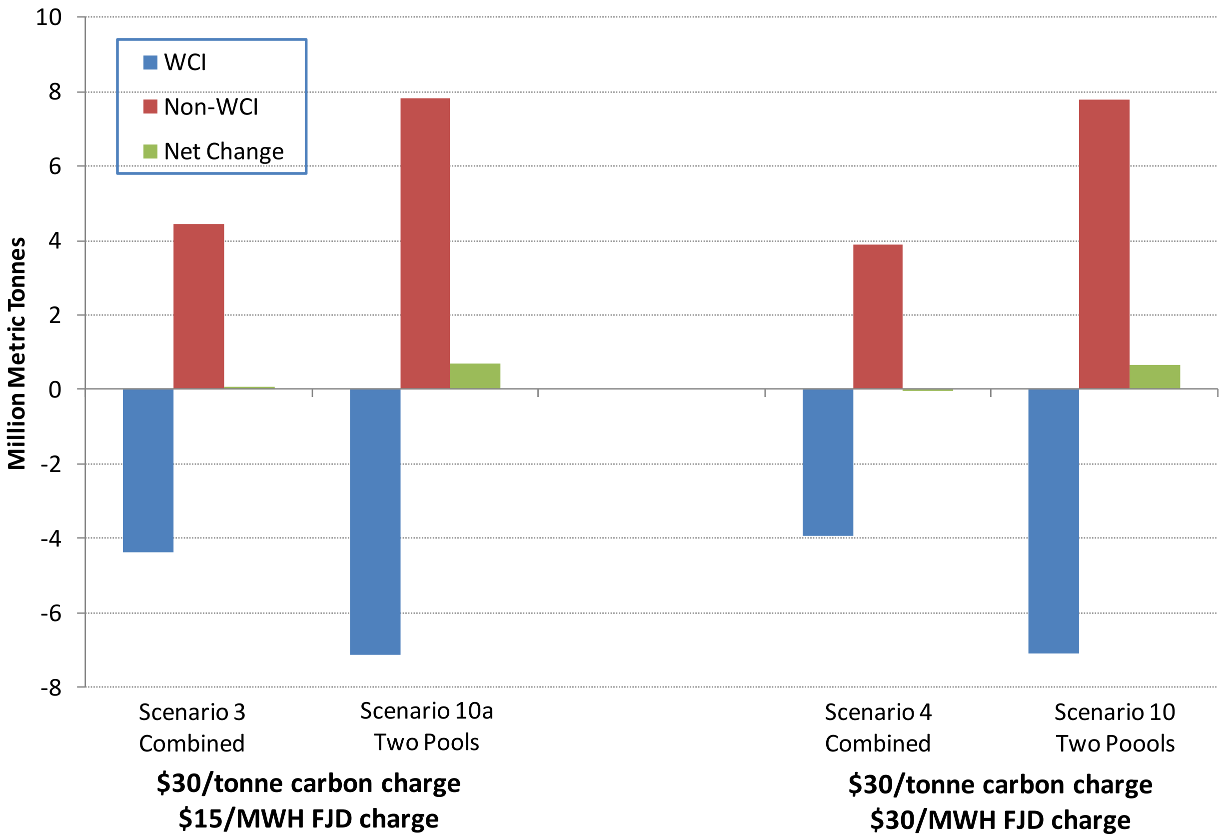


Figure 19: Change in WCI, Non-WCI and Total CO_2 Emissions in 2020– Complex Scenarios



4.2.2 Changes in Generation and Emissions by Province

Tables 25 and 26 summarize the changes in WCI generation and emissions for the more complex scenarios. As with the simple scenarios, the presence of a WCI allowance price decreases WCI generation and emissions, with the exception of Scenario 12 which has a common regulatory framework and allowance price structure in WCI, MGGRA and RGGI. In that scenario, there is relatively little change to WCI generation and emissions even with a WCI CO_2 allowance price.

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Table 25: Provincial Generation in 2020 – Complex Scenarios

Scenario	WCI Allowance Price	FJD Adder		Quebec Generation	Ontario Generation	Manitoba Generation	Total WCI Generation
	$/tonne	*kg/MWh*	*$/MWh*	*TWh*	*TWh*	*TWh*	*TWh*
Scenario 9 *[Base Case]*	0	0	0	232.2	140.9	36.7	409.8
Scenario 10	30	1000	30	229.6	125.6	36.7	391.9
Scenario 10a	30	500	15	229.6	125.6	36.7	391.9
Scenario 12	30	1000	30	231.7	137.4	36.7	405.7

Notes

1.Scenario 12 has MGGRA and RGGI CO_2 allowance prices of $30/tonne; Scenarios 10 and 10a have $0/tonne MGGRA CO_2 allowance price and $2.06/tonne RGGI CO_2 allowance prices

2.Allowance prices and FJD charges are $US 2008 real

Table 26: Provincial CO_2 Emissions in 2020 – Complex Scenarios

Scenario	WCI Allowance Price	FJD Adder		Quebec CO_2 Emissions	Ontario CO_2 Emissions	Manitoba CO_2 Emissions	Total WCI CO_2 Emissions
	$/tonne	*kg/MWh*	*$/MWh*	*Million tonnes*	*Million tonnes*	*Million tonnes*	*Million tonnes*
Scenario 9 *[Base Case]*	0	0	0	1.3	13.5	0.0	14.8
Scenario 10	30	1000	30	0.4	7.4	0.0	7.7
Scenario 10a	30	500	15	0.4	7.3	0.0	7.7
Scenario 12	30	1000	30	1.2	11.7	0.0	12.8

Notes

1.Scenario 12 has MGGRA and RGGI CO_2 allowance prices of $30/tonne; Scenarios 10 and 10a have $0/tonne MGGRA CO_2 allowance price and $2.06/tonne RGGI CO_2 allowance prices

2.Allowance prices and FJD charges are $US 2008 real

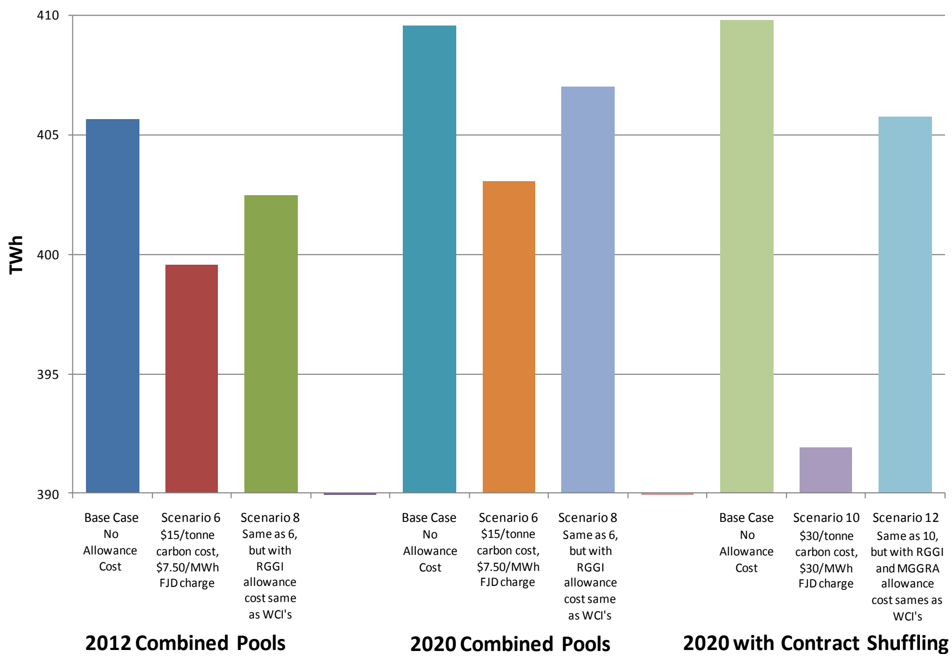
4.2.3 RGGI and MGGRA Scenarios

In several of the more complex scenarios, we also considered the effect on the WCI provinces of CO_2 regulation in MGGRA and RGGI.

In the base case, the ten RGGI states were assumed to have a low ($2.06/metric tonne) carbon price, and MGGRA (Illinois, Wisconsin, Minnesota, Iowa, Michigan) was assumed to have no carbon pricing. Both were subject to FJD charges where appropriate.

Several scenarios explored what would happen if eastern WCI, RGGI and/or MGGRA worked together to adopt similar carbon pricing regimes, and were therefore exempt from each other's FJD charges. For scenarios with the RGGI and MGGRA allowance prices aligned with the eastern WCI allowance prices, import (FJD) charges were applied to flows into WCI and MGGRA rather than just into WCI[15]. No FJD charge was applied to flows into RGGI. The results for these scenarios are shown in Figures 20 - 22.

Figure 20: WCI Generation in 2012 and 2020 – RGGI and MGGRA Scenarios



For both 2020 and 2012, Scenarios 8 and 12 – similar CO_2 allowance prices in MGGRA and RGGI as in WCI – led to higher levels of generation and CO_2 emissions in the WCI provinces, compared to Scenarios 6 and 10 where CO_2 prices were not aligned. There was still a reduction in generation and emissions compared to the Base Case with no allowance prices in the WCI or MGGRA, and a low allowance price in RGGI. This was true for scenarios with and without contract shuffling.

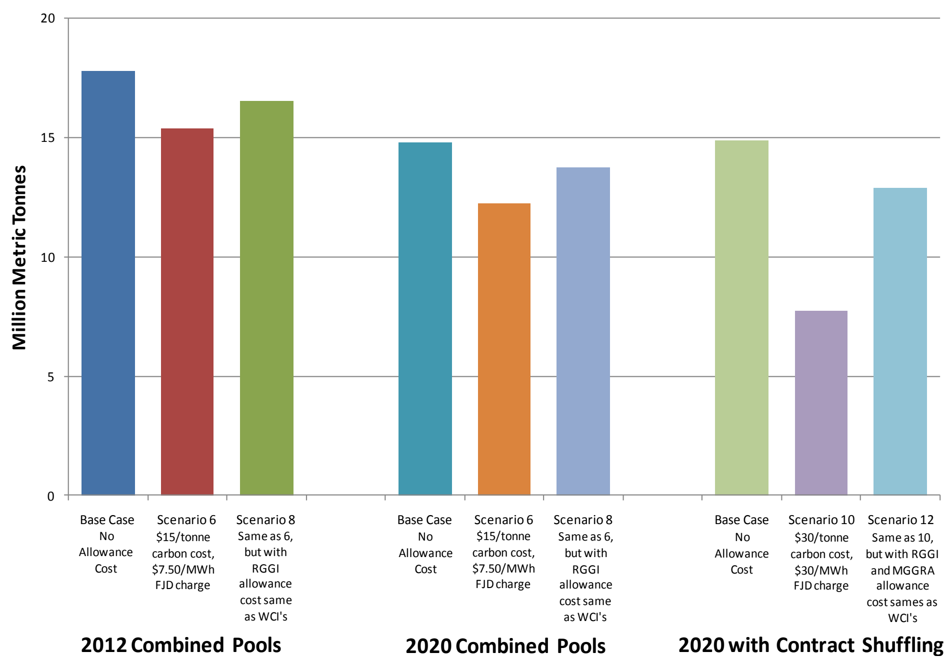
Figure 21 indicates the overall effect on total Eastern Interconnect CO_2 emissions. The combined regulatory effect leads to an overall reduction in total CO_2 emissions, from the substitution of gas for coal in non-WCI regions.

[15] No FJD charge was applied to flows into RGGI in this or any other scenario, as current RGGI regulations do not incorporate import charges into the RGGI region from non-RGGI regions

Effectively, the combination of consistent allowance prices in WCI, MGGRA and RGGI removes the economic justification for decreasing WCI thermal generation and consequently the reduction in WCI CO_2 emissions seen in other scenarios is much reduced. However, applying this level of CO_2 allowance prices to MGGRA and RGGI regions alters the economics of coal and gas plants in those regions, leading to greater gas-fired generation but overall lower CO_2 emissions[16].

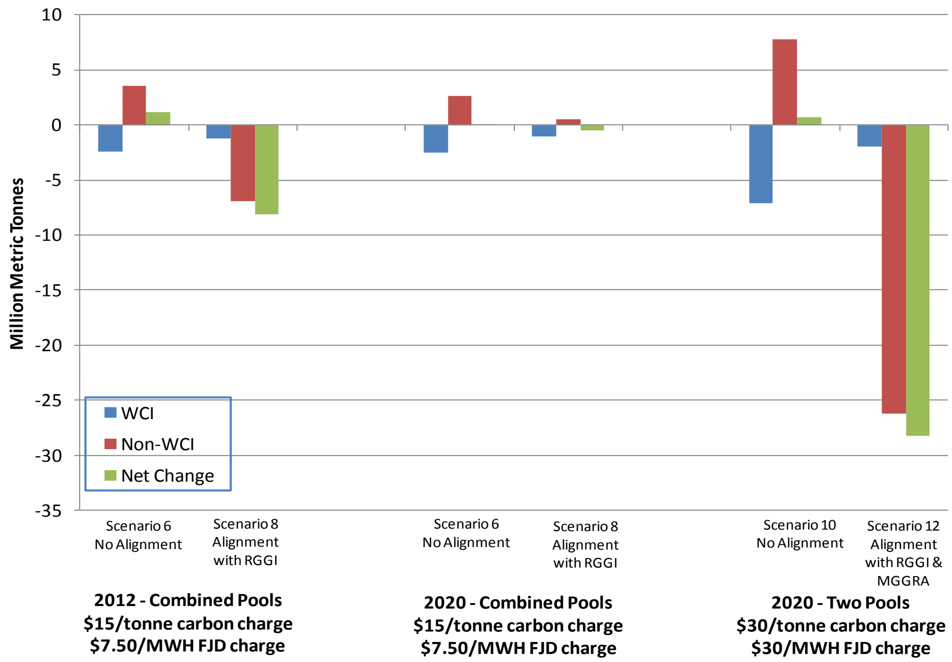
This is in contrast to the change in total emissions where there is no alignment of allowance prices and the overall effect is a slight increase in total CO_2 emissions across the Eastern Interconnect.

Figure 21: WCI CO_2 Emissions in 2012 and 2020 – RGGI and MGGRA Scenarios



[16] Although the CO_2 emissions are lower, the overall generation cost is higher than in the non-aligned case because there are CO2 emissions costs associated with substantially more thermal capacity.

Figure 22: Change in CO_2 Emissions in 2012 and 020 – RGGI and MGGRA Scenarios



4.3 Comparison of Current Study with E3 Report

The E3 report, discussed in Section 3.3 above, addressed the issue of contract shuffling by estimating the amount of hydro and gas capacity in non-WCI states in the WECC, and estimating the volume of CO_2 emissions that could be used for this purpose. This establishes a worst-case scenario. The current study addresses the contract shuffling issue in a much more detailed way, looking at system operation hour by hour and plant by plant.

The E3 report includes the possibility of contract shuffling by gas-fired plants, but assumes that plants selling into WCI pay import charges based on their actual emission rate. For example, if a gas plant's emission rate is 350 kg/MWh, and the import charges are based on a deemed emission rate of 500 kG/MWh, then the gas plant can be used in contract shuffling to avoid import charges equivalent to 150 kg/MWh. The analysis done in current study is much more complex, but some of the assumptions are simpler, as it would not be feasible to model more complex assumptions. In particular, the current study only considers contract shuffling by non-fossil generation, and it applies the same import charge to all generation in the fossil pool regardless of actual emission rates.

5 Conclusions

5.1 WCI Generation and Emissions

The modeling results showed a large (as much as 48%) decrease in the CO_2 emissions of the three WCI provinces as a result of introducing allowance prices. For scenarios with no similar CO_2 regulation in MGGRA and RGGI, the decrease in WCI emissions was offset by an increase in non-WCI emissions in every case, resulting in almost no net change in total emissions.

WCI emissions decrease because fossil generation (primarily in Ontario) falls when allowance prices are applied. This decrease in WCI generation leads to reduced exports from WCI. Non-WCI generation therefore needs to increase, and since only fossil generation has variable output, this means an increase in non-WCI fossil generation and CO_2 emissions. The impact of introducing WCI allowance prices in our analysis was consequently to shift fossil generation from the WCI provinces to non-WCI jurisdictions. The small changes in total emissions that result are from replacing one type of generation (e.g., gas in Ontario) with another (e.g., coal in Ohio).

In the scenarios, the majority changes in the pattern of WCI generation and CO_2 emissions occur in Ontario, the location of the majority of the WCI CO_2-emitting units.

The average carbon content of the increase in non-WCI generation is around 600 kg/MWh in 2012 and 400 kg/MWh in 2020. This is calculated as the increase in non-WCI emissions divided by the change in net imports (imports minus exports) into WCI. The reason for the change between 2012 and 2020 is that coal-fired generation is on the margin in non-WCI jurisdictions less often in 2020 than in 2012.

5.2 FJD Charges and Contract Shuffling

Import (FJD) charges reduce the attractiveness of importing power from non-WCI regions. Higher FJD charges lead to greater WCI generation and emissions, i.e. closer to those of the Base Case with no WCI regulation. However, WCI generation and emissions are much less sensitive to the level of the FJD charge than they are to the WCI allowance price.

The scenarios with “contract shuffling” distinguished between imports from non CO_2-emitting sources and imports from CO_2-emitting sources, and applied a zero charge for imports from non CO_2-emitting sources. This reduced the impact of any given level of FJD charges compared to the simple scenarios where this distinction between imports from different sources was not made.

5.3 Coordination with MGGRA and RGGI

The simulations that combined regulation in WCI with regulation in MGGRA and RGGI gave somewhat different results. The reductions in WCI generation and WCI CO_2 emissions that resulted from imposing allowance charges were much smaller when allowance prices were aligned across MGGRA, WCI and RGGI, compared to the scenarios with regulation in WCI only. This is because coordination of CO_2 allowances with RGGI and/or MGGRA reduces the incentive to import electricity from non-WCI jurisdictions, as the main sources of these imports are RGGI and MGGRA.

The overall CO_2 emissions from the Eastern Interconnect were reduced when there was combined regulation between WCI, MGGRA and RGGI (RGGI in terms of the RGGI allowance price). The analysis indicated this was because of a change in generation from coal to gas in MGGRA, and is not directly related to the WCI assumptions. It is a consequence of the effect of the additional allowance cost on the coal and gas MGGRA units, as discussed in Section 4.2.1.

5.4 CO_2 Leakage

The results of the WCI analysis indicated that CO_2 leakage - increases in non-WCI emissions - in all scenarios with WCI allowance prices where there was no regulatory coordination with MGGRA and RGGI. Import charges reduced the amount of leakage but did not completely eliminate this, and allowing contract shuffling increased leakage.

However, where WCI, MGGRA and RGGI have a consistent allowance price structure, there were in fact decreases in CO_2 emissions in WCI and in the non-WCI regions (i.e. no leakage). However this outcome is likely to be sensitive to the level of WCI allowance prices.

It should be noted that, given timing and budget constraints, the results presented in this report were based on a static modeling approach. In Navigant Consulting's analysis, demand, capacity, and the annual output of non-fossil plants (nuclear, hydro, wind, etc.) were kept constant. The only generation parameter that could change was the level of the output of different fossil generation facilities across the Eastern Interconnect. Consequently, a decrease in fossil generation in one area such as WCI must necessarily be offset by an increase in fossil generation in another, so that demand can be met.

In fact, imposing allowance prices in WCI would encourage consumers to reduce their usage because of higher prices, and would provide an incentive to build non-fossil capacity instead of fossil capacity, leading to a net reduction in CO_2 emissions. These dynamic impacts could not be captured in this study.

6 Appendices

6.1 Detailed Results for Simple Scenarios

Table 27: Summary 2012 Results – WCI Generation, Emissions, Flows for Simple Scenarios

	Scenario Details				Generation		Gross CO_2 Emissions		Flows	
Scenario	FJD Adder *$/MWh*	WCI Allowance Price *$/tonne*	RGGI Allowance Price *$/tonne*	MGGRA Allowance Price *$/tonne*	WCI *TWh*	Non-WCI *TWh*	WCI *Million Tonnes*	Non-WCI *Million Tonnes*	Imports Into WCI *TWh*	Exports From WCI *TWh*
Scenario 1 (Base Case)	0	0	2.06	0	406	2,946	17.8	1,771.6	7.9	50.3
Scenario 2	0	30	2.06	0	392	2,960	9.5	1,779.8	11.9	40.3
Scenario 3	15	30	2.06	0	392	2,959	10.2	1,779.9	11.5	40.7
Scenario 3a	30	60	2.06	0	387	2,965	4.7	1,783.5	14.4	37.7
Scenario 4	30	30	2.06	0	393	2,959	10.2	1,779.9	11.4	40.7
Scenario 5	0	15	2.06	0	399	2,953	15.2	1,774.9	8.9	44.8
Scenario 6	7.5	15	2.06	0	400	2,952	15.4	1,775.1	8.8	45.1
Scenario 7	15	15	2.06	0	400	2,952	15.4	1,775.2	8.9	45.1
Scenario 8	7.5	15	15	0	402	2,949	16.5	1,764.7	8.4	47.7

Table 28: Summary 2020 Results – WCI Generation, Emissions, Flows for Simple Scenarios

	Scenario Details				Generation		Gross CO_2 Emissions		Flows	
Scenario	FJD Adder *$/MWh*	WCI Allowance Price *$/tonne*	RGGI Allowance Price *$/tonne*	MGGRA Allowance Price *$/tonne*	WCI *TWh*	Non-WCI *TWh*	WCI *Million Tonnes*	Non-WCI *Million Tonnes*	Imports Into WCI *TWh*	Exports From WCI *TWh*
Scenario 1 (Base Case)	0	0	2.06	0	410	3,330	14.8	1,910.3	16.3	38.1
Scenario 2	0	30	2.06	0	392	3,348	7.7	1,918.0	24.6	29.0
Scenario 3	15	30	2.06	0	399	3,341	10.4	1,914.8	20.6	31.8
Scenario 3a	30	60	2.06	0	396	3,344	8.4	1,916.4	22.3	30.4
Scenario 4	30	30	2.06	0	400	3,340	10.8	1,914.2	20.1	32.5
Scenario 5	0	15	2.06	0	399	3,341	10.5	1,914.8	20.9	32.1
Scenario 6	7.5	15	2.06	0	403	3,336	12.2	1,912.9	18.8	34.2
Scenario 7	15	15	2.06	0	404	3,335	12.6	1,912.4	18.3	34.7
Scenario 8	7.5	15	15	0	407	3,332	13.7	1,910.9	17.5	37.0

Table 29: Summary 2012 Results - Imports and Exports for Quebec for Simple Scenarios

Scenario	FJD Adder	WCI Allowance Price	RGGI Allowance Price	MGGRA Allowance Price	Imports from WCI (Ontario)	Exports to WCI (Ontario)	Imports from Non-WCI	Exports to Non-WCI	Total Imports	Total Exports
	$/MWh	*$/tonne*	*$/tonne*	*$/tonne*	*TWh*	*TWh*	*TWh*	*TWh*	*TWh*	*TWh*
Scenario 1 (Base Case)	0	0	2.06	0	10.3	0.0	2.2	24.7	12.5	24.7
Scenario 2	0	30	2.06	0	9.6	0.2	2.2	23.9	11.8	24.0
Scenario 3	15	30	2.06	0	9.7	0.2	2.3	24.0	12.0	24.2
Scenario 3a	30	60	2.06	0	9.4	0.2	2.4	23.7	11.7	23.9
Scenario 4	30	30	2.06	0	9.7	0.2	2.3	24.1	12.0	24.2
Scenario 5	0	15	2.06	0	9.9	0.1	1.9	23.9	11.8	24.0
Scenario 6	7.5	15	2.06	0	9.9	0.1	2.0	24.0	11.9	24.1
Scenario 7	15	15	2.06	0	9.9	0.1	2.1	24.1	12.0	24.2
Scenario 8	7.5	15	15	0	10.2	0.0	2.1	24.5	12.2	24.5

Table 30: Summary 2012 Results – Imports and Exports for Ontario for Simple Scenarios

Scenario	FJD Adder	WCI Allowance Price	RGGI Allowance Price	MGGRA Allowance Price	Imports from WCI (Quebec and Manitoba)	Exports to WCI (Quebec and Manitoba)	Imports from Non-WCI	Exports to Non-WCI	Total Imports	Total Exports
	$/MWh	*$/tonne*	*$/tonne*	*$/tonne*	*TWh*	*TWh*	*TWh*	*TWh*	*TWh*	*TWh*
Scenario 1 (Base Case)	0	0	2.06	0	1.8	10.6	2.0	17.9	3.8	28.5
Scenario 2	0	30	2.06	0	2.2	9.8	5.6	9.2	7.8	18.9
Scenario 3	15	30	2.06	0	2.2	9.8	5.1	9.4	7.3	19.2
Scenario 3a	30	60	2.06	0	2.6	9.4	7.8	7.2	10.3	16.7
Scenario 4	30	30	2.06	0	2.2	9.8	5.1	9.4	7.3	19.2
Scenario 5	0	15	2.06	0	2.0	10.2	3.2	13.3	5.2	23.5
Scenario 6	7.5	15	2.06	0	2.0	10.2	3.0	13.6	5.0	23.8
Scenario 7	15	15	2.06	0	2.0	10.2	3.0	13.6	5.0	23.7
Scenario 8	7.5	15	15	0	1.8	10.5	2.6	15.6	4.4	26.0

Table 31: Summary 2012 Results – Imports and Exports for Manitoba for Simple Scenarios

Scenario	FJD Adder	WCI Allowance Price	RGGI Allowance Price	MGGRA Allowance Price	Imports from WCI (Ontario)	Exports to WCI (Ontario)	Imports from Non-WCI	Exports to Non-WCI	Total Imports	Total Exports
	$/MWh	*$/tonne*	*$/tonne*	*$/tonne*	*TWh*	*TWh*	*TWh*	*TWh*	*TWh*	*TWh*
Scenario 1 (Base Case)	0	0	2.06	0	0.3	1.8	3.7	7.7	4.0	9.5
Scenario 2	0	30	2.06	0	0.1	2.0	4.0	7.3	4.2	9.3
Scenario 3	15	30	2.06	0	0.1	2.0	4.0	7.3	4.2	9.3
Scenario 3a	30	60	2.06	0	0.1	2.3	4.3	6.8	4.3	9.1
Scenario 4	30	30	2.06	0	0.1	2.0	4.0	7.3	4.2	9.3
Scenario 5	0	15	2.06	0	0.2	1.9	3.8	7.5	4.0	9.4
Scenario 6	7.5	15	2.06	0	0.2	1.9	3.8	7.5	4.1	9.4
Scenario 7	15	15	2.06	0	0.2	1.9	3.8	7.5	4.0	9.4
Scenario 8	7.5	15	15	0	0.3	1.8	3.7	7.7	4.0	9.5

Table 32: Summary 2020 Results – Imports and Exports for Quebec for Simple Scenarios

Scenario	FJD Adder	WCI Allowance Price	RGGI Allowance Price	MGGRA Allowance Price	Imports from WCI (Ontario)	Exports to WCI (Ontario)	Imports from Non-WCI	Exports to Non-WCI	Total Imports	Total Exports
	$/MWh	*$/tonne*	*$/tonne*	*$/tonne*	*TWh*	*TWh*	*TWh*	*TWh*	*TWh*	*TWh*
Scenario 1 (Base Case)	0	0	2.06	0	5.6	1.6	2.4	24.7	8.0	26.4
Scenario 2	0	30	2.06	0	2.3	5.2	5.0	17.9	7.3	23.1
Scenario 3	15	30	2.06	0	3.9	3.2	3.3	20.5	7.2	23.7
Scenario 3a	30	60	2.06	0	3.7	3.8	3.5	19.6	7.3	23.3
Scenario 4	30	30	2.06	0	4.2	3.1	3.0	21.1	7.2	24.3
Scenario 5	0	15	2.06	0	3.3	3.3	3.8	20.3	7.0	23.6
Scenario 6	7.5	15	2.06	0	4.2	2.4	3.0	22.1	7.2	24.5
Scenario 7	15	15	2.06	0	4.5	2.3	2.6	22.5	7.1	24.8
Scenario 8	7.5	15	15	0	5.8	1.4	2.3	24.8	8.1	26.2

Table 33: Summary 2020 Results – Imports and Exports for Ontario for Simple Scenarios

Scenario	FJD Adder	WCI Allowance Price	RGGI Allowance Price	MGGRA Allowance Price	Imports from WCI (Quebec and Manitoba)	Exports to WCI (Quebec and Manitoba)	Imports from Non-WCI	Exports to Non-WCI	Total Imports	Total Exports
	$/MWh	*$/tonne*	*$/tonne*	*$/tonne*	*TWh*	*TWh*	*TWh*	*TWh*	*TWh*	*TWh*
Scenario 1 (Base Case)	0	0	2.06	0	3.9	5.7	11.5	3.3	15.3	9.0
Scenario 2	0	30	2.06	0	7.4	2.3	17.2	1.1	24.7	3.4
Scenario 3	15	30	2.06	0	5.5	3.9	14.9	1.4	20.4	5.3
Scenario 3a	30	60	2.06	0	6.0	3.7	16.4	0.9	22.4	4.6
Scenario 4	30	30	2.06	0	5.4	4.2	14.7	1.4	20.1	5.6
Scenario 5	0	15	2.06	0	5.6	3.3	14.7	1.8	20.3	5.1
Scenario 6	7.5	15	2.06	0	4.7	4.3	13.4	2.1	18.1	6.4
Scenario 7	15	15	2.06	0	4.6	4.5	13.2	2.2	17.8	6.6
Scenario 8	7.5	15	15	0	3.6	5.8	12.8	2.2	16.4	8.0

Table 34: Summary 2020 Results – Imports and Exports for Manitoba for Simple Scenarios

Scenario	FJD Adder	WCI Allowance Price	RGGI Allowance Price	MGGRA Allowance Price	Imports from WCI (Ontario)	Exports to WCI (Ontario)	Imports from Non-WCI	Exports to Non-WCI	Total Imports	Total Exports
	$/MWh	*$/tonne*	*$/tonne*	*$/tonne*	*TWh*	*TWh*	*TWh*	*TWh*	*TWh*	*TWh*
Scenario 1 (Base Case)	0	0	2.06	0	0.0	2.2	2.4	10.1	2.4	12.3
Scenario 2	0	30	2.06	0	0.0	2.3	2.4	9.9	2.4	12.2
Scenario 3	15	30	2.06	0	0.0	2.3	2.4	9.9	2.4	12.2
Scenario 3a	30	60	2.06	0	0.0	2.2	2.3	9.9	2.3	12.2
Scenario 4	30	30	2.06	0	0.0	2.3	2.4	9.9	2.4	12.2
Scenario 5	0	15	2.06	0	0.0	2.3	2.4	10.0	2.4	12.3
Scenario 6	7.5	15	2.06	0	0.0	2.3	2.4	10.0	2.4	12.2
Scenario 7	15	15	2.06	0	0.0	2.3	2.4	10.0	2.4	12.2
Scenario 8	7.5	15	15	0	0.0	2.3	2.4	10.0	2.4	12.2

6.2 Detailed Results for Complex Scenarios

Table 35: Summary 2020 Results - WCI Generation, Emissions, Flows for Complex Scenarios

	Scenario Details				Generation		Gross CO_2 Emissions		Flows	
Scenario	**FJD Adder** *$/MWh*	**WCI Allowance Price** *$/tonne*	**RGGI Allowance Price** *$/tonne*	**MGGRA Allowance Price** *$/tonne*	**WCI** *TWh*	**Non-WCI** *TWh*	**WCI** *Million Tonnes*	**Non-WCI** *Million Tonnes*	**Imports Into WCI** *TWh*	**Exports From WCI** *TWh*
Scenario 9 (Base Case)	0	0	2.06	0	410	3,330	14.8	1,911.7	16.3	38.4
Scenario 10	30	30	2.06	0	392	3,348	7.7	1,919.5	24.5	29.1
Scenario 12	30	30	30	30	406	3,332	12.8	1,885.5	16.5	35.9
Scenario 10a	15	30	2.06	0	392	3,348	7.7	1,919.6	24.6	29.1

6.3 Provincial Breakdown for Simple Scenarios

Table 36: Summary 2012 Results – WCI Generation by Type for Simple Scenarios

Scenario	WCI Allowance Price	FJD Adder		Manitoba				Ontario				Quebec			
	$/tonne	*kg/MWh*	*$/MWh*	*Coal*	*Gas/Oil*	*Non-Fossil*	*Total Generation*	*Coal*	*Gas/Oil*	*Non-Fossil*	*Total Generation*	*Coal*	*Gas/Oil*	*Non-Fossil*	*Total Generation*
Annual Generation (TWh)															
Scenario 1 *[Base Case]*	0	0	0	0.1	0.0	31.4	31.5	11.6	16.8	144.9	173.3	0.0	0.4	200.5	200.9
Scenario 2	30	0	0	0.0	0.0	31.4	31.5	6.2	8.3	144.9	159.3	0.0	0.4	200.5	200.8
Scenario 3	30	500	15	0.1	0.0	31.4	31.5	6.8	8.4	144.9	160.1	0.0	0.4	200.5	200.8
Scenario 3a	60	500	30	0.0	0.0	31.4	31.4	0.0	9.6	144.9	154.5	0.0	0.4	200.5	200.8
Scenario 4	30	1000	30	0.1	0.0	31.4	31.5	6.8	8.4	144.9	160.2	0.0	0.4	200.5	200.8
Scenario 5	15	0	0	0.1	0.0	31.4	31.5	11.5	10.3	144.9	166.7	0.0	0.4	200.5	200.8
Scenario 6	15	500	7.5	0.1	0.0	31.4	31.5	11.5	10.7	144.9	167.1	0.0	0.4	200.5	200.8
Scenario 7	15	1000	15	0.1	0.0	31.4	31.5	11.5	10.7	144.9	167.1	0.0	0.4	200.5	200.8
Scenario 8	15	500	7.5	0.1	0.0	31.4	31.5	11.5	13.7	144.9	170.1	0.0	0.4	200.5	200.9
Difference in Generation from Base Case (TWh)															
Scenario2	30	0	0	-0.1	0.0	0.0	-0.1	-5.4	-8.5	0.0	-13.9	0.0	0.0	0.0	0.0
Scenario3	30	500	15	0.0	0.0	0.0	0.0	-4.8	-8.4	0.0	-13.2	0.0	0.0	0.0	0.0
Scenario3a	60	500	30	-0.1	0.0	0.0	-0.1	-11.6	-7.2	0.0	-18.8	0.0	0.0	0.0	0.0
Scenario4	30	1000	30	0.0	0.0	0.0	0.0	-4.7	-8.3	0.0	-13.1	0.0	0.0	0.0	0.0
Scenario5	15	0	0	0.0	0.0	0.0	0.0	0.0	-6.5	0.0	-6.6	0.0	0.0	0.0	0.0
Scenario6	15	500	7.5	0.0	0.0	0.0	0.0	0.0	-6.1	0.0	-6.1	0.0	0.0	0.0	0.0
Scenario7	15	1000	15	0.0	0.0	0.0	0.0	0.0	-6.1	0.0	-6.1	0.0	0.0	0.0	0.0
Scenario8	15	500	7.5	0.0	0.0	0.0	0.0	-0.1	-3.1	0.0	-3.2	0.0	0.0	0.0	0.0

Table 37: Summary 2020 Results – WCI Generation by Type for Simple Scenarios

Scenario	WCI Allowance Price	FJD Adder		Manitoba				Ontario				Quebec			
	$/tonne	*kg/MWh*	*$/MWh*	*Coal*	*Gas/Oil*	*Non-Fossil*	*Total Generation*	*Coal*	*Gas/Oil*	*Non-Fossil*	*Total Generation*	*Coal*	*Gas/Oil*	*Non-Fossil*	*Total Generation*
Annual Generation (TWh)															
Scenario 1 *[Base Case]*	0	0	0	0.0	0.0	36.7	36.7	0.0	34.1	106.6	140.7	0.0	3.0	229.1	232.2
Scenario 2	30	0	0	0.0	0.0	36.7	36.7	0.0	18.5	107.0	125.5	0.0	0.7	228.9	229.6
Scenario 3	30	500	15	0.0	0.0	36.7	36.7	0.0	24.7	107.2	131.9	0.0	1.4	228.9	230.3
Scenario 3a	60	500	30	0.0	0.0	36.7	36.7	0.0	20.0	109.2	129.2	0.0	1.0	228.9	229.9
Scenario 4	30	1000	30	0.0	0.0	36.7	36.7	0.0	25.3	107.2	132.5	0.0	2.0	228.9	230.9
Scenario 5	15	0	0	0.0	0.0	36.7	36.7	0.0	25.0	106.6	131.6	0.0	1.4	229.0	230.4
Scenario 6	15	500	7.5	0.0	0.0	36.7	36.7	0.0	28.7	106.6	135.3	0.0	2.1	229.0	231.1
Scenario 7	15	1000	15	0.0	0.0	36.7	36.7	0.0	29.2	106.6	135.8	0.0	2.6	229.0	231.6
Scenario 8	15	500	7.5	0.0	0.0	36.7	36.7	0.0	31.7	106.8	138.4	0.0	2.9	229.0	231.9
Difference in Generation from Base Case (TWh)															
Scenario2	30	0	0	0.0	0.0	0.0	0.0	0.0	-15.7	0.4	-15.3	0.0	-2.3	-0.2	-2.5
Scenario3	30	500	15	0.0	0.0	0.0	0.0	0.0	-9.4	0.6	-8.8	0.0	-1.7	-0.2	-1.8
Scenario3a	60	500	30	0.0	0.0	0.0	0.0	0.0	-14.2	2.6	-11.5	0.0	-2.1	-0.2	-2.3
Scenario4	30	1000	30	0.0	0.0	0.0	0.0	0.0	-8.8	0.6	-8.2	0.0	-1.1	-0.2	-1.3
Scenario5	15	0	0	0.0	0.0	0.0	0.0	0.0	-9.2	0.0	-9.1	0.0	-1.6	-0.2	-1.8
Scenario6	15	500	7.5	0.0	0.0	0.0	0.0	0.0	-5.5	0.0	-5.5	0.0	-0.9	-0.1	-1.1
Scenario7	15	1000	15	0.0	0.0	0.0	0.0	0.0	-4.9	0.0	-4.9	0.0	-0.5	-0.1	-0.6
Scenario8	15	500	7.5	0.0	0.0	0.0	0.0	0.0	-2.5	0.2	-2.3	0.0	-0.1	-0.1	-0.2

Note

1.Minor variations in non-fossil generation across different scenarios is a PROMOD rounding error

Economic Analysis and Modeling Support to the Western Climate Initiative

ENERGY 2020 Model Inputs and Assumptions

Revision Date - 26 April 2010

Prepared for:
Western Governors' Association

Prepared By:
ICF International
1725 I St. NW
Suite 1000
Washington DC
20006

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Acronyms & Definitions

AEO	Annual Energy Outlook (published by EIA)
ARB	California Air Resources Board
BPA	Bonneville Power Administration
Btu	British Thermal Units
CAC	Criteria Air Contaminants (SO_x, NO_x, PM, etc.)
CFL	Compact Fluorescent Light bulb
CHP	Combined Heat and Power
CO_2e	Carbon Dioxide equivalent
GDP	Gross Domestic Product
GO	Gross Output
GWP	Global Warming Potential
DG	Distributed Generation
E3	Energy and Environmental Economics, Inc.
EIA	Energy Information Administration
EPACT	Energy Policy Act of 2005
ESCO	Energy Service Company
GHG	Greenhouse Gas
IECC	International Energy Conservation Code
IGCC	Integrated Gasification Combined Cycle
kW	Kilowatt
kWh	Kilowatt-hour
Mt	Megatonne
MW	Megawatt
MWe	Megawatt electric
Mt CO_2e	Megatonnes Carbon Dioxide Equivalent (also referred to as MTCE)
NOx	Nitrogen Oxides
OGCC	Oil/Gas Combined Cycle Turbine
OGCT	Oil/Gas Combustion Turbine
OGST	Oil/Gas Steam Turbine
PC	Pulverized Coal
REMI	Regional Economic Models, Inc.
RECS	Renewable Energy Certificates
Rest of US	Balance of systems in US
SO_x	Sulfur Oxides (including sulfur dioxide)
USEPA	United States Environmental Protection Agency
W	Watt
WCI	Western Climate Initiative
WECC	Western Electricity Coordinating Council

1 Background and Project Scope

The Western Climate Initiative (WCI) retained ICF International and its partner Systematic Solutions Inc. (SSI), to assist in modeling a cap-and-trade system for the western US and Canada. For 30 years, ICF has been known for its sophisticated models. Over that time, ICF has worked to build, enhance, and apply these tools for a variety of public and private sector clients to help answer complex questions on energy and environmental market issues. Over the same period, SSI has performed analysis to solve problems in all facets of the energy market, including electric and natural gas utilities, energy extracting industries, and the transportation sector. In addition, both firms have applied macroeconomic models in conjunction with their energy market modeling tools to address broader questions of economic impacts.

When this modeling was initiated, all eight WCI Partner jurisdictions were located within the Western Electricity Coordinating Council (WECC) region. In late 2008, ICF was authorized to expand the modeling effort to include all 11 of the current partners; including the provinces of Manitoba, Ontario and Québec. In order to properly represent the expanded geographic coverage of the WCI, the model was expanded to represent all of the US and Canada. In the process of building this expanded model, ICF took the opportunity to update some information in the model and address issues raised by the WCI Economic Modeling Team (EMT) and WCI stakeholders. The update also included revising the economic forecasts to include the effects of the economic recession.

This report describes the ENERGY 2020 model, assumptions in the analysis, and the input data and data sources.

2 Analytic Approach

This project uses ENERGY 2020 to model the business-as-usual outlook for the WCI Partner jurisdictions[1] as well as surrounding states and provinces and the impact of potential greenhouse gas (GHG) emissions reduction policies.

ENERGY 2020 is an integrated multi-region energy model that provides complete and detailed, all-fuel demand and supply sector simulations. These simulations can additionally include macroeconomic interactions to determine the benefits or costs to the local economy of new facilities or changing energy prices. The model can be used in regulated as well as deregulated and transitioning environments. GHG and criteria air contaminant pollution emissions and costs, including allowances and trading, are endogenously determined, thereby allowing assessment of environmental risk and co-benefit impacts.

The basic implementation of ENERGY 2020 for North America now contains a user-defined level of aggregation down to the 10 provincial and 50 state (and sub-state) level. ENERGY 2020 contains historical information on all generating units in the US and Canada. Data for Mexico can be incorporated as needed. ENERGY 2020 is parameterized with local data for each region/state/province as well as all the associated energy suppliers it simulates. Thus, it

[1] Arizona, California, Montana, New Mexico, Oregon, Utah, Washington, British Columbia, Manitoba, Ontario and Québec.

captures the unique characteristics (physical, institutional and cultural) that affect how people make choices and use energy. Collections of state and provincial models are currently validated from 1986 to the latest quarterly numbers.[2]

ENERGY 2020 can be linked to a detailed macroeconomic model to determine the economic impacts of energy/environmental policy and the energy and environmental impacts of national economic policy. For US regional and state level analyses, the REMI macroeconomic model is regularly linked to ENERGY 2020.[3] The Informetrica macroeconomic model is linked to ENERGY 2020 for Canadian national and provincial efforts.[4] The REMI and Informetrica macroeconomic models include inter-state/provincial, US and world trade flows, price and investment dynamics, and simulate the real-time impact of energy and environmental concerns on the economy and vice versa.

The structure of the model is well tested and has been used to simulate not only US and Canadian energy and environmental dynamics, but also those of several countries in South America, Western, Central, and Eastern Europe. These efforts include strategic and tactical analyses for both planning and energy industry restructuring/deregulation. In the 1990s, the US EPA made ENERGY 2020 available to interested states to analyze emissions, energy, and economic impacts of state-level climate change initiatives. Further, the model has been used successfully for deregulation analyses in all the US states and Canadian provinces. Many US and Canadian energy suppliers use the model for the analysis of combined electricity and gas deregulation dynamics.[5]

The default model simulates demand by three residential categories (single family, multi-family, and agriculture/rural), over 40 NAICS commercial and industrial categories[6], and three transportation services (passenger, freight, and off-road). There are approximately six end-uses per category and six technology/mode families per end-use.[7] Currently the technology families correspond to six fuels groups (oil, gas, coal, electric, solar and biomass) and 30 detailed fuel products. The transportation sector contain 45 modes including various type of automobile, truck, off-road, bus, train, plane, marine and alternative-fuel vehicles. More end-uses, technologies, and modes can be added as data allow. For all end-uses and fuels, the model is parameterized based on historical, locale-specific data. The load duration curves are dynamically built up from the individual end-uses to capture changing conditions under consumer choice and combined gas/electric programs.

Each energy demand sector includes cogeneration, self-generation, and distributed generation simulation, including mobile-generation, micro-turbines, and fuel-cells. Fuel-switching responses

[2] Energy supplier data comes from FERC and US DOE for the US and Statistics Canada. US and Canadian fuel and demand data come from the US Department of Energy and Natural Resources Canada, respectively. US and Canadian pollution data come from US EPA and Environment Canada, respectively.

[3] Regional Economic Models, Inc. www.remi.com

[4] Informetrica Limited www.informetrica.ca

[5] ENERGY 2020 is the only model known to have simulated and predicted the dynamics that occurred in the UK electric deregulation. These include gaming, market consolidation and re-regulation dynamics.

[6] NAICS is the North America Industrial Classification System which was developed jointly by the U.S., Canada, and Mexico to provide new comparability in statistics about business activity across North America.

[7] End-uses include Process Heat, Space Heating, Water Heating, Other Substitutable, Refrigeration, Lighting, Air Conditioning, Motors, and Other Non-Substitutable (Miscellaneous). Detailed modes include: small auto, large auto, light truck, medium-weight truck, heavy-weight truck, bus, freight train, commuter train, airplane, and marine. Each mode type can be characterized by gasoline, diesel, electric, ethanol, NG, propane, fuel-cell, or hybrid vehicles.

are rigorously determined. The technology families (which can be split, as an option, to portray specific technology dynamics) are aggregates that, within the model, change building shell, economic-process and device efficiency and capital costs as price or other information that the decision makers see, change. ENERGY 2020 utilizes the historical and forecast data developed for each technology family to parameterize and disaggregate the model.

The supply portion of the model includes endogenous detailed electric supply simulation of capacity expansion/construction, rates/prices, load shape variation due to weather, and changes in regulation.[8] The model dispatches plants according to the specified rules whether they are optimal or heuristic and simulates transmission constraints when determining dispatch.[9] A sophisticated dispatch routine selects critical hours along seasonal load duration curves as a way to provide a quick but accurate determination of system generation. Peak and base hydro usage is explicitly modeled to capture hydro-plant impacts on the electric system.

ENERGY 2020 supply sectors include electricity, oil, natural gas, refined petroleum products, ethanol, land-fill gas, and coal supply. Energy used in primary production and emissions associated with primary production and its distribution is included in the model. The supply sectors included in a particular implementation of ENERGY 2020 will depend on the characteristics of the area being simulated and the problem being addressed. If the full supply sector is not needed, then a simplified simulation determines delivered-product prices.

The ENERGY 2020 model includes pollution accounting for both combustion (by fuel, end-use, and sector) and non-combustion, and non-energy (by economic activity) for SO_2, NO_2, N_2O, CO, CO_2, CH_4, PMT, $PM_{2.5}$, PM_5, PM_{10}, VOC, CF_4, C_2F_6, SF_6, and HFC at the state and provincial level by economic sector. Other (gaseous, liquid, and solid) pollutants can be added as desired. Pollution does not need to be determined directly by coefficients but can recognize the accumulation of capital investments that result in pollution emission with usage. National and international allowance trading is also included. Plant dispatch can consider emission restrictions.

The model captures the feedback among energy consumers, energy suppliers, and the economy using Qualitative Choice Theory and co-integration.[10] For example, a change in price affects demand that then affects future supply and price. Increased economic activity increases demand; increased demand increases the investment in new supplies. The new investment affects the economy and energy prices. The energy prices also affect the economy.

Finally, the system includes confidence and validity testing software that places uncertainty bounds on simulation results, quantifies confidence intervals, and ranks the contributions to uncertainty in future conditions. This feature can be used to limit data efforts to information most important to the analysis.

---

[8] ENERGY 2020 does include a complete, but aggregate representation of the electric transmission system. Electric transmission data is provided by FERC, the Department of Energy, and the National Electric Reliability Council. The dispatch technologies in the basic model include: Oil/Gas Combustion turbine, Oil/Gas Combined Cycle, Oil/Gas Combined Cycle with CCS, Oil/Gas Steam Turbine, Coal Steam Turbine, Advanced Coal, Coal with CCS, Nuclear, Baseload Hydro, Peaking Hydro, Small Hydro, Wind, Solar, Wave, Geothermal, Fuel-cells, Flow-Battery Storage, Pumped Hydro, Biomass, Landfill Gas, Trash, and Biogas.

[9] A 110 node transmission system is used in the default model, but a full AC load-flow bus representation model has also been interfaced with ENERGY 2020.

[10] The model has used the work of Daniel McFadden and Clive Granger since its inception in the late 1970s.

In order to assess the potential impacts of proposed policy options, a b*usiness-as-usual* scenario is developed as a point of reference. This *Reference Case* represents a scenario that is viewed as a reasonable expectation of how the economy, energy use and emissions might develop over time.

Part of the nature of developing a Reference Case is the need to address inherently uncertain issues that can have significant impacts on future energy use and emissions. No forecast is going to be *right* or *accurate* in that no one can tell today how some of the key underlying issues may develop. Given the level of uncertainty involved in any projection of a possible future, caution should be used in applying a high level of precision to the modeling results. Understanding the Reference Case, however, can be extremely useful in providing an underlying structure against which to model proposed policies, and in determining directionality and cause and effect.

Numerous assumptions are required to perform an analysis of this type across a range of topic areas, including economic developments, fuel and electric markets, and regulatory structures. Projected outcomes are only as good as the input assumptions upon which they are based, with more rigorous assumptions leading to a more rigorous analysis. The inputs and assumptions described in this document were developed to provide as accurate a representation as possible of the activities and structures underlying energy use and GHG emissions in the WCI Partner jurisdictions.

3 Reference Case Inputs

ENERGY 2020 derives energy demands, such as the demand for electricity based on economic activity and device efficiency. The following sections provide a brief overview of the data inputs and assumptions as well as the sources of data used in the Reference Case. Actual data inputs for specific elements such as generating units, emission factors, etc., can be provided separately in Excel spreadsheets as required.

As a multi-sector analytical tool, ENERGY 2020 requires data and assumptions covering a broad range of economic sectors and their interactions. In most cases, the necessary data – both historical and projected – is available from the federal government (EIA, EPA, etc.). In past analyses, ENERGY 2020 has relied heavily on these federal sources to populate and calibrate the model. In developing the model for this project, a considerable amount of state-specific information was available and has been used wherever possible.

The following sections provide an overview of the data and assumptions that are required to perform the multi-sector analysis, and list the data sources used to populate ENERGY 2020.

Data inputs for ENERGY 2020 are required in five areas: [11]

1. Population and economic
2. Fuel prices
3. Energy use and consumption
4. Emissions and air regulations
5. Electricity generation capacity and operation

[11] "Data" here refers to both historical data and assumptions and projections of future inputs.

The sections below list the key data elements required in each of these areas, along with the sources that have been used to supply these data for other analyses. Appendix B lists a number of default data sources used by the model. The sections that follow provide a more specific description of the data used for this project including state-specific data used in place of national sources.

ENERGY 2020 requires both historical data and projections to calibrate and generate forward-looking projections. Various historical data will be used for the period 1985-2005 (the last year for which certain detailed sectoral and end-use are available). Projections for the period to be modeled (e.g. through 2030) will be gathered where possible to provide points of comparison and check the reasonableness of the projection.

The implementation of ENERGY 2020 for this project began with inclusion of the states and provinces within the Western Electricity Coordinating Council (WECC); specifically Arizona, California, Montana, New Mexico, Oregon, Utah, Washington, and British Columbia. Manitoba was initially not included in this modeling due to the complexity of extending the model beyond the WECC. Since that time, new partners have joined the WCI, including Ontario and Quebec. The current phase of the project expands the modeling to include all eleven current WCI Partner jurisdictions. In order to fully represent the interactions between these jurisdictions and their neighbouring states and provinces, the model has been expanded to represent all of the US and Canada.

3.1 *Population and Economic Data*

Demographic and economic data is required to generate demands for services. The historic data for the US states was obtained from the US Bureau of Economic Analysis (BEA). For the Canadian provinces, historic data is from Statistics Canada's CANSIM.

The following data sources were used to establish the reference case for the WCI policy modeling:

Description of Data/Input	**Sources**	**Detailed Reference**
Total population, historical and growth over time	US Census Bureau	*Historic (1985-2006):* Regional Economic Information System, Bureau of Economic Analysis, U.S. Department of Commerce http://www.bea.gov/regional/spi/default.cfm?satable=summary *California:* California population taken from: CEC *California Energy Demand 2008-2018 Staff Revised Forecast*
	Statistics Canada	Statistics Canada Table 051-0001 (based on census data)
	Future	For US - Future annual population growth rates are taken from Regional Forecasts from AEO then applied to the state historical population. Annual Energy Outlook 2007 (February 2007 release). http://www.eia.doe.gov/oiaf/aeo/supplement/suptab_1.xls through suptab_9.xls For Canada: projected based on Informetrica forecast.
Population by housing type	US Census Bureau	Population Estimates Program, Population Division

Description of Data/Input	Sources	Detailed Reference
(single-family, multi-family, etc.)	Statistics Canada	Household type, Structural Type of Dwelling and housing tenure for Private Households of Canada
Households by housing type (single-family, multi-family, etc.)	US Census Bureau	Household splits (data through 2001 then held constant): *Source: U.S. Census Bureau, Housing and Household Economic Statistics Division* Last Revised: *December 16, 2005* http://www.census.gov/hhes/www/housing/census/historic/units.html **Household size** US Census Bureau, Census 2000 - assumes household size is same for all housing types in state. **Number of households** Calculated based on population, household fraction, and household size.
	Statistics Canada	Household type, Structural Type of Dwelling and Housing Tenure for Private Households of Canada
	Future	Projected based on Informetrica forecast.
Personal income	US Bureau of Economic Analysis	*Historic (1985-2006)*: Bureau of Economic Analysis, 6/24/07 http://www.bea.gov/regional/spi/default.cfm?satable=summary *California*: Estimates provided by ARB (see Appendix C).
	Statistics Canada	Statistics Canada CANSIM table 384-0012
	Future	Apply changes in historic Personal Income to Total GRP ratio and apply to future to forecast out to 2030.

Project partners were provided with the default projections proposed for use in the modeling and invited to provide alternative jurisdiction-specific projections.

Several partners elected to accept the initial model projections, including:

- Montana
- Oregon
- Utah
- British Columbia
- California

It should be noted that the economic projection for California had been provided by the state based on work done as part of a prior project.

Some partners chose to provide jurisdiction-specific projections for some of the demographic and economic data, including:

- Arizona: personal income; population (state total); and gross output (from REMI)
- New Mexico: population
- Washington: population

For all other partners data from the sources listed in the tables above was used.

Population, housing and economic output projections provided by the partners are presented in Appendix C.

3.1.1 Economic Forecast

Economic conditions changed quite dramatically over the course of this project. ENERGY 2020 requires a detailed state and provincial level sector-by-sector forecast for the US and Canadian economy as a basis for modeling future economic activity and emissions. A projection for the US economy was obtained from Regional Economic Models, Inc. (REMI). For the Canadian economy, a long term projection prepared by Informetrica Ltd., was made available by the National Energy Board. Both of these projections pre-dated the economic downturn that started in late 2008. Given the speed with which the economy has changed, we found that economic forecasts with the level of detail required by the model were not yet available at the time when the Reference Case was being prepared.

In order to provide a more realistic representation of current economic expectations, ICF/SSI in consultation with the Economic Modeling Team (EMT) sought more recent projections that would reflect current expectations of the two economies. For the US, the projection of the Congressional Budget Office[12] was selected as providing a reasonable representation of a consensus view at that time. Recognizing the strong interaction between the two national economies, we sought projections for the Canadian economy which projected comparable US conditions to those presented in the CBO forecast. The Conference Board of Canada,[13] in its Winter 2009 Outlook, provides a forecast for both the Canadian and US economy. The depth and length of the US downturn presented in the Board's US outlook were reasonably aligned with the Congressional Budget Office's expectations. Unfortunately this projection did not have the level of detail required by the model. As a result, an earlier Conference Board of Canada forecast was used which implied a less severe US recession than the CBO forecast. This Canadian forecast therefore projected less of a downturn for Canada than the projection used for the U.S. These two forecasts were used to adjust the existing more detailed projections in order to reflect the effects of the economic downturn. In the case of the Conference Board projection, considerable sector detail was available to reflect differences in these impacts between provinces. Where jurisdiction specific projections had been provided by partners, these projections were also adjusted to reflect the changes in the broader economy.

3.2 *Energy Price Data*

Energy prices can play a significant role in end user decisions on equipment, capital and operating decisions. Fuel costs can be critical in determining the costs of electric dispatch, as well as input costs of some industrial processes and home heating. ENERGY2020 calculates future electric prices based in part on these fuel costs.

[12] Congress of the United States, Congressional Budget Office, The Budget and Economic Outlook: Fiscal Years 2009 to 2019, January 2009.
[13] ICF/SSI used the Conference Board's "Provincial Long Term Database" which provided the most recent available economic forecast available. The Board published a summary of its expectations for the Canadian economy in its "Canadian Outlook Executive Summary: Global Recession Weighs Heavily on Canada, Winter 2009".

Energy prices are largely determined by international markets, although domestic demand, such as electric sector demand for natural gas can influence prices. As a result, fuel prices are treated by the model as an exogenous input.

Historic energy price data are taken from US DOE State Energy Data and Statistics Canada. The model currently uses energy price forecast data for the US from the Energy Information Administration's 2009 Annual Energy Outlook Reference Case Price scenario for 2009 to 2030.[14] For Canada, the National Energy Board's price forecast is used[15].

Biomass Cost *(per MBtu in 2006$)*	
Residential	$11.53
Commercial	$10.09
Industrial	$10.06

Biomass prices in the model are based on research completed for a previous project, shown in the table below. Unlike other fuels, biomass prices are significantly influenced by local cost and supply issues.

Power prices are calculated endogenously by the model based on generation costs and dispatch. While, the model estimates retail electricity prices, actual consumer prices may differ as a result of political, regulatory or market influences. The model can be calibrated to actual prices, within reasonable parameters, for the historic period.

Given the time and resources available for the project, the model does not account for the different regulatory regimes among the partner jurisdictions with respect to electric price regulation (i.e., cost-of-service ratemaking vs. various forms of market-driven pricing). The intent of the modeling is rather to produce reasonable estimates of retail prices at the state or provincial level based on generation costs and historical mark-ups above generation costs.

3.3 *Historic Energy Consumption Data*

ENERGY 2020 models energy use at the end-use level within each economic sector based on the existing physical stock and the efficiency of that stock. The database of device efficiencies reflects both the average efficiency of energy use for current stocks and the efficiency/energy alternatives available to consumers at the margin. Technology and efficiency choices are modeled based on past experience with consumer choice rather than on a purely economic evaluation.

Historic energy use and consumption data used in the model is derived from the federal Energy Information Administration (EIA) State Energy Data (SEDS) database. Where state-specific data were available, these data was used to replace national data sources.

Default sectoral and end-use data as well as energy intensities are based on the Residential Energy Consumption Survey (RECS), Commercial Energy Consumption Survey (CECS) and Manufacturers Consumption Energy Survey (MECS).

[14] Energy Information Administration, Annual Energy Outlook 2008, Report #DOE/EIA-0383(2008), June 2008, http://www.eia.doe.gov/oiaf/aeo/
[15] Canada's Energy Future: An Energy Market Assessment, November 2007. http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/nrgyftr/2007/nrgyftr2007-eng.html

Description of Data/Input	Sources Used/Available
Residential Data - Household income by housing type - No. of people per household - End-use consumption data, including fuels used for space and water heating, air conditioning, etc.	2001 EIA Residential Energy Consumption Survey (RECS), by Census Region and Division (2005 RECS in process) http://www.eia.doe.gov/emeu/recs/contents.html For Canada – Natural Resources Canada Office of Energy Efficiency Database http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/comprehensive_tables/index.cfm?attr=0
Commercial Data - Floor area by sub-sector - End-use consumption data, including fuels used for space and water heating and energy intensities	2003 EIA Commercial Buildings Energy Consumption Survey (CBECS), by Census Region and Division (2007 CBECS underway) http://www.eia.doe.gov/emeu/cbecs/contents.html For Canada – NRCan OEE Database
Industrial/Manufacturing Data - Energy use by fuel for each sub-sector and end-use	2002 EIA Manufacturing Energy Consumption Survey (MECS), by Census Region (2006 MECS underway) http://www.eia.doe.gov/emeu/mecs/contents.html For Canada – NRCan OEE Database
State/Provincial Energy Data: - Energy consumption and expenditures by sector and energy source	2004 EIA State Energy Data System (SEDS) http://www.eia.doe.gov/emeu/states/_seds.html Canada: NRCan OEE Database and CANSIM

3.4 *Historic Emission Data*

3.4.1 Emissions and Air Regulations

Historic GHG emissions are based on the Canadian national inventory published by Environment Canada and the US GHG emissions inventory as published by the EPA.[16] ENERGY 2020 is calibrated using historic information on all of the major GHG emissions including:

- Carbon dioxide (CO_2),
- Nitrous oxide (N_2O),
- Methane (CH_4),
- Sulfur hexafluoride (SF_6),
- Hydrofluorocarbons (HFCs) and
- Perfluorocarbons (PFCs).

GHG emissions are presented in CO_2 equivalent (CO_2e) terms. The global warming potentials used to convert the different greenhouse gas emissions into CO_2e terms are provided in Appendix H.

[16] EPA website: http://www.epa.gov/climatechange/emissions/usinventoryreport.html

Input	Sources Used/Available
Emissions by sector, end-use, fuel & GHG	US EPA http://www.epa.gov/climatechange/emissions/usinventoryreport.html Environment Canada http://www.ec.gc.ca/pdb/ghg/inventory_e.cfm

3.4.2 Emission Factors

Emission factors for most fuels are based on values used by ICF in developing national and state inventories. For the transportation sector however, the emission factors for CH_4 and N_20 pollutants were adapted from the Canadian National Inventory Report.[17] ENERGY 2020 calculates GHG emissions at the point of combustion for most fuels. Upstream emissions from extraction and processing are captured as part of those respective economic sectors.

Emissions associated with the use of biomass as a fuel are deemed to be biogenic and therefore not contribute to global warming. As a result, the model assumes no GHG emissions are created from the use of biomass.

Emissions from ethanol and other biofuels represent an exception from a modeling perspective. In order to capture the emissions associated with their production and distribution, the model applies full cycle emission factors for these fuels. While the combustion of ethanol and biodiesel are not deemed to result in any anthropogenic emissions, the model uses an emission factor to recognize upstream emissions.

The full-cycle emission factors used in the model for each biofuels type are shown in the table below:[18]

Corn Ethanol	76 g CO_2e / MJ
Cellulosic Ethanol	14 gCO_2e / MJ
Biodiesel	30 gCO_2e / MJ

When these fuels are used in combination with other fuels, for example in a mix of gasoline and ethanol, the emissions associated with gasoline combustion are reported as part of total gasoline-related emissions.

3.5 *Electricity Sector Data*

3.5.1 Generation Data

The electricity sector differs from other sectors in the extent to which emissions associated with power use within the state may result from emissions outside the WCI region as power is imported from or exported to other areas.

[17] Environment Canada. National Inventory Report 1990-2005, Greenhouse Gas Sources and Sinks in Canada, April 2007. (Annex 12 Emission Factors)
[18] Alexander Farrell, UC Berkeley and Daniel Sperling, UC Davis, A Low-Carbon Fuel Standard for California Part 1: Technical Analysis May 29, 2007 Table 2-3 http://www.energy.ca.gov/low_carbon_fuel_standard/UC-1000-2007-002-PT1.PDF

ENERGY 2020 contains information on every generating unit in the state or province, as well as in neighboring jurisdictions which may supply power to the state. The model tracks and uses the following information for each generating unit:

- Historic Peak Capacity (MW);
- Historic generation levels (GWh);
- Type of fuel used;
- Heat rate;
- Historic annual fuel use (PJ);
- Emissions by pollutant type;
- O&M costs;
- Capacity factors;
- Emission rates;
- Outage rates;
- State or Province;
- Physical location (latitude and longitude);
- Ownership information;
- Plant type (Hydraulic, Coal, Combined Cycle Turbine, etc.)

The data on existing and committed generating units in the US was obtained from the National Electric Energy Data System (NEEDS) 2006 database and reconciled with a list of plants from BPA. The database of plants in Canada was developed based on the Canadian IPM®[19] module, modified and updated based on information from Statistics Canada, Environment Canada and the National Energy Board.

3.5.2 Electricity Generation Capacity and Operation Data

ENERGY 2020 is populated with data describing the type, operation and performance of every generating unit in the US and Canada. In order to improve model performance, some smaller units with common characteristics have been combined (i.e. wind units at the same site, or small hydraulic units). In addition to plant-level data, the table below includes other inputs necessary to describe the electric system, including transmission capability.

Input	Sources Used/Available
Plant type	Annual Electric Generator Report: EIA Form 860 (2006) Canadian IPM® Base Case 2004[20] Natural Resources Canada, Canada's Energy Outlook: Reference Case 2006[21] Supplemented by National Energy Board info.
Plant capacity	Annual Electric Generator Report: EIA Form 860 (2006) Canada: as above
Plant historical generation	EIA Form 906/920 (2001-2006) Total generation output by plant type for California from

[19] ICF's Integrated Planning Model®.
[20] http://www.ec.gc.ca/cleanair-airpur/caol/canus/IPM_TECHNICAL/ipm_technical_report/toc_e.cfm
[21] http://www.nrcan-rncan.gc.ca/com/resoress/publications/peo/peo-eng.php

Input	Sources Used/Available
	CEC Canada: as above
Plant fuel type	Annual Electric Generator Report: EIA Form 860 (2006) Canada: as above
Plant Heat Rate	EIA Form 906/920 (2001-2006) Canada: as above
Plant fuel consumption	EIA Form 906/920 (2001-2006)
Plant emissions by pollutant	EPA CAMD (2001-2006) Environment Canada
Plant costs (operation and maintenance, variable and fixed)	CA: E3 model data Canada: as above
Plant historical capacity factor	EIA Form 906/920 (2001-2006) Statistics Canada
Plant availability (outages)	Calculated using generation data Statistics Canada
Plant owner and location	Annual Electric Generator Report: EIA Form 860 (2006) Canada: as above
Planned capacity additions and retirements	Annual Electric Generator Report: EIA Form 860 California Public Utility Commission GHG Modeling process (E3) NRCan Energy Outlook
Transmission Capability	Canada: National Energy Board, *Canadian Electricity Trends and Issues (2001)* & *Canadian Electricity Exports and Imports (2001)*; National Resources Canada, *Electric Power in Canada 1998 – 1999*; NERC, *2004 Summer Assessment* & *2004 Winter Assessment: Reliability in the Bulk Electricity Supply in North America* Western US – Additional data provided by BPA and reports from the WECC (Approved 2006 Spring OTC Limits, March 16, 2006).

This data has been compared to generation data provided as part of modeling for the California Public Utilities Commission.[22]

The resulting list of generating units was matched to emission data from the EPA and Environment Canada in order to calculate emission rates. The resulting emission rates for the targeted GHG emissions were then reviewed for reasonableness based on plant type and capacity factors, etc.

Historic generation by plant type will be calibrated with historic generation data available from the EIA.

[22] www.ethree.com/cpuc_ghg_model.html

3.5.3 Transmission Structure and Dispatch

Power flows between neighboring US states are modeled within ENERGY 2020 based on existing transmission capabilities and interconnections as obtained from NERC reports.

Appendix D describes the inter-regional transmission capabilities between model regions (or nodes) as well as the maximum capacity limit of each transmission path used in the model. Interconnection capacities and transmission nodes used in the model were based on the IPM® Model 2006[23] updated to reflect changes in the region based on past work for past clients including the Bonneville Power Administration and review by the Economic Modeling Team.

Generation is dispatched at the node level for a set of sample hours in each season. Each node is economically dispatched, selecting lowest cost generation first with the resulting clearing price determining the generation price for that node as described in Appendix A. As part of the calculation the model can utilize resources from a neighboring node within the constraints of the transfer capacity between nodes. The transfer of energy between nodes is subject to a 1% loss to represent additional transmission losses.

3.5.4 Planned Capacity Changes

As part of the modeling process, ENERGY 2020 builds new capacity endogenously as needed to meet capacity and reserve requirements or to minimize the total cost of generation (e.g., in response to allowance prices). At any given time, however, plans may already be in place to build, re-furbish, upgrade or retire generation facilities. These plans must be incorporated into the model in order to reflect decisions and commitments that have already been made.

For this project, we reviewed information on generation projects planned in the Region, with particular emphasis on planned coal facilities. This list was then reviewed with the WCI Economic Modeling Team to determine which projects were felt to be most likely to proceed based on the current status. While it is not possible to determine which specific projects will proceed, for modeling purposes we have assumed that the units listed in Appendix F will be built during the modeled period.

ENERGY 2020 can determine the need for new generation based on a pre-determined reserve requirement. Normally, this determination is based on the highest level of demand for power and the available capacity at the time of that peak. Some types of generation, such as wind or some types of hydro-electric generation however, may not be available at the time of the peak. For modeling purposes the model assumes that only 15% of installed wind capacity is available at the time of the peak.

[23] Table 3.5 of section 3 of the documentation for the EPA Base Case 2006 (v3.0) posted on the EPA website: http://epa.gov/airmarkets/progsregs/epa-ipm/index.html#docs

3.5.5 New Generation Characteristics

The costs and characteristics of new generation are based on information developed as part of the GHG modeling process for the California Public Utility Commission[24] and are shown in Appendix G.

Carbon capture and storage (CCS) is not assumed to be available until after 2020. The performance and cost assumptions for new generating units equipped with CCS are shown in Appendix G. It should be noted that these costs represent capture costs only and do not include transportation or sequestration costs.

The model assumes that no new nuclear generation capacity will come online through 2020. Ontario nuclear units returning to service after scheduled refurbishment are not considered to be “new” capacity.

3.5.6 Industrial Generation and Co-generation

ENERGY 2020 models both utility generation, which supplies the power grid, and industrial generation which supplies a particular end user. Industrial generation is defined as power generation that is within the industrial end user’s facility and is not used to supply power to the grid. Industrial generation, as defined in ENERGY 2020, could also be referred to as self-generation or load displacement generation. Industrial generation may be supplied by any of the fuels listed below:

- Biomass
- Coal
- LPG
- Oil
- Solar
- Steam

Co-generation, or combined heat and power facilities, simultaneously generate electricity and supply a heat load. ENERGY 2020 recognizes that co-generation may occur either as industrial generation or as utility generation and may use any of a number of fuels.

- Within the power sector, these plants are treated as ‘must run’ units, meaning that they will always operate when available. Power from these units contributes to overall electricity supply. Heat from these units may be captured as part of a separate steam supply system, however, limited data is available regarding overall US steam demand.
- Within the industrial sector, co-generation capacity will run based on heating requirements. Heat produced from co-generation is used to meet industrial heat requirements based on a co-generation heat rate. Co-generated electricity is used to meet industrial power requirements, reducing net demand from the grid.

Where the heat contribution of co-generation is significant, the preferred modeling approach is to include these units in the industrial sector.

[24] www.ethree.com/cpuc_ghg_model.html

The databases used to represent electricity generation often include all significant generators, including both utility and industrial boilers and generators. By contrast, reported electricity consumption information tends to be based on metered electricity sales, and as such are net of self generation. Total electricity consumption and generation will generally be slightly higher than reported electricity sales. It is therefore important in calibrating the model with historic electricity consumption that existing generation used as industrial or self-generation be appropriately identified.

3.6 *Transportation*

ENERGY 2020 models passenger, freight and off road transportation separately, based on different underlying drivers. Transportation is assumed to be a derived demand based on levels of economic output (for freight) or personal income (for passenger). As the economic drivers (industrial gross output and personal income) grow, transportation demand increases. The amount of transportation required per unit of economic output changes over time based on historic trends.

Transportation requirements are developed for each geographic area in the model based on historic demands for transportation, consumer preferences, business requirements, and the cost for each mode of transportation. Consumers of transportation select among available modes within the model based on preferences and relative costs. Mode choices include bus, train, and various types of personal and freight vehicles. Consumers choose among modes based on consumer preferences and cost. The model uses average vehicle lifetimes to vintage the vehicle stock.

Personal vehicle choices are made in a similar manner. Consumers consider capital cost, fuel cost and efficiency as well as non-price factors in their purchase decision and seek to maximize perceived utility. Historically, non-price factors such as vehicle size, performance and appearance have dominated the choice decision with efficiency playing a relatively minor role. Costs are presented in the model in terms of the capital cost per mile traveled for different vehicle classes. Larger vehicles therefore have a higher associated capital cost as well as lower energy efficiency for the level of delivered service (miles traveled).

The transportation categories represented in the model are shown below.

E2020 Classifications				
Economic Categories	**Modes**	**Vehicle Classes** *(Personal Vehicles)*	**Fuel Types** *(Personal Vehicles)*	**Technology Types**
Passenger	Personal Vehicles	Light	Gasoline	Internal Combustion Engine
Freight	Motorcycle	Medium	Diesel	Hybrids
Off Road	Train	Heavy	Propane	Fuel Cell
	Plane		CNG	Plug-In Hybrid
	Marine		Electric	
			Ethanol	
			Hydrogen	

At present, plug-in hybrid and fuel cell options are not populated in the model. As more information on the costs and characteristics of these options becomes available these choices can be made available to transportation consumers.

Vehicle and modal efficiencies used in the model are based on the *Transportation Energy Data Book* (Edition 26, 2007)[25] published by the US Department of Energy's Oak Ridge National Laboratory. Specific data references are provided in the table below.

Input	Sources Used/Available
*All tables below are from **Transportation Energy Data Book** (Edition 26, 2007)[26] published by the US Department of Energy's Oak Ridge National Laboratory.*	
Average fuel economy	Tables 4.17 and 4.18
New Vehicle Efficiency	Tables 4.7 and 4.8
Scrap/Survival Rates	Tables 3.8, 3.9 and 3.10
Freight Truck Fuel Economy	Tables 5.1 and 5.2
Bus Efficiency	Table 2.13
Rail Efficiency – Passenger	Table 9.10 and 9.11
Rail Efficiency - Freight	Table 9.8
Marine – Freight	Table 9.5
Air Travel	Table 9.2

The model reflects the most recent changes in new passenger vehicle in CAFÉ standards, as embodied in the *Energy Independence and Security Act of 2007* (see section 4.8).

Off road transportation energy use in ENERGY 2020 is driven by activity in the Agriculture, Forestry and Construction sectors.

3.7 *Built Environment*

ENERGY2020 has been used to model energy for almost three decades. Much of the data on energy efficiency and costs was originally based on information provided by the Energy Information Administration's *Annual Report to Congress*[27] which was last published in 1980. Over the years, these data has been updated based on information gathered from clients as part of numerous projects. The resulting cost and efficiency data is used as default values in the model.

When a new model is built for a particular project, actual historic energy use is input to the model (generally from the EIA SEDS database) and allocated by sector based on census region data from the most recent energy surveys available from the EIA (e.g. Residential Energy Consumption Survey, Commercial Building Energy Consumption Survey, etc). Average and maximum device efficiencies are adjusted within the model over time in calibrating to this actual

[25] http://cta.ornl.gov/data/download26.shtml
[26] http://cta.ornl.gov/data/download26.shtml
[27] EIA, Annual Report to Congress, 1980: Volume 3. Energy Information Administration, USDOE, Report #: DOE/EIA-0173(80)/3.

energy use data. For the WCI project, ICF and SSI have subjected these data to an internal review and updated the values based on expert opinion and data from a variety of sources.

Appendix J presents the assumptions used in modeling the residential and commercial sectors, showing assumed levels of efficiency by period, maximum efficiency levels, initial and operating costs per mmBtu of energy use and device lifetimes for each end use for each fuel type. This data is used in the choice curves within the model.

Several of the jurisdictions involved in the WCI have had a long history of promoting energy efficiency and demand side management for electricity and natural gas energy use. As a result, average appliance and equipment efficiencies are expected to be higher than for the US and Canada as a whole. Where data permits, end-use data within the model has been adjusted to reflect current levels of efficiency and market saturations.

The Reference Case does not assume any increase in equipment or appliance efficiency other than the improvements due to the *Energy Independence and Security Act of 2007*, as noted in section 4.8.

3.8 *Programs/Policies Incorporated in Reference Case*

The *Energy Independence and Security Act of 2007* was passed into law in early January 2008. The following assumptions will be used to model the Act in the Reference Case:

- Renewable Fuels: The Act specifies a minimum volume of biofuels to be produced each year. For modeling purposes we have assumed that this volume of biofuels is produced and consumed in each year. The model assumes that each of the US states will use their pro-rata share of the available fuels.
- Residential Boilers and Furnace Fans: Savings estimates developed by the ACEEE for each state has been used to model this portion of the Act, using only the benefits realized by upgrades to the residential energy boilers, leaving out any energy benefits associated with reduced electricity consumption by furnace fans.
- Walk-In Coolers and Walk-In Freezers: Savings estimates developed by the ACEEE for each state has been used to model this portion of the Act.
- Electric Motor Efficiency Standards: The model will utilize the ACEEE savings projections, pro-rated to each states relative industrial electricity sales.
- External Power Supply Efficiency Standard: savings estimates developed by the ACEEE for each state have been used to model this portion of the Act.
- Energy Efficient Light Bulbs: The base assumptions are that general service lighting accounts for about 90% of residential lighting, 10% of commercial lighting and 5% of industrial lighting.
- Metal Halide Lamp Fixtures: The model assumes that 15% of commercial lighting and 60% of industrial lighting now use metal halide fixtures. For new installations the model assumes that 80% of this market would use pulse start ballasts.

On May 19, 2009, the Obama administration announced its intention to establish standards for vehicle GHG emissions and CAFÉ standards which would align with the GHG emission standards previously proposed by California. As a result, a national standard will be established which will require the fuel efficiency of new passenger cars and light trucks to reach an average fleet efficiency of 35.5 mpg by 2016. For modeling purposes we have assumed a fixed percentage increase in the efficiency of new vehicles each year starting in 2010 to reach the mandated level by 2016. Information relating to the cost of implementing this policy was based on estimates by the NHTSA[28]. We have assumed that fleet efficiency will continue to increase beyond 2016 but have included that increase in the complementary policies.

For the Canadian provinces, the model assumes that existing requirements for biofuels are met. Existing legislation requires that all gasoline sold in Canada contain 5% ethanol by 2012 and that all fuel oil and diesel contain 2% biofuels by 2010.[29]

The reference case includes Renewable Portfolio Standards for each US state as well as renewable energy targets established by Canadian provinces. Please refer to Appendix I for summaries of each jurisdiction's RPS.

3.9 Alternate Reference Case

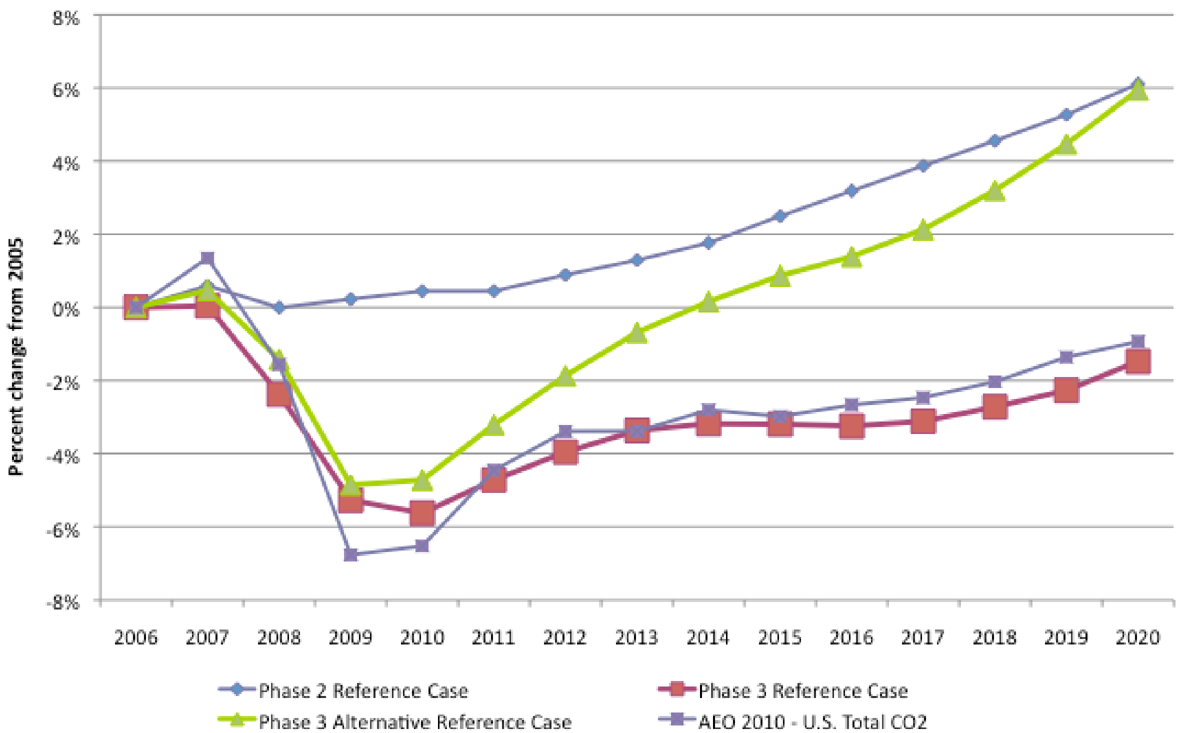
In testing the sensitivity of the analysis to different assumptions the EMT decided to model an "Alternate Reference Case." This Alternate case involved changing three assumptions in the main Reference Case:

1. That the economy would grow more rapidly; adding 0.5% per year growth starting in 2010.
2. That the biofuels mandate established by the US Energy Independence and Security Act (EISA) will not be fully met by 2020. Instead, the Alternate Reference assumes the level of biofuels reflected in the US Annual Energy Outlook (AEO) 2009.
3. Given uncertainties around the future price of oil and gas, the Alternate Reference assumes that prices follow a trajectory mid-way between the reference and low energy price scenario presented in the AEO 2009.

All of these 'alternate' assumptions have the effect of increasing the base level of GHG emissions relative to the base Reference Case. The comparison between the two cases is shown below.

[28] NHTSA, Corporate Average Fuel Economy Rulemaking, Document No. WP.29-145-13, June 2008, see also: NHTSA, Final Environmental Impact Statement, Corporate Average Fuel Economy Standards, Passenger Cars and Light Trucks, Model Years 2011 to 2015, October 2008.
[29] Renewable Fuels Strategy: ecoENERGY for Biofuels. Canada Gazette: http://canadagazette.gc.ca/partI/2006/20061230/html/notice-e.html#i3

Assumption	Base Reference Case	Alternative Reference run
Economic growth	Accounts for economic recession based on January 2009 Congressional Budget Office forecast	Faster economic growth to assess implications of a stronger than expected recovery
Fuel price forecast	AEO 2009 mid case	Average of AEO 2009 mid and low cases. Lower fuel prices results in more fuel consumption
Energy efficiency program impacts (used in complementary policy run)	Reduced demand for electricity and natural gas by 0.5% per year	Reduced demand for electricity and natural gas by 1.0% per year



4 Complementary Policies

It is expected that a number of programs to increase energy efficiency and reduce energy requirements will be introduced in conjunction with any cap-and-trade system implemented. These policies would complement the cap-and-trade system to assist in meeting GHG reduction goals. While it is expected that each partner will introduce its own particular set of policies to achieve these reductions, a *Complementary Policies* scenario was modeled that includes the following WCI-wide policies. These policies are in addition to any existing policies represented in the Reference Case or Alternate Reference. Some of these policies were modeled differently for the Reference Case and the Alternate Reference, as described below:

- **Vehicle Miles Traveled** – The combined effect of transportation and fuel programs recently put in place and being pursued is assumed to be equivalent to reducing vehicle miles traveled (VMT) by 2 percent from the reference case by 2020, beginning in 2008.

- **Energy Efficiency Programs** – The combined effect of energy efficiency programs recently put into place and being pursued (affecting the use electricity, natural gas, fuel oil and propane) are assumed to reduce energy use by *one-half of one percent in each year* below the reference forecast between 2012 and 2020. This change was introduced through increases to process and device efficiencies across the residential, commercial and industrial sectors. The costs of actual equipment upgrades associated with these efficiency gains are captured in the model. However, program and administration costs are not modeled by ENERGY 2020. The costs associated with implementing such a program could be funded through auction revenues. In the **Alternate Reference case**, which includes more robust economic growth, efficiency programs are assumed to reduce growth in energy use by *one percent each year* over the same period.

  - **Efficiency Improvement** - In order to translate this policy into modeling terms, ICF/SSI assumed that the increase in efficiency would be implemented across all sectors (residential, commercial and industrial) and all end uses. Through an iterative process, operating this policy on a stand-alone basis, we determined a level of efficiency gain for marginal devices for each year that would achieve the targeted reduction in energy use. The increase in efficiency was introduced into the model through a multiplier applied evenly across processes and devices.

  - **Economies of Scale** - An assumption was made that as more efficient devices were required, the cost of devices would benefit from economies of scale; shifting the cost curve for the efficiency improvement down.

    For modeling purposes the EMT directed that the economies of scale achieved as these technologies gain market share be limited to no more than 10% reduction in cost. In addition, the model will be constrained such that this reduction does not bring the cost of more efficient devices to a level below the cost for standard devices with current levels of efficiency.

  - **Retrofits** - No retrofits, or premature retirements of existing equipment, were assumed in the modeling. The efficiency improvements required to meet the policy target were assumed to take place at the margin. In ENERGY 2020 devices and processes are each continually replaced with assumed lifetimes of less than 20 years so at least 5% of the devices and processes are replaced each year.

  - **Process Efficiency Impacts on Device Investments** – Changes in process efficiency generally reflect changes in the level of energy service required (e.g. the amount of lighting reduced due to day-lighting or improved design or water heating needs reduced due to more efficient end-use devices). To the extent the process efficiency increases, this tends to lower the level of device investment required in these end uses; as lower lighting requirements are reflected in fewer new fixtures being required. For modeling purposes, we have assumed that 30% of the efficiency gains attained under the complementary policy will come from process efficiency gains, while 70% come from device efficiency gains.

- **Vehicle Efficiency Improvements** – The efficiency improvements included in the Reference Case (described above) result in new vehicle efficiency improvements until 2016. While no further improvements beyond that time are required under current law or regulation, the EMT has assumed that all WCI Partner jurisdictions will require continued improvements in vehicle efficiency through to 2020. The assumed improvement between 2016 and 2020 is based on emission reductions currently contemplated by the California ARB in its Scoping Plan.[30] This would increase the average efficiency of new cars and light trucks to 42.5 mpg by 2020.[31] The change in vehicle costs required to meet this standard are based on estimates by the California Air Resources Board.[32]

- **Ontario Coal Phase-out** – Assumes that Ontario phases out its coal-fired electricity generation by 2015, replacing it with hydro and wind power.

5 Sensitivity Analyses

The EMT ran several sensitivity cases to test the effects of different assumptions regarding the effectiveness of the complementary policies, economic forecasts, fuel prices and electricity generation costs, and growth rate of allowance prices.

5.1 *Sensitivity Case: Half-Effectiveness of Complementary Policies*

The purpose of this sensitivity case is to examine what happens if the energy efficiency and VMT programs achieve only half of their assumed emission reductions. Specifically, this case assumes that:

- The energy efficiency programs reduce the rate of growth in electricity and natural gas demand by only 0.25 percent per year, starting in 2012.
- Vehicle miles traveled decrease by only 1 percent from the reference case by 2020.
- The clean car standards are unchanged.
- The Ontario coal phase-out is unchanged.

5.2 *Sensitivity Case: Alternative Economic Forecast*

The purpose of this sensitivity case is to examine the implications of a different economic forecast than that assumed in the main policy case. The alternative economic forecast is described in a previous section.

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[30] California Air Resources Board, Climate Change Scoping Plan: a Framework for change, December 2008 Discussion Draft, Pursuant to AB 32: The California Global Warming Solutions Act of 2006.

[31] California Air Resources Board, Comparison of Greenhouse Gas Reductions for the United States and Canada under U.S. CAFÉ Standards and California Air Resources Board Greenhouse Gas Regulations – An Enhanced Technical Assessment, 25 February 25, 2008.

[32] California Environmental Protection Agency, Air Resources Board, Regulations to Control Greenhouse Gas Emissions from Motor Vehicles, Final Statement of Reasons, August 4, 2005.

5.3 *Sensitivity Case: High Fuel Prices and Electricity Generation Costs*

The purpose of this sensitivity case is to examine the implications of energy prices being higher than assumed in the main policy case. There has been considerable stakeholder comment that the energy price forecast in the main policy case may be too low. Additionally, some stakeholders have commented that the power generation cost assumptions may be too low, indicating that recent increases in commodity prices have had an impact on these costs. This sensitivity case includes both increased energy prices and increased power generation costs as a set of conditions that could occur together in the future. In this case, energy prices are assumed to start at 2008 prices and increase in real terms by 50% by 2020, and capital and O&M costs for power generation are assumed to be 30% higher than in the main policy case. This case required its own reference and complementary policies runs.

5.4 *Sensitivity Case: 4% Annual Growth In Allowance Prices*

The purpose of this sensitivity case is to examine the implications of a slow-rising allowance price trajectory. This case uses a growth rate in the allowance price of 4 percent per year instead of 8 percent per year in the cases discussed above.

5.5 *Sensitivity Case: 12% Annual Growth In Allowance Prices*

The purpose of this sensitivity case is to examine the implications of a faster-rising allowance price trajectory. This case uses a growth rate in the allowance price of 12 percent per year instead of 8 percent per year in the cases discussed above.

Appendix A: The ENERGY 2020 Model

The Model – ENERGY 2020

ENERGY 2020 is an integrated multi-region, multi-sector energy analysis system that simulates the supply, price and demand for all fuels. It is a causal and descriptive model, which dynamically describes the behavior of both energy suppliers and consumers for all fuels and for all end-uses. It simulates the physical and economic flows of energy users and suppliers. It simulates how they make decisions and how those decisions causally translate to energy-use and emissions.

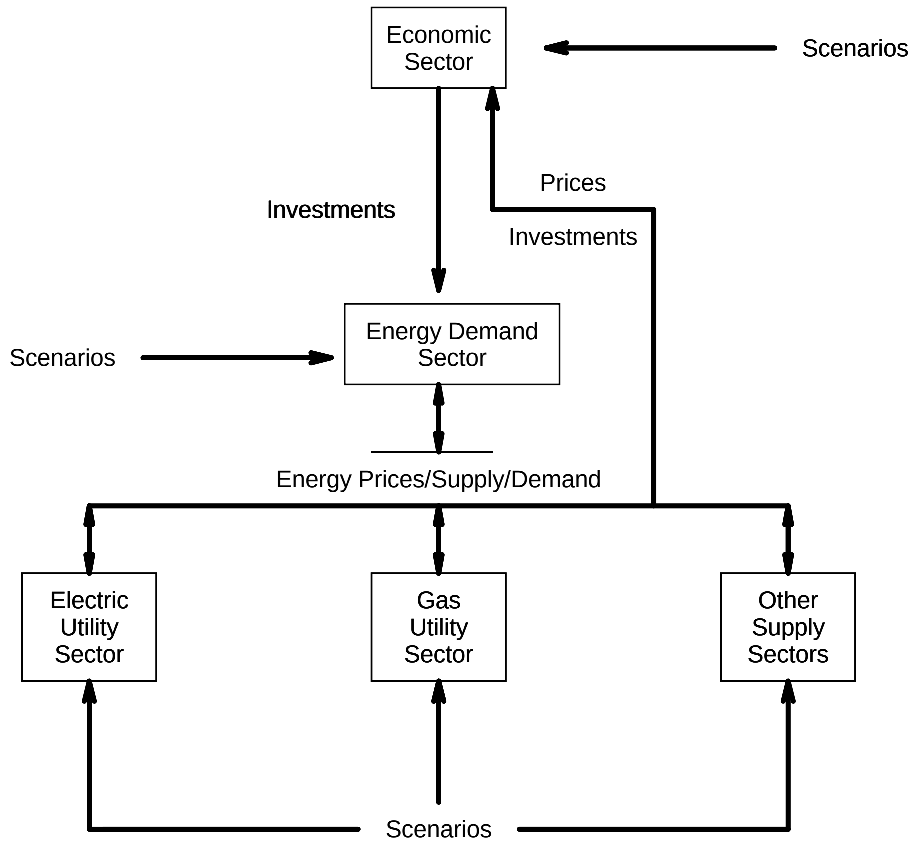
ENERGY 2020 is an outgrowth of the FOSSIL2/IDEAS model developed for the US Department of Energy (DOE) and used for all national energy policy since the Carter administration.[33] This early version of ENERGY 2020 was developed in 1978 at Dartmouth College for the DOE's Office of Policy Planning and Analysis.

Model Overview:

The basic structure of ENERGY 2020 is provided in Figure 1.1. Energy Demand sector interacts with the Energy Supply sector to determine equilibrium levels of demand and energy prices. Energy Demand is driven by the Economy sector, which in turn provides inputs to the Economy sector in terms of investments in energy using equipment and processes and energy prices. The model has a simplified Economy sector to capture the linkages between the energy system and the macro-economy. However, the model is best run with full integration with a macroeconomic model such as REMI. Given the modular nature of ENERGY 2020, additional sectors or modules from other, non-ENERGY 2020 related, models (macroeconomic, supply such as oil, gas, renewables etc.) can be incorporated directly into the ENERGY 2020 framework.

[33] *FOSSIL2 was the original version but was renamed to IDEAS a few years ago to reflect its evolutionary development since its original construction.*

Figure 1.1: ENERGY 2020 Overview



Energy Demand:

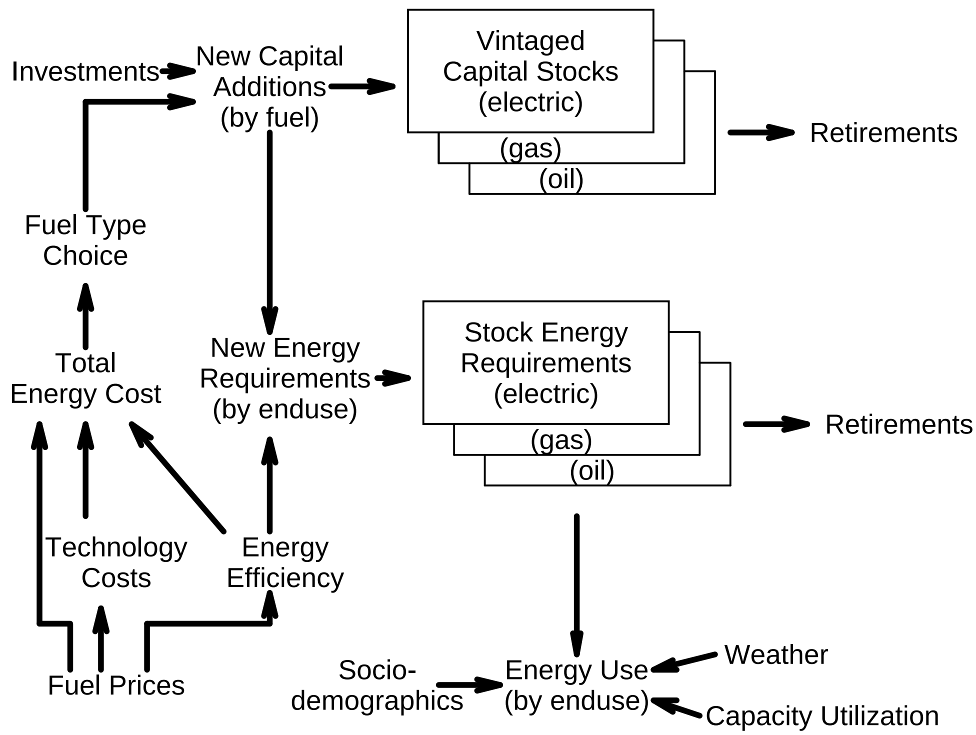
The demand sector of the model represents the geographic area by disaggregating the four economic sectors into subsectors based on energy services. As many or as few subsectors can be incorporated as required. Multiple technologies, multiple end-uses and multiple fuels are detailed. The level of detail that can be incorporated is of course subject to the data availability. The four economic sectors are:

- Residential sector which includes three classes, single family, multifamily and rural/agricultural with 8 end-uses including space heating, water heating, lighting, cooling, refrigeration, other substitutable, and other non-substitutable.
- Commercial sector which is aggregated into one class and end-uses including space heating, water heating, cooling, lighting, other substitutable, other non-substitutable.
- Industrial sector which includes 10 (23 for US) 2-digit SIC categories and is further broken down into process heat, motors, lighting, miscellaneous as the end uses.
- Transportation sector which includes several modes of transportation including automobile, truck, bus, train, plane, marine and electric vehicles. Also, each of the residential, commercial and industrial sectors has separate transportation demands.

For each of the end-uses, up to six fuels are modeled, for example, the residential space heating has the choice of a gas, oil, coal, electric, solar and biomass space heating technologies. Added end-uses, technologies and modes can be added as data allow. For all end-uses and fuels, the model is parameterized based on historical locale-specific data. The load duration curves are dynamically built up from the individual end-uses to capture changing condition under consumer choice and combined gas/electric programs.

A few basic concepts are crucial to an understanding of how the model simulates the energy system. These concepts including, the capital stock driver, the modeling of energy efficiency through trade-off curves, the fuel market share calculation, utilization multipliers and the cogeneration module are discussed below in abbreviated form. Figure 1.2 (Demand Overview) illustrates the demand sector interactions.

Figure 1.2: Demand Overview



Energy Demand as a Function of Capital Stock:

The model assumes that energy demand is a consequence of using capital stock in the production of output. For example, the industrial sector produces goods in factories, which require energy for production; the commercial sector requires buildings to provide services; and the residential sector needs housing to provide sustained labor services. The occupants of these buildings require energy for heating, cooling, and electromechanical (appliance) uses.

The amount of energy used in any end-use is based on the concept of energy efficiencies. For example, the energy efficiency of a house along with the conversion efficiency of the furnace determines how much energy the house uses to provide the desired warmth. The energy efficiency of the house is called the capital stock energy or process efficiency. This efficiency is primarily technological (e.g. insulation levels) but can also be associated with control or life-style changes (e.g. less household energy use because both spouses work outside the home.) The furnace efficiency is called the device or thermal efficiency. Thermal efficiency is associated with air conditioning, electromotive devices, furnaces and appliances.

The model simulates investment in energy using capital (buildings and equipment) from installation to retirement through three age classes or vintages. This capital represents embodied energy requirements that will result in a specified energy demand as the capital is utilized, until it is retired or modified.

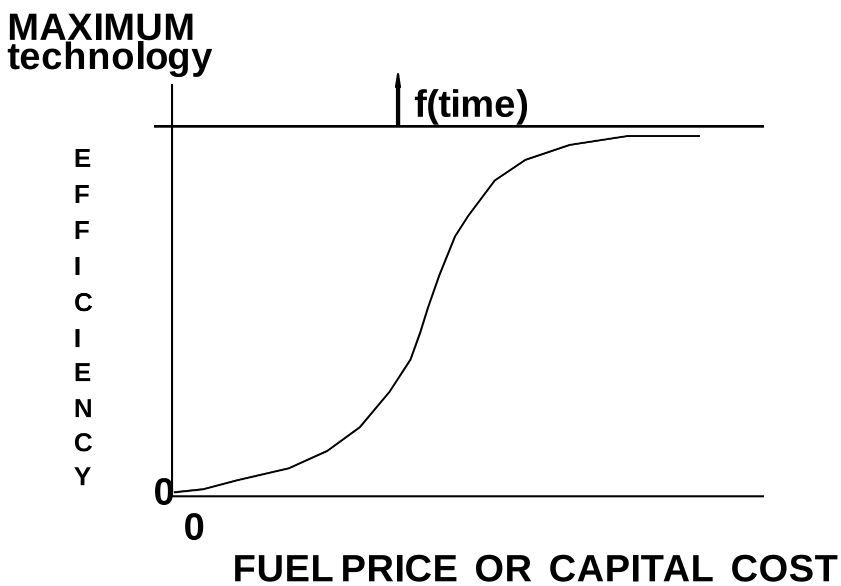
The size and efficiency of the capital stock, and hence energy demands, change over time as consumers make new investments and retire old equipment. Consumers determine which fuel and technology to use for new investments based on perceptions of cost and utility. Marginal trade-offs between changing fuel costs and efficiency determine the capital cost of the chosen technology. These trade-offs are dependent on perceived energy prices, capital costs, operating costs, risk, access to capital, regulations and other imperfect information.

The model formulates the energy demand equation causally. Rather than using price elasticities to determine how demand reacts to changes in price, the model explicitly identifies the multiple ways price changes influence the relative economics of alternative technologies and behaviors, which in turn determine consumers' demand. In this sense, price elasticities are outputs, not inputs, of the model. The model accurately recognizes that price responses vary over time, and depend upon factors such as the rate of investment, age and efficiency of the capital stock, and the relative prices of alternative technologies.

Device and Process Energy Efficiency:

The energy requirement embodied in the capital stock can be changed only by new investments, retirements, or by retrofitting. The efficiency with which the capital uses energy has a limit determined by technological or physical constraints. The trade-off between efficiency and other factors (such as capital costs) is depicted in Figure 1.3 (Efficiency/Capital Cost Trade-Off). The efficiency of the new capital purchased depends on the consumer's perception of this trade-off. For example, as fuel prices increase, the efficiency consumers choose for a new furnace is increased despite higher capital costs. The amount of the increase in efficiency depends on the perceived price increase and its relevance to the consumer's cash flow.

Figure 1.3: Efficiency/Capital Cost Trade-Off



The standard the model efficiency trade-off curves are called consumer-preference curves because they are estimated using cross-sectional (historical) data showing the decisions consumers made based on their perception of a choice's value. Many planners are now interested in measure-by-measure or least-cost curves which use engineering calculations and discount rates to show how consumers should respond to changing energy prices. Another analysis focuses on the technical/price differences in alternative technologies and the incentives needed to increase the market-share or market penetration of a specific technology. This perspective on the choice process uses market share curves. The model allows the user to select any of these three types of curves to represent the way consumers make their choices. Shared savings, rebate, subsidy programs, etc. can be tested using any of the curves.

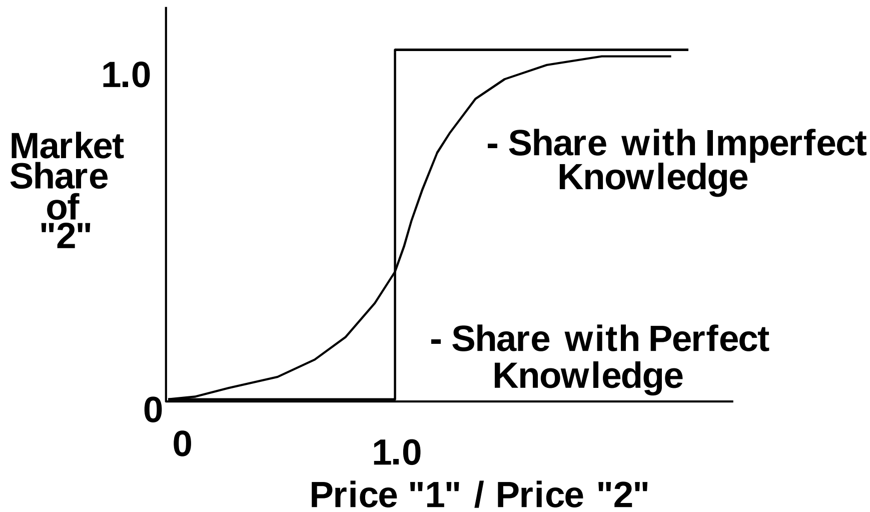
Cumulative investments determine the average embodied efficiency. The efficiency of new investments versus the average efficiency of existing equipment is one measure of the gap between realized and potential conservation savings.

The model uses saturation rates for devices to represent the amount of energy services necessary to produce a given level of output. Saturation rates may change over time to reflect changes in standard of living or technological improvements. For example, air conditioning has historically increased with rising disposable incomes. These rates can be specified exogenously or can be defined in relation to other variables within the model (such as disposable income).

The Market Share Calculation:

Not all investment funds are allocated to the least expensive energy option. Uncertainty, regional variations, and limited knowledge make the perceived price a distribution. The investments allocated to any technology are then proportional to the fraction of times one technology is perceived as less expensive (has a higher perceived value) than all others. This process is shown graphically in Figure 1.4 (Market Share Dynamics).

Figure 1.4: Market Share Dynamics



Short Term Budget Responses:

A short-term, temporary response to budget constraints is included in the model. Customers reduce usage of energy if they notice a significant increase in their energy bills. The customers' budgets are limited and energy use must be reduced to keep expenditures within those limits. These cutbacks are temporary behavioral reactions to changes in price, and will phase out as budgets adjust and efficiency improvements (true conservation) are implemented. This causes the initial response to changing prices to be more exaggerated than the long-term response, a phenomenon called "take-back" in studies of consumer behavior.

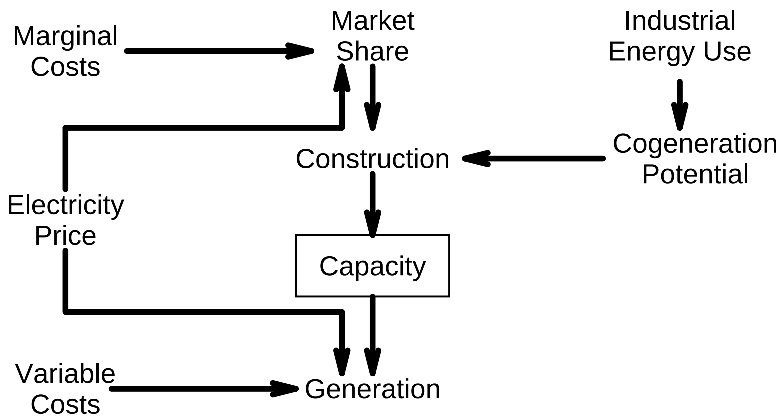
Accounting for Fungible Demand:

Some furnaces and processes can use multiple fuels. That is, they can switch almost instantaneously between, for example, gas and oil or coal and biomass as prices or the market dictates. Energy demand that is affected by this short-term fuel switching phenomena is called fungible demand. The model explicitly simulates this market share behavior.

Modeling Cogeneration:

Most energy users meet their electricity requirements through purchases from a utility. Some users (industrial and commercial) can, however, convert some of their own waste heat into usable electricity when economics warrant such action. Other users (residential and commercial) can purchase self-generation energy sources such as gas turbines, diesel-generators or fuel cells. Figure 1.5 shows a simplified overview of the cogeneration structure.

Figure 1.5: Cogeneration Concepts



In the model all energy used for heating is a candidate for cogeneration. The cost of cogeneration is the fixed capital cost of the investment plus the variable fuel costs (net of efficiency gains). This cogeneration cost is estimated for all technologies and compared to the price of electricity. The marginal market share for each cogeneration technology is based on this comparison.

Cogeneration is restricted to consumers who directly produce part of their own electricity requirement. Companies which generate power primarily for resale to the electric utility are considered independent power producers and are included in the electric supply model.

Energy Supply:

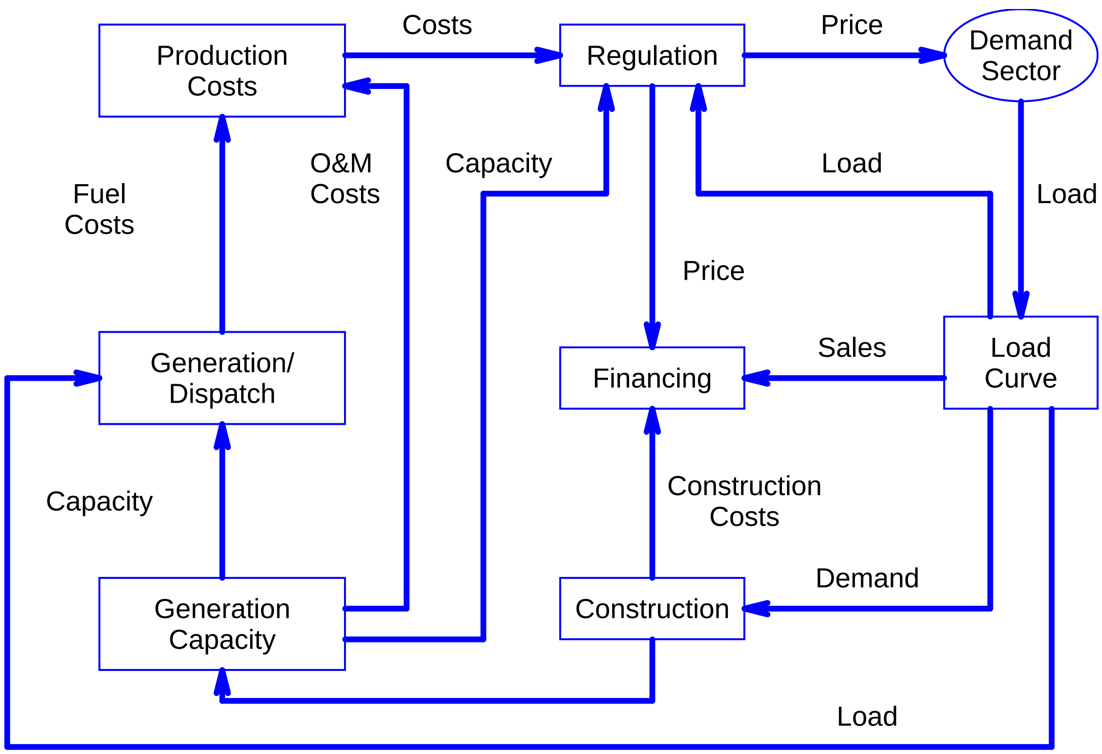
For electric and gas utilities (separate or combined), ENERGY 2020 internally and self-consistently simulates sales, load (by end-use, time-of-use, and class), production (across thirty-six dispatch types), demand-side management (by technology), forecasting, capacity expansion (new generation, independent power producers, purchases, and DSM), all important financial variables, and rates (by class, end-use, and time-of-use.)

The version currently used in this analysis only has the electricity utility sector (a full fledged natural gas utility sector for Canada is currently unavailable in the model, only a simplified natural gas supply function is used to calculate the supply price response).

With the inclusion of the electric utility sector, the generic supply model turns over the calculation of electricity prices to that sector. The model is capable of endogenously simulating the forecasting of capacity needs, as well as the planning, construction, operation and retirement of generating plants and transmission facilities. Each step is financed in the model by revenues, debt, and the sale of stock. The simulated utility, like its real world counterpart, pays taxes and generates a complete set of accounting books. In ENERGY 2020, the regulatory function is modeled as a part of the utility sector. The regulator sets the allowed rate of return, divides revenue responsibility among customer classes, approves rate base, revenues and expenses, and sets fuel adjustment charges.

The interactions in the electric utility sector are summarized in Figure 1.6

Figure 1.6: Electric Utility Structure Overview



Expansion Planning:

The utility sector endogenously forecasts future demand for electricity. From the forecast it projects the future capacity required meeting future demand by taking into account retirements and plants already under construction. Construction of additional capacity is initiated if future electricity requirements, including reserves, are forecast to exceed available capacity (using seasonal ratings).

If additional capacity is needed to meet forecasted needs, the basic capacity expansion module in ENERGY 2020 determines whether base or peaking capacity is required. The model determines the maximum number of hours that new peaking capacity can be economically operated, before it would be less expensive to construct and operate base load capacity instead. If the forecasted peaking capacity would operate more than that economic maximum, base loads units are initiated, otherwise peaking units are initiated. Any plant type including geothermal, wind, biomass and storage can be considered.

New plants, of a pre-specified minimum size, are initiated when the reserve margin would be violated if the plants were not built or if base load capacity is inadequate to serve base load energy needs at the end of the forecast period. The model does allow the minimum reserve margin to be temporarily violated at the peak if new base load capacity is scheduled to be available within the year. Peaking units are allowed to serve more than the maximum economical number of hours until base load capacity comes on-line.

Minimum plant size is exogenous. The mix of new base load plants (i.e. alternative coal technologies, hydro, or nuclear) is user-specified in the standard ENERGY 2020 configuration. The model also evaluates the financial implications of new construction, including total construction costs, cost schedules, and AFUDC/CWIP. The gross rate on AFUDC equals the weighted average cost of capital. The actual construction progress and financial impacts are simulated on a year by year basis.

ENERGY 2020 can also be configured to consider intermediate load units, firm purchases contracts, external sales, independent power producers, and demand-side options. These options can be optionally selected based on endogenous least-cost analysis or can be chosen by user-specified criteria to meet. A detailed automatic Integrated Resource Planning module that would endogenously choose (with user control) from DSM measures utility and non-utility generation and purchase alternatives using linear programming techniques is now being offered as an enhancement.

Financing:

The ENERGY 2020 utility finance sub-sector simulates the activities of a utility's finance department. It forecasts funding requirements and follows corporate policies for obtaining new funds. The model simulates borrowing and issuing of stock, and can repurchase stock or make investments if it has excess cash. Cash flows are explicitly modeled, as are any decision that affects them. Coverage ratios, intermediate- and long-term debt limits, capitalization, rates of return, new stock issues, bond financing, and short-term investments are endogenously calculated. The model keeps track of gross, net, and tax assets. It also calculates the depreciation values used for the income statement and tax obligations.

For this project, this element of the model is not used, and a simpler approach to estimating retail electricity prices is used.

Regulation:

The utility sector sets electricity prices according to regulatory requirements. The regulatory procedures use allowed rate-of-return and test year cost and demands to determine allowed revenues. Electricity prices are calculated from peak-demand fractions by allocation of costs. Any other allocation scheme can also be considered. The regulatory sub-sector of ENERGY 2020 automatically factors in a wide variety of regulatory policies and options. More importantly, the model can be readily modified to consider a wide spectrum of scenarios.

The regulatory process revolves around a test year, usually one year forward, when proposed rates will go into effect. The utility sector forecasts test year sales and peak demands by season and customer class, just as it does to determine capacity needs. These test year demand estimates are used to allocate responsibility for system peak, and therefore, generation capacity costs.

Fuel costs for the test year are estimated by dispatching the plants that will be available in the test year, using the dispatching routine explained below. Fuel costs and operating and maintenance costs are adjusted for expected inflation, and these costs are factored into the electricity rates using forecasted sales.

ENERGY 2020 calculates the utility rate-base according to a detailed conventional rate making formula. The model allows the user to adjust allowable costs, and has been used extensively to evaluate alternative rate-base scenarios for individual plants, including allowing return of, but no return on investment, and partial disallowment of construction and interest costs.

The ENERGY 2020 system also includes estimation of avoided costs, which determines when the utility may be required to purchase third party power. Environmental constraints, such as air pollution restrictions, can also be included in the model. If ENERGY 2020 is configured as a regional or state-wide system, municipal utilities, with their unique tax and rate structures, are incorporated. Similarly, regional or power pool interchange is also recognized by ENERGY 2020. As with the other sectors of ENERGY 2020, the regulatory subsector is flexible enough to accommodate any existing or hypothetical circumstance.

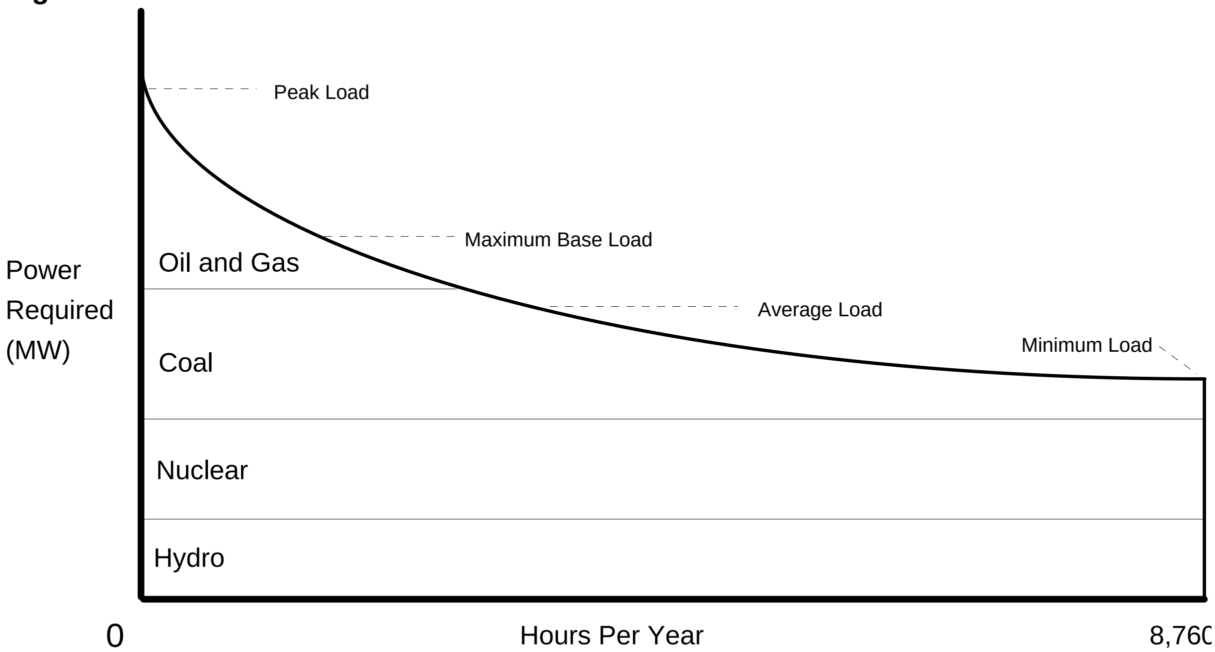
For this project, this element of the model is not used, and a simpler approach to estimating retail electricity prices is used.

Operations:

Each end-use in ENERGY 2020 has a related set of load shape factors. Typically, these factors define the relationship between peak, minimum and average load for each season. These factors when combined with the weather-adjusted energy demand by end-use and corrected for cogeneration, resale, and load management programs, form the basis of the approximated system load duration curve. Alternatively, unit hourly loads for each end-use for three days per month (average weekday, weekend and peak weekday) are used.

The standard ENERGY 2020 production subsector uses an advanced de-rating or chronological method to estimate the seasonal or hourly dispatch of plants. It purchases power externally when economic or necessary. Plant availability and generation for coal, nuclear, hydroelectric, oil and gas are currently considered, as well as pumped storage, firm purchases, interruptible load, and fuel switching and qualified facilities. Figure 1.7 also shows a typical plant dispatch schedule.

Figure 1.7: Generation from the Load Curve



The ENERGY 2020 system estimates conventional fuel costs based on the unit dispatch, heat rates, and fuel prices (from the supply sector.) Nuclear fuel costs are capitalized and depreciated throughout the re-fuelling cycle. Nuclear fuel expenses also include fuel disposal costs.

ENERGY 2020 explicitly models the costs of maintaining the transmission and distribution (T&D) system. New facility investments are scheduled and incurred endogenously. In addition, the user can specify the decision rules that dictate T&D expenditures. ENERGY 2020 also explicitly models both fixed and variable operation and maintenance costs, power pool interchanges, nuclear decommissioning costs, plant capital additions, plant cancellations, and general administration costs.

Model Applications:

The structure of the model is well tested and has been used to simulate not only US and the Canada energy and environmental dynamics but also those of several countries in Western, Central and Eastern Europe. Current efforts include strategic and tactical analyses for South America deregulation. Further, the model has been used successfully for deregulation analyses in over 50 energy suppliers and in all the US states and Canadian provinces. Several US and Canadian energy suppliers currently use the model for the analysis of combined electricity and gas deregulation dynamics.[34] The model contains confidence and validity packages that allow it to determine how to take maximal advantage of RTO rules. The ISO NE used the model to find gaps in its rules and to develop more efficient market conditions. The model was used for the CAPX/ISO to model to show, before the fact, many of the “games” played in the California market.

[34] *ENERGY 2020 is the only model known to have simulated and predicted the dynamics that occurred in the UK electric deregulation. These include gaming, market consolidation and re-regulation dynamics.*

Appendix B: Data Sources

The following describes the default data sources used in ENERGY 2020. Where these data has been replaced by jurisdiction-specific information, the jurisdiction-specific data is described in the main body of the document.

Historical Energy Prices and Demands

Historic energy prices and demands are from *State Energy Data*, Integrated Energy Statistics Divisions of the Office of Energy Markets and End Use, Energy Information Administration, USDOE. This document provides annual time series estimates of State-level energy consumption, prices, and expenditures by major economic sectors. In 2000, the *State Energy Data* replaced two former EIA reports: State Energy Data Report (SEDR) and State Energy Price and Expenditure Report (SEPER). Tables by major economic sector can be found at: http://www.eia.doe.gov/emeu/states/_states.html. New tables by energy source can be found at: http://www.eia.doe.gov/emeu/states/multi_states.html.

Future Energy Prices

To estimate future energy prices, we apply the forecasted price growth rates from the *Annual Energy Outlook (AEO*) *2008* to the prices from the last historical year (obtained from *State Energy Data*). The Annual Energy Outlook 2008 presents a forecast and analysis of US energy supply, demand, and prices through 2030.
http://www.eia.doe.gov/oiaf/aeo/supplement/index.html

Note that there is a gap between the most recently reported historical year of data and the first forecast year. We resolve this by including one year's worth of price data from the AEO of the previous year.

Future Energy Demands

Future energy demands are computed by the model, but the model can calibrate to future energy demands if desired. In this project, the model projections have been compared to other forecasts but have not been calibrated to any other forecast.

Device Energy Efficiency Standards

Device efficiency standards come mainly from the *Energy Policy Act of 1992*, with some efficiencies coming from other selected sources.
http://energy.navy.mil/publications/law_us/92epact/hr776toc.htm
This initial base of efficiency standards have been updated as new regulations have come into effect. Requirements in the ***Energy Independence and Security Act*** have also been included in the Reference Case.

Device Capital Cost, Efficiency, and Device Lifetimes; Cogeneration Capital Costs, Heat Rates and Parameters

These values were originally developed from the *Annual Report to Congress, 1980: Volume 3*. Energy Information Administration, USDOE, Report #: DOE/EIA-0173(80)/3. ICF and SSI have reviewed and updated these data which is used to provide the shape of choice curves within the model based on expert opinion and data from a variety of sources. The values used are presented in Appendix J.

End-Use Load Shapes
The end use load shapes were originally based on 1995 NEPOOL published reports. Load shapes for temperature sensitive loads are modified based on actual weather data for the state/region being modeled.

Industrial Energy Splits, Industrial End Use Splits and Commercial End-Use Splits
The energy that we obtain from *State Energy Data* is a total value that needs to be split among different industries and/or uses (end use demands, cogeneration demands, feedstock demands). We obtain the splits among industries and uses from the *Manufacturing Energy Consumption Survey*, Energy Information Administration, USDOE. The Manufacturing Energy Consumption Survey is conducted every five years and provides detailed data on energy consumption in the manufacturing sector. http://www.eia.doe.gov/emeu/mecs/contents.html

Residential Devices Saturations and Market Shares
Residential devices saturations and market shares are obtained from the *Residential Energy Consumption Survey*, Energy Information Administration, USDOE.
http://www.eia.doe.gov/emeu/recs/contents.html

Inflation Rate
Historical inflation rates are calculated from the consumer price index reported by the Bureau of Labor. Projections for inflation from 2004 through 2030 are calculated from the consumer price index projections of the *Annual Energy Outlook 2008*, Energy Information Administration, USDOE. http://www.eia.doe.gov/oiaf/aeo/index.html.

Fuel Choice Variance Factors, Return on Investment, and Maximum Process Efficiency Multiplier
The fuel choice variance factors, return on investment and maximum process efficiency multiplier variables come from projections obtained from the DEMAND81 energy model. Backus, George A. 1981. DEMAND81: National Energy Policy Model. Four Volumes. AFC 7-10. School of Industrial Engineering. Purdue University. West Lafayette, Indiana. These factors are updated as part of the calibration process.

Process Capital Costs
The data was developed from the US I/O Tables by REMI in $1987 and have been updated based on work with past clients.

Residential Energy Usage Per Appliance
The average usage per appliance was originally based on *NEPOOL April 1994 Forecast for Massachusetts*. The miscellaneous end use category is computed by adding the residential energy for all miscellaneous end uses and dividing by the number of households. Average use per appliance has been updated since that time based on input from various clients and is calibrated to actual energy use as part of the process of calibrating to actual energy use.

Number of Households
The number of households comes from the United States Census, US Census Bureau.
http://www.census.gov/main/www/cen2000.html.

Appendix C: Jurisdiction specific forecasts

Arizona

Population Forecast	
Year	**Population**
2006	6,239,482
2007	6,432,007
2008	6,622,885
2009	6,812,137
2010	6,999,810
2011	7,186,070
2012	7,370,993
2013	7,554,429
2014	7,736,022
2015	7,915,629
2016	8,093,110
2017	8,268,253
2018	8,441,095
2019	8,611,507
2020	8,779,567

REMI 2006 Forecast Output - Arizona

Arizona Personal Income - Billions of Nominal $

	2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Earnings by Place of Work	148	157	169	181	193	205	217	230	243	255	268	281	294	307	320
Contr for Gov Social Ins	16	18	19	20	22	23	25	27	28	30	31	33	35	37	38
Adj for Residence	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Dividends, Interest, and Rent	34	37	39	43	46	49	52	55	58	61	65	69	72	76	81
Personal Current Transfer Receipts	30	33	35	38	41	43	46	48	51	54	57	60	63	67	70
Personal Income	196	210	226	243	258	274	290	307	325	341	359	377	395	414	433
Personal Taxes	22	25	27	29	31	33	35	37	39	41	43	45	48	50	52
Disp Pers Inc	173	185	198	213	227	241	255	270	285	300	316	331	348	364	381
Personal Income Pct Change		**7%**	**7%**	**8%**	**6%**	**6%**	**6%**	**6%**	**6%**	**5%**	**5%**	**5%**	**5%**	**5%**	**5%**

REMI 2006 Forecast Output - Arizona Arizona Output by Industry - $2000															
	2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Forestry, Fishing, Other	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Mining	2.6	2.0	2.3	2.5	2.4	2.3	2.2	2.1	2.0	2.1	2.2	2.2	2.3	2.3	2.4
Utilities	7.0	7.0	7.2	7.4	7.6	7.7	7.9	8.0	8.2	8.4	8.7	9.0	9.2	9.5	9.7
Construction	23.4	22.9	23.9	25.9	27.0	28.1	29.2	30.2	31.4	32.3	33.1	33.9	34.5	35.2	35.7
Manufacturing	63.5	63.6	70.9	78.9	85.3	92.1	99.0	106.2	114.0	120.1	126.3	132.8	139.1	145.7	152.2
Wholesale Trade	20.1	20.8	22.9	25.3	27.4	29.6	31.9	34.4	37.2	39.0	40.9	42.8	44.7	46.7	48.6
Retail Trade	27.8	29.3	31.3	34.0	35.9	38.0	40.0	42.2	44.6	46.5	48.5	50.5	52.5	54.5	56.4
Transp, Warehousing	11.7	12.0	12.6	13.3	13.9	14.5	15.1	15.7	16.3	16.9	17.5	18.2	18.7	19.3	19.9
Information	12.7	13.2	14.0	15.1	16.1	17.1	18.1	19.2	20.5	21.4	22.3	23.3	24.2	25.1	26.1
Finance, Insurance	29.5	30.3	31.7	33.3	34.6	36.0	37.4	38.9	40.5	41.9	43.3	44.8	46.2	47.6	49.0
Real Estate, Rental, Leasing	46.2	47.4	49.7	52.5	54.7	57.1	59.4	61.9	64.5	66.7	68.8	70.9	72.9	74.9	76.8
Profess, Tech Services	16.7	17.0	18.1	19.5	20.6	21.8	23.0	24.3	25.7	26.8	28.0	29.3	30.5	31.7	32.9
Mngmt of Co, Enter	4.6	4.8	5.2	5.7	6.1	6.6	7.1	7.5	8.1	8.5	8.9	9.3	9.6	10.0	10.4
Admin, Waste Services	14.7	15.2	16.0	16.9	17.8	18.7	19.5	20.5	21.5	22.3	23.1	24.0	24.8	25.6	26.4
Educational Services	2.2	2.3	2.4	2.5	2.5	2.6	2.7	2.8	2.9	3.0	3.1	3.2	3.3	3.4	3.5
Health Care, Social Asst	22.3	23.2	24.2	25.3	26.5	27.7	28.9	30.3	31.7	33.0	34.3	35.7	37.0	38.3	39.6
Arts, Enter, Rec	3.3	3.4	3.6	3.8	3.9	4.1	4.3	4.5	4.7	4.9	5.1	5.2	5.4	5.6	5.7
Accom, Food Services	11.1	11.5	11.9	12.5	12.8	13.2	13.6	14.0	14.5	14.8	15.2	15.5	15.9	16.2	16.5
Other Services (excl Gov)	7.6	7.8	8.1	8.5	8.8	9.2	9.5	9.9	10.3	10.6	11.0	11.4	11.7	12.1	12.4
Total	**$327.5**	**$333.9**	**$356.5**	**$383.3**	**$404.4**	**$426.8**	**$449.2**	**$472.9**	**$498.8**	**$519.6**	**$540.8**	**$562.3**	**$583.0**	**$604.1**	**$624.7**
Annual Percent Change		**2.0%**	**6.8%**	**7.5%**	**5.5%**	**5.5%**	**5.3%**	**5.3%**	**5.5%**	**4.2%**	**4.1%**	**4.0%**	**3.7%**	**3.6%**	**3.4%**

California Population and Household Projections:

	B	C	D	E	F	G	H	I	J	K
14	**California**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**
15	Population (Millions)	34.6	35.0	35.5	35.8	36.2	36.5	36.9	37.2	37.6

	B	L	M	N	O	P	Q	R	S	T	U	V
14	**California**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
15	Population (Millions)	38.0	38.4	38.9	39.3	39.7	40.1	40.6	41.0	41.4	41.9	42.3

	B	C	D	E	F	G	H	I	J	K	L
66	**California Households (Thousands)**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
67	Total	12,038	12,204	12,358	12,488	12,597	12,703	12,841	12,978	13,116	13,256
68	Single Family	7,697	7,803	7,901	7,984	8,054	8,122	8,210	8,297	8,386	8,475
69	Multi Family	3,776	3,828	3,876	3,917	3,952	3,985	4,028	4,071	4,114	4,158
70	Other Residential	565	573	580	586	591	596	603	609	616	622

	B	M	N	O	P	Q	R	S	T	U	V
66	**California Households (Thousands)**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
67	Total	13,397	13,540	13,686	13,832	13,981	14,130	14,280	14,431	14,582	14,734
68	Single Family	8,565	8,657	8,750	8,844	8,939	9,034	9,130	9,227	9,323	9,420
69	Multi Family	4,202	4,247	4,293	4,339	4,386	4,432	4,479	4,527	4,574	4,622
70	Other Residential	629	636	643	649	656	663	670	678	685	692

California Gross Output by Industry

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V
18	**California Gross Output (Billions of 2000 $/Year)**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
19	Total	9,618	9,704	9,931	10,387	10,715	11,107	11,436	11,795	12,215	12,649	13,096	13,545	14,009	14,483	14,903	15,317	15,724	16,134	16,547	16,964
20	Single Family	781	776	786	808	831	854	879	904	929	956	983	1,011	1,039	1,069	1,099	1,130	1,162	1,195	1,229	1,264
21	Multi Family	247	246	249	256	263	271	278	286	294	303	311	320	329	338	348	358	368	378	389	400
22	Other Residential	35	35	35	36	37	38	39	40	41	43	44	45	46	48	49	50	52	53	55	56
23	Transportation Services	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2
24	Pipelines	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2
25	Communication	63	64	62	69	68	74	78	83	88	93	98	103	109	114	118	122	126	131	135	140
26	Utilities	15	21	22	23	23	23	23	23	23	23	23	23	23	23	24	24	25	26	26	27
27	Wholesale	75	75	75	77	83	89	94	99	104	110	116	122	129	136	141	146	151	156	162	167
28	Retail	122	126	128	131	134	140	147	153	158	162	167	172	177	183	188	194	200	206	212	218
29	FIRE	276	287	301	322	332	342	351	360	367	375	383	392	400	409	419	430	441	452	463	475
30	Offices - Business Services	171	166	169	177	183	192	199	207	215	223	231	240	248	257	266	274	283	292	301	311
31	Education	9	10	10	11	12	12	12	13	13	13	13	13	14	14	14	15	15	15	16	16
32	Health & Social	69	75	79	82	85	87	90	93	95	97	100	102	105	108	111	114	118	121	125	130
33	Food, Lodging, Recreation	48	50	52	55	56	58	59	61	62	63	64	65	66	67	68	70	71	73	74	76
34	Government	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2
35	Food & Tobacco	15	16	15	14	15	16	16	16	16	16	16	17	17	17	17	17	18	18	18	18
36	Textiles	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
37	Apparel	5	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	5
38	Lumber	2	2	2	2	2	2	2	2	2	3	3	3	3	3	3	3	3	3	3	3
39	Furniture	3	3	3	3	3	4	4	4	4	4	4	4	4	4	4	4	4	5	5	5
40	Paper	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	3	3	3	3
41	Printing	22	20	20	21	22	23	25	26	27	29	31	32	34	36	37	39	41	42	44	45
42	Chemical	13	10	13	17	16	17	17	17	17	18	18	18	18	19	19	20	20	21	21	22
43	Petroleum Products	7	5	6	8	12	12	12	12	12	11	11	11	11	11	11	12	12	12	13	13
44	Rubber	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2
45	Leather	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2
46	Nonmetallic Minerals	4	4	4	4	4	4	4	4	5	5	5	5	5	5	5	5	5	5	5	6
47	Primary Metals	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	3	3	3	3	3
48	Fabricated Metals	11	9	9	9	10	11	11	11	11	11	11	11	11	12	12	12	13	13	14	14
49	Machines	9	7	7	8	7	7	7	7	7	7	7	7	7	7	7	7	8	8	8	9
50	Computers	42	34	30	28	30	35	39	44	49	55	62	68	75	82	87	91	96	100	105	109
51	Electric Equipment	4	3	3	3	3	3	3	3	3	3	3	3	3	3	4	4	4	4	4	4
52	Transport Equipment	12	12	11	11	9	9	10	10	10	11	11	12	12	12	13	13	14	14	14	15
53	Other Manufacturing	9	9	10	10	11	11	11	12	12	12	13	13	14	14	15	15	16	16	17	18
54	Mining Except Oil & Gas	2	2	2	3	3	4	4	4	4	4	3	3	3	3	3	4	4	4	4	4
55	Oil & Gas Extraction	4	3	4	5	7	7	6	6	6	6	6	6	6	6	6	6	6	6	7	7
56	Construction	56	56	57	63	70	71	70	69	70	71	71	72	73	73	75	76	77	79	80	82
57	Forestry	6	6	6	6	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	7
58	Agriculture	11	12	14	17	15	15	15	15	15	15	15	15	16	16	16	17	17	17	18	18

New Mexico:

	B	C
12	Year	Population (Millions)
13	2001	1.82
14	2002	1.85
15	2003	1.88
16	2004	1.91
17	2005	1.95
18	2006	1.98
19	2007	2.01
20	2008	2.05
21	2009	2.08
22	2010	2.16
23	2011	2.19
24	2012	2.23
25	2013	2.26
26	2014	2.30
27	2015	2.34
28	2016	2.37
29	2017	2.41
30	2018	2.45
31	2019	2.49
32	2020	2.53

Washington: population

Year	Population (Millions)
1990	4.9
1991	5.0
1992	5.1
1993	5.3
1994	5.4
1995	5.5
1996	5.6
1997	5.7
1998	5.8
1999	5.8
2000	5.9
2001	6.0
2002	6.0
2003	6.1
2004	6.2
2005	6.3
2006	6.4
2007	6.5
2008	6.6
2009	6.7
2010	6.8
2011	6.9
2012	7.0
2013	7.1
2014	7.2
2015	7.3
2016	7.4
2017	7.5
2018	7.6
2019	7.7
2020	7.7

Appendix D: Inter-Regional Transmission Capacity for WECC as modeled in ENERGY 2020

Region From	Region To	Capacity Limit (MW)
Alberta	British Columbia	1,000
British Columbia	Alberta	1,200
Allston, OR	Olympia, WA	4,200
Olympia, WA	Allston, OR	4,200
Allston, OR	Williamet, OR	4,120
Williamet, OR	Allston, OR	4,120
Arizona	LADWP, CA	1,229
LADWP, CA	Arizona	1,229
Arizona	New Mexico	2,500
New Mexico	Arizona	2,500
Arizona	Pace, UT	600
Pace, UT	Arizona	600
Arizona	San Diego & Imperial Valley, CA	1,133
San Diego & Imperial Valley, CA	Arizona	1,133
Arizona	Southern California	2,150
Southern California	Arizona	2,150
Arizona	WAPA L.C. (AZ,NM)	9,999
WAPA L.C. (AZ,NM)	Arizona	9,999
British Columbia	North Puget, WA	2,850
North Puget, WA	British Columbia	2,000
British Columbia	Spokane, WA	200
Spokane, WA	British Columbia	200
British Columbia	West Kootenay, BC	9,999
West Kootenay, BC	British Columbia	9,999
Bonanza, UT	Bridger, WY	300
Bridger, WY	Bonanza, UT	300
Bonanza, UT	Pace, UT	785
Pace, UT	Bonanza, UT	400
Bonanza, UT	WAPA R.M., CO	650
WAPA R.M., CO	Bonanza, UT	650
Bridger, WY	Eastern Idaho	2,200
Eastern Idaho	Bridger, WY	600
Bridger, WY	WAPA R.M., CO	1,450
WAPA R.M., CO	Bridger, WY	1,450
Bridger, WY	Wyoming R.M.	400
Wyoming R.M.	Bridger, WY	400
Bridger, WY	Yellowtail, MT	625
Yellowtail, MT	Bridger, WY	400
Brownlee, ID	Lower Columbia (WA,OR)	50
Lower Columbia (WA,OR)	Brownlee, ID	50
Brownlee, ID	McNary, WA	300
McNary, WA	Brownlee, ID	300

Region From	Region To	Capacity Limit (MW)
Brownlee, ID	Oxbow, OR	1,700
Oxbow, OR	Brownlee, ID	1,700
Brownlee, ID	Southern Idaho	1,850
Southern Idaho	Brownlee, ID	1,850
Coulee, WA	Grant County, WA	2,396
Grant County, WA	Coulee, WA	2,396
Coulee, WA	Mid Columbia (WA,OR)	1,844
Mid Columbia (WA,OR)	Coulee, WA	1,844
Coulee, WA	North Puget, WA	1,451
North Puget, WA	Coulee, WA	1,451
Coulee, WA	Olympia, WA	126
Olympia, WA	Coulee, WA	126
Coulee, WA	Seattle South, WA	5,275
Seattle South, WA	Coulee, WA	5,275
Coulee, WA	Spokane, WA	1,140
Spokane, WA	Coulee, WA	1,140
Eastern Idaho	Garrison, MT	224
Garrison, MT	Eastern Idaho	337
Eastern Idaho	Idaho	400
Idaho	Eastern Idaho	270
Eastern Idaho	Pace, UT	400
Pace, UT	Eastern Idaho	630
Eastern Idaho	Southern Idaho	2,557
Southern Idaho	Eastern Idaho	2,557
Garrison, MT	WAPA U.M., MT	200
WAPA U.M., MT	Garrison, MT	200
Garrison, MT	Western, MT	1.300
Western, MT	Garrison, MT	1.300
Garrison, MT	Yellowtail, MT	2,573
Yellowtail, MT	Garrison, MT	2,573
Idaho	Ogden, UT	9,999
Ogden, UT	Idaho	9,999
Idaho	Pace, UT	9,999
Pace, UT	Idaho	9,999
Idaho	Wyoming R.M.	9,999
Wyoming R.M.	Idaho	9,999
LADWP, CA	Lower Columbia (WA,OR)	3,100
Lower Columbia (WA,OR)	LADWP, CA	3,100
LADWP, CA	Pace, UT	1,400
Pace, UT	LADWP, CA	1,200
LADWP, CA	Sierra, NV	235
Sierra, NV	LADWP, CA	235
LADWP, CA	Southern Nevada	1,841
Southern Nevada	LADWP, CA	1,841
LADWP, CA	Southern California	9,999
Southern California	LADWP, CA	9,999

Region From	Region To	Capacity Limit (MW)
LADWP, CA	WAPA L.C. (AZ,NM)	1,231
WAPA L.C. (AZ,NM)	LADWP, CA	1,231
Lower Columbia (WA,OR)	Malin, OR	1,708
Malin, OR	Lower Columbia (WA,OR)	1,708
Lower Columbia (WA,OR)	McNary, WA	1,948
McNary, WA	Lower Columbia (WA,OR)	1,948
Lower Columbia (WA,OR)	Mid Columbia (WA,OR)	5,277
Mid Columbia (WA,OR)	Lower Columbia (WA,OR)	5,277
Lower Columbia (WA,OR)	Slatt, OR	3,031
Slatt, OR	Lower Columbia (WA,OR)	3,031
Lower Columbia (WA,OR)	Williamet, OR	3,334
Williamet, OR	Lower Columbia (WA,OR)	3,334
Lower Granite Dam, WA	Mid Columbia (WA,OR)	5,560
Mid Columbia (WA,OR)	Lower Granite Dam, WA	5,560
Lower Granite Dam, WA	Spokane, WA	1,155
Spokane, WA	Lower Granite Dam, WA	1,155
Malin, OR	PG and E, CA	4,800
PG and E, CA	Malin, OR	4,800
Malin, OR	Sierra, NV	300
Sierra, NV	Malin, OR	300
Malin, OR	Southern Idaho	1,500
Southern Idaho	Malin, OR	1,500
Malin, OR	Southern Oregon	4,782
Southern Oregon	Malin, OR	4,782
McNary, WA	Mid Columbia (WA,OR)	2,000
Mid Columbia (WA,OR)	McNary, WA	2,000
McNary, WA	Slatt, OR	2,854
Slatt, OR	McNary, WA	2,854
McNary, WA	Williamet, OR	227
Williamet, OR	McNary, WA	227
Baja, Mexico	San Diego & Imperial Valley, CA	800
San Diego & Imperial Valley, CA	Baja, Mexico	800
Mid Columbia (WA,OR)	Oxbow, OR	400
Oxbow, OR	Mid Columbia (WA,OR)	400
Mid Columbia (WA,OR)	Seattle South, WA	3,700
Seattle South, WA	Mid Columbia (WA,OR)	3,700
Mid Columbia (WA,OR)	Slatt, OR	4,100
Slatt, OR	Mid Columbia (WA,OR)	4,100
Mid Columbia (WA,OR)	Spokane, WA	273
Spokane, WA	Mid Columbia (WA,OR)	273
Mid Columbia (WA,OR)	Williamet, OR	2,600
Williamet, OR	Mid Columbia (WA,OR)	2,600
N. King, WA	Seattle South, WA	526
Seattle South, WA	N. King, WA	526
New Mexico	PS Colorado	558
PS Colorado	New Mexico	558

Region From	Region To	Capacity Limit (MW)
New Mexico	WAPA L.C. (AZ,NM)	817
WAPA L.C. (AZ,NM)	New Mexico	817
New Mexico	WAPA R.M., CO	690
WAPA R.M., CO	New Mexico	690
North Puget, WA	Seattle North, WA	3,000
Seattle North, WA	North Puget, WA	3,000
North Puget, WA	Seattle South, WA	3,000
Seattle South, WA	North Puget, WA	3,000
Ogden, UT	Pace, UT	9,999
Pace, UT	Ogden, UT	9,999
Olympia, WA	Seattle South, WA	4,500
Seattle South, WA	Olympia, WA	4,500
OVERTHRS, WY	Wyoming R.M.	9,999
Wyoming R.M.	OVERTHRS, WY	9,999
Oxbow, OR	Southern Idaho	90
Southern Idaho	Oxbow, OR	50
Oxbow, OR	Spokane, WA	450
Spokane, WA	Oxbow, OR	300
Pace, UT	Scenic SW, UT	300
Scenic SW, UT	Pace, UT	300
Pace, UT	Sierra, NV	205
Sierra, NV	Pace, UT	205
Pace, UT	Station Load, WY	9,999
Station Load, WY	Pace, UT	9,999
Pace, UT	WAPA L.C. (AZ,NM)	265
WAPA L.C. (AZ,NM)	Pace, UT	265
Pace, UT	Wyoming R.M.	9,999
Wyoming R.M.	Pace, UT	9,999
PG and E, CA	Sierra, NV	160
Sierra, NV	PG and E, CA	150
PG and E, CA	Southern Oregon	30
Southern Oregon	PG and E, CA	80
PG and E, CA	Southern California	3,400
Southern California	PG and E, CA	3,000
PS Colorado	WAPA R.M., CO	9,999
WAPA R.M., CO	PS Colorado	9,999
Southern California Edison	Southern California	200
Southern California	Southern California Edison	200
Scenic SW, UT	Southern Nevada	300
Southern Nevada	Scenic SW, UT	300
Scenic SW, UT	St. George, UT	9,999
St. George, UT	Scenic SW, UT	9,999
Scenic SW, UT	Station Load, WY	26
Station Load, WY	Scenic SW, UT	26
San Diego & Imperial Valley, CA	Southern California	5,000
Southern California	San Diego & Imperial Valley, CA	5,000

Region From	Region To	Capacity Limit (MW)
Seattle North, WA	Seattle South, WA	1,690
Seattle South, WA	Seattle North, WA	1,690
Sierra, NV	Southern Idaho	262
Southern Idaho	Sierra, NV	500
Sierra, NV	Southern California	17
Southern California	Sierra, NV	17
Southern Oregon	Williamet, OR	4,495
Williamet, OR	Southern Oregon	4,495
Southern Nevada	Southern California	2,754
Southern California	Southern Nevada	2,754
Southern Nevada	WAPA L.C. (AZ,NM)	4,554
WAPA L.C. (AZ,NM)	Southern Nevada	4,554
Southern California	WAPA L.C. (AZ,NM)	1,140
WAPA L.C. (AZ,NM)	Southern California	1,140
Spokane, WA	West Kootenay, BC	200
West Kootenay, BC	Spokane, WA	200
Spokane, WA	Western, MT	1,300
Western, MT	Spokane, WA	2,200
Station Load, WY	Wyoming R.M.	9,999
Wyoming R.M.	Station Load, WY	9,999
WAPA L.C. (AZ,NM)	WAPA R.M., CO	485
WAPA R.M., CO	WAPA L.C. (AZ,NM)	485
WAPA U.M., MT	Yellowtail, MT	390
Yellowtail, MT	WAPA U.M., MT	390

Source: Federal Energy Regulatory Commission, *FERC-714 Annual Power System Reports*
http://www.transmission.bpa.gov/orgs/opi/FERC714/index.shtm

Appendix E: Data Sets Used in ENERGY 2020

This Appendix describes the initial set definitions for ENERGY 2020 used for this project. The sets are the dimensions of the variables (sometimes called indexes) which delineate the scope and detail of the model. For example, the time frame set could be defined as a base year 1990 and every 5 years.

Time Frame

The initial historical year for calibration is 1990.
Current end year of the analysis is 2020, but analysis can be extended to 2030 or beyond.
The last historic year of data will be 2005.
All data sets include annual data for each year of history and the forecast.

For some data sets, the period covered by actual data will depend on available data (e.g., emissions).

Geographical Areas

Each area in the model will represent a state or a province (no sub-state break-outs).
The model will provide separate results for the eleven WCI Partner jurisdictions. The surrounding region (the rest of the WECC) and the rest of the US and Canada are also modeled.

The states and provinces included in the WCI region for modeling purposes include:

- Arizona
- New Mexico
- Washington
- Ontario
- California
- Oregon
- British Columbia
- Quebec
- Montana
- Utah
- Manitoba

Generating Units

The list of units is based on the NEEDS database for the US plus a similar database for the units in Canada. Within the Region and the rest of the US, some of the smaller plants may be aggregated by plant type in order to allow the expedite model operation. Under these assumptions regarding aggregation, this version of the model will include approximately 3,000 units/plants.

Electric Companies

Although ENERGY 2020 can model individual utilities or groups of utilities, for the WCI project the model assumes that each state has a single aggregate utility.

Sectors and Classes

The energy demand portion of the model will simulate residential, commercial, industrial, and transportation demands. There will be an electric sales class for each sector.

Emission Only Sectors

Several sectors generate emissions, but do not have full energy demand simulations in the model. These include solid waste, waste water, incineration, and land use. It may be possible to develop a full energy demand simulation for one or more of these.

Pollutants

The model currently has the capability to cover 15 pollutants, although the final set will depend on project requirements and available data. The GHG pollutants include Carbon Dioxide, Methane, Nitrous Oxide, Sulfur-Hexafluoride, Perfluorocarbon, and Hydrofluorocarbon. The criteria air pollutants include Sulfur Dioxide, Nitrogen Oxides, Total Particulate Matter, Volatile Organic Compounds, Carbon Monoxide, Particulate Matter $_{2.5}$, Particulate Matter $_{10}$, Mercury, and Ozone.

Fuels

There are currently two sets of fuels in the model. The largest category contains 33 fuels (shown below). The second category is the list of technologies which the energy demand sectors choose from. This smaller set contains only the basic types of fuels (Electricity, Natural Gas, Oil, LPG, Biomass, Solar). The aggregate category oil is later broken out into the different types of oil (LFO, HFO, petroleum coke, etc.).

Entire List of Fuels

- Asphalt
- Aviation Fuel
- Biomass
- Coal
- Coke
- Coke Oven Gas
- Diesel
- Electric
- Ethanol
- Geothermal
- Heavy Fuel Oil
- Hydro
- Hydrogen
- Kerosene
- Landfill Gases
- Light Fuel Oil
- LPG
- Lubricants
- Motor Gasoline
- Naphtha Specialties
- Natural Gas
- Nuclear
- Oil, Unspecified
- Other Non-Energy Products
- Petrochemical Feedstocks
- Petroleum Coke
- Solar
- Steam
- Still Gas
- Wave
- Wind
- Unknown 1
- Unknown 2

Electric Generation Plants Types

The electric generation plant types are used to hold the data for future generic plants which the model will construct endogenously. The list currently includes:

- Gas/Oil Peaking
- Gas/Oil Combined Cycle
- Gas/Oil Steam
- Coal
- Coal Advanced
- Coal with CCS
- Gas CC with CCS
- Nuclear
- Base Hydro
- Peak Hydro
- Other Generation
- Biomass
- Landfill Gas
- Wind
- Solar
- Fuel Cells
- Pumped Hydro
- Small Hydro
- Wave
- Geothermal
- Other Storage
- Biogas
- Trash

Residential Sectors

The residential sector is split into housing types:

- Single Family
- Multi-Family
- Other Residential

Commercial Sectors

- Transportation Services
- Pipelines
- Communication
- Electric Utilities
- Gas Utilities
- Water & Other Utilities
- Wholesale
- Retail
- FIRE
- Offices - Business Services
- Education
- Health & Social
- Food, Lodging, Recreation
- Government

Industrial Sectors

- Food & Tobacco
- Textiles
- Apparel
- Lumber
- Furniture
- Pulp & Paper Mills
- Converted Paper
- Printing
- Petrochemicals
- Industrial Gas
- Other Chemicals
- Fertilizers
- Petroleum Products
- Rubber
- Leather
- Cement
- Glass
- Lime & Gypsum
- Other Non-Metallic
- Iron & Steel
- Aluminum
- Other Nonferrous
- Fabricated Metals
- Machines
- Computers
- Electric Equipment
- Transport Equipment
- Other Manufacturing

- Iron Ore Mining
- Other Metal Mining
- Non-metal Mining
- Light Oil Mining
- Heavy Oil Mining
- Frontier Oil Mining
- Oil Sands In-Situ
- Oil Sands Mining
- Oil Sands Upgraders
- Gas Mining
- Coal Mining
- Construction
- Forestry
- Agriculture

Transportation Sectors

- Passenger
- Freight
- Off Road

Miscellaneous Sectors

- Misc. & Street Lighting
- Electric Resale
- Utility Electric Generation
- Industry Electric Generation
- Steam Generation
- Solid Waste
- Waste Water
- Incineration
- Land Use

Residential End-Uses

- Space Heating
- Water Heating
- Other Substitutable
- Refrigeration
- Lighting
- Air Conditioning
- Other Non-Substitutable

Commercial End-Uses

- Space Heating
- Water Heating
- Other Substitutable
- Refrigeration
- Lighting
- Air Conditioning
- Other Non-Substitutable

Industrial End-uses

- Process Heat
- Electric Motors
- Other Substitutable
- Miscellaneous

Transportation End-Uses

- Ground
- Air/Water

Residential, Commercial, and Industrial Technology Types

Each technology type has its own trade-off curve which determines the efficiency and the capital cost of the technology type. These curves allow the model to contain many different technologies within these broad types.

- Electric
- Gas
- Coal
- Oil
- Biomass
- Solar
- LPG
- Steam

Transportation Technology Types

Several technology types are provided for transportation, and each of these contains a trade-off curve which allows the model to simulate even more individual technologies.

- Plug-in Hybrids
- Light Gasoline
- Light Diesel
- Light Propane
- Light CNG
- Light Electric (Plug-in)
- Light Ethanol
- Light Hybrid Gasoline
- Light Hybrid Diesel
- Light Fuel Cell Gasoline
- Light Fuel Cell CNG
- Light Fuel Cell Hydrogen
- Medium Gasoline
- Medium Diesel
- Medium Propane
- Medium CNG
- Medium Ethanol
- Medium Hybrid Gasoline
- Medium Hybrid Diesel
- Medium Fuel Cell Gasoline
- Medium Fuel Cell CNG
- Medium Fuel Cell Hydrogen
- Heavy Gasoline
- Heavy Diesel
- Heavy Propane
- Heavy CNG
- Heavy Ethanol
- Heavy Hybrid Gasoline
- Heavy Hybrid Diesel
- Heavy Fuel Cell Gasoline
- Heavy Fuel Cell CNG
- Heavy Fuel Cell Hydrogen
- Motorcycle
- Bus Gasoline
- Bus Diesel
- Bus Propane
- Bus CNG
- Bus Fuel Cell Gasoline

- Bus Fuel Cell Hydrogen
- Bus Fuel Cell Ethanol
- Train
- Plane
- Marine
- Off Road

Prices

Delivered energy prices are presented for the following fuels:

- Residential Electricity
- Residential Natural Gas
- Residential Coal
- Residential Oil
- Residential Biomass
- Residential LPG
- Residential Steam
- Commercial Electricity
- Commercial Natural Gas
- Commercial Coal
- Commercial Oil
- Commercial Biomass
- Commercial LPG
- Commercial Steam
- Industrial Electricity
- Industrial Natural Gas
- Industrial Coal
- Industrial Oil
- Industrial Biomass
- Industrial LPG
- Industrial Steam
- Gasoline
- Diesel
- Aviation Fuel
- Transportation HFO
- Transportation Natural Gas
- Transportation LPG
- Electric Utility Residual Oil
- Electric Utility Distillate Oil
- Electric Utility Natural Gas
- Electric Utility Coal
- Electric Utility Nuclear
- Electric Utility Biomass
- Ethanol
- Hydrogen

Electric Load Segments

The model dispatches for 6 different hour types (high peak, low peak, high intermediate, low intermediate, high base load, low base load) for each of the four seasons.

Appendix F: Planned or Committed Coal Plants Post-2005

State	Plant_Name	Plant Type	On-Line Year	Capacity (MW)	Fuel	HeatRate	Owner	Notes
AZ	Bowie Power Station LLC	Oil/Gas Combined Cycle	2012	500	NaturalGas	7,548	Southwestern Power Group IILLC	
AZ	Bowie Power Station LLC	Oil/Gas Combined Cycle	2010	500	NaturalGas	7,548	Southwestern Power Group IILLC	
AZ	Springerville	Coal	2010	400	Coal	10,178	Salt River Project	
CO	Comanche	Coal	2009	750	Coal	8,763	Public Service Co of Colorado	
NE	Nebraska City	Coal	2009	663	Coal	9,508	Omaha Public Power District	
NV	TS Power Plant	Coal	2008	200	Coal	10,700	Newmont Nevada Energy Investment, LLC	
TX	J K Spruce	Coal	2010	750	Coal	9,273	City of San Antonio	
WY	Wygen 2	Coal	2007	70	Coal	11,044	Cheyenne Light Fuel & Power Co	
WY	Wygen 3	Coal	2010	100	Coal		Black Hills Corporation	
CO	Lamar Plant	Oil/Gas Steam	1972	25	Natural Gas	14,500	City of Lamar	
CO	Lamar	Coal (Advanced)	2008	39	Coal	9,000	Lamar Utility Board	Repowering
NE	Public Power Generation Agency, Whelan Energy Center 2	Coal	2012	220	Coal	10,047	Public Power Generation Agency	
NM	Estancia Biomass Power Plant	Biomass	2010	25	Biomass (wood)	12,000	Western Water & Power Production LLC	
ND	Great River Energy, Spiritwood	Combined Heat & Power	2010	99		9,000		
TX	Tuminent (TXU) Oak Grove Plant	Coal (Lignite)	2009/10	1600	Lignite	9,130		
TX	Luminent (TXU) Sandow 5	Coal (Advanced)	2009	600	Coal	9,130		
TX	City Public Service, Spruce Plant	Coal	2009	750	Coal	9,000		
WY	Black Hills Corporation, Wygen II Plant	Coal	2008	95		12,500	Black Hills Corporation	
WY	Basin Electric Coop, Dry Fork	Coal (Advanced)	2011	385	Coal	9,000	Basin Electric Coop	
WY	North American Power Gp, 2 Elk Power Plant Unit 1	Coal	2010	325	Coal	9,000	North American Power Group	
WY	DKRW Energy LLC	Coal	2010	200	Coal	9,000	DKRW	

Note: These units have been included for modeling purposes only. It is not possible to determine at this time which specific projects will be completed.

Appendix G: New Generation Performance and Cost Assumptions

Table 1A. Input Values to Busbar Energy Costs - California Resources (2008 $)

Resource Technology	2020 Overnight Capital Cost ($/kW) ($/kW)		Fixed O&M Cost ($/kW-year)		Variable O&M Cost ($/MWh)		Capacity Factor
	Low (if range)	High (if range)	Low (if range)	High (if range)	Low (if range)	High (if range)	
Biogas	$3,065		$139		1.20		80%
Biomass	$4,484		$65		1.20		80%
Geothermal	$3,339	$8,131	$157	$226	1.20		90%
Hydro - Small	$2,539	$5,170	$14	$31	0.94	1.81	25% - 65%
Solar - Thermal	$3,235		$64		1.20		37% - 40%
Wind	$1,962		$37		1.20		27% - 40%
Coal ST	$2,479		$33		1.20		85%
Coal IGCC	$2,866		$47		1.20		85%
Coal IGCC with CCS	$4,101		$55		1.20		85%
Gas CCCT	$1,054		$14		1.20		90%
Gas CT	$807		$15		1.20		5%
Hydro - Large	$1,486	$2,193	$9	$13	0.63	0.89	12% - 57%
Nuclear	$3,999		$83		1.20		85%

Table 1B. Input Values to Busbar Energy Costs - Rest of WECC Resources (2008 $)

Resource Technology	2020 Overnight Capital Cost ($/kW) ($/kW)		Fixed O&M Cost ($/kW-year)		Variable O&M Cost ($/MWh)		Capacity Factor	Nominal Heat Rate (Btu/kWh)
	Low (if range)	High (if range)	Low (if range)	High (if range)	Low (if range)	High (if range)		
Biogas	$2,350	$2,835	$107	$128	0.92	1.11	80%	13,648
Biomass	$3,438	$4,148	$50	$60	0.92	1.11	80%	8,911
Geothermal	$1,582	$19,451	$157	$226	0.96	1.11	90%	n/a
Hydro - Small	$1,758	$4,782	$11	$28	0.71	1.69	22% - 65%	n/a
Solar - Thermal	$2,588	$2,939	$51	$58	0.96	1.09	36% - 39%	n/a
Wind	$1,504	$1,815	$28	$34	0.92	1.11	27% - 40%	n/a
Coal ST	$1,901	$2,293	$26	$31	0.92	1.11	85%	8,844
Coal IGCC	$2,197	$2,651	$36	$43	0.92	1.11	85%	8,309
Coal IGCC with CCS	$3,144	$3,794	$42	$51	0.92	1.11	85%	9,713
Gas CCCT	$808	$975	$11	$13	0.92	1.11	90%	6,917
Gas CT	$619	$747	$11	$14	0.92	1.11	5%	10,807
Hydro - Large	$1,122	$2,031	$5	$11	0.41	0.78	15% - 65%	n/a
Nuclear	$3,066	$3,699	$63	$76	0.92	1.11	85%	10,400

Note: Variable O&M Costs do not include fuel costs. Range of costs is similar for several of the technologies.
Source: Energy and Environmental Economics, Inc., CPUC GHG Modeling - Generation Costs (Word document), 11/16/2007.www.ethree.com/cpuc_ghg_model.html

Appendix H: Global Warming Potential

ENERGY 2020 models emissions of each of the six greenhouse gases reported under the Kyoto protocol. These emissions are then translated into equivalent quantities of CO_2 emissions (CO_2e) based on the global warming potential of each of the gases.

The Global Warming Potential (GWP) values used in ENERGY 2020 are shown in the table below.

Greenhouse Gas	Global Warming Potential
Carbon Dioxide (CO_2)	1
Methane (CH_4)	21
Nitrous Oxide (N_2O)	310
Sulfur Hexafluoride (SF_6)	23,900
Perfluorocarbons (PFC)	7,000
Hydrofluorocarbons (HFC)	1,300

These values are consistent with the Global Warming Potential values used in the 1996 Second Assessment Report based on 100-year warming potential for the individual gases. In the case of HFCs and PFCs the GWP values used in the model are based on an estimated average GWP for these gases.

Appendix I: Renewable Portfolio Standards: Partner Jurisdictions and Rest of North America

State or Prov	Target	Policy
United States		
AZ	15% of generation from renewables by 2025	Regulated electric utilities must generate 15% of their energy from renewables by 2025. By 2012, at least 30% of the standard must be derived from distributed renewable energy (4.5% of total electricity sales by regulated utilities). RES specifies what technologies qualify (Solar Water Heat, Solar Space Heat, Solar Thermal Electric, Solar Thermal Process Heat, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Geothermal Heat Pumps, CHP/Cogeneration, Solar Pool Heating (commercial only), Daylighting (non-residential only), Solar Space Cooling, Solar HVAC, Additional technologies upon approval, Anaerobic Digestion, Fuel Cells using Renewable Fuels) and allow for the addition of new technologies as they become feasible. Penalties for non-compliance. The new rules also require a growing percentage of the total resource portfolio to come from distributed generation.
CA	Major utilities 20% from renewable sources by 2010 on a retail sales basis	California's Investor-Owned Utility, Electric Service Providers, Small and Multi-Jurisdictional Utilities and Community Choice Aggregators to produce at least 20% of their electricity using renewable sources by 2010 based on renewable retail sales. Eligible technologies: Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Geothermal Electric, Municipal Solid Waste, Anaerobic Digestion, Small Hydroelectric, Tidal Energy, Wave Energy, Ocean Thermal, Biodiesel, and Fuel Cells using Renewable Fuels.

State or Prov	Target	Policy
MT	10% of generation load to be renewable by 2010; 15% by 2015	Each investor-owned and public utility should: Meet 20% of its load using renewable energy resources by 2020, increasing to 25% by 2025. The legislation contains a cost cap that encourages utilities to invest in renewable generation that is cost competitive with conventional generation. Eligible technologies: wind, solar, geothermal, existing hydroelectric projects, landfill or farm-based methane gas, wastewater-treatment gas, low-emission, nontoxic biomass, and fuel cells where hydrogen is produced with renewable fuels.
NM	10% of generation by 2011; 15% renewable by 2015; 20% by 2020	Applies to Investor-Owned Utility, Rural Electric Cooperative. IOUs: 15% power generation from renewable sources and 20% by 2020. RECs: 10% by 2020. This legislation expands on NM's current RPS requiring that 10% of the state's nergy come from such sources by 2011. IOUs must also meet: 20% of RPS from solar (4% of total sales); 20% of RPS from wind (i.e. 4% of total sales); 10% of RPS from geothermal and biomass (2% of total sales); 3% of RPS from distributed renewables (0.6% of total sales) by 2020. Eligible technologies: Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Zero emission technology with substantial long-term production potential, Anaerobic Digestion, Fuel Cells using Renewable Fuels

State or Prov	Target	Policy
OR	25% of electric load must be renewable sources by 2025 (ramps up from 2015)	Largest utilities 25% of their electric load with new renewable energy sources by 2025. Interim targets of 5% by 2011; 15% by 2015; 20% by 2020; and 25% by 2025. Based on total retail sales volumes. Eligible technology: wind, solar, wave, geothermal, biomass, new hydro or efficiency upgrades to existing hydro facilities. Utilities are not required to comply with the standard if doing so will result in retail electricity price increases of more than 4%. If none of a utility's options for compliance are cost-effective, they can make an Alternative Compliance Payment (ACP) to help meet their renewable energy requirement. The level of the ACP will be determined by the PUC and will be set to provide adequate incentive for the utility company to generate qualifying renewable electricity instead of using an ACP payment to meet the RPS. The ACP will be placed into an account that can be used in the future to acquire renewable energy, invest in conservation or, for consumer-owned utilities, research and development.
UT	20% of sales by 2025 for Rocky Mountain Power and Co-ops or municipal electric utilities, if cost effective	The retail sales are adjusted by subtracting the non-carbon sources of energy (e.g. hydro, nuclear) and future carbon sequestration from the total retail sales. The 20% target would then apply to the carbon component of the utility's portfolio.Requires plans and reports concerning an electrical corporation's or municipal electric utility's progress in acquiring renewable energy.Requires the Utah Geological Survey to make rules concerning carbon capture and geological storage of captured carbon emissions.
WA	All new long term baseload facilities must meet 1,100 lbs CO_2/MWh starting July 2008	GHG performance standard for all new, long-term baseload electric power generation. Under the standard, all baseload generation for which utilities enter into long-term contracts must meet a greenhouse gas emissions standard of 1,100 pounds per MWh beginning in July 2008
WA	15% of production to be renewable by 2020 (small & low growth utilities exempt, so effectively 14%)	All utilities serving >25,000 people to produce 15% of their energy using renewable sources by 2020. Eligible technology: wind, solar, and tidal power as well as landfill-methane capture.

State or Prov	Target	Policy
CANADA		
PEI	15% by 2010	
Nfld	n/a	
NB	10% renewables by 2016	
NS	18.5% of electricity needs from renewables by 2013	
PQ	Produce 4,000 MW of electricity from wind by 2015	Additional hydro projects will begin operation by 2012, totalling 1,054 MW. The 1500Mw La Romaine facility will is projected to come on line in 2014.
ON	No coal-fired electricity generation in the province by 31 December 2014 Conserve 6,300 MW of electricity by 2025 (40% by 2010)50% increase in renewable energy capacity by 2015, including hydro; 15,700 MW by 2025 including up to 1,000 MW of renewable power to the grid by 2010	Regulation to phase out use of coal-fired generation enacted in 2007. Renewable power RFP being contracted for capacity and generation
MB	1,000 MW of wind power by 2016 Energy saving target of 842 MW of electricity by 2017	Most of Manitoba's power production is already from renewable sources. Target: 1,000 MW of wind power by 2016. The 1,000 MW will reduce GHGs by 3.5 Mt annually, and stimulate $2 billion in new investments. As a part of this, the province intends to add 300 MW of wind (starting construction in 2007-08). The 300 MW is in addition to the 99 MW St. Leon wind farm, which is already in operation.

State or Prov	Target	Policy
SK	Demand side management to reduce needs by 300 MW by 2017 New and replacement generation emissions-free or fully offset	By 2017, we commit to saving at least 300 megawatts of SaskPower's electricity generation through demand side management practices. Ensure all of SaskPower's new and replacement electricity generation facilities are either emissions-free or fully offset by emission credits
AB	By 2008, more than 12.5% of Alberta's total electricity generated will be generated from renewables	12.5% renewables, primarily wind and biomass
BC	Offset all O&G grid power emissions by 2016.	All existing natural gas and oil-fired generating facilities part of the integrated grid will need to completely offset their GHG emissions by 2016. All coal will need to use CCS, sequester or otherwise offset emissions, and all new O&G must not add to current levels of emissions50% of incremental electricity requirements to be met through conservation
BC	Maintain 90% clean sources - all new sources zero emissions.	Maintaining 90% clean power supply, including hydro. Note that no nuclear will be built in the province. Government will issue guidelines to define what sources qualify as clean or renewable and provide additional policy direction as required. In 2004, power generation accounted for only 3% of the total amount of GHG emitted.
NWT	n/a	Taltson River Hydro development (36 MW) set for construction and online by 2011 4 mini hydro possibilities
Yukon	n/a	$7M to install third turbine at Aishihik hydo plant planned to be in service between 2009 & 2012 (7 MW capacity)
Nunavut	n/a	n/a

Province or State	E2020 Description	RPS since 05/01/08	2020 RPS % Region Sales Target	State goal for renewable (% of sales)	Out of State Permitted	New Restrictions on generation location
IA	MAPP	no	0.2%	105 MW	Yes	Must own facilities located in the state or enter into long term contracts to purchase or wheel electricity from facilities located within the utility's service area
MN	MAPP	no	11.2%	Xcel Energy: 30% by 2020 All Others: 25% by 2025*	Yes	Allowed to use out of state generation - Local benefits. The commission shall take all reasonable actions within its statutory authority to ensure this section is implemented to maximize benefits to Minnesota citizens, balancing factors such as local ownership of or participation in energy production, development and ownership of eligible energy technology facilities by independent power producers, Minnesota utility ownership of eligible energy technology facilities, the costs of energy generation to satisfy the renewable standard, and the reliability of electric service to Minnesotans
ND	MAPP	no	0.7%	State Renewable Goal: 10% by 2015	%	"A portion or all of the renewable energy and recycled energy objective may be met by the purchase and retirement of renewable energy and recycled energy certificates representing credits from qualified sources and facilities as defined in section 49-02-26 and section 5 of this Act. Renewable energy and recycled energy certificates do not need to be acquired from an in-state facility."
NE	MAPP	no	N/A	N/A	N/A	N/A
SD	MAPP	yes	0.6%	Voluntary RPS 10% by 2015	N/A	N/A
E2020 Region: MAPP			12.7%			

Province or State	E2020 Description	RPS since 05/01/08	2020 RPS % Region Sales Target	State goal for renewable (% of sales)	Out of State Permitted	New Restrictions on generation location
DE	MidWest	no	0.2%	20% by 2019	No	Energy sold or displaced by a customer-sited eligible energy resource can generate renewable energy credits for RPS compliance, provided the system is sited in Delaware.
IL	MidWest	no	2.4%	25% by 2025 Tech. Min. 75% wind	Yes after 2011	Through 2011, eligible resources must be located in-state.
IN	MidWest	no	0.0%	N/A	N/A	N/A
KY	MidWest	no	0.0%	N/A	N/A	N/A
MD	MidWest	yes	1.3%	Standard: Tier 1: 20% in 2022 and beyond; Tier 2: 2.5% in 2006 through 2018 Tech. Min. 2% solar electric in 2022 as part of the Tier 1 requirement. Suppliers also receive 110% - 120% credit for wind and 110% credit for methane during a specified timeframe	Yes	Solar resources must be connected with the distribution grid serving Maryland, except that on or before December 31, 2011, solar resources not connected to the Maryland grid are eligible only if offers for solar RECs from Maryland grid sources are not made to an electricity supplier that would satisfy the RPS.
MI	MidWest	no	2.2%	20% by 2020 at least 5% must be from solar	Yes	Allowed to use out of state generation

Province or State	E2020 Description	RPS since 05/01/08	2020 RPS % Region Sales Target	State goal for renewable (% of sales)	Out of State Permitted	New Restrictions on generation location
NJ	MidWest	yes	1.8%	22.5% by 2021 (2.12% from solar; 17.88% from other Class I renewables; 2.5% from Class II or additional Class I renewables)	Yes	To qualify as "Class I" or "Class II" renewable energy, electricity must be generated within or delivered into the PJM region. "Class I" or "Class II" renewable energy delivered into the PJM region must be generated at a facility that began construction on or after January 1, 2003, in order to qualify.
OH	MidWest	yes	1.5%	25% from alt. energy resources by 2025 (12.5% renewables). Additional 12.5%of the overall 25% standard can also be met through alternative energy resources like third-generation nuclear power plants, fuel cells, energy-efficiency programs, and clean coal technology that can control or prevent CO_2 emissions	50%	At least half of this renewable energy must be generated in-state.

Province or State	E2020 Description	RPS since 05/01/08	2020 RPS % Region Sales Target	State goal for renewable (% of sales)	Out of State Permitted	New Restrictions on generation location
PA	MidWest	no	2.6%	Standard: 18% during compliance year 2020-2021 (8% Tier I and 10% Tier II) Technology Minimum: Solar PV set-aside of 0.5% for June 1, 2020 and thereafter	Yes	Allowed to use out of state generation - Energy derived only from alternative energy sources inside the geographical boundaries of this Commonwealth or within the service territory of any regional transmission organization that manages the transmission system in any part of this Commonwealth shall be eligible to meet the compliance requirements under this act. Electric distribution companies and electric generation suppliers shall document that this energy was not used to satisfy another state's renewable energy portfolio standards
WI	MidWest	no	0.7%	Requirement varies by utility (statewide target of 10% by 12/31/15)	Yes	Allowed to use out of state generation
WV	MidWest	no	0.0%	N/A	N/A	N/A
E2020 Region Code: MW			**12.7%**			

Province or State	E2020 Description	RPS since 05/01/08	2020 RPS % Region Sales Target	State goal for renewable (% of sales)	Out of State Permitted	New Restrictions on generation location
CT	NPCC	no	3.2%	*in % of sale* 27% by 2020 20% Class I resources 3% Class I or Class II resources 4% Class III resources by 2010	Yes	Electric suppliers or distribution may satisfy the requirements by: (A) purchasing Class I or II renewable sources within the jurisdiction of the regional independent system operator, or within the jurisdiction of NY, PA, NJ, MD, DE, provided the department determines such states have a renewable portfolio standard that is comparable to this section; or (B) by participating in a renewable energy trading program within said jurisdictions as approved by the Department of Public Utility Control. Eligibility for resources postponed until at least 1/1/2010
MA	NPCC	yes	1.0%	Class I Std: 4% of sales by end 2009, additional 1% of sales each year thereafter, no stated end date Class II Std: 3.6% of annual sales Alt. Energy Portfolio Std: 0.75% of sales by end 2009, reaching 5% in 2020, and an additional 0.25% of sales each year thereafter	%	In meeting the "Class I" standard, retail suppliers must provide a portion – to be determined by the DOER – of the required renewable energy from new, in-state, on-site systems of <2MW in capacity which began commercial operation after December 31, 2007.

Province or State	E2020 Description	RPS since 05/01/08	2020 RPS % Region Sales Target	State goal for renewable (% of sales)	Out of State Permitted	New Restrictions on generation location
ME	NPCC	yes	0.5%	Standard: Class I: 10% new resources by 2017 (and for each year thereafter) Class II: 30% by 2000 Tech. Min: No	N/A	NE-ISO
NH	NPCC	no	0.6%	By 2025: 16% Class I 0.3% Class II 6.5% Class III 1% Class IV	Yes	From other states in the New England control area and adjacent states
NY	NPCC	yes	12.8%	Standard: 24% by 2013 Technology Minimum: 2% of total incremental RPS requirement is set-aside for the Customer-Sited Tier, for a total of 0.1542% of customer-sited generation*	Yes	Allowed to use out of state generation - Main Tier: Limited to the electricity sold in a retail sale in NY State made by a load serving entity to a customer – self-generation is not eligible Customer-sited Tier: Only facilities located in NY are eligible – self generation is eligible Resources eligible for the Customer-Sited Tier include fuel cells, photovoltaic, wind, and methane digesters. Customer-Sited Tier systems are generally limited to the size of the load at the customer's meter.

Province or State	E2020 Description	RPS since 05/01/08	2020 RPS % Region Sales Target	State goal for renewable (% of sales)	Out of State Permitted	New Restrictions on generation location
RI	NPCC	no	0.5%	16% by 2019 and thereafter (14% must be from new sources)	Yes	Generation Units must be located in NEPOOL or in a control area adjacent, provided the associated Generation Attributes shall be applied to the RES only to the extent that the energy produced by the Generation Unit is actually delivered into NEPOOL for consumption by NE customers. The delivery of such energy from the Generation Unit into NEPOOL must be verified by: (a) a unit-specific bilateral contract for the sale and delivery of such energy into NEPOOL; (b) confirmation from ISO that the renewable energy was actually settled in the ISO Market Settlement System; and, (c) (1) confirmation through the North American Reliability Council tagging system that the import of the energy into NEPOOL actually occurred; or, (2) any such other requirements.
VT	NPCC	yes	0.4%	RPS Goals: (1) increase in retail electricity sales between 2005-2012; (2) 20% of state-wide electric retail sales and CHP by 2017; (3) 25% of all energy consumed from renewables by 2025	Yes	Allowed to use out of state generation - The public service board shall ensure that all electricity provider and provider-affiliate disclosures and representations made with regard to a provider's portfolio are accurate and reasonably supported by objective data. Further, the public service board shall ensure that providers disclose the types of generation used and whether the energy is Vermont-based, and shall clearly distinguish between energy or tradable energy credits provided from renewable and non-renewable sources and existing and new sources.
E2020 Region Code: NP			19.0%			

Province or State	E2020 Description	RPS since 05/01/08	2020 RPS % Region Sales Target	State goal for renewable (% of sales)	Out of State Permitted	New Restrictions on generation location
AK	Rest of US	no	0.0%	N/A	N/A	N/A
AL	Rest of US	no	0.0%	N/A	N/A	N/A
AR	Rest of US	no	0.0%	N/A	N/A	N/A
FL	Rest of US	no	2.9%	RPS Goal: to develop RPS by Feb. 1, 2009. Each electricity provider, except municipal utilities and rural cooperatives, must supply an as-yet unspecified amount of renewable energy to its customers. Although HB 7135 does not specify the RPS target, the Governor EO 07-127 from July 13, 2007 requires utilities to produce at least 20% of their electricity from renewables.	N/A	N/A
GA	Rest of US	no	0.0%	N/A	N/A	N/A
HI	Rest of US	yes	0.1%	*% in sales* 10% by 12/31/2010; 15% by 12/31/2015; and 20% by 12/31/2020 (including existing renewables)	N/A	

Province or State	E2020 Description	RPS since 05/01/08	2020 RPS % Region Sales Target	State goal for renewable (% of sales)	Out of State Permitted	New Restrictions on generation location
KS	Rest of US	no	0.0%	N/A	N/A	N/A
LA	Rest of US	no	0.0%	N/A	N/A	N/A
MO	Rest of US	no	0.6%	Goal: 11% by 2020*	N/A	n/a
MS	Rest of US	no	N/A	N/A	N/A	N/A
NC	Rest of US	no	1.0%	Standard: 12.5% of 2020 retail sales by 2021 for investor-owned utilities; 10% of 2017 retail sales by 2018 for electric cooperatives and municipal utilities Technology Minimum: 0.2% solar electricity and thermal energy by 2018; 0.2% swine waste by 2018; 900,000 MWh of poultry waste by 2014	25%	Obligated utilities may: "Purchase renewable energy certificates derived from in-state or out-of-state new renewable energy facilities. Certificates derived out-of-state new renewable energy facilities shall not be used to meet <25% of the requirements, provided that this limitation shall not apply to an electric public utility with less than 150,000 NC retail jurisdictional customers as of 31 December 2006." Qualifying out-of-state facilities must be in service after 2006 or hydro facilities under 10 MW.
OK	Rest of US	no	0.0%	N/A	N/A	N/A
SC	Rest of US	no	0.0%	N/A	N/A	N/A
TN	Rest of US	no	0.0%	N/A	N/A	N/A

Province or State	E2020 Description	RPS since 05/01/08	2020 RPS % Region Sales Target	State goal for renewable (% of sales)	Out of State Permitted	New Restrictions on generation location
TX	Rest of US	no	1.0%	5,880 MW by 1/1/2015 Target of at least 500 MW from renewables other than wind	No - unless direct transmission connection.	Energy delivered into a transmission system where it is commingled with electricity from non-renewable resources cannot be verified as delivered to TX customers, thus eligible out of state generation requires a dedicated transmission line.
VA	Rest of US	no	0.6%	Standard: 12% of base year (2007) sales by 2022 Technology Minimum: None, but wind and solar power receive a double credit toward RPS goals.	Yes	Out of state generation allowed. Eligible renewable energy is (i) generated/purchased in the Commonwealth or in the interconnection region of the regional transmission entity, as it may change from time to time; (ii) generated by a public utility providing electric service in the Commonwealth from a facility in which the public utility owns at least a 49 percent interest and that is located in a control area adjacent to such interconnection region; or (iii) represented by certificates issued by an affiliate of such regional transmission entity, or any successor to such affiliate, and held or acquired by such utility, which validate the generation of renewable energy by eligible sources in such region.
Total E2020 Region Code: RU			**6.2%**			

Appendix J: Efficiency and Cost Data – Built Environment

Residential:

Residential Device Standards	
Equipment	**Effective Efficiency Standard**
Gas hot water from 1990 to the final year	59%
Oil hot water from 1990 to the final year	51%
Electric hot water from 1990 to the final year (inc.tank losses)	92%
LPG hot water from 1990 to the final year	59%
Electric air conditioning for 1990	260% COP = 2.6
Electric air conditioning for 1991	261% COP = 2.61
Electric air conditioning for 1992 to 2006	265% COP = 2.65
Electric air conditioning for 2007 to the final year	344% COP = 3.44
Electric Refrigeration for 1990 to 1992	34.5%
Electric Refrigeration for 1993	40.0%
Electric Refrigeration for 1994 to 2000.	42.0%
Electric Refrigeration from 2001 to the final year	54.7%
Biomass space Heating from 1993 to the final year (wood burning equipment)	63.0%
Gas space Heating from 1993 to the final year	80.0%
Oil space Heating from 1993 to the final year	80.0%
LPG space Heating from 1993 to the final year	80.0%

Residential (cont'd.)

Maximum Device Efficiency							
(Btu/Btu)	Electric	N.Gas	Coal	Oil	Biomass	LPG	Steam
Primary Heat	278%	97%	97%	97%	78%	97%	99%
Water Heating	250%	86%	97%	97%	78%	97%	99%
Other Substitutable Loads	130%	97%	97%	97%	65%	97%	99%
Refrigerators	98%	0%	0%	0%	0%	0%	0%
Lighting	95%	0%	0%	0%	0%	0%	0%
Air Conditioning	447%	113%	0%	0%	0%	113%	0%
Other Non-Substitutable Loads	98%	0%	0%	0%	0%	0%	0%

Note – Electric heating applications include heat pumps.
Non-substitutable loads are those loads which require electricity (refrigerators, electronics, etc.).
Substitutable loads are those loads which can use multiple fuels (i.e. Range, dryers, etc.).

Device Capital Cost								
1985$/mmBtu/Year	Electric	N.Gas	Coal	Oil	Biomass	Solar	LPG	Steam
Space Heating	17.7	23.1	19.0	36.0	17.2	132.0	23.1	36.0
Water Heating	8.5	18.5	19.0	23.5	17.2	82.0	18.5	23.5
Other Substitutable Loads	65.0	85.0	19.0	85.0	17.2	-	85.0	85.0
Refrigerators	96.5	-	-	-	-	-	-	-
Lighting	0.23	-	-	-	-	-	-	-
Air Conditioning	4.4	34.1	-	-	-	-	34.1	-
Other Non-Substitutable Loads	19.8	-	-	-	-	-	-	-

Device Operating Costs								
1985 $/mmBtu	Electric	N.Gas	Coal	Oil	Biomass	Solar	LPG	Steam
Space Heat	0.018	0.024	0.011	0.020	0.013	0.012	0.024	0.030
Water Heating	-	-	-	-	-	0.010	-	-
Other Substitutable Loads	-	-	-	-	-	-	-	-
Refrigeration	-	-	-	-	-	-	-	-
Lighting	-	-	-	-	-	-	-	-
Air Conditioning	0.015	0.017	-	-	-	-	0.017	-
Other Non-Substitutable Loads	-	-	-	-	-	-	-	-

Residential (cont'd.)

Physical Life of Equipment in Years (Residential)							
	Space Heat	Water Heating	Substitutable Loads	Refrigeration	Light	Air Conditioning	Non-Substitutable Loads
Electric	18	15	13	18	6	15	10
Natural Gas	18	15	13	0	0	15	0
Coal	18	15	13	0	0	0	0
Oil	18	15	13	0	0	0	0
Biomass	18	15	13	0	0	0	0
Solar	18	15	13	0	0	0	0
LPG	18	15	13	0	0	0	0
Steam	18	15	13	0	0	0	0

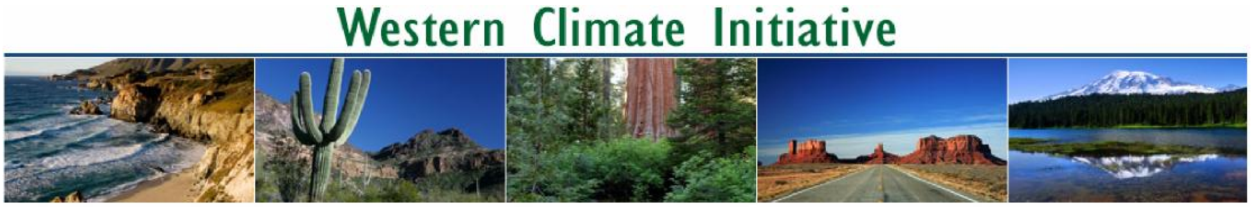
Commercial:

Device Efficiency Standards (Commercial)								
Btu/Btu	Electric	N.Gas	Coal	Oil	Biomass	Solar	LPG	Steam
Space Heating (primary)	450%	97%	97%	97%	65%	1000%	97%	99%
Water Heating	400%	97%	97%	97%	65%	1000%	97%	99%
Other Substitutable Loads	130%	97%	97%	97%	65%	1000%	97%	99%
Refrigerators	140%	0%	0%	0%	0%	0%	0%	0%
Lighting	95%	0%	0%	0%	0%	0%	0%	0%
Air Conditioning	400%	240%	0%	0%	0%	0%	200%	0%
Other Non-Substitutable Loads	98%	0%	0%	0%	0%	0%	0%	0%

Device Capital Cost (Commercial)								
$/mmBtu/Year	Electric	N.Gas	Coal	Oil	Biomass	Solar	LPG	Steam
Primary Heat	9.20	7.5	42.2	19.0	25.5	138.9	22.9	42.2
Water Heating	5.20	8.9	42.2	19.0	-	138.9	22.9	42.2
Other Substitutable Loads	19.80	11.3	11.3	19.0	-	-	11.3	11.3
Refrigeration	0.21	-	-	-	-	-	-	-
Lighting	0.02	-	-	-	-	-	-	-
Air Conditioning	9.20	34.1	-	-	-	-	34.1	-
Other Non Substitutable Loads	22.00	-	-	-	-	-	-	-

Device Operating Cost Fraction ($/Year/$)								
1985 $/mmBtu	**Electric**	**N.Gas**	**Coal**	**Oil**	**Biomass**	**Solar**	**LPG**	**Steam**
Space Heating (primary)	0.02	0.03	0.01	0.03	0.01	0.01	0.03	0.04
Water Heating	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00
Other Substitutable Loads	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Refrigeration	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lighting	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Air Conditioning	0.01	0.02	0.00	0.00	0.00	0.00	0.03	0.00
Other Non-Substitutable Loads	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Physical Life of Equipment in Years							
	Space Heat	**Water Heating**	**Substitutable Loads**	**Refrigeration**	**Light**	**Air Conditioning**	**Non-Substitutable Loads**
Electric	18	8	10	15	7	18	7
Natural Gas	25	8	10	0	0	18	0
Coal	18	8	10	0	0	0	0
Oil	25	8	10	0	0	0	0
Biomass	18	8	10	0	0	0	0
Solar	18	8	10	0	0	0	0
LPG	18	8	10	0	0	18	0
Steam	18	8	10	0	0	0	0



July 7, 2010

Highlights of WCI Economic Analysis

The Partner jurisdictions of the Western Climate Initiative (WCI) have released an updated economic analysis confirming that its regional plan to reduce greenhouse emissions (GHG) is both environmentally achievable and economically positive.

Key Results of the WCI Economic Modeling Analysis

- The WCI Partner jurisdictions can meet their 2020 regional emissions reduction goal while realizing modest net cost savings.
- Policies implemented in conjunction with cap-and-trade, such as energy efficiency and clean car standards, have the potential to significantly reduce emissions and contain costs.
- Carbon allowance banking and offsets are important design elements for achieving emissions reductions and limiting costs.
- Higher-than-expected fuel prices would make it less costly to achieve the emissions reduction goal and would lower the allowance prices. Conversely, lower-than-expected fuel prices, coupled with a faster economic recovery, would raise the allowance price.

The economic analysis indicates that the WCI Partner jurisdictions can achieve the goal of reducing emissions to 15 percent below 2005 levels by 2020—and realize net cost savings of approximately US$100 billion between 2012 and 2020.

The report released today updates a 2008 economic analysis and incorporates new data reflecting the following:

- Expanded WCI membership (to include Manitoba, Québec, and Ontario)
- The 2008—2009 economic recession
- Various economic model improvements identified after extensive consultation with stakeholders

The updated economic analysis considered a range of scenarios with varying assumptions about future economic growth, fuel prices, and other factors. In each instance, the analysis showed that the WCI program would deliver net cost savings—even when the assumptions resulted in different carbon allowance prices. These findings are similar to the results of other recent economic analyses.

Western Climate Initiative

Updated Economic Analysis of the WCI Cap-and-Trade Program

WCI Stakeholder Call

July 13, 2010

Overview

- Highlights
- Changes since last analysis
- Results
- Next steps
- Stakeholder questions

Highlights

- The economic analysis demonstrates that the WCI program
  - can address climate change as a region and continue to grow the economy
  - can reduce dependence on imported oil
  - embodies policies that are affordable, gradual, and not disruptive to the Partners' economic growth

Highlights

- Transitioning from dirty energy to clean energy is a smart, affordable investment, with net economic benefits
- The cost savings are attributable to increased energy efficiency and reduced fuel consumption
- The WCI program will also stimulate investment and innovation in a green economy and produce clear environmental benefits, including cleaner air

Highlights

- The most expensive thing we can do is nothing. Examples include:
  - $36 billion in damage from sea-level in the San Francisco Bay area by 2050 ($100 billion state-wide by 2085)
  - $3 billion per year in CA agricultural crop losses by 2050
  - $1,250 per household per year in WA due to higher energy costs, health-related costs, and other factors by 2020

How the Model Works

- We used ENERGY 2020, an integrated North American economy, energy and emissions model. Major outputs include:
  - Emissions of GHGs and conventional air pollutants
  - Energy-related investments and expenditures on devices, processes, fuel, and operation and maintenance
  - Electric power sector results, including demand, generation, capacity, wholesale prices, LSE revenues and rates
  - Levels of energy efficiency and fuel use by type
- Using the model iteratively, we can determine the carbon price necessary to induce a 15% emission reduction

Changes Since Last Analysis

- Informed by stakeholder calls, meetings, written comments following September 2008 analysis
- Manitoba, Ontario, and Québec now included
- Economic forecast adjusted for recession
- Fuel price forecast updated
- Allowance banking and phasing of the cap are more appropriately simulated
- WCI offset limit more accurately simulated
- Offset supply and costs based on US EPA analysis

Changes Since Last Analysis

- Greater detail on electricity sector results included
- Energy efficiency policies assumed to reduce annual growth by 0.5% instead of 1.0% and now include program administration and O&M costs
- Phase I clean car standards included in reference case instead of cap-and-trade case
- Phase II clean car standards costs updated
- See Tables 1-2 and Figures 1-2 in report for a complete list of changes and further detail

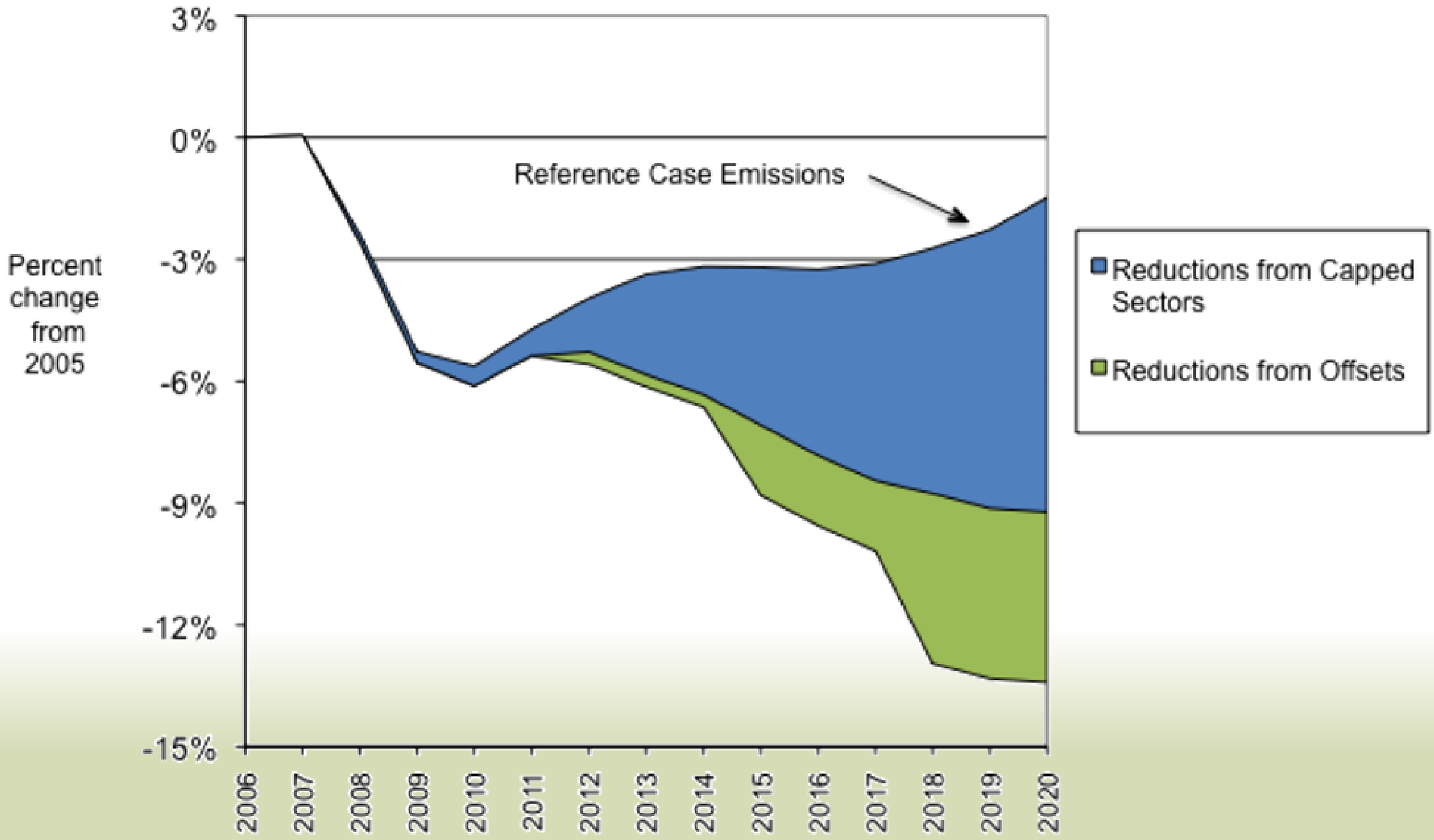
Results

- Results continue to show that WCI emissions reduction goal can be met with modest net cost savings
  - 15% below 2005 emissions levels by 2020
  - Savings of US$100 billion over the 2012-2020 period
- Policies implemented in conjunction with cap-and-trade help reduce emissions and limit costs

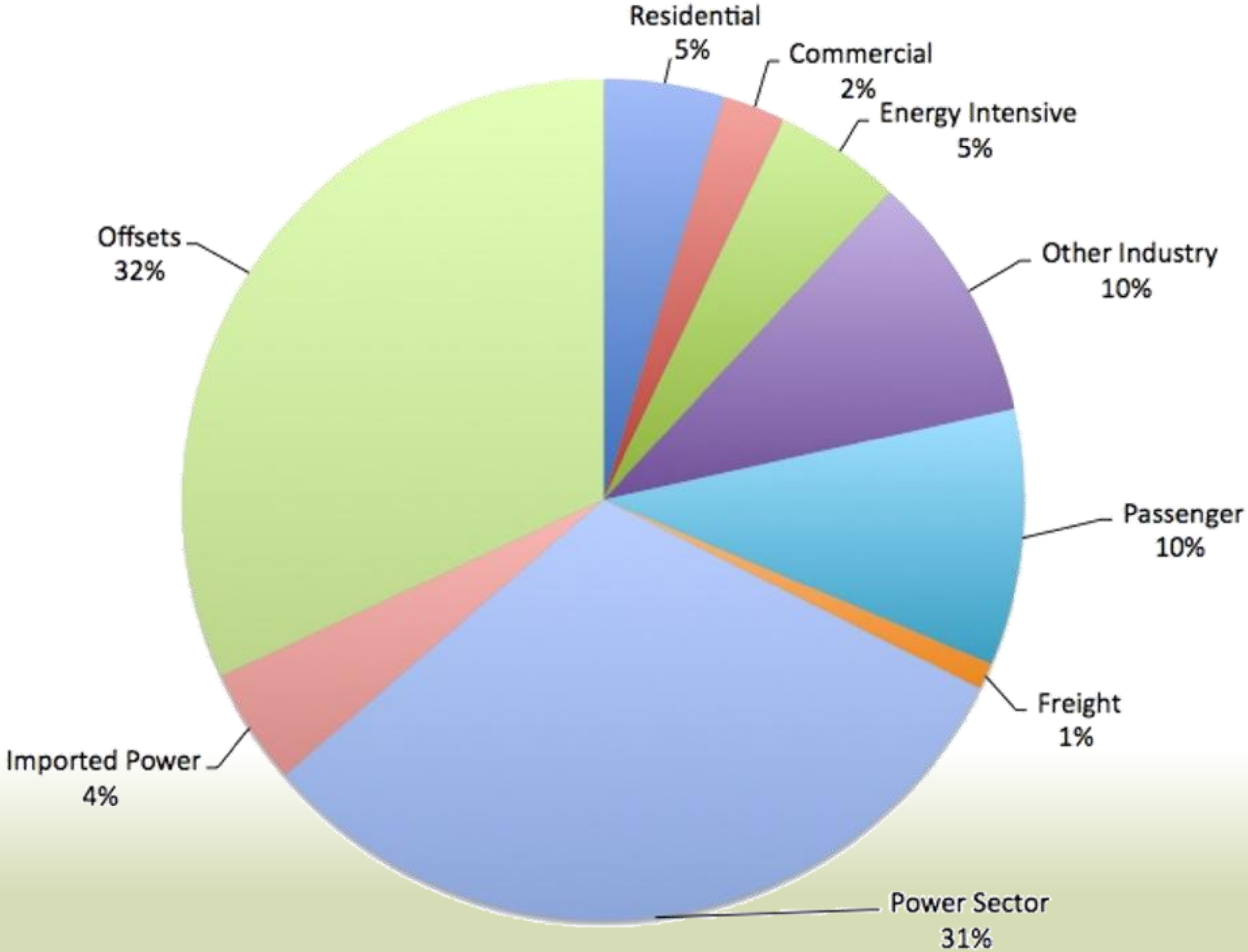
Results

- Allowance banking and carbon offsets are important design elements for achieving emissions reductions and limiting costs
- Varying assumptions about energy prices, economic growth, and the effectiveness of policies implemented in conjunction with a cap-and-trade program continues to demonstrate net cost savings, although their magnitude and the price of allowances vary across these scenarios

GHG Emissions Reductions Under the Cap
(Main Policy Case)



Source of Emissions Reductions Under the Cap
(Main Policy Case Relative to Reference Case, 2012-2020)



The WCI recommends offsets account for no more than 49% of emission reductions relative to emission levels in 2012 and 2015. The chart above, however, expresses reductions relative to the reference case. Hence, the offsets percentage appears smaller.

Cost Savings and Allowance Prices (Main Policy Case and Sensitivity Cases)

Economic Modeling Scenarios	Cost Savings 2012–2020 (2007 USD)	Emissions Allowance Price in 2020 (2007 USD)
Main Policy Case	US$102 billion	US$33 per metric ton
Sensitivity Cases		
Complementary policies only half as effective as in main case	At least US$38 billion	At least US$50 per metric ton
Faster economic growth and lower primary energy prices	At least US$202 billion	At least US$50 per metric ton
Higher energy prices and power plant construction costs	US$106 billion	US$13 per metric ton

Next Steps

- Continue developing comprehensive climate change policies informed by these results
- Incorporate results into state- and province-specific analyses
- While the WCI has completed economic modeling of its program design, it will continue accepting stakeholder comments for consideration during implementation of the cap and other policies

http://www.westernclimateinitiative.org/contact-form

Western Climate Initiative

July 7, 2010

WCI Plan to Reduce Greenhouse Gas Emissions is Environmentally Achievable and Economically Positive

An updated economic analysis by the Western Climate Initiative Partner Jurisdictions underscores the benefits of a regional plan to mitigate climate change and spur investment in clean-energy technologies.

The Partner jurisdictions of the Western Climate Initiative (WCI) today released an updated economic analysis indicating that its regional plan to address climate change and help foster a clean-energy economy can significantly reduce greenhouse gas (GHG) emissions and achieve cost savings of approximately US$100 billion by 2020.

Working together, the seven U.S. states and four Canadian provinces that comprise the WCI have forged a comprehensive strategy to mitigate climate change that will spur investment in clean-energy technologies, create green jobs and reduce dependence on imported oil. When fully implemented, the plan will reduce GHG emissions to 15 percent below 2005 levels by 2020.

The WCI Partner jurisdictions are not alone in acting to address the challenge of climate change. The WCI is one of three regional initiatives in North America with action plans in place to reduce GHG emissions and accelerate the transition to a clean-energy economy. Although the WCI plan is not the first regional climate policy to be implemented, it is the most comprehensive and covers a broad range of economic sectors.

The report released, “Updated Economic Analysis of the WCI Regional Cap-and-Trade Program,” updates the 2008 WCI economic analysis by incorporating new data that reflects expanded WCI membership (the inclusion of Manitoba, Québec, and Ontario), the 2008—2009 economic recession, and various economic model improvements identified after extensive consultation with stakeholders.

The updated economic analysis indicates that the WCI Partner jurisdictions can achieve the goal of reducing emissions to 15 percent below 2005 levels by 2020, support continued economic growth, and realize net cost savings of approximately US$100 billion between 2012 and 2020. The cost savings are attributed to increased energy efficiency and reduced fuel consumption.

The plan will also stimulate investment and innovation in a green economy, spur the creation of green jobs within the WCI region, and result in a cleaner environment.

The estimated savings are modest (less than 0.2%) relative to the combined size of the WCI Partner jurisdiction economies, but they underscore that mitigation of GHG emissions and the move to a clean-energy economy can be achieved without negatively impacting the regional economy. This result is consistent with other recent state and federal analyses of climate mitigation programs.

The updated economic analysis evaluated a range of scenarios using varying assumptions about future economic growth, fuel prices and other factors. In each instance, the analysis showed that the WCI program would support robust economic growth and deliver net cost savings—even when the assumptions resulted in different carbon allowance prices.

Some of the WCI Partner jurisdictions will use the results of this economic analysis as the foundation for state- or province-specific analyses. The updated analysis will also inform ongoing WCI discussions on a comprehensive climate program that includes other emissions reduction strategies in addition to cap-and-trade.

While this report completes the economic modeling of the WCI design elements, the WCI Economic Modeling Team welcomes comments on the recent analysis. The WCI Partners will consider comments when devising an approach to implementing the cap-and-trade program and in continued work on other emission reductions strategies.

The report is available on the WCI website. The WCI Economic Modeling Team will hold a stakeholder conference call to present the analysis and results on Tuesday, July 13 from 10:00 am to 11:00 am PDT. To join the call dial 1-800-868-1837 and enter participant code 659537#. A PowerPoint presentation will be posted to the WCI website at the time of the call.

About the Western Climate Initiative

The Western Climate Initiative is a coalition of seven U.S. states and four Canadian provinces working together to identify, evaluate, and implement policies to mitigate climate change and spur investment in clean-energy technologies that create green jobs and reduce dependence on imported oil. The WCI regional approach is based on extensive economic analyses, stakeholder input, technical work, collaboration, and compromise. It reflects an understanding among the WCI Partner jurisdictions that a comprehensive solution to our economic, energy, and environmental challenges requires a coordinated regional strategy that respects the interests, needs, and circumstances of each jurisdiction.

Western Climate Initiative

Updated Economic Analysis of the WCI Regional Cap-and-Trade Program

July 2010

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Appendix 12

Overview

This report summarizes the results of an economic analysis conducted by the Partner jurisdictions of the Western Climate Initiative (WCI). It updates the results of a 2008 economic analysis that informed the design of the WCI regional cap-and-trade program, which will reduce greenhouse gas (GHG) emissions contributing to climate change, spur development of new clean-energy jobs and technologies, and help achieve a strong economy.

The updated analysis incorporates new data reflecting expanded WCI membership, the economic downturn of 2008–2009, and various model improvements recommended by WCI Partner jurisdictions and stakeholders. Results of the updated analysis are consistent with the results of the 2008 report:

- The WCI GHG emissions reduction goal—a reduction of 15 percent from 2005 levels by 2020—can be achieved with a net savings of about US$100 billion between 2012 and 2020.
- Complementary policies such as standards for energy efficiency and clean cars are an important part of reducing emissions and containing costs.
- Offsets and allowance banking provisions in the cap-and-trade program are important features for containing costs.
- Savings to the economy may vary depending on such factors as future economic growth, fuel prices, and effectiveness of complementary policies.

WCI Partners and Observers

U.S. Partner jurisdictions comprise 19% of the total U.S. population and 20% of the U.S. GDP
Canadian Partner jurisdictions comprise 79% of the total Canadian population and 76% of the Canadian GDP.

Manitoba

GDP .... 48,586 Million C$
Population.................. 1,186,700
Largest Source of Emission .. Transportation

British Columbia

GDP .... 190,214 Million C$
Population.................. 4,380,300
Largest Source of Emission .. Transportation

Washington

GDP .... 311,270 Million US$
Population.................. 6,468,424
Largest Source of Emission .. Transportation

Oregon

GDP .... 158,233 Million US$
Population.................. 3,747,455
Largest Source of Emission .. Transportation

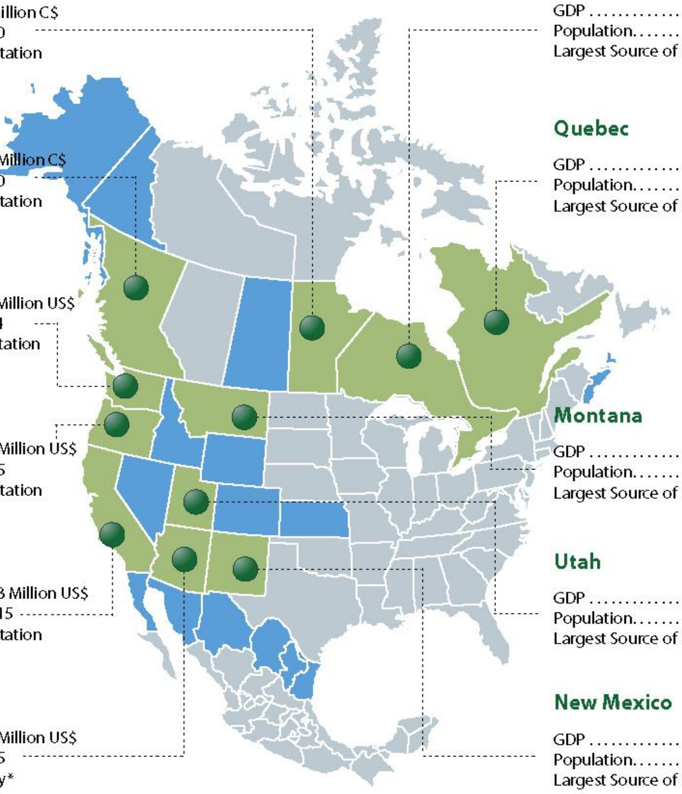
California

GDP .... 1,812,968 Million US$
Population.................. 36,553,215
Largest Source of Emission .. Transportation

Arizona

GDP .... 247,028 Million US$
Population.................. 6,338,755
Largest Source of Emission .. Electricity*

*includes tribal lands



Ontario

GDP .... 582,019 Million C$
Population.................. 12,803,900
Largest Source of Emission ... Transportation

Quebec

GDP .... 298,157 Million C$
Population.................. 7,700,800
Largest Source of Emission ... Transportation

Montana

GDP .... 34,253 Million US$
Population.................. 957,861
Largest Source of Emission ... Electricity

Utah

GDP .... 105,658 Million US$
Population.................. 2,645,330
Largest Source of Emission ... Electricity

New Mexico

GDP .... 76,178 Million US$
Population.................. 1,969,915
Largest Source of Emission ... Electricity

Partners   Observers

Observers

CANADA: Nova Scotia, Saskatchewan, Yukon; **UNITED STATES:** Alaska, Colorado, Idaho, Kansas, Nevada, Wyoming;
MEXICO: Baja California, Chihuahua, Coahuila, Nuevo Leon, Sonora, Tamaulipas

Source for US data: U.S. Census Bureau and U.S. Bureau of Economic Analysis; Source for Canadian data: Statistics Canada
U.S. and Canada population figures 2009; U.S. and Canada GDP figures 2008

The Western Climate Initiative

The Western Climate Initiative (WCI) is a coalition of seven U.S. states and four Canadian provinces working together to identify, evaluate, and implement policies to address climate change at a regional level.

Established in 2007, the WCI is a comprehensive effort to reduce GHG pollution, spur growth in new green technologies, help build a strong clean-energy economy, and reduce dependence on oil.

Through a regional cap-and-trade program and complementary policies, the WCI goal is to reduce emissions of the pollution that causes global warming to 15 percent below 2005 levels by 2020.

The WCI is one of three GHG initiatives in North America with action plans in place to achieve a transition to clean-energy economies. Others include the Regional Greenhouse Gas Initiative (RGGI) in the Northeastern and Mid-Atlantic states and the Midwestern Greenhouse Gas Reduction Accord in the midwestern United States.

A unique feature of the WCI is the consensus achieved among its 11 Partner jurisdictions in developing a GHG emissions reduction strategy that accommodates the diverse economies and interests of its members and takes into account lessons learned from existing programs.

The Imperative for Action

The WCI Partner Jurisdictions are motivated to act by four critical factors:

- The impacts of climate change already being experienced in the region
- The forecast of far more significant adverse climate change impacts if we do not act now
- The economic costs of inaction
- The economic opportunities associated with a green economy

Current climate change impacts include rising temperatures and changing precipitation patterns that are resulting in higher sea levels, longer droughts, increased flooding, more wildfires, and less water availability. Future impacts expected from unabated climate change include more extreme sea-level increases, longer heat waves, unhealthy air quality, more unpredictable water availability, and reduced biodiversity as invasions of non-native species increase and local habitat moves northward and to higher elevations. These impacts will affect a wide range of people, ecosystems, and economic sectors, including electricity generation, health care, agriculture, and tourism.

While the precise cost of inaction is uncertain, it is likely to far exceed the cost of undertaking well-conceived climate change mitigation activities. A number of Partner jurisdictions have evaluated the potential economic impact of climate change. An April 2010 report by the State of California's Climate Action Team, for example, forecast the

cost of coastal flooding associated with sea-level rise in the San Francisco Bay area at $36 billion by 2050 and nearly $100 billion for all of California by 2085.[1] The report also predicted severe consequences for California's agriculture industry, with reduced crop yields and lower crop quality resulting in losses estimated at $3 billion annually by 2050. Washington State's Department of Ecology released a 2009 report indicating that inaction could cost the average Washington household $1,250 per year by 2020 and more than double that amount by 2080, due to higher energy costs, increased health-related costs, and a variety of other factors.[2]

At the same time, WCI Partner jurisdictions are taking action to reduce these costs and are realizing the benefits associated with the transition to a clean-energy economy. In the U.S., the seven WCI Partner states comprise 20 percent of the U.S. economy, yet they garnered 60 percent of venture capital investments directed toward clean-technology businesses between 2006 and 2008. In 2007, the proportion of green businesses and green jobs in the economies of WCI Partner states was 20 percent higher than in the U.S. economy as a whole.[3] British Columbia's green businesses contributed C$15.3 billion to the provincial economy in 2008, and that number is expected to grow significantly in the next decade. Jobs tied directly or indirectly to B.C.'s green economy are also forecast to increase—from nearly 166,000 jobs in 2008 to more than 225,000 in 2020.[4]

In Ontario, environmental industries represent about 40 per cent of the Canadian environmental industry sector revenues.[5]

The WCI Cap-and-Trade Program

In September 2008, following 18 months of stakeholder consultation, analysis, and Partner deliberations, the WCI Partner jurisdictions released Design Recommendations for the WCI Regional Cap-and-Trade Program. Cap-and-trade has proven to be a successful means of reducing air pollution and is considered one of the most effective strategies to reduce GHG emissions. For example, the U.S. Acid Rain Program has reduced emissions 40 percent below 1990 levels—at a fraction of the cost originally estimated by the U.S. EPA.[6] Cap-and-trade programs place a market value on emissions reductions and provide incentives for emitters and investors to seek out the lowest-cost opportunities to reduce emissions, including energy efficiency and process improvements, greater use of renewable and lower-polluting fuels, and other clean-energy innovations.

As described in the *Design Recommendations* and subsequent policy documents released by the WCI Partners, each WCI Partner jurisdiction will have

[1] See www.climatechange.ca.gov/publications/cat/index.html.
[2] See www.ecy.wa.gov/climatechange/economic_impacts.htm.
[3] See www.pewcenteronthestates.org/trends_detail.aspx?id=53588
[4] See http://www.globe-net.com/media/118121/bcge_report_feb_2010.pdf.
[5] See http://www.nrtee-trnee.com/eng/issues/programs/climate-prosperity/benchmarking/benchmarking-eng.php and http://www.ene.gov.on.ca/en/news/2008/031301.php
[6] See www.edf.org/page.cfm?tagID=1085.

an emissions allowance budget consistent with its jurisdiction-specific emissions goal, along with the flexibility to decide how to allocate its allowance budget. For example, a Partner could give allowances to emitters operating within its jurisdiction, auction the allowances to willing buyers, or provide for some combination of the two.[7] Facilities that reduce their emissions below their allowance holdings can sell the excess allowances or "bank" them for use in a later compliance period. Selling excess allowances allows covered facilities to recoup some of their emissions reduction costs, while banking allowances will lessen the costs later, as the cap becomes more stringent.

In the initial compliance period, beginning in 2012, the program will cover emissions from electricity—including electricity generated outside the WCI Partner jurisdictions but used by them—industrial combustion at large sources, and industrial process emissions for which adequate quantification methods exist. In the second compliance period, beginning in 2015, the program will expand to include fuels combusted at industrial, residential, and commercial buildings that are not otherwise covered as emissions sources, as well as transportation fuels. The first compliance period will encompass about half of the economy-wide emissions in the WCI Partner jurisdictions. Starting with the second compliance period, the program will cover about 90 percent of GHG emissions in the WCI jurisdictions.

In crafting its cap-and-trade program, the WCI Partners carefully assessed the designs and performance of programs such as the U.S. Environmental Protection Agency's Acid Rain Program, the European Union's Emission Trading System, and the Regional Greenhouse Gas Initiative.

To ensure compliance with the overall cap, the cap-and-trade program includes a rigorous emissions reporting requirement, which will be followed consistently across participating jurisdictions. Each WCI Partner will require annual emissions reports (using equivalent measurement protocols and verified by a third party) from entities and facilities covered by the cap. This element of the program is consistent with well-designed cap-and-trade programs that have had compliance rates of more than 99 percent. At the end of each three-year compliance period, facilities and entities with covered emissions will be required to submit to their state or provincial government emissions allowances and offsets equal to the amount of GHGs they released or were responsible for during that compliance period. If the facility or entity does not have sufficient emissions allowances and offsets to cover its emissions, a requirement to submit three allowances will be assessed for each one that they are short, in addition to any penalties that may be applicable in the state or province where the violation occurred.

[7] An allowance is a tradable "permit," and one allowance is required to emit each metric ton of covered greenhouse gases, measured in carbon dioxide equivalents (CO_2e).

Economic Analysis

An important consideration in crafting the WCI Design Recommendations in 2008 was an economic modeling analysis (referred to here as Phase 2) of various cap-and-trade program design options. The Phase 2 analysis[8] showed that the WCI Partner jurisdictions could achieve the goal of reducing emissions to 15 percent below 2005 levels by 2020 and could realize a modest net cost savings through an increase in energy efficiency and reduced fuel consumption. These savings would be in addition to the benefits the region would accrue from a cleaner environment and spin-offs resulting from investment and innovation in a green economy.

A Phase 3 economic analysis was recently completed to account for expansion of the WCI (to include Manitoba, Québec, and Ontario) and the economic downturn of 2008–2009. It also reflects various model improvements identified by the WCI Economic Modeling Team (EMT) and stakeholders, including updated fuel price forecasts, assumptions about offset price and availability, algorithms for allowance banking, costs of implementing complementary policies, detail of model outputs for the electric power sector, and simulation of the WCI two-phase approach to capping emissions in 2012 and 2015.

The Economic Model: ENERGY 2020

The Phase 3 analysis was conducted by the WCI Economic Modeling Team—with support from its contractors, ICF International and Systematic Solutions, Inc. (SSI)—using ENERGY 2020, a well-established and well-tested multi-region, multi-sector energy model that can simulate energy demand, energy supply, energy costs, and GHG emissions under user-defined scenarios. The basic workings of the model have been described in multiple stakeholder conference calls, workshops, and reports.

The model simulates demand in more than 40 commercial and industrial categories, three transportation services (passenger, freight, and off-road), and three residential categories. There are approximately six end uses per category and six technology/mode families per end use. For all end uses and fuels, the model is parameterized based on historical, locale-specific data. Load duration curves for electricity demand are dynamically built up from individual end uses to capture changing conditions under consumer choice and combined gas/electric programs. Technology and efficiency choices are modeled based on past experience with consumer choice rather than on a purely economic evaluation.

Additional information about the ENERGY 2020 model can be found in the appendix to this report and in WCI's *Assumptions Book for ENERGY 2020* at www.westernclimateinitiative.org/component/remository/Economic-Modeling-Team-Documents/

[8] See www.westernclimateinitiative.org/component/remository/general/design-recommendations/Design-Recommendations-Appendix-B/.

In consultation with the EMT, ICF International and Systematic Solutions Inc. used ENERGY 2020 to run a main policy case along with several "sensitivity" cases. All cases estimate the costs (and cost savings) of meeting the regional GHG reduction goal, as well as an allowance (or carbon) price required to provide sufficient incentive for the emissions reductions. The main policy case simulates the design of the WCI cap-and-trade program and expectations of future economic growth, fuel prices, the use of offset credits, and complementary policies. Because these expectations affect the potential cost of the cap-and-trade program, several "sensitivity" cases were also run to estimate the range of costs under alternative future scenarios. Specifically, the EMT looked at complementary policies being only half as effective, a faster rate of economic growth (with lower fuel prices as well), higher fuel and electricity generation costs, and alternative carbon price escalation rates over the period of the cap (2012–2020).

Offsets

The WCI cap-and-trade program design recommendations include multiple features to provide flexibility and low-cost compliance options, including the limited use of offset credits. Offsets are reductions in GHG emissions from industries outside the capped sectors, such as forestry and agriculture. Offset credits may be issued for projects that sequester carbon dioxide from the air or reduce GHG emissions, as long as they meet rigorous criteria to ensure that emissions reductions are real, verifiable, surplus/additional, permanent, and enforceable. Offset credits may be purchased and traded like allowances and used along with allowances to meet a compliance obligation. The WCI program limits the use of offsets for compliance purposes to ensure that a majority of the required emissions reductions are achieved by the sources covered by the cap-and-trade program. Assumptions about the cost and availability of compliance-grade offsets in the future are important when modeling because the more available and cost-effective they are, the more the program's overall costs will be reduced.

Complementary Policies

The WCI Partner jurisdictions recognize that other policies, working in concert with a cap-and-trade program, will address market barriers that limit the use of cost-effective technologies and help achieve the regional GHG reduction goal. Complementary policies promote cost-effective emissions reductions that would not typically be responsive to the price signal created by the cap-and-trade program. They also reduce emissions in sectors not covered by the cap, prevent emissions shifting (or leaking) to sources outside the cap or the capped region, and encourage investments in low-carbon technologies.

Examples of complementary policies include energy efficiency targets and standards, emissions performance standards for electric power, renewable energy standards, renewable/low-carbon fuels standards, transportation planning, mass transit, government procurement policies, and direct government funding and investment in key technologies. These policies are identified in state and provincial climate action plans, and many have been implemented or are in the process of being implemented.

Assumptions about the effectiveness of complementary policies are important when modeling the costs of a cap-and-trade program. To meet the regional GHG reductions goal, any emissions reductions not achieved by complementary policies will have to be achieved through the cap-and-trade mechanism. The WCI Economic Modeling Team (EMT) made the following assumptions about complementary policies in its modeling:[9]

- **Ontario Coal Phase-Out.** Ontario will be phasing out coal-fired electricity generation between 2010 and 2014.[10]
- **Clean Car Standards.** The second phase of the California Clean Car Standards (Pavley II) will be implemented regionwide in 2017, with the effect of improving the efficiency of new passenger vehicles from 35.5 mpg in 2016 to 42.5 mpg by 2020.[11]
- **Energy Efficiency.** The combined effect of energy efficiency programs recently put in place and being pursued will reduce the growth rate of electricity and natural gas demand by 0.5% each year, starting in 2012.[12]

Summary of Economic Modeling Results

- The WCI can meet its 2020 regional emissions reduction goal with modest net cost savings.
- Complementary policies such as energy efficiency and clean car standards have the potential to significantly reduce emissions and contain costs. In this analysis, complementary policies result in negative costs, or cost savings.
- Banking and offsets are also important design elements for achieving emissions reductions and limiting costs.
- Higher-than-expected fuel prices would make it less costly to achieve the emissions goal, with lower allowance prices. Conversely, lower-than-expected fuel prices, coupled with a faster economic recovery, would raise the allowance price.

[9] The cost of obtaining the emissions reductions associated with these policies is included in the modeling results. A literature review of travel demand reduction programs showed a broad range of potential planning and development costs and savings, including potential infrastructure savings. This analysis excludes these potential costs and savings, and focuses solely on the impacts on vehicle use and fuel use.

[10] See news.ontario.ca/mei/en/2009/09/ontarios-coal-phase-out-plan.html.

[11] See arb.ca.gov/cc/ccms/ccms.htm.

[12] This is less than the 1.0% assumed in the Phase 2 analysis and is reasonable as a minimum expectation considering the efficiency provisions of the American Recovery and Reinvestment Act of 2009 in addition to complementary policies identified in state and provincial climate action plans. Studies by the California Energy Commission and the Northwest Power and Conservation Council suggest that a reduction of 1.0% is achievable with currently cost-effective measures.

- **Vehicle Miles Traveled (VMT).** The combined effect of transportation and fuel programs recently put in place and being pursued is equivalent to reducing the fore-casted travel demand so that VMT in 2020 is lower by 2%, starting in 2008.

Summary of Economic Modeling

The results of the WCI economic modeling suggest that the GHG emissions reduction goal for 2020 can be achieved with a cost savings of approximately US$100 billion in the region between 2012 and 2020. While significant, these savings are relatively modest (less than 0.2%) relative to the size of the overall economy of the 11 WCI Partner jurisdictions.

The cost savings result from the complementary policies, with the largest proportion of the savings attributable to a 2% reduction in the use of personal vehicles by 2020, and to a lesser extent by the energy efficiency investments that reduce the growth rate of electricity and natural gas consumption.[13] In practice, the cap-and-trade program is expected to facilitate and ensure the cost savings of complementary policies. That is, the *combination* of the price signal and market incentives associated with the cap-and-trade program *and* their effect on production and consumption choices would enable complementary policies to have their full emissions and cost-saving effects.

Economic Modeling Scenarios	Cost Savings 2012–2020 (2007 USD)	Emissions Allowance Price in 2020 (2007 USD)
Main Policy Case	US$102 billion	US$33 per metric ton
Sensitivity Cases		
Complementary policies only half as effective as in main case	At least US$38 billion	At least US$50 per metric ton
Faster economic growth and lower primary energy prices	At least US$202 billion	At least US$50 per metric ton
Higher energy prices and power plant construction costs	US$106 billion	US$13 per metric ton

[13] The net savings include the cost of administering and achieving the reduction in annual electricity and natural gas demand growth anticipated from complementary policies. The planning and development costs and benefits associated with reducing travel demand are not included in the analysis due to modeling and data limitations, although it is not clear that these costs and benefits would significantly affect the results.

To achieve the necessary emissions reductions under cap-and-trade, WCI modeling forecasts a carbon allowance price of US$33 in 2020. This is higher than the US$24 predicted in the WCI Phase 2 modeling but on par with government analyses of the WCI and other cap-and-trade proposals. (See Page 43 in the Appendix for details.)

In addition to the main policy case, three sensitivity runs were conducted with ENERGY 2020 to determine how cost savings might change if different assumptions about complementary policies and future economic growth and energy prices are made. As shown in the table above, the WCI program would continue to deliver net cost savings, although if future economic growth and energy prices deviate substantially from what is expected, allowance prices could range from US$13 to over US$50 to fully achieve the WCI emissions reduction goal.

Emissions Reductions

Total emissions from capped sectors in the reference case (a business-as-usual modeling scenario) are projected to be 7,999 million metric tons (Mt) of carbon dioxide equivalents from 2012 to 2020. To achieve a 15% reduction below 2005 emissions levels, WCI modeling forecasts a cumulative reduction of 719 Mt. Of this total, 235 Mt of reductions would be from offsets and 484 Mt would be achieved within the capped sectors. Figure 1 shows more specifically where WCI modeling forecasts that the 719 Mt of reductions will come from.

Figure 2 shows the projected trend in emissions reductions. Rather than reducing emissions in a straight line to 15% in 2020, sources in the WCI region are predicted to "over comply" with the cap in earlier years and "bank" the excess allowances for use in 2019 and 2020. In this way, the same

Figure 1. Source of Emissions Reductions Under the Cap, Main Policy Case Relative to the Reference Case, 2012–2020

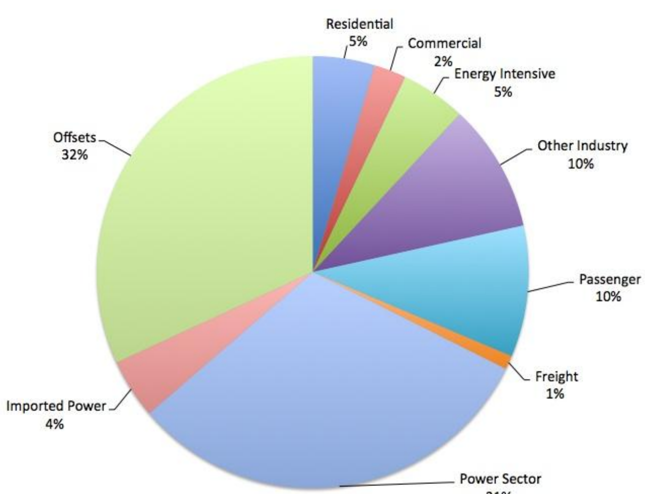
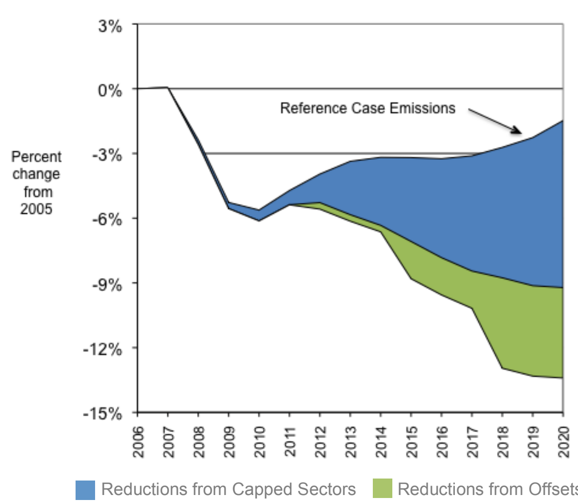


Figure 2. GHG Emissions Reductions Under the WCI Program



amount of emissions reductions is achieved, but sooner and with more flexibility at lower costs.

A Note About the Economic Analysis

Models are by necessity simplified representations of the real-world economy. They cannot predict the future, but they can shed light on important economic relationships, test the robustness of alternative policy architectures (e.g., against the uncertainty of future energy and commodity prices, technological development, etc.) and thereby help inform the design of a market-based climate change policy.[14] While ENERGY 2020 estimates the direct cost of energy use, it is not a macroeconomic model and does not estimate how direct costs (and cost savings) will translate into broader effects such as economic output, trade, employment, and government revenues. ENERGY 2020 results can be, and have been, used as inputs to macroeconomic models. But given the modest costs and savings predicted by ENERGY 2020 relative to the size of the WCI economy, such an analysis has not been conducted.

Other economic analyses, including macroeconomic analyses, however, have been conducted by individual WCI Partner jurisdictions. Some of these analyses are more detailed or are more specifically tailored to the programs and policies of the sponsoring jurisdiction. The WCI regional analysis does not replicate all aspects of these studies, nor is it a substitute.

Looking Ahead

The WCI Partner jurisdictions will be scheduling a conference call with stakeholders to review the analysis and results. Stakeholder comments are welcome and will be taken into consideration as WCI Partners continue implementing their GHG reduction policies. However, no further regional economic analysis or revisions to this report are planned by the WCI Partner jurisdictions.

The WCI Partner jurisdictions are also moving forward on several other fronts, including:

- Release of the *Detailed Program Design* in summer 2010, which will support the implementation of the cap-and-trade program by Partner jurisdictions.
- Development of policies and processes associated with the offset program.
- Establishment of carbon emissions allowance budgets for each Partner jurisdiction.
- Ongoing collaboration and development of complementary policies.
- Ongoing collaboration with other North American regional cap-and-trade programs.

For More Information: www.westernclimateinitiative.org

[14] See www.pewclimate.org/white-paper/economic-models-are-insights-not-numbers.

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Description of Analysis

This analysis was directed by the WCI Economic Modeling Team (EMT), with support from its contractors ICF International and Systematic Solutions, Inc. The EMT first analyzed the economic impacts of a WCI cap-and-trade program in 2008 using the ENERGY 2020 model designed and applied by its contractors. The EMT refers to this analysis as the Phase 2 analysis because it supplemented preliminary (Phase 1) work with population and economic forecasts provided by some WCI states for use in lieu of nationally available data. The results of the Phase 2 analysis informed the development of the *Design Recommendations for the WCI Regional Cap-and-Trade Program* and concluded that the program could achieve the WCI emissions reduction goal with a small cost savings, equal to about 0.2 percent of the region's gross domestic product.[15]

The analysis presented here (the Phase 3 analysis) updates the results of the Phase 2 analysis to account for new Partners within the WCI, the economic downturn of 2008-2009, and various model improvements identified by the EMT and WCI stakeholders. The differences between the Phase 2 and Phase 3 modeling are summarized in Tables 1 and 2 and in Figures 1 and 2.

The EMT modeling results are expressed as differences between "reference runs" and "cap-and-trade runs". Reference runs simulate energy use and emissions of the economy under a business-as-usual forecast. Cap-and-trade runs simulate the energy use and emissions of the economy after imposing a carbon price sufficient to reduce emissions to the level of the WCI regional goal.

It is important to note that this analysis does not model the costs of climate change, and therefore the benefits of cap-and-trade and complementary policies in terms of avoided costs, nor any co-benefits (such as reduced smog and resulting health improvements, for example).

Included in the cap-and-trade runs is a set of assumptions regarding the costs and energy use impacts of complementary policies under development by the WCI jurisdictions. Complementary polices are regulations and incentive programs that reduce energy use and greenhouse gas emissions, often at a net savings to the users of fuel. The costs of a cap-and-trade program depend on the effectiveness of complementary policies because any emission reductions not achieved by the complementary policies must be met through the cap-and-trade mechanism. The EMT therefore conducted "sensitivity runs" for the cap-and-trade program in which some of the major complementary policies were assumed to be only half as effective as in the cap-and-trade runs. The EMT also conducted sensitivity runs testing assumptions about the rate of economic growth, future fuel and electricity generation costs, and carbon (or allowance) price escalation rates over the period of the cap (2012-2020).

[15] The WCI's greenhouse gas emissions reduction goal is an aggregate reduction of 15% below 2005 levels by 2020.

Table 1: Differences Between Phase 2 and Phase 3 Modeling

Issue	Type	Phase 2	Phase 3	Comment
Jurisdictions included	Model capability	8 WCI Partners in the WECC	All 11 WCI Partners	Required substantial additions to the model, including specifications for the electric sector throughout U.S. and Canada
Program scope	Program definition	Compared broad scope throughout to narrow scope throughout	Represents program design with narrow scope (2012) followed by broad scope (2015)	Required model changes to be consistent with WCI Design Recommendations
Allowance budget	Program definition	Set in 2012 and linear decline through 2020	Set in 2012 for narrow scope. Set in 2015 for broad scope, with continued reduction in 2012 scope.	Setting the Phase 3 allowance budget in 2015 required assumptions regarding the rate of decline from 2012 to 2015
Electric sector outputs	Model capability	No detailed electric sector outputs	Added electric sector outputs to show investment costs and operating costs	Response to stakeholder request
Offset limit	Program definition	5% of cap	49% of emission reductions	Phase 3 limit is more strict and consistent with the WCI Design Recommendations
Offset supply	Assumption	Unlimited supply available at $20 per metric ton	Supply curve modeled using U.S. EPA analysis of domestic offset supply over time, adjusted to include Canadian supply	Phase 3 supply assumptions remain simplistic, but are an improvement over Phase 2. Offset prices start lower but can exceed $20 per metric ton.
Economic growth forecast	Assumption	Forecast did not include the recession. Used a single forecast.	Updated forecast to include the recession. Created an alternative forecast with extra growth post 2012	Figure 1: shows the Phase 2 and Phase 3 economic forecasts. The new forecast tends to decrease costs.

Issue	**Type**	**Phase 2**	**Phase 3**	**Comment**
Fuel price forecasts	Assumption	Annual Energy Outlook 2008 High Case as Reference Case	Reference run: Annual Energy Outlook 2009 Mid Case. Alternative Reference run: Average of AEO Mid and Low Cases High Price Case: AEO High Case	Figure 2 shows the Phase 2 and Phase 3 fuel price forecasts for crude oil. The higher fuel price forecast in the reference run leads to price driven efficiency improvements.
Policies included in the reference run	Assumption	US: EISA requirements Canada: CSA standards and "ecoENERGY" Renewable Fuels Strategy Partner: RPS requirements	All Phase 2 reference case policies plus the vehicle standards agreement through 2016 (modeled as Pavley 1)	By putting the Pavley 1 standards in the reference run, the emission reductions and cost savings are in the reference run and are not counted as part of the program
Costs of efficiency improvements in devices and processes	Assumption	Included declining costs due to economies of scale so that more efficient technologies cost less than standard technologies	Requires that more efficient devices and processes always cost more than standard technologies	This change in assumption increases the cost of improving efficiency. It is a conservative assumption (i.e., may overstate costs)
O&M costs	Assumption	Not estimated	Added for Phase 3 to capture non-fuel cost impacts on O&M associated improved efficiency	This change in assumption increases the costs of improving efficiency, resulting in a better estimate
Costs of reducing vehicle emissions beyond Pavley 1	Assumption	Not estimated	Added for Phase 3 to reflect incremental costs of additional efficiency improvements	This change in assumption increases the costs of improving efficiency, resulting in a better estimate
Complementary policies included	Program definition	Energy efficiency VMT reductions Vehicle standards	Energy efficiency VMT reductions Vehicle standards post 2016	The vehicle standards through 2016 are in the reference run

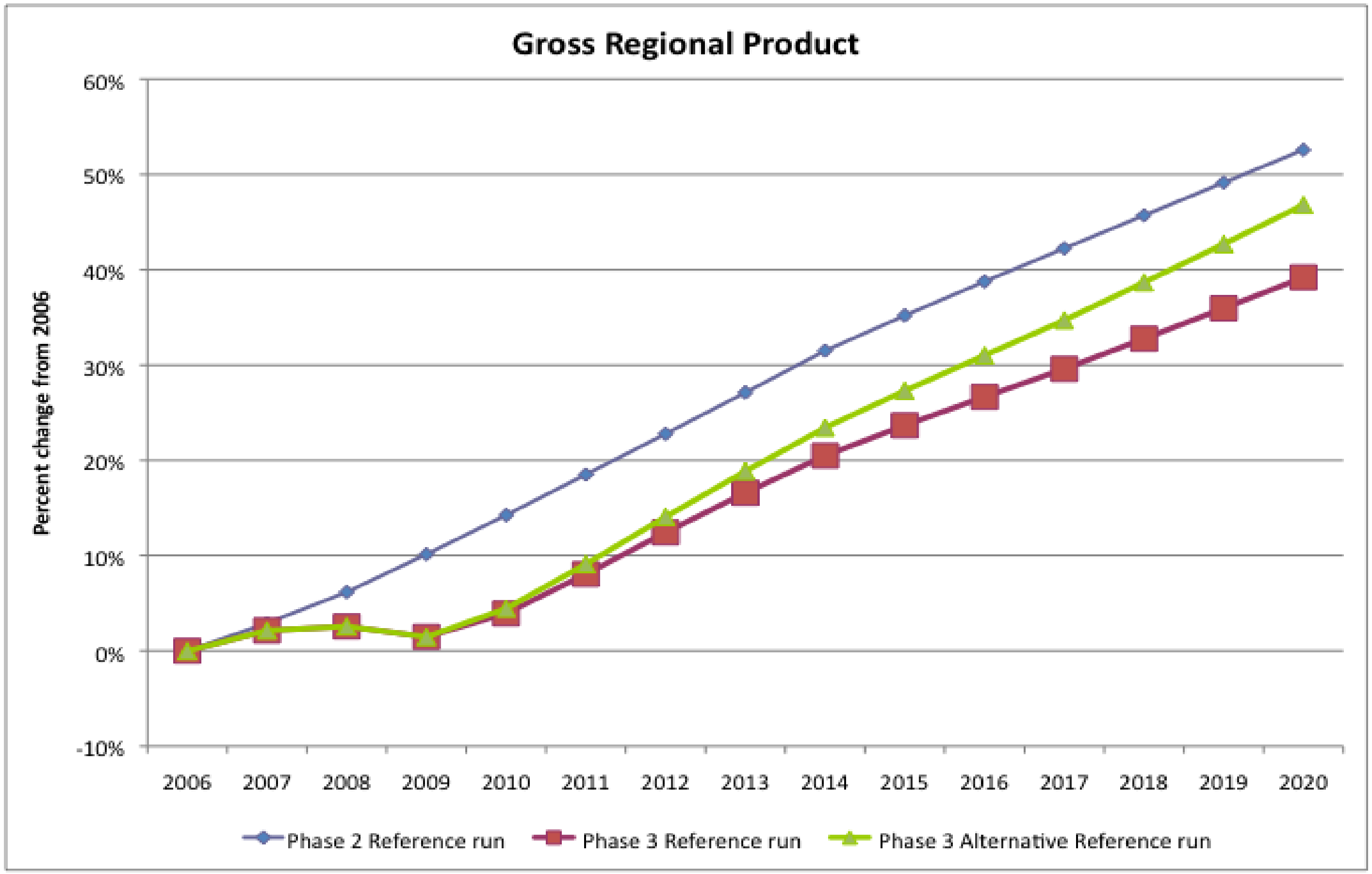
Issue	Type	Phase 2	Phase 3	Comment
Effect of energy efficiency programs	Assumption	Energy efficiency reduces rate of growth in electricity and natural gas demand by 1% each year	Energy efficiency reduces rate of growth in electricity and natural gas demand by 0.5% each year. (In the alternative economic forecast sensitivity case, 1% is assumed.)	The Phase 3 assumption regarding the effects of the EE programs makes it more costly to achieve the emissions target
Cost of administering energy efficiency programs	Assumption	Did not calculate program administration costs	Calculates program administration costs based on experience from existing electricity and natural gas programs	Phase 3 calculations add costs to the program
Banking algorithm	Model capability	Used a "rule of thumb" to approximate potential allowance banking behavior	Simulate economically rational banking behavior, namely increases in allowance prices over time that reflect the opportunity cost of banking allowances	An 8% annual increase in allowance price is assumed to reflect risk and time value of money. Sensitivity cases were analyzed using 4% and 12%.

Table 2: Summary of How Differences Between Phase 2 and Phase 3 Modeling Affect Cost Estimates

Phase 3 Aspects That Tend to Reduce Cost Estimates	Phase 3 Aspects That Tend to Increase Cost Estimates
Economic Forecast: Recession reduces emissions	Less gas-fired generation capacity build-out
Fuel Prices: 2009 forecast is higher	Phase I of the Clean Car Standards are placed in the reference run. All emission reductions (and cost savings) become part of the reference run and are not attributed to the WCI program.
	Costs for Phase II of the Clean Car Standards (2017 and beyond) were added, increasing costs
	The effect of energy efficiency programs is assumed to reduce electricity and natural gas growth by 0.5% instead of 1.0%, reducing the impact of efficiency programs increasing costs
	Costs for administering energy efficiency programs were added
	Devices exceeding energy efficiency standards are assumed to always have higher costs than standard devices, and their costs are not allowed to decrease by more than 10% over time
	Operation and maintenance costs were increased for more-efficient devices

Phase 2 and Phase 3 modeling differences that neither reduce nor increase cost estimates, or whose effects are uncertain, are not listed in this table.

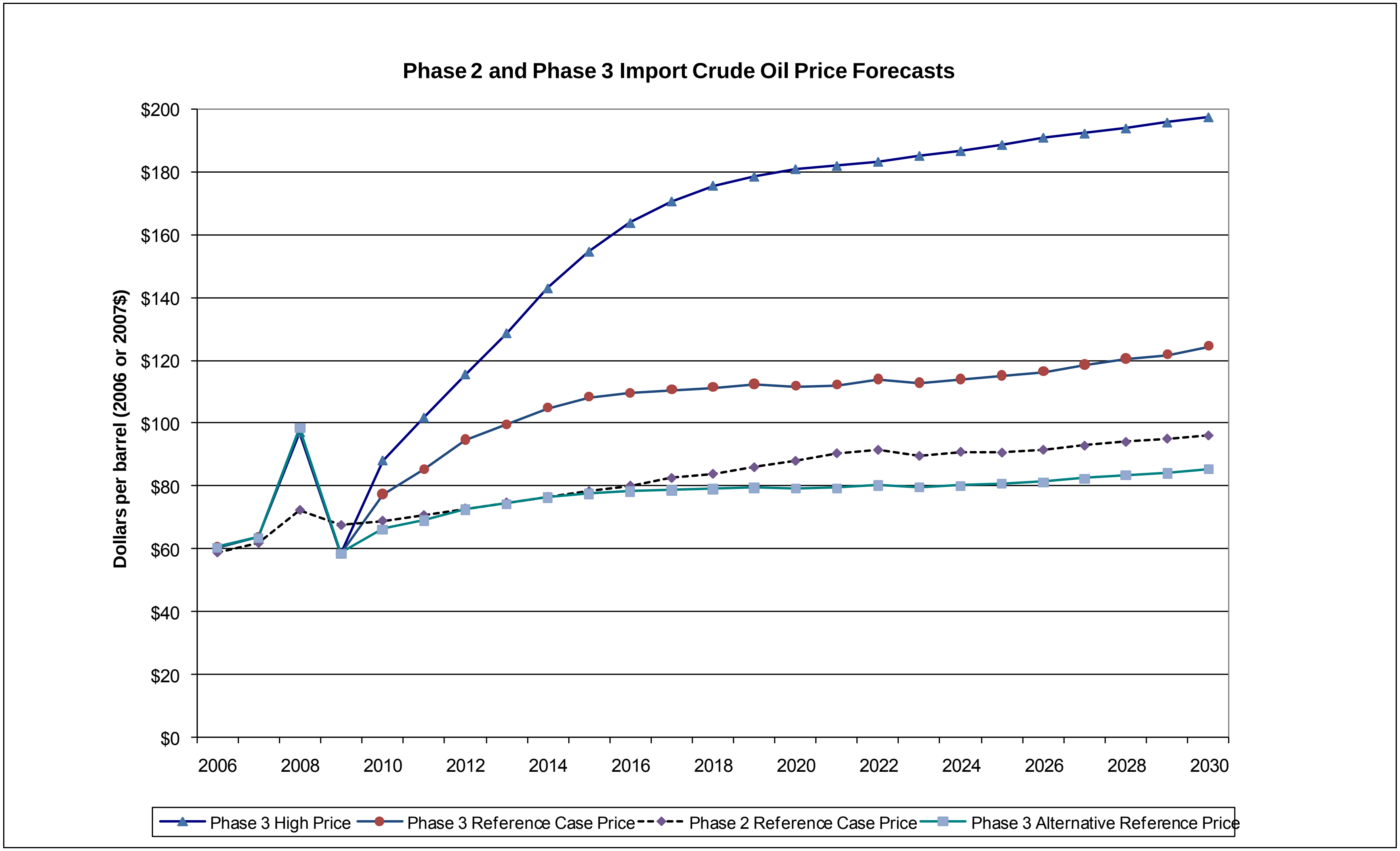
Figure 1: Economic Forecasts Used in Phase 2 and Phase 3 Modeling



Average annual growth rates from 2006 to 2020:

Phase 2 Reference run: 3.1% per year
Phase 3 Reference run: 2.4% per year
Phase 3 Alternative reference run: 2.8% per year

Figure 2: Fuel Price Forecasts Used in Phase 2 and Phase 3 Modeling



Results for all cap-and-trade and sensitivity runs include the change in emissions and net cost to covered sectors relative to the reference runs, as well as the 2020 allowance price required to achieve the WCI regional goal and the total market value of allowances over the 2012-2020 period. Additional details on the ENERGY 2020 model and the EMT's analytical approach can be found below and in the *Assumptions Book for Energy 2020* posted on the WCI website.[16]

Definitions

2012 is the first year of the first compliance period, and the starting year of the WCI cap-and-trade program.

2015 is the first year of the second compliance period, at which point additional sectors are subject to the cap.

2020 is the final year of the third compliance period, and the end year of the economic analysis.

Allowance budget means the number of allowances assumed to be issued throughout the region in a given year. In the WCI cap-and-trade program, one allowance is required to emit each metric ton of covered greenhouse gas emissions, expressed in carbon dioxide equivalents (CO_2e). For purposes of economic modeling, an allowance budget was determined for each year such that the WCI regional goal would be met in 2020 through a linear decline starting in 2012. The difference between the reference case emissions for covered sectors and the allowance budgets represents the total 9-year emission reduction that the main policy and sensitivity cases must achieve.

Allowance value means the allowance price in a given year multiplied by the allowance budget for that year.

Banking means that covered sources emit less than the allowance budget in one compliance period and bank the remaining allowances for use in a later compliance period. This banking allows covered sources to make cost-effective reductions earlier and lessen the costs later.

Compliance period means a three-year period at the end of which an emission source must hold a sufficient number of compliance instruments (allowances and offset credits) to account for its emissions during that period. The WCI compliance periods are 2012-2014, 2015-2017, and 2018-2020.

Compliance means that at the end of each compliance period emissions from all covered sectors, summed over each year since 2012, must be equal to or less than the allowance budgets issued since 2012, after accounting for offsets.

Covered sector means a sector of the economy whose emissions are covered by the cap-and-trade program in a given compliance period.

Uncovered sources are emission sources that are not included in the program scope in a given year.

[16] The posting on the WCI website is at: http://www.westernclimateinitiative.org/component/remository/Economic-Modeling-Team-Documents/

Narrow scope in the modeling means emissions from electric power generation within the WCI Partner jurisdictions, emissions from electric power generation outside the WCI Partner Jurisdictions for power imported into the WCI Partner Jurisdictions, and emissions from industrial fuel combustion and processes within the WCI Partner Jurisdictions.

Broad scope in the modeling means the narrow scope plus passenger and freight transport emissions and emissions from all remaining fossil fuel combustion, including residential, commercial, agriculture, and waste & wastewater. These emissions are covered in the second and third compliance periods. Not included in the broad scope are process emissions from agriculture, waste & wastewater, and high Global Warming Potential gases, such as refrigerants.

Reference run means an application of ENERGY 2020 to a business-as-usual scenario (i.e., absent any cap or other GHG abatement policies not already adopted).

Complementary policies run means an application of ENERGY 2020 in which complementary policies have been added to the reference conditions.

Cap-and-trade run means an application of ENERGY 2020 in which an allowance price has been imposed on the reference and complementary policies conditions. All of the cap-and-trade runs include complementary policies.

Case means a family of ENERGY 2020 runs consisting of a reference run, a complementary policies run, and a cap-and-trade run. Each case is characterized by assumptions on economic growth, energy/fuel prices, and effectiveness of complementary policies (full or half), generation cost, and allowance-price growth rate.

Abatement means the change in emissions in covered sectors due to complementary policies and the cap-and-trade policy. Specifically, it is the difference between the emissions in a cap-and-trade run and the emissions in the reference run. Reductions through offsets, therefore, are not included in this use of the term abatement.

Abatement cost means the resource cost to bring about abatement. In this analysis, proper quantification of total abatement costs requires that the value of allowances used in the electric power sector be subtracted from the abatement costs. This is required because electricity prices in the model were assumed to include the full market value of allowances in order to effectuate proper energy use decisions among end users in the residential, commercial, industrial, and transportation sectors. Because allowance values represent a financial transfer and not a resource (or abatement) cost, the allowance value is subtracted from the abatement cost so that it reflects the actual cost of reducing emissions.

Reduction means the difference between emissions in the reference run and the allowance budgets. Reductions define the threshold for compliance with the cap-and-trade program, whereas abatement refers to the decrease in emissions from covered sectors, which will be less than the reductions to the extent that offsets are used.

WCI regional goal (or target) is 15% below 2005 levels by 2020 of greenhouse gas (GHG) emissions for the entire regional economy.

WECC is the Western Electricity Coordinating Council.

Methodology and Assumptions

This section begins with two subsections describing the ENERGY 2020 model and the general modeling assumptions and input data. Following subsections describe how banking, offsets, and complementary policies are included in the modeling, as they are key factors in the design and cost-containment of the program. The final subsection describes the remaining assumptions pertinent to the main policy case and sensitivity cases.

ENERGY 2020

ENERGY 2020 was the model used in this analysis. A detailed description of ENERGY 2020 is available in the *Assumptions Book for Energy 2020* posted on the WCI website.[17] Additional documentation is available at the California Air Resources Board (ARB) website.[18] Below is a brief description of the model.

ENERGY 2020 is an integrated, multi-region energy model that provides all-fuel demand and supply sector simulations. The model simulates demand by three residential categories (single family, multi-family, and agriculture/rural), over 40 NAICS commercial and industrial categories,[19] and three transportation services (passenger, freight, and off-road). There are approximately six end-uses per category and six technology/mode families per end-use. End-uses include process heat, space heating, water heating, refrigeration, lighting, air conditioning, and motors. The technology families correspond to six fuels groups (oil, gas, coal, electric, solar and biomass) and 30 detailed fuel products. The transportation sector contains 45 modes, including various types of automobile, truck, off-road, bus, train, plane, marine and alternative-fuel vehicles. More end-uses, technologies, and modes can be added as data allow. For all end-uses and fuels, the model is parameterized based on historical, locale-specific data. The load duration curves for electricity demand are dynamically built up from the individual end-uses to capture changing conditions under consumer choice and combined gas/electric programs.

Each energy demand sector includes cogeneration, self-generation, and distributed generation simulation, including mobile-generation, micro-turbines, and fuel-cells. Fuel-switching responses are rigorously determined. The technology families (which can be split, as an option, to portray specific technology dynamics) are aggregates that, within the model, change building shell, economic-process and device efficiency and capital costs as price or other information that the decision makers see,

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[17] The posting on the WCI website is at:
http://www.westernclimateinitiative.org/component/remository/Economic-Modeling-Team-Documents/
[18] The posting on the ARB website is at:
http://www.arb.ca.gov/cc/scopingplan/economics-sp/models/models.htm.
[19] NAICS is the North America Industrial Classification System which was developed jointly by the U.S., Canada, and Mexico to provide new comparability in statistics about business activity across North America.

change. ENERGY 2020 utilizes the historical and forecast data developed for each technology family to parameterize and disaggregate the model.

The supply portion of the model includes endogenous detailed electric supply simulation of capacity expansion/construction, rates/prices, load shape variation due to weather, a complete (but aggregate) representation of the electric transmission system, and changes in regulation. The model dispatches plants according to the specified rules whether they are optimal or heuristic and simulates transmission constraints when determining dispatch. A dispatch routine selects critical hours along seasonal load duration curves as a way to determine system generation. Peak and base hydro usage is explicitly modeled to capture hydro-plant impacts on the electric system.

In addition to modeling electricity supply, ENERGY 2020 can also model the supply of oil, natural gas, refined petroleum products, ethanol, land-fill gas, and coal. In the Phase 3 modeling, however, prices for these energy sources were provided exogenously to the model.

ENERGY 2020 includes pollution accounting for both combustion (by fuel, end-use, and sector) and non-combustion processes, and non-energy (by economic activity) for all GHGs that would be covered by the WCI cap-and-trade program, as well as conventional air pollutants at the state and provincial level by economic sector.

ENERGY 2020 can simulate the impacts of a wide variety of GHG mitigation policies, including regulations, demand reduction programs, taxes, and emission caps with trading. These capabilities were used in the reference runs (to reflect existing policies) and in cases involving complementary policies and the WCI cap-and-trade design. Details on specific policies included in the modeling appear in later sections and in the *Assumptions Book*.

ENERGY 2020 is not a macroeconomic model and does not predict the downstream effect of energy prices, costs, and cost savings on factors such as economic output, household income, trade and employment, although its outputs can and have been used in such assessments.

General Modeling Assumptions

This section presents an overview of the major assumptions used in the modeling. These assumptions are included in all modeling runs, except for the assumptions on economic growth, fuel prices, and electricity generation costs, which are altered in two of the sensitivity cases. The *Assumptions Book for ENERGY 2020* includes additional detail on the assumptions and model inputs, including links to data sources.

<u>Geographic Coverage</u>: The Phase 3 modeling covers the lower 48 states of the U.S. and all of Canada, which includes the 11 WCI Partners. By covering the entire electric grid in addition to the energy/emissions impacts in the 11-Partner region, the impacts of the WCI programs and policies on electricity generation in the non-WCI WECC states and provinces can be examined.

Sectors and Sources: The Phase 3 modeling includes energy use in all sectors, as well as most industrial process emissions. Landfill methane emissions and non-energy agriculture emissions are included in the total emissions estimates, but emission reductions are not estimated for these sources.[20] The analysis is based on gross emissions, so that forestry emissions and sinks are excluded.

WCI Population Forecast: A key driver in the ENERGY 2020 energy demand simulations is population forecast. Table 3 shows the population growth forecast used.

Table 3: Population Forecast for WCI Partners, Selected Years (Millions)

Jurisdiction	2006	2012	2015	2020
Arizona	6.2	7.4	7.9	8.8
British Columbia	4.3	4.6	4.8	5.1
California	37.4	40.1	41.5	44.1
Manitoba	1.2	1.2	1.2	1.2
Montana	0.9	1.0	1.1	1.2
New Mexico	2.0	2.6	2.7	2.8
Ontario	12.7	13.6	14.1	14.8
Oregon	3.7	4.0	4.1	4.4
Quebec	7.6	7.8	7.9	8.1
Utah	2.6	3.1	3.3	3.7
Washington	6.4	7.0	7.3	7.7
Total	**85.1**	**92.4**	**96.0**	**101.9**

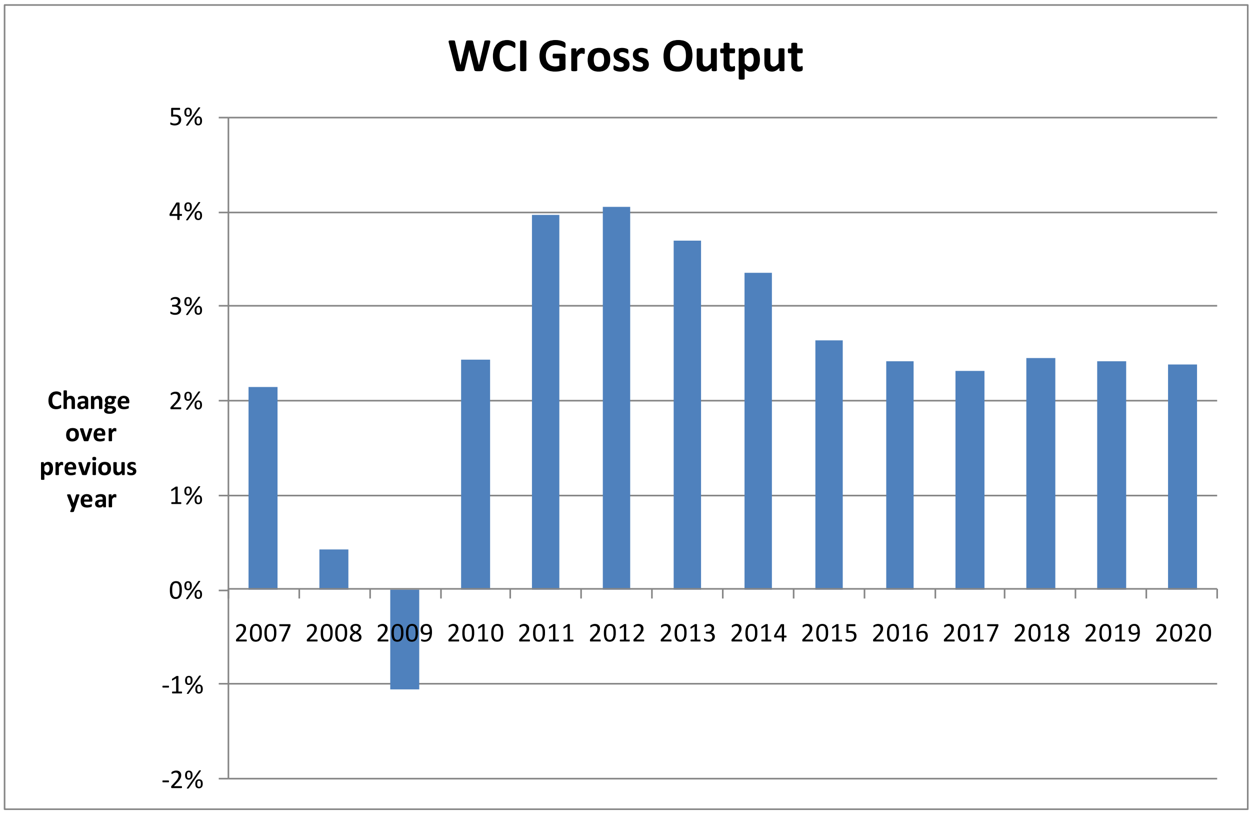
WCI Economic Growth Forecast: Another key driver in the ENERGY 2020 simulation of energy demand is sector-specific economic growth. Table 4 and Figure 3 show the gross economic output forecast for the WCI region.

Table 4: Regional Gross Economic Output Forecast for the WCI Region, Selected Years (Billion of 2007 US dollars)

2006	2009	2012	2015	2020	Avg. Annual Growth Rate 2006-2020
5,514	5,595	6,199	6,819	7,675	2.4%

[20] Examples of non-energy agriculture emissions are methane emissions from livestock and livestock manure management, and carbon and N_2O emissions from agricultural soils.

Figure 3: Regional Gross Economic Output Forecast for WCI Partners



Emission Abatement Options: The model simulates decisions by energy users for each end use, including: fuel choice; investment in end use efficiency (e.g., by purchasing devices that are more efficient than the minimum required by standards); and end-use utilization (how much the device is used). End-use specific choices are simulated as needed, such as mode choice for freight movement and passenger transportation. Choices are simulated based on costs (increased capital costs versus the value of fuel saved) as well as non-price attributes (convenience, acceptance of the technology). Past purchasing behavior is used to calibrate the non-price choice parameters for each end use.

Energy Independence and Security Act of 2007 (EISA): The reference runs, main policy case, and sensitivity cases include the requirements of the EISA, appliance and lighting energy efficiency standards, and the renewable fuels standard (RFS). These requirements are assumed to be implemented fully in the U.S. WCI Partner jurisdictions. For the Canadian provinces, lighting, equipment and appliance standards as defined by the Canadian Standards Association[21] as well as federal "ecoENERGY" Renewable Fuels Strategy.[22]

[21] http://www.oee.nrcan.gc.ca/regulations/home_page.cfm

[22] This strategy requires 5% average renewable content based on the gasoline pool that is produced or imported, starting in 2010, and 2% average renewable content in diesel fuel and heating oil (distillate) by 2012. The Canada Gazette indicates that the 2% renewable content in diesel fuel and heating oil is equivalent to 5% renewable content in on-road diesel use. (See http://canadagazette.gc.ca/partI/2006/20061230/html/notice-e.html#i3)

Clean Car Standards: All cases incorporate the Clean Car Standards through 2016, equivalent to California's Pavley I. In April, 2010, the U.S. federal government established standards for vehicle GHG emissions and CAFÉ standards which would align with the GHG emission standards previously proposed by California. (At the same time, the Canadian federal government also announced rules that would effectively align with those in the U.S.) As a result, a national standard was established which will require the fuel efficiency of new passenger cars and light trucks to reach an average fleet efficiency of 35.5 mpg by 2016. The Phase 3 modeling assumes a fixed percentage increase in the efficiency of new vehicles each year starting in 2010 to reach the mandated level by 2016. Information relating to the cost of implementing this policy was based on estimates by the NHTSA.[23] Efficiency improvements beyond 2016 (Pavely II) are included the complementary policies runs.

Renewable Portfolio Standards: All modeling runs incorporate the renewable portfolio standards (RPSs) currently in effect in the states and provinces. See Appendix I of the *Assumptions Book for ENERGY 2020* for details.

Fuel Prices: An important variable in the modeling is the forecast of fuel prices (oil, coal, natural gas, etc.). The model calculates electricity prices internally. Table 5 shows the AEO 2009 reference-case price forecast used in the modeling. State- and province-specific retail prices are derived in the model from the prices shown in this table.

Table 5: Fuel Price Forecast

	2006	2012	2015	2020
World Oil Price (2007 US$/barrel)	60.70	94.84	108.52	112.05
Natural Gas Wellhead Price (2007 US$/mmBtu)	6.91	6.75	6.90	7.43
Coal Prices (2007 US$/ton)	25.29	27.69	27.77	27.38

Source: EIA Annual Energy Outlook 2009 reference price series.

Technology Assumptions: To conduct the analysis, assumptions are required regarding the availability, cost, and use of a range of technologies through 2020. This analysis adopts assumptions, listed below, which overall are conservative in that they tend to increase the cost of achieving the WCI emissions goal. The WCI Partner jurisdictions recognize the promise of a variety of technologies as a means of reducing emissions, and they are promoting their development in some cases. However, their near-term commercial deployment remains uncertain. These assumptions are made for modeling purposes, and do not reflect WCI policy recommendations regarding the promise or use of these technologies.

- Coal Plants: Coal plants that are already planned and committed are assumed to be completed as planned and brought into service. No additional new coal plants are assumed to be built by 2020 in the WECC region beyond those already planned and committed. See Appendix F of the

[23] NHTSA, Corporate Average Fuel Economy Rulemaking, Document No. WP.29-145-13, June 2008, see also: NHTSA, Final Environmental Impact Statement, Corporate Average Fuel Economy Standards, Passenger Cars and Light Trucks, Model Years 2011 to 2015, October 2008.

Assumptions Book for ENERGY 2020 for a list of coal plants that are assumed to be planned and committed.

- Nuclear Plants: No new nuclear power plants are assumed to be built by 2020 in the WECC region.
- Carbon capture and storage: Carbon capture and storage is assumed for this analysis to not be feasible for electric power generation through 2020.
- Hydropower: No new hydropower capacity is assumed to be built in the WECC region through 2020.
- Plug-in hybrids: Electric vehicles, including plug-in hybrids, are assumed to be not available in significant numbers through 2020.
- Electricity Generation Costs: The Phase 3 modeling uses estimates of power generation capital costs, operating costs, and heat rates developed for a recent study by the California Public Utilities Commission, summarized in Table 6.

Table 6: Summary of Power Generation Cost Inputs

Technology	Total Capital Costs $/kW	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Capacity Factor	Nominal Heat Rate
Biogas	$2,623	107.5	0.01	85%	11,566
Biomass	$3,836	50.18	2.96	85%	15,509
Geothermal	$3,575	154.92	-	90%	-
Hydro - Small	$2,530	13.14	3.3	50%	-
Solar - Thermal	$2,840	49.63	-	40%	-
Wind	$1,983	28.51	-	37%	-
Coal ST	$2,671	25.91	4.32	85%	8,844
Coal IGCC	$3,087	36.36	2.75	85%	8,309
Coal IGCC with CCS	$5,127	42.82	4.18	85%	9,713
Gas CCCT	$878	11.04	2.4	90%	6,917
Gas CT	$794	11.4	3.36	5%	10,807
Hydro - Large	$2,530	13.14	3.3	50%	-
Nuclear	$4,999	63.88	0.47	85%	10,400
<5MW CHP	$1,952	11.04	2.4	40.5%	9,700
>5MW CHP	$1,259	11.04	2.4	85%	9,220

Cost Basis Year = 2005.
All estimates are 2008 U.S. dollars.
Source: E3 GHG Calculator v2b, tab Gen Cost". Available at:
http://www.ethree.com/GHG/GHG%20Calculator%20v2b.zip

Allowance Banking

The EMT's methodology enables allowances to be banked when allowance prices are low and for banked allowances to be used when allowance prices are high. In its Phase 2 analysis, the EMT applied ENERGY 2020 in a mode that simulated a year-to-year clearing of the market for GHG allowances. In this mode, ENERGY 2020 applied the relevant annual emission cap and simulated emitters choosing among reduction options, offsets, and banking in response to a price for allowances. The model iterated until it found the market-clearing price for that year that met the emissions cap. This year-to-year mode required that the EMT specify a decision rule for emitters on when to bank allowances and when to withdraw them from the bank.

In its Phase 3 analysis, the EMT relied on a second approach, with stronger grounding in economic principles expected to guide banking by emitters. This approach assumes allowance prices in different years are linked by the discount rate of the allowance holders. In other words, holders of allowances recognize the time value of money so that when they bank an allowance in one time period (incurring the opportunity cost of not using it), they expect that it will have greater value in a future time period. Economic principles suggest that when banking is allowed under a cap-and-trade system, the allowance price will grow over time at a rate equal to the time value of money and investment risk.[24]

This approach was incorporated into the modeling by using ENERGY 2020 to evaluate vectors of allowance prices covering the period 2012-2020 (growing annually at a specified annual discount rate of 8%), rather than iterating a single year at a time and then moving on to the next year. Appropriate constraints were designed to reflect the limit on the use of offsets and the prohibition on borrowing of allowances.

The bank flow in any year is defined as follows:

Bank flow = Allowance budget – Capped sector emissions + Offsets used

The number of banked allowances in a given year is the sum of the annual bank flows from 2012 up to and including that year.

When a cap-and-trade system allows banking, the flexibility given to emitters means that a model can examine the ***cumulative*** cap over the relevant time period (along with allowed offsets), and iterate toward the price ***vector*** (i.e., price trajectory over the 2012-2020 period) that would result in meeting the cumulative cap. This approach assumes that emitters are likely to bank and use allowances in an economically rational manner and that the allowance price will rise over time to reflect the time value of money and investment risk.

[24] See, e.g., R. Newell et al, Managing Permit Markets to Stabilize Prices, Resources for the Future, June 2003, p.5 (http://www.rff.org/documents/RFF-DP-03-34.pdf), and P. Joskow, A.D. Ellerman et al, Emissions Trading Under the U.S. Acid Rain Program: Evaluation of Compliance Costs and Allowance Market Performance, Center for Energy and Environmental Policy Research, MIT (undated), p. 24, fn.38 (http://faculty-gsb.stanford.edu/wilson/archive/E542/classfiles/Joskow_napap.pdf).

Offsets

The modeling effort used an offset supply curve to calculate, for each year, the number of offsets available at the allowance price, as shown in Figure 4. The offset supply curve is based on a 2005 report by U.S. EPA.[25] Then the offset limit in the WCI program design is applied for each compliance period. According to Section 9.2 of the *Design Recommendations for the WCI Regional Cap-and-Trade Program*, the offset limit equals "49 percent of the total emissions reductions from 2012-2020."[26] The number of offsets actually used is the lesser of the offsets available from the offset supply curve and the offset limit.

Figure 4: Offset Supply Curves

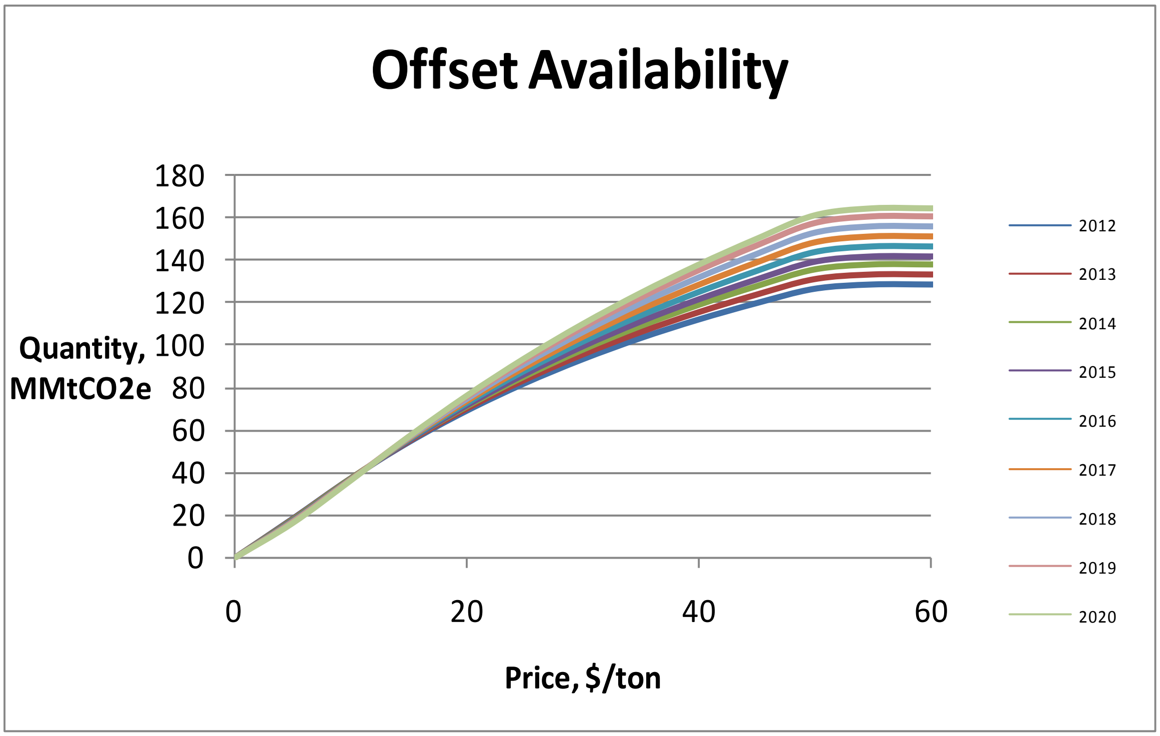


Table 7 shows the calculation of the offset limit for the main policy case. The "reduction calculation line" is equal to the 2012 narrow scope emissions of the complementary policies run, which is 464 Mt for the main policy case and discount rate sensitivity cases. For 2015 and beyond, the reduction calculation line also includes the other covered sector emissions for 2015, which is 464 + 597 = 1,061 Mt for the main policy case and discount rate sensitivity cases. The "total emission reductions" are the difference between the reduction calculation line and the allowance budget. The offset limit is 49 percent of the reductions.

[25] U.S. EPA, Greenhouse Gas Mitigation Potential in U.S. Forestry and Agriculture, 2005, http://www.epa.gov/sequestration/pdf/greenhousegas2005.pdf

[26] The emissions reductions in this case are relative to the 2012 emissions, not the reference case projections for 2012-2020.

Table 7: Calculation of Offset Limit, Main Policy Case and Discount Rate Sensitivity Cases

Year	Complementary policies run emissions, narrow scope (Mt)	Complementary policies run emissions, other covered sectors (Mt)	Reduction calculation line (Mt)	Allowance budget (Mt)	Reductions (Mt)	Offset limit (Mt)
2012	464		464	464	-	-
2013			464	456	8	4
2014			464	449	16	8
2015		597	464+597= 1,061	1,038	23	11
2016			1,061	1,017	44	22
2017			1,061	996	66	32
2018			1,061	975	87	42
2019			1,061	953	108	53
2020			1,061	932	129	63
Total						**235**

Complementary Policies

The following assumptions were made in the complementary policy run used in the main policy case and in three of the five sensitivity cases. The assumptions are somewhat different for the two sensitivity cases examining half effectiveness of complementary policies and high fuel price and electricity generation costs. These differences are explained in the Cases Analyzed section of this appendix.

Ontario Coal Phase-Out: Ontario will be phasing-out coal-fired electricity generation between 2010 and 2014.[27]

Clean Car Standards: This is equivalent to California's Pavley II. (Pavley I is included in the reference run.) This policy starts in 2017. By 2020, per-mile GHG emissions from new passenger vehicles decrease by 17 percent relative to new vehicle emissions in 2016.[28] ENERGY 2020 estimates the fuel savings and

[27] See news.ontario.ca/mei/en/2009/09/ontarios-coal-phase-out-plan.html.
[28] This is based on emission reductions contemplated in "California Air Resources Board, Climate Change Scoping Plan: a Framework for change, December 2008 Discussion Draft." Also see "California Air Resources Board, Comparison of Greenhouse Gas Reductions for the United States and Canada under U.S. CAFÉ Standards and California Air Resources Board Greenhouse Gas Regulations – An Enhanced Technical Assessment, 25 February 25, 2008."

changes to device investments and increases in operation and maintenance costs. Change in vehicle costs are based on estimates from the California Air Resources Board.[29]

Energy Efficiency: The combined effect of energy efficiency programs recently put in place and being pursued are assumed to reduce the rate of growth in electricity and natural gas demand by 0.5% each year starting in 2012.[30] ENERGY 2020 estimates the fuel savings and changes to device and process investments and operation and maintenance costs. The modeling also includes program administration cost, which is $0.6 billion per year by 2020.[31]

VMT Reduction: The combined effect of transportation and fuel programs recently put in place and being pursued is assumed to be equivalent to reducing travel demand so that vehicle miles traveled (VMT) are lower by 2 percent from the reference case by 2020, beginning in 2008. ENERGY 2020 estimates the fuel savings and decrease in device investment and operation and maintenance costs due to less wear and tear on the vehicles. ENERGY 2020 does not estimate the planning and development costs and savings associated with reducing travel demand. A brief literature review of travel demand programs and policies indicated a broad range of potential planning and development costs and savings, including potentially significant infrastructure savings. This analysis excludes these potential planning and development costs and savings, and focuses solely on the impacts on vehicle use and fuel use.

Other Cap-and-Trade Modeling Assumptions

This section describes assumptions regarding the cap, reductions, allowance prices, and compliance. These topics are relevant only to the cap-and-trade runs and not to the reference or complementary policies runs.

Allocation of Allowances: The model does not distinguish between freely allocated allowances and auctioned allowances. Rather, it determines the change in energy use and the costs associated with that change. These abatement costs are the same regardless of whether allowances are freely allocated or auctioned. The allocation method, instead, determines who benefits from the market value of the allowances.

Allowance Budgets: Recommendations to the WCI Partners on setting allowance budgets are under development by the WCI Cap Setting and Allowance Distribution (CSAD) Committee. However, for purposes of completing this economic modeling, the EMT had to make reasonable assumptions about the allowance budget and based these assumptions on the WCI Design Recommendations.

In the modeling, the cap for 2020 is assumed to be 15% below the 2006 model-estimated emissions, since this is the first year for which modeling results are available. Ideally, model-estimated emissions for 2005 would be available as the basis for the 2020 budget, but this is not expected to have a significant effect since U.S. and Canadian emissions, as reported by the federal governments, actually

[29] California Environmental Protection Agency, Air Resources Board, Regulations to Control Greenhouse Gas Emissions from Motor Vehicles, Final Statement of Reasons, August 4, 2005.
[30] For example, electricity sales for 2017 in the reference run are 1.2 percent higher than sales for 2016. In the complementary policies run, electricity sales for 2017 are 1.2% - 0.5% = 0.7% higher than sales in 2016.
[31] The EMT assumed administration costs of $6/MWh of electricity saved and $1/MMBtu of natural gas saved.

declined slightly between 2005 and 2006. Furthermore, all reductions necessary to meet the WCI economy-wide goal are assumed to come from sectors covered by the cap, which provides a slightly conservative estimate of the cost to the covered sectors. Thus:

2020 allowance budget = 0.85 x 2006 emissions[32] – 2020 emissions from uncovered sources

For modeling purposes, the 2012 allowance budget was set as the 2012 emissions from the narrow scope estimated in the complementary policies run. Emissions associated with imported power are included in the 2012 allowance budget. The trajectory for the first compliance period is based on the rate of reduction that would be required if the broad scope were in place in 2012. For modeling purposes, the 2015 allowance budget was set in two parts. The first part was the continued trajectory of the narrow scope emissions that started in 2012. The second part was the best estimate of the emissions covered for the first time in 2015. Emissions from these newly covered sources were estimated from the complementary policies run. The total allowance budget in 2015 is the sum of these two parts. The trajectory from 2015 to 2020 is a straight line, as defined in the *WCI Design Recommendations*.

Discount Rate: A real discount rate of 5% was used in annualizing costs and calculating net present values of cost streams. As noted above, the time value of money is also used to model allowance banking and use over time. The modeling used a rate of 8% to model banking, reflecting both the discount rate and investment risk specific to holding allowances. Sensitivity cases with values of 4% and 12% were also analyzed.

Compliance: As noted above, the goal of compliance is that the emissions in the capped sectors, summed over 2012-2020, equals the annual allowance budgets plus offsets, summed over 2012-2020. (Over-compliance in the first two compliance periods is acceptable. The banked allowances can be used in the final compliance period.) The emissions are a decreasing function of allowance price and offsets are an increasing function of the allowance price, up to the offset limit.

First Jurisdictional Deliverer: All cases incorporate a proxy to represent the first jurisdictional deliverer approach described in the *WCI Design Recommendations*. Consequently, emissions from electricity imported into the WCI Partner Jurisdictions from outside the WCI Partner jurisdictions are included in the analysis.

Cases Analyzed

This report presents six cases – that is, six families of model runs. Each family of runs consists of a reference run, a complementary policies run (that is, the complementary policies applied to the reference run), and cap-and-trade run (that is, an allowance price imposed on the complementary policies run). The cases are:

- Main policy case

[32] 2006 emissions include emissions associated with power imported from non-WCI jurisdictions.

- Sensitivity cases, which differ from the main policy case in the following ways:
    - Half-effectiveness of complementary policies (shares reference run with main policy case).
    - Alternative economic forecast, high economic growth, low energy prices (requires its own reference and complementary policies runs).
    - High fuel price and high electricity generation cost (requires its own reference and complementary policies runs).
    - Allowance price growth rate of 4% per year for cap-and-trade (shares reference run and complementary policies run with main policy case).
    - Allowance price growth rate of 12% per year for cap-and-trade (shares reference run and complementary policies run with main policy case).

The allowance price applies to the narrow scope sectors in 2012-2014 and to the broad scope sectors in 2015-2020. ENERGY 2020 determines the energy use changes and GHG emissions. The number of banked allowances is calculated from the emissions, the allowance budget, and number of offsets used.

Main Policy Case

This case simulates the effects of the WCI cap-and-trade program under the EMT's primary set of assumptions regarding future socio-economic conditions, complementary policies, and offset availability and costs. The following sensitivity cases allow the EMT to gauge the sensitivity of the main policy case results to changes in some of these key assumptions.

Sensitivity Case: Half-Effectiveness of Complementary Policies

The purpose of this sensitivity case is to examine what happens if the energy efficiency and VMT programs achieve only half of their assumed emission reductions. Specifically, this case assumes that:

- The energy efficiency programs reduce the rate of growth in electricity and natural gas demand by only 0.25 percent per year, starting in 2012.
- Vehicle miles traveled decrease by only 1 percent from the reference case by 2020.
- The clean car standards are unchanged.
- The Ontario coal phase-out is unchanged.

Sensitivity Case: Alternative Economic Forecast

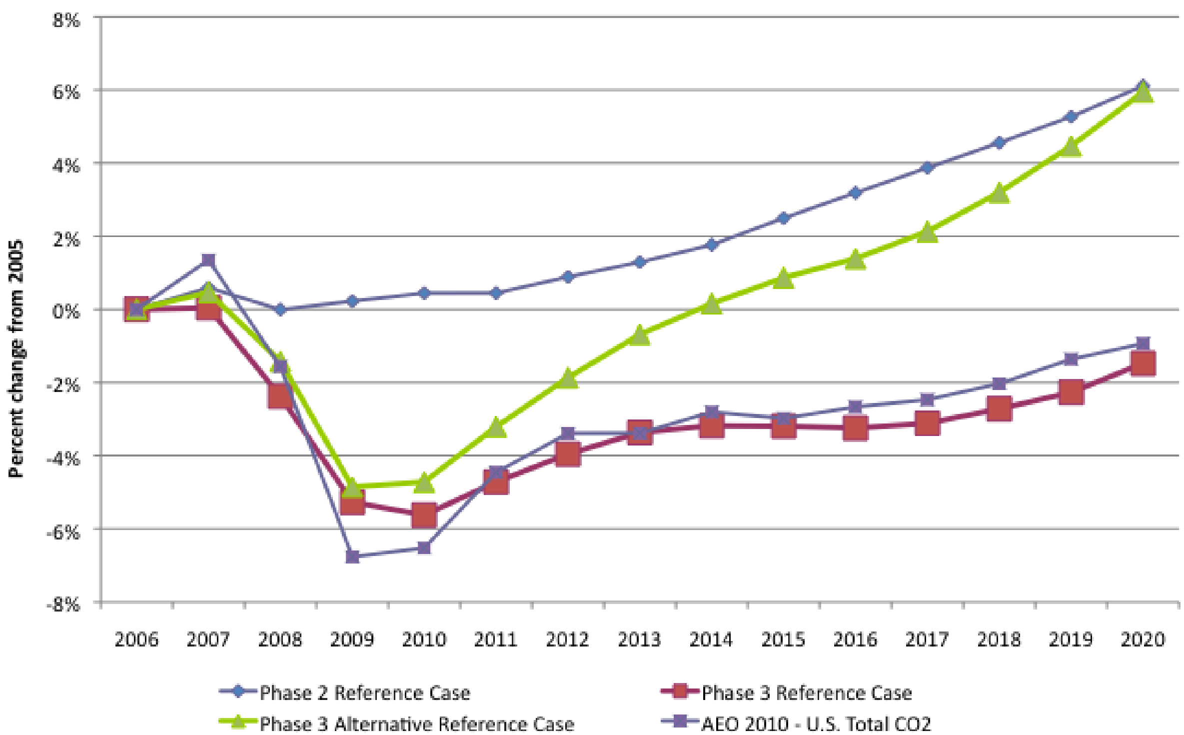
The purpose of this sensitivity case is to examine the implications of a different economic forecast than that assumed in the main policy case. The alternative economic forecast assumes a growth rate of 2.8 percent per year, about 0.5 percent per year higher than in the forecast used for the main policy case.

For energy prices, the alternative forecast uses the average of the AEO 2009 reference-price and low-price forecasts. This case also assumes that the EISA biofuels mandate will not be fully met by 2020. Instead, the case assumes the level of biofuels reflected in the AEO 2009. Each of these changes has the effect of increasing emissions in the reference case, and together, increase the challenge of meeting the WCI regional goal. Since the higher growth of the economy would also increase opportunities to become more energy efficient, an alternative complementary policies run was conducted for this sensitivity case in which the energy efficiency programs achieve a 1 percent per year decrease in the electricity and natural gas demand growth, starting in 2012. Table 8 and Figure 5 summarize the differences between the reference and alternative reference runs.

Table 8: Reference Run and Alternative Reference Run Assumptions

Assumption	Reference run	Alternative Reference run
Economic growth	Accounts for economic recession based on January 2009 Congressional Budget Office forecast	Faster economic growth to assess implications of a stronger than expected recovery
Fuel price forecast	AEO 2009 mid case	Average of AEO 2009 mid and low cases. Lower fuel prices results in more fuel consumption
Energy efficiency program impacts (used in complementary policy run)	Reduced demand for electricity and natural gas by 0.5% per year	Reduced demand for electricity and natural gas by 1.0% per year

Figure 5: Reference Run and Alternative Reference Run Emission Compared to the Latest National Forecast



Sensitivity Case: High Fuel Prices and Electricity Generation Costs

The purpose of this sensitivity case is to examine the implications of energy prices being higher than assumed in the main policy case. There has been considerable stakeholder comment that the energy price forecast in the main policy case may be too low. Additionally, some stakeholders have commented that the power generation cost assumptions may be too low, indicating that recent increases in commodity prices have had an impact on these costs. This sensitivity case includes both increased energy prices and increased power generation costs as a set of conditions that could occur together in the future. In this case, energy prices are assumed to start at 2008 prices and increase in real terms by 50% by 2020, and capital and O&M costs for power generation are assumed to be 30% higher than in the main policy case. This case required its own reference and complementary policies runs.

Sensitivity Case: 4% Annual Growth In Allowance Prices

The purpose of this sensitivity case is to examine the implications of a slow-rising allowance price trajectory. This case uses a growth rate in the allowance price of 4 percent per year instead of 8 percent per year in the cases discussed above.

Sensitivity Case: 12% Annual Growth In Allowance Prices

The purpose of this sensitivity case is to examine the implications of a faster-rising allowance price trajectory. This case uses a growth rate in the allowance price of 12 percent per year instead of 8 percent per year in the cases discussed above.

Results and Discussion

Emission Results for the Main Policy Case

Figure 6 shows the emission results of ENERGY 2020 for the main policy case. Offsets, complementary policies, and additional emission reductions caused by the cap are each important to achieving the WCI regional goal. Together, these emission reductions meet an allowance budget that decreases linearly to 15 percent below 2005 levels by 2020. Emission reductions in 2020 are predicted to be 13.4 percent below 2005 emissions due to over-compliance in earlier years and the use of banked allowances in 2019 and 2020.

Figure 6: Greenhouse Gas Emission Reductions Under the WCI Program, 2006-2020

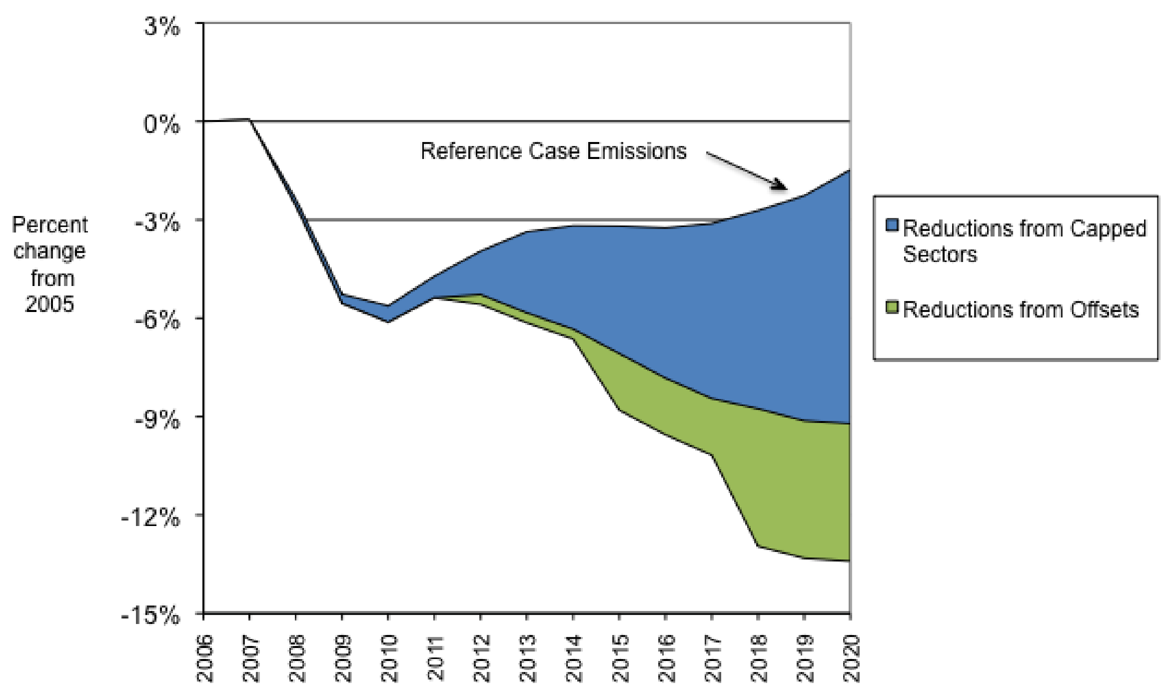
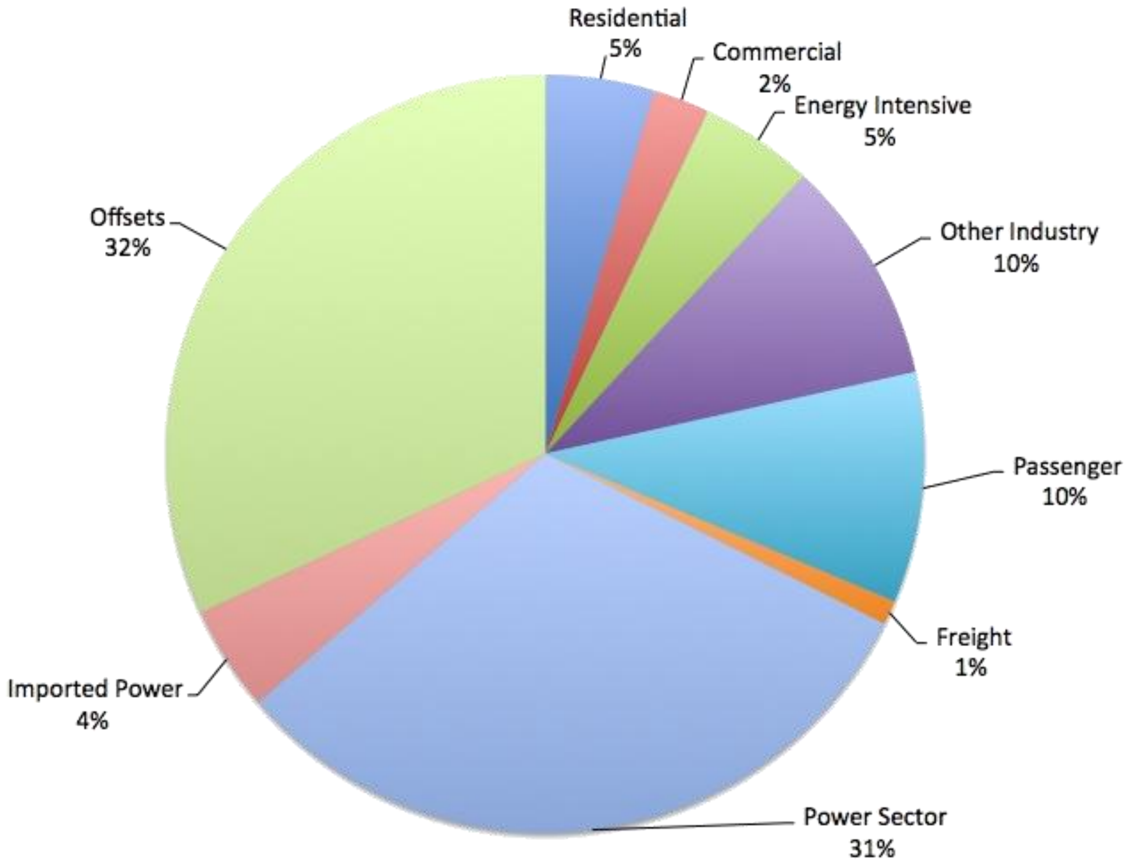


Figure 7 shows the relative amount that each type of reduction contributes to the total emissions reduced by the program over the period 2012-2020. Total emissions from capped sectors for this period in the reference run is 7,999 million metric tons (Mt) of carbon dioxide equivalents. The allowance budget described in Other Cap-and-Trade Modeling Assumptions would reduce emissions by 719 Mt over the 2012-2020 period. The contribution of each sector to this reduction is shown in Figure 8.

Figure 7: Source of Emission Reductions Under the Cap, Main Policy Case Relative to the Reference Case, 2012-2020



Economic Results for the Main Policy Case and Sensitivity Cases

Table 9 summarizes the results for the six cap-and-trade cases. The main policy case achieves the WCI regional goal at an allowance price of $33 in 2020. The net cost over the period analyzed (abatement cost plus offset cost) is -$102 billion, which represents a net cost savings. The sensitivity cases indicate that reducing the effectiveness of complementary polices by half, or assuming a rapid economic recovery and low energy prices, raise allowance prices to over $50, but still produce a net cost savings.[33] The sensitivity cases also suggest allowance prices would be much lower than the main policy case if energy prices and electricity production costs in the reference case are higher than expected.

Table 10 provides detailed cost estimates for the main policy case by sector and cost type, summed over the years 2012-2020. Negative costs (i.e., savings) are shown in parentheses. The cost savings result from the complementary policies. The largest single savings are attributable to the passenger transportation sector. In particular, the reduction in VMT reduces expenditures on fuel and on other vehicle costs. Figure 8 shows the fuel cost savings, other costs, and total costs for all sectors for the main policy case. The total savings of $102 billion, however, is modest relative to the size of the WCI

[33] Modeling runs were not performed for allowance prices over $50. This price, however, achieved 94% of the emission reductions required by the cap for both sensitivity cases.

economy (less than 0.2 percent of the combined economies of the 11 WCI Partner jurisdictions). The total market value of all allowances distributed in the main policy case is $188 billion.

Table 9: Summary of Economic Results for Main Policy and Sensitivity Cases (savings in parentheses)

Case Description	Abatement by covered sectors, 2012-2020 (Mt CO2e)	Reduction from offsets, 2012-2020 (Mt CO2e)	Abatement cost,* 2012-2020 (2007 $B)	Offset cost, 2012-2020 (2007 $B)	Allowance price in 2020 that achieves compliance (2007 $)	Allowance value 2012-2020 (2007 $B)
Main policy case	484	235	(105)	3	33	188
Sensitivity Cases						
Half the VMT reduction and energy efficiency improvements	483	243	< (38)	3	> 50	> 285
Faster economic growth & lower primary energy prices**	816	291	< (202)	4	> 50	> 287
Higher energy prices and power plant construction costs	420	208	(106)	2	13	72
4% annual allowance price escalation	484	235	(105)	3	28	179
12% annual allowance price escalation	484	235	(106)	3	39	200

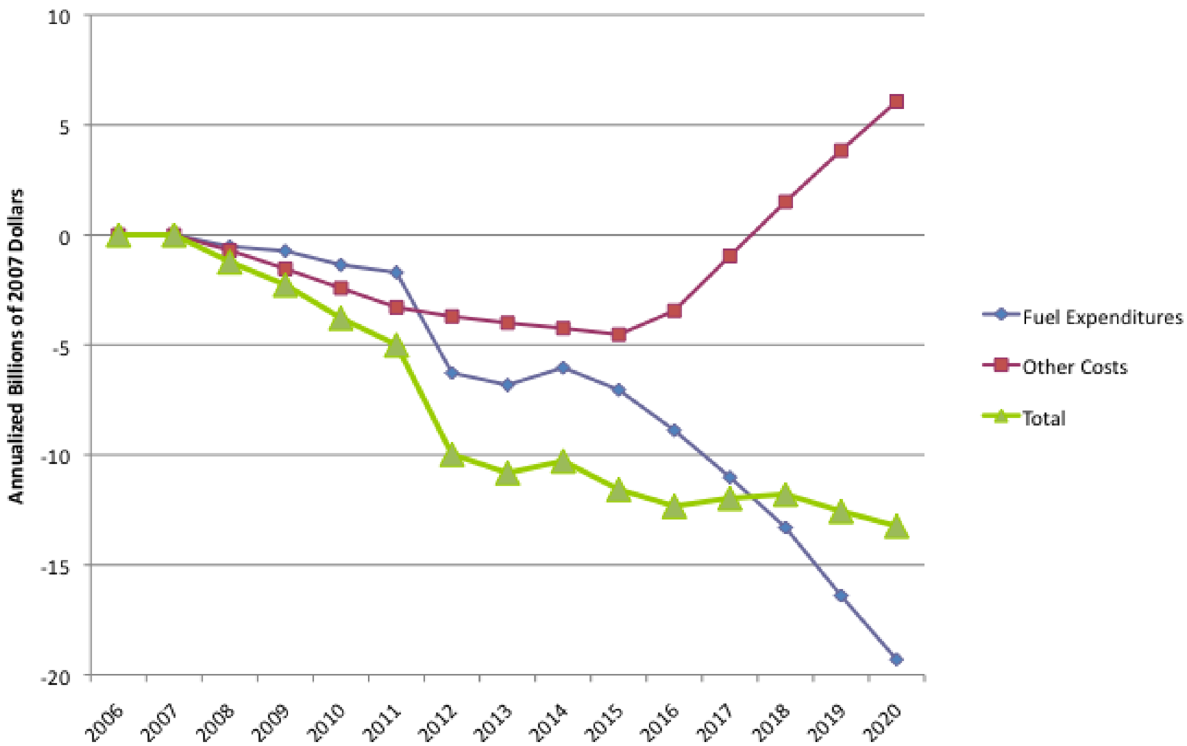
* Abatement cost includes approximately $3B for energy efficiency program administration.
** This case assumes greater economic growth will create more opportunities to improve energy efficiency and therefore reduce the annual growth rates by 1% per year instead of 0.5% per year.

Table 10: Economic Results for the Main Policy Case by Sector and Cost Type, 2007 Million US$ Summed Over 2012-2020 (savings in parentheses)

Sector	Fuel	Device	Process	O&M	Total
Residential	(21,880)	20,830	350	2,710	2,010
Commercial	(18,020)	8,030	350	1,580	(8,060)
Energy Intensive Industry*	(14,760)	580	320	730	(13,130)
Paper	(3,540)	(710)	90	(10)	(4,170)
Chemicals	(3,000)	(410)	30	(160)	(3,540)
Petroleum	(250)	1,790	190	850	2,580
Nonmetallic Minerals	(1,050)	(170)	30	(90)	(1,280)
Primary Metals	(3,320)	(70)	0	20	(3,370)
Mining Except Oil & Gas	(2,630)	(160)	(10)	(80)	(2,880)
Oil and Gas Extraction	(970)	310	(10)	200	(470)
Other Industry	(3,300)	1,480	(330)	940	(1,210)
Passenger Transportation	(29,680)	(51,510)	0	(7,760)	(88,950)
Freight Transportation	(3,000)	30	0	9,130	6,160
Agriculture	(4,430)	(20)	(20)	(100)	(4,570)
Waste & Wastewater	0	0	0	0	0
Total**	(95,070)	(20,580)	670	7,230	(107,750)

* Energy Intensive Industry is a subtotal of the seven energy-intensive sectors listed beneath it.
** Does not include offset costs or complementary policies administrative costs, which are estimated and reported separately.

Figure 8: Economic Results for the Main Policy Case by Year, 2007 Billion US$



The half-effectiveness of complementary policies case achieves compliance for an allowance price trajectory that has a higher price than $50 in 2020. (The modeling effort did not include any runs higher than $50.)

The alternative economic forecast case also achieves compliance for an allowance price above $50 in 2020. The potential for savings, however, is higher in this case than any other (at least $198 billion). This is because the faster economic growth was assumed to create more opportunities to improve energy efficiency. Hence, complementary policies were assumed to reduce the growth rate of electricity and natural gas demand by 1 percent in each year. Nonetheless, the faster economic growth and lower fuel prices leads to greater emissions in the reference run and a greater need for emission reductions in the cap-and-trade run, requiring an allowance price greater than $50 to achieve the WCI regional goal.

The high energy price and electricity generation cost sensitivity case achieves compliance at a lower allowance price of $13. The allowance price is so low that the WCI offset limit is not reached because offset prices begin to exceed the allowance price. The cost savings potential is larger than the main policy case because the low allowance price preserves a greater portion of the savings from the complementary policies.

The final two sensitivity cases imply that the precise slope of the price trajectory (discount rate) assumed by the EMT has little effect on the economic results.

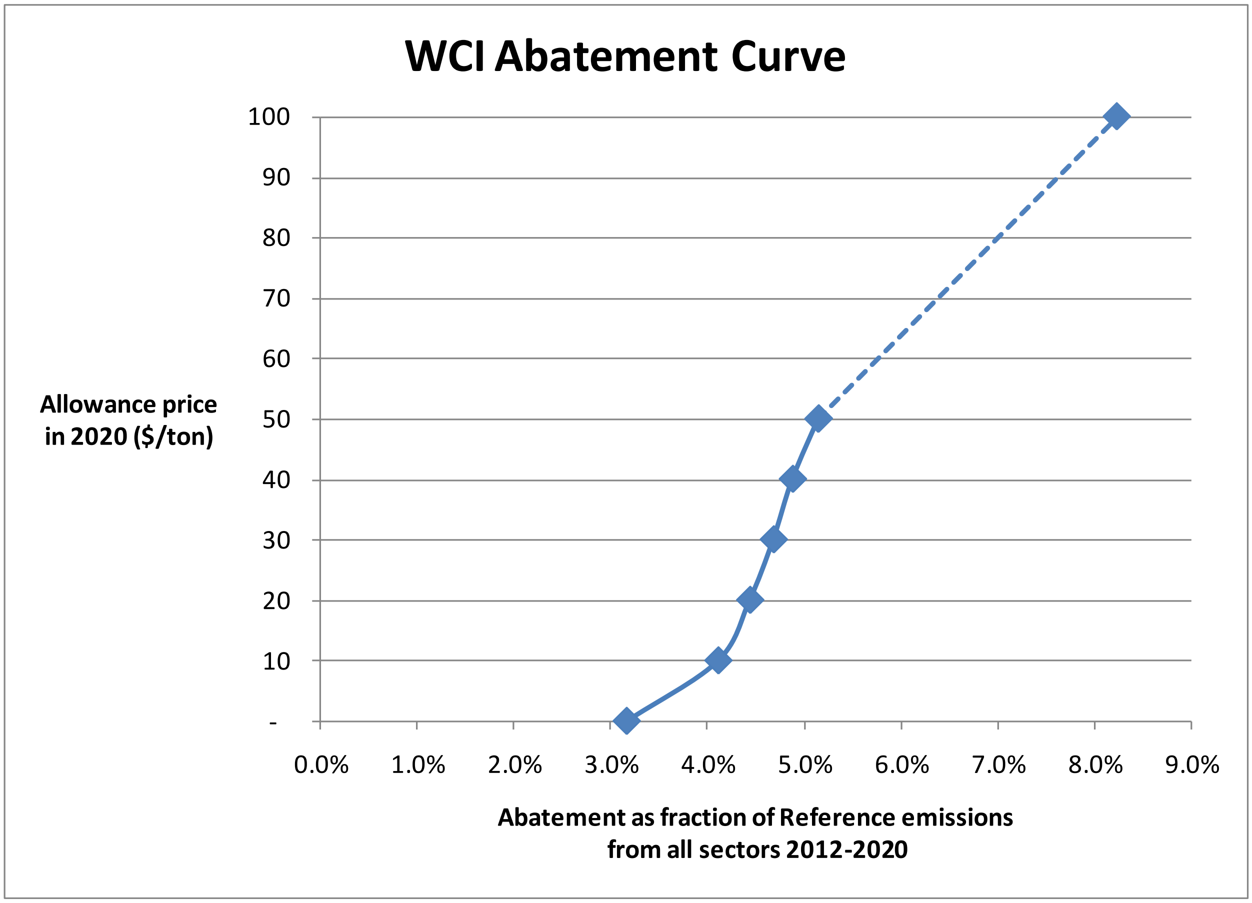
To put the results of Table 9 into some context, the 2020 allowance prices estimated in other studies are provided below. These studies differed from the EMT's analysis and from each other in their geographic scope, emission targets, time period, use of offsets, and type of computational model used.

- WCI 2008, $24 in 2020.[34]
- California Scoping Plan, $10 in 2020.[35]
- Updated Analysis of California's Scoping Plan, $21.[36]
- U.S. EPA analysis of Waxman-Markey (ACES), $20 in 2020.[37]
- Congressional Budget Office analysis of Waxman-Markey, $28 in 2020.[38]
- Energy Information Agency analysis of Waxman-Markey, $32 in 2020.[39]
- U.S. EPA analysis of Kerry-Lieberman (APA), $24 in 2020.[40]

Finally, Figure 9 shows the abatement curve for the main policy case. The curve suggests that reducing emissions from three percent below the reference case to four percent below the reference case, and from five to eight percent below the reference case, can be achieved through modest escalation of allowance prices. In the four to five percent range, however, the cost of abatement alternatives rises faster as greater emission reductions are sought within this range.

[34] http://www.westernclimateinitiative.org/component/remository/Economic-Modeling-Team-Documents/Appendix-B-Economic-Modeling-Results/
[35] http://www.arb.ca.gov/cc/scopingplan/document/scopingplandocument.htm
[36] http://www.arb.ca.gov/cc/scopingplan/economics-sp/economics-sp.htm
[37] http://www.epa.gov/climatechange/economics/economicanalyses.html
[38] http://energycommerce.house.gov/Press_111/20090620/cbowaxmanmarkey.pdf
[39] http://www.eia.doe.gov/oiaf/servicerpt/hr2454/pdf/sroiaf(2009)05.pdf
[40] http://www.epa.gov/climatechange/economics/economicanalyses.html

Figure 9: Abatement for the Main Policy Case



Conclusions

- The WCI emissions reduction goal for 2020 can be achieved with a net cost savings of approximately $100 billion in the WCI region over the 2012-2020 period. While significant, these savings are modest (less than 0.2 percent) relative to the economic size of the 11 WCI Partner jurisdictions.

- The allowance price predicted in 2020 to achieve the regional emission reduction goal in the main policy case is $33, which is higher than the $24 predicted in the Phase 2 modeling but comparable to the results of other independent studies.

- Complementary policies have the potential to significantly reduce emissions and contain costs. In this analysis, they produce negative costs, or cost savings. Complementary policies provide net savings because the reduction in fuel and other expenditures is greater in magnitude than the cost of the emission reductions. If complementary policies have roughly half the effect that the EMT assumed in the main policy case, then an allowance price of over $50 would be required to achieve the WCI regional goal.

- Higher-than-expected fuel prices would make it less costly to achieve the emissions goal, with lower allowance prices. Conversely, lower-than-expected fuel prices, coupled with a faster economic recovery, would raise the allowance price.

- Banking and offsets are important design elements to achieve emissions reductions and limit costs. Although no sensitivity cases were conducted to test the EMT's assumptions about offsets, it appears that none of the cases analyzed here would achieve the regional goal at an allowance price below $50 if not for the availability and price of offsets assumed in this report.

Detailed Results for the Reference Run and Main Policy Case

Description of Outputs

Table 11 through Table 16 present detailed results for the reference run used in the main policy case. Table 17 through Table 23 present detailed results for a representative cap-and-trade case. All dollars shown are 2007 dollars. These tables present annual results for selected years: 2006 (the first year modeled); 2012 (when the narrow scope begins); 2015 (when the broad scope begins); 2020 (the final year modeled). Another column shows the average annual growth rate for 2006-2020. For the cap-and-trade cases, the final column compares the 2020 value with the 2020 value from the reference run. Below are brief explanations of the model results shown in the tables.

Greenhouse Gas (GHG) Emissions: GHG emissions are presented in millions of metric tons of carbon dioxide equivalent (Mt CO_2e). Emissions for the 11 WCI Partner jurisdictions included in the analysis are presented by major sector.

Total Energy Use: Total energy use is reported by fuel type in units of TBtu/year.

Electric Sector: Outputs for the electric sector include:

- Generation capacity in units of megawatts (MW) by generation type. Note that estimated generation capacity grows due to capacity additions, but capacity retirement is not calculated. Consequently, generation capacity does not decline in the model outputs.

- Generation output in units of gigawatt-hours per year (GWh/year) by generation type.

- Electricity sales in units of GWh/year, including electricity imports into the eight WCI Partner jurisdictions in the WECC.

- Generating utility costs in $M/year, as requested by stakeholders.

Transportation Sector: Outputs for the transportation sector include VMT for passenger and freight vehicles, as well as miles traveled per passenger. The fleet average efficiency and marginal efficiency (for new vehicles) are reported for four vehicle types in miles per gallon. The average vehicle market share and marginal vehicle market share are reported for passenger vehicles.

Fuel Prices: Fuel prices are reported for electricity, natural gas, coal, fuel oil, LPG, gasoline, and diesel in 2007 dollars per million Btu (2007 $/mmBtu). The prices include the forecasted energy prices (presented in Table 5 above for the reference run) as well as the costs of delivering the fuels to market, but not fuel taxes. The prices reported for the cap-and-trade policy cases also include the allowance price, reflecting the appropriate carbon content of the fuel.

Fuel Expenditures: Fuel expenditures are reported by major sector. Estimates of fuel expenditures do not include the value of the allowances, although they do take into account the increase in the price of electricity driven by the allowance price.

Costs and Savings: For the cap-and-trade cases, costs and savings are reported in millions of 2007 dollars per year ($M/Yr). Total costs are reported by major sector, which are the sum of changes in fuel expenditures, changes in investment costs, and changes in O&M. Investment costs increase as more efficient devices, buildings, and processes are purchased in response to the limit on GHG emissions. The investment costs are annualized using a 5% real discount rate over the life of the equipment. The annualized costs are counted each year over the life of the equipment. The estimates of total costs include both the change in fuel expenditures and the change in investment costs. As shown in the tables below, the fuel expenditure savings typically offset most or all of the increased investment costs. The sub-total does not include the adjustments for program administration of the complementary policies or the allowance value of the power sector. These adjustments are added to get the total cost.

Reference Run

A reference run represents a business-as-usual scenario through 2020 (i.e., absent any cap or other GHG abatement policies not already adopted). Table 11 through Table 16 show model outputs for the reference run used in the main policy case. This reference run was also used in the half effectiveness complementary policies sensitivity case and the discount rate sensitivity cases. Alternative reference runs were used to assess the other two sensitivity cases, but these outputs are not included in this report.

Table 11: Reference Run Greenhouse Gas Emissions

GHG Emissions *(Mt CO_2e)*	**2006**	**2012**	**2015**	**2020**	**Avg. Annual Growth Rate 2006-2020**
Residential	78	80	85	89	1.0%
Commercial	55	53	53	52	-0.4%
Energy Intensive	228	202	203	204	-0.8%
Other Industry	65	74	81	92	2.5%
Passenger	352	354	334	306	-1.0%
Freight	133	131	135	142	0.5%
Power Sector	200	156	162	176	-0.9%
Waste	42	48	52	57	2.1%
Agriculture (non energy)	69	71	75	81	1.2%
Imported Power	38	41	41	41	0.5%
Total	**1,260**	**1,210**	**1,219**	**1,241**	**-0.1%**

Table 12: Reference Run Energy Use

Total Primary Energy Use *(TBtu/year)*	**2006**	**2012**	**2015**	**2020**	**Avg. Annual Growth Rate 2006-2020**
Aviation Fuel	737	781	799	836	0.9%
Biomass	681	621	660	727	0.5%
Coal	1,455	1,290	1,343	1,462	0.0%
Diesel	1,673	1,668	1,711	1,771	0.4%
Ethanol	93	200	317	494	12.7%
Landfill Gases/Waste	34	35	35	35	0.1%
LPG	668	591	579	550	-1.4%
Motor Gasoline	4,166	4,028	3,677	3,216	-1.8%
Natural Gas	5,244	4,535	4,671	4,833	-0.6%
Nuclear	1,617	1,659	1,609	1,677	0.3%
Oil, Unspecified	1,545	1,429	1,441	1,468	-0.4%
Renewables	2,026	2,188	2,277	2,375	1.1%
Total	**19,939**	**19,025**	**19,119**	**19,444**	**-0.2%**

Table 13: Reference Run Electric Sector Results

Generation Capacity *(GW)*	**2006**	**2012**	**2015**	**2020**	**Avg. Annual Growth Rate 2006-2020**
Gas/Oil	71	82	83	87	1.5%
Coal	22	24	24	24	0.7%
Nuclear	24	24	24	24	0.0%
Hydro	109	113	114	114	0.3%
Biomass	3	3	4	5	3.6%
Wind	4	13	20	25	13.8%
Other Renewable	3	3	3	3	1.4%
Total	**236**	**262**	**273**	**282**	**1.3%**
Generation Output *(TWh/year)*	**2006**	**2012**	**2015**	**2020**	**Avg. Annual Growth Rate 2006-2020**
Gas/Oil	153	103	112	129	-1.2%
Coal	116	104	108	116	0.0%
Nuclear	155	159	154	161	0.2%
Hydro	504	528	536	550	0.6%
Biomass	15	17	20	25	3.7%
Wind	9	33	50	64	15.1%
Other Renewable	14	14	15	15	0.8%
Total	**966**	**958**	**995**	**1,060**	**0.7%**
Sales *(TWh/year)*	**2006**	**2012**	**2015**	**2020**	**Avg. Annual Growth Rate 2006-2020**
Residential	314	316	331	350	0.8%
Commercial	333	331	345	370	0.8%
Industrial	309	288	298	325	0.4%
Transportation	6	8	8	7	1.7%
Street/Misc	16	16	16	16	0.0%
Resale	-	-	-	-	#N/A
Total	**978**	**960**	**998**	**1,070**	**0.6%**
Generating Utility Costs (M$/Year)					
	2006	**2012**	**2015**	**2020**	**Avg. Annual Growth Rate 2006-2020**
Annualized Investments	6,595	11,448	9,204	6,501	-0.1%
Fuel Expenditures	20,583	18,387	21,831	29,671	2.6%
Operation & Maintenance	5,945	6,463	6,783	7,108	1.3%
Total	33,124	36,298	37,818	43,280	1.9%

Table 14: Reference Run Transportation Sector Results

Distance Travelled	2006	2012	2015	2020	Avg. Annual Growth Rate 2006-2020
Passenger (billions of vehicle miles traveled)	690.3	751.9	810.8	865.0	1.6%
Freight (billions of vehicle miles traveled)	102.6	105.1	110.4	117.9	1.0%
Passenger Miles/Person	7.9	8.0	8.1	8.2	0.3%

Average Vehicle Efficiency *(miles/gallon)*	2006	2012	2015	2020	Avg. Annual Growth Rate 2006-2020
Light Gasoline	23.2	25.6	28.8	34.8	2.9%
Medium Gasoline	23.2	25.6	28.8	34.7	2.9%
Heavy Gasoline	16.9	18.0	19.5	22.0	1.9%
Heavy Diesel	16.9	18.0	19.5	22.0	1.9%
Fleet Average (In-Use Vehicles)	20.9	23.0	25.9	30.7	2.8%

Marginal Vehicle Efficiency *(miles/gallon)*	2006	2012	2015	2020	Avg. Annual Growth Rate 2006-2020
Light Gasoline	24.2	33.4	41.9	45.0	4.5%
Medium Gasoline	24.2	33.4	41.9	44.9	4.5%
Heavy Gasoline	17.3	20.4	23.4	24.5	2.5%
Heavy Diesel	17.3	20.4	23.4	24.4	2.5%
Fleet Average (In-Use Vehicles)	21.2	27.8	33.4	35.6	3.7%

Average Vehicle Market Share *(Percent)*	2006	2012	2015	2020	Avg. Annual Growth Rate 2006-2020
Light Gasoline	36.8	36.5	36.7	37.2	0.1%
Medium Gasoline	34.1	34.2	34.6	35.1	0.2%
Heavy Gasoline	29.0	29.3	28.7	27.7	-0.3%

Marginal Vehicle Market Share *(Percent)*	2006	2012	2015	2020	Avg. Annual Growth Rate 2006-2020
Light Gasoline	36.7	36.5	38.1	38.2	0.3%
Medium Gasoline	33.8	34.3	36.1	36.2	0.5%
Heavy Gasoline	29.4	29.2	25.8	25.6	-1.0%

Table 15: Reference Run Fuel Prices (2007 $/mmBtu)

Sector	2006	2012	2015	2020	Avg. Annual Growth Rate 2006-2020
Residential					
Res Electricity Prices	27.1	26.9	27.2	27.2	0.0%
Res Natural Gas Prices	10.3	11.6	12.1	12.9	1.6%
Res Oil Prices	21.1	25.7	28.4	29.3	2.4%
Res LPG Prices	22.0	26.7	29.4	30.4	2.3%
Commercial					
Com Electricity Prices	26.4	25.7	25.9	25.8	-0.2%
Com Natural Gas Prices	9.0	10.1	10.5	11.3	1.6%
Com Oil Prices	19.6	24.3	27.0	28.0	2.6%
Com LPG Prices	20.4	25.0	27.7	28.7	2.5%
Industrial					
Ind Electricity Prices	16.4	15.9	16.0	15.7	-0.3%
Ind Natural Gas Prices	7.9	9.3	9.7	10.3	1.9%
Ind Coal Prices	2.0	2.2	2.1	2.1	0.5%
Ind Oil Prices	14.7	19.2	21.7	22.6	3.1%
Ind LPG Prices	20.1	24.8	27.4	28.4	2.5%
Transportation					
Gasoline Prices	23.0	27.5	30.3	31.4	2.3%
Diesel Prices	22.3	26.8	29.5	30.5	2.3%

Table 16: Reference Run Fuel Expenditures (2007 $billion/yr)

Sector	2006	2012	2015	2020	Avg. Annual Growth Rate 2006-2020
Residential	44.9	47.5	51.1	55.1	1.5%
Commercial	41.7	42.0	44.1	46.7	0.8%
Energy Intensive Industry*	42.2	43.7	47.0	48.3	1.0%
Paper	5.7	5.2	5.3	5.3	-0.5%
Chemicals	5.9	6.4	7.0	7.7	1.9%
Petroleum	16.2	17.2	18.7	18.7	1.0%
Nonmetallic Minerals	3.4	3.5	3.8	3.9	1.1%
Primary Metals	6.6	6.7	7.2	7.8	1.2%
Mining Except Oil and Gas	1.1	1.4	1.7	1.9	4.0%
Oil and Gas Extraction	3.3	3.4	3.4	2.9	-0.9%
Other Industry	18.8	20.7	23.1	24.8	2.0%
Passenger Transportation	100.1	122.7	128.2	123.0	1.5%
Freight Transportation	39.5	47.5	54.0	59.1	2.9%
Agriculture	4.2	4.2	4.5	4.5	0.5%
Waste & Wastewater	-	-	-	-	#N/A
Total	**291.5**	**328.2**	**351.9**	**361.6**	**1.6%**

* Energy Intensive Industry is a subtotal of the seven energy-intensive sectors listed beneath it.

Main Policy Case

The following tables shows detailed results for the main policy case, which achieves compliance with an allowance price of $33 per metric ton in 2020.

Table 17: Main Policy Case Greenhouse Gas Emissions

GHG Emissions *(Mt CO_2e)*	**2006**	**2012**	**2015**	**2020**	**Avg. Annual Growth Rate 2006-2020**	**Change from Ref @ 2020**
Residential	78	79	82	82	0.4%	-7.6%
Commercial	55	53	52	47	-1.1%	-9.0%
Energy Intensive	228	202	200	196	-1.1%	-3.7%
Other Industry	65	74	74	78	1.3%	-15.6%
Passenger	351	350	329	287	-1.4%	-6.2%
Freight	133	131	135	139	0.3%	-1.8%
Power Sector	199	148	137	141	-2.5%	-20.2%
Waste	42	48	52	57	2.1%	0.0%
Agriculture (non energy)	69	71	72	79	1.0%	-2.6%
Imported Power	38	38	38	36	-0.4%	-11.6%
Total	**1,260**	**1,193**	**1,170**	**1,144**	**-0.7%**	**-7.9%**

Table 18: Main Policy Case Energy Use

Total Primary Energy Use *(TBtu/year)*	**2006**	**2012**	**2015**	**2020**	**Avg. Annual Growth Rate 2006-2020**	**Change from Ref @ 2020**
Aviation Fuel	737	781	799	831	0.9%	-0.6%
Biomass	681	622	653	698	0.2%	-4.0%
Coal	1,455	1,213	1,114	1,160	-1.6%	-20.7%
Diesel	1,673	1,656	1,683	1,692	0.1%	-4.4%
Ethanol	93	197	313	472	12.3%	-4.5%
Landfill Gases/Waste	34	35	35	35	0.1%	0.0%
LPG	668	595	584	526	-1.7%	-4.4%
Motor Gasoline	4,166	3,983	3,621	2,981	-2.4%	-7.3%
Natural Gas	5,244	4,496	4,484	4,343	-1.3%	-10.1%
Nuclear	1,617	1,625	1,517	1,552	-0.3%	-7.5%
Oil, Unspecified	1,545	1,417	1,428	1,474	-0.3%	0.4%
Renewables	2,026	2,193	2,300	2,430	1.3%	2.3%
Total	**19,939**	**18,813**	**18,531**	**18,193**	**-0.7%**	**-6.4%**

Table 19: Main Policy Case Electric Sector Results

Generation Capacity *(GW)*	**2006**	**2012**	**2015**	**2020**	**Avg. Annual Growth Rate 2006-2020**	**Change from Ref @ 2020**
Gas/Oil	71	88	92	100	2.5%	15.7%
Coal	22	21	17	17	-1.7%	-28.7%
Nuclear	24	24	24	24	0.0%	0.0%
Hydro	109	113	116	117	0.5%	2.1%
Biomass	3	3	4	5	4.2%	8.2%
Wind	4	15	22	29	14.9%	15.3%
Other Renewable	3	3	3	3	1.2%	-2.9%
Total	**236**	**266**	**279**	**295**	**1.6%**	**4.7%**
Generation Output *(TWh/year)*	**2006**	**2012**	**2015**	**2020**	**Avg. Annual Growth Rate 2006-2020**	**Change from Ref @ 2020**
Gas/Oil	153	102	102	107	-2.5%	-16.8%
Coal	116	96	86	90	-1.8%	-22.4%
Nuclear	155	156	146	149	-0.3%	-7.3%
Hydro	504	527	545	564	0.8%	2.5%
Biomass	15	17	21	25	3.8%	1.0%
Wind	9	36	55	73	16.2%	14.1%
Other Renewable	14	15	15	15	0.8%	-0.2%
Total	**966**	**949**	**970**	**1,024**	**0.4%**	**-3.4%**
Sales *(TWh/year)*	**2006**	**2012**	**2015**	**2020**	**Avg. Annual Growth Rate 2006-2020**	**Change from Ref @ 2020**
Residential	314	311	318	328	0.3%	-6.3%
Commercial	333	325	329	347	0.3%	-6.3%
Industrial	309	284	288	308	0.0%	-5.3%
Transportation	6	8	8	7	1.3%	-6.5%
Street/Misc	16	16	16	16	0.0%	0.0%
Resale	-	-	-	-	#N/A	#N/A
Total	**978**	**945**	**959**	**1,007**	**0.2%**	**-5.9%**
Generating Utility Costs (M$/Year)	**2006**	**2012**	**2015**	**2020**	**Avg. Annual Growth Rate 2006-2020**	**Change from Ref @ 2020**
Annualized Investments	6,595	12,466	11,312	9,089	2.3%	39.8%
Fuel Expenditures	20,583	17,544	18,652	23,520	1.0%	-20.7%
Operation & Maintenance	5,945	6,558	6,938	7,358	1.5%	3.5%
Total	**33,124**	**36,568**	**36,902**	**39,967**	**1.4%**	**-7.7%**

Table 20: Main Policy Case Transportation Sector Results

Distance Travelled	2006	2012	2015	2020	Avg. Annual Growth Rate 2006-2020	Change from Ref @ 2020
Passenger (billions of vehicle miles traveled)	690.3	742.6	797.6	845.2	1.5%	-2.3%
Freight (billions of vehicle miles traveled)	102.6	105.1	110.4	116.9	0.9%	-0.8%
Passenger Miles/Person	7.9	7.9	8.0	8.0	0.1%	-2.3%

Average Vehicle Efficiency *(miles/gallon)*	2006	2012	2015	2020	Avg. Annual Growth Rate 2006-2020	Change from Ref @ 2020
Light Gasoline	23.2	25.6	28.8	35.9	3.2%	3.3%
Medium Gasoline	23.2	25.6	28.7	35.8	3.2%	3.3%
Heavy Gasoline	16.9	18.0	19.5	24.3	2.6%	10.0%
Heavy Diesel	16.9	18.0	19.5	24.2	2.6%	10.0%
Fleet Average (In-Use Vehicles)	20.9	23.0	25.8	32.5	3.2%	5.8%

Marginal Vehicle Efficiency *(miles/gallon)*	2006	2012	2015	2020	Avg. Annual Growth Rate 2006-2020	Change from Ref @ 2020
Light Gasoline	24.2	33.4	41.9	52.3	5.7%	16.3%
Medium Gasoline	24.2	33.4	41.9	52.3	5.7%	16.3%
Heavy Gasoline	17.3	20.4	23.4	33.1	4.7%	34.9%
Heavy Diesel	17.3	20.4	23.4	32.9	4.7%	34.7%
Fleet Average (In-Use Vehicles)	21.2	27.8	33.4	43.7	5.3%	22.8%

Average Vehicle Market Share *(Percent)*	2006	2012	2015	2020	Avg. Annual Growth Rate 2006-2020	Change from Ref @ 2020
Light Gasoline	36.8	36.5	36.7	37.1	0.0%	-0.2%
Medium Gasoline	34.1	34.2	34.6	35.0	0.2%	-0.2%
Heavy Gasoline	29.0	29.3	28.7	27.9	-0.3%	0.6%

Marginal Vehicle Market Share *(Percent)*	2006	2012	2015	2020	Avg. Annual Growth Rate 2006-2020	Change from Ref @ 2020
Light Gasoline	36.7	36.5	38.1	37.7	0.2%	-1.3%
Medium Gasoline	33.8	34.3	36.1	35.7	0.4%	-1.3%
Heavy Gasoline	29.4	29.2	25.8	26.6	-0.7%	3.7%

Table 21: Main Policy Case Fuel Prices (2007 $/mmBtu)

Sector	2006	2012	2015	2020	Avg. Annual Growth Rate 2006-2020	Change from Ref @ 2020
Residential						
Res Electricity Prices	27.1	26.9	28.3	28.7	0.4%	5.6%
Res Natural Gas Prices	10.3	11.6	12.1	15.1	2.8%	17.4%
Res Oil Prices	21.1	25.7	28.4	31.2	2.8%	6.3%
Res LPG Prices	22.0	26.7	29.4	31.9	2.7%	5.1%
Commercial						
Com Electricity Prices	26.4	25.7	27.0	27.3	0.2%	6.0%
Com Natural Gas Prices	9.0	10.1	10.5	13.4	2.9%	19.3%
Com Oil Prices	19.6	24.3	27.0	30.1	3.1%	7.5%
Com LPG Prices	20.4	25.0	27.7	30.2	2.8%	5.2%
Industrial						
Ind Electricity Prices	16.4	15.9	16.7	16.6	0.1%	5.5%
Ind Natural Gas Prices	7.9	9.3	10.8	11.8	2.9%	14.8%
Ind Coal Prices	2.0	2.2	3.4	3.8	4.8%	81.5%
Ind Oil Prices	14.7	19.2	23.3	25.0	3.8%	10.7%
Ind LPG Prices	20.1	24.7	28.7	30.2	3.0%	6.4%
Transportation						
Gasoline Prices	23.0	27.6	30.3	33.8	2.8%	7.5%
Diesel Prices	22.3	26.8	29.5	32.8	2.8%	7.4%

Table 22: Main Policy Case Fuel Expenditures (2007 $billion/yr)

Sector	2006	2012	2015	2020	Avg. Annual Growth Rate 2006-2020	Change from Ref @ 2020
Residential	44.9	46.8	50.5	53.5	1.3%	-2.9%
Commercial	41.7	41.4	43.9	46.0	0.7%	-1.5%
Energy Intensive Ind.*	42.2	43.5	46.5	46.7	0.7%	-3.1%
Paper	5.7	5.1	5.1	5.0	-0.9%	-5.6%
Chemicals	5.9	6.3	6.8	7.3	1.6%	-5.0%
Petroleum	16.2	17.3	18.9	18.4	0.9%	-1.4%
Nonmetallic Minerals	3.4	3.4	3.7	3.8	0.9%	-2.3%
Primary Metals	6.6	6.6	7.2	7.8	1.2%	0.3%
Mining Except Oil/Gas	1.1	1.4	1.5	1.5	2.2%	-21.9%
Oil & Gas Extraction	3.3	3.4	3.3	2.9	-1.0%	-2.5%
Other Industry	18.8	20.6	23.2	24.8	2.0%	0.0%
Passenger Transportation	100.1	121.4	126.5	115.1	1.0%	-6.5%
Freight Transportation	39.5	47.5	54.0	58.1	2.8%	-1.7%
Agriculture	4.2	4.1	4.1	3.9	-0.5%	-14.0%
Waste & Wastewater	-	-	-	-	#N/A	#N/A
Total	**291.5**	**325.2**	**348.8**	**348.1**	**1.3%**	**-3.7%**

* Energy Intensive Industry is a subtotal of the seven energy-intensive sectors listed beneath it.

Table 23: Main Policy Case Annualized Costs

Annualized Total Costs (2007 $billion/yr)				
Sector	**2006**	**2012**	**2015**	**2020**
Residential	-	0.0	1.4	3.3
Commercial	-	(0.2)	0.7	1.0
Energy Intensive Industry*	-	(0.2)	(0.3)	(1.4)
Paper	-	(0.1)	(0.2)	(0.5)
Chemicals	-	(0.1)	(0.2)	(0.5)
Petroleum	-	0.1	0.4	0.2
Nonmetallic Minerals	-	(0.0)	(0.1)	(0.2)
Primary Metals	-	(0.0)	0.0	0.0
Mining Except Oil & Gas	-	(0.1)	(0.2)	(0.5)
Oil and Gas Extraction	-	(0.0)	(0.1)	0.0
Other Industry	-	0.0	0.4	0.3
Passenger Transportation	-	(6.4)	(9.8)	(12.1)
Freight Transportation	-	(0.0)	0.0	1.5
Agriculture	-	(0.1)	(0.4)	(0.7)
Sub-Total	**-**	**(6.9)**	**(8.3)**	**(9.4)**
Program Costs	-	0.1	0.3	0.6
Power Sector Allowance Value (subtract from sub-total)	-	(3.3)	(3.9)	(5.8)
Total	**-**	**(10.1)**	**(11.9)**	**(14.6)**

* Energy Intensive Industry is a subtotal of the seven energy-intensive sectors listed beneath it.

Western Climate Initiative

Guidance for Developing
WCI Partner Jurisdiction Allowance Budgets

July 8, 2010

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1 Purpose And Summary

The purpose of this document is to provide recommended guidance to WCI Partner jurisdictions for calculating, establishing, and reviewing annual allowance budgets, the sum of which is the regional cap.[1] The *Design Recommendations for the WCI regional Cap-and-Trade Program* describe conceptually how these budgets should be developed.[2] Recognizing, however, that further technical analysis and regional coordination would be needed to develop the budgets properly and consistently across jurisdictions, the *WCI 2009-10 Work Plan* established the Cap Setting and Allowance Distribution (CSAD) Committee and charged the Committee with, among other things, proposing a methodology and/or guidelines for establishing and periodically reviewing Partner allowance budgets.[3]

The WCI Partner jurisdictions believe there is great value in developing a budget-setting process in advance of when budgets must be established and with public knowledge of how the process will be conducted. For this reason, the CSAD Committee released the draft of this guidance well ahead of when allowance budgets must be established, recognizing that changes to the method or process described within this guidance may be necessary in response to federal developments, state and provincial implementation schedules, availability and results of mandatory reporting data, and updated emission inventories and forecasts. While these factors will continue to influence the budget setting process, this document incorporates improvements identified to date by WCI stakeholders and Partner jurisdictions.[4]

The objectives of this guidance are to:

- Describe the responsibilities of WCI Partner jurisdictions and the CSAD Committee in the process of developing allowance budgets;
- Promote consistency across WCI Partner jurisdictions in establishing allowance budgets;
- Provide transparency to the budget-setting process such that WCI Partner jurisdictions and the public can be confident that budgets were determined fairly and using the best available data; and
- Establish a timeframe for the budget-setting process to work in concert with the development of jurisdictional regulations and the emergence of an allowance market.

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[1] In British Columbia, the emissions from transportation and residential, commercial, and industrial fuels will be covered by a carbon tax in lieu of a cap. The carbon tax will be integrated with the cap-and-trade program such that reductions incented by the tax, in combination with the cap on industrial sources, will achieve BC's GHG reduction goal.

[2] See http://www.westernclimateinitiative.org/the-wci-cap-and-trade-program/design-recommendations

[3] See http://www.westernclimateinitiative.org/component/remository/general/workplans/, CSAD Tasks 2.2 – 2.4.

[4] Written comments received from WCI stakeholders are posted at http://www.westernclimateinitiative.org/public-comments/document/15.

The guidance is organized into three major sections, as follows:

Section 1

- Summarizes the recommended major activities and outcomes in developing and reviewing allowance budgets (Table 1);
- Recommends how preliminary budgets should be calculated (Figure 1); and
- Provides a hypothetical illustration of a WCI Partner jurisdiction allowance budget (Figure 2).

Section 2

- Provides recommendations on how each WCI Partner jurisdiction should calculate preliminary allowance budgets.

Section 3

- Recommends a process to establish allowance budgets from the preliminary budgets;
- Recommends a process to finalize Partner budgets prior to the start each compliance period; and
- Recommends a process to establish budgets for WCI Partner jurisdictions joining the cap-and-trade program after 2012.

Section 4

- Summarizes the role of early reduction allowances (ERAs).

The guidance recognizes the major factors in, and recommends the procedures for, developing a Partner jurisdiction's allowance budgets. Although developed in a regionally-coordinated manner through these guidelines, each Partner jurisdiction will determine and adopt its own budget. Each Partner jurisdiction will also determine how allowances within its budget will be distributed (e.g., to address competitiveness and leakage issues). The guidance does not seek to resolve all outstanding technical issues or policy decisions likely to have an effect on a jurisdiction's allowance budgets, such as the best estimate of capped-source emissions in 2012 and 2015, but identifies where such data and policy decisions would be incorporated into the calculation of allowance budgets and provides a roadmap for coordinating regional efforts over the course of the program.

Finally, there is a role for those Partner jurisdictions implementing the WCI's cap-and-trade program in the process of developing, reviewing, and finalizing allowance budgets. Since the process would extend over several years, it is possible this role may be filled by the CSAD Committee or another regional committee/forum (e.g., a regional administrative organization).

Table 1. Summary Of Budget Development And Review Process.

	Activity	Completion	Outcome*	Purpose
Section 2	• CSAD contractor develops regionally-consistent forecasts of emissions from covered sources.	Q2 2010	Emission forecasts	Support determination of a best estimate of emissions from covered sources the year they enter program.
	• Each Partner calculates a preliminary allowance budget. (See Figure 1.)	Q3 2010	Preliminary budgets	Form a consistent starting point to develop budgets that meet Partner and regional goals.
Section 3.1	• Partners provide preliminary budgets and supporting information to CSAD. • CSAD conducts a first review of budgets/info for consistency. • Partners may revise budgets after considering CSAD review.	Q3 2010	Established budgets	Basis for developing jurisdictional rules. Provide early market signal. Support any pre-2012 auctioning.
	• CSAD conducts a second review of budgets/info for consistency. • Partner jurisdictions establish budgets, including any potential adjustments to address electricity generated in one Partner jurisdiction but consumed in another.	Q4 2010		
Section 3.2	• Partners inform CSAD of any changes to established budgets. • CSAD reviews any changes and emissions reporting data. • Partner jurisdictions finalize budgets.	Q4 2011	Final budgets	Account for final program rules and available emissions and market data. Increase allowance market certainty, enable full distribution of allowances.
Section 3.3	• Similar to 2011 process, but include assessment of the program's progress.	Q3 2014	Revised final budgets	Account for new data, program changes, and program performance.
	• Same as 2014 process, but incorrect or inaccurate emissions/forecast data not expected to be a factor by this time.	Q3 2017	Revised final budgets	Account for new data, program changes, and program performance.

* Each outcome will be made publicly available.

Figure 1. Calculation Of A Preliminary Allowance Budget.

2012 = 2012 emissions forecast for Phase I sources (including emissions associated with electricity imports), determined with CSAD contract support to account for:

- Population growth*
- Economic growth*
- Mandatory emissions reductions (including those from complementary policies)*

\+ 2012 forecast adjustments, determined by Partner jurisdictions to account for:

- Voluntary emissions reductions (including those from complementary policies)*
- Shut-down sources
- New sources

"Best Estimate"

2013 = 2012 preliminary budget - ROD_1

2014 = 2013 preliminary budget - ROD_1

2015 = 2014 preliminary budget - ROD_1 + 2015 best estimate of Phase II sources

2016 = 2015 preliminary budget - ROD_2

2017 = 2016 preliminary budget - ROD_2

2018 = 2017 preliminary budget - ROD_2

2019 = 2018 preliminary budget - ROD_2

2020 = 2019 preliminary budget - ROD_2

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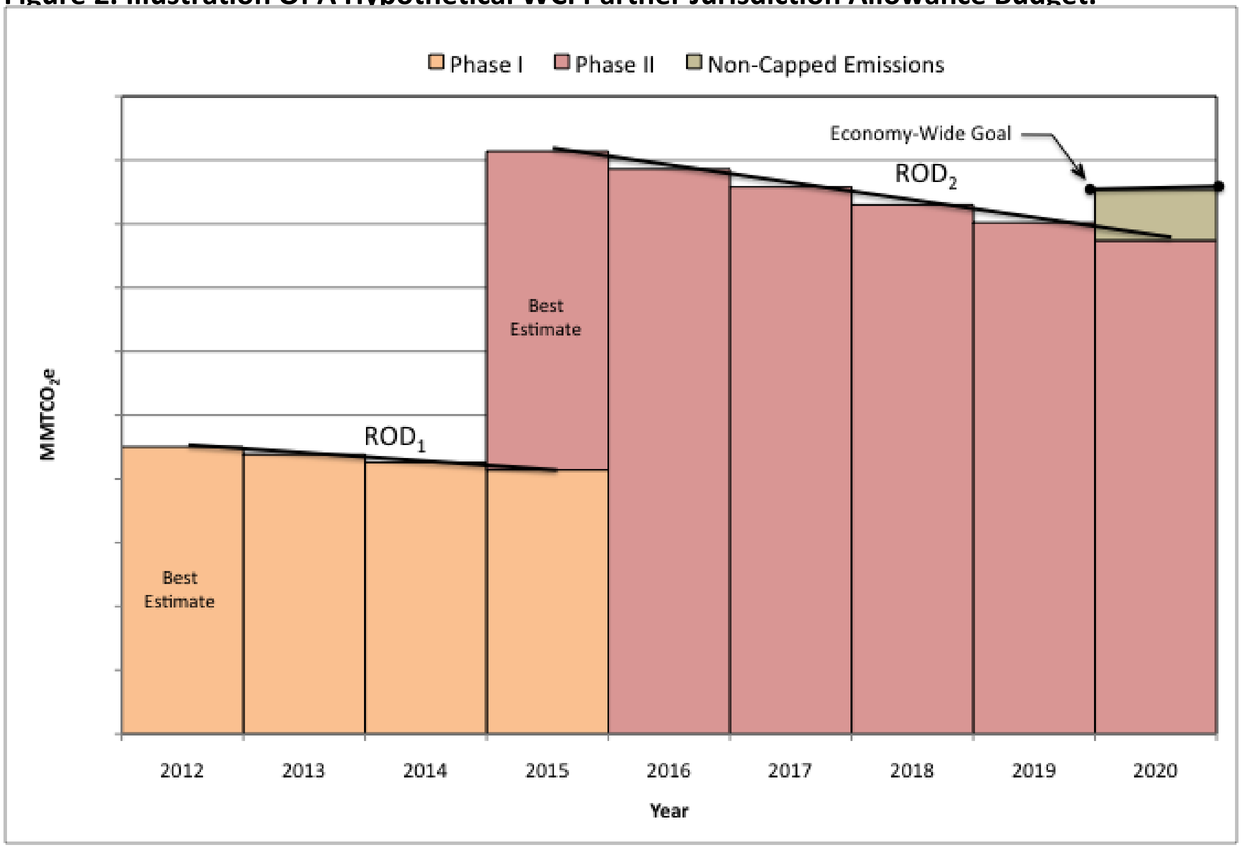
* These factors are also used to determine the 2015 best estimate for Phase II sources.

ROD_1 = Rate of decline (i.e., annual decline in allowance budgets) during Phase I, expressed in $MMTCO_2e$

ROD_2 = Rate of decline during Phase II

Figure 2. Illustration Of A Hypothetical WCI Partner Jurisdiction Allowance Budget.



2 Methodology For Calculating Preliminary Allowance Budgets

2.1 Preliminary Allowance Budget For 2012

1. The Partner jurisdiction will calculate its 2012 preliminary allowance budget as the best estimate of expected emissions for sources covered in the cap-and-trade program in the Partner's jurisdiction in 2012, accounting for population growth, economic growth (including new and shut-down sources), and voluntary and mandatory emission reductions through 2012. The best estimate will be an outcome of each Partner's application of the forecast methods recommended by the CSAD Committee and is shown as the first colored bar in Figure 2. Alternatively, the Partner jurisdiction may base its best estimate on its own emissions forecast if it considers the method to be more accurate for its jurisdiction than the regional method recommended by the Committee. For the purpose of determining the best estimate of 2012 emissions:

    a. New sources are sources which are not included in the Partner jurisdiction's emission inventory but are expected to be emitting covered GHGs prior to January 1, 2013. The Partner jurisdiction will estimate, using any methods developed by the Committee to promote consistency, covered emissions from new sources and include these emissions in its 2012 best estimate.

    b. Shut-down sources are sources which are included in the Partner jurisdiction's emission inventory but are expected to be permanently shut down prior to January 1, 2012. The Partner jurisdiction will remove covered emissions from shut-down sources from its 2012 best estimate.

    c. Voluntary emission reductions are the emissions avoided in 2012 as a result of consumers or sources taking action which reduces GHG emissions and is not required by law or regulation. Such action must occur prior to 2012 and should have permanent emission benefits (e.g., persisting until 2020).[5]

[5] Actions first taken in 2012 can not necessarily be considered voluntary when Phase I producers are subject to the cap and when consumers face the cap's consequent price increase.

2.2 Preliminary Allowance Budgets For 2013 And 2014

1. The Partner jurisdiction will determine an annual decline of allowance budgets for the first phase of the cap-and-trade program (ROD_1). ROD_1 shall be expressed in units of million metric tons of CO_2 equivalents ($MMTCO_2e$) and shall be greater than zero.[6]

2. The Partner jurisdiction will calculate its 2013 preliminary allowance budget as the 2012 preliminary allowance budget minus ROD_1.

3. The Partner jurisdiction will calculate its 2014 preliminary allowance budget as the 2013 preliminary allowance budget minus ROD_1.

2.3 Preliminary Allowance Budget For 2015

1. The Partner jurisdiction will calculate its 2015 preliminary allowance budget as the sum of the 2014 preliminary allowance budget minus ROD_1 plus the 2015 best estimate of expected emissions for sources first covered in the cap-and-trade program in the Partner's jurisdiction in 2015, accounting for population growth, economic growth, and voluntary and mandatory emission reductions. The best estimate of 2015 emissions will be an outcome of each Partner's application of the forecast methods recommended by the CSAD Committee and is shown as the top half of the 2015 bar in Figure 2. Alternatively, the Partner jurisdiction may base its best estimate on its own emissions forecast if it considers the method to be more accurate for its jurisdiction than the regional method recommended by the Committee. For the purpose of determining the best estimate of 2015 emissions:

    a. Voluntary emission reductions are the emissions avoided in 2015 as a result of consumers or sources taking action which reduces GHG emissions and is not required by law or regulation. Such action must occur prior to 2015 and should have permanent emission benefits (e.g., persisting until 2020).

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[6] The purpose of ROD_1 (and ROD_2 below) is to ensure, as stated in the Design Recommendations, that the trajectory for each WCI Partner jurisdiction's annual allowance budget for covered sectors will be a straight line from the year of initial coverage to 2020. This is the only way to ensure for planning purposes that the 2020 reduction goal is met. However, the actual annual trajectories of jurisdictional emissions and allowance distribution to specific sources will not necessarily follow a straight line reduction trajectory. For instance, any given Partner jurisdiction's emission reduction trajectory will depend on regional trading and the use of offsets by covered sources. In addition, the three-year compliance periods will allow covered sources to reduce emissions at various rates across the three-year period.

2.4 Preliminary Allowance Budgets For 2016 Through 2020

1. The Partner jurisdiction will determine a rate of decline for the second phase of the cap-and-trade program (ROD_2). ROD_2 shall be expressed in units of $MMTCO_2e$ per year and shall be greater than zero. ROD_2, in conjunction with any reductions in non-covered emissions in the Partner's jurisdiction, shall be sufficient to achieve the Partner jurisdiction's 2020 economy-wide goal.[7]

2. The Partner jurisdiction will calculate its preliminary allowance budgets for 2016 through 2020 by subtracting its ROD_2 from the prior year's preliminary allowance budget, starting with 2016 and continuing to 2020.

2.5 Preliminary Allowance Budgets For Partner Jurisdictions Whose Caps Begin After 2012

1. A Partner jurisdiction whose cap begins after 2012 will determine its preliminary annual allowance budget as described in Sections 2.1 through 2.4, with the exception that the Partner's first-year budget may be based on the best estimate of emissions for that year.

3 Process For Reviewing, Finalizing, And Adjusting Allowance Budgets

3.1 Establishing Annual Budgets In 2010

The purpose of this process is to compile and harmonize preliminary allowance budgets as much as possible for Partner consideration, revision, and agreement. The outcome of this process will be "established budgets" for each Partner jurisdiction in the summer of 2010.

The established budgets are intended to (a) provide a basis for each Partner jurisdiction in developing its regulations implementing the regional cap-and-trade program and (b) provide an early indication of the supply of allowances in the regional marketplace. Although established budgets may be revised when finalized prior to the start of the first compliance period (see Section 3.2), the limited and specific conditions under which such revisions would occur should preserve the value of established budgets as an early market signal.

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[7] ROD_2 may equal ROD_1 if the sectors capped in the second phase of the program are the same as those in the first.

1. Using a template common to all the WCI Partner jurisdictions, each Partner jurisdiction will provide the following to the CSAD Committee to facilitate the collection and comparison of the Partner data:

    a. A preliminary allowance budget for each year in the period 2012-2020.
    b. A ROD for each phase of the cap-and-trade program.
    c. An explanation of how the RODs were determined.
    d. A presumptive ROD_1, determined as the product of:
        i. the ROD resulting from a straight-line reduction from the 2012 best estimate of Phase I and Phase II source emissions to the 2020 preliminary budget, and
        ii. the ratio of the best estimate of Phase I source emissions to the best estimate of Phase I and II source emissions in 2012.
    e. A best estimate of economy-wide emissions in 2005 and 2020, assuming emissions from capped sources in 2020 are equivalent to the preliminary budget for 2020.[8]

2. The Committee will compile and review the jurisdictional preliminary budgets with respect to maintaining a regionally-consistent approach to achieving the regional goal.

3. After considering the Committee's review, the Partner jurisdiction may revise its preliminary budget.

4. The Committee will re-compile and review the jurisdictional preliminary budgets, including any budgets revised per the paragraph above, with respect to maintaining a regionally-consistent approach to achieving the regional goal.

5. After considering the Committee's review, the Partner jurisdiction will collaborate with other Partner jurisdictions in developing established budgets for each Partner jurisdiction. The established budget should include any potential adjustments which are part of an equitable solution to electricity generated in one Partner jurisdiction but consumed in another.

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[8] In British Columbia, the emissions from transportation and residential, commercial, and industrial fuels will be covered by a carbon tax in lieu of a cap. The carbon tax will be integrated with the cap-and-trade program, and the information provided by BC to the Committee will demonstrate how reductions incented by the tax, in combination with the cap on industrial sources, will achieve its GHG reduction goal.

3.2 Finalizing Annual Budgets Prior To The Start Of The First Compliance Period

The purpose of this process is to adjust, where necessary and according to Section 7.4 of the *Design Recommendations*, the established budgets from 2010. The outcome of this process will be a "final budget" for each Partner jurisdiction in autumn of 2011.[9]

1. The Partner jurisdiction will notify the Committee of any potential changes to its established budgets resulting from each of the following conditions:

    a. Changes in jurisdictions participating in the cap-and-trade program.
    b. Changes in scope or threshold of the WCI regional program design.
    c. Differences in scope or threshold between the jurisdiction's final regulations and the sources included in the 2012 and 2015 best estimates.
    d. Incorrect or inaccurate data that were used to determine the established budgets of 2010, including emissions from new and permanently shut down sources not identified in Section 2.1.
    e. Emissions data that were not available in 2010, such as those that may become available as a result of new mandatory reporting rules.

2. The Committee will review proposed changes to the established budgets and any supporting information with respect to maintaining a regionally-consistent approach to achieving the regional goal. The review will include collecting mandatory reporting data for capped sources in each Partner jurisdiction and comparing them to the 2012 and 2015 best estimates of Phase I and Phase II sources and Partner allowance budgets. Mandatory reporting data collected in 2011 will be especially important for finalizing budgets where the emissions data available in 2010 are uncertain or unavailable.

3. After considering the Committee's review, the Partner jurisdiction will collaborate with other Partner jurisdictions in finalizing budgets for each Partner jurisdiction.

4. The Partner representative will seek the appropriate approvals from its respective jurisdictional authorities for the final budgets discussed with other Partners.

[9] This date would allow time for submittal and review of the mandatory reporting data collected according to the WCI essential requirements, which would first be submitted to the Partner jurisdictions by April 1, 2011 and verified by September 1, 2011.

3.3 Adjusting Annual Budgets Prior To The Start Of The Second And Third Compliance Periods

The purpose of this process is to adjust, where necessary and according to Section 7.4 of the *Design Recommendations*, the budgets for Phase II of the program finalized in 2011. The potential outcome of this process would be a "revised final budget" for one or more Partner jurisdiction in the summers of 2014 and 2017.[10]

1. The Partner jurisdiction will notify the Committee of any potential adjustments to its final budgets resulting from each of the following conditions:

    a. Changes in jurisdictions participating in the cap-and-trade program.
    b. Changes in scope or threshold of the WCI regional program design.
    c. Changes in scope or threshold of the jurisdiction's regulations.
    d. Incorrect or inaccurate data that were used to determine the final budgets of 2011. This condition shall not apply after the start of the second compliance period.[11]

2. The Committee will review any proposed adjustments to the final budgets and any supporting information with respect to maintaining a regionally-consistent approach to achieving the regional goal. The review will include mandatory reporting data for capped sources in each Partner jurisdiction and potentially other data to assess the progress of the regional cap-and-trade program.

3. After considering the Committee's review, the Partner jurisdiction will collaborate with other Partner jurisdictions in any budget adjustments.

4. The Partner representative will seek the appropriate approvals from its respective jurisdictional authorities for any budget adjustments discussed with other Partners.

[10] Adjustments for Phase II budgets can occur earlier in the year than adjustments for Phase I budgets because verified data may be submitted earlier than September 1 for reporting years 2012 and later and because more mandatory data will be available in 2014 and 2017 than in 2011.

[11] By the time of the second compliance period, any inaccuracies should be revealed by the mandatory reporting data .

3.4 Establishing And Adjusting Budgets When A Jurisdiction Enters The Cap-And-Trade Program After 2012

1. Date Of Entry. A Partner jurisdiction may enter the regional cap-and-trade program on January 1 of any year agreed to by the entering jurisdiction and jurisdictions currently in the program.

2. The annual allowance budgets for the entering jurisdiction will be determined as follows:

   a. The entering jurisdiction will calculate preliminary annual allowance budgets as described in Section 2.5.
   b. The entering jurisdiction will provide to the other Partner jurisdictions at least six months prior to the date of entry all the applicable information described in Section 3.1.1.
   c. The Partner jurisdictions will collaborate on the development of the entering jurisdiction's budgets, particularly with respect to maintaining a regionally-consistent approach to achieving the regional goal.
   d. The Partner representative for the entering jurisdiction will seek the appropriate approvals from its respective jurisdictional authorities to adopt the budgets discussed with other Partners.

3. Any jurisdiction currently in the cap-and-trade program that has included allowances within its budgets to account for emissions associated with electricity imports from the entering jurisdiction will collaborate, bilaterally, with the entering jurisdiction on an equitable solution to avoid double allocating allowances for the same set of emissions.

4 Early Reduction Allowances

Guidelines for issuing ERAs are provided in separate documentation. The issuance of ERAs does not affect the budgets developed above in Sections 2 and 3.

Western Climate Initiative

Status Update on Market Oversight Recommendations

July 22, 2010

The WCI Partner jurisdictions are committed to strong market oversight and vigilant market monitoring. This update gives a short description of the status of WCI's market oversight recommendations.

The Partner jurisdictions have engaged stakeholders and employed expert advisers to identify and evaluate market oversight options. The WCI Partner jurisdictions released three reports: a white paper (November 2009); draft recommendations (April 2010); and a report on holdings limits (May 2010). The Partner jurisdictions solicited stakeholder feedback on each of these products, and have incorporated the feedback into their decisions. Through this process, the Partner jurisdictions identified twelve policy decisions to make for market oversight. The final recommendation or status of each of these twelve is described below:

1. Whether to treat compliance instrument derivatives as commodity derivatives for market oversight purposes.

A paramount question for WCI jurisdictions is whether oversight of markets for compliance instruments should primarily be similar to or different from oversight of other markets; and if the former, which markets to use as models. In other environmental cap-and-trade programs, compliance instruments have been considered to be sufficiently like commodities to be regulated by the same agencies and under the same framework. Following this model would allow the jurisdictions to rapidly bring existing rules and resources to bear on carbon markets. The Partners recommend that compliance instrument derivatives should be treated as commodity derivatives for market oversight purposes.

The Partners are committed to working with commodity derivatives regulators to ensure that oversight of compliance instrument markets is robust and fully integrated.

2. Whether to require the reporting of over-the-counter derivative contracts to a central repository.

Over-the-counter (OTC) derivatives markets may be comparable in size to or larger than exchange-traded derivatives markets, but in contrast to exchange contracts, OTC contracts are not typically reported to regulators. The Partners have considered a requirement that OTC derivatives based on compliance instruments be reported to a central repository. Financial reform proposals have included various approaches to reporting and regulation of OTC derivative contracts. Whether the Partner jurisdictions would recommend reporting of compliance instrument OTC derivatives, which would diverge from current framework for commodities derivatives regulation, may depend on the form and enactment of changes to that framework. Consequently, the Partners will closely watch this critical issue in monitoring the progress of financial reform.

3. Whether allowances and offsets should be treated differently.

Allowances and offset certificates are created by different processes and, because of the limit on the number of offset certificates that may be used for compliance, will be used differently. Consequently, the Partners have considered whether these differences imply a difference in the oversight of the respective markets. For the eleven other policy decisions identified in this section, the Partners recommend that allowances and offset certificates be treated identically.

4. Establishing a jurisdictional relationship with market participants.

The Partners recommend that a market participant's having an account in the tracking system or ownership interest in a compliance instrument can be used to establish a jurisdictional relationship with that participant. This does not exclude the use of other ways, e.g., physical presence, to establish a jurisdictional relationship.

5. Whether to limit market participation to compliance entities.

Limiting who could participate in cash and derivatives markets would be practically challenging and would reduce liquidity. It is doubtful that such limits would have any benefits in reducing the risks of manipulation. The Partners recommend that market participation should not be limited to compliance entities.

6. Whether to require registration of intermediaries as market professionals.

In securities and derivatives markets, many types of intermediaries (for example, brokers and advisers) are required to register as market professionals, which identifies them to regulators, screens them for fitness, and credentials them for other market participants, to ensure proficiency, financial viability, and good business conduct. The Partners recommend that intermediaries be required to register as market professionals. The jurisdictions may develop a list of acceptable registrations.

7. Whether to limit the number of compliance instruments an entity could hold.

An entity that controls a large fraction of the available instruments could have the ability to move prices through its behavior. Even the perception that an entity could exercise "market power" in this way can have an impact on other market participants. One approach to limiting this type of market power is to limit the number of compliance instruments one entity can hold. The Partners commissioned and released a consultant's report on such "holdings limits" and will continue to work to develop an appropriate recommendation that incorporates stakeholder input.

8. Whether to allow over-the-counter cash market transactions.

Cash transactions (for immediate delivery of allowances or offset certificates) could take place on a variety of venues with different characteristics. Some venues offer more transparency to the public and to market participants than others. Limiting the type of venues on which cash transactions could occur would enhance transparency, but if participants would prefer other venues, could lead to fewer trades overall. The Partner jurisdictions will not restrict market participants from using over-the-counter trades. Recognizing that venues like exchanges may enhance public price discovery and increase transparency, the Partner jurisdictions will work to encourage and facilitate exchange trading through the design of the WCI program and tracking system.

9. Whether to require the reporting of beneficial ownership.

"Beneficial ownership" is when one person holds property or another interest on behalf or for the benefit of another person. Knowing the actual identity of the beneficial owner is important for determining concentration of ownership in order to effectively monitor the markets. The Partners recommend that account holders be required to report the beneficial owners of each account, and their respective proportionate interest in the account. Account holders and those with ownership interest in compliance instruments must also disclose corporate affiliations (e.g., holding companies) when affiliates have compliance accounts or ownership interest in compliance instruments.

10. What information should be required for compliance instrument transfer.

To monitor the market and allow the tracking system to be a record of ownership, the Partners recommend requiring the following information be submitted to the tracking system to transfer compliance instruments between accounts:

- The identifying number of the account of origin;
- The name of the account representative authorizing the transfer from the account of origin;
- The identifying number of the receiving account;
- The name of the account representative authorizing the transfer to the receiving account;
- The serial numbers of the compliance instruments transferred;
- The price for each type of instrument.

The Partners will consider accommodating exchanges or others that may wish to "net" transactions and provide net reports, and not requiring price information for transfers between corporate affiliates.

11. What account and transfer information should be disclosed to the public.

The Partners are committed to transparency, but recognize that public release of some information can promote rather than inhibit market manipulation. The Partners recommend the following information be made public:

- The names, affiliations, and location (state or province in the US or Canada, or country if outside) of account holders, account authorized representatives, and beneficial owners of compliance instruments;
- The number of compliance instruments in each compliance account, but not each general account;
- The volume and price of transactions, when necessary aggregated to prevent the identification of parties to transactions.

12. How to perform market monitoring.

The Partners are committed to vigilant monitoring of compliance instrument markets, including coordinated efforts across jurisdictions. A description of jurisdiction and agency collaboration on monitoring is being developed.

Western Climate Initiative

Offset System Essential Elements Final Recommendations Paper

July 2010

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1 Executive Summary

This paper is the third paper issued by the WCI Offsets Committee as part of its efforts to offer design recommendations for the WCI offset system to the WCI Partner jurisdictions. This paper describes the final recommendations for the WCI offset definition and essential criteria. As such, it follows up on two previous papers—the first of which was an options paper for the definition and criteria and the second of which offered draft recommendations.

The first paper, entitled *Offset Definition (Task 1.1) and Eligibility Criteria (Task 1.2) White Paper*[1] ("the Criteria White Paper") was released in July 2009 and presented options for defining an offset and the criteria essential to generating an offset within the cap-and-trade program implemented by the WCI Partner jurisdictions. The release of the first paper was followed by a period of gathering stakeholder input through stakeholder conference calls and written comments from stakeholders.[2] The WCI Offsets Committee then prepared the second paper, the *Offset System Essential Elements Draft Recommendations Paper* (the "Criteria Draft Recommendations Paper"), based on the first options paper, stakeholder feedback, and input from WCI Partners. Following the release of that second paper in April 2010, stakeholders provided feedback via two conference calls and through written comments. This final recommendations paper presents final recommendations for the offset definition and essential criteria, based on draft recommendations, consideration of stakeholder feedback received, and further discussion with WCI Partners

A fair number of the final recommendations are unchanged from the draft recommendations or received only minor clarifying revisions. The most significant changes from the draft to final recommendations regard the additionality criterion. For ease of reference, all of the final recommendations in this paper are copied in Table 1.0 below.

[1] Available at this link:
http://www.westernclimateinitiative.org/components/com_publiccomments/documents/WCI-Offset_Definition_and_Criteria_072409.pdf
[2] The stakeholder comments are archived here:
http://www.westernclimateinitiative.org/public-comments/document/7

Table 1.0 Final Recommendations

Section	Criteria	Final Recommendations
3.1	Offset Definition	An offset certificate is a type of compliance instrument that is awarded by the program authority in a participating partner jurisdiction under the Partner jurisdiction's cap-and-trade program to the sponsor of a GHG emissions offset project, subject to all applicable limitations contained in the program design summary and recommendations included in this paper. An offset certificate represents a reduction or removal of one metric ton of carbon dioxide equivalent (tCO_2e). The reduction or removal must meet the recommended essential criteria for reductions and removals to be real, additional, permanent, and verifiable. Reductions and removals must also be clearly owned, adhere to recommended protocols, and result from a project located in a qualifying geographic area.
3.2.1	Offset Ownership	An offset project proponent must have legal ownership of the greenhouse gas emission reduction or removal resulting from the offset project. The offset project proponent will be responsible for all statements and information provided to the WCI Partner Jurisdiction issuing the offset certificate during the creation of the offset certificate and verification of the reduction or removal. The WCI Partners should establish a registry of offset certificates issued and make the registry publicly available.
3.2.2	Use of Approved Protocols	A WCI Partner jurisdiction will issue offset certificates for compliance with its cap-and-trade program only from projects which employ protocols that have been recommended through the WCI protocol review process ("WCI offset protocols").
3.2.3	Geographic Limits	A WCI Partner jurisdiction may issue offset certificates for projects located within its own jurisdiction as well as jurisdictions outside the WCI Partner Jurisdictions within North America. A WCI Partner jurisdiction will accept offset certificates issued by other WCI Partner jurisdictions. As described in section 9.8 of WCI's design document, WCI Partner jurisdictions may also accept offset certificates from outside North America.
4.1	Real	An offset certificate represents a reduction or removal of one metric ton of CO_2e that results from a clearly identified action or decision. A WCI offset project's reduction or removal is quantified using accurate and conservative methodologies that appropriately account for all relevant greenhouse gas sources and sinks and leakage risks. WCI offset projects result in emissions reductions or removals that take place at sources controlled by the project proponent.

Section	Criteria	Final Recommendations
4.2.1	Quantification, Uncertainty, and Accuracy	**Quantification:** WCI Partner jurisdictions shall ensure that net emission reductions or removals are capable of being measured or modeled in a reliable and repeatable manner that includes all relevant sources and sinks. Quantification methodologies for GHG emissions or emission reductions shall: • Be appropriate to the GHG source or sink • Be current at the time of quantification • Consider local conditions, whenever applicable • Account for uncertainty – be calculated in a manner that yields accurate and reproducible results • When uncertainty is above the defined threshold, apply the principle of conservativeness to GHG During quantification procedures, project proponents shall convert each type of GHG to metric tons of CO2e. In addition, WCI offset protocols shall use uniform quantification methods whenever feasible. **Uncertainty and accuracy:** Quantification methodologies and measurement techniques shall set standards for acceptable statistical precision and be based on the best available science. They shall also reduce bias, except for promoting conservative estimates. When uncertainty remains high in quantifying the amount of a greenhouse gas emission reduction or removal, the principle of conservativeness shall be applied. **Principle of conservativeness:** Where uncertainties are above the defined threshold, offset quantification methods should use more conservative quantification parameters, assumptions, and measurement techniques that minimize the risk of overestimating emission reductions and removals credited for a given project. The principle should be employed when significant uncertainties arise to ensure a higher level of confidence that all calculated reductions are real.

Section	Criteria	Final Recommendations
4.2.2	Leakage	To address activity-shifting and market leakage, WCI Partner jurisdictions will require assessments of whether functional equivalence has been maintained within projects and require that WCI offset protocols include methods for leakage assessments. WCI offset protocols will evaluate functional equivalence for each project. WCI offset protocols will also require an assessment of potential leakage associated with each project type. In general, WCI Partner jurisdictions prefer the following methods to review leakage risk: • A quantitative assessment of leakage will be performed whenever possible. • When a quantitative assessment is not feasible, a qualitative risk assessment will determine whether the risk of systematic leakage is significant or not. • WCI offset protocols will include a threshold to identify significant leakage. If leakage is found to be above the threshold, the WCI offset protocol quantification methodology will include a factor to account for leakage.

Section	Criteria	Final Recommendations
5.1	Additional	Offset certificates will be awarded only for the portion of greenhouse gas emission reductions or removals that would not have happened under a baseline scenario. The WCI Partner jurisdictions intend for additionality to be established in a manner that will require offset projects to be evaluated against a baseline that reflects conservative assumptions that are consistent across all WCI Partner jurisdictions. These assumptions will be described in the procedures for setting a baseline in WCI offset protocols. Modeling or other methods of developing the baseline shall use assumptions, methodologies, and values which assure that GHG reductions or removals from a project are not over-estimated (consistent with the principle of conservativeness in 4.2.1). When possible, the baseline shall be set using a sector-specific or activity-specific performance standard which is set in WCI offset protocols based on a regional assessment of project performance or common practice. WCI Partners intend that all baselines will reflect the most stringent regulatory and legal requirements of any WCI Partner jurisdiction (those requirements leading to the most conservative calculation of emission reductions). When a baseline based on the most stringent regulatory requirement is not practical because of regional differences, the WCI Partners may recommend a protocol using an alternative method. When it is not possible to set a baseline using a performance standard, a project-specific baseline may be used. Then the baseline will be set to reflect all binding agreements, regulatory requirements and legal requirements applicable to the project and also to ensure that the project is beyond business as usual.

Section	Criteria	Final Recommendations
5.2.1	Eligibility Date	Offsets may be awarded only for projects that are initially commenced on or after January 1, 2007, the start of the year in which the original WCI Memorandum of Understanding (MOU) beginning the development of the cap-and-trade program by Partner Jurisdictions was signed. Offset certificates may be awarded for all GHG reductions or removals occurring on or after January 1, 2007. An offset project proponent must apply to register its project with a WCI Partner Jurisdiction within one year of project commencement. Projects that commenced prior to finalization of the applicable WCI offset protocol must apply within one year of that protocol's finalization.
5.2.2	Crediting Period	The crediting period for non-sequestration WCI offset projects will be 10 years. At the end of a crediting period a project proponent may renew a project subject to the current WCI offset protocol for that project type. Renewal of a project at the end of a crediting period will include a reevaluation of a project's additionality and reevaluation of how the reductions are quantified and verified. Thus, the baseline scenario will be reevaluated at each renewal. The crediting period for sequestration projects will be specified by the applicable WCI offset protocol. However, any individual crediting period may not exceed 25 years before a renewal, and the total crediting period including all renewals may not exceed 100 years for sequestration projects. The applicable WCI offset protocol will also lay out the requirements for project renewal. At a minimum, the project must reevaluate quantification and monitoring methods based on the current WCI offset protocol. If possible, projects will also need to reassess project additionality and baselines in order to renew the project.

Section	Criteria	Final Recommendations
6.1	Permanent	With respect to offset project activities, permanence means either that reductions or removals are not reversible or that, if reductions or removals are reversed, the provisions outlined in the remainder of this recommendation must be met. Sequestration projects must be designed so that the net atmospheric effect of their greenhouse gas removal is comparable to the atmospheric effect achieved by non-sequestration projects. The atmospheric effect will be based on the current international standard established by the UNFCCC, which is currently 100 years. This international standard may be updated from time to time, and the WCI Partner jurisdictions will adopt the new international standard if/when it is updated. If an emission reduction is reversed after offset certificates are issued, the project developer must either replace the certificates representing reversed reductions with other compliance units from within the system or return certificates that were issued to the project. The number of certificates required to be replaced or returned will, at a minimum, be the difference between the atmospheric benefit the sequestration project until it was reversed and the total sequestration for which certificates were issued. Applicable approaches to assuring permanence for a project type will be included in the appropriate WCI offset protocol. In conformance with the applicable WCI offset protocols, project proponents shall follow or establish effective (i) monitoring systems, (ii) risk mitigation approaches, and (iii) contingency plans which address how, in the event of a reversal that is the result of proponent intention or negligence, any affected offset certificates will be replaced. The contingency plan shall include specific mechanisms that are exercisable at the time a reversal is identified whether or not the proponent is solvent, exists in its original form, and/or has ownership of or responsibility for the project. WCI Partner jurisdictions will establish mechanisms to address reversals that are not the result of proponent intention or negligence and where proponents' contingency measures prove inadequate.

Section	Criteria	Final Recommendations
7.1	Verifiable	With respect to offset project activities, verifiable means that a GHG reduction or removal, or assertion thereof, is well documented and transparent such that it lends itself to an objective review by a qualified verifier. Verifiers for WCI offsets will be independent third parties who have been accredited to a standard acceptable by the WCI Partner jurisdiction in which the project is registered.
7.2.1	Validation	With regards to WCI offsets, validation is a required review by an accredited independent third party or the WCI Partner jurisdiction to assess the likely result of reductions or sequestration from a proposed project that would use a WCI offset protocol.
7.2.2	Enforceable	Each Partner jurisdiction will, to the extent permissible by law, put in place sufficient compliance/enforcement mechanisms and detail for the jurisdiction to compel compliance with its requirements and with WCI offset protocols.
7.2.3	Material	Material misstatement means that errors, omissions or an aggregation of both in the reported GHG reductions or assertion exceeds a +5% threshold. For a WCI offset, the verifier must be able to state with reasonable assurance the total reported reductions or removals are free of material misstatement.
8.1	Transparency	Partner Jurisdictions' offset systems will provide transparency such that sufficient and appropriate protocol, project and certificate information is disclosed in a timely manner to allow offset system participants and the general public to make decisions with reasonable confidence.
8.2	Co-Benefits	WCI Partners recognize the environmental, social, economic and health benefits that may arise from an offset project and the offset system will focus on those benefits directly related to mitigating climate change. A WCI offset project is required only to result in a greenhouse gas emission reduction or removal.
8.3	Assessment of Environmental or Social Impacts	WCI offset projects must meet all applicable local environmental regulations and be in compliance with all applicable laws in the jurisdiction where the project is located. If environmental or socioeconomic assessments of the proposed project have been done, the project's registration application should reference this work and include a summary of the findings. WCI offset protocols for specific offset project types may require analysis of environmental and socioeconomic impacts beyond what the local jurisdiction would otherwise require and may require additional mitigation of potential negative impacts.

2 Purpose and Background

The purpose of the WCI Offset Committee is to make recommendations to the WCI Partner jurisdictions on the design and operation of the offset system as part of the WCI cap-and-trade program. In particular, this paper includes the Offsets Committee's final recommendations for criteria that reductions must meet in order to demonstrate that reductions from offset projects are sufficiently rigorous to meet compliance obligations within the regional cap-and-trade program. The WCI's September 2008 Design Recommendations document specified that the criteria ensure offsets result in a GHG reduction or removal that is real, additional, permanent, and verifiable.[3] The design of the offsets system must also ensure that the quantification of the GHG reduction or removal is accurate and not double-counted. According to the WCI's design principles, reductions from offsets must also be enforceable by the WCI Partner jurisdictions.

This final recommendations paper is the third and final stage in developing a clear definition of a WCI greenhouse gas (GHG) offset and the detailed eligibility criteria for GHG offset projects used for compliance purposes as identified in the WCI 2009/10 Workplan released in February 2009. On July 24, 2009 the WCI Offsets Committee released the *Offset Definition (Task 1.1) and Eligibility Criteria (Task 1.2) White Paper* ("the Criteria White Paper") describing options for defining a WCI GHG offset and the WCI essential offset criteria (real, additional, verifiable, and permanent), as well as other principles and technical considerations that are important for the offset system. On July 30, 2009 and August 27, 2009, the WCI Offset Committee held stakeholder webinars to discuss the released white paper. Stakeholders also submitted written comments via the WCI website by the August 21, 2009 deadline. On April 12, 2010 the WCI Offsets Committee released the *Draft Recommendations Offset Definition (Task 1.1) and Eligibility Criteria (Task 1.2) White Paper* ("the Criteria Draft Recommendations Paper") providing draft recommendations for defining a WCI offset and the essential offset criteria. On April 22, 2010 and May 5, 2010, the WCI Offset Committee held stakeholder conference calls to discuss the draft recommendations. Stakeholders also submitted written comments via the WCI website by the May 12, 2010 deadline.

The purpose of this final recommendation paper is to establish the final decision by the WCI Partner jurisdictions on the definition of a WCI offset and essential criteria. This paper provides the following for each criterion (or consideration):

- a final recommendation

[3] WCI Design Recommendations for the WCI Regional Cap-and-Trade Program: September 23, 2008; revised March 13, 2009. p. 10 Available at: http://www.westernclimateinitiative.org/ewebeditpro/items/O104F21252.pdf.

- a summary of stakeholder comments received on the draft recommendation
- a discussion of the final criteria recommendation

These final recommendations provide the basis for further work by the WCI Offsets Committee. The *Process Draft Recommendations Paper* will present the requirements for the registration, validation, monitoring, quantification, reporting, verification, certification, and issuance of offsets. Task 3, the review and development of WCI offset protocols has used these recommendations as the basis for the offset protocol evaluation. It will also provide a basis for Task 2's review of offsets and allowances from outside the WCI jurisdictions as they will have to determine the extent to which the criteria and supporting criteria are appropriate to offsets from other systems. For example, this paper includes a recommendation for the appropriate length of crediting periods in the WCI. The recommendation in this paper does not imply that the offsets from another system that uses crediting periods of a different length would be ineligible to meet WCI compliance obligations.

Like in the *Criteria Draft Recommendations Paper*, this paper frequently employs the term "WCI offset" and "WCI offset project." This paper uses those terms to describe an offset certificate issued by a WCI Partner Jurisdiction and the projects which are the basis for offset certificates issued by WCI Partner Jurisdictions.

3 Definition of an Offset

This section offers the final recommendations for the WCI offset definition and three key considerations in how WCI offsets are created which are referenced in the offset definition.

3.1 Offset

As noted in the *Criteria Draft Recommendations Paper*, the biggest consideration for the WCI Offsets Committee was how broad or prescriptive the offset definition should be. The final recommendation text for the offset definition revises the draft recommendation, with the new text intended for clarity only.

3.1.1 Final recommendation

An offset certificate is a type of compliance instrument that is awarded by the program authority in a participating partner jurisdiction under the Partner jurisdiction's cap–and-trade program to the sponsor of a GHG emissions offset project, subject to all applicable limitations contained in the program design summary and recommendations included in this paper An offset certificate represents a reduction or removal of one metric ton of carbon dioxide equivalent (tCO_2e). The reduction or removal must meet the recommended essential criteria for reductions and removals to be real, additional, permanent, and verifiable. Reductions and removals must also be clearly owned, adhere to recommended protocols, and result from a project located in a qualifying geographic area.

3.1.2 Summary of stakeholder input

Stakeholders' comments generally focused on aspects of the offset certificate after issuance, including comments that the definition should specify that offsets certificates once issued are not revocable, that offset certificates are bankable and tradable, and that the definition should be more specific that an emission elsewhere is being offset and that offsets are not property rights. One comment emphasized that "avoided" emissions be included in the definition.

3.1.3 Discussion of final recommendation

The Offsets Committee intended that the definition should be broad and refer to the main criteria while leaving the detail to be described within each criterion. Offsets are described in the Detailed Program Design as compliance instruments, which are bankable and tradable. With regard to offsets not constituting a property right, each jurisdiction will need to specify how offsets fit within their respective legal structures and will take this comment into consideration as they write the program regulations. The Committee did not include "avoided" emissions in the definition, as the term often implies that no real reduction took place, which conflicts with the criterion "real" and is inconsistent with the ISO.

3.2 Other considerations

This section includes the final recommendations for three issues referenced in the offset definition.

3.2.1 Ownership issues

The *Criteria Draft Recommendations Paper* included a description on the importance of clearly established ownership to the well functioning of an offset system. The final recommendation text regarding ownership is <u>unchanged</u> from the draft recommendation.

3.2.1.1 Final recommendation

An offset project proponent must have legal ownership of the greenhouse gas emission reduction or removal resulting from the offset project. The offset project proponent will be responsible for all statements and information provided to the WCI Partner Jurisdiction issuing the offset certificate during the creation of the offset certificate and verification of the reduction or removal. The WCI Partners should establish a registry of offset certificates issued and make the registry publicly available.

3.2.1.2 Summary of stakeholder input

Several stakeholder comments raised the concern that the draft recommendation was restrictive in a manner that could constrain the financial arrangements that are part of an offset project. Otherwise, the comments were generally supportive of the draft recommendation, and one other comment noted that additional guidance would be needed beyond this definition for implementation.

3.2.1.3 Discussion of final recommendation

The intent is to establish that each project has a proponent who has a superior legal claim to the reductions and that the proponent will bear the responsibility for meeting the process requirements during the offset project's operation. Beyond that, this recommendation is not restrictive in trying to define or restrict who the project proponent may be. The recommendation also still includes a sentence affirming the importance of a registry in tracking the ownership of issued offset certificates.

3.2.2 Use of approved protocols

As noted in the *Criteria Draft Recommendations Paper*, the WCI Partners are beginning a process to recommend protocols that meet the essential criteria. Aside from two minor clarifying edits, the final recommendation text regarding use of approved protocols is <u>unchanged</u> from the draft recommendation.

3.2.2.1 Final recommendation

A WCI Partner jurisdiction will issue offset certificates for compliance with its cap-and-trade program only from projects which employ protocols that have been recommended through the WCI protocol review process ("WCI offset protocols").

3.2.2.2 Summary of stakeholder input

Several stakeholder comments recommended project types they would like the WCI Partner Jurisdictions to more actively pursue (e.g., coal mine methane). Some comments also requested clarification about how offsets that have been issued by other offset systems would be treated by the WCI Partner jurisdictions. Other comments suggested that more detail was needed to explain how the WCI offset protocol recommendation process would work.

3.2.2.3 Discussion of final recommendation

The WCI offset protocols are intended to be adopted through each jurisdiction's legal processes, resulting in a harmonized set of protocols across the WCI. Since the comments generally discussed which protocols should be approved for use in the WCI region or how offsets generated in other systems would be treated by WCI Partner jurisdictions, the Committee directs stakeholders to its ongoing Task 3 and upcoming Task 2 work for additional information in response to the stakeholder concerns outlined in response to this supporting criterion.

3.2.3 Geographic limits

The *Criteria Draft Recommendations Paper* acknowledged that WCI's previous Design Recommendations document had implications for offsets in regards to geographic limits which should be included in the Essential Elements recommendations. Aside from a minor clarifying edit, the final recommendation text regarding geographic limits is unchanged from the draft recommendation.

3.2.3.1 Final recommendation

A WCI Partner jurisdiction may issue offset certificates for projects located within its own jurisdiction as well as jurisdictions outside WCI Partner Jurisdictions within North America.
A WCI Partner jurisdiction will accept offset certificates issued by other WCI Partner jurisdictions. As described in section 9.8 of WCI's design document, WCI Partner jurisdictions may also accept offset certificates from outside North America.

3.2.3.2 Summary of stakeholder input

Several comments suggested that the geographic limit should be even more restrictive, in particular, limiting offsets to only projects located in WCI Partner jurisdictions. Other comments suggested the geographic limit recommendation was too restrictive, lacking a rationale for why cost-effective projects on one side of a border would be ineligible while similar or even less cost-effective projects on the other side of the border would be eligible.

3.2.3.3 Discussion of final recommendation

This final recommendation continues to affirm the relevant recommendation from the WCI's Design Recommendations document published September 23, 2008. The WCI Partner jurisdictions have found a reasonable balance between emission reductions at covered sources and stimulating emission reductions beyond those sources and outside the WCI region. Agreements (e.g., MOU's) may need to be executed to facilitate projects outside WCI Partner jurisdictions.

4 Defining the Real criterion

This section provides the final recommendations for the Real criterion and its supporting criteria.

4.1 Real

The *Criteria Draft Recommendations Paper* explained that offset reductions or removals are real in order to ensure the integrity of the cap-and-trade system. Aside from a minor clarifying edit, the final recommendation text regarding the Real criterion is unchanged from the draft recommendation.

4.1.1 Final recommendation

An offset certificate represents a reduction or removal of one metric ton of CO_2e that results from a clearly identified action or decision. A WCI offset project's reduction or removal is quantified using accurate and conservative methodologies that appropriately account for all relevant greenhouse gas sources and sinks and leakage risks. WCI offset projects result in emissions reductions or removals that take place at sources controlled by the project proponent.

4.1.2 Summary of stakeholder input

Some stakeholder comments addressing the real criterion were generally supportive of the draft recommendation. Other comments suggested that the draft recommendation was too restrictive in disallowing the crediting of reductions that occur at sources not controlled by the project developers.

4.1.3 Discussion of final recommendation

Stakeholders expressed general support for the draft recommendation. A fuller explanation for the draft recommendation can be found in the *Criteria Draft Recommendations Paper*. The Committee acknowledges the somewhat controversial decision to restrict projects to those with reductions occurring at sources controlled by the project developers. Within the WCI region, this is justified by double-counting concerns. For other parts of the United States and Canada, the policy decision against crediting reductions which would be capped in the WCI region applies.[4]

The Offsets Committee also discussed whether to amend the draft recommendation for the real criterion with text explicitly addressing whether the WCI's definition for real prevents forward crediting of anticipated reductions or removals. The Committee decided that such text was not necessary as part of this recommendation given that the verifiable criterion presumes reductions or removals have already been realized in order to be verified. The WCI Partner jurisdictions will not issue offset certificates for anticipated reductions.

[4] See section 9.7 (page 11) of the WCI Design Recommendations (September 2008).

4.2 Supporting criteria

This section provides the final recommendations for the supporting criteria related to the Real criterion.

4.2.1 Quantification, uncertainty, and accuracy

The *Criteria Draft Recommendations Paper* provided the WCI Offset Committee's efforts to balance the natural tension between conservative and accurate estimates of emission reductions. The final recommendation text regarding quantification, uncertainty, and accuracy is unchanged from the draft recommendation.

4.2.1.1 Final recommendation

Quantification: WCI Partner jurisdictions shall ensure that net emission reductions or removals are capable of being measured or modeled in a reliable and repeatable manner that includes all relevant sources and sinks. Quantification methodologies for GHG emissions or emission reductions shall:

- Be appropriate to the GHG source or sink
- Be current at the time of quantification
- Consider local conditions, whenever applicable
- Account for uncertainty – be calculated in a manner that yields accurate and reproducible results
- When uncertainty is above the defined threshold, apply the principle of conservativeness to GHG

During quantification procedures, project proponents shall convert each type of GHG to metric tons of CO2e. In addition, WCI offset protocols shall use uniform quantification methods whenever feasible.

Uncertainty and accuracy: Quantification methodologies and measurement techniques shall set standards for acceptable statistical precision and be based on the best available science. They shall also reduce bias, except for promoting conservative estimates. When uncertainty remains high in quantifying the amount of a greenhouse gas emission reduction or removal, the principle of conservativeness shall be applied.

Principle of conservativeness: Where uncertainties are above the defined threshold, offset quantification methods should use more conservative quantification parameters, assumptions, and measurement techniques that minimize the risk of overestimating emission reductions and removals credited for a given project. The principle should be employed when significant uncertainties arise to ensure a higher level of confidence that all calculated reductions are real.

4.2.1.2 Summary of stakeholder input

Stakeholder feedback on quantification was diverse. Comments called for using a panel of experts to evaluate current science and quantification methods, approving projects only where there is a high level of confidence that reductions have occurred, developing procedures for reevaluating quantification methodologies and publication of changes in advance, and providing suggested language to explain the principle of conservativeness.

4.2.1.3 Discussion of final recommendation

After evaluating the diverse stakeholder feedback, the Offsets Committee has decided to leave the draft recommendation unaltered. Stakeholders may find a fuller explanation for the draft recommendation in the *Criteria Draft Recommendation Paper*. The Committee concluded that stakeholder comments for this draft recommendation generally provided very apt suggestions for the successful implementation of the WCI offsets system but generally did not suggest how the text itself may be changed. The notable exception to this is the stakeholder suggestion for additional language explaining the principle of conservativeness. The Committee notes for stakeholders that its definition for a principle of conservativeness would be as follows: erring on the side of caution while balancing accuracy standards with the need for cost-effective offset projects. The Committee was not comfortable, however, with including that text in the recommendation itself.

4.2.2 Leakage

As noted in the *Criteria Draft Recommendations Paper*, evaluating leakage is important to maintaining that quantified emissions reductions are real. The final recommendation text regarding leakage is unchanged from the draft recommendation.

4.2.2.1 Final recommendation

To address activity-shifting and market leakage, WCI Partner jurisdictions will require assessments of whether functional equivalence has been maintained within projects and require that protocols include methods for leakage assessments. WCI offset protocols will evaluate functional equivalence for each project. WCI offset protocols will also require an assessment of potential leakage associated with each project type. In general, WCI jurisdictions prefer the following methods to review leakage risk:

- A quantitative assessment of leakage will be performed whenever possible.
- When a quantitative assessment is not feasible, a qualitative risk assessment will determine whether the risk of systematic leakage is significant or not.
- WCI offset protocols will include a threshold to identify significant leakage. If leakage is found to be above the threshold, the WCI offset protocol quantification methodology will include a factor to account for leakage.

4.2.2.2 Summary of stakeholder input

Most stakeholder comments supported the assessment of leakage when clear guidelines, policies, or procedures are included in WCI offset protocols. Others requested guidance or further discussion on how to determine market (external) leakage as well as functional equivalence.

4.2.2.3 Discussion of final recommendation

After reviewing stakeholder comments, the Offsets Committee has the left the draft recommendation regarding leakage unchanged. In recognition of the comment requesting additional guidance, the Committee does offer some further discussion on the topics. Further guidance for evaluating leakage will be contained within each WCI offset protocol.

Projects must determine if a significant risk of leakage exists in accordance with WCI offset protocol methods and offset criteria. If the determination results in 'no risk of leakage' in specific cases, the WCI offset protocol may waive a leakage assessment. If the leakage assessment finds a significant risk above a pre-determined threshold, the WCI offset protocol may require a project to mitigate the risk by using a factor to account for leakage when determining the level of GHG emissions or removals.

To ensure a meaningful comparison can be made between the project and baseline case, the baseline must be 'functionally equivalent' to the project. Functional equivalence assesses whether a project is reducing emissions simply by reducing the production of a good or service – instead of providing the same level of production with fewer total GHG emissions. In other words, the baseline must be able to deliver the same types and levels of products or services as the project. An example of functional equivalence would be a biomass and natural gas fired boiler – if both deliver the same quantity and quality of heat, they are functionally equivalent.

The WCI offset protocol used as the basis for a GHG project plan should provide a justified baseline assessment for the particular project type in question. The end result must be the selection of a conservative baseline scenario that is unlikely to overestimate the level of GHG emissions (or underestimate the level of GHG removals) under the business as usual case. In cases where multiple potential baselines appear equally likely to occur even after application of a detailed barriers test or other selection process, the baseline that would result in the lower emission reductions for the project should be selected.

5 Defining the Additional criterion

This section provides the final recommendations for the Additional criterion and its supporting criteria.

5.1 Additionality and Baseline

The final recommendation <u>differs</u> from the draft recommendation based on stakeholder comments and further discussion by the Offsets Committee considering stakeholder feedback.

5.1.1 Final recommendation

Offset certificates will be awarded only for the portion of greenhouse gas emission reductions or removals that would not have happened under a baseline scenario.

The WCI Partner jurisdictions intend for additionality to be established in a manner that will require offset projects to be evaluated against a baseline that reflects conservative assumptions that are consistent across all WCI Partner jurisdictions. These assumptions will be described in the procedures for setting a baseline in WCI offset protocols. Modeling or other methods of developing the baseline shall use assumptions, methodologies, and values which assure that GHG reductions or removals from a project are not over-estimated (consistent with the principle of conservativeness in 4.2.1).

When possible, the baseline shall be set using a sector-specific or activity-specific performance standard which is set in WCI offset protocols based on a regional assessment of project performance or common practice. WCI Partners intend that all baselines will reflect the most stringent regulatory and legal requirements of any WCI Partner jurisdiction (those requirements leading to the most conservative calculation of emission reductions). When a baseline based on the most stringent regulatory requirement is not practical because of regional differences, the WCI Partners may recommend a protocol using an alternative method.

When it is not possible to set a baseline using a performance standard, a project-specific baseline may be used. Then the baseline will be set to reflect all binding agreements, regulatory requirements and legal requirements applicable to the project and also to ensure that the project is beyond business as usual.

5.1.2 Summary of stakeholder input

Stakeholders generally supported the recommended preference for a performance-standard baseline. It was suggested that the definition should clarify that the WCI's intent that additional reductions and removals would not have otherwise occurred in the absence of the offset project. Several comments expressed concern that exclusive reliance on a baseline method will allow eligibility for some non-additional projects and suggested that a common practice or barrier test accompany the performance standard.

While there was some support for using a regional regulatory baseline, many commenting stakeholders were concerned that setting a baseline at the most stringent regulatory requirement would unduly limit offset supply and could be difficult to apply in some sectors (e.g., forestry). From their point of view, projects which the WCI Partner jurisdictions should view as additional would be deemed to be non-additional. Those concerned suggested that the WCI apply this on a case-by-case basis or remove this part of the draft recommendation completely.

5.1.3 Discussion of final recommendation

Given the depth of the comments on additionality, the Offsets Committee gave the recommendation a fairly extensive makeover. Given the extent of the changes, the discussion below does not focus so much on changes from the draft recommendation but on discussing the final recommendation itself.

The recommended definition of additionality and baseline is consistent with the International Standards Organization's (ISO) 14064-2 standard by defining what is additional as emission reductions or removals beyond any reductions or removals achieved under a baseline scenario. Under this definition offset projects can generate offsets for early adoption of activities that will be required in the future by a current or expected regulation until the requirement takes effect. However, new regulations or requirements that were not implemented or expected during project registration or renewal will not affect project additionality until the end of the current crediting period.

Each WCI offset protocol must lay out the methodologies that a project proponent shall use to determine additionality and model the baseline scenario. The WCI Partners prefer protocols that take a sector-specific or activity-specific performance standard approach to determining additionality. In this method, the baseline is set as the performance standard or the minimum actions required by law, whichever is higher.

In setting baselines it is the intent of WCI Partners that the performance standard will be set to reflect the most stringent regulatory or legal requirements in any WCI Partner jurisdictions. This will result in the most conservative assessment of offset reductions, helping to ensure the integrity of the WCI offset system. Setting a performance standard based on the most stringent regulation in any WCI jurisdiction will 'level the playing field' among WCI Partner jurisdictions and remove any incentive to weaken or solely maintain environmental protections in order to qualify more offset projects. For some project types it will be difficult to apply this standard based on regional differences. In these protocols, the WCI Partners may address regional differences using alternative methods.

When a performance standard approach is not the best alternative for a certain project type or it will take a number of years to develop a reasonable performance standard, the WCI Partners may recommend protocols that use alternative methods as long as they meet the criteria for determining additionality and baseline. When an alternative method is used, the baseline will reflect the chosen standard and the regulatory and legal requirements applicable in the jurisdiction where the project is located. Methods such as a common practice test, investment test, barrier analysis, or other tests of financial additionality can be used to determine whether a project is beyond business as usual.

The WCI Partners intend to use baselines that exceed this minimum by favoring performance standards since performance standards generally set higher baselines and are thus more conservative. Performance standards are designed to capture common practice or business-as-usual investment activity such that there is high confidence that the reductions or removals of greenhouse gas emissions by offset projects exceed those already occurring – especially when what is already occurring exceeds regulatory requirements.

The WCI Partners are retaining the option of using proportional additionality as the means to develop performance standards for sequestration projects in agriculture and forestry. Proportional additionality models sector activity in aggregate across either a WCI jurisdiction or the WCI region as a whole– the level of project activity that would occur absent the offset programs of WCI Partner Jurisdictions (i.e., baseline activity) and the level of aggregate project activity that is induced in response to the WCI offset program. The portion of a projects emissions reductions or sequestration over the sectoral baseline is considered additional. Over time as practices become more common projects receive a small portion of offset credit for these actions.

The WCI Partners' draft recommendation for additionality and baseline sets an overall standard but at the same time provides flexibility by deferring to the WCI offset protocols the specific methods used to achieve the standard. For example, WCI offset protocols may include additionality tests for project types that do not lend themselves to a performance standard approach. In this way, WCI offset protocols for project types that otherwise would be excluded can still be included in Partner Jurisdictions' offset programs. The WCI Offset Committee generally concurs with the prevailing view of commenting stakeholders concerned about using investment, funding or financial barriers tests in determining additionality. Thus, Partner Jurisdictions will not require them on a system-wide level, although they could be required by a WCI offset protocol where they are deemed appropriate for a given project type.

5.2 Supporting criteria

This section provides the final recommendations for the supporting criteria related to the Additional criterion.

5.2.1 Eligibility date

The offset project eligibility start date establishes a date such that only projects commenced after that date are eligible to generate offset certificates. The final recommendation differs from the draft recommendation based on stakeholder comments and further discussion by the Offsets Committee considering stakeholder feedback.

5.2.1.1 Final recommendation

Offsets may be awarded only for projects that are initially commenced on or after January 1, 2007, the start of the year in which the original WCI Memorandum of Understanding (MOU) beginning the development of the cap-and-trade program by Partner Jurisdictions was signed. Offset certificates may be awarded for all GHG reductions or removals occurring on or after January 1, 2007.

An offset project proponent must apply to register its project with a WCI Partner Jurisdiction within one year of project commencement. Projects that commenced prior to finalization of the applicable WCI offset protocol must apply within one year of that protocol's finalization.

5.2.1.2 Summary of stakeholder input

Most written comments addressed the project eligibility date. Many supported an eligibility date earlier than that proposed in the draft recommendation (September 23, 2008) while some other stakeholders suggested a later project start date, or at least a later date before which reductions could be credited with offset certificates. Overall, stakeholders suggested a number of alternative project eligibility dates ranging from January 1, 2001 to January 1, 2012.

5.2.1.3 Discussion of final recommendation

This recommendation establishes a project eligibility start date of January 1, 2007. This is based on the date when the WCI was established. The Offsets Committee believes that projects initiated before the formation of the WCI cannot readily claim they were developed based on incentives from the WCI cap-and-trade program. The MOU establishing the WCI was signed by the governors of five U.S. states on February 26, 2007. The WCI Partners have chosen to make the eligibility start date the beginning of the year in which the WCI was created.

5.2.2 Crediting period

As noted in the Criteria Draft Recommendations Paper, a crediting period determines how long an approved offset project is eligible to generate offset certificates. The final recommendation differs from the draft recommendation based on stakeholder comments and further discussion by the Offsets Committee considering stakeholder feedback.

5.2.2.1 Final recommendation

The crediting period for non-sequestration WCI offset projects will be 10 years. At the end of a crediting period a project proponent may renew a project subject to the current WCI offset protocol for that project type. Renewal of a project at the end of a crediting period will include a reevaluation of a project's additionality and reevaluation of how the reductions are quantified and verified. Thus, the baseline scenario will be reevaluated at each renewal.

The crediting period for sequestration projects will be specified by the applicable WCI offset protocol. However, any individual crediting period may not exceed 25 years before a renewal, and the total crediting period including all renewals may not exceed 100 years for sequestration projects. The applicable WCI offset protocol will also lay out the requirements for project renewal. At a minimum, the project must reevaluate quantification and monitoring methods based on the current WCI offset protocol. If possible, projects will also need to reassess project additionality and baselines in order to renew the project.

5.2.2.2 Summary of stakeholder input

Stakeholders offered a number of comments concerning the length of a crediting period and the number of crediting period renewals for which each project should be eligible. There was support from stakeholders for both extending and shortening the recommended crediting period for both sequestration and non-sequestration projects. Stakeholders also suggested not limiting the number of crediting period renewals for projects that continue to generate real, additional, and verifiable reductions.

5.2.2.3 Discussion of final recommendation

During a crediting period a project will generate certificates based on the methods laid out in the applicable WCI offset protocol at the time a project is registered. A project will continue to generate certificates throughout the crediting period assuming it reduces or sequesters more greenhouse gases beyond the baseline established at the time project registration. Changes in regulations or the WCI offset protocol itself will not affect a project during its current crediting period, unless the project developer chooses to use the updated protocol instead of the protocol version in place at the time of project registration.

Crediting period length remains unchanged from the draft recommendation. However, the final recommendation lifts the limit on the number of renewals for non-sequestration projects. For project renewal, non-sequestration projects will undergo a full reevaluation of all criteria based on the current WCI offset protocol for that project type.

Sequestration project will be able to renew a crediting period such that the total crediting period for any project does not exceed 100 years. A WCI offset protocol will lay out the criteria a project must meet in order to qualify for renewal. At a minimum the project proponent will need to modifying quantification and monitoring methods and plans to reflect the current practices laid out in the most recent WCI offset protocol for that project type. For project types where it is possible to reassess additionality, the project will need to undergo a full reevaluation of baselines to ensure it continues to meet the criteria for additionality. For project types such as afforestation where it is impossible to reassess the project baseline, projects will still be eligible for crediting period renewal assuming they continue to sequester carbon.

6 Defining the Permanent criterion

This section provides the final recommendation for the Permanent criterion.

6.1 Permanent

As noted in the *Criteria Draft Recommendations Paper*, permanence is an issue which needs to be addressed in projects which involve a risk of reversal, most notably geologic and terrestrial sequestration of carbon (i.e., carbon that is stored in biomass and soil). The final recommendation text revises the draft recommendation.

6.1.1 Final recommendation

With respect to offset project activities, permanence means either that reductions or removals are not reversible or that, if reductions or removals are reversible, the provisions outlined in the remainder of this recommendation must be met.

Sequestration projects must be designed so that the net atmospheric effect of their greenhouse gas removal is comparable to the atmospheric effect achieved by non-sequestration projects. The atmospheric effect will be based on the current international standard established by the UNFCCC, which is currently 100 years. This international standard may be updated from time to time, and the WCI Partner jurisdictions will adopt the new international standard if/when it is updated.

If an emission reduction is reversed after offset certificates are issued, the project developer must either replace the certificates representing reversed reductions with other compliance units from within the system or return certificates that were issued to the project. The number of certificates required to be replaced or returned will, at a minimum, be the difference between the atmospheric benefit the sequestration project until it was reversed and the total sequestration for which certificates were issued. Applicable approaches to assuring permanence for a project type will be included in the appropriate WCI offset protocol.

In conformance with the applicable WCI offset protocols, project proponents shall follow or establish effective (i) monitoring systems, (ii) risk mitigation approaches, and (iii) contingency plans which address how, in the event of a reversal that is the result of proponent intention or negligence, any affected offset certificates will be replaced. The contingency plan shall include specific mechanisms that are exercisable at the time a reversal is identified whether or not the proponent is solvent, exists in its original form, and/or has ownership of or responsibility for the project.

WCI Partner jurisdictions will establish mechanisms to address reversals that are not the result of proponent intention or negligence and where proponents' contingency measures prove inadequate.

6.1.2 Summary of stakeholder input

Stakeholder groups offered valuable feedback on the permanent criterion. There was consensus that the environmental integrity of the offsets system needs to be ensured. There was also broad agreement that various measures including buffer pools, pro-rating, discounting and replacement could be employed in order to maintain the atmospheric benefit of projects. Stakeholders expressed concern over the 100-year standard for assessing permanence, and at least one stakeholder suggested creating temporary or short-term credits. Stakeholders also expressed support for an approach where the buyer of offsets is not held liable for reversals, with some stakeholders suggesting that punitive penalties be applied for intentional reversals.

6.1.3 Discussion of final recommendation

The final recommendation for the permanent criterion remains largely unchanged from the draft recommendation. Following review of stakeholder feedback regarding permanence and further discussion among themselves, the WCI Partners revised the permanence recommendation to clarify when reversals will necessitate the replacement of issued offset certificates. This recommendation provides the system-level requirements, with additional detail to be provided in the WCI offset protocols.

Some stakeholder comments suggested measures for assessing permanence (e.g., use of conservation easement). Under the final recommendation, such measures will be evaluated at the protocol level. The WCI Offsets Committee understands the concern over the appropriateness of a 100-year standard and has included provisions for the possible reevaluation of the standard. The WCI Partners also discussed the possibility of temporary crediting, but experience with this approach to date suggests that it may not sufficiently incentivize the desired sequestration activities.

7 Defining the Verifiable criterion

This section provides the final recommendation for defining the Verifiable criterion and three supporting criteria.

7.1 Verifiable

As noted in the *Criteria Draft Recommendations Paper*, the biggest question related to the term verifiable is who will objectively review the GHG assertion or reduction and making a finding whether the GHG assertion or reduction is accurate. The final recommendation text is unchanged from the draft recommendation.

7.1.1 Final recommendation

With respect to offset project activities, verifiable means that a GHG reduction or removal, or assertion thereof, is well documented and transparent such that it lends itself to an objective review by a qualified verifier. Verifiers for WCI offsets will be independent third parties who have been accredited to a standard acceptable by the WCI Partner jurisdiction in which the project is registered.

7.1.2 Summary of stakeholder input

Several stakeholders offered written comments on this criterion. Stakeholder suggestions included that the WCI should enable a public comment process as part of the verification process and that accreditation requirements should be harmonized across the WCI region. There were recommendations to prohibit verifiers from having a financial stake in the offsets projects they verify.

7.1.3 Discussion of final recommendation

The Offsets Committee regards the stakeholder comments as providing helpful guidance for the WCI Partner jurisdictions to implement an effective verification program for WCI offsets. From these comments, the Committee did not find a reason to modify the draft recommendation. Many of the stakeholder comments on the draft recommendation were related to offsets process (e.g., accreditation of verifiers) and will be addressed in the *Process Draft Recommendations Paper*. The Offsets Committee also wishes to stress its view that emission reductions and removals being verifiable prevents so-called forward crediting of offset certificates until after the reductions have been realized and verified.

7.2 Supporting Criteria

This section includes final recommendations for three supporting criteria related to the verifiable criterion.

7.2.1 Validation

As noted in the *Criteria Draft Recommendations Paper*, the key questions regarding validation were whether validation would be required and who would perform the validation. The final recommendation differs from the draft recommendation. The changes are not so much because of stakeholder comment but a result of further consideration by the Offsets Committee as it drafted the *Process Draft Recommendations Paper*.

7.2.1.1 Final recommendation

With regards to WCI offsets, validation is a required review by an accredited independent third party or the WCI Partner jurisdiction to assess the likely result of reductions or sequestration from a proposed project that would use a WCI offset protocol.

7.2.1.2 Summary of stakeholder input

Stakeholders offered a mixed view on validation. Some stakeholders commented that a validation step is absolutely necessary, while others suggested that validation should not be required at all. Some suggested that third-party validation should not be required.

7.2.1.3 Discussion of final recommendation

After further discussion, the Offsets Committee has concluded that validation is necessary in the offsets process. Project details must be evaluated at some point, and the Committee's recommendation is to require validation prior to project registration. The final recommendation retains for each WCI Partner jurisdiction the flexibility to have validation performed either by an accredited third party auditor or by itself.

7.2.2 Enforceable

Enforceability is key to ensuring that offset project developers comply with the WCI offset protocols and offset system requirements. The final recommendation text is unchanged from the draft recommendation.

7.2.2.1 Final recommendation

Each Partner jurisdiction will, to the extent permissible by law, put in place sufficient compliance/enforcement mechanisms and detail for the jurisdiction to compel compliance with its requirements and with WCI offset protocols.

7.2.2.2 Summary of stakeholder input

Stakeholders generally commented enforcement requirements and penalties should be consistent across all WCI Partner jurisdictions. A couple written comments suggested more detail should be provided.

7.2.2.3 Discussion of final recommendation

The *Criteria Draft Recommendations Paper* offered the Offsets' Committee reasoning for the above recommendation. After reviewing the stakeholder comments, the Offsets Committee did not identify any reason to change the recommendable regarding the enforceable criterion. The Committee does appreciate stakeholder comments for more detail on the enforcement process in regards to WCI offsets, and this detail will be provided in a future deliverable from the Offsets Committee.

7.2.3 Material

As explained in the *Criteria Draft Recommendations Paper*, the term "materiality" refers to a threshold beyond which differences in reported emissions/reductions are deemed unacceptable. The final recommendation <u>revises</u> the draft recommendation.

7.2.3.1 Final recommendation

Material misstatement means that errors, omissions or an aggregation of both in the reported GHG reductions or assertion exceeds a +5% threshold. For a WCI offset, the verifier must be able to state with reasonable assurance the total reported reductions or removals are free of material misstatement.

7.2.3.2 Summary of stakeholder input

There were few written comments offering comments specific to the Materiality supporting criterion. One suggestion from stakeholders was to define material misstatement as errors or emissions resulting in significant overestimates (e.g., +5% only, not ±5%) since underestimates of emission reductions do not harm environmental integrity of the overall program. Another suggestion from stakeholders was to apply a different threshold for small projects as their errors could exceed materiality thresholds despite affecting only a small number of tons.

7.2.3.3 Discussion of final recommendation

The level of the ±5% threshold in the draft recommendation was consistent with the materiality threshold for emitters with mandatory reporting obligations in the WCI jurisdictions (as described in the Essential Reporting Requirements document). Following suggestion from stakeholder comment, the WCI Offsets Committee has modified its previous reasoning about not deviating the threshold from that used for mandatory reporting. Because of the uncertainty inherent with most offsets, it may be appropriate to apply the threshold only to overestimated reductions and not to underestimated reductions. The Offsets Committee considered the stakeholder suggestion about a different threshold for smaller projects but concluded based on current information to recommend the same threshold to all projects regardless of size—consistent with the same threshold being applied to all emitters under mandatory reporting regardless of their size.

8 Other considerations

This section includes final recommendations for three considerations that were of importance to the Offsets Committee for this paper but did not otherwise fit well under the discussions of the offset definition or essential criteria.

8.1 Transparency

The final recommendation text for transparency is unchanged from the draft recommendation, aside from a minor clarifying edit.

8.1.1 Final recommendation

Partner Jurisidictions' offset systems will provide transparency such that sufficient and appropriate protocol, project and certificate information is disclosed in a timely manner to allow offset system participants and the general public to make decisions with reasonable confidence.

8.1.2 Summary of stakeholder input

Several stakeholders provided written comment on transparency, and each tended to focus on a different aspect of a transparent offset system, including (a) concern whether system requirements would not sufficiently respect the privacy of small family farms involved in generating offsets, (b) the importance of registries making standardized information available, and (c) the importance of timely public disclosure of offset documents allowing for public comments on proposed projects.

8.1.3 Discussion of final recommendation

Unaltered, this recommendation maintains the important role of transparency in the WCI offsets system. As discussed in the Criteria Draft Recommendations Paper, details regarding transparency will be provided via subsequent deliverables from the Offsets Committee, including the *Process Draft Recommendations Paper* (Task 1.3) and other deliverables from Task 1.5.

8.2 Co-benefits

The final recommendation text regarding co-benefits is unchanged from the draft recommendation.

8.2.1 Final recommendation

WCI Partners recognize the environmental, social, economic and health benefits that may arise from an offset project and the offset system will focus on those benefits directly related to mitigating climate change. A WCI offset project is required only to result in a greenhouse gas emission reduction or removal.

8.2.2 Summary of stakeholder input

Written stakeholder comments generally supported the draft recommendation, although that support was not unanimous. Some comments also suggested that priority or advantage should be given to offsets with positive co-benefits or that the WCI's registration and reporting processes for offsets require a report on any co-benefits.

8.2.3 Discussion of final recommendation

While stakeholders are not unanimous in supporting this recommendation, the Offsets Committee believe it has made the appropriate recommendation and leaves the draft recommendation unchanged. With this recommendation, the WCI Partner jurisdictions keep the focus of the offsets program on GHG emissions reductions and removals—the reason behind establishing the WCI regional cap-and-trade program—but they also remain neutral on how co-benefits associated with an offset project may be treated or claimed by policies or programs other than the greenhouse gas cap-and-trade program (as noted and explained in the *Criteria Draft Recommendations Paper*).

8.3 Assessment of Environmental or Social Impacts

The final recommendation text regarding assessment of environmental or social impacts is unchanged from the draft recommendation.

8.3.1 Final recommendation

WCI offset projects must meet all applicable local environmental regulations and be in compliance with all applicable laws in the jurisdiction where the project is located. If environmental or socioeconomic assessments of the proposed project have been done, the project's registration application should reference this work and include a summary of the findings. WCI offset protocols for specific offset project types may require analysis of environmental and socioeconomic impacts beyond what the local jurisdiction would otherwise require and may require additional mitigation of potential negative impacts.

8.3.2 Summary of stakeholder input

Several stakeholders provided written comment on this draft recommendation with none explicitly supporting the draft recommendation. A few comments indicated that the draft recommendation was not strong enough in what would be required, while other comments suggested that the draft recommended requirements were too strong and could inhibit the development of offsets.

8.3.3 Discussion of final recommendation

While stakeholders did not explicitly support the draft recommendation regarding co-impacts, the divide between stakeholders who think the recommendation is either too lax or too stringent indicates to the Offsets Committee that they have struck a reasonable balance to address concerns over potential negative co-impacts from the implementation of offset projects. The Offsets Committee anticipates that more specific detail on co-impacts will become available as WCI offset protocols are completed.

9 Conclusion

This paper has presented the final recommendations for defining a WCI offset and its essential criteria, as well as other supporting criteria and considerations. These recommendations will inform the ongoing work of the Offsets Committee. As these are final recommendations, the Offsets Committee is not seeking further stakeholder feedback on these recommendations, but the Offsets Committee does thank stakeholders for their patience and feedback through multiple stages. Table 9.0 below updates stakeholders on planned deliverables from the Offset Committee's Essential Elements (Task 1) work.

Table 9.0 Offsets Committee Task 1 Workplan

Task 1 Subtasks	Subtask Description	Deliverables (Dates)
1.1	Define a WCI GHG offset	Options Paper—June 2009 Draft Recommendations—April 2010 Final Recommendations—July 2010
1.2	Develop detailed eligibility criteria for GHG offset projects for compliance purposes under the cap-and-trade system	Options Paper—June 2009 Draft Recommendations—April 2010 Final Recommendations—July 2010
1.3	Develop detailed requirements for the registration, validation, monitoring, quantification, reporting, verification, certification, and issuance of offsets	Draft Recommendations—August 2010 Final Recommendations—TBD
1.4	Recommend aspects of regulation and enforcement related to offsets that should be included in the cap-and-trade essential elements	TBD
1.5	Recommend functions of the regional administrative body and tracking system related to the offset system	TBD

Western Climate Initiative

Guidance to Partners for Distributing Early Reduction Allowances

June 22, 2010

1. Introduction/Purpose

According to the September 23, 2008 *Design Recommendations for the WCI Regional Cap-and-Trade Program*, Early Reduction Allowances (ERAs) may be awarded for reductions by covered facilities between January 1, 2008 and January 1, 2012. As proposed in the Design Recommendations, ERAs would be issued in addition to a WCI jurisdiction's allowance budget. Therefore, those reductions must be voluntary, additional, real, verifiable, permanent, and enforceable in order to preserve the integrity of the WCI cap-and-trade program. Issuance of ERAs for eligible reductions is itself voluntary, and not required by WCI partner jurisdiction. ERAs are fungible compliance units, in the same way as allowances.

There are two approaches for identifying ERA eligible projects:

1) Under the program authority review, a WCI partner may use existing emissions information to identify potentially eligible projects and request those projects to submit emissions information in order to assess and verify their eligibility. The program authority review enables Partner jurisdictions that already have much of the data required under the application process (second approach below) to minimize their administrative burden by not requiring an application process. Projects awarded ERAs under the program authority review must still meet all requirements set forth in this document with the exception of the application process (section 4.2).

Or

2) A WCI partner jurisdiction may institute a process where emission sources apply for ERA consideration. Once the application is made for an emissions source, and verification provided, the WCI Partner Jurisdiction will decide whether to approve the application and award ERAs for the early reduction, or reject the application.

Under both approaches, the burden of proving that a project qualifies for ERAs is the responsibility of the source or facility claiming the reduction. A Partner jurisdiction may require the verification of the information provided be carried out by a government agency or may require it be done by an accredited third party verifier.

This guidance document presents the requirements and methodologies for the issuance and distributions of ERAs under both approaches.

2. Greenhouse Gases Covered

For the purpose of the Early Reduction Allowance (ERA) program, the Committee recommends covering all the GHGs covered in the GHG cap and trade program. That includes: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), nitrogen trifluoride (NF_3), and perfluorocarbons (PFCs).

3. Common Requirements for Awarding Early Reduction Allowances

This section presents the common requirements that Partners recommend to include in their Early Reduction Allowance provisions.

Eligibility

To be eligible to receive ERAs, a project must involve permanent emissions reductions at a source subject to the greenhouse gas emissions requirements of the Partner jurisdiction's cap-and-trade program (covered source). This means that the owner or operator of that source must be required to surrender allowances/credits to cover the source's emissions at the end of a compliance period. Restricting eligibility to projects that occur at covered sources in the Partner jurisdiction will help prevent double counting and will allow the distribution of ERAs to build upon the WCI's monitoring and reporting work to date.

ERAs should only be awarded when the source or facility can demonstrate that the reductions were the result of a clear project or action.

Government-controlled sources are eligible to receive ERAs for emissions reductions so long as they meet all of the requirements of this document, including that the owner or operator of that source is required to surrender allowances/credits to cover the source's emissions at the end of a compliance period, and that the reductions are voluntary.

Eligibility Period

A Partner jurisdiction may issue ERAs for a project that reduced emissions on or after January 1, 2008 and before January 1, 2012.[1]

Real

One WCI ERA represents a reduction or removal of one metric ton of carbon dioxide equivalent emissions (CO_2e) resulting from a clearly identified action or decision without an increase in emissions intensity. A reduction is not considered real if it comes from a decrease in production alone or from a shutdown or a closure of a source or a facility. Instead, the source or facility must demonstrate a reduction in emissions intensity <u>and</u> a reduction in absolute emissions for the period of time that ERAs are being sought. The source or facility that may be awarded ERAs must provide adequate information to demonstrate that a project has actually occurred.

[1] See Section 5, below, for discussion of special considerations applicable to jurisdictions that enter the cap-and-trade program after 2012.

In addition, a Partner jurisdiction may also require sources or facilities to show reductions are beyond best practice standards. Best practice standards can be defined by the jurisdiction for certain operations, sources or facilities who may be required to prepare an evaluation demonstrating their actions are beyond best practices in their industry.

Voluntary

A WCI ERA project and the accompanying reduction in emissions, both, must be the result of a clearly identified action or decision that is surplus to any requirements from existing legislation, regulation, executive order and other regulatory obligations.

Permanent

With respect to the issuance of ERAs, permanence means that reductions or removals are not reversible. To issue ERAs for carbon capture and storage projects, the Partner jurisdiction must (a) have in place monitoring and verification requirements that are sufficient to enable the Partner Jurisdiction to establish that the sequestration is permanent; (b) have the ability to assure that ERAs will be replaced where a reversal occurs; and (c) apply these requirements to the applicable project

Additional

ERAs will be awarded in addition to partner allowance budgets. Therefore, in order to preserve the emissions reduction goals of the WCI cap-and-trade program and to provide incentives for reductions to take place before the program starts, projects should be rewarded ERAs for reductions and sequestrations of greenhouse gases that might have been deferred without an ERA program. Because the ERA program is of limited duration, WCI Partners have adopted a streamlined approach to additionality which minimizes the administrative burden.

Specifically, with respect to the ERA program, a reduction or removal will be considered additional if the source or facility can demonstrate that:

1. the reduction or sequestration results from a clearly identified action or decision that was initiated during the eligibility period; and
2. the annual averages of absolute emissions and emission intensity for the period of time that ERAs are being sought, are below the annual averages of absolute emissions and emission intensity for the reference period (2005-2007).

Fuel switching projects will only be considered additional if the source or facility can also demonstrate that the fuel switched to was more costly during the ERA eligibility period than the fuel switched from, or if the regulated facility underwent an equipment change during the ERA period to enable the switch to a lower carbon fuel.

Verifiable

With respect to ERA projects, verifiable means that a GHG reduction or removal, or assertion thereof, is well documented and transparent such that it lends itself to an objective review by a Partner jurisdiction or a qualified verifier.

Ownership

A source or facility for which ERAs are being sought must demonstrate that they own the GHG emission reduction resulting from the ERA project. This will help the jurisdiction ensure that the ERA is awarded to the source or facility actually responsible for the reduction, and will help avoid double counting of those reductions by other parties through the ERA provisions, or as offsets in voluntary registries.

Enforceability

The source or facility seeking recognition for a project is accountable to the WCI Partner Jurisdiction issuing an ERA for all statements and information provided to the WCI Partner Jurisdiction regarding the ERA project. Jurisdictions should adopt any measures they deem necessary to ensure their ability to enforce against the source or facility receiving ERAs.

4. Quantification methodology

4.1.1. Quantification of Emission Reductions

The total number of ERAs attributed to a project is based on cumulative reductions over the ERA period for the eligible project, and is calculated as follows:

If $I_{base} \leq I_{ERA}$, then:

Total ERAs Awarded = 0

If $I_{base} > I_{ERA}$, then:

Total ERAs Awarded = $A \times (E_{base} - E_{ERA})$ If $P_{base} \leq P_{ERA}$

Total ERAs Awarded = $[A \times (E_{base} - E_{ERA})] \times (P_{ERA}/P_{base})$ If $P_{base} > P_{ERA}$

Where:

A is the number of consecutive calendar years from when the ERA project/action begins and the end of 2011. The source or facility will indicate the number of years for which ERAs are being sought.

$\mathbf{E_{base}}$ and $\mathbf{P_{base}}$ are the average yearly emissions and production from January 1, 2005 to the end of 2007.

$\mathbf{E_{ERA}}$ and $\mathbf{P_{ERA}}$ are the average yearly emissions and production during the years where the source or facility is seeking ERAs (i.e. the number of consecutive calendar years from when the ERA project/action begins and the end of 2011).

$\mathbf{I_{base}}$ is the average emission intensity (emissions per unit of output) of the base period (i.e. from January 1, 2005 to the end of 2007)

$\mathbf{I_{ERA}}$ is the average emission intensity (emissions per unit of output) during the years for which the source or facility is seeking ERAs (i.e. the number of consecutive calendar years from when the ERA project/action begins and the end of 2011).

When using the above equations, applicants should use entire calendar years. Thus, the ERA period must start either on January 1, 2008, January 1, 2009, January 1, 2010, or January 1, 2011.

4.1.2. Data requirements

Emissions

All quantification should be done using the WCI Essential Reporting Requirements or the equivalent methods approved by the Partner Jurisdictions.

Output

Output is the amount of a good or service produced by a covered source or facility. Electricity generators should report net MWh of electricity produced. Industrial sources or facilities should use standardized forms of reporting, where such data is available. For example, industrial units located in the U.S. could report production using the same metrics as provided to the Federal Reserve for their *Industrial Production and Capacity Utilization Report*. However, in the event that such metrics are not accurate measures of output for a particular class of sources or facilities, then WCI partner jurisdictions may wish to allow those sources or facilities to propose alternative metrics. To mitigate gaming, sources or facilities should use the same metric for approximating output in both the base period (January 1, 2005 to January 1, 2008) and the early reduction period (January 1, 2008 to January 1, 2012).

Verification

All emissions and output reports used to establish ERA baselines or generate ERAs must be verified by an independent third party or government entity. Third party verifiers must be accredited to a standard acceptable by the WCI Partner Jurisdiction in which the project is registered. The source or facility awarded ERAs for a reduction project must keep for a period of at least 7 years and submit, under request, all documents related to the quantification of the reduction or removal.

4.2. Specific requirements and description of the application process

WCI Partner jurisdictions who choose the application process will need all applications for ERAs to be submitted no later than July 1, 2012. This timeline will provide the applicants with sufficient time after their emissions data is finalized to complete their applications for ERAs. The timeline will also provide sufficient time to Partner jurisdictions to issue ERAs no later than the first quarter of 2013 and Partner jurisdictions will endeavor to award them before the end of 2012.

Applications for ERAs should be submitted to the WCI jurisdiction in which the source or facility has a compliance obligation and where the reductions or removal took place. To reduce the administrative burden of reviewing applications, the WCI will develop standardized forms that Partner jurisdictions can require applicants to use. In addition, some Partner jurisdictions may also provide pre-application consultation.

4.3. Specific requirements and description of the program authority review

The program authority review enables Partner jurisdictions that already have much of the facility-level information specified in sections 4.1.1 and 4.1.2 above to minimize their administrative burden by not requiring an application process.

Under this approach, a Partner jurisdiction estimates emission reductions based on this facility-level information to determine a Partner's maximum number of potential ERAs it is planning on distributing.

To ensure no ERA gets awarded for unrealized emission reductions, the information used to determine the number of ERAs the Partner jurisdiction expects to issue will be verified by a government agency or independent third party after the reductions take place. In the case emission reductions are lower than expected; the total number of ERAs the Partner jurisdiction plans to issue will be reduced to reflect actual reductions that took place during the eligibility period.

As with the application process, the Partner jurisdiction will issue ERAs no later than the first quarter of 2013 and will endeavor to award them before the end of 2012. Only verified emission reductions receive ERAs, even if this is less than the initial estimate. ERAs cannot be issued beyond the amount of the initial estimate or beyond verified emission reductions.

5. Special Considerations for Individual Project Types

This section provides additional guidance for project types that present unique challenges to ensuring that their emissions reductions are voluntary, additional, real, verifiable, permanent, and enforceable.

Fuel Switching

Switching from high to low carbon intensity fuels can help a source or facility reduce its GHG emissions. Sometimes fuel switching will occur naturally due to changes in relative fuel prices. To ensure that ERAs are only awarded for projects that might have been deferred without an ERA program, fuel switching projects should only qualify for reductions if the fuel switched to is more costly during the ERA period than the fuel switched from, or if the regulated facility underwent an equipment change during the ERA period to enable the switch to a lower carbon fuel. As discussed previously under the ownership guidelines, sources or facilities must demonstrate that they have ownership over the emissions reductions for which they are seeking ERAs. Therefore, if a source or facility is seeking ERAs for switching from a high to a low carbon fuel, then they must also demonstrate that the reductions are not also being claimed by the fuel provider and thus double counted in any other regulatory or voluntary program (e.g., to meet renewable fuel standards or low carbon fuel standards).

Fuel Providers

Fuel providers can receive ERAs for a reduction in on-site emissions. They can also receive ERAs for reductions that result from the reduction in the carbon intensity of the provided fuel, through the use of lower-carbon, or carbon-neutral sources. However, for such reductions to qualify for ERAs, they cannot contribute to compliance with any required low carbon fuel standard or renewable fuel standard. Reductions in fuel sales are not eligible for ERAs because such projects do not result in a reduction in the intensity of emissions. As discussed previously under the ownership guidelines, the source or facility must demonstrate that they have ownership over the emissions reductions for which they are seeking ERAs. Therefore, if a fuel provider is seeking ERAs for reducing the carbon intensity of their fuels, then they must demonstrate that the reductions are not also being claimed by the user of the fuel and thus double counted in any other regulatory or voluntary program (e.g., as ERAs or as offsets in a voluntary registry). Also, the fuel provider must demonstrate that the reductions are indeed voluntary, and are not being used to meet renewable or low carbon fuel standards.

Electricity Importers

Using the application process, ERAs may be issued for electricity imported into a WCI Partner jurisdiction that does not come from another WCI Partner jurisdiction as long as it meets all other criteria outlined in Section 3 above. An importer would apply to the Partner jurisdiction with whom they have a compliance obligation. To qualify as an ERA, the capped entity will need show ownership of a qualifying reduction in both absolute emissions and emissions intensity at a specific facility whose power is produced for consumption within the WCI Partner jurisdiction.

6. Issuance of ERAs

Allowance prices are the product of relative supply and demand. The issuance of ERAs increases allowance supply, and thus will impact allowance prices. Therefore, in order to minimize market volatility partner jurisdictions should announce the total number of ERAs that they intend to issue on the same day. That information should be posted publicly to maximize transparency, and to ensure that all parties have access to this market-relevant information. To ensure that regulated entities can adequately factor ERAs issued into their compliance planning, WCI partners should publicly post the number of ERAs to be issued.

WCI Partner jurisdictions will review the applications and/or supporting material, and issue ERAs no later than the first quarter of 2013, and will endeavor to award them before the end of 2012.

7. ERA Implications for Budget Setting

Please see CSAD Task 2 documents for a discussion on the relationship between ERAs and Budget Setting.

8. Considerations for Jurisdictions that Implement the WCI Cap-and-Trade Program After 2012.

The September 2008 Design Document identified two mechanisms for recognizing early action. First, WCI Partner jurisdictions may issue Early Reduction Allowances in 2012 that are in addition to each WCI Partner jurisdiction's 2012 allowance budget. The other is early action and set asides allowances that come out of the individual Partner jurisdiction's allowance budget. The latter may be issued by any Partner including those that enter the cap-and-trade program after 2012. In addition, the Partners will evaluate and consider mechanisms to incentivize GHG reductions prior to the commencement of the program such as benchmarking.

Western Climate Initiative

Voluntary Renewable Energy Market: Issues and Recommendations

July 27, 2010 (Revised from January 14, 2010 Version)

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1 Executive Summary

In January of 2010 the Western Climate Initiative released an initial version of this paper, *Voluntary Renewable Energy Market: Issues and Draft Recommendations*. It was released for stakeholder comment and discussed at a stakeholder meeting on January 21st, 2010. This final version of the paper reflects stakeholder comment that was received at that session and through the comment period, as well as further reflection by the WCI electricity team.

Voluntary purchases of renewable energy products have played an important role in expanding the renewable energy market in many WCI Partner jurisdictions. However, the voluntary renewable energy (VRE) market may be impacted by the implementation of a greenhouse gas cap-and-trade program. The impact on the VRE market depends in part on expectations that VRE consumers may have about the emission reduction benefits associated with their purchases. Renewable generators located in capped jurisdictions no longer contribute to greenhouse gas emission reductions once a cap is in effect because the level of allowable emissions is determined by the cap. In light of this, consumers motivated primarily by the desire to reduce greenhouse gases may choose to opt out of the VRE market or direct their purchases to uncapped jurisdictions. WCI Partner jurisdictions that wish to address potential impacts on the VRE market from the cap-and-trade program have the option to adjust their baseline allowance budget to reserve (or "set aside") a pool of allowances for retirement that ensures that emission reductions occur for VRE market purchases. This type of VRE policy (a "VRE set aside") has been implemented in the cap-and-trade system in the US Northeast (the Regional Greenhouse Gas Initiative, or RGGI), and has been proposed in Australia. Conversely, no such program exists in the European cap-and-trade system or proposed federal US programs.

The WCI Design Recommendations provide that WCI Partner jurisdictions have broad discretion in determining whether to reserve their allowances for designated purposes. In accordance with these recommendations, no program-wide recommendation is made as to whether all Partner jurisdictions should implement a VRE set aside. While it is important, if not necessary, for linked cap and trade programs to harmonize on certain elements, it is not important for all Partner jurisdictions to harmonize on the choice of whether to implement a VRE set aside.

This paper focuses on discussing the key design elements of VRE set asides and provides recommendations to those WCI Partner jurisdictions that do choose to implement a VRE set aside. Elements on which it is important for the WCI Partner jurisdictions to harmonize are highlighted. These recommendations are summarized below in Table 1. Differences between the draft recommendations proposed in January 2010 and the final recommendations made in this paper are also noted in the table. Stakeholder comments on the original draft recommendations are summarized at the end of this report.

Table 1: Summary of Draft and Final Recommendations on VRE Set Aside Design Elements

Design Element	Draft Versus Final Recommendation	WCI Partner jurisdictions that choose to implement a VRE set aside should:	Importance of Harmonization
Accounting Mechanism for VRE Set Aside Program	Draft Recommendation	Include a requirement that the measurement of voluntary renewable energy purchases that form the basis of any allowance retirement be based, first and foremost, on transactions verified through established REC tracking systems that span some or all of the WCI region (e.g., WREGIS). In addition, to account for those purchases that are not tracked through an established system (or for regions without such a system) provision should be made to accept transactions that are certified through a third-party verification system for voluntary renewable energy that includes, at a minimum, a requirement that the seller must attest to not having previously sold or otherwise transferred the greenhouse gas benefits of the renewable energy product.	High
	Final Recommendation	Include a requirement that the measurement of voluntary renewable energy purchases that form the basis of any allowance retirement be based on transactions verified through established REC tracking systems that span some or all of the WCI region (e.g., WREGIS).	
Defining Eligible Renewable Energy Project Types	No Change	Define their own eligibility requirements for their VRE set aside programs. They may choose to mirror existing RPS or other statutory definitions or to define a separate list of qualifying project types.	Low
Jurisdictional Retirement Responsibility	Draft Recommendation	Retire allowances using a generator-based approach in which allowances are retired whenever RECs from a facility in that WCI Partner jurisdiction's territory are purchased and retired by a customer in the VRE market with no limitation on the customer's location. Alternatively, the retirement should be based on VRE sales if RECs are not used.	High
	Final Recommendation	Retire allowances using a generator-based approach in which allowances are retired whenever RECs from a facility in that WCI Partner jurisdiction's territory are purchased and retired by a customer in the VRE market with no limitation on the customer's location. WCI Partner jurisdictions should also consider requiring that renewable energy produced by VRE-eligible facilities in a non-WCI Partner jurisdictions and sold on a specified basis to the WCI Partner jurisdiction be counted as if those facilities were located in the WCI Partner jurisdiction.	

Upper Limit on Retirement Amount	Draft Recommendation	Choose whatever upper limit (if any) that is found appropriate for that jurisdiction. Partner jurisdictions must determine if they will cover shortfalls by either borrowing allowances from a future year or lowering the per MWh retirement rate.	Low
	Final Recommendation	Choose whatever upper limit (if any) that is found appropriate for that jurisdiction. Partner jurisdictions should cover shortfalls that do occur in a compliance period by moving any remaining allowances not dedicated to other purposes into the set aside account or borrowing allowances from future years' VRE set aside accounts. In addition, when the number of allowances to be retired approaches the chosen limit, the WCI Partner jurisdiction could choose to close the eligibility of the VRE set aside to new projects and therefore restrict the supply to near the level of the limit to ensure long-term stability for existing projects.	
Time Limit on VRE Set Aside Program	Draft Recommendation	Choose whatever time limit (if any) that is found appropriate for that jurisdiction. Partner jurisdictions may choose to base time limits on periodic reviews of the cost-competitiveness of the technologies supported by the set aside program.	Low
	Final Recommendation	Choose whatever time limit (if any) that is found appropriate for that jurisdiction. However, to provide greater certainty to project developers, Partner jurisdictions should consider a minimum length of time from the date a VRE-eligible facility commences operations that it will be supported by the set aside. Partner jurisdictions may choose to delist technologies from eligibility based on periodic reviews of the cost-competitiveness of the technologies supported by the set aside program, but the last eligibility date for delisted project types should be announced well in advance.	
Emission Attribution for VRE Purchases	No Change	Work together to develop a rate based on a marginal dispatch analysis, such as the WCI Default Emission Factor Calculator, for each major grid region. However, use of this rate should be optional and specific assignment of emissions left to jurisdictional discretion.	Medium

2 Background

The WCI Partner jurisdictions committed to a set of principles when designing the WCI Regional Cap-and-Trade Program. A theme in those principles is the support of renewable energy by "diversifying energy sources" and "stimulating investment … in low carbon technologies"[1]. Therefore, increasing the amount of energy generated by renewable energy sources in the WCI region is a key goal of the WCI Partners. Much of the growth in renewable energy in the WCI region will happen through the economic incentives created by cap-and-trade, government mandates on load-serving entities to obtain renewable energy, and other complementary policies such as direct procurement or feed-in tariffs. Additional growth may come from energy consumers that make individual, voluntary decisions to purchase renewable energy in the voluntary renewable energy (VRE) market.

At present individual decisions to purchase renewable energy in the WCI region can potentially lead to reductions in greenhouse gas emissions.[2] Implementing a cap-and-trade program changes that dynamic because under a cap-and-trade program the amount of greenhouse gas emissions allowed in the region are pre-established by the cap level. As a result, decisions to purchase renewable energy – beyond what is cost-effective after imposition of a carbon price – free up emission allowances that would have been needed to generate electricity from fossil fuels, allowing other regulated entities to emit more than they could have otherwise. In essence, the voluntary purchase of renewable energy lessens the regulatory burden on greenhouse gas emitters. A large number of such VRE purchases has the potential to marginally decrease the cost of the program by eliminating the need for what may have otherwise been the most expensive[3] mitigation measure necessary to meet the cap. Therefore, in order for VRE purchases from facilities in the WCI region to deliver climate benefits beyond those achieved by the cap, those purchases must either lead to a reduction in the total number of allowances in the system or the emissions value of the allowances in the WCI system must be reduced.[4]

VRE consumers may be motivated to support renewable energy due to any one of various benefits renewable energy provides. These benefits include economic development ("green

[1] Western Climate Initiative, "Design Recommendations for the WCI Regional Cap-and-Trade Program", September 23, 2008.

[2] This assumes that those decisions happen in the context of a program structure that can guarantee incremental increases in renewable energy generation. Without a firm program structure the same generation mix may simply be allocated differently; zero-carbon electricity may get diverted to interested customers while the energy mix to indifferent customers may become slightly more carbon intensive as zero-emission sources are stripped out.

[3] And therefore likely the price setting mitigation measure.

[4] For example, starting in 2010 the SO_2 allowances, which were allocated in perpetuity by the Acid Rain program, are worth less than a ton under EPA's more recent Clean Air Interstate Rule in order to reduce emissions more rapidly than envisioned when the Acid Rain program was established.

jobs"), reduced dependence on fossil fuels ("energy independence"), reduced use of nuclear power, and numerous environmental benefits, including reduced (or avoided) greenhouse gas emissions.[5] Customers in the VRE market that are largely motivated by the desire to reduce greenhouse gas emissions, and that are aware that the presence of a cap and trade system will undermine those emissions benefits, may either stop purchasing VRE products or direct their purchases to sources in uncapped areas. As a result, the VRE market in the WCI region may be significantly impacted by the introduction of a cap-and-trade system. However, the extent of the impact on the VRE market is difficult to predict.

Support of the VRE market through a policy mechanism may be necessary to support a robust VRE market if consumer expectations of greenhouse gas reductions through voluntary purchases of renewable energy are not sufficiently met. This paper focuses on the key issues in deciding whether the VRE market should be actively supported by jurisdictions in the WCI cap-and-trade program and if so, how a policy mechanism that supports the VRE market should be designed and implemented.

3 Current Status of the Voluntary Renewable Energy Market

The VRE market started when some utilities began offering green power programs to their customers. These programs enabled their customers to support the development of "green power"—wind and other renewable energy generation—by paying the incremental cost of renewable energy above the cost of the conventional generation sources the utility would otherwise build. The utility in turn used the revenue to purchase electricity from renewable generators or to build renewable resources of its own. The introduction of renewable energy credits (RECs) which allowed the renewable attributes to be sold separately from the power enabled other players besides utility customers to participate by allowing buyers to pay for renewable energy generated anywhere in the United States. Renewable developers and utilities could sell RECs to anyone who wanted to be able to claim that, in principle, large percentages of their electricity came from green resources.

Today, green power programs are flourishing in the United States. More than 750 utilities offer them nationwide and 13 states mandate that their utilities offer them to customers, including the WCI Partner jurisdictions of Washington, Oregon, Montana, and New Mexico.[6] The average rate of participation in 2008 among eligible customers was 2.2% with the top ten programs reaching from 5% of customers up to a high of 21%. Actual energy sales amounted to almost 5 million MWh in regulated energy markets. In restructured markets, sales of green power tend

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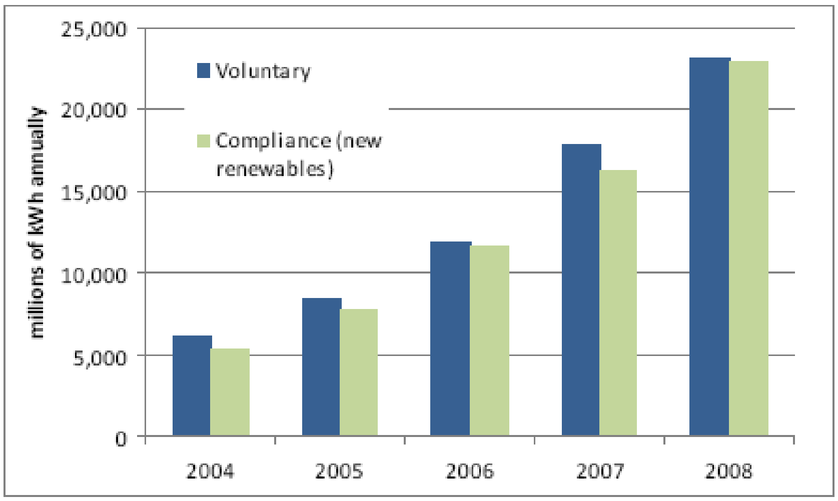
[5] Another factor driving VRE purchase decisions is whether they are perceived as producing incremental growth to the renewable energy market. For purposes of this paper, it is assumed that the VRE market provides enough value to the renewable energy market to produce additional renewable capacity beyond business-as-usual levels.
[6] See http://apps3.eere.energy.gov/greenpower/markets/state_policies.shtml.

to be in the form of RECs, which accounted for over 80% of VRE sales. Direct renewable energy sales in restructured markets and voluntary RECs combined amounted to almost 20 million MWh in 2008. Total VRE direct sales and RECs accounted for 0.7% of electricity sales nationally.[7] Residential customers dominated the markets for sales of energy while commercial customers dominated the REC markets, which have been growing much faster than the market for green energy products.

Figure 1: Comparison of Voluntary and Compliance Markets for Renewable Energy in the United States (Source: NREL)[1]

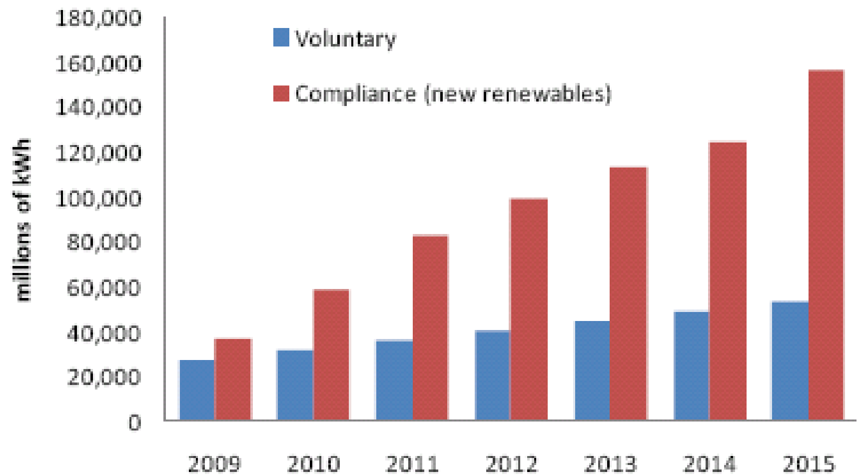


Note: Compliance market data sourced from Lawrence Berkeley National Laboratory (LBNL) (Barbose 2009)

Although green power programs have grown rapidly over the last ten years, renewable portfolio standards (RPS) in many states have served to drive a comparable amount of new renewable generation capacity (See Figure 1). Twenty nine states plus the District of Columbia now have legislation requiring load serving entities to supply increasing percentages of their resource portfolios with renewable energy with targets ranging from 10-25% by the 2020s. It is projected that these amounts will soon overtake the voluntary market (See Figure 2).

[7] US. DOE/EIA, 2009. Electric Power Monthly – Retail Sales of Electricity to Ultimate Customers: Total by End-Use Sector. http://www.eia.doe.gov/cneaf/electricity/epm/table5_1.html

Figure 2: Projected Voluntary Renewable Energy Market Relative to Compliance Market to 2015 in the United States (Source: NREL[1])



The voluntary market in Canada is relatively small compared to the US. A minority of provinces have utility green pricing programs or private green marketing programs. This reflects the fact that electricity generation already incorporates a large renewables component in most provinces. In addition, most provinces have adopted renewables procurement programs through government-owned utilities, with results similar to an RPS but without RECs, leaving limited opportunity for voluntary renewables. The degree of government ownership may also pose a barrier, in that private sector investment opportunities are limited in many provinces. Nonetheless a small number of retailers have been successful in establishing a voluntary market for renewable energy in some provinces. Voluntary renewables marketing has been most prevalent in the provinces with greater private ownership, including Ontario. The voluntary market for renewables in Canada today is estimated to be around 500,000 MWh/year[8].

4 Overview of VRE Support Policies under Cap-and-Trade

Because a significant portion of the VRE market has been driven by purchasers motivated by a desire to reduce greenhouse gas emissions[9], the implementation of cap and trade may harm the VRE market. WCI Partner jurisdictions must decide whether to support the VRE market to ensure that it is not disadvantaged by the adoption of a cap-and-trade program. The alternative is to simply allow the VRE market to adapt to the presence of cap and trade programs. These two approaches are described and discussed in detail below.

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[8] Commission for Environmental Cooperation, *Fostering Electricity Markets in North America,* April 2007, http://www.cec.org/files/pdf/ECONOMY/Fostering-RE-MarketsinNA_en.pdf

[9] Historically a small number of VRE market participants (largely corporate buyers) have been responsible for the majority of VRE sales, while the majority of VRE market participants are individual residential green power customers with minimal purchases. The market behavior of these two groups of VRE market participants may vary, which greatly complicates predicting how the VRE market will respond to cap-and-trade programs.

4.1 Allowance Budget Adjustment Approach ("VRE Set Aside")

One possible policy response to support a VRE market would be to implement a VRE budget adjustment mechanism to allow the desired emission reductions to occur when VRE products are purchased from facilities subject to the cap. This is achieved by carving out a number of allowances from the Partner's base budget and setting those allowances aside to potentially be retired based on the estimated amount of voluntary renewable energy expected to either come on line in that Partner's state or province, or the amount of VRE products purchased by consumers in that state or province. Once the expected energy sales (in terms of MWhs) have been verified, allowances would be permanently retired. If there is a balance, those allowances could be released, or rolled over to the set aside for the following time period.

Historically programs that reserve a portion of an overall budget of allowances for a certain purpose within a cap-and-trade system have been called a "set aside", referring to the fact that this portion of the allowances are reserved and literally set aside for the designated purpose. Once allowances are set aside their value can be directed to support the designated purpose, or the allowances can be retired depending on how the program is designed. In the case of implementing a VRE budget adjustment mechanism for the purposes of ensuring that emission reductions accompany the VRE products in the marketplace, it is necessary that the allowances be retired. Following this tradition, most of the literature on addressing the VRE market focuses on "VRE set asides" to describe the VRE budget adjustment mechanism described here. This paper will continue this tradition and refer to the policy option described in this section as a "VRE set aside". It is important to understand that the VRE set aside referred to in this paper is what is known as an "unallocated set aside" because the allowances are specifically intended to be retired (and not allocated to a programmatic use). Using the allowances set aside from the jurisdiction's overall budget for other purposes, such as selling them and using the revenue (except for any unused balance), would defeat the purpose of the VRE set aside program.

Determining the number of allowances to set aside requires two steps. First, the implementing jurisdiction must estimate the future size of the VRE market in its jurisdiction. Market data and tracking systems can be used to estimate, track and verify voluntary renewable energy expected to come on line and enter the VRE marketplace. These estimates can assist WCI Partner jurisdictions in establishing the number of allowances to set aside for a given year. For example, WCI Partner jurisdictions could use data from their energy agencies or organizations such as the Center for Resource Solutions.[10] The second step is the use of an emission factor to convert the MWh estimate of VRE sales to metric tons of greenhouse gases. Emissions factors are discussed further in Section 6.5.

[10] Center for Resource Solutions; 2008 Green E Verification Report; http://www.green-e.org/docs/2008%20Green-e%20Verification%20Report.pdf

In order for allowances to be retired from the set aside, VRE market participants will need to submit verification reports of the VRE sales. This could be accomplished via tracking systems such as the Western Renewable Energy Generation Information System (WREGIS). WREGIS covers the Western Electricity Coordinating Council region (the western grid) and generates a REC for every MWh of renewable energy generation that is verified.

Table 2: Example of Voluntary Renewable Energy Set Aside Mechanism

Estimated VRE MWh sold in 2012	Example Set Aside Emission Factor	Allowances in 2012 Reserve	Actual VRE MWh sold in 2012	2012 Allowances Retired by Jurisdiction	2012 Allowances Unused
1,000,000	0.40 tCO2e	400,000	900,000	360,000	40,000

Table 2 provides an example of how a voluntary renewable energy set aside mechanism could work. Based on information provided by VRE vendors, the state or province estimates approximately 1,000,000 MWh of electricity (or a combination of direct energy sales and RECs) will be sold into the voluntary renewable energy market in 2012. The jurisdiction has determined that 0.40 metric tons CO_2e per MWh will be the emission rate used to retire allowances from the set aside for every MWh of voluntary renewable energy generated annually. Thus, the jurisdiction sets 400,000 allowances aside in the VRE reserve account. At the end of the year, the jurisdiction certifies that only 900,000 MWh of VRE were sold in 2012. In this case, only 360,000 allowances will be retired and the remainder is released or rolled over to 2013.

If a set aside is created for the VRE market, it may set an interesting precedent. Assuming that most VRE buyers are primarily motivated by a desire to reduce greenhouse gas emissions, the rationale for creating a VRE set aside could apply equally to other products and actions that reduce emissions. For example, many households and firms undertake measures to reduce their energy consumption. Without a set aside for energy efficiency, it could be argued that some of these households and firms may no longer implement efficiency measures knowing that if they do, total greenhouse gas emissions will not change.

A counterargument to this example is that energy efficiency is generally cost-effective, and those who implement efficiency measures benefit from their actions. Purchasers of VRE products, on the other hand, pay a premium for the superior environmental attributes of renewable energy, in effect providing a public good at their own expense. This difference may justify the creation of a set aside for VRE but not energy efficiency. However, there are other examples where consumers pay a premium for environmental attributes that are not cost-effective. Presumably, purchasers of hybrid vehicles do so largely for the environmental advantages that such vehicles provide because in most cases, these vehicles only recoup their price premiums over long time horizons (if ever). If a VRE set aside is established, vendors of hybrid vehicles may also ask for a hybrid-vehicle set aside using similar logic.

For these reasons, WCI Partner jurisdictions that choose to implement a VRE set aside may need to provide a rationale for limiting such a set aside mechanism to only VRE products. Otherwise additional set asides for different classes of products may be required, necessitating tracking the sales of a wide variety of products, and potentially leading to an unacceptably large pool of unallocated allowances dedicated to set asides.

4.2 No Intervention Approach

There are various reasons that WCI Partner jurisdictions may choose not to create a VRE set aside. Some jurisdictions may have little VRE market activity or no VRE market at all. Others may decide that the future growth of renewable energy will be driven mostly by mandatory renewable portfolio standards or other policies that put a price on greenhouse gas emissions. Others may not want to establish a program that potentially reduces the number of total allowances available for distribution or auction, including the possibility of losing the value of those allowances to support other types of programs for promoting renewable energy[11]. A VRE set aside may also impact allowance prices (which may in fact help to offset the fiscal impact of a reduced number of allowances), and can potentially have some impact on the opportunity for firms that reduce their emissions to sell excess allowances. However, the economic effects of a VRE set aside – both positive and negative -- are exceedingly difficult to predict and depend on the complex interactions of the supply and demand of allowances. Finally, some jurisdictions may conclude that the VRE market will continue to be viable for a number of reasons regardless of whether total greenhouse gas emissions reductions can be guaranteed to take place when purchases of renewable energy occur.

One reason the VRE market may continue to be viable is that some buyers may value other environmental or socioeconomic benefits associated with renewable energy more than greenhouse gas reductions and would continue to buy VRE products from jurisdictions participating in a cap-and-trade system even if greenhouse gas reductions are not ensured. Other buyers may be more concerned with their personal “carbon footprints” than with the impacts that their purchase decision have on total greenhouse gas emissions. This is because from the perspective of an individual consumer, buying VRE products still reduces the carbon footprint of the individual buyer even if total emissions (at the jurisdictional or regional level) do not fall.[12] However, it is important to note that these motivations would seem to be more likely for residential and commercial consumers, which have historically made up a small

[11] For example, increased funds for existing public purpose funds supporting renewable energy projects.
[12] This assumes the purchase is from a jurisdiction participating in the cap-and-trade program.

proportion of the total volume of VRE purchases. Large corporations have appeared to be more focused on greenhouse gas reduction benefits[13], although the behavior of large corporate customers in the VRE market in the future is unclear (especially when some of these corporate customers may be regulated entities in any future cap-and-trade program).

In the jurisdictions that choose not to implement a VRE set aside, VRE markets may adapt in several ways. VRE certifiers face the option of either de-certifying renewable generators from eligibility in their programs or changing the way they market VRE from capped jurisdictions. For example, VRE marketers could sell RECs from capped jurisdictions with the understanding that no emission reductions claims can be made when those RECs are used. Purchasers of these RECs should understand that while claims of using "renewable" or "zero-greenhouse gas" power would continue to be valid, any claim to an emission reduction would not be valid. Alternatively, generators or marketers of VRE products can potentially obtain and retire a sufficient number of emission allowances within the cap-and-trade system to provide the emissions reduction advertised or otherwise conveyed to the buyer of those renewable energy products (if there is an auction or other means to obtain allowances). It would be up to each seller in the VRE market to decide whether or not they want to package a given amount of greenhouse gas emission reductions with their renewable energy products, and they would obtain the appropriate amount of allowances and bundle or retire them to meet that claim.

If there is concern that, in the absence of a VRE set aside program, some sellers of VRE products may claim emission reductions for which they have no basis there are several options. One option may be to simply enforce existing consumer protection law at the state or provincial level. In the USA the National Association of Attorneys General's (NAAG) has already determined that making invalid claims to emission reductions may violate existing consumer protection laws and has promulgated guidance for states on enforcement options[14]. Therefore, it may not be necessary for a WCI Partner Jurisdiction to take any additional action in order to ensure that a legal basis exists for enforcing the market to ensure that valid emission reduction claims are tied to actual emission reductions.

Government intervention in the form of an explicit requirement to obtain allowances before making emission reduction claims may be an another option if it is felt that existing law or rules are not sufficient to ensure that false claims are not made in the VRE market. Since it is likely that the provisions for this type of government-backed guarantee would happen in a legal or regulatory framework outside of the cap-and-trade system (e.g., consumer fraud rules) this approach would likely not involve including a program element specific to the VRE market in the cap-and-trade program. Therefore, even if a VRE set aside program is silent on how

[13] Based on corporate press releases (see submitted comments), but more precise data are lacking.
[14] NAAG, *Environmental Marketing Guidelines For Electricity*, December 1999.

environmental claims of VRE marketers are addressed, it is important to understand that VRE marketers may be subject to rules or regulations outside of the cap-and-trade system that will likely prevent them from making false emission reduction claims in the VRE market.

It is important to note that an approach of requiring that allowances be obtained (either explicitly or implicitly through existing law or regulations) for VRE products sold to consumers would increase the price premium for VRE products and disadvantage renewable facilities in capped jurisdictions that seek to compete in the VRE market. Even if it is not required by law or regulation, it is possible that many VRE sellers would include allowances as part of their VRE product offering. As a result, the VRE market in the WCI region would be impacted, although it is difficult to predict the extent to which the overall market would be reduced.

5 Status of VRE Approaches in Other Trading Schemes and Proposed Federal Legislation

The following existing or proposed cap-and-trade programs were reviewed to identify how they address the VRE market prior to the development of the recommendations in this paper.

- Regional Greenhouse Gas Initiative (RGGI), the greenhouse gas emissions cap-and-trade program currently in place in the Northeastern United States.
- European Union Emissions Trading Scheme.
- American Clean Energy and Security Act of 2009 (H.R.2454), commonly referred to as Waxman-Markey, which was passed by the U.S. House of Representatives.
- Kerry-Lieberman, the U.S. Senate version of American Clean Energy and Security Act of 2009 that is still undergoing debate and revision in the US Senate.
- The proposed Australian Carbon Pollution Reduction Scheme.

Table 3 below summarizes how these proposals or programs address the VRE market:

Table 3: Treatment of Voluntary Renewable Energy in Cap-and-Trade Systems and Proposals

Cap-and-trade program or proposed legislation	Voluntary Renewable Energy Market Directly Addressed?	Policy Mechanism Used to Address VRE Market	Potential Indirect Means of Addressing VRE Market
US Regional			
Regional GHG Initiative (RGGI)	Yes	Set aside as optional element of RGGI Model Rule.	Not necessary
European Union			
EU Emissions Trading System (EU ETS)	No	None	Unclear
US National Legislation and Proposals			
American Clean Energy And Security Act of 2009 (Waxman-Markey)	No	None	Allowances are distributed to states for renewable energy. States may use those allowances to implement a program like a VRE set aside at a state-by-state level.
Kerry-Lieberman (Senate version of ACES)	No	None	Discussion draft only, presumably similar to Waxman-Markey
Australia National Legislation			
Carbon Pollution Reduction Scheme (proposed)	Yes	By taking GreenPower (official VRE program) purchases above 2009 levels into account when setting program's emission caps.	Not necessary

5.1 Overview of the Australian VRE Market Approach

Australia's proposed greenhouse gas emission trading scheme is referred to as the Carbon Pollution Reduction Scheme (CPRS). This trading scheme would potentially reduce emissions from approximately 5 to 25 percent of 2000 levels by 2020, depending on the status of international treaty negotiations on a new binding global emissions reduction treaty.

The framework contains a provision for tightening the cap to recognize the contribution of additional renewable energy purchases.[15,16] The scheme sets a baseline for renewable energy purchases at the 2009 levels and factors renewable energy into setting the cap. If purchases go over that baseline the cap will be adjusted to recognize these contributions. If purchases fall below the baseline there will not be an adjustment of the cap.

Twice in 2009 the Australian Senate voted against establishing the program. The new Australian Prime Minister Julia Gillard has indicated she intends to pursue the legislation again.

[15] http://www.climatechange.gov.au/government/initiatives/cprs/voluntary-action.aspx
[16] http://whitepaper.climatechange.gov.au/emissionstrading/householdassistance/pubs/fs_GreenPower.pdf

5.2 Overview of the RGGI Model of a VRE Set Aside

The RGGI Model Rule contains a provision for a VRE set aside program. In RGGI the number of allowances retired is pegged to the CO_2 emissions that would have been avoided in the absence of the cap. This is calculated using two types of data:

- The amount of voluntary renewable energy purchased (typically in megawatt-hours, or MWh); and,
- The emissions rate of the electric generating source that would have run had the renewable energy not been purchased (expressed in tons CO_2/MWh).

Because the number of allowances reserved for the set aside is based on *ex ante* estimates of VRE sales, it is possible that the number may be too high or too low in any given year. The Model Rule contains provisions to adjust the size of the VRE set aside in subsequent years accordingly.

These set aside provisions are an optional part of the RGGI Model Rule, and therefore participating jurisdictions are not obligated to adopt them. However, at this time 9 of the 10 RGGI states have adopted them.

6 Implementation of VRE Set Asides in WCI Jurisdictions

A key decision made by the WCI Partner jurisdictions in the "Design Recommendations for the WCI Regional Cap-and-Trade Program" is that each jurisdiction has discretion over how the allowances apportioned to that jurisdiction are to be used. Other than agreeing that "some portion" of the apportioned allowances will be used for purposes like supporting renewable energy, which a VRE set aside would fit under, there is currently no common agreement among the Partner jurisdictions to require a VRE set aside in the design of each jurisdiction's cap and trade program. In keeping with the WCI design recommendations, it is therefore up to each individual WCI Partner jurisdiction whether or not to implement a VRE set aside program in their jurisdiction. For those jurisdictions that do choose to put in place a VRE set aside program there are a number of design issues associated with implementation. The remainder of this paper focuses on those key design issues that will need to be examined by any WCI Partner jurisdiction that chooses to implement a VRE set aside program.

An important consideration in examining the design elements of a VRE set aside program is the extent to which certain elements need to be harmonized across participating jurisdictions. In other words, for each of the design elements examined below can each jurisdiction make its own policy choice without impacting the effectiveness of a VRE set aside program in either another WCI Partner jurisdiction or the WCI region as a whole? Particular attention to this question is given as each design issue is addressed. For comparison, the approach that RGGI took for each of these points of implementation is also summarized. Finally, the draft recommendation originally proposed to WCI Partner jurisdictions for each design question is given, as well as the final recommendation of the WCI Partners, after considering stakeholder comments.

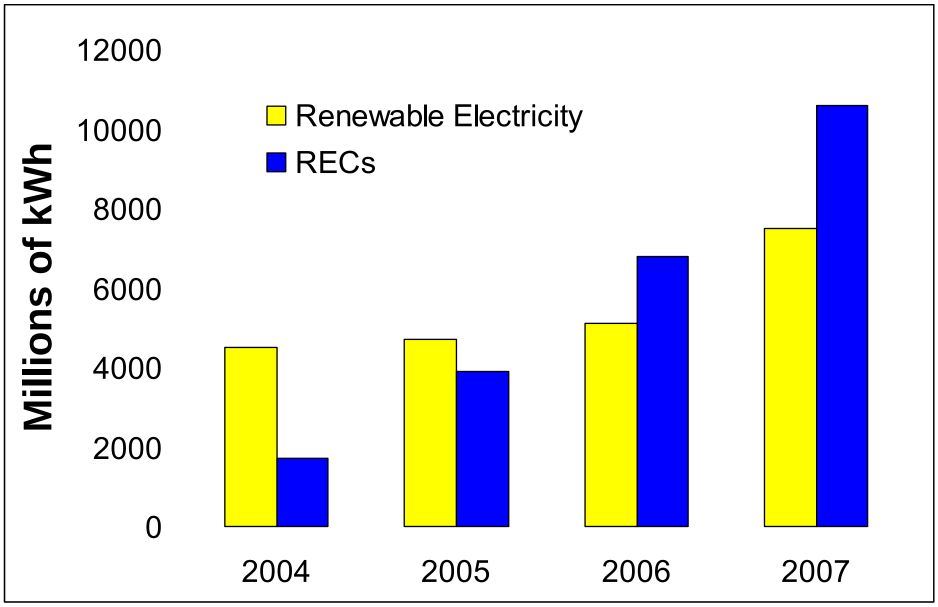
6.1 Accounting Mechanism for the VRE Set Aside

There are two broad classes of products in the voluntary renewable electricity market: renewable electricity and renewable energy credits (RECs). RECs are the renewable attributes created by the generation of electricity from a renewable source and serve as proof of generation of (typically) one MWh of renewable energy generation. They can be sold bundled with the electricity underlying the REC or unbundled and bought and sold independently of the electricity produced. Unbundled RECs are often re-bundled with generic electricity to rebrand the generic electricity as green electricity. RECs may be defined solely by their primary attribute (i.e., that a MWh of renewable electricity was generated) or they may include reference to secondary attributes such as the greenhouse gas emissions avoided by displacing conventional generation. The inclusion of secondary attributes varies across states with respect to RECs used for compliance with renewable portfolio standards, but RECs used in the secondary market generally include reference to the secondary attributes.

When implementing a VRE set aside program, a decision has to be made as to what "currency" the program should use. One option is to base the program on actual renewable energy sales, and typically the basis for measuring VRE transactions are documents such as the sales receipt, sales contract, or other similar proof of the transaction. Another option is to use RECs as the currency to serve as the proof of renewable generation. This is convenient since the primary purpose of a REC is to serve as an easily transferable and trackable proxy for other legal documents (such as sales contracts) which provide the legal basis for ownership of the renewable energy in the voluntary renewable energy market. For this reason, renewable energy programs of all types (voluntary and mandatory) are increasingly using RECs. According to the National Renewable Energy Laboratory[17], about 95 percent of residential consumers purchased renewable electricity (typically through green power utility programs) instead of unbundled RECs in 2007. However, nonresidential customers clearly prefer unbundled RECs, which amount to over 90 percent of sales for these customers. REC sales (99% of which are to nonresidential consumers) accounted for nearly three-quarters of all voluntary renewable product sales in 2007 (see Figure 3).

[17] Lori Bird, Claire Kreycik, and Barry Friedman. Green Power Marketing in the United States: A Status Report (11th Edition). National Renewable Energy Laboratory. http://www.nrel.gov/docs/fy09osti/44094.pdf

Figure 3: Estimated Annual Green Power Sales 2004-2007[18,19]



RGGI Model Rule

The RGGI model rule allows the use of both renewable electricity[20] and unbundled RECs. Some RGGI states rely primarily on the use of RECs for tracking VRE purchases but others allow purchases of both renewable electricity and unbundled RECs to qualify for their programs.[21]

Draft Recommendation

> *WCI Partner jurisdictions that choose to implement a VRE set aside should include a requirement that the measurement of voluntary renewable energy purchases that form the basis of any allowance distribution be based, first and foremost, on transactions verified through established REC tracking systems that span some or all of the WCI region (e.g., WREGIS). In addition, to account for those purchases that are not tracked through an established system (or for regions without such a system) provision should be made to accept transactions that are certified through a third-party verification system for voluntary renewable energy that includes, at a minimum, a requirement that the seller must attest to not having previously sold or otherwise transferred the greenhouse gas benefits of the renewable energy product.*

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[18] Ibid.
[19] 2006 sale figures for renewable electricity may be underestimated because of data gaps (Ibid).
[20] Note that this means both renewable electricity purchased directly and bundled RECs (REC + electricity).
[21] RGGI State Set-Aside Provisions for Voluntary Renewable Energy (VRE). Draft August 21, 2009. http://www.epa.gov/greenpower/documents/events/rggi_status_table.pdf

The decision as to whether to use RECs or the renewable electricity (i.e., using contracts as the proof of generation) as the principal mechanism for tracking the quantity of VRE applicable to the set aside is one design feature where harmonization across WCI Partner jurisdictions is critical. Non-harmonization raises the potential for double-counting the renewable attribute because one jurisdiction may retire allowances for the electricity generated while another retires allowances for the RECs purchased for the same electricity. Harmonization ensures that each MWh of renewable energy in the voluntary market is claimed only once by a final user.

Final Recommendation

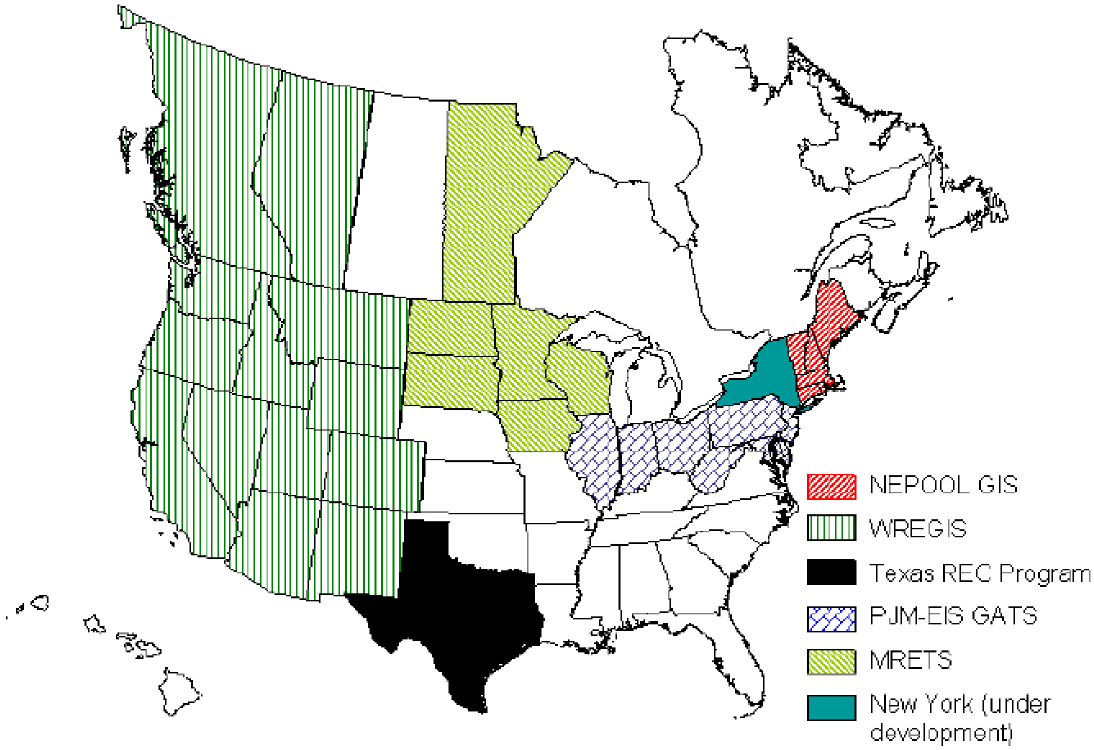
> *WCI Partner jurisdictions that choose to implement a VRE set aside should Include a requirement that the measurement of voluntary renewable energy purchases that form the basis of any allowance retirement be based on transactions verified through established REC tracking systems that span some or all of the WCI region (e.g., WREGIS).*

With the launch of the North American Renewables Registry, and the general growth of REC tracking systems throughout the US and Canada, it was felt that the original draft recommendation that allowed for both REC tracking systems and third-party verification systems was unnecessarily broad. The added assurance provided by formal REC tracking systems is worth requiring for any VRE set-aside program, especially since all renewable energy projects in North America now have access to at least one formal REC tracking system.

6.2 Defining Eligible Renewable Energy Project Types

WCI Partner jurisdictions will need to decide which types of voluntary renewable energy projects should be encouraged through a VRE set aside. Establishing common criteria is challenging as jurisdictional RPS criteria vary, suggesting disparity about the types of renewable energy that each region wants to encourage. Requiring that renewable projects meet RPS criteria where applicable may provide additional assurance that allowances are only retired for desired projects so long as those RECs can be retired in a regional or North America-wide tracking system (see Figure 4).

Figure 4 -- Map of Regional Tracking Systems (Source: NREL)[22]



In addition, VRE certifying organizations (typically independent non-profit organizations or government agencies) have their own eligibility criteria that they are likely to overlay on any state or jurisdictional eligibility criteria.[23,24] In both cases, the eligibility criteria are likely to address not only the types of eligible renewable energy, but also provide some assurances that the renewable projects used for voluntary program purposes are authentic and also meet additional criteria which consumers may find desirable. For example, both the Canadian EcoLogo and the Green-E certification program for VRE certify that the projects that meet their requirements are "additional", i.e., that those projects were not required by government mandate and that the VRE purchase is helping to advance the renewable energy market above and beyond what would be happening without the purchase.

One issue worth noting, which is an ongoing concern with tracking and verification systems used in both the mandatory and voluntary renewable energy markets, is some of the market barriers that small-scale "behind the meter" renewable energy systems (typically residential

[22] Lori Bird and Elizabeth Lokey. Interaction of Compliance and Voluntary Renewable Energy Markets. National Renewable Energy Laboratory. October 2007. http://apps3.eere.energy.gov/greenpower/pdfs/42096.pdf
[23] Green-e certification criteria can be found at http://www.green-e.org/docs/energy/Appendix%20D_Green-e%20Energy%20National%20Standard.pdf
[24] An example of this can be found in Green-e's RGGI update http://www.resource-solutions.org/pressreleases/2008/120508-2.htm.

solar photovoltaic systems) have encountered in entering the VRE marketplace. In some cases the additional administrative costs or process issues associated with either (or both) the REC tracking systems used for the mandatory renewable market or the certification programs in the voluntary market have prevented the owners of these installations from becoming VRE market participants. If the VRE set aside policy option is focused solely on addressing the traditional VRE market, the VRE set aside option may not be of direct assistance to all entities that voluntarily produce renewable energy. Nonetheless, the decisions to install these smaller systems may be driven by similar motivations as in the VRE product market (i.e., greenhouse gas emission reductions). Therefore it may be worth including behind the meter distributed resources, such as residential systems, in the list of eligible resources for the VRE set aside to further encourage their growth. Since these systems are generally not registered with generation information systems like WREGIS and may not be configured to report output data at all, quantifying these systems for inclusion in the VRE set aside can be a challenge. WCI Partner jurisdictions that include small-scale solar or wind systems among their VRE set aside eligible resources will have to determine whether to limit eligibility to systems with metered output or whether to accept generation estimates for unmetered systems.

<u>RGGI Model Rule</u>

The RGGI Model Rule limits eligibility for retirement from the VRE set aside to electricity generated from biomass, wind, solar thermal, photovoltaic, geothermal, hydroelectric facilities certified by the Low Impact Hydropower Institute, wave and tidal action, and fuel cells powered by renewable fuels. However, this particular definition was intended to be optional. Several states have adopted it, while others have limited eligibility to renewables that meet their own RPS standards.

Draft and Final Recommendation

> *WCI Partner jurisdictions that choose to implement a VRE set aside should define their own eligibility requirements for their VRE set aside programs. They may choose to mirror existing RPS or other statutory definitions or to define a separate list of qualifying project types.*

Unlike the choice of accounting mechanism, jurisdictional consistency on eligibility criteria is less important. Marketers of VRE products will adapt to whatever eligibility criteria jurisdictions adopt. If a facility is eligible for set aside retirements, marketers will know that emission reduction claims are supported and can market energy or RECs from the facility accordingly. A modest advantage to harmonization is that potential project developers would not have to keep track of eleven different sets of eligibility criteria when financing and developing projects in WCI Partner jurisdictions.

6.3 Jurisdictional Retirement Responsibility

Another variable to consider when designing a VRE set aside is whether the jurisdiction responsible for retiring allowances is determined by the location of the purchaser or the generator. For example, when a renewable facility in a WCI Partner jurisdiction produces RECs that are used in the VRE market and then retired by an entity in another WCI Partner jurisdiction, which jurisdiction bears the responsibility for retiring allowances? Either approach is feasible, but the underlying rationale and effect differ. The purchaser-based approach serves to assure consumers in the jurisdiction where the VRE set aside is based that emission reductions occur regardless of the location of the renewable electricity facility. The generator-based approach supports renewable energy development in the jurisdiction where the VRE set aside is based by allowing emission reduction claims in the marketing of the VRE product to customers.

6.3.1 Purchaser-Based Responsibility

Under the purchaser-based approach, a WCI Partner jurisdiction retires allowances whenever a retail customer, utility, or VRE aggregator serving customers in the jurisdiction retires RECs from the VRE market from a facility in a capped jurisdiction.[25] The application of the set aside could be limited by various geographic criteria. If the goal is to both protect in-jurisdiction consumers and promote renewable development in the jurisdiction, the set aside could be limited to purchases from in-jurisdiction generators. If adoption of the set asides is widespread in the WCI Partner jurisdictions then jurisdictions may opt to apply the set aside to purchases from sources in any WCI Partner jurisdiction. Alternatively, this reciprocity could extend further to apply the set aside to purchases from any capped source (assuming that the capped source selling RECs in the VRE market is not already supported by a generator-based set aside).

This system is relatively simple where there is a direct connection between the in-jurisdiction person or entity retiring the RECs (or purchasing the electricity) and the facility. However, the fact that some VRE products consist of RECs purchased from a large number of facilities by VRE marketers complicates matters. If, for example, a REC retailer buys 5,000 RECs from capped jurisdictions and 5,000 RECs from uncapped jurisdictions, and then sells 5,000 RECs to customers in uncapped jurisdictions and 5,000 RECs to customers in a capped jurisdiction with a purchaser-based set aside, how many RECs should the set aside jurisdiction count when it retires allowances?

One option would be to assume that all customers receive the same share of RECs from each facility, that is, that all of the RECs are thoroughly mixed and then sold to customers. If the set aside jurisdiction assumes that all customers receive the same mix of renewables, then the

[25] Renewables from uncapped regions do not require allowance retirement because their generation does avoid additional fossil-based electric generation.

jurisdiction would apply 2,500 RECs toward its set aside on the basis that half of the 5,000 RECs used by customers in the jurisdiction came from capped areas and half came from uncapped areas. However, that would entail that 2,500 RECs from a capped area were sold to customers in uncapped jurisdictions, necessitating that those RECs could not be associated with claims of emission reductions.

Another option would be to allow REC marketers to specify the renewable generators used to supply RECs to their various customers. Under this approach, REC marketers in a purchaser-based model are likely to direct the maximum amount of RECs from capped areas to those jurisdictions that implement a set aside to ensure that no RECs are left without credible emission reduction claims.

The participation of large organizations with locations in multiple jurisdictions may add further complication to accounting under the purchaser-based approach. For example, if the headquarters of a large corporation is located in a set aside jurisdiction, and the headquarters coordinates the purchase of several hundred thousand RECs for its facilities throughout North America, a VRE marketer might report all of those RECs as being consumed in the set aside jurisdiction. If the jurisdiction does not believe that it should have responsibility for retiring allowances for all of the RECs in this example, either the marketer or the customer could provide information on the customer organization's consumption within the jurisdiction.

If the rationale for the set aside is to protect consumers in WCI Partner jurisdictions, VRE consumers based in a WCI Partner jurisdiction could simply buy RECs from uncapped jurisdictions. However, to the extent that demand for VRE is driven by customers primarily motivated by contributing to absolute greenhouse gas reductions, this "no action" solution to protecting consumers will push investment in renewable facilities serving the voluntary market toward uncapped jurisdictions. Purchaser-based retirement responsibility would not cover sales of RECs from facilities in the jurisdiction to VRE consumers in uncapped areas or capped areas without a set aside.

Because the RGGI Model Rule provisions do not retire allowances for exported renewable products, renewable energy generated inside the RGGI region will not have an emissions benefit when sold outside the RGGI region unless allowances are purchased and retired by the renewable energy marketers. This has led Green-e to announce that they are no longer certifying renewable energy generated inside the RGGI region and sold outside the RGGI region.[26] It is not clear whether this will have practical implications for the RGGI states in the short-term. High REC prices inside several RGGI states indicate that in-region supply of certain

[26] Green-e Energy Policy Update: RGGI State Set-Aside Provisions for Voluntary Renewable Energy Sales and Green-e Energy Eligibility. Green-e. December 5, 2008. http://www.resource-solutions.org/where/pressreleases/2008/120508-2.htm

types of renewables is already struggling to meet demand. This may be an indicator that the RGGI states are not currently strongly situated as net exporters of renewable energy products.

Purchase and generation data for WCI partner states available from Green-e and the National Renewable Energy Laboratory suggest that WCI Partner US States on the whole appear to generate more renewable products for sale on the voluntary market than they purchase from it, meaning that they are a net exporter of voluntary renewable energy products. Constraining retirement to in-region purchases could disrupt the market for renewable generation in WCI Partner jurisdictions.

Unfortunately, comparable data do not appear to be available for the Canadian WCI Partner jurisdictions, making it challenging to determine whether constraining retirement to in-region purchases would disrupt the market for renewable generation in Canada.

6.3.2 Generator-Based Responsibility

Under the generator-based approach to retirement responsibility, a WCI Partner jurisdiction would retire allowances whenever RECs from a facility in its territory were retired by customers in the voluntary market. Like the purchaser-based approach, the set aside could be limited to purchases by customers in the same jurisdiction, other WCI Partner jurisdictions, other capped jurisdictions, or to apply regardless of the customer's location. One advantage to a generator-based approach with no limitation on the customer's location is that it enables renewable generators in the jurisdictions to be certified for the VRE market without any further need to track where VRE sales ultimately occur (i.e., where RECs are retired). If set aside jurisdictions impose a geographic limitation, then generators participating in the VRE market risk having some portion of their output being decertified (or marketed as a different "no avoided emissions" product) based on the purchaser's location. All other options introduce an additional complication of having to track either where the RECs used in each jurisdiction were generated or where the purchasers of RECs from generators in each jurisdiction are located.[27]

The WCI Partners have recommended that no greenhouse gas emissions be attributed to "null" renewable energy from which RECs have been unbundled and sold separately.[28] Consequently, renewable facilities that are not located in a WCI Partner jurisdiction but sell their power on a specified basis into a Partner jurisdiction also would not avoid greenhouse gas emissions. WCI Partner jurisdictions could consider expanding the scope of facilities eligible for their VRE set asides to include the output, or portion thereof, imported into their jurisdictions from renewable energy facilities that participate in the VRE market.

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[27] Or where the renewable energy is generated if the accounting system for the VRE set aside is not based on RECs.
[28] Treatment of Renewable Energy Certificates in the WCI Cap-and-Trade Program.
http://www.westernclimateinitiative.org/component/remository/Electricity-Team-Documents/

Table 4 summarizes the combinations of jurisdictional retirement responsibility and geographic eligibility.

Table 4: Comparison of Options for Geographic Treatment of Voluntary Renewable Energy

Limitation→ ↓ Responsibility	Purchased from/sold to own jurisdiction	Purchased from/sold to any WCI jurisdiction	Purchased from/sold to any capped jurisdiction	Purchased from/sold to any jurisdiction
Purchaser-Based	Equivalent to gen-based, need to account for number of RECs from in-jurisdiction sources	Need to account for number of RECs used from sources in WCI Partner jurisdictions	Need to account for number of RECs used from all capped (e.g. RGGI) sources	N/A (no need to have purchaser-based version because purchases from uncapped jurisdictions do not need set aside)
Generator-Based	Equivalent to purchaser-based, need to track where RECs are retired	Need to track where RECs are retired	Expands application to sales to entities in other capped jurisdiction such as RGGI or Midwestern Accord jurisdictions, need to track where RECs are retired	Generators receive one certification, good for sales to all jurisdictions, no need to track where RECs retired

6.3.3 Implications of Geographic Treatment Options

In-region renewable development may be maximized under a purchase approach by retiring allowances only for renewable energy generated in the region, and under a generator approach by retiring allowances for all renewable generation including exports. Retirement for out-of-region generation is only necessary when renewables are located in a capped state, and then the question is which program should bear the responsibility for the retirement.

<u>RGGI Model Rule</u>

The RGGI Model Rule uses a purchaser-based responsibility in which each state retires allowances for VRE purchases occurring in the state. The RGGI Model Rule provides for the retirement of allowances for in-state sales regardless of where the REC is generated. Because these RECs may come from uncapped states, the RGGI Model Rule may be retiring too many allowances for in-region purchases. However, some RGGI states have adopted VRE set aside provisions that only retire allowances for generation in RGGI states, which avoids this problem.[29]

Draft Recommendation

> *WCI Partner jurisdictions that choose to implement a VRE set aside should retire allowances using a generator-based approach in which allowances are retired whenever RECs from a facility in that Partner jurisdiction's territory are purchased and retired by a customer in the VRE market with no limitation on the customer's location. Alternatively, the retirement should be based on VRE sales if RECs are not used.*

Harmonization on the jurisdictional responsibility is essential to avoid introducing considerable and unnecessary confusion into the VRE market. Consider two WCI Partner jurisdictions states, one with a purchaser-based set aside (Jurisdiction A) and the other with a generator-based set aside (Jurisdiction B). If RECs from a generator in Jurisdiction B are retired by an entity in Jurisdiction A, then both jurisdictions would retire allowances for the same MWhs. If RECs from a generator in Jurisdiction A are retired by an entity in Jurisdiction B, then neither jurisdiction would retire allowances.

This draft recommendation has some interesting implications for both the WCI Partner jurisdictions and RGGI states. There is considerable variation among the RGGI states in how they treat voluntary purchases of renewable energy generated outside their borders. While some states only retire allowances for renewable energy generated within the RGGI states, others do not constrain geographic scope in this manner. The RGGI voluntary renewable energy program is purchaser-based. Therefore, no RGGI state retires allowances to account for in-state renewable generation that meets out of state voluntary renewable energy demand. As a result, the RGGI rule does not contemplate a scenario under which allowances have already been retired to account for renewable energy sold into the voluntary market. Therefore, it is not clear whether those states would retire allowances for renewable energy based in a WCI Partner jurisdiction that is sold into the RGGI market if a WCI Partner jurisdiction has already retired allowances to account for that electricity. While there is an environmental benefit to retiring more allowances than is warranted for an individual purchase of voluntary renewable energy, the RGGI and WCI Partner jurisdictions have a financial interest in not retiring more allowances than is warranted. Therefore, it could be advantageous for any WCI Partner jurisdictions that plan on adopting a generation-based VRE program to work with the RGGI states that retire allowances for generation outside the RGGI region to collaboratively determine an appropriate path forward.

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[29] RGGI State Set-Aside Provisions for Voluntary Renewable Energy (VRE). Draft August 21, 2009. http://www.epa.gov/greenpower/documents/events/rggi_status_table.pdf

Final Recommendation

> *WCI Partner jurisdictions that choose to implement a VRE set aside should retire allowances using a generator-based approach in which allowances are retired whenever RECs from a facility in that WCI Partner jurisdiction's territory are purchased and retired by a customer in the VRE market with no limitation on the customer's location. WCI Partner jurisdictions should also consider requiring that renewable energy produced by VRE-eligible facilities in a non-WCI Partner jurisdictions and sold on a specified basis to the WCI Partner jurisdiction be counted as if those facilities were located in the WCI Partner jurisdiction.*

The final recommendation was expanded with an additional option for jurisdictions to consider that reflects the concerns raised by some stakeholders about facilities located in non-Partner jurisdictions that sell their energy into Partner jurisdictions. Because this additional program option focuses only on facilities that import electricity on a specified basis it is not critical that this additional option be harmonized among Partner jurisdictions, i.e, double counting would not be an issue since only the portion of renewable imports relevant to that jurisdiction are included. Therefore, this final recommendation calls for the harmonized use of a generator-based approach to accounting for the VRE set aside, but allows for an optional expansion of that set aside to capture all renewable facilities that are not reducing capped emissions.

6.4 Retirement Limits

Because establishing a VRE set aside involves removing allowances that could be used for other purposes, such as funding energy efficiency or R&D, jurisdictions may wish to limit the amount of allowances placed in the VRE reserve. In addition, jurisdictions may consider limiting the number of compliance periods the program will remain in effect.

6.4.1 Upper Limit on Retirement Amount

As described in Section 4.1, a key component to establishing a VRE set aside is determining the total allowances that would be dedicated for retirement to support the VRE market. However, the need to access allowances for compliance purposes may lead covered entities to resist dedicating a large number of allowances to support one sector of the economy. For that reason WCI Partner jurisdictions may choose to limit the amount of allowances that are dedicated to supporting the VRE market.

Many of the RGGI states have adopted either a constant limit on the number of allowances reserved for the VRE set aside or a portion of the budget, ranging from 1 to 2 percent. Given the regional strength as an exporter of voluntary renewable products, if the WCI Partner jurisdictions adopt VRE set aside provisions that acknowledge out-of-region purchases of in-region renewable generation, then a larger set aside might be appropriate (as a fraction of electricity emissions). However, it is important to note that the WCI program is an economy-wide program and therefore its base budget is much larger than electric sector emissions. This means that more VRE sales can be supported with 1% of the budget from the economy-wide WCI program than 1% of the budget from the RGGI program, which only covers the electric sector.

Establishing limits does provide planning certainty to regulated entities. However, while short-term predictions about the amount of electricity generated in a jurisdiction for the VRE market may be reasonably accurate, uncertainty increases substantially the further out in time predictions are made. It is helpful to divide the issue of setting limits into long-term and short-term timeframes. In the long-term, a limit can be maintained by closing off the VRE set aside to new projects once the amount of VRE generation supported by the set aside begins to approach the limit. In order to provide certainty to VRE project developers, jurisdictions that set limits should make updated estimates of the remaining VRE capacity readily available and announce in advance what cut-off date for new generation facilities will be used. If a project that had previously sold its RECs in the voluntary market begins to sell its RECs in the compliance market, it would free up capacity for additional projects to be supported by the VRE set aside.

Because the generation from many renewable resources is variable, a year with unusually high wind or small hydro production could lead to more demand for retirement of allowances than the number of allowances in the set aside. There are three ways that a Partner jurisdiction with a VRE set aside may respond if a shortfall in the number of allowances reserved for the set aside occurs. As many of the RGGI states have chosen, allowances may be retired on a first-come, first-served basis as verification reports are submitted. However, such a provision would introduce considerable uncertainty in the VRE market about the ability to make emission reduction claims. A second approach would pro-rate the reductions by lowering the per MWh rate at which allowances are retired rather than exclude some VRE transactions from set aside eligibility after the fact. While this approach would eliminate uncertainty about whether some transactions will be excluded from the set aside, it introduces uncertainty about the amount the amount of greenhouse gas reductions that can be claimed. This would give the jurisdiction time to re-evaluate the retirement limits and avoid having some transactions disqualified from the set aside eligibility assumed by parties at the time those transactions were arranged. If a jurisdiction has hit its limit for several years and compensated by adjusting the de facto retirement rate downward, it is possible that VRE certifiers may respond by decertifying facilities located in that jurisdiction. The third approach is essentially to guarantee that all projects approved for VRE set aside eligibility will have allowances retired at the *ex ante* rate announced by the jurisdiction. To do so, a jurisdiction that reaches the retirement limit in a given year could retire any allowances remaining from previous years' set aside. If there are no remaining allowances, the jurisdiction could transfer unallocated current-year allowances from other accounts within the allowance budget. Generally, these allowances would have to come from a general auction account or other account where allowances have not been dedicated to a specific purpose. A jurisdiction could also borrow some allowances from a future period to make up the shortfall. While estimating the number of allowances needed for the set aside would still be useful for planning purposes, this approach means that effectively no firm limit on the VRE set aside exists.

RGGI Model Rule

The VRE set aside provisions in the RGGI Model Rule provide for states to retire enough allowances to make all voluntary renewable energy purchases whole. However, all nine states that have adopted a VRE set aside have limited the total number of allowances that may be retired to around 1% to 2% of the state allowance budget. Most states adopted these limits expecting that this limit would be adequate to satisfy demand for the next several years.

Draft Recommendation

> *WCI Partner jurisdictions that choose to implement a VRE set aside should choose whatever upper limit (if any) that is found appropriate for that jurisdiction. Partner jurisdictions must determine if they will cover shortfalls by either borrowing allowances from a future year or lowering the per MWh retirement rate.*

It is not important for jurisdictions to harmonize on the issue of limits to allowances in the set aside. Because there is significant disparity in member jurisdictions' renewable capacity, then if retirement limits are pursued, each jurisdiction may wish to calculate its own.

Final Recommendation

> *WCI Partner jurisdictions that choose to implement a VRE set aside should choose whatever upper limit (if any) that is found appropriate for that jurisdiction. Partner jurisdictions should cover shortfalls that do occur in a compliance period by moving any remaining allowances not dedicated to other purposes into the set aside account or borrowing allowances from future years' VRE set aside accounts. In addition, when the number of allowances to be retired approaches the chosen limit, the WCI Partner jurisdiction could choose to close the eligibility of the VRE set aside to new projects and therefore restrict the supply to near the level of the limit to ensure long-term stability for existing projects.*

Based on stakeholder comment and further reflection it was decided that lowering the per MWh retirement rate was not a practice that should be recommended for harmonization across the WCI Partner jurisdictions. Therefore the recommendation now emphasizes an approach that would keep the VRE market whole by redirecting allowances or borrowing allowances from future years. Additionally, it includes a process for maintaining the long-term demand for VRE set aside allowances at the approximate level of the limit.

6.4.2 Time Limit on VRE Set Aside Program

In determining whether or not a set aside is necessary, consideration may be given to how long a set aside for this purpose should be available. If the price premium for renewable energy is a central justification for a VRE set aside, then the rationale for the program, or certain technologies covered by the program, may weaken over time. Cap and trade programs work by putting a price on the right to emit greenhouse gases, thereby incentivizing conservation, efficiency, and alternative sources of energy. As a price signal propagates through the economy, additional investments in energy efficiency and alternative energy become cost-effective. Thus, there is greater prevalence of low-carbon investments and purchases because such decisions are economically beneficial, as well as environmentally beneficial. If the price of allowances is low and/or renewable energy technology has not progressed enough to make renewable energy cost-competitive, a VRE set aside could be justified to encourage those willing to pay a premium to cover the spread between conventional and renewable energy. But what happens when renewable energy technology advances and rising allowance prices make renewable energy cost-competitive? In other words, if the rationale used to justify a VRE set aside is that VRE consumers are willing to pay a premium to provide a public good, what happens when a premium is no longer needed?

If the public goods aspect of the VRE market serves as the primary justification of a set aside, then WCI Partner jurisdictions that choose to implement them should consider making them contingent on a continued price premium for the technologies supported by the set aside. The set aside program should be re-evaluated periodically to determine whether the technologies supported by the set aside have attained price parity with conventional alternatives. Presumably, with the combination of rising costs for fossil fuels (as a result of the cap and trade price signal or other factors) and technological progress many sources of renewable energy will be cost-competitive in the next ten to fifteen years. As renewable technologies become cost-competitive, they would be removed from the list of eligible sources.

It is important to note that the delisting of an eligible technology should apply to the date that a project receives its final permits for construction (or some other project milestone). Once a project has been deemed eligible for the set aside, Partner jurisdictions should consider giving projects a lengthy window of time, perhaps ten to twenty years, during which allowances will be retired on the facility's behalf, even if the technology is later removed from the eligible list of technologies. Additionally, the decision to delist a technology should be made well in advance of the final operational date of eligibility. This is necessary to provide certainty for renewable energy developers whose projects wish to participate in the VRE market.

RGGI Model Rule

There is no time limit in the model rule, and at present no RGGI states have adopted one.

Draft Recommendation

> *WCI Partner jurisdictions that choose to implement a VRE set aside should choose whatever time limit (if any) that is found appropriate for that jurisdiction. Partner jurisdictions may choose to base time limits on periodic reviews of the cost-competitiveness of the technologies supported by the set aside program.*

This is not an area where harmonization among WCI Partner jurisdictions is important.

Final Recommendation

> *WCI Partner jurisdictions that choose to implement a VRE set aside should choose whatever time limit (if any) that is found appropriate for that jurisdiction. However, to provide greater certainty to project developers, Partner jurisdictions should consider a minimum length of time from the date a VRE-eligible facility commences operations that it will be supported by the set aside. Partner jurisdictions may choose to delist technologies from eligibility based on periodic reviews of the cost-competitiveness of the technologies supported by the set aside program, but the last eligibility date for delisted project types should be announced well in advance.*

It is not important that WCI Partner jurisdictions harmonize regarding whether they implement a time limit. However, it is important for jurisdictions that decide to remove a technology from the list of VRE eligible technologies to follow the recommended procedure or develop an alternative approach that provides similar certainty for the VRE market.

6.5 Attributing Emissions to Voluntary Renewable Energy Purchases

A central feature of designing a VRE set aside is determining the rate at which allowances will be retired for every MWh of verified eligible VRE. If the goal of the VRE set aside is to preserve the right to make legitimate emission reduction claims comparable to the claims that could be made before implementation of a cap, that suggests basing the allowance retirement rate on the emissions that would have been avoided by VRE facilities in the absence of a cap. However, estimating the emissions avoided by renewable electricity requires a complex analysis of the resources serving the grid region where the facility is located.

Power from many generating units is dispatched to meet fluctuating demand, and the impact of a given renewable energy facility could cause one or more plants to reduce their output. This effect is referred to as the "operating margin." In the longer term, investment in renewable energy capacity could displace the construction of a new fossil-fired plant altogether. This effect is referred to as the "build margin."[30]

Since the exact units affected by the output from a renewable energy facility cannot be known at every moment, estimated avoided emissions rates are necessary. One method of estimating the emissions rate is to use the average emissions rate for the jurisdiction in which the VRE purchase is made or the jurisdiction where the renewable energy was generated. This calculation is straightforward, but it is unlikely to be very accurate.[31] Marginal emission factors better reflect the generation sources displaced by output from renewable energy facilities. Use of an emission factor for the region where the electricity was generated would be consistent with the generator-based responsibility recommended in section 6.3.

One option may be to use the Default Emissions Factor Calculators that the WCI Electricity Team is developing for the purpose of attributing emissions to electricity imported into the WCI region. The Calculators are designed to calculate marginal emission factors based on operating margins of existing plants. Therefore, they do not capture the build margin effect. Because the build margin effect is more speculative and reflects the longer term effects of adding hundreds of megawatts of renewable energy capacity, the Calculators or other operating margin analysis tools should provide adequate accuracy for purposes of the VRE set aside.

<u>RGGI Model Rule</u>

The RGGI Model Rule defines the benefit of a voluntary renewable energy purchase as the marginal CO_2 emissions rate (lbs CO_2/MWh) in the control area where the generation occurred. However, if the data necessary to determine the marginal emissions rate is unavailable, then the average emissions rate can be used.

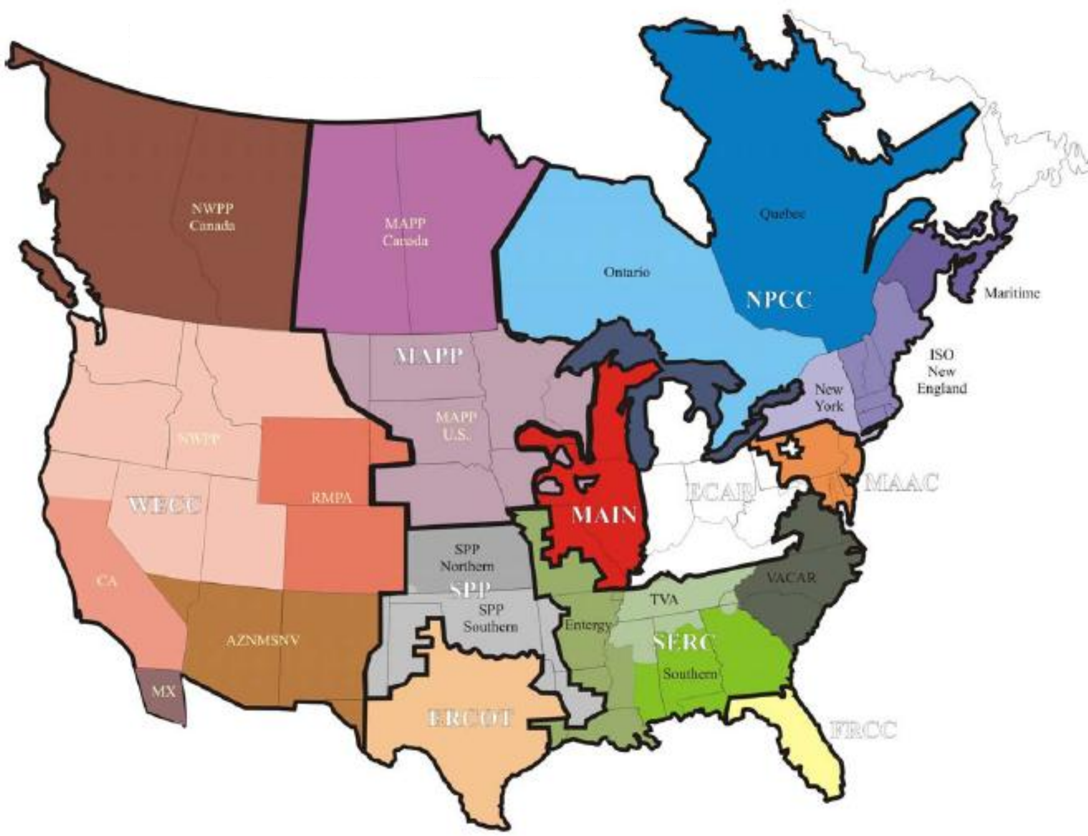
The RGGI Model Rule simply refers to a "control area." The interconnection of electric grids seems to make state and provincial borders less relevant than NERC regions (e.g., WECC) and

[30] Derik Broekhoff, 2007. *Guidelines for Quantifying GHG Reductions from Grid-Connected Electricity Projects.* World Resources Institute/World Business Council for Sustainable Development. http://www.wri.org/publication/guidelines-quantifying-ghg-reductions-grid-connected-electricity-projects
[31] Ibid.

NERC sub-regions (e.g., AZNMSNV) (See Figure 5). If allowance retirement is tied to use of renewable energy products, then a broader region may be desirable as RECs are likely to come from sub-regions different than where they are "used." However, if allowance retirement is tied to generation, than smaller sub-regions may be useful. At this time, it is not yet clear whether marginal emissions rates are calculated for each NERC region and sub-region.

Several of the RGGI states intend to use the marginal emissions rate calculated by their NERC Sub-region, ISO New England (ISO-NE). ISO New England (ISO-NE) began calculating marginal emissions rates in 1994 in order to analyze the impact of Demand Side Management programs. This analysis continues today, though the methodology has changed over time. Currently, ISO-NE calculates the marginal emissions rate using the actual hourly generation and monthly air emissions rate[32] of marginal fossil units, which are defined as all units whose primary fuel is oil or natural gas.

Figure 5: NERC Regions and Sub-Regions (Source: NERC)



[32] The emission rates are mainly based on actual emissions reported in the EPA Clean Air Markets database, along with some data from the NEPOOL Generation Information System (GIS), and some rates from EPA's eGRID.

Previously, the ISO-NE marginal emissions rate was based on the emissions rate of units that would have run had demand been higher. This employed a production simulation model developed to replicate system operations for the previous year. The marginal emissions rate was calculated as the difference between modeled historical emissions and modeled emissions when load was 500 MW higher in each hour. According to the 2006 Marginal Emissions Rate Analysis, ISO-NE moved away from the production simulation model because "the reference case never exactly matched the previous year's unit level energy production because of numerous modeling reasons including market dynamics, specific outages and deratings." [33] Additional communications with ISO-NE indicate that prior to switching methods, a comparison of the two methods was performed and yielded "very similar" results, and therefore, they decided to go with the "more straightforward" approach of evaluating actual emissions from oil and gas fired units.[34]

Draft and Final Recommendation

> *WCI Partner jurisdictions that choose to implement a VRE set aside should work together to develop a rate based on a marginal dispatch analysis, such as the WCI Default Emission Factor Calculator, for each major grid region. However, use of this rate should be optional and specific assignment of emissions left to jurisdictional discretion.*

Harmonization on the allowance retirement rate is not essential, and in the current market, avoided emissions rates are either not quantified or vary by location.

7 Stakeholder Comments on Draft Recommendations

Stakeholders provided written comments on the original draft recommendation in January and February of 2010, and discussed with the WCI Partners their comments during the WCI Electricity Collaborative on January 21, 2010 in Phoenix, AZ. The Western Climate Initiative would like to thank everyone who took the time to comment on the original version of this paper, as well as contribute comments on this topic in general throughout the WCI process. Taken together, this paper and the submitted comments have helped fill an important void in the literature on this topic and will hopefully be helpful in the future as this topic is addressed by other regions and at the federal level.

Table 5 on the following pages summarizes the comments that were received by the WCI Partners on the original paper:

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[33] 2006 New England Marginal Emission Rate Analysis. ISO New England. September 2008. http://www.iso-ne.com/genrtion_resrcs/reports/emission/2006_mea_report.pdf

[34] Email communication. Kurt Dahdah. Customer Service. ISO New England. 12/30/08.

Table 5: Stakeholder Comments on VRE Issues and Draft Recommendations Paper

Topic	Comment	Submitted By	Additional Information
7.1 Accounting Mechanism for the VRE Set Aside	Opposes pre-determined limits on the size of the set-aside	Center for Resource Solutions	
	Set-aside should reduce the number of allowances in WCI Partner jurisdictions and not simply lower the per MWh retirement rate	Western Climate Advocates Network (WeCAN)	Risk that a purchase of VRE's could generate fewer avoided emissions than expected, or lead to no actual avoided emissions.
	Set-aside should be estimated in advance of each compliance period, then removed from the total pool of allowances created under the cap.	Nextera Energy	Data available from the National Renewable Energy Laboratory, the Western Region Electricity Generation information system etc. Include an "off the top" rule similar to RGGI which sets aside and retires allowances to account for voluntary action on renewable energy.
	Free allocations to Local Distribution Companies (LDCs) should be differentiated	West Associates	Since LDCs are regulated, any benefits of free allowances will be passed onto consumers
	Jurisdictions should create set-asides for demand side measures and ensure value accrues to those that incur the costs of delivering demand side programs	Power Workers' Union	Ensure generators do not benefit from windfall profits at the expense of LDCs
	Calculate future set-aside needs based on baseline of demand, reviewed annually and compared with certificates issued, to adjust for recent growth	Renewable Energy Markets Association	
	Ensure mechanism for set-aside of allowances based on voluntary demand for eligible renewable energy.	Renewable Energy Markets Association	Create certainty that a purchase of voluntary renewable energy will result in retirement of equivalent allowances.
	Set-asides should not be available for energy efficiency or hybrid vehicles	Renewable Energy Markets Association	Building / hybrid vehicle owners derive economic advantage from efficiency measures and do not require an allowance set-aside

	Set-aside should be allowed to be determined by market demand; no predetermined limit on the size of the VRE set-aside	Renewable Energy Markets Association; Western Climate Advocates Network (WeCAN)	Reduced need for allowances resulting from more renewable supply should result in a cost-neutral policy; estimated size of VRE market demand should guide allowance set-asides
	Likely size of set-aside markets should be estimated by those jurisdictions who decide to implement a set-aside program, and baseline allowance adjusted accordingly.	Southern California Edison Company	
	Ensure sufficient set-asides are allocated to renewable energy producers to ensure voluntary purchases fully displace carbon-sourced electricity.	Southwest Energy Efficiency Project (SWEEP)	Consider effects on the sale of EHV if those investments are not seen to displace carbon-generated electricity, as those purchasers are largely motivated by climate considerations.
	Adopt a uniform approach across WCI Partner jurisdictions	Western Climate Advocates Network (WeCAN)	Simplify implementation and compliance for the VRE market
	Set-asides should not be monetized, but retired when actual voluntary activity takes place	Southern California Edison Company	Concern is around increasing costs without seeing a corresponding benefit
7.2 Defining Eligible Renewable Energy Project Types	Adopt a uniform approach for eligibility requirements across WCI Partner jurisdictions	Renewable Energy Markets Association	Lack of uniform criteria could result in unintended consequences for renewable energy development
	Eligibility should be based on location of the renewable energy purchaser, not the generator	Nextera Energy	
	Treatment of renewable energy in mandatory/voluntary markets must be uniform	Southern California Edison Company	Definition/evaluation of a voluntary renewable energy purchase in the voluntary market must be the same as in compliance market on order to ensure emissions reductions from VRE are real, verifiable and additional.
	Supports WCI Partner jurisdictions requiring VRE marketers to acquire allowances from the market on the same basis as carbon-sourced generators	West Associates	Allows VRE marketers to include the cost of acquiring and retiring allowances in the cost of their VRE products, in the amount of GHG emissions displaced by each VRE product

	Recommends measures that require VRE marketers to acquire GHG allowances to fully cover emissions attributed to VRE electricity products	West Associates	This approach efficiently embeds the costs of covering GHG emissions attributed to the VRE electricity products in their cost to VRE customers.
7.3 Jurisdictional Retirement Responsibility	Agrees with recommended approach based on location of generator, not purchaser, for jurisdictional retirement responsibility.	Renewable Energy Markets Association; Center for Resource Solutions; Western Climate Advocates Network (WeCAN)	Encourages out-of-jurisdiction demand, generates positive effects both within and outside WCI Partner jurisdictions
	Bundling emissions allowances with renewable energy is unacceptable	Renewable Energy Markets Association; West Associates	Adds expense and creates confusion for consumers; concern that VRE electricity products could be double counted, thus increasing emissions under the cap
	Adopt a uniform approach across WCI Partner jurisdictions on coverage for shortfalls	Renewable Energy Markets Association	Transparency/ consumers can be certain purchase will result in allowance retirement
7.4 Retirement Limits	Oppose a time limit or "sunset" to implementation of the VRE approach	Center for Resource Solutions; Renewable Energy Markets Association; Western Climate Advocates Network (WeCAN)	Unnecessary at this time; increasing adoption of renewable generation will reduce the need for allowances in future. May need further review but not conceivably before 2020.
	Supports retirement of allowances and borrowing from a future time period; oppose lowering the per MWh retirement rate	Center for Resource Solutions	
7.5 Attributing Emissions to Voluntary Renewable Energy Purchasers	Adopt a uniform approach across WCI Partner jurisdictions for treatment of emissions factors	Renewable Energy Markets Association	Transparency/ consumers credited consistent with energy that is displaced; use Green-E's standard requires MWhs must contain all the GHG emission reduction benefits associated with the MWh of renewable energy when it was generated.
	Use marginal emission avoided (not average emissions factor)	Renewable Energy Markets Association	Average emission factors may discount carbon benefits of renewable generation, reduce individual generator responsibility for determining allowance requirements

OTHER	Comment	Submitted By	Additional Information
Compliance	Adopt uniform dates across WCI Partner jurisdictions for filing deadlines	Renewable Energy Markets Association	Reduce burden on marketers to track multiple filing deadlines
	Recognize only established tracking authorities	Renewable Energy Markets Association	Generators and claimants would be required to register with established tracking authority
	Environmental claims about purchase of VRE's must be verifiable	Renewable Energy Markets Association	To avoid optics of greenwashing, ensure reporting requirements follow consistent with NAAG guidelines
Potential effect of VRE approach on Markets	Recommend measures that recognize large purchasers as the drivers of VRE market growth	Center for Resource Solutions	15 largest business purchasers (US) can demonstrate specific, quantitiative claims with respect to avoided carbon emissions
	Economic benefits should be more clearly highlighted; recognize demand-side effects on demand for and supply of allowances and the cumulative, interactive effects on allowances prices.	Center for Resource Solutions; Western Climate Advocates Network (WeCAN)	Lowered demand for allowances due to fossil fuel-based avoided generation; jobs benefit of not undercutting a growing market are examples. Highlights the overall benefit to implementing a VRE set-aside
	White paper should model effect of VRE set aside on allowance prices	Independent Energy Producers Association	White paper is unclear on what potential impacts on allowance prices may be from including VRE set aside approach within the cap and trade program
Adoption of VRE set-aside approach	Advise that WCI Partner jurisdictions proceed with caution in regard to linking RECs to a cap and trade system so as not to disrupt the renewable markets	Waste Management	Potential to confuse and duplicate renewable energy programs that currently work well
	Treatment of renewable energy in mandatory/voluntary markets	West Associates	LDCs may incur additional compliance costs under RPS as they may be left to purchase allowances to offset GHG emissions imputed to power not sold directly byVRE marketers to customers, from which the environmental attributes have been stripped.
	Recognize that growth of the VRE market would likely be undermined by introduction of cap and trade without a VRE set-aside	Western Climate Advocates Network (WeCAN)	Marketing environment would be more challenging under cap and trade without a VRE set-aside

	Generally supportive; advocate a uniform approach across WCI Partner jurisdictions	Center for Resource Solutions, Renewable Energy Markets Association, West Associates	Adds certainty and ensures equity for both the allowance market and the VRE market
	Generally supportive; allow jurisdictions to decide whether or not to implement	Power Workers' Union	Addresses differing needs of jurisdictions
	Not needed - effective GHG emissions reductions can be achieved through existing measures such as RPS and cap and trade programs.	Southern California Edison Company	
	Opposes VRE approach as proposed	Southern California Public Power Authority	Not necessary to support voluntary renewable energy; raises difficult issues regarding elements to be harmonized, treatment of other voluntary measures; reduces the size and value of the allowance pool
	Rewrite those portions that address alternatives to no set-aside	Renewable Energy Markets Association	Seeks a straightforward recommendation to support each jurisdiction adopting a VRE set-aside
General	Environmental Attributes are not a "secondary attribute" of RECs.	Center for Resource Solutions	RECs were developed to enable commoditization of claims to the benefits of renewable energy.
	White paper should not work from the assumption that individual jurisdictions will choose to implement a VRE; it should present details that will allow stakeholders to assess the effect of including a VRE set-aside within the cap and trade system	Independent Energy Producers Association	Since each jurisdiction will make its own decision, paper should focus on guidance on the data and details that must be presented
	WCI Partner jurisdictions should negotiate reciprocity if linking with other programs	Nextera Energy	
	Strike paragraph headlined "RGGI Model Rule" from bottom of page 15 to top of page 16 from the paper	Renewable Energy Markets Association	Believes this leaves incorrect impression that it is problematic to use unbundled RECs to qualify for the VRE set-aside under RGGI.
	Strike paragraph headlined from bottom of page 3 to top of page 4 which discusses the voluntary market for carbon offsets.	Renewable Energy Markets Association	Commenter believes this paragraph is confusing and irrelevant (see REMA letter pg 14)

Annex: Optional VRE Set aside Language in RGGI Model Rule[35]

Voluntary renewable energy purchase. A purchase of electricity from renewable energy generation or renewable energy attribute credits by a retail electricity customer on a voluntary basis. Renewable energy includes electricity generated from biomass, wind, solar thermal, photovoltaic, geothermal, hydroelectric facilities certified by the Low Impact Hydropower Institute, wave and tidal action, and fuel cells powered by renewable fuels. The renewable energy generation or renewable energy attribute credits related to such purchases may not be used by the generator or purchaser to meet any regulatory mandate, such as a renewable portfolio standard.

(d) Voluntary renewable energy market set-aside allocation. For each control period, the REGULATORY AGENCY shall allocate to the voluntary renewable energy market set-aside account a certain number of tons, calculated as set forth in this subdivision, from the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program base budget set forth in section XX5.1, as applicable. The REGULATORY AGENCY shall administer the voluntary renewable energy set-aside in accordance with this subdivision.

(1) The REGULATORY AGENCY will open and manage a general account for the voluntary renewable energy market set-aside for each control period.

(2) The number of tons that will be allocated to the voluntary renewable energy market set-aside account in a specific control period will be determined as set out in this paragraph.

(i) Any person may submit data to the REGULATORY AGENCY documenting purchases of voluntary renewable energy that meet the requirements of this subdivision by no later than the July 30 prior to the beginning of a control period. Such data must be from reputable sources, which may include retail electricity providers, organizations that certify renewable energy products, and other parties as determined by the REGULATORY AGENCY. To be considered, data must be verifiable and document the following for voluntary renewable energy purchases.

(a) Documentation of voluntary renewable energy or renewable energy attribute credit purchases by retail customers, by customer class, in the State during the most recent three-year period for which data are available.

(b) Documentation that the renewable energy or renewable energy attributes related to voluntary renewable energy or renewable energy attribute credit sales was procured by the retail provider.

(c) Time period when the retail purchase(s) was made.

(d) State where the electricity was generated or the renewable energy attribute credit was created, including documentation of facility name, unique generator identification number, and fuel type.

(e) Time period when the electricity was generated or the renewable energy attribute credit was created.

[35] Regional Greenhouse Gas Initiative Model Rule. 1/5/07 Final with Corrections. http://rggi.org/docs/model_rule_corrected_1_5_07.pdf

(ii) Subject to the timely receipt of adequate data pursuant to subparagraph (i) of this paragraph, and based on such data, the REGULATORY AGENCY shall project the voluntary renewable energy purchases in the State during a control period that represents renewable energy generation in one or more participating states. The megawatthours (MWh) of projected voluntary renewable energy purchases in a control period shall be multiplied by the marginal CO_2 emissions rate (lbs. CO_2/MWh) in the control area where the generation occurred, as determined by the REGULATORY AGENCY. If data to determine the marginal emissions rate is unavailable, the average emissions rate shall be used, as determined by the REGULATORY AGENCY.

(iii) The CO2 tons to be allocated to the voluntary renewable energy set-aside account shall be calculated as follows:

CO2 tons = MP x EF

where:

CO2 tons, rounded down to the nearest whole ton, is the number of allowances to be placed in the reserve account.

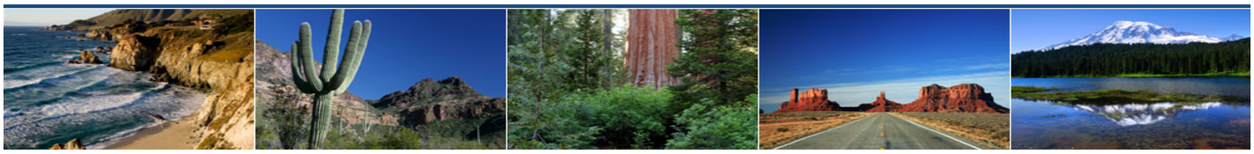
MP is the projected MWh of voluntary renewable energy purchases in the State during the future control period that meets the requirements of this subdivision.

EF is the CO2 emissions factor for the control area where the electricity represented by the sale was generated.

(iv) If following the end of a control period, the number of CO2 allowances allocated to the voluntary renewable energy set-aside account is less than the number of CO2 tons represented by the actual MWh of voluntary renewable energy purchases during the control period, the REGULATORY AGENCY will add the difference between CO2 tons represented by actual purchases, as calculated in accordance with subparagraph (iii) of this paragraph, and CO2 allowances held in the set-aside account to the projection for the following control period, pursuant to paragraph (2) of this subdivision. If following the end of a control period, the number of CO2 allowances allocated to the voluntary renewable energy set-aside account is greater than the number of CO2 tons represented by the actual MWh of voluntary renewable energy purchases during the control period, the REGULATORY AGENCY will subtract the difference between CO2 tons represented by actual purchases, as calculated in accordance with subparagraph (iii) of this paragraph, and CO2 allowances held in the set-aside account from the projection for the following control period, pursuant to paragraph (2) of this subdivision. In no event shall the size of the voluntary renewable set-aside exceed ___________ tons.

(3) As of the December 31 that is after the end of a control period for which an allocation has been made to the voluntary renewable energy set-aside account, the REGULATORY AGENCY shall determine the actual MWh of voluntary renewable energy purchases that occurred during the control period. The REGULATORY AGENCY shall retire CO2 allowances in the voluntary renewable energy set-aside account in an amount up to the number of tons of CO2 represented by actual voluntary renewable energy purchases, based on actual MWh purchases and the emissions factor determined pursuant to paragraph (2) of this subdivision.

Western Climate Initiative



Design for the WCI Regional Program

July 2010

Western Climate Initiative

July 27, 2010

To All Interested Parties:

Today, the Partner jurisdictions of the Western Climate Initiative are pleased to release the “Design for the WCI Regional Program.” Since the release of the WCI Design Recommendations in September 2008, we have been working together to develop these design details which are needed to implement the program.

This document provides a roadmap to inform the WCI Partner jurisdictions in their development of implementing regulations. It has been developed by the WCI Partner jurisdictions working collaboratively with stakeholders, advisors, and outside experts who have all made invaluable contributions. We especially want to recognize Franz Litz and Nicholas Bianco at the World Resources Institute in Washington, D.C. and Lydia Dobrovolny at Ross & Associates in Seattle, WA for their outstanding efforts in the preparation of this document.

The release of this Program Design is a major milestone for the WCI. Between now and the program start date of January 2012, the WCI Partners will continue working together to resolve outstanding design issues and begin putting in place the administrative systems and infrastructure needed to operate the program.

While not all WCI Partner jurisdictions will implement the cap-and-trade program when it begins in January 2012, those currently expecting to move ahead at the start will create a robust market for achieving GHG emissions reductions in the western U.S. and Canada. It is also important to recognize that all WCI Partners have participated in crafting the program design and that the program is structured so that additional Partners can join in the future.

From the beginning, the Partners’ strategy for addressing climate change has recognized the need for broad collaborative action to reduce GHG emissions. All of the WCI Partner jurisdictions have adopted climate action plans, and are taking steps to reduce emissions. In addition to our efforts to implement a cap-and-trade program, we are working to advance other policies needed to reduce GHG emissions. WCI Partner jurisdictions are also working closely with our federal governments to promote national and international action and ensure coordination among state, provincial, regional, and national programs.

On behalf of the governors and premiers of the Western Climate Initiative jurisdictions, we thank you for your interest in this work and for your ongoing contributions to our effort. We know that together we can meet the challenge of climate change while promoting economic vitality throughout the region.

Sincerely,
The WCI Partners

State of Arizona

Benjamin Grumbles
Department of Environmental Quality

Province of British Columbia

Tim Lesiuk
Climate Action Secretariat

Jessica Verhagen
Climate Action Secretariat

State of California

Michael Gibbs
Cal/EPA
Co-Chair, WCI

Kevin Kennedy
Air Resources Board

James Goldstene
Air Resources Board

Province of Manitoba

Neil Cunningham
Manitoba Conservation

State of Montana

Paul Cartwright
Department of Environmental Quality

State of New Mexico

Sarah Cottrell
Environment Department

Jim Norton
Environment Department

Sandra Ely
Environment Department

Western Climate Initiative

Province of Ontario

John Lieou
Ministry of the Environment

Jim Whitestone
Ministry of the Environment

Doug MacCallum
Ministry of Energy and Infrastructure

State of Oregon

Ivo Trummer
Office of the Governor

Province of Québec

Robert Nöel de Tilly
Ministére du Développement durable, de l'Environnement et des Parcs
Co-Chair, WCI

Jean-Yves Benoit
Ministére du Développement durable, de l'Environnement et des Parcs

State of Utah

Dianne R. Nielson
Office of the Governor

State of Washington

Janice Adair
Department of Ecology

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DESIGN SUMMARY

1. Introduction

The Western Climate Initiative (WCI) is a collaboration of seven U.S. states and four Canadian provinces that have been working together since 2007 to identify, evaluate, and implement policies to address climate change.[1] The WCI Partner jurisdictions reflect diverse geographies, climates, populations, industries, and energy and transportation infrastructures (see Figure 1). Nevertheless, the Partners share a commitment to tackling the economic, energy, and environmental challenges associated with greenhouse gas (GHG) emissions, recognizing that:

- Adverse impacts of climate change are already being experienced in our states and provinces.
- Acting now reduces the risk of far more significant adverse climate change impacts and associated unacceptable economic harm.
- Acting now reduces costs for future generations and provides substantial economic opportunities for the residents of our jurisdictions, contributing to job growth and economic recovery, and reducing reliance on imported fossil fuels.

A Comprehensive Initiative

The WCI Partner jurisdictions have developed a comprehensive strategy to reduce regional GHG emissions to 15 percent below 2005 levels by 2020. This goal is based on the individual GHG emission reduction goals of the Partner jurisdictions. Our strategy will also spur investment in and development of clean-energy technologies, create green jobs, and protect public health. The WCI Partner jurisdictions' plan includes the following elements:

- **Using the power of the market.** A market-based approach that caps GHG emissions and uses tradable permits will provide incentives for companies and inventors to create new technologies that increase efficiency, promote greater use of renewable or lower-polluting fuels, and foster process improvements that reduce dependence on fossil fuels.
- **Encouraging reductions throughout the economy.** To reduce compliance costs and encourage emissions reductions, offset certificates will reward emissions reductions in sectors such as forestry and agriculture that are not covered by emissions caps.

[1] Memorandum of Understanding establishing the Western Regional Climate Action Initiative. February 26, 2007.

- **Advancing core policies and programs to speed the transition to a clean energy economy** by targeting cost-effective emissions reductions, including:
  - Expanding energy efficiency programs that reduce customer utility bills;
  - Encouraging additional renewable energy sources that diversify supply resources and reduce air and water pollution;
  - Tackling transportation emissions through vehicle emissions standards, fuel standards, and incentives for improved community and transportation planning;
  - Establishing performance benchmarks and standards for high-emitting industries to spur innovation and improve competitiveness; and
  - Identifying best practices in workforce and community programs to help individuals transition to new jobs in the clean energy economy.

The WCI Partner jurisdictions' comprehensive strategy is good for the environment and good for the economy. It encourages the lowest cost reductions in GHG emissions and improved energy efficiency. Economic modeling conducted by the Partner jurisdictions indicates that the program will result in modest cost savings between 2012 and 2020. The strategy balances the principles adopted by the WCI Partner jurisdictions to maximize total benefits throughout the region, including reducing air pollutants, diversifying energy sources, and advancing economic, environmental, and public health objectives, while also avoiding localized or disproportionate environmental or economic impacts.

From the beginning, the Partner jurisdictions' strategy for addressing climate change has recognized the need for broad collaborative action to reduce GHG emissions. All of the WCI Partner jurisdictions have adopted climate action plans, and are taking steps to reduce emissions. We also are in discussions with other regional greenhouse gas initiatives—the Regional Greenhouse Gas Initiative (RGGI) and the Midwestern Greenhouse Gas Reduction Accord—to further broaden the collaboration on mitigation activities. In addition, WCI Partner jurisdictions are working closely with our federal governments to promote national and international action, and to ensure coordination among state, provincial, regional, and national programs.

The WCI Partner jurisdictions understand that even if it were possible to substantially reduce or even eliminate GHG emissions today, our jurisdictions would still feel the impacts of climate change due to emissions that have already occurred. Scientific research continues to confirm that our water resources, natural ecosystems, air quality, and environment-dependent industries like agriculture and tourism will be significantly impacted by changes in climate. Consequently, in addition to limiting GHG emissions, efforts are needed to address the impacts of climate change. The WCI Partner jurisdictions are therefore also committed to undertaking preparation and adaptation efforts.

Figure 1: Western Climate Initiative Partners and Observers

WCI Partners and Observers

U.S. Partner jurisdictions comprise 19% of the total U.S. population and 20% of the U.S. GDP
Canadian Partner jurisdictions comprise 79% of the total Canadian population and 76% of the Canadian GDP.

Manitoba
GDP .... 49 Billion C$
Population................. 1,186,700
Largest Source of Emission .. Transportation

British Columbia
GDP .... 190 Billion C$
Population................. 4,380,300
Largest Source of Emission .. Transportation

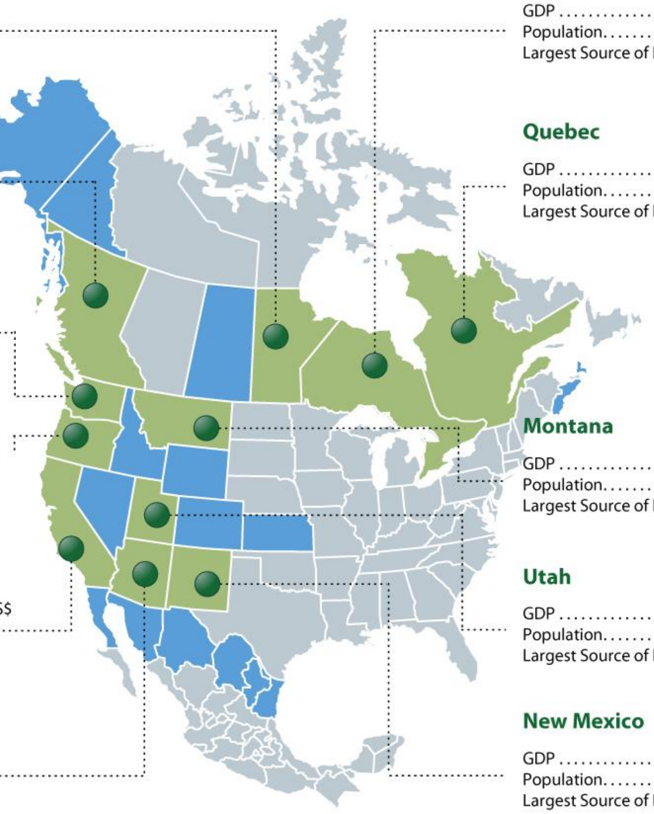
Washington
GDP .... 311 Billion US$
Population................. 6,468,424
Largest Source of Emission .. Transportation

Oregon
GDP .... 158 Billion US$
Population................. 3,747,455
Largest Source of Emission .. Transportation

California
GDP .... 1,813 Billion US$
Population................. 36,553,215
Largest Source of Emission .. Transportation

Arizona
GDP .... 247 Billion US$
Population................. 6,338,755
Largest Source of Emission .. Electricity*

* includes tribal lands



Ontario
GDP .... 582 Billion C$
Population................. 12,803,900
Largest Source of Emission ... Transportation

Quebec
GDP .... 298 Billion C$
Population................. 7,700,800
Largest Source of Emission ... Transportation

Montana
GDP .... 34 Billion US$
Population................. 957,861
Largest Source of Emission ... Electricity

Utah
GDP .... 106 Billion US$
Population................. 2,645,330
Largest Source of Emission ... Electricity

New Mexico
GDP .... 76 Billion US$
Population................. 1,969,915
Largest Source of Emission ... Electricity

Partners   Observers

Observers

CANADA: Nova Scotia, Saskatchewan, Yukon; **UNITED STATES:** Alaska, Colorado, Idaho, Kansas, Nevada, Wyoming; **MEXICO:** Baja California, Chihuahua, Coahuila, Nuevo Leon, Sonora, Tamaulipas

Source for US data: U.S. Census Bureau and U.S. Bureau of Economic Analysis; Source for Canadian data: Statistics Canada
U.S. and Canada population figures 2009; U.S. and Canada GDP figures 2008

Expanding Collaborative Action on Climate Change

GHG emissions are emitted from a broad range of activities worldwide. Unlike other air pollutants, GHG emissions contribute equally to climate change regardless of source or location. Efforts to mitigate climate change must ultimately address emissions from all major sources on a global basis.

As the WCI Partner jurisdictions move forward in the months and years ahead, the Partners will continue collaborating to develop a portfolio of core policies and programs to reduce GHG emissions. The governors and premiers of the Partner jurisdictions invite their colleagues across North America, including leaders of Native American tribes and Canada's First Nations, to join us to expand our effort to reduce GHG emissions and limit the impacts of a changing climate.

Sharing Our Progress through this Report

This document updates the design for the WCI Regional Cap-and-Trade Program, providing a roadmap to inform the WCI Partner jurisdictions in their development of implementing regulations. During the nearly two years since *Design Recommendations for the WCI Regional Cap-and-Trade Program* was released, the WCI Partner jurisdictions have worked collaboratively with stakeholders, advisors, and experts to develop the details needed to put the program in place. The WCI Partner jurisdictions have also had the benefit of building on the experience of program operations in Europe and RGGI, as well as proposed programs in other regions and countries.

The remainder of this document is organized as follows:

Design Summary: The Design Summary provides the highlights of the WCI Cap-and-Trade Program. The presentation is organized around the primary policy recommendations for the program, as follows:

- The WCI Cap-and-Trade Program
- Relying on High-Quality Emissions Data From Rigorous Reporting
- Setting the Program Emissions Limits
- Enhancing Compliance Flexibility and Program Adaptability to Manage Compliance Costs
- Maintaining Competitiveness and Preventing Emissions Leakage
- Electricity Sector
- Designing for High-Quality Offsets
- Designing a Fair and Transparent Auction
- Ensuring a Well-Functioning Market
- Linking Programs
- Coordinating Program Administration

Documentation: Referenced throughout the document are materials prepared by WCI committees and teams that form the basis for the program design recommendations. In most instances, the relevant white papers and/or draft recommendations were released for stakeholder comment and were discussed in public conference calls and/or meetings. These materials are listed at the end of the Design Summary and are available on the WCI website.[2]

[2] See www.westernclimateinitiative.org.

Detailed Design: The Detailed Design is organized around the primary operational components of the program. As the WCI Partner jurisdictions developed the Detailed Design, we found that variations in jurisdictional authorities, regulatory procedures, and administrative requirements inevitably lead to differences in the manner in which program rules are written. Consequently, the Detailed Design was prepared with the understanding and expectation that each jurisdiction's rule language may vary from the material included here. The intent, however, is that even with differences in language or approach, the ability to implement the core program design in a compatible manner across jurisdictions is preserved, so that the integrity of the regional effort is assured.

2. The WCI Cap-and-Trade Program

As part of a comprehensive strategy to reduce GHG emissions, the WCI Partner jurisdictions have recommended a market-based program that provides an incentive to limit emissions and promotes technological innovation.[3] Cap-and-trade has proven to be a successful means of reducing air pollution. It also is considered one of the most cost-effective and reliable strategies for pricing carbon emissions and providing emitters of GHG emissions with an incentive to limit pollution. With the trading component, cap-and-trade allows emitters to be flexible and creative in how to make needed reductions (see Figure 2).

The WCI program design includes a broad scope, encompassing nearly 90 percent of economy-wide emissions in the WCI Partner jurisdictions. The merits of pricing emissions broadly throughout the economy have been recognized in most of the recent federal proposals in the U.S. A forthcoming study by the National Research Council also recommends a broad scope, stating: "An economy-wide carbon pricing policy would provide the most cost-effective reduction opportunities, would lower the likelihood of significant emissions leakage, and could be designed with a capacity to adapt in response to new knowledge."[4] Similarly, in 2009 the National Round Table on the Environment and the Economy published a report on carbon pricing in Canada, including: "To achieve stated reduction targets at the least possible cost, all emissions must be covered as fully as possible. This requires a unified pricing policy that consciously takes into account all emissions across all sectors and all jurisdictions."[5]

The WCI Partner jurisdictions understand that in addition to covering most sectors of the economy, a broad geographic scope will also reduce overall

[3] In September 2008, following 18 months of stakeholder consultation, analysis, and Partner deliberations, the WCI released *Design Recommendations for the WCI Regional Cap-and-Trade Program*.

[4] National Research Council of the National Academies, Limiting the Magnitude of Future Climate Change, The National Academies Press, Washington, D.C., forthcoming, p. 5. Prepublication summary available at: www.nap.edu/catalog/12785.html.

[5] The National Round Table on the Environment and the Economy, *Achieving 2050 : A Carbon Pricing Policy for Canada*, *2009*, p.29.

compliance costs and can help mitigate leakage risks. A larger carbon market across a diverse set of emission sources provides a wider range of reduction opportunities. There are multiple paths for achieving the broad geographic and economy-wide coverage that is preferred for a cap-and-trade program. The WCI Partner jurisdictions also recognize alternative schedules for implementation can be accommodated and will continue to encourage additional jurisdictions to join the program after the expected start date of January 1, 2012.

Figure 2: How the WCI Cap-and-Trade Program Works

The WCI Cap-and-Trade Program will be composed of the individual jurisdictions' cap-and-trade programs implemented through state and provincial regulations. Each WCI Partner jurisdiction implementing the cap-and-trade program design will issue "emission allowances" to meet its jurisdiction-specific emissions goal. The total number of available allowances serves as the "cap" on emissions. The allowances can be bought and sold ("traded"). A regional allowance market is created by the Partner jurisdictions recognizing one another's allowances for compliance. Through this recognition, the emissions allowances issued by each jurisdiction will be usable throughout the jurisdictions for compliance purposes.

The WCI Cap-and-Trade Program includes rigorous emissions reporting requirements that ensure accurate and timely measurement and recording of GHG emissions by the entities included in the program. At least once each three years, covered entities are required to turn into the state or province one "emission allowance" for each metric ton of carbon dioxide equivalent (CO_2e) emissions they emit and report. To reduce the total amount of emissions, the number of allowances issued will be reduced over time.

There is no restriction on who can own emission allowances—they can be sold between and among covered entities or third parties. Entities that reduce their emissions below the number of allowances they hold can sell their excess allowances or hold them for later use. Selling excess allowances allows entities to recoup some of their emissions reduction costs, while holding allowances for later use will lessen future compliance costs. This "trading" of emission allowances keeps compliance costs lower than would otherwise be the case because it provides flexibility in how and when reductions are made. It also puts a price on the emissions, which provides an incentive to innovate and find new ways to reduce emissions.

The WCI program design includes important features to ensure that the participating jurisdictions achieve their emissions goals affordably and cost-effectively. Emission offsets, representing emissions reductions from sources not covered by the program, can be used for compliance in limited quantity along with allowances from other trading programs that have been recognized by the WCI Partner jurisdictions. There is no limitation on how long an emission allowance may be held for future use. Allowing entities to turn in allowances in three-year periods provides flexibility as to when emissions reductions are made.

3. Relying on High-Quality Emissions Data from Rigorous Reporting

Accurate, timely, and consistent GHG emissions data is essential for an effective GHG emissions reduction effort. A cap-and-trade program in particular requires that all emitters in the program have high-quality emissions data so they can submit the correct number of emission allowances to cover their emissions. Accordingly, the WCI Partner jurisdictions have developed a reporting program that specifies quantification methods that are rigorous, technically feasible, cost-effective, and sufficiently accurate to support the cap-and-trade program.[6]

To minimize the reporting burden in the U.S., the WCI Partners' reporting requirements are harmonized with the U.S. EPA Mandatory Reporting Rule for GHG emissions[7] so that a facility will be able to submit a single report satisfying both the WCI Partners' requirements and the U.S. EPA rule. Because the U.S. EPA reporting rule is not designed to support a cap-and-trade program, it includes a range of quantification and measurement methods. The WCI Partners' specifications often require the more rigorous methods among the options included in the U.S. EPA rule in order to achieve the accuracy required in the WCI Partners' program.

The WCI Partner jurisdictions are also developing a Canadian version of the reporting requirements. Any necessary adjustments to existing requirements will be phased in over time. Several Canadian WCI Partners are developing a one-window GHG emissions reporting interface with Environment Canada. A report by a facility to the one window interface would meet the requirements of both the federal and provincial government, thus obviating the need for duplicate reporting.

The WCI Partner jurisdictions are continuing to develop reporting protocols for some emission sources that do not yet have adequate quantification methods. Chief among these are oil and gas production, natural gas processing, and natural gas transmission and distribution, which are significant sources of GHG emissions in some WCI Partner jurisdictions. In the spring of 2010, U.S. EPA released proposed requirements for GHG emissions reporting for oil and gas operations. To support the U.S. EPA's effort to require reporting in this sector and to align U.S. EPA reporting requirements with WCI Partner needs, the WCI Partner jurisdictions evaluated the proposed rule and submitted extensive comments to EPA.[8]

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[6] *Final Essential Requirements for Mandatory Reporting*. July 2009.

[7] *Proposed Harmonization of Essential Requirements for Mandatory Reporting in U.S. Jurisdictions with EPA Mandatory Reporting Rule*. June 2010. Information about the U.S. EPA Greenhouse Gas Reporting Program is available at: http://www.epa.gov/climatechange/emissions/ghgrulemaking.html.

[8] *WCI Comments on the Proposed Mandatory Reporting of GHG Emissions from Proposed Reporting for Oil and Gas Operations (Subpart W)*. June 2010.

For Canadian jurisdictions, specific quantification methods may be required for some sources due to different royalty data systems, equipment specifications, and metering requirements. The WCI Partner jurisdictions will review EPA's final reporting rule for the oil and gas sector and determine its appropriateness for a regional cap-and-trade program.

4. Setting the Program Emissions Limits

The WCI Cap-and-Trade Program is designed to reduce GHG emissions to 15 percent below 2005 levels by 2020, which is the sum of the emissions goals of the Partner jurisdictions. The emissions limit is created by each jurisdiction issuing a limited number of "emission allowances," referred to as the jurisdiction's allowance budget, and requiring emitters to:

- Report their emissions annually;[9] and
- Submit sufficient emission allowances and offset certificates[10] to cover their reported emissions.

The jurisdiction's allowance budget therefore is the primary determinant of the total limit on the emissions from all the emitters in the program in the jurisdiction, along with the number of offset certificates that can be used.

The WCI Partner jurisdictions recommend that each jurisdiction develop its allowance budget in the same manner to ensure consistency and transparency throughout the program.[11] Additionally, the Partner jurisdictions recommend a common limit on the use of offset certificates be applied uniformly.[12]

Partner Allowance Budgets

The WCI Partner jurisdictions recommend setting allowance budgets to provide for a gradual emission reduction to the 2020 emission target. Accordingly, the Partners recommend that each Partner's 2012 allowance budget for emitters covered in 2012 be the best estimate of actual emissions anticipated in 2012. With this approach, the allowance budgets are sufficient to enable emissions to continue as expected in the first year of the program.

In 2015, the program is designed to expand to cover providers of transportation fuels and residential and commercial fuels.[13] Consequently, Partners' allowance budgets increase in 2015 to reflect the addition of these emissions. The increase in the allowance budgets in 2015 to cover these emissions is recommended to be the best

[9] Reporting is discussed above in section 3.

[10] Offsets are discussed below in section 8.

[11] *Guidance for Developing WCI Partner Allowance Budgets*. June 2010.

[12] *WCI Recommendations for Implementing the Offset Limit*. March 2010.

[13] The WCI Partner jurisdictions acknowledge that individual jurisdictions may utilize other fiscal measures, such as British Columbia's carbon tax, to address transportation fuels and fuel use by residential and commercial sources that contribute to achieving overall comparable GHG emissions reductions and internalize the price of carbon as expected through the cap-and-trade program.

estimate of expected actual emissions from these sources. So, again, the allowance budgets are sufficient to cover expected emissions from the sources during the first year they are included in the program.

The remainder of the Partners' allowance budgets are defined by calculating the 2020 budget and the values from 2012 to 2015 and from 2015 to 2020. The WCI Partner jurisdictions recommend that the 2020 allowance budgets be set to achieve each jurisdiction's economy-wide 2020 emissions target, so that the number of allowances issued plus emissions from uncapped sectors will equal each jurisdiction's 2020 target. A linear decline from 2012 to 2015, and then from 2015 to 2020, is recommended to enable a gradual ramp-down.

WCI Partners' economic analysis has shown that this gradual linear decline can be achieved with a slight net savings.[14] Figure 3 graphically illustrates an allowance budget.

Recognizing Early GHG Reductions with Allowances

The WCI Partner jurisdictions recognize the value of reducing emissions as soon as possible, including prior to the start of the program. A number of approaches have been identified that some Partners may use to provide incentives for early action, including issuing Early Reduction Allowances (ERAs) for emissions reductions that occur during the period of 2008 through 2011. To be eligible to receive ERAs, the reductions must be voluntary, additional, real, verifiable, permanent, and enforceable.[15] Once issued, the ERAs may be used in the same manner as other emission allowances.

Offset Certificates and Instruments from Other Programs

The WCI Partner jurisdictions recommend that offset certificates and approved compliance instruments from other programs (such as another cap-and-trade program) be used along with emission allowances to comply with the program. The WCI Partners' economic analysis found that the use of such instruments can help reduce compliance costs for emitters. However, the WCI Partner jurisdictions believe that covered emitters should make the majority of the emissions reductions needed to achieve the 2020 emissions goal. Accordingly, the WCI Partner jurisdictions recommend that the use of offsets certificates and other approved instruments not exceed 49 percent of the aggregate required emissions reductions across all the Partner jurisdictions' programs.

Using the sum of the Partner allowance budgets, a total limit on the use of offset certificates and approved compliance instruments from other programs will be calculated and applied to all emitters in the program in all of the compliance periods. The limit will be expressed as a portion of the emitters' emissions that can be covered by offset certificates or approved compliance instruments from other programs. For example, if

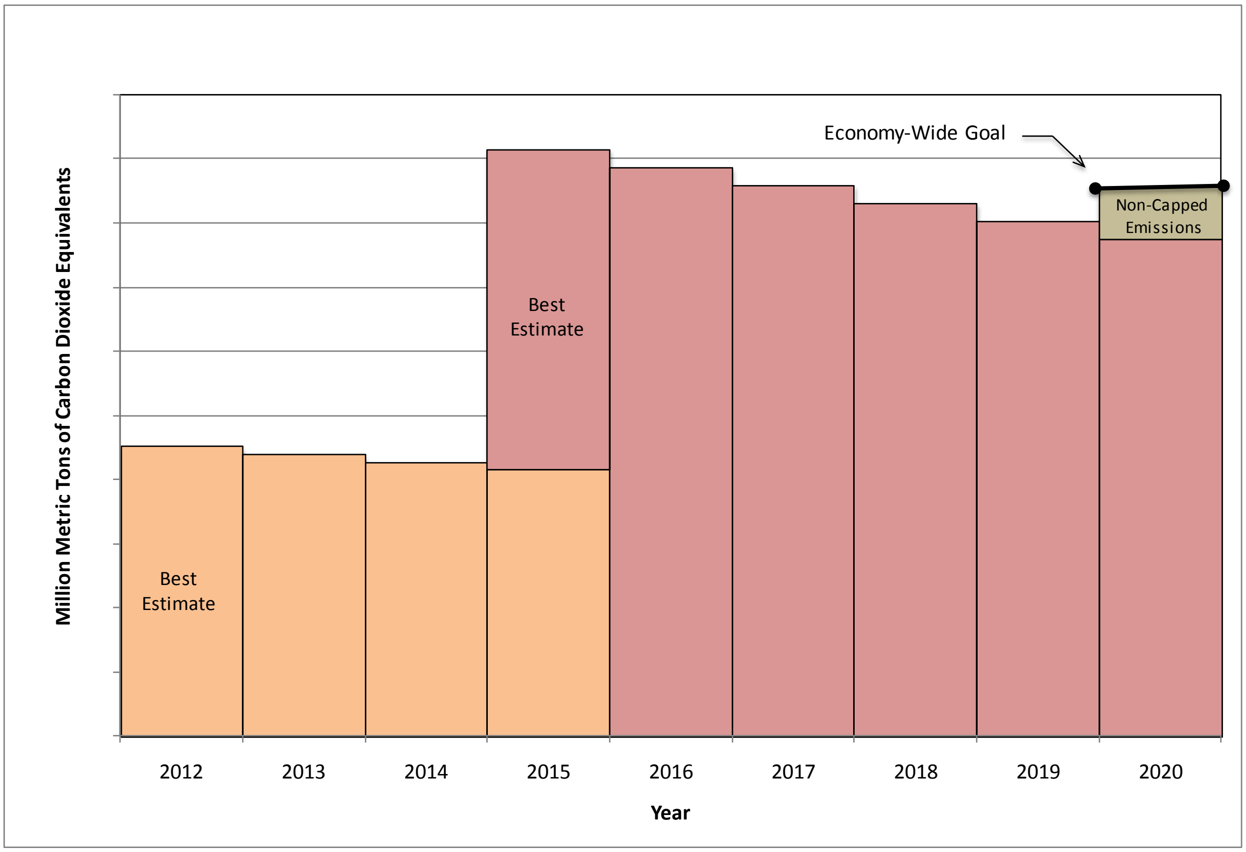
[14] *Updated Economic Analysis of the WCI Regional Cap-and-Trade Program*. July 2010.

[15] *Guidance for Distributing Early Reduction Allowances*. June 2010.

the limit is calculated to be 5 percent,[16] then an emitter of 100,000 metric tons of CO_2e could comply with the program using at most 5,000 offset certificates or approved compliance instruments from other programs. The remainder of the emissions (95,000 metric tons in this example) would need to be covered by emission allowances issued by a WCI Partner.

In sum, emission allowances, ERAs, offset certificates, and approved compliance instruments from other programs constitute the total allowable emissions from emitters in the WCI Cap-and-Trade Program.

Figure 3: Graphic Illustration of a Jurisdiction Allowance Budget



The 2012 allowance budget declines through 2015, when the newly covered emissions are added to the program. The budget then declines through 2020. The 2020 allowance budget is shown below the 2020 economy-wide goal because some emissions are not covered by the cap-and-trade program. The difference between the 2020 allowance budget and the economy-wide goal is the emissions that are not covered by the cap-and-trade program.

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[16] Note that 49 percent of emissions reductions translates into a much smaller percentage of total emissions allowed under the program.

5. Enhancing Compliance Flexibility and Program Adaptability to Manage Compliance Costs

The WCI Cap-and-Trade Program is designed to achieve its environmental objectives reliably and cost effectively. Multiple program features provide compliance flexibility while ensuring that emission goals are achieved (see Figure 4). WCI Partners' analysis of the program design finds that these features ensure that the program is supportive of economic growth and job creation.[17]

WCI Partners' analysis also examined scenarios in which potential future conditions could lead to compliance costs being higher than expected. The findings show that combinations of circumstances could result in compliance cost increases that may impact consumers or industry competitiveness, and increase emissions leakage risk.[18] Examples of such conditions may include:

- Technology Costs: Technologies to reduce emissions may be more costly or may require more time to install than anticipated.
- Weather: Increased incidence or prolonged duration of droughts, possibly associated with the early physical impacts of climate change, may unexpectedly reduce the availability of hydroelectric power, requiring increased reliance on fossil fuel generating resources. Similarly, heat waves or periods of extreme cold associated with greater weather variability may increase demand for electricity or heating fuels.
- Electric Sector Upset: Disruptions to low-carbon electricity supplies, such as unplanned maintenance at a nuclear power facility or loss of transmission capacity to wind resources, could lead to temporary increases in reliance on fossil fuel generating resources.
- Uncertainty in Emissions Estimates: Continuing uncertainty about the strength and timing of the economic recovery makes estimates of expected emissions in 2012 and 2015 uncertain. Inadvertently setting the allowance budget too low due to this uncertainty may lead to greater emissions reductions being required than planned, and higher compliance costs.

The WCI Partner jurisdictions recognize that one or more of these types of conditions could occur, individually or in combination. Accordingly, approaches that enable the program to adapt to changing circumstances are under consideration, including the following:

1. Partners could establish allowance reserves from which emission allowances could be released under high-price conditions. Allowance reserves have been included in recent U.S. legislative proposals, which provide examples for consideration. The WCI Partner jurisdictions will further evaluate how allowance reserves might reduce the risks of high compliance costs, including examining:

[17] *Updated Economic Analysis of the WCI Regional Cap-and-Trade Program*. July 2010.

[18] Emissions leakage is discussed in section 6.

– The appropriate size of reserves;
– Methods for filling the reserves while maintaining the environmental integrity of the program;
– Conditions under which the reserves would be activated;
– Mechanisms for releasing allowances from the reserves; and
– Purposes for which allowances released from the reserves could be used.

2. Entities could be allowed to comply using a limited number of allowances from the next compliance period. The design recommends prohibiting borrowing allowances from future compliance periods to comply in the current period. However, this prohibition could be relaxed in recognition that some allowances from the next compliance period will already be in circulation at the time of the current compliance deadline. Consequently, some allowances from the next period will already be owned, and entities need not borrow them in order to use them to comply. Adding this provision to the program design could help reduce the risk of allowance prices spiking just prior to the compliance deadline. The WCI Partner jurisdictions will consider how this approach might be used, including:

   – The conditions under which allowances for the next compliance period could be used to comply in the current period;
   – Potential limits on the use of allowances from the next compliance period; and
   – Risks of increasing the stringency of the next compliance period and options for reducing these risks.

3. Special purpose allowance pools or other mechanisms could be created that target localized conditions that affect compliance costs locally. For example, allowances could be released in response to an electric sector upset in a jurisdiction. The WCI Partner jurisdictions will further consider the use of such special purpose allowance pools or other mechanisms in the context of:

   – The size needed to mitigate individual jurisdictional risks;
   – The conditions for activating allowance pools or mechanisms; and
   – Methods for filling and managing special pools at the individual jurisdiction level.

When combined with an auction floor price (see Figure 4), these mechanisms would help create boundaries on the range of allowance prices: new features under consideration would mitigate risks of high compliance costs and high allowance prices, while the auction floor price reduces the risks of low allowance prices. The auction floor price could also result in allowances remaining unsold at auction, which could be transferred to help fill allowance reserves. The WCI Partner jurisdictions recommend these types of mechanisms as preferred over hard price caps that have the potential to undermine the environmental integrity of the program and which could limit the ability to link to other cap-and-trade programs in the future.

Figure 4: WCI Program Design Recommendations that Provide Compliance Flexibility

Mechanisms	Impact
Allow a limited number of offset certificates and other approved compliance instruments for compliance	Allowing offset certificates and other approved compliance instruments for compliance can reduce compliance costs and reduce allowance prices. The limit on the use of offset certificates and other approved compliance instruments recommended by WCI Partner jurisdictions ensures that a majority of the required emissions reductions are achieved at the covered sources.
Unlimited banking	Unlimited banking allows compliance entities to decide how best to use emission allowances over time. This flexibility can substantially reduce compliance costs across compliance periods.
Multi-year compliance period	Multi-year compliance periods provide flexibility for compliance entities, and recognize that emission reduction efforts may take time to phase in, particularly in the early years of the program.
Linking among programs	Linking among cap-and-trade programs (such as among the WCI Partner jurisdictions), improves efficiency and reduces compliance costs by enlarging the carbon market across a diverse set of emissions sources with a range of emission reduction opportunities.
Broad scope	A broad scope for the cap-and-trade program helps improve efficiency and reduce compliance costs by covering a diverse set of sources with a range of emission reduction opportunities.
Other low-carbon core policies and programs	Other low-carbon core policies and programs can motivate or require emissions reductions that—due to market barriers—would not otherwise be undertaken solely in response to price considerations. These policies can reduce overall program compliance costs.
Auction floor price	The auction floor price keeps allowances out of the market, at least temporarily, in the event that the demand at auction results in a price that would be below an acceptable level. This feature helps correct an inadvertent over-allocation of allowances.

6. Maintaining Competitiveness and Preventing Emissions Leakage

The WCI Partner jurisdictions' recommendations are designed to maintain and enhance economic competitiveness while preventing emissions leakage. Competitiveness can be enhanced by early investments in cost-effective efficiency improvements, diversifying fuel supplies—particularly in the transportation sector—spurring innovation, and reducing exposure to fossil fuel price volatility. Improved air quality and public health also make our communities more livable, attracting families and businesses that create new economic opportunities and jobs.

Emissions leakage would occur if production activity shifts from WCI Partner jurisdictions to non-Partner jurisdictions so that emissions reductions in the WCI Partner jurisdictions are negated by comparable increases in another jurisdiction. Incentives may be used, particularly through the allocation of emission allowances, to minimize leakage risks and support WCI Partner jurisdictions' economic growth and jobs. Although the WCI Partner jurisdictions recommend that the value of the emission allowances be directed to enhance economic competitiveness and prevent emissions leakage, each Partner jurisdiction has the opportunity to apply these resources in the ways that best meet its needs.

> Benchmarking is an approach for promoting efficiency by evaluating GHG emissions performance among similar facilities or operations in an industrial sector. It uses an objective indicator of efficiency (a benchmark) to compare the facilities or operations to an industry standard or best practice metric. Benchmarking can be used in a cap-and-trade program as a basis for distributing allowances to industrial facilities covered by the program. Using benchmarks in this way can recognize and reward facilities that use best practices or that have already reduced emissions.

WCI Partner jurisdictions have been focusing on energy-intensive, trade-exposed ("EITE") industries, which may be particularly vulnerable to competition and leakage. Free distribution of emission allowances to EITE industries has been identified as one approach to promote competitiveness and minimize leakage, with benchmarking being considered as a basis for distributing allowances.[19] Free distribution based on benchmarking is the approach the EU proposes to take for its Phase III, and is embodied in leading national U.S. legislative proposals. A different approach would require imports into WCI Partner jurisdictions to comply with their cap-and-trade rules. This approach is recommended for the electricity sector and is described in more detail in the next section.

Differing allowance allocation methods could also affect competitiveness among WCI Partner jurisdictions, particularly for EITE industries. WCI Partner jurisdictions are continuing to examine harmonizing allowance distribution approaches, particularly among similar facilities or entities in the same industry. Use of common benchmarking approaches would facilitate this harmonization, thereby addressing potential competitiveness concerns prior to the program initiation.

If analysis demonstrates that allowance distribution to a particular sector could be harmonized by some WCI Partner jurisdictions to maintain competitiveness among similar facilities or entities—and if that analysis reveals that it is advisable to address those competitiveness issues—WCI Partner jurisdictions may recommend standardizing the distribution of allowances in those circumstances. Sectors where analysis is required include those with process (non-combustion) emissions where the greatest

[19] Two WCI co-sponsored workshops examined benchmarking issues. Materials from the September 17, 2009 Benchmarking Workshop in Toronto, ON are available: http://www.ene.gov.on.ca/en/air/climatechange/benchmarking.php. Materials from the May 19th, 2010 Greenhouse Gas Benchmarking Symposium in Seattle, WA are available at http://www.westernclimateinitiative.org/component/remository/Partner-Meeting-Materials/2010-05-19-(Seattle-Benchmarking-Symposium)/.

emission reduction potential is associated with large technology changes and high GHG emission intensity, such as aluminum, steel, cement, lime, pulp and paper, and oil refining.

7. Electricity Sector

The electricity sector has unique characteristics that are reflected in the WCI Cap-and-Trade Program design recommendations. The interconnected nature of the North American electricity grid creates the potential for leakage, and existing practices see considerable quantities of electricity transacted among jurisdictions. To maintain a level playing field and a consistent price for carbon, the emissions associated with imports of electricity are included in WCI Partner jurisdiction emissions. In addition, environmental requirements and voluntary initiatives have created existing markets for renewable energy in many jurisdictions, raising issues of their potential interaction with a cap-and-trade market. These issues have been examined and recommendations have been developed to address them.

Electricity Imports

The WCI Partner jurisdictions recommend that emissions from electricity generated outside the WCI Partner jurisdictions but consumed within them be included in the program. To include these emissions, the point of regulation is defined as the First Jurisdictional Deliverer (FJD), which is the first entity that delivers electricity over which the consuming WCI Partner jurisdiction has regulatory authority.[20]

Different approaches were examined in extensive consultations with stakeholders to determine how to define the boundary for FJD and treat transactions which pass through multiple jurisdictions. After considering practical, administrative, regulatory and enforcement aspects, the WCI Partner jurisdictions recommend the use of individual jurisdiction boundaries for FJD.[21] For jurisdictions that are not able to implement the full FJD approach, the Administrative Approach was developed as an alternative, under which the jurisdiction creates a reserve of allowances to cover emissions associated with imports.[22]

Imported power may be from a known generation source (with known emissions) or from an unspecified source. For the purposes of assigning emissions to unspecified sources, the *Default*

[20] The FJD recommendation and consequences have been further examined and refined in stakeholder consultations and consultant studies including the *Electricity Leakage Analysis Summary Report* (March 2009); *Draft Open Access Technologies Inc. (OATI) Analysis of Electricity Imports in the Western Electricity Coordinating Council (WECC) Region* (February 2010); and *Electricity Imports, Exports and Leakage in the Eastern WCI Partner jurisdictions: Quebec, Ontario and Manitoba* (July 2010).

[21] Considerations on the boundary issue are described in *Discussion Paper on FJD Boundary Options for Regulating Electricity Imports* (January 2009), and the decision laid out in *Announcement Regarding the FJD Approach* (July 2009).

[22] *Covering Emissions From Imported Electricity: An Administrative Approach*. May 2010.

Emissions Calculator[23] was developed and the concept validated with stakeholders. With this approach, all generators in a jurisdiction or area are identified along with their recent historical emissions. Using criteria on capacity factors and type of generation, marginal generation available to supply the imported power is identified and an emissions factor calculated.

Renewable Energy

To address the interaction between the WCI Cap-and-Trade Program and existing markets for renewable energy, WCI Partner jurisdictions recommend:

- Renewable Energy Certificates (RECs) will have no compliance role in the WCI Cap-and-Trade Program. This recommendation maintains the separate and distinct markets for RECs and GHG allowances, and avoids complications from overlap of the two regulatory regimes.[24]
- To recognize the impacts of voluntary investments in renewable energy, an optional mechanism was developed for use by WCI Partner jurisdictions. This approach employs a set-aside of allowances to be retired in recognition of voluntary renewable energy purchases, thus enabling voluntary investments to reduce GHG emissions under a cap-and-trade regime.[25]

Recognizing the importance of renewable energy in reducing GHG emissions, Partner jurisdictions can choose to freely allocate allowances from within their allowance budgets to entities that export renewable electricity (e.g., hydroelectricity) outside WCI Partner jurisdictions, in accordance with section 6 of the Detailed Design.

Competitiveness

The highly interconnected nature of the electricity sector in North America led to a focus on competitiveness in the electricity sector, and the recommendation that the distribution of allowance value or auction revenues in that sector could be standardized as a means to address competitiveness across WCI Partner jurisdictions.[26] While the FJD compliance obligation helps to maintain the competitiveness of electricity generation in WCI Partner jurisdictions with respect to imported electricity, for WCI Partner jurisdictions that currently export electricity, fossil-fired electricity exports that would be less competitive in non-WCI markets must also be considered.[27] The WCI Partner jurisdictions are examining potential options for mechanisms to address this issue.

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[23] 2007 and 2006 *Draft Default Emission Factor Calculators*. February 2010.

[24] Considerations on the treatment of RECs are described in the discussion paper *Renewable Portfolio Standards, Renewable Energy Certificates, and GHG Accounting (RECs) Accounting* (December 2008). The decision is further explained in the announcement *Treatment of Renewable Energy Credits in the WCI Cap-and-Trade Program* (May 2010).

[25] This approach is described in *Voluntary Renewable Energy Market: Issues and Recommendations*. July 2010.

[26] This issue was explored in GHG Allowance Allocation Options in the Electricity Sector. January 2009.

[27] An example of this effect can be found in the report *Electricity Imports, Exports and Leakage in the Eastern WCI Partner Jurisdictions: Quebec, Ontario and Manitoba*. July 2010.

8. Designing for High-Quality Offsets

The WCI Partner jurisdictions include offsets in the WCI Cap-and-Trade Program design to reduce compliance costs by introducing a broader range of emissions reduction opportunities. The WCI Partner jurisdictions' recommendations for offsets maintain the integrity of the emissions cap by ensuring that emissions reductions or removals achieved through an offset project are functionally equivalent to emissions reductions achieved by a regulated emissions source. Emphasis is placed on assuring the quality of offsets, not only to ensure that the program's environmental goals are achieved, but also with the objective of informing the national and international deliberations on offsets.

The WCI Partner jurisdictions recommend the following for the definition of an offset and criteria to evaluate an offset project.

- **Definition**: A GHG offset is a reduction or removal of GHG emissions as a result of a project or activity that occurs outside the sectors regulated by the cap-and-trade program. An offset certificate issued by a WCI Partner jurisdiction represents a reduction or removal of one metric ton of CO_2e. To be issued an offset certificate by a WCI Partner jurisdiction, each reduction or removal must meet all recommended offset criteria, have clearly identified ownership, follow an accepted protocol, and result from a project located in Canada, the U.S., or Mexico.
- **Criteria**: Offset projects approved by WCI Partner jurisdictions will meet the criteria described in the *Offset System Essential Elements Final Recommendations*.[28] The criteria recommended by WCI Partner jurisdictions are consistent with the leading offset systems in use worldwide, and will allow the adoption of protocols that produce consistent offsets across the WCI region. The other North American emissions trading systems—RGGI and the Midwestern Greenhouse Gas Reduction Accord—share the goal of ensuring the quality of offsets. The three regional programs released a paper on offset quality that is consistent with the offset criteria recommended by the WCI Partner jurisdictions.[29]

WCI Partner jurisdictions will leverage existing protocols to align with the essential criteria and, through their rulemaking processes, make the protocols applicable for use in all WCI Partner jurisdictions. WCI Partner jurisdictions have evaluated existing protocols against WCI Partners' offset criteria,[30] and are continuing to establish key protocol components for each priority project type. This is being done in consultation with sector experts and stakeholders, enabling where possible the use of existing protocols and flexibility for the

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[28] *Offsets System Essential Elements Final Recommendations*. June 2010.

[29] *Ensuring Offset Quality: Design and Implementation Criteria for a High Quality Offset Program*. May 2010.

[30] *Review of Existing Offset Protocols Against WCI Offset Criteria*. April 2010.

protocol authors and national or voluntary offset program developers to easily take advantage of and harmonize with WCI Partner jurisdiction progress.

Similar to the essential criteria, the process of offset project approval through certificate issuance contains important features to ensure offset quality. The WCI Partner jurisdictions are continuing to finalize the process, with the goal of having a streamlined process and protocols in time for adoption by Partners who need to incorporate these elements into their legislative and/or regulatory processes. These steps will include specific requirements for registration, validation, monitoring, quantification, reporting, verification, certification, and issuance of offsets. WCI Partner jurisdictions will harmonize the project approval process in consultation with stakeholders prior to the start of the program.

9. Designing a Fair and Transparent Auction

Selling emission allowances at auction is one mechanism for distributing allowances. Both the European program and RGGI use auctions, with RGGI relying almost exclusively on auctions for distributing allowances. The WCI Partner jurisdictions expect to auction allowances as one component of allowance distribution. The portion of allowances auctioned may vary across jurisdictions based on jurisdiction-specific authorities and circumstances, and may also change over time.

The WCI Partner jurisdictions plan to auction emission allowances in a regionally coordinated manner to ensure fairness and transparency, maximize efficiency, and ensure consistent application of state and provincial laws. To accomplish these objectives, the WCI Partner jurisdictions recommend the following for the design of a regionally coordinated auction:

- **Auction format, timing and frequency**: A sealed bid, single round, uniform price (lowest winning bid) auction that will take place quarterly. The sealed bid, single round auction format mitigates the potential for market manipulation and is relatively simple to understand. A quarterly auction balances the cost of running the auctions with flexibility for participants, and creates regular market price signals. This approach is consistent with auctions in other cap-and-trade programs.
- **Reserve price**: A reserve or "floor" price applied to all of the allowances on offer at the auction. As further described in section 10, this feature addresses an inadvertent over-allocation of allowances to the market and the risk of persistently low compliance costs. The method for determining a reserve price will be set in advance of the first auction.
- **Vintages**: Allowances from future compliance periods may be sold concurrently to aid market liquidity, reduce uncertainty, and contribute to market efficiency.
- **Lot size**: Allowances will be sold in lot sizes of 1,000 (equal to 1,000 metric tons),

allowing flexibility for auction participants. This lot size is not so large as to discourage participation by smaller entities, yet of sufficient size to make transaction costs manageable.

- **Participant access and financial assurance**: An auction that is open to anyone with an account in the tracking system and able to meet pre-qualification financial assurance requirements will ensure fairness. Requiring bidders to submit an approved form of financial assurance (e.g., cash, bond, letter of credit) that covers the full value of their bid will contribute to accountability and help prevent market manipulation. Such assurances are consistent with auction procedures in other cap-and-trade programs.
- **Information transparency**: The clearing price and total number of purchased allowances will be disclosed publicly after the auction. Disclosure of auction results contributes to both transparency and price discovery and is also consistent with other programs.
- **Mitigation of market manipulation**: Auctions will include a purchase limit and WCI Partner jurisdictions will undertake monitoring and reporting measures that will mitigate market manipulation.

WCI Partner jurisdictions continue to consult on several auction design elements that require additional analysis, including the following:

- Methods for determining reserve prices.
- A non-competitive auction component that would allow bidders to purchase a limited number of allowances, without submitting a bid schedule, at the clearing price as determined by the competitive bidding.
- The ability of Partner jurisdictions to incorporate a consignment option that would allow parties to make their allowances available for purchase in the auction.
- The level of detail to disclose when announcing the auction results, to balance the need for transparency while protecting auction participant information.
- Currency exchange issues relating to a potential bi-national auction.

Partner jurisdictions also continue to discuss recommendations for treatment of allowances that remain unsold at auction. WCI Partner jurisdictions can retire allowances, roll allowances to a future auction, or supply allowance reserves. In addition, the WCI Partner jurisdictions are developing a method for jurisdictions that are not auctioning allowances to manage their allowance budgets in a way that is equitable and supports the WCI Partner jurisdiction's cost containment goals.

10. Ensuring a Well-Functioning Market

The WCI Cap-and-Trade Program is designed to harness market forces to spur technological innovation and reduce GHG emissions at the lowest possible cost. For the program to achieve these goals, participants must be able to trade emission allowances and offset certificates in a well-functioning market. To accomplish this, the WCI Partner jurisdictions are recommending specific policies to ensure fair and equal access to the market, transparent operations and timely public disclosure of critical information to maintain public confidence, and a market free of manipulation so that prices reflect supply and demand conditions.

Recent market events in the U.S. and elsewhere underscore the need for comprehensive and effective market monitoring and oversight. To achieve the necessary level of effectiveness, the WCI Partner jurisdictions recommend coordinating among several institutions based on existing authorities and capabilities. Financial reform under consideration in the U.S. and Canada could alter existing authorities, with the expectation of enhancing oversight. As needed, these recommendations may be revised in light of financial reform to ensure comprehensive and effective oversight is maintained.

The WCI Partner jurisdictions' recommendations reflect the following roles:

- The U.S. and Canadian WCI Partner jurisdictions have primary responsibility for the auction market, including all aspects of its design, operation, monitoring, and enforcement.
- The U.S. and Canadian WCI Partner jurisdictions also have primary responsibility for oversight and enforcement of the "cash market" in which allowances and offset certificates are traded for immediate delivery. Oversight responsibility may be shared, however, with trading organizations.
- In the U.S., the Commodity Futures Trading Commission has primary responsibility for oversight of the derivatives market.[31] In Canada, provincial regulatory authorities provide derivative market oversight. The WCI Partner jurisdictions have been in discussions with these organizations to develop this approach, and recommend formalizing the coordination prior to the start of the program.

Recommendations for the areas in which WCI Partner jurisdictions have primary responsibility are to: [32] impose necessary requirements on all owners of allowances and offset certificates; encourage the use of effective trading venues; and conduct effective monitoring of market activity and conditions. The requirements that apply to owners of allowances and offset certificates focus

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[31] A derivative is a financial instrument that derives its value from one or more other underlying assets. A contract to purchase an emission allowance in six months at a specific price is an example of a derivative. Derivatives are traded on exchanges and between individual parties (referred to as "over the counter" or OTC).

[32] The WCI Partner market oversight recommendations are listed in the *Market Oversight July Status Update*. For a discussion of market oversight options, see *Market Oversight Draft Recommendations*. April 2010.

on providing information that enables the WCI Partner jurisdictions to know the identity and inter-relationships of market participants and to evaluate their activity in the auction and cash markets. Key aspects of this information will be disclosed publicly so that the public will know how the markets are working.

Reporting and disclosure also will help regulators uncover conditions that may make manipulation possible. To further reduce the risk of manipulation, the WCI Partner jurisdictions are considering placing a limit on the allowances and offset certificates that any one entity can hold. [33] Such a limit would be in addition to the limit on purchases in any single auction, discussed above. The WCI Partner jurisdictions note that some of the information provided by allowance and offset certificate owners must be maintained as confidential to avoid revealing information that would assist market manipulation rather than prevent it.

Market participants' use of well organized and effectively managed trading venues (such as exchanges) will help ensure transparent and competitive pricing and equal access to the market, benefitting market participants and the public. Accordingly, the WCI Partner jurisdictions propose to encourage qualified venues to develop cash markets, provided the venues conduct effective oversight of their cash markets and enable access for regulatory oversight.

Vigilant market monitoring will be necessary across all aspects of these recommendations. The WCI Partner jurisdictions recommend that professional market intermediaries be identified and registered. Provisions for collaborative analysis and information sharing among Partner jurisdictions are also recommended to ensure effective and comprehensive monitoring across the program.

[33] For a discussion of holding limits under consideration by the WCI Partner jurisdictions, see *Report on Holdings Limits*. May 2010.

11. Linking Programs

The WCI Partner jurisdictions are committed to promoting broad collaborative action to reduce GHG emissions. Accordingly, the WCI program recommendations are designed to facilitate linking among the WCI Partner jurisdictions as well as linking with jurisdictions participating in other programs. Several benefits of linking include:

- Incorporating more opportunities to reduce GHG emissions can improve cost-effectiveness while also achieving greater emissions reductions.
- Expanding the geographic coverage of the price on GHG emissions can reduce the risk of emissions leakage and maintain competitiveness.
- Enlarging the market for emission allowances and offsets can improve market liquidity, reduce volatility, and reduce the likelihood of manipulation.
- Collaborating among jurisdictions can provide an opportunity to share administrative functions, reducing the costs of program operation and enhancing consistency across jurisdictions.

Linking among the WCI Partner jurisdictions will be achieved by recognizing each other's instruments for compliance purposes. Through this recognition, the emission allowances and offset certificates issued by each jurisdiction will be usable throughout the linked jurisdictions for compliance purposes. Prior to linking, a Partner jurisdiction will have the opportunity to review each jurisdiction's program to assess its consistency with the program design, including: allowance budgets; information requirements and tracking systems; emissions accounting for electricity traded between Partner jurisdictions; monitoring, reporting, verification, compliance, and enforcement provisions; and treatment of offsets. Ensuring consistency with the program design will protect the integrity of each jurisdiction's program and the regional effort as linking is instituted.

The WCI Partner jurisdictions are also actively exploring linkages with other government-approved cap-and-trade systems. Initially, WCI Partner jurisdictions will consider unilateral linking to accept compliance instruments from trading programs external to WCI Partner jurisdictions. Prior to initiating a unilateral link, external programs will also be evaluated to ensure that they exhibit the integrity inherent in the WCI Cap-and-Trade Program design recommendations. In particular, a mechanism will be developed to ensure the compliance instruments from external programs can only be used once.

WCI Partner jurisdictions will also consider the recognition of offsets that are not part of an external cap-and-trade program. In this case, the criteria that are relevant for offsets will be used to evaluate the acceptability of the external offset program.[34]

Over the longer term, WCI Partner jurisdictions will work with jurisdictions participating in other

[34] The specific mechanisms for recognizing offsets from other systems are still under consideration.

regional trading programs to explore bilateral or multilateral linkages so that compliance instruments from those jurisdictions and compliance instruments issued by WCI Partner jurisdictions are fully fungible. Jurisdictions participating in the three regional climate initiatives in North America—WCI, RGGI, and the Midwestern Greenhouse Gas Reduction Accord—have been working cooperatively to share experiences in the design and implementation of regional cap-and-trade programs, inform federal decision making on climate change policy, and explore the potential for further collaboration among the three regional programs. This work will provide a potential roadmap for developing bilateral or multilateral linkages.

12. Coordinating Program Administration

Implementation of the WCI Cap-and-Trade Program by Partner jurisdictions requires effective administrative processes. This section describes three areas of proposed coordination: the tracking system for emission allowances and other compliance instruments; compliance verification and enforcement; and a regional administrative organization.

Tracking System

The tracking system is an integral component of the WCI Cap-and-Trade Program. Its purpose is to ensure the accurate accounting of the issuance, holding, transfer, retirement, and cancellation of compliance instruments. The tracking system must be simple to use, secure, flexible in an evolving environment, consistent with legal requirements in WCI Partner jurisdictions, and meet the WCI Partner jurisdictions' transparency objectives. The WCI Partner jurisdictions will ensure a regional tracking system is in place prior to the start of the program.

The WCI Partner jurisdictions will establish and maintain a tracking system that enables an effective and transparent regional cap-and-trade program. The tracking system will notably:

- Be a standardized electronic database that is accessible online.
- Contain separate accounts to record the compliance instruments held by each person or entity and to whom and from whom they are issued or transferred.
- Ensure there are no transfers incompatible with the rules implementing the WCI Cap-and-Trade Program.
- Provide for public access to relevant information, as well as confidentiality of information as appropriate.
- Restrict certain functions to account holders, to authorized staff of regulatory authorities, or to system maintenance service providers.
- Have the ability to generate specific public reports.

Section 7 of the Detailed Design contains more information on the tracking system. The WCI Partner jurisdictions are evaluating the suitability of developing the tracking system from others already in use in other markets.

Compliance Verification and Enforcement

Each WCI Partner jurisdiction will use its authority to enforce compliance with the WCI Cap-and-Trade program within its own jurisdiction. The WCI Partner jurisdictions recognize that during the first compliance period, unforeseen issues are likely to arise. Each WCI Partner jurisdiction should aim for full compliance, and engage in compliance promotion to reduce the potential for non-compliance. Consequently, the WCI Partner jurisdictions are committed to providing appropriate technical and compliance assistance to the program participants.

A degree of harmonization and a necessary level of stringency for compliance verification and enforcement are essential in linking cap-and-trade programs among WCI Partner jurisdictions to ensure consistent programmatic outcomes and a level playing field for covered sources. The degree of harmonization is subject to each WCI Partner jurisdiction's legislative and administrative processes and acknowledges that each jurisdiction maintains sovereignty in the administration of its program.

Of particular importance is ensuring that all linked programs can take similarly effective steps in the event that a covered source does not have sufficient compliance instruments to cover its emissions for the previous compliance period. In such circumstances, requirements must apply that:

- Operate without requiring the cooperation of the covered source;
- Are non-discretionary; and
- Are of sufficient magnitude to incentivize compliance.

To achieve this common level of performance, the WCI Partner jurisdictions recommend that:

- One compliance instrument be submitted for each ton of emissions by the compliance deadline; and
- Emissions for which compliance instruments are not provided by the compliance deadline be considered "excess emissions," with the following increased compliance obligation:
  - One compliance instrument to cover each metric ton of excess emissions (the compliance requirement had compliance instruments been submitted on time); and
  - Three additional compliance instruments for each metric ton of excess emissions.

The increased compliance obligation for excess emissions does not preclude WCI Partner jurisdictions from also establishing administrative, civil and criminal penalties for non-compliance. If a WCI Partner jurisdiction is unable to implement the increased compliance obligation for excess emissions, the Partner jurisdiction may substitute a monetary payment that provides a comparable incentive for timely compliance.

Regional Administrative Organization

Implementation of a regional cap-and-trade program requires coordination between WCI Partner jurisdictions in order to ensure integrity, efficiency and consistency. This coordination may be achieved through a Regional Administrative

Organization that is designed to perform the following functions to support the WCI Cap-and-Trade Program:

- Coordinate the regional auction of allowances.
- Track emissions and provide public information on progress towards the WCI Partners' emissions goals.
- Report to Partners on market activity.
- Serve as a forum for WCI Partner jurisdictions to update one another on program progress.
- Coordinate Partner review and adoption of protocols of offsets.
- Coordinate Partner review and adoption of updated reporting protocols.
- Coordinate Partner review and issuing of offsets certificates.
- Suggest criteria and means for Partners to accredit service providers to deliver validation and verification services.

The WCI Partner jurisdictions are considering creating a regional organization or retaining an existing organization to provide these services. RGGI has created a non-profit corporation, RGGI Inc., which is an example of the type of organization that the WCI Partner jurisdictions are considering.

DOCUMENTATION

The following materials were developed by WCI committees and teams, and form the basis for the WCI program design recommendations. In most cases, white papers, technical documents, and draft recommendations were developed and/or reviewed in consultation with stakeholders through written comment, public conference calls, and meetings.

Reporting

- *Final Essential Requirements for Mandatory Reporting*. July 2009. Available at: http://www.westernclimateinitiative.org/component/remository/Reporting-Committee-Documents/Final-Essential-Requirements-for-Mandatory-Reporting Note: An amended version of these essential requirements, appropriate for use in the Canadian Partner jurisdiction, is under development.
- *Proposed Harmonization of Essential Requirements for Mandatory Reporting in U.S. Jurisdictions with EPA Mandatory Reporting Rule*. June 2010. Available at: http://www.westernclimateinitiative.org/component/remository/Reporting-Committee-Documents/Proposed-Harmonization-of-Essential-Requirements-for-Mandatory-Reporting-in-U.S.-Jurisdictions-with-EPA-Mandatory-Reporting-Rule
- *WCI Comments on the Proposed Mandatory Reporting of GHG Emissions from Proposed Reporting for Oil and Gas Operations (Subpart W)*. June 2010. Available at: http://www.westernclimateinitiative.org/component/remository/general/WCI-Comments-on-the-Proposed-Mandatory-Reporting-of-GHG-Emissions-from--Proposed-Reporting-for-Oil-and-Gas-Operations-(Subpart-W)

Setting the Program Emissions Limits

- *Guidance for Developing WCI Partner Allowance Budgets*. June 2010. Available at: http://www.westernclimateinitiative.org/component/remository/Cap-Setting--and--Allowance-Distribution-Committee-Documents/Guidance-for-Developing-WCI-Partner-Allowance-Budgets/
- *WCI Recommendations for Implementing the Offset Limit*. March 2010. Available at: http://www.westernclimateinitiative.org/component/remository/Cap-Setting--and--Allowance-Distribution-Committee-Documents/WCI-Offset-Limit-Recommendations
- *Guidance for Distributing Early Reduction Allowances*. June 2010. Available at: http://www.westernclimateinitiative.org/component/remository/Cap-Setting--and--Allowance-Distribution-Committee-Documents/Guidance-for-Distributing-Early-Reduction-Allowances/

Electricity Sector

- *Electricity Leakage Analysis Summary Report*. March 2009. Available at: http://www.westernclimateinitiative.org/component/remository/Electricity-Team-Documents/Electricity-Leakage-Analysis-Summary-Report

- *Electricity Imports, Exports and Leakage in the Eastern WCI Partner jurisdictions: Quebec, Ontario and Manitoba*. July 2010. Available at: http://www.westernclimateinitiative.org/component/remository/Electricity-Team-Documents/Electricity-Analysis-in-the-Eastern-WCI-Partners

- *Draft Open Access Technologies Inc. Analysis of Electricity Imports in the Western Electricity Coordinating Council (WECC) Region*. February 2010. Available at: http://www.westernclimateinitiative.org/component/remository/Electricity-Team-Documents/Draft-OATI-Analysis-(2-18-10)

- *Announcement Regarding the FJD [First Jurisdictional Deliverer] Approach*. July 2009. Available at: http://www.westernclimateinitiative.org/component/remository/Electricity-Team-Documents/Announcement-Regarding-the-FJD-Approach

- *Discussion Paper on FJD [First Jurisdictional Deliverer] Boundary Options for Regulating Electricity Imports*. January 2009. Available at: http://www.westernclimateinitiative.org/component/remository/Electricity-Team-Documents/FJD-Boundary-Options-Discussion-Paper

- *Covering Emissions From Imported Electricity: An Administrative Approach*. May 2010. Available at: http://www.westernclimateinitiative.org/component/remository/Electricity-Team-Documents/Covering-Emissions-From-Imported-Electricity-An-Administrative-Approach/

  2007 and 2006 Draft Default Emission Factor Calculators. February 2010. Available at: http://www.westernclimateinitiative.org/component/remository/Electricity-Team-Documents/2007-Draft-Default-Emissions-Factor-Calculator and www.westernclimateinitiative.org/component/remository/Electricity-Team-Documents/2006-Draft-Default-Emissions-Factor-Calculator. Note: Various methodologies can be used to calculate default emission factors. The WCI Electricity Team discussed these options with stakeholders on a conference call in December 2008 and developed this simplified spreadsheet approach that approximates the load duration curve modeling methodology discussed with stakeholders. The Team will develop spreadsheets for additional years as needed, and use these spreadsheets to calculate the default emission factors that will be recommended to the Partners for use by WCI jurisdictions.

- *Discussion Paper on Renewable Portfolio Standards, Renewable Energy Certificates, and GHG Accounting*. December 2008. Available at: http://www.westernclimateinitiative.org/component/remository/Electricity-Team-Documents/Discussion-Paper-Renewable-Energy-Certificates-(RECs)-Accounting
- *Treatment of Renewable Energy Credits in the WCI Cap-and-Trade Program*. May 2010. Available at: http://www.westernclimateinitiative.org/component/remository/Electricity-Team-Documents/Treatment-of-Renewable-Energy-Credits-in-the-WCI-Cap-and-Trade-Program
- *Voluntary Renewable Energy Market: Issues and Recommendations*. July 2010. http://www.westernclimateinitiative.org/component/remository/Electricity-Team-Documents/Voluntary-Renewable-Energy-Market-Issues-and-Recommendations/
- *GHG Allowance Allocation Options in the Electricity Sector*. January 2009. Available at: http://www.westernclimateinitiative.org/component/remository/Electricity-Team-Documents/Jan-15-2009-Technical-Advisory-Group-Meeting-Materials/GHG-Allowance-Allocation-Options-in-the-Electricity-Sector

Offsets

- *Offset System Essential Elements Final Recommendations*. June 2010. Available at: http://www.westernclimateinitiative.org/component/remository/Offsets-Committee-Documents/Offsets-System-Essential-Elements-Final-Recommendations.
- *Review of Existing Offset Protocols Against WCI Offset Criteria*. April 2010. Available at: http://www.westernclimateinitiative.org/component/remository/Offsets-Committee-Documents/WCI-Review-of-Existing-Offset-Protocols

Auction Design

- *Auction Design White Paper*. April 2010. Available at: http://www.westernclimateinitiative.org/component/remository/Markets-Committee-Documents/Auction-Design-White-Paper. Note: This white paper served to inform the decisions by the WCI Partner jurisdictions on auction design. See Section 9, above, for the final auction design recommendations.

Ensuring a Well-Functioning Market

- *Status Update on Market Oversight Recommendations*. July 2010. Available at: http://www.westernclimateinitiative.org/component/remository/Markets-Committee-Documents/Markets-Oversight-July-Status-Update

- *Market Oversight Draft Recommendations*. April 2010. Available at: http://www.westernclimateinitiative.org/component/remository/Markets-Committee-Documents/Market-Oversight-Draft-Recommendations
- *Report on Holdings Limits*. May 2010. Available at: http://www.westernclimateinitiative.org/component/remository/Markets-Committee-Documents/Report-on-Holdings-Limits

Economic Analysis

- *Updated Economic Analysis of the WCI Regional Cap-and-Trade Program*. July 2010. Available at: http://www.westernclimateinitiative.org/component/remository/Economic-Modeling-Team-Documents/Updated-Economic-Analysis-of-the-WCI-Regional-Cap-and-Trade-Program

DETAILED DESIGN

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1. Purpose

Over the past 18 months, the Western Climate Initiative (WCI) Partner jurisdictions (the "Partners") have developed the detailed design necessary to implement the program described in their September 2008 Design Recommendations for the WCI Regional Cap-and-Trade Program. In addition to providing a detailed program design summary, this document sets out the process the Partners will use for continued cooperation in the design and implementation of individual Partner-level components of the program. This design summary represents a significant milestone in a more than 3-year cooperative effort to develop a regional cap-and-trade program that will reduce greenhouse gas (GHG) emissions and stimulate economic growth in participating Partner jurisdictions.

1.1 Brief History. This cap-and-trade design is one part of a broader cooperative effort among seven U.S. states and four Canadian provinces to reduce GHG emissions throughout their jurisdictions. The cooperative effort began in February 2007 between the governors of Arizona, California, New Mexico, Oregon and Washington, who have since been joined by the premiers of British Columbia, Manitoba, Ontario and Quebec, and the governors of Montana and Utah. These governors and premiers called for the Partners to collaborate on setting an overall regional GHG reduction goal consistent with the jurisdiction-by-jurisdiction goals, and a design for a regional multi-sector mechanism to achieve the GHG reduction goal. They also called for promotion of clean and renewable energy, increased energy efficiency, and national policies that reflect the needs and interests of the Partner jurisdictions.

1.2 Purpose and Use of this Document. Each Partner jurisdiction will seek any necessary legislative authority and develop its own administrative rules in order to participate in a WCI regional cap-and-trade program. This detailed program design is intended to inform the development of proposed legislation and/or regulatory language in Partner jurisdictions in order to enable those jurisdictions to implement state- and provincial-level cap-and-trade programs that can be linked together in a common market. This document specifies the areas of program design that are expected to be the same across all participating Partner jurisdictions in order to create that common market and those areas that may vary. This is not a model rule.

1.3 Process for Amending the Detailed Program Design. The Partners acknowledge that this detailed program design represents a starting point for individual Partner jurisdiction's participation in a WCI regional cap-and-trade program. The Partners further acknowledge that each Partner jurisdiction is subject to its own legislative and administrative processes. The basis of the WCI Regional Cap-and-Trade Program is to provide opportunities to obtain low-cost emissions reductions through emission trading on a common market, allowance banking, and inclusion of an offsets component. This common market provides for "allowances" or other compliance instruments issued by one jurisdiction to be recognized by another and "traded" across state and provincial borders. Certain elements of the program design need to be the same in order to create a functional multi-jurisdictional market, and to establish a single WCI-wide transparent carbon price. If during the development and implementation individual Partner jurisdictions find they must vary from the agreed upon design parameters but desire to remain linked to the other implementing Partner jurisdictions, the individual Partner jurisdiction will prepare a written proposal for how the variance will not adversely affect the regional carbon market.

2. Definitions

This section provides some of the key terms that a Partner jurisdiction may decide to use in the drafting of legislation or rule language. It is expected that individual Partner jurisdictions will have substantial flexibility in constructing definitions sections. Actual terms used within a Partner's law or regulation need not match the terms used here so long as they accomplish the same substantive end as the terms here defined. Partners will consider, however, instances in which the use of same terminology is beneficial to the functioning of the regional cap-and-trade market, and in those instances may recommend use of the same terminology.

2.1 Account number. The identification number given by the program authority or its agent to each WCI Tracking System (WTS) account in accordance with WCI's numbering system. This identification number is unique within the WCI Regional Cap-and-Trade Program, and will identify the jurisdiction that opened the account.

2.2 Allocate or allocation. The distribution by the program authority of a number of allowances, either by auction, sale, or at no cost, to a covered unit or other individual for any other reason, or temporarily to an allocation set-aside or other special purpose account.

2.3 Allowance. A type of compliance instrument that is a limited authorization by the program authority or a participating jurisdiction under the Partner jurisdiction's Cap-and-Trade Program to emit up to one metric ton in carbon dioxide equivalent (CO_2e) of GHGs, subject to all applicable limitations contained in this detailed program design summary, that may be allocated by the program authority out of its annual allowance budget under section 5.1.

2.4 Alternate authorized account representative. For a covered source and each covered unit at the source, the natural person who is authorized by the owners and operators of the source and all covered units at the source, in accordance with 4.3.2, to represent and legally bind each owner and operator in matters pertaining to the Partner jurisdiction's Cap-and-Trade Program or, for a general account, the natural person who is authorized, under section 7.2.2.2, to transfer or otherwise dispose of compliance instruments held in the general account.

2.5 Approved trading program. A system of reducing GHG emissions external to the WCI Cap-and-Trade Program that a Partner jurisdiction, in consultation with all other participating Partner jurisdictions, determines should be linked to the Partner jurisdiction's Cap-and-Trade program under section 9 of the detailed program design summary. An approved trading program may be a program focused exclusively on project-based reductions.

2.6 Approved program compliance units. The compliance instrument from an approved trading program that may be used for compliance purposes in the Partner jurisdiction's Cap-and-Trade program, subject to any limitations set out in this detailed program design. An approved program compliance unit can be a project-based reduction from an approved trading program.

2.7 Authorized account representative. For a covered source and each covered unit at the source, the natural person who is authorized by the owners and operators of the source and all covered units at the source, in accordance with section 4.3.1, to represent and legally bind each owner and operator in matters pertaining to the Partner jurisdiction's Cap-and-Trade Program or, for a general account, the natural person who is authorized, under 7.2.2.2, to hold, transfer, retire or cancel or otherwise dispose of compliance instruments held in the general account.

2.8 Award. The determination by the program authority of the number of Early Reduction Allowances to be issued into the compliance account of a covered unit or a covered source pursuant to section 5.2, or the determination by the program authority of the number of offset certificates to be recorded in the general account of a project sponsor pursuant to section 8.

2.9 Bilateral link or linking. The acceptance of approved program compliance units from an approved trading program to meet compliance obligations under the Partner jurisdiction's Cap-and-Trade Program, and the reciprocal approval of compliance instruments issued by participating Partner jurisdictions to meet compliance obligations in the approved trading program.

2.10 Budget emissions limitation. For a covered source, the metric-ton equivalent in verified emissions for the compliance period that is equal to the total quantity of compliance instruments in the source's compliance account and available for compliance surrender or deduction for the source on the compliance instrument surrender deadline.

2.11 Budget permit.[1] The legally binding and enforceable permit issued by the program authority pursuant to the program authority's permitting regulations, to a covered source or covered unit which specifies the Partner jurisdiction's Cap-and-Trade Program requirements applicable to the covered source and to each covered unit at the covered source, and to the owners and operators and the authorized account representative of the covered source and each covered unit.

2.12 CO_2 equivalent (CO_2e). A measure for comparing carbon dioxide with other GHGs, based on the quantity of any given GHG multiplied by its Global Warming Potential (GWP).

2.13 Combined cycle system. A system comprised of one or more combustion turbines, heat recovery steam generators, and steam turbines configured to improve overall efficiency of electricity generation or steam production.

2.14 Combustion turbine. An enclosed fossil or other fuel-fired device that is comprised of a compressor (if applicable), a combustor, and a turbine, and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine.

[1] Some Partner jurisdictions will use permitting as one of the mechanisms for enforcing program requirements. Others will enforce requirements under their laws and regulations and through interaction with covered sources and holders of compliance instruments through the WTS.

2.15 Commence operation. To begin any mechanical, chemical, or electronic process, including, with regard to a unit, start-up of a unit's combustion chamber or start-up of any processes that produce GHG emissions. For First Jurisdictional Deliverers and fuel suppliers, to begin to deliver electricity or supply fuel into the Partner jurisdiction.

2.16 Compliance account. A WTS account, established by the program authority or its agent for a covered source under section 7.2.1, in which are held compliance instruments available for use by the source for a compliance period for the purpose of meeting the requirements of section 4.4.

2.17 Compliance instrument. An allowance, an offset certificate or an approved program compliance unit.

2.18 Compliance instruments held or hold compliance instruments. The compliance instruments recorded by the program authority or its agent, or submitted to the program authority or its agent for recordation, in accordance with section 7.2.4, in a WTS account.[2]

2.19 Compliance instrument deduction or deduct compliance instruments.[3] The permanent withdrawal of compliance instruments by the program authority or its agent from a WTS compliance account to cover the verified emissions from a covered source for a compliance period, determined in accordance with section 7.2.5, or for the forfeit or retirement of compliance instruments as provided for in this detailed program design. This constitutes the permanent removal of the compliance instrument from circulation or use in any participating Partner jurisdiction and cannot be reversed or altered by any person or jurisdiction, except to correct for compliance instruments erroneously deducted.

2.20 Compliance instrument surrender deadline.[4] Midnight of the June 30th occurring after the end of the relevant compliance period or, if that June 30th is not a business day, midnight of the first business day thereafter and is the deadline by which compliance instruments must be submitted for recordation in a covered source's compliance account surrendered in order for the source to meet the requirements of section 4.4 for the compliance period immediately preceding the deadline.[5]

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[2] This provision is consistent with past practice in U.S. cap-and-trade programs. It is important to note that there will be differences in the way that participating partner jurisdictions in Canada implement the compliance mechanism for the program. The most significant of these differences will be noted throughout this document.

[3] This method of deducting compliance instruments from a source's compliance account represents current practice in the United States. An acceptable alternative method is contained in the British Columbia legislation, where a covered sources are required to transfer surrender compliance units into its compliance account, where the surrendered compliance units will be retired by the program authority where they cannot be removed except by the program authority for compliance deduction.

[4] At present, Partner jurisdictions are considering whether the June 30th deadline is practical. If the June 30th deadline is not practical, the Partner jurisdictions will agree on the earliest practical date for a common compliance instrument surrender deadline.

[5] Some Partner jurisdictions are considering whether to require interim surrender obligations in years prior to the end of the compliance periods. Prior to making a recommendation, the Partner jurisdictions are assessing potential impacts on the compliance instrument market and the implications of interim surrender requirements varying among Partner jurisdictions.

2.21 Compliance obligation. The requirement to surrender sufficient compliance instruments to cover verified emissions during the compliance period.

2.22 Compliance period. The compliance period is a three-calendar-year time period. The first compliance period is from January 1, 2012 to December 31, 2014. Each subsequent sequential three-calendar-year period is a separate compliance period.

2.23 Covered Entity. Any entity subject to the Partner jurisdiction's Cap-and-Trade program by meeting the applicability criteria of section 3.2.

2.24 Covered source. A source that includes one or more covered units and is subject to the Partner jurisdiction's Cap-and-Trade Program requirements under section 3.2.

2.25 Covered unit. A unit that is subject to the Partner jurisdiction's Cap-and-Trade Program requirements.

2.26 Early reduction allowance. A type of allowance that is awarded to the covered source that has implemented eligible projects or activities pursuant to section 5.2.

2.27 Electricity importer.[6] An owner of imported electricity as it is delivered to the first point of delivery in the Partner jurisdiction of the final point of delivery.

2.28 Electricity Source. A stationary source that emits greenhouse gases other than from eligible biomass in the process of producing electricity for sale.

2.29 Electricity transmission and distribution operation" means all electric power transmission and distribution systems that operate gas-insulated substations, circuit breakers, other switchgear, gas insulated lines, or power transformers containing SF6 or PFC that are part of an electric power system.

2.30 Eligible biomass. Each Partner jurisdiction will define eligible biomass in its discretion, provided it must be carbon neutral. CO_2 emissions from combustion of eligible biomass are not included in the Partner jurisdiction's Cap-and-Trade Program, except for purposes of reporting.

2.31 Excess emissions. Each metric ton of carbon dioxide equivalent (CO2e) emitted by a covered source for which the owner or operator has not surrendered compliance instruments by the compliance instrument surrender deadline, and which therefore exceeds the budget emissions limitation for the covered source.

2.32 First Jurisdictional Deliverer or FJD. The owner or operator of an electricity source in a Partner jurisdiction, or an electricity importer that is jurisdictional to the program authority or the immediate downstream purchaser or recipient of electricity from a non-jurisdictional electricity importer.

2.33 Fossil fuel. Natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material.

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[6] Given the differences in electricity systems among Partner jurisdictions, it is likely that the definitions related to the first jurisdictional deliverer will vary from jurisdiction to jurisdiction.

2.34 Fossil fuel-fired. A fossil fuel-fired unit is a unit that, alone or in combination with any other fuel, combusts fossil fuels.

2.35 Fuel. A solid, liquid or gaseous combustible material.

2.36 Fuel supplier. Suppliers of petroleum products or natural gas, whether distributors or importers.

2.37 General account. A WTS account, established under section 7, which is not a compliance account and is not any other special purpose account created for this program. General accounts may be established for specific purposes required for program administration.

2.38 Greenhouse Gas or GHG. Any of the following atmospheric gases: carbon dioxide (CO_2), methane (CH_4), nitrogen trifluoride (NF_3), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), and perfluorocarbons (PFCs).

2.39 Global Warming Potential (GWP). A measure of the radiative forcing (heat-absorbing ability) of a particular gas relative to that of carbon dioxide (CO_2) after taking into account the decay rate of each gas (the amount removed from the atmosphere over a given number of years) relative to that of CO_2. Global Warming Potentials used in this design summary are defined in Table WCI.10-1 of the *Final Essential Requirement for Mandatory Reporting*[7].

2.40 Hydrofluorocarbons or HFCs. A class of GHGs consisting of hydrogen, fluorine, and carbon, including all HFCs listed in Table WCI.10-1 of the *Final Essential Requirement for Mandatory Reporting*.

2.41 Industrial Source. Any stationary source that:

2.41.1 is not an electricity source; and

2.41.2 is in—

2.41.2.1 the manufacturing sector or other industrial sectors as defined in North American Industrial Classification System codes 21, 31, 32, and 33; or

2.41.2.2 the natural gas processing or natural gas pipeline transportation sector (as defined in North American Industrial Classification System codes 211112 or 486210).

2.42 Imported electricity. Electricity brought into a participating Partner jurisdiction that did not originate in any participating Partner jurisdiction.

2.43 Link or linking. The process by which non-Partner-jurisdiction trading programs are approved by the Partner jurisdiction, thereby qualifying approved program compliance units for use as compliance instruments in the Partner jurisdiction's Cap-and-Trade Program.

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[7] Available at: http://www.westernclimateinitiative.org/component/remository/Reporting-Committee-Documents/Final-Essential-Requirements-for-Mandatory-Reporting.

2.44 Multi-jurisdictional retail provider. A retail provider that provides electricity to consumers in the Partner jurisdiction and in one or more other participating Partner jurisdictions in a contiguous service territory.

2.45 Offset certificate. A type of compliance instrument that is awarded by the program authority in a participating Partner jurisdiction under the Partner jurisdiction's Cap-and-Trade program to the sponsor of a GHG emissions offset project subject to all applicable limitations contained in this detailed program design summary.

2.46 Offset project. An offset project includes all equipment, materials, items, or actions directly related to the reduction of GHG emissions or the sequestration of carbon specified in a registration submitted pursuant to section 8. Equipment, materials, items, or actions unrelated to an offset project reduction of GHG emissions or the sequestration of carbon, but occurring at a location where an offset project occurs, shall not be considered part of an offset project, unless specified in section 8.

2.47 Operator. Any person who operates, controls, or supervises a covered unit or a covered source and shall include, but not be limited to, any holding company, utility system, or plant manager of such a unit or source.

2.48 Output. The amount of a good or service, or intermediate feedstock, produced by a covered entity; for electricity sources, MWh of electricity produced, for industrial sources the units of production included in the Federal Reserve's Industrial Production and Capacity Utilization Report or another metric approved by the Partner jurisdiction.

2.49 Owner. Any of the following persons:

2.49.1 Any holder of any portion of the legal or equitable title in a covered unit; or

2.49.2 Any holder of a leasehold interest in a covered unit, other than either a passive lessor or a person who has an equitable interest through such lessor, whose rental payments are not based, either directly or indirectly, upon the revenues or income from the covered unit; or

2.49.3 Any purchaser of power from a covered unit under a life-of-the-unit contractual arrangement in which the purchaser controls the dispatch of the unit; or

2.49.4 With respect to any general account, any person who has an ownership interest with respect to the compliance instruments held in the general account and who is subject to the binding agreement for the authorized account representative to represent that person's ownership interest with respect to the compliance instruments.

2.50 Participating Partner jurisdiction. A jurisdiction that has adopted a corresponding regulation as part of the WCI Regional Cap-and-Trade Program and that has mutually acknowledged the compliance instruments of the Partner jurisdiction.

2.51 Partner jurisdiction's Cap-and-Trade Program. The regulatory system created in individual Partner jurisdictions informed by this detailed program design. When linked to other Partner jurisdictions' Cap-and-Trade Programs, the linked system is the WCI Regional Cap-and-Trade Program.

2.52 Perfluorocarbons or PFCs. Synthetic compounds derived from hydrocarbons through the replacement of hydrogen with fluorine atoms, including the PFCs listed in Table WCI.10-1 of the *Final Essential Requirement for Mandatory Reporting*.

2.53 Petroleum and natural gas system. Means (a) natural gas distribution facility as that term is proposed for definition in 40 CFR 98.238 in vol 75 Federal Register No. 69; (b) onshore petroleum and natural gas production facility as that term is proposed for definition in 40 CFR 98.238 in vol 75 Federal Register No. 69;[8] (c) onshore natural gas processing plants as that term is proposed for definition in 40 CFR 98.230 in vol 75 Federal Register No. 69; and (d) all other petroleum and natural gas systems that constitute a facility for purposes of application of the reporting thresholds under United States proposed regulations for reporting of GHG emissions

2.54 Point of delivery. A point on an electricity transmission or distribution system where a power supplier delivers electricity to the receiver of that electricity. This point can be an interconnection with another system or a substation where the transmission provider's transmission and distribution systems are connected to another system, or a distribution substation where electricity is imported into the Partner jurisdiction over a multi-jurisdictional retail provider's distribution system.

2.55 Process emissions. The emissions from industrial processes (e.g., cement production, ammonia production) involving chemical or physical transformations other than fuel combustion. For example, the calcination of carbonates in a kiln during cement production or the oxidation of methane in an ammonia process that results in the release of process GHG emissions to the atmosphere. Emissions from fuel combustion to provide process heat are not part of process emissions, whether the combustion is internal or external to the process equipment.

2.56 Program authority. The agency or government department charged with administering the Partner jurisdiction's Cap-and-Trade Program.

2.57 Province. Any Canadian province or territory.

2.58 Serial number. When referring to allowances and offset certificates, the unique identification number assigned to each allowance by the program authority or its agent under sections 6 and 7.2.4 in accordance with the WCI's numbering system.

2.59 Source.[9] Any governmental, institutional, commercial, or industrial structure, installation, plant, building, that emits or has the potential to emit any air pollutant; or any entity or installation that

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[8] The proposed definition aggregates certain operations based on the three digit Geological Province Code of the American Association of Petroleum Geologists. WCI Partners may also choose to aggregate all operations that are otherwise within the definition of onshore petroleum and natural gas production facility that are within their jurisdiction.

[9] The definitions of source and unit should be read to prevent the splitting of physical facilities or entities into smaller facilities or entities to avoid triggering applicable emissions thresholds. The Partner jurisdictions intend, for example, to combine the emissions from units that are located on one or more contiguous or adjacent properties; are under common control of the same owner(s) or operator(s); and form a producing unit, function as a single integrated site, or have the same first two digits of the Standard Industrial Classification or same first three digits of the North American Industry Classification System.

distributes petroleum-based or coal-based liquid fuel, petroleum coke, or natural gas liquid that when combusted will emit any air pollutant; or any entity or installation that delivers electricity generated outside participating Partner jurisdictions into a Partner jurisdiction; or any electricity transmission and distribution operation or a petroleum and natural gas system. A "source" with multiple units shall be considered a single "source."

2.60 State. Any U.S. State, the District of Columbia, the Commonwealth of Puerto Rico, the Virgin Islands, Guam, and American Samoa and includes the Commonwealth of the Northern Mariana Islands.

2.61 Submit or serve. To send or transmit a document, information, or correspondence to the person specified in accordance with the applicable regulation.

2.62 Unit. A fossil fuel-fired stationary boiler, combustion turbine, combined cycle system, mobile non-road equipment, or any industrial process equipment that emits GHGs, or the entity or installation that distributes petroleum-based or coal-based liquid fuel, petroleum coke, or natural gas liquid that when combusted will emit any air pollutant; or the entity or installation that delivers into a Partner jurisdiction electricity generated outside participating Partner jurisdictions.

2.63 Unit operating day. A calendar day in which a unit emits any GHG.

2.64 Verification. A systematic, independent and documented process for the evaluation of a covered source's emissions data report against the Program Authority's reporting procedures and methods for calculating and reporting GHG emissions.

2.65 Verified emissions. The total number of metric tons of GHGs in CO_2e emitted by a covered source, or a covered unit, quantified, monitored, reported and verified in accordance with sections 4.1 and 7.1.

2.66 Voluntary renewable energy purchase.[10] The permanent retirement of renewable energy certificates by a retail electricity customer or by a load-serving entity on behalf of its customers. The renewable energy certificates retired for a voluntary renewable energy purchase must be tracked by the program authority and generated by a VRE-eligible facility and must not have been used to comply with a mandatory renewable energy standard.

2.67 VRE-eligible facility.[11] An electricity generation facility that uses renewable resources or fuels deemed eligible by the program authority.

2.68 WCI Numbering system. The method of assigning allowances and offset certificates identifiers to indicate the vintage year, the year allocated or awarded, the participating Partner jurisdiction and order issued, and of assigning identification numbers for each WTS account.

[10] This definition is necessary only if an optional voluntary renewable energy set-aside program is implemented by the participating Partner jurisdiction as described in 6.3.

[11] This definition is necessary only if an optional voluntary renewable energy set-aside program is implemented by the participating Partner jurisdiction as described in 6.3.

2.69 WCI Regional Cap-and-Trade Program. A multi-jurisdiction GHG emissions reduction program established consistent with this detailed program design on carbon pricing within participating Partner jurisdictions and corresponding regulations in other participating Partner jurisdictions as a means of reducing GHG emissions from covered sources.

2.70 WCI tracking system, or WTS. The tracking system that enables accounts to be established for the creation, issuance, cancellation, banking, transfer, surrendering, and deletion of compliance instruments.

3. Program Coverage

Section 3 establishes the coverage of the program, including the emissions and covered emissions sources. It is expected that Partners will attempt to adhere to these coverage provisions, including the timing of coverage, and that deviations from coverage and timing requirements would need to be proposed to other Partners before linking with other Partner jurisdictions. The sections below detail the greenhouse gases covered (section 3.1), the emissions and sources covered (section 3.2) and the liability provisions for owners, and operators and first deliverers (section 3.3).

This document does not repeat the descriptions of the emissions reporting requirements, the foundation of the Cap-and-Trade Program that are already been described in the Final Essential Requirements for Mandatory Reporting[12]*. It is expected that each participating Partner jurisdiction will implement emissions reporting requirements consistent with the Final Essential Requirements for Mandatory Reporting.*

3.1 Covered Gases

3.1.1 The Partner jurisdiction's Cap-and-Trade Program covers the following greenhouse gases: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), nitrogen trifluoride (NF_3), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs) and perfluorocarbons (PFCs).

3.1.2 If, from time to time, the Partners determine that an additional GHG should be covered by the program, they will confer and make a recommendation to add the GHG.

3.2 Covered Emissions Sources

Any source that, at any time, meets the requirements of paragraph 3.2.1, 3.2.2, or 3.2.3 below, shall be a covered unit or a covered source and be subject to the requirements of the Partner jurisdiction's Cap-and-Trade Program, provided if a source demonstrates that its verified emissions have fallen below the 25,000-metric-ton CO_2e threshold for three consecutive calendar years, then the source may apply to the program authority for a determination that the source is no longer subject to

[12] Available at: http://www.westernclimateinitiative.org/component/remository/Reporting-Committee-Documents/Final-Essential-Requirements-for-Mandatory-Reporting.

the Partner jurisdiction's Cap-and-Trade Program.[13] In the event that a program authority determines that a source is no longer covered by the Partner jurisdiction's Cap-and-Trade Program, then it may, as a condition of its determination, require that the source return any allowances that have been distributed to the source's compliance account for years that the source will not have a compliance obligation. A program authority may also require a source receiving such a determination to accept an enforceable condition, in a permit or otherwise, limiting the source's emissions to a level below the 25,000-metric-ton CO_2e threshold and/or to continue monitoring and reporting its emissions under section 4.1 below. In the event that a source receiving a determination of non-applicability under this section emits 25,000 metric tons CO_2e or more in any year subsequent to the determination, that source will be once again subject to the requirements of the Partner jurisdiction's Cap-and-Trade Program beginning in the year the source reaches or exceeds the threshold.

3.2.1 Any source that emits 25,000 or more metric-tons CO_2e in any calendar year in total verified emissions, excluding emissions from combustion of eligible biomass, from one or more of the activities listed in this paragraph.[14,15] This determination shall be based on the source's highest verified emissions during any year after January 1, 2009, collected pursuant to sections 4.1 and 7.1. A source will be subject to a compliance obligation beginning in 2012, or commencing in the year the source first emits 25,000 metric tons CO_2e in verified emissions, whichever is later.

3.2.1.1 General stationary fuel combustion at sources.

3.2.1.2 Process or other emissions from industrial activities at sources in the following categories:

3.2.1.2.1 Adipic acid manufacturing

3.2.1.2.2 Aluminum manufacturing

3.2.1.2.3 Ammonia manufacturing

3.2.1.2.4 Cement manufacturing

3.2.1.2.5 Electricity generation

3.2.1.2.6 Electronics manufacturing

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[13] Individual Partner jurisdictions may implement requirements that are more stringent for covered sources that seek a determination that the Partner jurisdiction's Cap-and-Trade Program no longer applies to them.

[14] Individual emission points within the listed sources will be examined by the Partners for applicability to the 25,000-metric-ton threshold and may be withheld if quantification methods do not form a suitable basis for market trading. Additional activities (e.g., magnesium production, underground coal mines, wastewater treatment, etc.) may be added once appropriate quantification methods have been developed.

[15] A source emitting more than 25,000 metric tons CO2e for the first time in a calendar year starting in 2012 will have reported its GHG emissions in the following calendar year. This delay might create some administrative issues when trying to cover the source for this first year it emits more than the threshold and Partner jurisdictions will work together to find ways to mitigate those issues.

3.2.1.2.7 Ferroalloy production

3.2.1.2.8 Fluorinated GHG production

3.2.1.2.9 Glass Production and other uses of carbonates

3.2.1.2.10 HCFC-22 production and HFC-23 Destruction

3.2.1.2.11 Hydrogen production

3.2.1.2.12 Iron and steel manufacturing

3.2.1.2.13 Lead production

3.2.1.2.14 Lime manufacturing

3.2.1.2.15 Nitric acid manufacturing

3.2.1.2.16 Petrochemical production

3.2.1.2.17 Petroleum and natural gas systems

3.2.1.2.18 Petroleum refineries

3.2.1.2.19 Phosphoric acid production

3.2.1.2.20 Pulp and paper manufacturing

3.2.1.2.21 SF6 emissions from electrical equipment

3.2.1.2.22 Soda ash manufacturing

3.2.1.2.23 Zinc production

3.2.1.2.24 Ore pelletization

3.2.1.2.25 Titanium dioxide production

3.2.1.2.26 Ethanol production

3.2.1.2.27 Silicon carbide production

3.2.1.2.28 Any other industrial facilities

3.2.2 Any first jurisdictional deliverer of electricity,[16] including generators, retail providers, and marketers, that provide electricity into the participating Partner jurisdiction, the production of which generates 25,000 metric tons CO_2e or more in any calendar year in total verified emissions, excluding emissions from combustion of eligible biomass.[17] This determination shall be based on the source's

[16] Partner jurisdictions will consider provisions necessary to prevent entities from circumventing applicability by dividing electricity deliveries in a manner designed to stay below the applicability threshold. Partners may also chose to address electricity imports through an administrative approach, detailed below in section 6.4.

[17] A source emitting more than 25,000 metric tons CO2e for the first time in a calendar year starting in 2012 will have reported its GHG emissions in the following calendar year. This delay might create some administrative issues when trying to cover the

highest verified emissions during any year after January 1, 2009, collected pursuant to sections 4.1 and 7.1. A source will be subject to a compliance obligation beginning in 2012, or commencing in the year the source first emits 25,000 metric tons CO_2e in verified emissions, whichever is later.

3.2.3 From and after January 1, 2015, any fuel supplier within the participating Partner jurisdiction that distributes liquid transportation fuel, petroleum coke, natural gas, propane, heating fuel, or any other fossil fuel sold or imported for consumption in the participating Partner jurisdiction in quantities that when combusted would emit 25,000 metric tons CO_2e or more in any calendar in total verified emissions, excluding emissions from combustion of eligible biomass.[18,19] This determination shall be based on the source's highest verified emissions during any year after January 1, 2009, collected pursuant to sections 4.1 and 7.1. A source will be subject to a compliance obligation beginning in 2015, or commencing in the year the source first emits 25,000 metric tons CO_2e in verified emissions, whichever is later.

3.2.4 In the event that a source does not have verified emissions data meeting the requirements of sections 4.1 and 7.1, the program authority may make the determination of applicability based on available emissions data collected pursuant to sections 4.1 and 7.1.

3.2.5 If the program authority determines that emissions data collected pursuant to the requirements of sections 4.1 and 7.1, is not available for any year after 2009, a source that commenced operation prior to January 1, 2012 may apply to use other emissions data acceptable to the program authority for that year to demonstrate that the requirements of the Partner jurisdiction's Cap-and-Trade Program do not apply.

3.3 Compliance Liability

Any provision of the Partner jurisdiction's Cap-and-Trade Program that applies to a covered source or covered unit (including those requirements applicable to the authorized account representative of a covered source or unit) shall also apply to the owners and operators of such source or unit, except that the requirements applicable to first jurisdictional deliverers and deliverers of fuel from outside the participating Partner jurisdiction shall apply only to the owners of the electricity or the fuel at the time it enters the participating Partner jurisdiction.

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source for this first year it emits more than the threshold and Partner jurisdictions will work together to find ways to mitigate those issues.

18 WCI Partners acknowledge that individual jurisdictions may utilize other fiscal measures, such as British Columbia's carbon tax, to address transportation fuels and fuel use by residential and commercial sources that contribute to achieving overall comparable GHG emissions reductions and internalize the price of carbon as expected through the WCI Regional Cap-and-Trade Program.

19 A source emitting more than 25,000 metric tons CO2e for the first time in a calendar year starting in 2015 will have reported its GHG emissions in the following calendar year. This delay might create some administrative issues when trying to cover the source for this first year it emits more than the threshold and Partner jurisdictions will work together to find ways to mitigate those issues.

4. Requirements for Covered Sources

Section 4 details all of the requirements applicable to covered sources under the Partner jurisdiction's Cap-and-Trade Program. Although implementing language may vary from what is presented here, it is expected that Partner jurisdictions will adhere to the substance of these minimum requirements when drafting individual Partner jurisdiction laws and regulations. Partner jurisdictions may impose additional requirements on their sources. Partners jurisdictions are expected to require a covered source or entity to: (a) quantify, monitor, report, and verify emissions for purposes of determining the compliance instrument surrender requirement (section 4.1); (b) take all necessary actions to make the program requirements enforceable (section 4.2); (c) adhere to the requirements of the WTS (section 4.3); (d) surrender compliance instruments to cover emissions in the compliance period (sections 4.4 and 4.5); (e) comply with requirements to surrender additional compliance instruments in the event the source fails to meet surrender requirements by the compliance instrument surrender deadline (section 4.6); and (f) keep records available for inspection by the Partner jurisdiction for a minimum number of years (section 4.7).

4.1 Quantification, monitoring, reporting and verification requirements

4.1.1 The owners and operators and, to the extent applicable, the authorized account representative of each covered source and each covered unit at the source shall comply with the requirements of Section 7.1 of this detailed program design summary.

4.1.2 The emissions measurements recorded and reported in accordance with Section 7.1 shall be used to determine the number of compliance instruments that must be surrendered under Section 4.4.

4.2 Making Cap-and-Trade Program requirements enforceable

Participating Partner jurisdictions will enforce program requirements contained in their laws and regulations, and through interaction with covered sources and holders of compliance instruments in the WCI tracking system. Some participating Partner jurisdictions may also incorporate program requirements in the permits of covered sources.

4.3 Authorized account representative requirements

4.3.1 Authorization and responsibilities of the authorized account representative

4.3.1.1 Except as provided under section 4.3.2, each covered source, including all covered units at the source, shall authorize as their agent one and only one authorized account representative, with regard to all matters under the Partner jurisdiction's Cap-and-Trade Program concerning the source or any covered unit at the source.

4.3.1.2 As determined by each Partner jurisdiction, the authorized account representative of the covered source shall be selected by an agreement binding on the owners and operators of the source and all covered units at the source.

4.3.1.3 Upon receipt by the program authority or its agent of a complete account certificate of representation under section 4.3., the authorized account representative of the source shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator of the covered source represented and each covered unit at the source in all matters pertaining to the Partner jurisdiction's Cap-and-Trade Program, notwithstanding any agreement between the authorized account representative and such owners and operators. The owners and operators shall be bound by any decision or order issued to the authorized account representative, by the program authority, or a court regarding the source or unit.

4.3.1.4 No WTS account shall be established for a covered source or covered unit, until the program authority or its agent has received a complete account certificate of representation under section 4.3.4 for an authorized account representative of the source and the covered units at the source.

4.3.1.5 Each submission under the Partner jurisdiction's Cap-and-Trade Program shall be submitted, signed, and certified by the authorized account representative for each covered source and covered unit on behalf of which the submission is made. Each such submission shall include the following certification statement by the authorized account representative: "I am authorized to make this submission on behalf of the owners and operators of the covered sources or covered units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

4.3.1.6 The program authority or its agent will accept or act on a submission made on behalf of owners or operators of a covered source or a covered unit only if the submission has been made, signed, and certified in accordance with section 4.3.1.5.

4.3.2 Alternate authorized account representative

4.3.2.1 An account certificate of representation may designate one and only one alternate authorized account representative who may act on behalf of the authorized account representative. The agreement by which the alternate authorized account representative is selected shall include a procedure for authorizing the alternate authorized account representative to act in lieu of the authorized account representative.

4.3.2.2 Upon receipt by the program authority or its agent of a complete account certificate of representation under section 4.3.3, any representation, action, inaction, or submission by the alternate authorized account representative shall be deemed to be a representation, action, inaction, or submission by the authorized account representative.

4.3.2.3 Except in this section and sections 4.3.1.1, 4.3.2, 4.3.3, and 7.2.2.2, whenever the term "authorized account representative" is used in this detailed program design, the term shall be construed to include the alternate authorized account representative.

4.3.3 Changing the authorized account representative and the alternate authorized account representative; changes in owners or operators

4.3.3.1 Changing the authorized account representative. The authorized account representative may be changed at any time upon receipt by the program authority or its agent of a superseding complete account certificate of representation under section 4.3.4. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous authorized account representative or alternate authorized account representative prior to the time and date when the program authority or its agent receives the superseding account certificate of representation shall be binding on the new authorized account representative and the owners and operators of the covered source and the covered units at the source.

4.3.3.2 Changing the alternate authorized account representative. The alternate authorized account representative may be changed at any time upon receipt by the program authority or its agent of a superseding complete account certificate of representation under section 4.3.4. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous or alternate authorized account representative or alternate authorized account representative prior to the time and date when the program authority or its agent receives the superseding account certificate of representation shall be binding on the new alternate authorized account representative and the owners and operators of the covered source and the covered units at the source.

4.3.3.3 Changes in the owners and operators

4.3.3.3.1 In the event a new owner or operator of a covered source or a covered unit is not included in the list of owners and operators submitted in the account certificate of representation, such new owner or operator shall be deemed to be subject to and bound by the account certificate of representation, the representations, actions, inactions, and submissions of the authorized account representative and any alternate authorized account representative of the source or unit, and the decisions, orders, actions, and inactions of the program authority, as if the new owner or operator were included in such list.

4.3.3.3.2 Within 30 days following any change in the owners and operators of a covered source or a covered unit, including the addition of a new owner or operator, the authorized account representative or alternate authorized account representative shall submit a revision to the account certificate of representation amending the list of owners and operators to include the change.

4.3.4 Account certificate of representation

4.3.4.1 A complete account certificate of representation for an authorized account representative or an alternate authorized account representative shall include the following elements in a format prescribed by the program authority or its agent:

4.3.4.1.1 Identification of the covered source and each covered unit at the source for which the account certificate of representation is submitted;

4.3.4.1.2 The name, address, email address, telephone number, and facsimile transmission number of the authorized account representative and any alternate authorized account representative;

4.3.4.1.3 A list of the owners and operators of the covered source and of each covered unit at the source;

4.3.4.1.4 The following certification statement by the authorized account representative and any alternate authorized account representative: "I certify that I was selected as the authorized account representative or alternate authorized account representative, as applicable, by an agreement binding on the owners and operators of the covered source and each covered unit at the source. I certify that I have all the necessary authority to carry out my duties and responsibilities under the Partner jurisdiction's Cap-and-Trade Program the owners and operators of the covered source and of each covered unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the program authority or a court regarding the source or unit."; and

4.3.4.1.5 The signature of the authorized account representative and any alternate authorized account representative and the dates signed.

4.3.4.2 Unless otherwise required by the program authority or its agent, documents of agreement referred to in the account certificate of representation shall be submitted to the program authority or its agent. Neither the program authority nor its agent shall be under any obligation to review or evaluate the sufficiency of such documents when submitted.

4.3.5 Objections concerning the authorized account representative

4.3.5.1 Once a complete account certificate of representation under section 4.3.4 has been submitted and received, the program authority and its agent will rely on the account certificate of representation unless and until the program authority or its agent receives a superseding complete account certificate of representation under section 4.3.4.

4.3.5.2 Except as provided in subdivision 4.3.3.1 and 4.3.3.2, no objection or other communication submitted to the program authority or its agent concerning the authorization, or any representation, action, inaction, or submission of the authorized account representative shall affect any representation, action, inaction, or submission of the authorized account representative or the finality of any decision or order by the program authority or its agent under the Partner jurisdiction's Cap-and-Trade Program.

4.3.5.3 Neither the program authority nor its agent will adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any authorized account representative, including private legal disputes concerning the proceeds of compliance instrument transfers.

4.3.6 Delegation by authorized account representative and alternate authorized account representative

4.3.6.1 An authorized account representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the program authority or its agent under this program.

4.3.6.2 An alternate authorized account representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the program authority or its agent under this program.

4.3.6.3 In order to delegate authority to make an electronic submission to the program authority or its agent in accordance with sections 4.3.6.1 and 4.3.6.2, the authorized account representative or alternate authorized account representative, as appropriate, must submit to the program authority or its agent a notice of delegation, in a format prescribed by the program authority that includes the following elements:

4.3.6.3.1 The name, address, email address, telephone number, and facsimile transmission number of such authorized account representative or alternate authorized account representative;

4.3.6.3.2 The name, address, email address, telephone number and facsimile transmission number of each such natural person;

4.3.6.3.3 For each such natural person, a list of the type of electronic submissions under sections 4.3.6.1 and 4.3.6.2 for which authority is delegated to him or her; and

4.3.6.3.4 The following certification statements by such authorized account representative or alternate authorized account representative:

4.3.6.3.4.1 "I agree that any electronic submission to the program authority or its agent that is by a natural person identified in this notice of delegation and of a type listed for such electronic submission agent in this notice of delegation and that is made when I am an authorized account representative or alternate authorized account representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under section 4.3.6.4 shall be deemed to be an electronic submission by me."

4.3.6.3.4.2 "Until this notice of delegation is superseded by another notice of delegation under section 4.3.6.4, I agree to maintain an email account and to notify the program authority or its agent immediately of any change in my email address unless all delegation authority by me under section 4.3.6 is terminated."

4.3.6.4 A notice of delegation submitted under section 4.3.6.3 shall be effective, with regard to the authorized account representative or alternate authorized account representative identified in such notice, upon receipt of such notice by the program authority or its agent and until receipt by the program authority or its agent of a superseding notice of delegation by such authorized account representative or alternate authorized account representative as appropriate. The superseding notice of delegation may replace any previously identified electronic submission agent, add a new electronic submission agent, or eliminate entirely any delegation of authority.

4.3.6.5 Any electronic submission covered by the certification statement in section 4.3.6.3.4.1, and made in accordance with a notice of delegation effective under section 4.3.6.4, shall be deemed to be an electronic submission by the authorized account representative or alternate authorized account representative submitting such notice of delegation.

4.3.7 Following the establishment of a WTS account under section 7.2, all submissions to the program authority or its agent pertaining to the account, including, but not limited to, submissions concerning the deduction or requests to surrender or transfer of compliance instruments from in the account, shall be made only by the authorized account representative for the account or someone with delegated authority under section 4.3.6.

4.4 Compliance instrument surrender requirement

4.4.1 The owners and operators of each covered source and each covered unit shall surrender a number of compliance instruments equal to the total verified emissions from that covered source by available for compliance deductions under section 7.2.5, not exceeding the offset certificate usage limit established by the program authority, as of the compliance instrument surrender deadline at the latest.

4.4.2 Each metric ton of verified emissions emitted in excess of the number of compliance instruments surrendered or deducted (i.e., emissions exceeding the budget emissions limitation) shall constitute a separate violation of program requirements and applicable law.

4.4.3 A covered unit shall be subject to the requirements under section 4.4.1 starting on the later of January 1, 2012 or the date on which the unit commences operation and meets the applicability requirements of section 3.2.

4.4.4 Compliance instruments shall be held in, surrendered to or deducted from, or transferred among WTS accounts in accordance with sections 4.3, 4.4, 4.5, 4.6, and 7.2.

4.4.5 A compliance instrument shall not be surrendered/deducted, in order to comply with the requirements under section 4.4.1, for a compliance period that ends prior to the year for which the compliance instrument was allocated or issued.[20] An offset certificate or an approved program compliance unit shall not be surrendered or deducted, in order to comply with the requirements under section 4.4.1, beyond the applicable percent limitations on the use of offsets established by the program authority.

4.4.6 A compliance instrument under the Partner jurisdiction's Cap-and-Trade Program is a limited authorization by the program authority or a participating Partner jurisdiction to emit one metric ton of CO_2e in accordance with the Partner jurisdiction's Cap-and-Trade Program. The program authority or a participating Partner jurisdiction shall retain the right to terminate or limit such authorization.

[20] Partner jurisdictions are considering additional mechanisms to address cost risks. Among the options under consideration is the limited use for compliance of allowances that are already owned and that were allocated or issued for future compliance periods.

4.4.7 A compliance instrument under the Partner jurisdiction's Cap-and-Trade Program does not constitute a property right for any purpose.

4.5 Compliance certification requirement[21]

4.5.1 Applicability and deadline for submission. For each compliance period in which a covered source is subject to the surrender requirements of section 4.5.3, the authorized account representative of the source shall submit to the program authority or its agent by midnight on June 30th following the relevant compliance period, a compliance certification report.[22]

4.5.2 Contents of report. The authorized account representative shall include in the compliance certification report under section 4.5.1 the following elements, in a format prescribed by the program authority:

4.5.2.1 Identification of the source and each covered unit at the source;

4.5.2.2 The total metric tons of GHG emissions in CO_2e from the source and each covered unit at the source, monitored, reported, and verified in compliance with sections 4.1 and 7.1;

4.5.2.3 At the authorized account representative's option, the serial numbers of the compliance instruments that are to be surrendered and/or deducted from the covered source's compliance account under section 7.2.5 for the compliance period, including the serial numbers of any offset certificates that are to be surrendered and/or deducted subject to the limit on the use of offsets certificates established by the program authority; and

4.5.2.4 The compliance certification under section 4.5.3.

4.5.3 Compliance certification. In the compliance certification report under 4.5.3.1 of this section, the authorized account representative shall certify, based on reasonable inquiry of those persons with primary responsibility for operating the source and the covered units at the source in compliance with the Partner jurisdiction's Cap-and-Trade Program, whether the source and each covered unit at the source for which the compliance certification is submitted was operated during the calendar years covered by the report in compliance with the requirements of the Partner jurisdiction's Cap-and-Trade Program. The compliance certification report shall include the following information:

4.5.3.1 Whether the covered source was operated in compliance with the requirements of section 4.4 (compliance instrument surrender requirements); and

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[21] This requirement to provide a certification report is included as just one example of how compliance instrument surrender and deductions might be handled by a Partner jurisdiction. It is possible to carry out this mechanism without a certification statement.

[22] At present, Partner jurisdictions are considering whether the June 30th deadline is practical. If the June 30th deadline is not practical, the Partner jurisdictions will agree on the earliest practical date for a common compliance instrument surrender deadline. Some Partner jurisdictions are also considering whether to require interim surrender obligations in years prior to the end of the compliance periods. Prior to making a recommendation, the Partner jurisdictions are assessing potential impacts on the compliance instrument market and the implications of interim surrender requirements varying among Partner jurisdictions.

4.5.3.2 Whether the source was operated in compliance with the requirements of section 4.1 (emissions monitoring and reporting requirements).

4.6 Additional requirements in the event of non-compliance. The owners and operators of a covered source that has excess emissions in any compliance period shall:

4.6.1 Forfeit the compliance instruments required for surrender and/or deduction under section 7.2.5.4, provided offset certificates shall not be used to cover such excess emissions; and

4.6.2 Pay any fine, penalty, or assessment or comply with any other remedy imposed under the Partner jurisdiction's other laws and regulations.

4.7 Recordkeeping requirements

4.7.1 Unless otherwise provided, the owners and operators of the covered source and each covered unit at the source shall keep on site at the source each of the following documents for a period of 7 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 7 years, in writing by the program authority.

4.7.1.1 The account certificate of representation for the authorized account representative for the source and each covered unit at the source and all documents relied on as a basis for the statements in the account certificate of representation, in accordance with section 4.5.3, provided that the certificate and documents shall be retained on site at the source beyond such 7-year period until such documents are superseded because of the submission of a new account certificate of representation changing the authorized account representative.

4.7.1.2 All emissions monitoring information, (including information regarding gaps in or a lack of monitoring) in accordance with [*Refer to program authority's reporting rule*].

4.7.1.3 Copies of all reports, compliance certifications, and other submissions and all records made or required under the Partner jurisdiction's Cap-and-Trade Program.

4.7.1.4 Copies of all documents referenced or relied on to complete a covered permit application (if applicable) and any other submission under the Partner jurisdiction's Cap-and-Trade Program or to demonstrate compliance with the requirements of the Partner jurisdiction's Cap-and-Trade Program.

4.7.2 The authorized account representative of a covered source and each covered unit at the source shall submit the compliance reports and compliance certifications to the program authority required under the Partner jurisdiction's Cap-and-Trade Program, including those under section 4.5.3.

5. Compliance Instruments

Section 5 details the compliance instruments that may be issued and recognized in the Partner jurisdiction's Cap-and-Trade Program. It is expected that each participating Partner jurisdiction will adopt allowance budget-setting processes (section 5.1), as well as provisions to issue and accept early *reduction allowances (section 5.2), issue offset certificates (section 5.3) and accept approved compliance unit provisions (section 5.4) of this detailed program summary. In the event that a participating Partner jurisdiction wishes to issue a compliance instrument not agreed to below, or to recognize as a compliance instrument allowances or offsets that are not contemplated in this design summary, the participating Partner jurisdiction will first raise the proposal with the other participating Partner jurisdictions to ensure that any linking arrangements can be preserved.*

5.1. Establishing annual allowance budgets

The process for establishing annual allowance budgets for each Partner jurisdiction is detailed in *Guidance for Developing WCI Partner Allowance Budgets.*[23]

5.2. Early reduction allowances (ERAs)

The program authority may award early reduction allowances (ERAs) to a covered source for certain reductions in the covered source's GHG emissions that are achieved by the source during the early reduction eligibility period in accordance with the requirements of this section.

5.2.1. Eligibility

5.2.1.1. General requirements. Early reduction allowances may be awarded for a clearly identified project or action carried out at a covered source during the eligibility period that meets all criteria under this Section 5.2.

5.2.1.2. Government-controlled covered sources. Covered sources that are government controlled are eligible to receive ERAs provided they meet all requirements of this section 5.2.

5.2.1.3. Eligibility period. The program authority may issue ERAs for eligible ERA projects that reduce emissions on or after January 1, 2008 and prior to January 1, 2012.

5.2.2. Criteria applicable to all ERA projects

5.2.2.1. Real. To be eligible for the award of ERAs, the project must produce a reduction or removal of one metric ton of CO_2e for each ERA, without any increase in emissions intensity at the covered source. A reduction is not considered real if it comes from a decrease in production alone or from a shutdown or a closure of a source or a facility. Instead, the covered source must demonstrate a reduction in emissions intensity and a reduction in absolute emissions during the eligibility period. A Partner jurisdiction may also require sources or facilities to show reductions are beyond best practice standards. Best practice standards can be defined by the Partner jurisdiction for certain types of covered sources. An applicant covered source may be required to prepare an evaluation demonstrating their actions are beyond best practices in their industry.

[23] Available at http://www.westernclimateinitiative.org/component/remository/Cap-Setting--and--Allowance-Distribution-Committee-Documents/Guidance-for-Developing-WCI-Partner-Allowance-Budgets/.

5.2.2.2. Voluntary. An ERA project and the accompanying reductions in emissions must be surplus to any requirements from existing legislation, regulation, executive order and other regulatory obligations.

5.2.2.3. Permanent. To be eligible for the award of ERAs, the project must produce a reduction or removal that is permanent. For ERAs, permanent means that the reductions or removals are not reversible.[24]

5.2.2.4. Additional. To be eligible for the award of ERAs, the project must produce a reduction or removal that might have been deferred until after the start of the Partner jurisdiction's Cap-and-Trade Program. A reduction or removal will be deemed additional if:

5.2.2.4.1. The ERA project was initiated during the eligibility period;

5.2.2.4.2. The annual GHG emissions and emissions intensity for the period of time ERAs are requested are below the annual averages of absolute emissions and emission intensity for the years 2005 to 2007; and

5.2.2.4.3. If the project or action is fuel switching, the fuel to which the covered source switched was more costly during the eligibility period than the fuel from which the covered source switched, or the covered source underwent an equipment change during the eligibility period to enable the switch to a lower-carbon fuel.

5.2.2.5. Verifiable. To be eligible for the award of ERAs, the project must produce a reduction or removal that is verifiable. For ERAs, verifiable means that the reduction or removal has been well documented and transparent, such that an objective review is possible by a Partner jurisdiction or a certified verifier.

5.2.2.6. Ownership. To be eligible for the award of ERAs, the applicant covered source must demonstrate that it owns the emissions reductions resulting from the project or action.

5.2.2.7. Enforceable. To be eligible for the award of ERAs, the applicant covered source must be accountable to the Partner jurisdiction for all statements and information provided regarding the application for ERAs.

5.2.3. Application by covered source

5.2.3.1. Application deadline. All applications for the award of ERAs must be filed with the Partner jurisdiction where the reductions and removals that are the subject of the application took place no later than July 1, 2012.

[24] For carbon capture and storage projects, the Partner jurisdiction must (a) have in place monitoring and verification requirements that are sufficient to enable the Partner jurisdiction to establish that the sequestration is permanent; (b) have the ability to assure that ERAs will be replaced where a reversal occurs; and (c) apply these requirements to the applicable project.

5.2.3.2. Application forms and consultation. Partner jurisdictions may request any applications be made using forms developed in consultation with other participating Partner jurisdictions. Applicants may also be provided with pre-application consultation with the Partner jurisdiction.

5.2.4. Quantification of reductions

5.2.4.1. Data requirements

5.2.4.1.1. Emissions. All quantification of reductions under this section 5.2 shall be done using verified emissions data or equivalent methods approved by the Partner jurisdiction.

5.2.4.1.2. Output.[25] Reliable measures of covered source output will be prescribed by the Partner jurisdiction for purposes of quantifying reductions. Output is the amount of a good or service produced by a covered source.

5.2.4.1.3. Verification and recordkeeping. All emissions and output reports used to establish ERA baselines or calculate ERAs must be verified by an independent third party approved by the Partner jurisdiction or the program authority. The applicant covered source must retain all records relating to the ERA application for a period of at least 7 years and submit, under request, all documents related to the quantification of the reduction or removal.

5.2.4.2. Quantification by covered source. ERAs will be calculated based on the cumulative reductions during the eligibility period at the covered source, to be calculated as follows:

If $I_{base} \leq I_{ERA}$, then:
Total ERAs Awarded = 0

If $I_{base} > I_{ERA}$, then:
Total ERAs Awarded = $A \times (E_{base} - E_{ERA})$ If $P_{base} \leq P_{ERA}$
Total ERAs Awarded = $[A \times (E_{base} - E_{ERA})] \times (P_{ERA}/P_{base})$ If $P_{base} > P_{ERA}$

Where:

A is the number of consecutive calendar years from when the ERA project/action begins and the end of 2011. The applicant will indicate the number of years for which he requests ERAs.

$\mathbf{E_{base}}$ and $\mathbf{P_{base}}$ are the average yearly emissions and production from January 1, 2005 to the end of 2007.

$\mathbf{E_{ERA}}$ and $\mathbf{P_{ERA}}$ are the average yearly emissions and production during the years where the applicant covered source is seeking ERAs (i.e. the number of consecutive calendar years from when the ERA project begins and the end of 2011).

[25] Electricity generators should report net MWh of electricity produced. Industrial sources should use standardized forms of reporting, where such data is available. For example, industrial sources located in the U.S. could report production using the same metrics as provided to the Federal Reserve for their *Industrial Production and Capacity Utilization Report*. However, in the event that such metrics are not accurate measures of output for a particularly class of sources, then WCI partner jurisdictions may wish to allow those sources to propose alternative metrics. To mitigate gaming, facilities should use the same metric for approximating output in both the base period (years 2005 to 2007) and the early reduction period (years 2008 to 2012).

I_{base} is the average emission intensity (emissions per unit of output) of the base period (2005-2007) for the applicant covered source

I_{ERA} is the average emission intensity (emissions per unit of output) during the years for which the applicant the applicant covered source is seeking ERAs (i.e. the number of consecutive calendar years from when the ERA project begins and the end of 2011).

When using the above equations, the applicant covered source should use entire calendar years. Thus, the ERA period must start either on January 1, 2008, January 1, 2009, January 1, 2010, or January 1, 2011.

5.2.5. Award by program authority without application

5.2.5.1. Requirements. A Partner jurisdiction may, in lieu of requiring an application from a covered source, award ERAs to a covered source upon a finding that the covered source has undertaken a project or action meeting the requirements of sections 5.2.1 and 5.2.2.

5.2.5.2. Quantification of ERAs by program authority. A Partner jurisdiction may quantify ERAs on its own motion, provided the Partner jurisdiction has access to the data required in section 5.2.4.1, and utilizes the quantification methodology prescribed in section 5.2.4.2, and the information used is verified by a government agency or independent third party.

5.2.5.3. The information used to determine the number of ERAs a Partner jurisdiction expects to award will be verified by a government agency or independent third party after the reductions take place. In the case emissions reductions are lower than expected; the total number of ERAs to be awarded will be reduced to reflect actual reductions that took place during the eligibility period.

5.2.6. Special provisions for specific ERA types

This section provides additional guidance for project types that present unique challenges to ensuring that their emissions reductions are voluntary, additional, real, verifiable, permanent, and enforceable.

5.2.6.1. Fuel switching. Switching from high to low carbon intensity fuels can help a covered source reduce its GHG emissions. Sometimes fuel switching will occur naturally due to changes in relative fuel prices. To ensure that ERAs are only rewarded for projects adopted due to the ERA program, fuel switching projects should only qualify for reductions if the fuel switched to is more costly during the ERA period than the fuel switched from, or if the covered source underwent an equipment change during the ERA period to enable the switch to a lower carbon fuel. As discussed previously under section 5.2.2.6, applicants must demonstrate that they have ownership over the emissions reductions for which they are applying for ERAs. Therefore, if an applicant covered source wishes to receive ERAs for switching from a high to a low carbon fuel, then they must demonstrate that the reductions are not also being claimed by the fuel provider and thus double counted in any other regulatory or voluntary program (e.g., to meet renewable fuel standards or low carbon fuel standards).

5.2.6.2. Fuel providers. Fuel providers can receive ERAs for a reduction in on-site emissions. They can also receive ERAs for reductions that result from the reduction in the carbon intensity of the provided fuel, through the use of lower-carbon, or carbon-neutral sources. However, for such reductions to qualify for ERAs, they cannot contribute to compliance with any required low carbon fuel standard or renewable fuel standard. Reductions in fuel sales are not eligible for ERAs because such projects do not result in a reduction in the intensity of emissions. As discussed previously under section 5.2.2.6, applicants must demonstrate that they have ownership over the emissions reductions for which they are applying for ERAs. Therefore, if an applicant covered source wishes to receive ERAs for reducing the carbon intensity of their fuels, then they must demonstrate that the reductions are not also being claimed by the user of the fuel and thus double counted in any other regulatory or voluntary program (e.g., as ERAs or as offsets in a voluntary registry). Also, the applicant must demonstrate that the reductions are indeed voluntary, and are not being used to meet renewable or low carbon fuel standards.

5.2.6.3. Electricity importers. ERAs may be issued to first jurisdictional deliverers of electricity imported into a participating Partner jurisdiction originating outside of participating Partner jurisdictions, assuming it meets all other criteria outlined in this section 5.2. A first jurisdictional deliverer would apply to the Partner jurisdiction with which they have a compliance obligation. To qualify as an ERA, the FJD will need to show ownership of a qualifying reduction in both absolute emissions and emissions intensity at a specific facility whose power is produced for consumption within the WCI Partner jurisdiction.

5.2.7. Timing of award among participating Partner jurisdictions. The award of ERAs will occur on the same day no later than the first quarter of 2013 after information concerning the number of ERAs to be issued is announced publicly.

5.3 Offset certificates

The program authority may accept offset certificates as a compliance instrument awarded in accordance with Section 8, provided acceptance of offset certificates is subject to the limitation to be established by the program authority.

5.4 Approved program compliance units

The program authority may accept approved program compliance units as a compliance instrument, provided acceptance of approved program compliance units is subject to the limitation on the use of such units to be established by the program authority. The Partner jurisdiction will develop, in consultation with other participating Partner jurisdictions, a mechanism to ensure the validity of external compliance units and to make sure those units can only be used once for compliance by any program.

6. Distributing Allowances

Section 6 relates to the distribution of allowances. The Partner jurisdictions have largely left allowance distribution decisions open to the discretion of each Partner jurisdiction, with the exception of the process-related agreements detailed below concerning timing and notice of distributions (section 6.1), and the use of a common auction platform (section 6.2). In addition, two optional set-aside provisions are included relating to recognition of voluntary renewable energy purchases (section 6.3) and the administrative approach to covering electricity imports (section 6.4).Participating Partner jurisdictions can choose to freely allocate allowances from within their allowance budgets (e.g., to entities that export *renewable hydroelectricity outside participating Partner jurisdictions in order to acknowledge the importance of renewable energy in reducing GHG emissions).*

6.1 Allowance decisions and competitiveness

Each Partner jurisdiction will (a) notify other Partners in advance of the first compliance period, and at least one year before the beginning of each subsequent compliance period, about the total quantity of allowances it will allocate for that period; how and when it proposes allowances will be distributed, including if and how it will take into account the need to provide access to allowances for new entrants; and what will happen to allowances if a covered source shuts down; and (b) discuss and seek to address any competitiveness issues or concerns another Partner may have about the Partner's allowance distribution method. WCI Partner jurisdictions may standardize the distribution of allowances as necessary to address competitive impacts in advance of the first compliance period. After January 1, 2012, any public disclosure of information pertaining to the quantity of allowances that will be allocated; how and when those allowances will be distributed, including allowances for new entrants and the treatment of covered sources that have shut down, will be done in a coordinated manner among Partner jurisdictions to minimize the risk of inappropriate market impacts.

6.2 Coordinated auctions

Allowances to be auctioned will be sold through regionally coordinated auctions, which would be run in accordance with the auction design recommendations contained in Section 9 of the Detailed Summary.

6.3 Voluntary renewable energy set-aside allocation[26]

6.3.1 For each compliance period in which the WCI Partner jurisdiction chooses to maintain the program, the Partner Jurisdiction shall allocate to the voluntary renewable energy set-aside account a certain number of allowances, calculated as set forth below, from the Partner jurisdiction's Cap-and-Trade Program base budget. The program authority will open an account and administer the voluntary renewable energy set-aside program.

6.3.1.1 The number of allowances allocated to the voluntary renewable energy market set-aside account in a specific compliance period is determined by first projecting the amount of electricity used for voluntary renewable energy purchases produced by VRE-eligible facilities in that WCI Partner jurisdiction.[27] Each WCI Partner jurisdiction shall determine which technologies or fuel sources are eligible for its program. The estimate of voluntary renewable energy purchases shall be made regardless of the location of the purchaser. The megawatt-hours (MWh) of projected voluntary renewable energy purchases in the compliance period shall be multiplied by an appropriate greenhouse gas

[26] Implementation of the voluntary renewable energy set-aside program is optional at the discretion of each Partner jurisdiction.

[27] A WCI Partner jurisdiction may also wish to add the following program element to the end of this sentence, "or produced by VRE-eligible facilities not located in a participating Partner jurisdiction and sold on a specified basis in the Partner jurisdiction." See the discussion in *Voluntary Renewable Energy Market: Issues and Recommendations* for more information.

emissions rate, as determined by the program authority. A Partner jurisdiction may elect to limit the total allowances allocated to such an account.

6.3.1.2 As of the December 31 that is after the end of a compliance period for which an allocation has been made to the voluntary renewable energy set-aside account, the program authority shall determine the actual MWh of voluntary renewable energy purchases that occurred during the compliance period. To the extent possible, the program authority will use established renewable energy credit tracking systems that span some or all of the participating Partner jurisdictions, such as the Western Renewable Energy Generation Information System. The program authority shall retire allowances in the voluntary renewable energy set-aside account in an amount up to the number of allowances represented by actual voluntary renewable energy purchases multiplied by the emissions factor used in 6.3.1.1 above.

6.3.1.3 If following the end of a compliance period, the number of allowances allocated to the voluntary renewable energy set-aside account is less than the number of allowances represented by the actual MWh of voluntary renewable energy purchases during the compliance period multiplied by the emissions factor, the program authority will make up the difference by retiring unallocated allowances remaining from the previous compliance period, adding the difference between allowances represented by actual purchases and allowances held in the set-aside account to the projection for the following compliance period, or a combination of the two. If following the end of a compliance period, the number of allowances allocated to the voluntary renewable energy set-aside account is greater than the number of allowances represented by the actual MWh of voluntary renewable energy purchases during the compliance period, the program authority will add the allowances remaining in the set-aside from the previous compliance period to the allowances dedicated to a purpose chosen by the Partner jurisdiction.

6.4 Administrative approach to covering first jurisdictional deliverers

In lieu of covering first jurisdictional deliverers as covered sources under the Partner jurisdiction Cap-and-Trade Program, a Partner jurisdiction may chose to cover emissions attributable to imported electricity through the administrative approach detailed in *Covering Emissions from Imported Electricity: An Administrative Approach.*[28] This approach calls for the creation of an optional reserve pool of allowances, a portion of which are to be retired to cover the emissions attributable to imported electricity during the compliance period.

[28] Available at http://www.westernclimateinitiative.org/component/remository/Electricity-Team-Documents/Covering-Emissions-From-Imported-Electricity-An-Administrative-Approach.

7. Administration of the Program by the Program Authority

Section 7 details the implementation responsibilities of the participating Partner jurisdiction, including: (a) the rules for emissions monitoring and reporting (section 7.1), and (b) the operating parameters for the emissions and allowance tracking system (section 7.2).

7.1 Quantification, monitoring, verification, reporting and recordkeeping requirements

Owners and operators, and to the extent applicable, the authorized account representative of a covered unit, shall comply with the monitoring, recordkeeping and reporting requirements as provided in the Essential Requirements of Mandatory Reporting.

7.2 Emissions and compliance instrument tracking system.[29]

This section relates the tracking system that participating Partner jurisdictions will establish and maintain. The tracking system will (a) be a standardized electronic database, accessible online; (b) contain separate accounts to record the compliance instruments held by each person; (c) ensure there are no transfers that are incompatible with the rules implementing the cap-and-trade program in different jurisdictions; (d) provide for public access to certain information and confidentiality as appropriate; (e) restrict certain functions to account holders, to authorized staff of regulatory authorities, or to system maintenance service providers; and (f) have the ability to generate specific public reports and customized reports for regulatory authorities.

7.2.1 Establish compliance accounts for covered sources

7.2.1.1 Nature and function of compliance accounts. Consistent with section 7.2.1.2, the program authority or its agent will establish (or require each covered source to establish) one compliance account for each covered source. Surrenders, deductions or transfers of compliance instruments pursuant to sections 7.2.5 and 7.2.6 will be recorded in the tracking system. *[Allowances allocated to covered sources under sections 6 and 7.2.4 will be recorded in the compliance or general accounts.]*

7.2.1.2 Establishment of compliance accounts. Upon receipt of a complete account certificate of representation under section 4.3.4, the program authority or its agent will establish a compliance account for each covered source for which the account certificate of representation was submitted.

7.2.2 Establish general accounts

7.2.2.1 Nature and function of general accounts. Consistent with section 7.2.2.2, the program authority or its agent will establish, upon request, a general account that any person that meets the requirements outlined in 7.2.2 can obtain. Transfers of compliance instruments under this section will be recorded in the tracking system.

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[29] Wherever submissions are required in the tracking system, electronic submissions are anticipated.

7.2.2.2 Establishment of general accounts upon application. Any person may apply to open a general account for the purpose of holding and transferring compliance instruments. An application for a general account must designate a single authorized account representative and a single alternate authorized account representative who may act on behalf of the authorized account representative. The agreement by which the alternate authorized account representative is selected shall include a procedure for authorizing the alternate authorized account representative to act in lieu of the authorized account representative. A complete application for a general account shall be submitted to the program authority or its agent and shall include the following elements in a format prescribed by the program authority or its agent:

7.2.2.2.1 Name, address, email address, telephone number, and facsimile transmission number of the authorized account representative and any alternate authorized account representative;

7.2.2.2.2 At the option of the authorized account representative, organization name and type of organization;

7.2.2.2.3 A list of all persons subject to a binding agreement for the authorized account representative or any alternate authorized account representative to represent their ownership interest with respect to the compliance instruments held in the general account, including a statement of each beneficial owner's percentage ownership interest and a statement of affiliations between beneficial owners;

7.2.2.2.4 The following certification statement by the authorized account representative and any alternate authorized account representative: "I certify that I was selected as the authorized account representative or the alternate authorized account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to compliance instruments held in the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under the Partner jurisdiction's Cap-and-Trade Program on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any order or decision issued to me by the program authority or its agent or a court regarding the general account.";

7.2.2.2.5 The signature of the authorized account representative and any alternate authorized account representative and the dates signed; and

7.2.2.2.6 Unless otherwise required by the program authority or its agent, documents of agreement referred to in the application for a general account shall not be submitted to the program authority or its agent. Neither the program authority nor its agent shall be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

7.2.2.3 Authorization of authorized account representative

7.2.2.3.1 Upon receipt by the program authority or its agent of a complete application for a general account under section 7.2.2.2:

7.2.2.3.1.1 The program authority or its agent will establish a general account for the person or persons for whom the application is submitted.

7.2.2.3.1.2 The authorized account representative and any alternate authorized account representative for the general account shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to compliance instruments held in the general account in all matters pertaining to the Partner jurisdiction's Cap-and-Trade Program, notwithstanding any agreement between the authorized account representative or any alternate authorized account representative and such person. Any such person shall be bound by any decision or order issued to the authorized account representative or any alternate authorized account representative by the program authority or its agent or a court regarding the general account.

7.2.2.3.1.3 Any representation, action, inaction, or submission by any alternate authorized account representative shall be deemed to be a representation, action, inaction, or submission by the authorized account representative.

7.2.2.3.2 Each submission concerning the general account shall be submitted, signed, and certified by the authorized account representative or any alternate authorized account representative for the persons having an ownership interest with respect to compliance instruments held in the general account. Each such submission shall include the following certification statement by the authorized account representative or any alternate authorized account representative: "I am authorized to make this submission on behalf of the persons having an ownership interest with respect to the compliance instruments held in the general account. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I consent to the jurisdiction of the [Insert name of State or Province] and its courts for purposes of enforcement of the laws, rules and regulations pertaining to the Partner jurisdiction's Cap-and-Trade Program and the WTS, and I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

7.2.2.3.3 The program authority or its agent will accept or act on a submission concerning the general account only if the submission has been made, signed, and certified in accordance with section 7.2.2.4.

7.2.2.4 Changing authorized account representative and alternate authorized account representative; changes in persons with ownership interest.

7.2.2.4.1 The authorized account representative for a general account may be changed at any time upon receipt by the program authority or its agent of a superseding complete application for a general account under section 7.2.2.2. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous authorized account representative, or the previous alternate authorized account representative prior to the time and date when the program authority or its agent receives the superseding application for a general account shall be binding on the new authorized account representative and the persons with an ownership interest with respect to the compliance instruments in the general account.

7.2.2.4.2 The alternate authorized account representative for a general account may be changed at any time upon receipt by the program authority or its agent of a superseding complete application for a general account under section 7.2.2.2. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous authorized account representative, or the previous alternate authorized account representative, prior to the time and date when the program authority or its agent receives the superseding application for a general account shall be binding on the new alternate authorized account representative and the persons with an ownership interest with respect to the compliance instruments in the general account.

7.2.2.4.3 In the event a new person having an ownership interest with respect to compliance instruments in the general account is not included in the list of such persons in the application for a general account, such new person shall be deemed to be subject to and bound by the application for a general account, the representations, actions, inactions, and submissions of the authorized account representative and any alternate authorized account representative, and the decisions, orders, actions, and inactions of the program authority or its agent, as if the new person were included in such list.

7.2.2.4.4 Within 1 day following any change in the persons having an ownership interest with respect to compliance instruments in the general account, including the addition or deletion of persons, the authorized account representative or any alternate authorized account representative shall submit a revision to the application for a general account amending the list of persons having an ownership interest with respect to the compliance instruments in the general account to include the change.

7.2.2.5 Objections concerning authorized account representative

7.2.2.5.1 Once a complete application for a general account under section 7.2.2.2 has been submitted and received, the program authority or its agent will rely on the application unless and until a superseding complete application for a general account under section 7.2.2.2 is received by the program authority or its agent.

7.2.2.5.2 Except as provided in sections 7.2.2.4.1 and 7.2.2.4.2, no objection or other communication submitted to the program authority or its agent concerning the authorization, or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative for a general account shall affect any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative or the finality of any decision or order by the program authority or its agent under the Partner jurisdiction's Cap-and-Trade Program.

7.2.2.5.3 Neither the program authority nor its agent will adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative for a general account, including private legal disputes concerning the proceeds of compliance instrument transfers.

7.2.2.6 Delegation by authorized account representative and alternate authorized account representative

7.2.2.6.1 An authorized account representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the program authority or its agent provided for under section 7.2.2 and 7.2.5.

7.2.2.6.2 An alternate authorized account representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the program authority or its agent provided for under sections 7.2.2 and 7.2.5.

7.2.2.6.3 In order to delegate authority to make an electronic submission to the program authority or its agent in accordance with sections 7.2.2.6.1 and 7.2.2.6.2, the authorized account representative or alternate authorized account representative, as appropriate, must submit to the program authority or its agent a notice of delegation, in a format prescribed by the program authority that includes the following elements:

7.2.2.6.3.1 The name, address, email address, telephone number, and facsimile transmission number of such authorized account representative or alternate authorized account representative;

7.2.2.6.3.2 The name, address, email address, telephone number and facsimile transmission number of each such natural person, herein referred to as "electronic submission agent";

7.2.2.6.3.3 For each such natural person, a list of the type of electronic submissions for which authority is delegated to him or her; and

7.2.2.6.3.4 The following certification statements by such authorized account representative or alternate authorized account representative:

7.2.2.6.3.4.1 "I agree that any electronic submission to the program authority or its agent that is by a natural person identified in this notice of delegation and of a type listed for such electronic submission agent in this notice of delegation and that is made when I am a authorized account representative or alternate authorized account representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 7.2.2.6.3 shall be deemed to be an electronic submission by me."

7.2.2.6.3.4.2 "Until this notice of delegation is superseded by another notice of delegation under section 7.2.2.6.3, I agree to maintain an email account and to notify the program authority or its agent immediately of any change in my email address unless all delegation authority by me is terminated."

7.2.2.6.4 A notice of delegation submitted under section 7.2.2.6.3 shall be effective, with regard to the authorized account representative or alternate authorized account representative identified in such notice, upon receipt of such notice by the program authority or its agent and until receipt by the program authority or its agent of a superseding notice of delegation by such authorized account representative or alternate authorized account representative as appropriate. The superseding notice of delegation may replace any previously identified electronic submission agent, add a new electronic submission agent, or eliminate entirely any delegation of authority.

7.2.2.6.5 Any electronic submission covered by the certification in section 7.2.2.6.3.4 and made in accordance with a notice of delegation effective under section 7.2.2.6.3 shall be deemed to be an electronic submission by the authorized account representative or alternate authorized account representative submitting such notice of delegation.

7.2.3 Account identification. The program authority or its agent will assign an identifying number that is unique within the WCI Regional Cap-and-Trade Program and in accordance with the WCI Numbering System to each account established under sections 7.2.1 and 7.2.2.

7.2.4 Provide for recordation of allowances in accounts

7.2.5 Provide for the surrender and/or deduction of compliance instruments from compliance accounts using compliance certification statements and/or default method.[30]

7.2.5.1 Compliance instruments available for compliance surrender and/or deduction. Compliance instruments that meet the following criteria are available to be surrendered and/or deducted in order for a covered source to comply with the requirements of section 4.4 for a compliance period.

7.2.5.1.1 The allowances, other than offset certificates, are of allocation years that fall within a prior compliance period or the same compliance period for which the allowances will be surrendered and/or deducted.

7.2.5.1.2 The compliance instruments are held in the covered source's compliance account as of the compliance instrument surrender deadline for that compliance period or are transferred into the compliance account by a compliance instrument transfer correctly submitted for recordation under section 7.2.6 by the compliance instrument surrender deadline for that compliance period.

[30] As discussed above, a Partner jurisdiction could implement the allowance deduction mechanism in alternative ways. The method provided here as an example is the approach taken by the U.S. Environmental Protection Agency in its cap-and-trade programs. 40 CFR Part 96.

7.2.5.1.3 For offset certificates, the number of offset certificates that are available to be surrendered and/or deducted in order for a covered source to comply with the requirements of section 4.4 for a compliance period may not exceed the limit established by the program authority as a percentage of the covered source's compliance obligation for that compliance period, as determined in accordance with section 4.1 and 7.1.

7.2.5.1.4 The compliance instruments are not necessary for surrender and/or deductions for excess emissions for a prior compliance period under section 7.2.6.

7.2.5.2 Surrender and/or Deductions for compliance. Following the recordation, in accordance with section 7.2.6, of compliance instrument transfers submitted for recordation in the covered source's compliance account by the compliance instrument surrender deadline for a compliance period, the program authority or its agent will surrender and/or deduct compliance instruments available under section 7.2.5.1 to cover the covered source's verified GHG emissions (as determined in accordance with section 7.1) for the compliance period, as follows:

7.2.5.2.1 Until the amount of compliance instruments deducted equals the number of metric tons of total verified emissions, determined in accordance with section 7.1, from all covered units at the covered source for the compliance period; or

7.2.5.2.2 If there are insufficient compliance instruments to complete the compliance instrument surrender and/or deductions in section 7.2.5.2.1, the source shall exhaust all compliance instruments available under section 7.2.5.1 remaining in the compliance account.

7.2.5.3 Identification of available compliance instruments by serial number; default compliance instrument surrender and/or deductions

7.2.5.3.1 The authorized account representative for a source's compliance account may request that specific compliance instruments, identified by serial number, in the compliance account be surrendered and/or deducted for emissions or excess emissions for a compliance period in accordance with sections 7.2.5.2 and 7.2.5.4. Such identification shall be made in the compliance certification report submitted in accordance with section 4.5.

7.2.5.3.2 The program authority or its agent will deduct compliance instruments for a compliance period from the covered source's compliance account, in the absence of an identification or in the case of a partial identification of available compliance instruments by serial number under section 7.2.5.3.1, in the following order:

7.2.5.3.2.1 First, subject to the relevant compliance instrument surrender and/or deduction limitations under sections 7.2.5.1.3 and 7.2.5.4, offset certificates and approved program compliance units. Offset certificates and approved program compliance units shall be surrendered and/or deducted in chronological order (i.e., those from earlier years shall be surrendered and/or deducted before those from later years).

7.2.5.3.2.2 Second, any allowances that are available for surrender and/or deduction under section 7.2.5.1. Allowances shall be surrendered and/or deducted in chronological order (i.e., allowances from earlier allocation years shall be surrendered and/or deducted before compliance instruments from later allocation years). In the event that some, but not all, allowances from a particular allocation year are to be surrendered and/or deducted, allowances shall be surrendered and/or deducted by serial number, with lower serial number compliance instruments surrendered and/or deducted before higher serial number compliance instruments.

7.2.5.4 Surrender and/or Deductions for excess emissions

7.2.5.4.1 After making the deductions for compliance under section 7.2.5.3, the program authority or its agent will deduct from the covered source's compliance account a number of compliance instruments, from allocation years that occur after the compliance period in which the source has excess emissions, equal to three times the number of the source's excess emissions (3x the allowances shortage). In the event that a source has insufficient compliance instruments to cover three times the number of the source's excess emissions, the source shall be required to immediately transfer sufficient compliance instruments into its compliance account. Offset certificates and/or approved program compliance units shall not be used cover excess emissions.

7.2.5.4.2 The program authority may prevent any transfer of allowances from any general account held by the owners and operators of the covered source or covered units that has excess verified emissions.

7.2.5.4.3 Any compliance instrument deduction required under section 7.2.5.4.1 shall not affect the liability of the owners and operators of the covered source or the covered units at the source for any fine, penalty, or assessment, or their obligation to comply with any other remedy, for the same failure to timely comply with the surrender obligation, as imposed under applicable Jurisdiction law. The following guidelines will be followed in assessing fines, penalties, assessments or other remedies.[31]

7.2.5.4.3.1 For purposes of determining the number of days of violation for a fine, penalty or assessment, if a covered source has excess emissions for a compliance period, each day after the compliance period that the source remains out of compliance constitutes a day in violation unless the owners and operators of the unit demonstrate that a lesser number of days should be considered.

7.2.5.4.3.2 Each metric ton of excess verified emissions is also a separate violation.

7.2.5.4.4 The propriety of the program authority's or its agent's determination that a covered source had excess emissions and the concomitant deduction of compliance instruments from that GHG covered source's account may be later challenged in the context of the initial administrative enforcement, or any civil or criminal judicial action arising from or encompassing that

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[31] It should be noted that the provisions of section 7.2.5.4.3 apply to enforcement actions that may be taken by the program authority and not to the requirement to surrender three additional allowances to cover each metric ton of excess emissions.

excess emissions violation. The commencement or pendency of any administrative enforcement, or civil or criminal judicial action arising from or encompassing that excess emissions violation will not act to prevent the program authority or its agent from initially deducting the compliance instruments resulting from the program authority's original determination that the relevant covered source has had excess emissions. Should the program authority's or its agent's determination of the existence or extent of the covered source's excess emissions be revised either by a settlement or final conclusion of any administrative or judicial action, the program authority or its agent will act as follows:

7.2.5.4.4.1 In any instance where the program authority's or its agent's determination of the extent of excess emissions was too low, the program authority or the agent will take further action under sections 7.2.5.4.1 and 7.2.5.4.2 to address the expanded violation.

7.2.5.4.4.2 In any instance where the program authority's or its agent's determination of the extent of excess emissions was too high, the program authority or the agent will distribute to the relevant covered source a number of compliance instruments equaling the number of compliance instruments deducted which are attributable to the difference between the original and final quantity of excess emissions. Should such covered source's compliance account no longer exist, the compliance instruments will be provided to a general account selected by the owner or operator of the covered source from which they were originally deducted.

7.2.5.5 The program authority or its agent will record in the appropriate compliance account all deductions from such an account pursuant to sections 7.2.5.1 and 7.2.5.4.

7.2.5.6 Action by the program authority on submissions

7.2.5.6.1 The program authority may review and conduct independent audits concerning any submission under the Partner jurisdiction's Cap-and-Trade Program and make appropriate adjustments of the information in the submissions.

7.2.5.6.2 The program authority may deduct compliance instruments from or transfer compliance instruments to a source's compliance account based on information in the submissions, as adjusted under section 7.2.5.4.3.

7.2.6 Provide for compliance instrument transfers

7.2.6.1 Submission of compliance instrument transfers. The authorized account representatives wanting to transfer compliance instruments shall propose the transfer through the online tracking system. When proposing a transfer, the following information will need to be provided in a format specified by the program authority or its agent:[32]

[32] The information required for transfer of compliance instruments will be used to execute the transfer in the WTS, to conduct market oversight, and to support transparency. Information that could be used to identify parties to a transaction will be maintained confidential and not released to the public. Aggregate volume data and aggregate price data (that do not reveal individual trade data) are expected to be released publicly on a coordinated basis at regular intervals, such as daily or weekly.

7.2.6.1.1 The numbers identifying both the transferor and transferee accounts;

7.2.6.1.2 A specification by serial number of each compliance instrument to be transferred; and

7.2.6.1.3 The printed name and signature of the authorized account representative of the transferor account and the date signed;

7.2.6.1.4 The purchase price for each instrument or group of instruments transferred, except when the transfers were from affiliates disclosed on the affiliated entities list.

7.2.6.2 Recordation

7.2.6.2.1 Within five business days of receiving an compliance instrument transfer, except as provided section 7.2.6.2.2, the program authority or its agent will record a compliance instrument transfer by moving each compliance instrument from the transferor account to the transferee account as specified by the submission, provided that the transfer is correctly submitted section 7.2.6.1; and the transferor account includes each compliance instrument identified by serial number in the transfer.

7.2.6.2.2 A compliance instrument transfer into or out of a compliance account that is submitted for recordation following the compliance instrument surrender deadline and that includes any compliance instruments that are of allocation years that fall within a compliance period prior to or the same as the compliance period to which the compliance instrument surrender deadline applies will not be recorded until after completion of the deduction process under section 7.2.5.

7.2.6.2.3 Where a compliance instrument transfer submitted for recordation fails to meet the requirements of section 7.2.6.1, the program authority or its agent will not record such transfer.

7.2.6.3 Notification

7.2.6.3.1 Notification of recordation. Within five business days of recordation of a compliance instrument transfer under section 7.2.6.2, the program authority or its agent will notify each party to the transfer. Notice will be given to the authorized account representatives of both the transferor and transferee accounts.

7.2.6.3.2 Notification of non-recordation. Within 10 business days of receipt of a compliance instrument transfer that fails to meet the requirements of 7.2.6.1, the program authority or its agent will notify the authorized account representatives of both accounts subject to the transfer of a decision not to record the transfer, and the reasons for such non-recordation.

See Section 10 of the Design Summary and the *Market Oversight July Status Update* for a description of the market oversight recommendations.

7.2.6.3.3 Nothing in this section shall preclude the resubmission of a compliance instrument transfer for recordation following notification of non-recordation.

7.2.7 Provide for banking of compliance instruments not deducted or transferred. Each compliance instrument that is held in a compliance account or a general account will remain in such account unless and until the compliance instrument is surrendered and/or deducted, or transferred.

7.2.8 Correcting account errors. The program authority or its agent may, at its sole discretion and on his or her own motion, correct any error in any WTS account. Immediately, and in no event later than 10 business days of making such correction, the program authority or its agent will notify the authorized account representative for the account.

7.2.9 Allow for closing of general accounts

7.2.9.1 An authorized account representative of a general account may instruct the program authority or its agent to close the account by submitting a statement requesting deletion of the account from the WTS and by correctly submitting for recordation under section 7.2.6 a compliance instrument transfer of all compliance instruments in the account to one or more other WTS accounts.

7.2.9.2 If a general account shows no activity for a period of six years or more and does not contain any compliance instruments, the program authority or its agent may notify the authorized account representative for the account that the account will be closed in the WTS 20 business days after the notice is sent. The account will be closed after the 20-day period unless before the end of the 20-day period the program authority or its agent receives a correctly submitted transfer of compliance instruments into the account under section 7.2.6 or a statement submitted by the authorized account representative demonstrating to the satisfaction of the program authority or its agent good cause as to why the account should not be closed. The program authority or its agent will have sole discretion to determine if the authorized account representative demonstrated that the account should not be closed.

8. Offsets Program

Section 8 sets out the essential criteria for the issuance of offset certificates. The steps for Partner jurisdictions to create offset certificate include specific requirements for registration, validation, monitoring, quantification, reporting, verification, certification and issuance of offsets. These requirements are detailed in an upcoming WCI paper on Offset Process Draft Recommendations on which WCI Partners will solicit stakeholder input.

8.1 Offset certificates will be issued only for reductions that are real, additional, permanent, verifiable and enforceable, as described in the definitions for each in the table below.

Criteria	Definition
Real	The offset certificate represents a reduction or removal of one metric ton of CO_2e that results from a clearly identified action or decision. The offset project's reduction or removal is quantified using accurate and conservative methodologies that appropriately account for all relevant greenhouse gas sources and sinks and leakage risks. Offset projects result in emissions reductions or removals that take place at sources controlled by the project proponent.
Quantification, Uncertainty, and Accuracy	Quantification: WCI Partner jurisdictions shall ensure that net emissions reductions or removals are capable of being measured or modeled in a reliable and repeatable manner that includes all relevant sources and sinks. Quantification methodologies for GHG emissions or emissions reductions shall: • Be appropriate to the GHG source or sink • Be current at the time of quantification • Consider local conditions, whenever applicable • Account for uncertainty—be calculated in a manner that yields accurate and reproducible results When uncertainty is above the defined threshold, apply the principle of conservativeness to GHG. During quantification procedures, project proponents shall convert each type of GHG to metric tons of CO_2e. In addition, offset protocols shall use uniform quantification methods whenever feasible. Uncertainty and accuracy: Quantification methodologies and measurement techniques shall set standards for acceptable statistical precision and be based on the best available science. They shall also reduce bias, except for promoting conservative estimates. When uncertainty remains high in quantifying the amount of a greenhouse gas emission reduction or removal, the principle of conservativeness shall be applied. Principle of conservativeness: Where uncertainties are above the defined threshold, offset quantification methods should use more conservative quantification parameters, assumptions, and measurement techniques that minimize the risk of overestimating emissions reductions and removals credited for a given project. The principle should be employed when significant uncertainties arise to ensure a higher level of confidence that all calculated reductions are real.
Leakage	To address activity-shifting and market leakage, WCI Partner jurisdictions will require assessments of whether functional equivalence has been maintained within projects and require that WCI offset protocols include methods for leakage assessments. Offset protocols will evaluate functional equivalence for each project. Offset protocols will also require an assessment of potential leakage associated with each project type. In general, WCI Partner jurisdictions prefer the following methods to review leakage risk: • A quantitative assessment of leakage will be performed whenever possible. • When a quantitative assessment is not feasible, a qualitative risk assessment will determine whether the risk of systematic leakage is significant or not. • Offset protocols will include a threshold to identify significant leakage. If leakage is found to be above the threshold, the offset protocol quantification methodology will include a factor to account for leakage.

Criteria	Definition
Additional	Offset certificates will be awarded only for the portion of greenhouse gas emissions reductions or removals that would not have happened under a baseline scenario. The WCI Partner jurisdictions intend for additionality to be established in a manner that will require offset projects to be evaluated against a baseline that reflects conservative assumptions that are consistent across all WCI Partner jurisdictions. These assumptions will be described in the procedures for setting a baseline in offset protocols. Modeling or other methods of developing the baseline shall use assumptions, methodologies, and values which assure that GHG reductions or removals from a project are not over-estimated. When possible, the baseline shall be set using a sector-specific or activity-specific performance standard which is set in offset protocols based on a regional assessment of project performance or common practice. WCI Partners intend that all baselines will reflect the most stringent regulatory and legal requirements of any WCI Partner jurisdiction (those requirements leading to the most conservative calculation of emissions reductions). When a baseline based on the most stringent regulatory requirement is not practical because of regional differences, the WCI Partners may recommend a protocol using an alternative method. When it is not possible to set a baseline using a performance standard, a project-specific baseline may be used. Then the baseline will be set to reflect all binding agreements, regulatory requirements and legal requirements applicable to the project and also to ensure that the project is beyond business as usual.
Eligibility Date	Offsets may be awarded only for projects that are initially commenced on or after January 1, 2007, the date of the original WCI Memorandum of Understanding (MOU) beginning the development of the WCI cap-and-trade program. An offset project proponent must apply to register its project with a WCI Partner Jurisdiction within one year of project commencement. Projects that commenced prior to finalization of the applicable offset protocol must apply within one year of that protocol's finalization.
Crediting Period	The crediting period for non-sequestration offset projects will be 10 years. At the end of a crediting period a project proponent may renew a project subject to the current offset protocol for that project type. Renewal of a project at the end of a crediting period will include a reevaluation of a project's additionality and reevaluation of how the reductions are quantified and verified. Thus, the baseline scenario will be reevaluated at each renewal. The crediting period for sequestration projects will be specified by the applicable offset protocol. However, any individual crediting period may not exceed 25 years before a renewal, and the total crediting period including all renewals may not exceed 100 years for sequestration projects. The applicable offset protocol will also lay out the requirements for project renewal. At a minimum, the project must reevaluate quantification and monitoring methods based on the current offset protocol. If possible, projects will also need to reassess project additionality and baselines in order to renew the project.
Permanent	With respect to offset project activities, permanence means either that reductions or removals are not reversible or that, if reductions or removals are reversed, the provisions outlined in the remainder of this recommendation must be met. Sequestration projects must be designed so that the net atmospheric effect of their greenhouse gas removal is comparable to the atmospheric effect achieved by non-sequestration projects. The atmospheric effect will be based on the current

Criteria	Definition
	international standard established by the UNFCCC, which is currently 100 years. This international standard may be updated from time to time. If an emission reduction is reversed after credits are issued, the project developer must either replace the reversed credits with other compliance units from within the system or return credits that were issued to the project. Applicable approaches to assuring permanence for a project type will be included in the appropriate offset protocol. In conformance with the applicable offset protocols, project proponents shall follow or establish effective (i) monitoring systems, (ii) risk mitigation approaches, and (iii) contingency plans which address how, in the event of a reversal that is the result of proponent intention or negligence, any affected offset certificates will be replaced. The contingency plan shall include specific mechanisms that are exercisable at the time a reversal is identified whether or not the proponent is solvent, exists in its original form, and/or has ownership of or responsibility for the project. WCI Partner jurisdictions will establish mechanisms to address reversals that are not the result of proponent intention or negligence and where proponents' contingency measures prove inadequate.
Verifiable	With respect to offset project activities, verifiable means that a GHG reduction or removal, or assertion thereof, is well documented and transparent such that it lends itself to an objective review by a qualified verifier. Verifiers for offsets will be independent third parties who have been accredited to a standard acceptable by the WCI Partner jurisdiction in which the project is registered.
Validation	Validation is a required review by an accredited independent third party or the WCI Partner jurisdiction to assess conformance of a proposed project to WCI requirements, criteria and an offset protocol. The WCI Partner jurisdictions may not require third party validation in all cases but may approve protocols that require a validation step.
Enforceable	Each Partner jurisdiction will, to the extent permissible by law, put in place sufficient compliance/enforcement mechanisms and detail for the jurisdiction to compel compliance with its requirements and with offset protocols.
Material	Material misstatement means that errors, omissions or an aggregation of both in the reported GHG reductions or assertion exceeds a +5% threshold. The verifier must be able to state with reasonable assurance the total reported reductions or removals are free of material misstatement.
Transparency	The offset system will provide transparency such that sufficient and appropriate protocol, project and certificate information is disclosed in a timely manner to allow offset system participants and the general public to make decisions with reasonable confidence.
Assessment of Environmental or Social Impacts	Offset projects must meet all applicable local environmental regulations and be in compliance with all applicable laws in the jurisdiction where the project is located. Offset protocols for specific offset project types may require analysis of environmental and socioeconomic impacts beyond what the local jurisdiction would otherwise require and may require additional mitigation of potential negative impacts.

9. Linking to Other Programs

Section 9 relates to whether and how Partner jurisdictions will link their individual trading programs with other Partner jurisdictions, as well as whether and how Partner jurisdictions will accept compliance units from Non-WCI programs.

9.1 Approval of link to another program

In evaluating another program for purposes of determining whether to link the Partner jurisdiction's Cap-and-Trade program to the other program, the Partner jurisdiction will consult with other participating Partner jurisdictions and consider whether the other program:

9.1.1 Implements a binding and annually declining aggregate total greenhouse gas emissions cap that limits the quantity of allowances that can be issued and covers one or more economic sectors; and

9.1.2 Includes the following, to the extent deemed necessary under the circumstances:

9.1.2.1 The transparent allocation of allowances;

9.1.2.2 Provisions to avoid the double counting of emissions or allowances in the electric sector;

9.1.2.3 A standardized and secured tracking system in the form of an electronic database containing common data elements to track the issuance, holding, transfer and cancellation of compliance instruments, to provide for public access and confidentiality as appropriate, and to ensure that there are no transfers which are incompatible with the Partner jurisdiction's implementation of the Cap-and-Trade program;

9.1.2.4 A comprehensive account registration requirement for all tracking system accounts;

9.1.2.5 The capability to transfer relevant and necessary information on all transactions and transfers between accounts in linked jurisdictions;

9.1.2.6 Provisions to ensure that offset certificates accepted into the system provide equal or greater assurance of the integrity of such offset certificates to that called for in the detailed program design;

9.1.2.7 Restrictions to the use of offset certificates comparable to the quantitative usage limit established in the detailed program design;

9.1.2.8 Provisions for comparable monitoring, reporting, verification, compliance, and enforcement of its greenhouse gas emissions to that set forth in the *Final Essential Requirements for Mandatory Reporting*; and

9.1.2.9 Provisions that compliance instruments that are voluntarily retired or used to meet an obligation to surrender compliance instruments equal to verified emissions are disqualified from further use in any system.

9.1.2.10 Existing links with other programs meet similar criteria

9.1.3 Includes enforcement mechanisms that:

9.1.3.1 Provide general market surveillance, identify suspect transactions, and provide for investigations and enforcement actions;

9.1.3.2 Ensure consequences for noncompliance are comparable between the systems to be linked, and in particular that the consequences of failing to meet compliance unit surrender requirements are automatic;

9.1.3.3 Respond in a timely manner to requests by enforcement agencies in the Partner jurisdiction and all jurisdictions approved by the Partner jurisdiction for relevant and necessary information on market participants under investigation; and

9.1.3.4 Transfer between systems in a timely manner relevant and necessary notice and information concerning all relevant enforcement actions undertaken by the system's jurisdictional enforcement authority

9.1.4 Is capable of transferring between linked jurisdictions all information necessary to monitor market trends on a regional basis, including:

9.1.4.1 Aggregate verified emissions data, the compliance status of entities covered by the cap and trade program and expected issuance of offset certificates;

9.1.4.2 Information that can be released to the public in a coordinated and consistent manner; and

9.1.4.3 Information necessary to collaborate on market oversight functions.

9.1.5 Provides an equal degree of protection for confidential business information.

9.2 Establishing a bilateral link to another program

Once a Partner jurisdiction determines that another program meets the criteria in section 9.1, the Partner jurisdiction and the other jurisdiction will mutually acknowledge that their programs are compatible and will:

9.2.1. Allow the mutual recognition of compliance instruments issued to meet compliance obligations;

9.2.2. Provide that after any compliance instrument is used to meet an obligation to surrender compliance instruments, it shall be disqualified for subsequent use under any system, whether such use is a sale, exchange, or submission to meet an obligation to surrender compliance instruments under a cap-and-trade program; and

9.2.3. Ensure that the tracking system (or systems) permits the transfer of compliance instruments from one jurisdiction to another, that a jurisdiction will record when a compliance instrument is transferred out of its tracking system, and that the system can be counted on to sever the linking relationship should severance be necessary.

9.3 Establishing a unilateral link to another program

9.3.1 In the absence of mutual recognition of compliance instruments between a Partner jurisdiction and another trading program, unilateral linking can be accomplished by allowing sources with a compliance obligation to surrender compliance instruments from an approved trading program. The same criteria can be applied in determining whether to approve the external trading program. In the case of a unilateral link to an external program that generates offsets but is otherwise not a cap-and-trade program, the Partner jurisdiction will apply only those criteria that are relevant to offset programs.

9.3.2 In the case of unilateral links, the Partner jurisdictions will develop a suitable mechanism to ensure the validity of external compliance units and to make sure those units can only be used once for compliance in any program.

Western Climate Initiative

Program Design Recommendations for the WCI Regional Program

WCI Stakeholder Call

July 27, 2010

Today's Release

- Comprehensive strategy to reduce greenhouse gases and spur a clean-energy economy
- Culmination of two years of work since WCI released initial design recommendations in 2008
- Program Design and supporting material available at: http://westernclimateinitiative.org/program-design
- WCI Partners include *Arizona, British Columbia, California, Manitoba, Montana, New Mexico, Ontario, Oregon, Québec, Utah, and Washington*

The Program Design

- Reduce greenhouse gas emissions to 15% below 2005 levels by 2020
- Includes an emissions cap and other core policies that are affordable, gradual, and support economic growth
- Based on extensive analysis and stakeholder consultation
- Provides a roadmap to inform Partners in their development of implementing regulations

Program Benefits

- Reduces costly impacts that climate change will have on water resources, natural ecosystems, air quality, and environment-dependent industries like agriculture and tourism
- Provides incentives for clean-energy technologies
- Creates green jobs
- Increases energy security
- Protects public health

Program Specifics

- The WCI Partners are advancing core policies and programs that:
  - Use a market-based approach to cap most emissions
  - Encourage reductions throughout the economy
  - Expand energy efficiency programs
  - Encourage additional renewable energy sources
  - Tackle transportation emissions

Program Specifics

- Economically- and geographically-broad cap covers nearly 90% of the region's emissions, providing flexibility to achieve least-cost emission reductions
- Jurisdictions with caps beginning in 2012 will include most of the region's emissions
- The WCI program accommodates jurisdictions with alternative schedules

Document Organization

- Design Summary
  - Highlights
  - Policy Recommendations
- Documentation
- Detailed Design
  - Operational Components

Next Steps

- Develop outstanding program design issues
- Put in place administrative systems and infrastructure
- Continue advancing core policies and programs
- Work closely with federal governments to promote national and international action and ensure coordination among state, provincial, regional and national programs

September 8, 2010 Harmonization Mandatory Reporting in Canadian Jurisdictions with the WCI Essential Requirements and the EPA Greenhouse Gas Reporting Program

List of Commenters

BC Forest Sector Working Group on Climate Change

Canadian Association of Petroleum Producers

Canadian Gas Association

Canadian Steel Producers Association

Cement Association of Canada

Forest Products Association of Canada

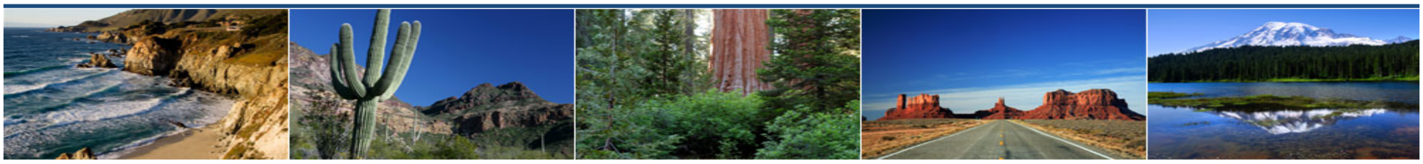
Husky Energy

Spectra Energy

Terasen Gas

Western Climate Advocates Network

Western Climate Initiative



Harmonization of Essential Requirements for Mandatory Reporting in Canadian Jurisdictions with the WCI Essential Requirements for Mandatory Reporting and the EPA Greenhouse Gas Reporting Program

September 8, 2010

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1 Introduction

On July 16, 2009, the WCI published the Final Essential Requirements for Mandatory Reporting (the "ERs") to be implemented by the WCI Partner jurisdictions. On September 22, 2009, U.S. EPA adopted its final Mandatory Greenhouse Gas Reporting Rule (the "EPA rule"), implementing the GHG Reporting Program. Many U.S. facilities in the WCI region will be subject to both reporting programs. Specifically, most facilities with emissions of CO_2e greater than or equal to 25,000 metric tons per year in WCI states will be subject to both programs.

The WCI Partners were concerned that the existence of two different reporting systems in a U.S. WCI state could result in the imposition of duplicative or conflicting reporting obligations on facilities subject to both programs. In order to avoid the imposition of this burden on reporting facilities, the Partners directed the WCI Reporting Committee to develop amended ERs that are harmonized with the EPA rule. Finalization of the harmonized ERs is expected in the near future. The harmonized ERs will be in the same format as the EPA rule, and include some recommended changes to ensure a level of accuracy in reported emissions sufficient for a cap-and-trade program.

In order to maintain consistency across all WCI jurisdictions, it was necessary for the Canadian WCI provinces to adopt harmonized ERs containing emission estimation methods and monitoring requirements equivalent to the harmonized ERs nearing approval by the WCI Partners.

Therefore, the Reporting Committee has developed amended WCI ERs that are methodically consistent with the WCI harmonized ERs but appropriate for use in the Canadian jurisdictions. The format of the harmonized Canadian ERs follows the original WCI format, a format that had already been used in guidance documents and regulations in several Canadian WCI jurisdictions.

The remainder of this document provides the principles applied to the harmonization process and approach used, and summarizes the changes made from the original WCI ERs.

2 Canadian Harmonization Principles

In developing harmonized ERs for use in Canadian jurisdictions that modify the existing ERs, the WCI Canadian Reporting Committee members applied the following principles:

1. A Canadian facility should apply the same functions, equations, sampling protocols and measurement criteria as U.S. facilities subject to the U.S. version of the

harmonized ERs. This means that the harmonized ERs will achieve the same level of reporting accuracy for Canadian and U.S. facilities, but the U.S. version may require more data elements to be reported to harmonize with the EPA rule.

2. The quantification methods included in the harmonized ERs must remain sufficiently reliable and accurate to be employed in a greenhouse gas (GHG) cap-and-trade program.

3. The WCI reporting system must remain suitable for use in Canadian jurisdictions. For example, it must allow reporting in metric as well as English units and must where necessary include Canada-specific emission factors.

4. The harmonized ERs should facilitate harmonization with Canadian federal reporting. Some Canadian jurisdictions are working with Environment Canada to develop a one-window reporting tool for provincial and national GHG reporting requirements.

3 Canadian Harmonization Approach

For the Canadian jurisdictions, the key requirement is that the WCI reporting system as a whole require the use of comparable methodologies and produce comparable results for facilities of the same type, so that a “ton is a ton” in both the U.S. and Canada. For Canadian jurisdictions it is not nearly as important to avoid small differences between the ERs and the EPA rule as it is for the U.S. jurisdictions, where differences create a risk of inadvertent non-compliance.

Canadian Partners have invested substantial resources in developing regulations to implement the existing WCI ERs. In addition, the provinces face technical and legal issues with the incorporation by reference of the EPA rule that do not apply to the states. The WCI is therefore proposing amendments to the existing WCI ERs to assure that they conform in substance with the U.S. version of the harmonized ERs as well as the interest provinces have in harmonizing their reporting programs with Environment Canada’s.

In the U.S. harmonization package a series of emission sources were listed as reporting only. The following list expands upon those sources based on the increased scope of the Canadian harmonization package:

Items Identified as Reporting Only in Harmonized ERs

Section(s)	Reporting Requirement
WCI.040 (EPA 98.32(b), 98.33(f))	Fugitive HFC emissions from cooling units at electricity generators
WCI.200 (EPA 98.253(h))	GHG emissions from asphalt blowing operations at petroleum refineries
WCI.200 (EPA 98.253(l))	CH_4 from equipment leaks at petroleum refineries
WCI.200 (98.253(m))	CH_4 from storage tanks at petroleum refineries
WCI.200 (98.253(n))	CH_4 from crude oil, intermediate, or product loading operations at petroleum refineries
WCI.100	Coal storage emissions
WCI.280	Mobile equipment

3.1 Verification

The amount of data to be reported by facilities in Canadian jurisdictions is less than the data required to be reported under the harmonized U.S. ERs. Canadian facilities that are subject to third party verification will have emissions reports evaluated by accredited third-party verifiers, whereas U.S. facilities reporting under the EPA rule and harmonized U.S. ERs will have their reports verified internally by EPA. Therefore, given the requirement for third-party verification, there is less of a need for detailed unit level data to be submitted online to the Canadian jurisdictions, as compared to what is required to be reported to the EPA for their internal verification.

3.2 Missing Data Procedures

The EPA rule includes procedures in each subpart for replacing missing data resulting from monitoring failures. With the exception of methodologies for facilities subject to 40 Code of Federal Regulation (CFR) Part 75 (the Acid Rain Program), these missing data procedures do not appear to be sufficiently rigorous to support a cap-and-trade system. There is no limitation on the amount of data that may be missing, and replacement methods appear to be both inadequate (e.g., many use only one or two available data points) and inequitable (e.g., Part 75 power plants have to apply punitive methods, while other facilities do not).

In order to move forward with a harmonization proposal in time to allow implementation for the 2011 reporting year, the proposed harmonized ERs retain the EPA missing data procedures. The proposed Canadian harmonized ERs also adopt the EPA missing data procedures.

Before implementation of the cap-and-trade program, WCI intends to revisit this issue. The WCI will investigate whether the EPA missing data procedures can be modified to be more consistent with the needs of a cap-and-trade program while adhering to the harmonization principles in section.

Missing data procedures are intended to provide flexibility due to unforeseen operational failures; however, some facilities may use them to avoid the regulatory requirements (or to under-report actual emissions). As a partial measure to address the possibility of avoiding requirements or gaming, the harmonized U.S. ERs include a provision making it clear that the use of a missing data procedure does not excuse a facility's failure to follow the monitoring requirements of the rule. This provision is being considered for adoption in the Canadian ERs.

4 Summary of Changes to WCI ERs

The table on pages 7 through 9 of this document summarizes the changes to the WCI ERs that the WCI Canadian Partners are proposing to implement in WCI Canadian jurisdictions. The specific language for the changes is set forth in the Appendices.

5 Other Changes to the Proposal

The Reporting Committee is currently developing the Canadian ER harmonization methods for upstream oil and gas and natural gas transmission and distribution. These are expected to be ready for stakeholder review by early October. Several other newly proposed or finalized U.S. EPA quantification methods (e.g. magnesium production, underground coal mining, electronics manufacturing) are under consideration for Canadian harmonization by the WCI, they may be released for stakeholder comment at the same time or at a later date. Due to time constraints, the WCI have not yet included these subparts in the final harmonized ERs for U.S. States.

The industrial wastewater treatment method recently finalized by the EPA has been adopted as part of the Canadian WCI petroleum refineries quantification method (for logistical reasons), but is required to be reported for all facilities.

Also, the Reporting Committee is considering some modifications to the WCI general provisions (i.e. WCI 1 to 9), to harmonize with the provisions in Subpart A of the U.S. harmonization package. The potential modifications under consideration would cover provisions on monitor calibration and definitions (such as pipeline quality natural gas).

Further EPA rule revisions, such as conforming changes to Subpart A, are expected to be finalized and go into effect later this year. To ensure the harmonized ERs are consistent with the EPA rule, Subpart A of the harmonized ERs was recently updated to reflect these changes. Additional consequential modifications to the Canadian ERs may therefore be required for harmonization.

Deadlines for the submission of verification statements were added to the U.S. version of WCI.8. These deadlines were initially established by WCI.2, which is not included in U.S. harmonized ERs.

6 Stakeholder Comments

This section to be completed after the public consultation period is over.

Summary of Changes to the WCI ERs for Purposes of Reporting in Canadian Jurisdictions

Source Category	§	Change Summary
General Stationary Combustion	WCI.20	• Several changes to harmonize with EPA Part 98, Subpart C, including added exemptions for portable equipment, emergency generators, and emergency equipment (including emergency flares). • Reduced sampling frequency for some types of fuels. • Relaxed biomass methods by allowing use of emission factors. • Very large combustion sources (greater than 250 million BTU of heat input) will have to measure fuel carbon content or put CEMs in place. • Method 4 (CEMS) now incorporates Canadian standards. • Clarification of many methodologies to explain applicability to sources.
Refinery Fuel Gas Use within a Petroleum Refinery	WCI.30	• Removed method based on HHV for estimating CO_2 from refinery fuel gas, flexigas, and low heat content gas. • Reduced sampling frequency • Reference to WCI.26 for procedures for estimating missing data.
Electricity Generation and Cogeneration	WCI.40	Added new definitions and procedures for estimating missing data.
Adipic Acid Manufacturing	WCI.50	• Added option to estimate emissions based on continuous process monitors. • Require annual performance test including measurement of production rate. • Require monthly calculations on productions, emissions and controls if continuous process monitors are used. • More specific method for determination of site-specific emission factor based on performance test. • Added requirement to determine N_2O abatement efficiency, if applicable. • Expanded and more specific monitoring requirements. • Added procedures for estimating missing data.
Electricity Imports	WCI.60	• No changes made; original methods stand and not re-released at this time.
Primary Aluminum Manufacturing	WCI.70	• Expanded reporting requirements to be consistent with Part 98, Subpart F. • CF_4 and C_2F_6 emissions estimation methods changed from requirement for daily production data to monthly production data. • Added procedures for estimating missing data.
Ammonia Manufacturing	WCI.80	WCI.80 was never finalized; therefore a new section based on EPA 98, subpart G was developed.
Cement Manufacturing	WCI.90	• Removed reporting requirement for plant-specific CKD calcination rate. • Changed equation for estimating CKD emission factor based on Part 98, Subpart H. • Added procedures for estimating missing data.
Coal Storage	WCI.100	Added procedures for estimating missing data.

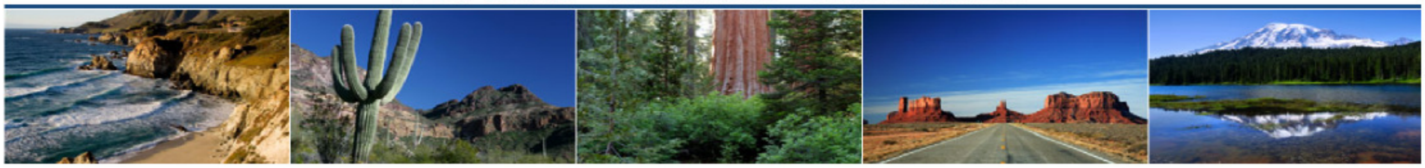
Summary of Changes to the WCI ERs for Purposes of Reporting in Canadian Jurisdictions (Continued)

Source Category	§	Change Summary
HCFC-22 Production	WCI.120	WCI.120 was never finalized; therefore a new section based on EPA 98, subpart O was developed.
Hydrogen Production	WCI.130	• Added requirement to report amount of carbon in unconverted feedstock. • Modified equations to separate calculations for liquid, gaseous and solid fuels and feedstocks. • Added specific sampling and analytical methods.
Glass Production	WCI.140	WCI.140 was never finalized, therefore a new WCI section based on EPA 98, subpart N, was developed
Iron and Steel Manufacturing	WCI.150	• Revised all reporting requirements, calculation methods, and monitoring requirements to match Part 98, Subpart Q. Now provides more specific breakdown of methods for discrete processes. • Allow coke oven gas and blast furnace gas to be reported upstream at the point of generation, rather than at the combustion unit. • Added new procedures for estimating missing data.
Lead Production	WCI.160	• Expanded and clarified monitoring requirements. • Added new procedures for estimating missing data.
Lime Manufacturing	WCI.170	• Changed reporting requirements for byproducts and wastes from monthly to quarterly. • Changed byproduct quantity sampling from quarterly to monthly. • Added procedures for estimating missing data.
Carbonates Use	WCI.180 (new)	Adopted EPA method in WCI format; no changes.
Petroleum Refineries (including Industrial Waste Water Treatment)	WCI.200	• Several changes made to harmonize with EPA Part 98, Subpart Y, which provide greater flexibility on the major sources such as flares, startup and shutdown conductions, and malfunctions. • Clarified source definition. • Clarified methods to be used for uncontrolled and controlled emissions from some sources, such as asphalt production. • More sources explicitly listed in reporting requirements. • Added methods for several new sources to harmonize with Subpart Y, including delayed coking and coke calcining. • Added procedures for estimating missing data.
Pulp and Paper Manufacturing	WCI.210	Made changes to be consistent with Part 98, Subpart AA: • Changed to use methods in WCI.20 (General Stationary Combustion) for fossil-fuel combustion (CO_2, CH_4, N_2O emissions). • For biogenic emissions from kraft or soda chemical recovery furnaces, added method based on high heat value of spent liquor solids. • Added new method for estimating CO_2 emissions from make-up chemical use.

Summary of Changes to the WCI ERs for Purposes of Reporting in Canadian Jurisdictions (Continued)

Source Category	§	Change Summary
Soda Ash Manufacturing	WCI.220	• Changed reporting requirements slightly to match Part 98, Subpart C. • More options for estimating CO_2 emissions if a CEMS is not used. • Expanded sampling, analysis, and measurement requirements. • Added new procedures for estimating missing data.
Electricity Transmission (and SF_6 from Electrical Equipment in Electricity Generation)	WCI.230	WCI.230 was never finalized, therefore a new WCI section was developed by BC for Canadian WCI jurisdictions based on EPA Part 98, Subpart DD and Canadian industry standard methods.
Zinc Production	WCI.240	• Additional requirements to report carbon content of input materials if missing data procedures are used • Equation variables clarified • Updated carbon content sampling and analysis methods • Added new procedures for estimating missing data.
Copper and Nickel Production	WCI.260 (new)	WCI.260 was never finalized, therefore a new WCI section was developed by Ontario for Canadian WCI jurisdictions. The method is based on the EC method with some clarifications on sampling frequencies but no significant differences.
Ferroalloy Production	WCI.270	New method developed for Canadian WCI jurisdictions based on EPA Part 98, Subpart K.
Mobile (Nonroad) Equipment	WCI.280 (new)	WCI.280 was never finalized, therefore a new WCI section based on methods developed by BC for Canadian WCI jurisdictions was used.
Petrochemical Manufacturing	WCI.300	• Clarified and expanded definition of petrochemical facilities. • Changed calculation methods (and some monitoring methods) to refer to refinery methods (WCI.203) for flares, and general combustion methods (WCI.20) for non-flare combustion sources and process vents. • Added new methods for gaseous, liquid, and solid feedstocks and products to be consistent with EPA part 98, Subpart X. • Added procedures for estimating missing data.
Nitric Acid Manufacturing	WCI.310	Made all changes similar as those made to adipic acid manufacturing
Phosphoric Acid Production	WCI.340	New section developed for Canadian WCI jurisdictions based on EPA Part 98, Subpart Z (with no changes except to drop requirement for estimating emissions by source of phosphate rock.)
Natural Gas Transmission, Distribution, and Storage	WCI.350 (new)	New section being developed for Canadian WCI jurisdictions based on EPA Part 98, Subpart W, WCI Reporting Committee, Oil and Gas Subcommittee recommendations to EPA (May 2010) and Canada-specific methods, sampling and measurement protocols and emission factors.
Petroleum and Natural Gas Production and Gas Processing	WCI.360 (new)	New section being developed for Canadian WCI jurisdictions based on EPA Part 98, Subpart W, WCI Reporting Committee, Oil and Gas Subcommittee recommendations to EPA (May 2010) and Canada-specific methods, sampling and measurement protocols and emission factors.

APPENDICES



§ WCI.20 GENERAL STATIONARY COMBUSTION

§ WCI.21 Source Category Definition

Stationary fuel combustion sources are devices that combust solid, liquid, or gaseous fuel generally for the purpose of producing electricity, generating steam or providing useful heat or energy for industrial, commercial, or institutional use; or reducing the volume of waste by removing combustible matter. Stationary fuel combustion sources are boilers, simple and combined cycle combustion turbines, engines, incinerators (including units that combust hazardous waste), and process heaters. This source category does not include portable equipment, emergency generators, and emergency equipment (including emergency flares).

§ WCI.22 Greenhouse Gas Reporting Requirements

The emissions data report shall include the following information at the facility level:

(a) Annual greenhouse gas emissions in metric tons, reported as follows:

(1) Total CO_2 emissions for fossil and biomass fuels, reported by fuel type. For units that burn both fossil fuels and biomass, the annual CO_2 emissions from combustion of all fossil fuels combined and the annual CO_2 emissions from combustion of all biomass fuels combined; reporting CO_2 emissions by type of fuel for these units is not required.

(2) Total CH_4 emissions, reported by fuel type.

(3) Total N_2O emissions, reported by fuel type.

(b) Annual fuel consumption:

(1) For gases, report in units of standard cubic meters.

(2) For liquids, report in units of kiloliters.

(3) For non-biomass solids, report in units of metric tons.

(4) For biomass solid fuels, report in units of bone dry metric tons.

(c) Annual weighted average carbon content of each fuel, if used to compute CO_2 emissions.

(d) Annual weighted average high heat value of each fuel, if used to compute CO_2 emissions.

(e) Annual steam generation in kilograms, for units that burn biomass fuels or municipal solid waste and generate steam.

§ WCI.23 Calculation of CO_2 Emissions

For each fuel, calculate CO_2 mass emissions using one of the four calculation methodologies specified in this section, subject to the restrictions in WCI.23(e).

(a) Calculation Methodology 1. Calculate the annual CO_2 mass emissions for each type of fuel by substituting a fuel-specific default CO_2 emission factor, a default high heat value, and the annual fuel consumption into Equation 20-1:

Equation 20-1

$$CO_2 = Fuel \times HHV \times EF \times 0.001$$

Where:

CO_2	=	Annual CO_2 mass emissions for the specific fuel type (metric tons).
Fuel	=	Mass or volume of fuel combusted per year (express mass in metric tons for solid fuel, volume in standard cubic meters for gaseous fuel, and volume in kiloliters for liquid fuel).
HHV	=	Default high heat value of the fuel, from Table 20-1 and 20-1a (GJ per metric ton for solid fuel, GJ per kiloliter for liquid fuel, or GJ per cubic meter for gaseous fuel).
EF	=	Fuel-specific default CO_2 emission factor, from Tables 20-1a, 20-2, 20-3, 20-5, or 20-7, as applicable (kg CO_2/GJ).
0.001	=	Conversion factor from kilograms to metric tons.

(b) Calculation Methodology 2. Calculate the annual CO_2 mass emissions using a default fuel-specific CO_2 emission factor, a high heat value provided by the supplier or measured by the operator, using Equation 20-2, except for emissions from the combustion of biomass fuels, for which the operator may instead elect to use the method shown in Equation 20-3. For use of calculation methodology 2 for municipal solid waste, Equation 20-3 must be used.

(1) For any type of fuel for which an emission factor is provided in Tables 20-1a, 20-2, 20-3, 20-5, or 20-7, as applicable, except biomass fuels when the operator elects to use the method in WCI.23(b)(2), use Equation 20-2:

Equation 20-2

$$CO_2 = \sum_{p=1}^{n} Fuel_p \times HHV_p \times EF \times 0.001$$

Where:

CO_2	=	Annual CO_2 mass emissions for a specific fuel type (metric tons).
n	=	Number of required heat content measurements for the year as specified in WCI.25.
$Fuel_p$	=	Mass or volume of the fuel combusted during the measurement period "p" (express mass in metric tons for solid fuel, volume in standard cubic meters for gaseous fuel, and volume in kiloliters for liquid fuel).
HHV_p	=	High heat value of the fuel for the measurement period (GJ per metric ton for solid fuel, GJ per kiloliter for liquid fuel, or GJ per cubic meter for gaseous fuel).
EF	=	Fuel-specific default CO_2 emission factor, from Tables 20-1a, 20-2, 20-3, 20-5, or 20-7, as applicable (kg CO_2/GJ).
0.001	=	Conversion factor from kilograms to metric tons.

(2) For units that combust municipal solid waste and that produce steam, use Equation 20-3. Equation 20-3 of this section may also be used for any solid biomass fuel listed in Table 20-2 of this subpart provided that steam is generated by the unit.

$$CO_2 = Steam \times B \times EF \times 0.001$$ **Equation 20-3**

Where:

CO_2	=	Annual CO_2 mass emissions from biomass solid fuel or municipal solid waste combustion (metric tons).
Steam	=	Total mass of steam generated by biomass solid fuel or municipal solid waste combustion during the reporting year (metric tons steam).
B	=	Ratio of the boiler's design rated heat input capacity to its design rated steam output capacity (GJ/metric ton steam).
EF	=	Default emission factor for biomass solid fuel or municipal solid waste, from Table 20-2 or Table 20-7, as applicable (kg CO_2/GJ).[1]
0.001	=	Conversion factor from kilograms to metric tons.

(c) Calculation Methodology 3. Calculate the annual CO_2 mass emissions for each fuel by using measurements of fuel carbon content or molar fraction (for gaseous fuels only), conducted by the operator or provided by the fuel supplier, and the quantity of fuel combusted.

(1) For a solid fuel, except for the combustion of municipal solid waste, use Equation 20-4 of this section:

Equation 20-4

$$CO_2 = \sum_{i=1}^{n} Fuel_i \times CC_i \times 3.664$$

Where:

CO_2	=	Annual CO_2 mass emissions from the combustion of the specific solid fuel (metric tons).
n	=	Number of carbon content determinations for the year.
$Fuel_i$	=	Mass of the solid fuel combusted in measurement period "i" (metric tons).
CC_i	=	Carbon content of the solid fuel, from the fuel analysis results for measurement period "i" (percent by weight, expressed as a decimal fraction, e.g., 95% = 0.95).
3.664	=	Ratio of molecular weights, CO_2 to carbon.

(2) For biomass fuels, in units that produce steam, use either Equation 20-4 above or Equation 20-5; for municipal solid waste combustion in units that produce steam, use Equation 20-5:

$$CO_2 = Steam \times B \times EF \times 0.001$$ **Equation 20-5**

Where:

CO_2	=	Annual CO_2 mass emissions from biomass solid fuel or municipal solid waste combustion (metric tons).
Steam	=	Total mass of steam generated by biomass solid fuel or municipal solid waste combustion during the reporting year (metric tons steam).

[1] The ER required development of a site-specific emission factor for MSW. For harmonization with Part 98, Subpart C, this requirement was deleted. However, jurisdictions may allow or require testing to develop a site-specific emission factor as an alternative to the default emission factors in Subpart C, Table C-1.

B = Ratio of the boiler's design rated heat input capacity to its design rated steam output capacity (GJ/metric ton steam).
EF = Default emission factor for biomass solid fuel or municipal solid waste, from Table 20-2 or 20-7, as applicable (kg CO_2/GJ), adjusted no less often than every third year as provided in WCI.25(a)(7)(B).
0.001 = Conversion factor from kilograms to metric tons.

(3) For a liquid fuel, use Equation 20-6 of this section:

$$CO_2 = \sum_{i=1}^{n} 3.664 \times Fuel_i \times CC_i \qquad \textbf{Equation 20-6}$$

Where:
CO_2 = Annual CO_2 mass emissions from the combustion of the specific liquid fuel (metric tons).
n = Number of required carbon content determinations for the year, as specified in WCI.25.
$Fuel_i$ = Volume of the liquid fuel combusted in measurement period "i" (kiloliters).
CC_i = Carbon content of the liquid fuel, from the fuel analysis results for measurement period "i" (metric ton C per kiloliter of fuel).
3.664 = Ratio of molecular weights, CO_2 to carbon.

(4) For a gaseous fuel, use Equation 20-7 of this section:

$$CO_2 = \sum_{i=1}^{n} 3.664 \times Fuel_i \times CC_i \times \frac{MW}{MVC} \times 0.001 \qquad \textbf{Equation 20-7}$$

Where:
CO_2 = Annual CO_2 mass emissions from combustion of the specific gaseous fuel (metric tons).
n = Number of required carbon content and molecular weight determinations for the year, as specified in WCI.25.
$Fuel_i$ = Volume of the gaseous fuel combusted in period "i" (a day or month, as applicable) (scm).
CC_i = Average carbon content of the gaseous fuel, from the fuel analysis results for the period "i" (day or month, as applicable) (kg C per kg of fuel).
MW = Molecular weight of the gaseous fuel, from fuel analysis (kg/kg-mole).
MVC = Molar volume conversion factor (24.1 scm per kg-mole for STP of 20°C and 1 atmosphere or 23.7 scm per kg-mole for STP of 60°F, and 1 atmosphere).
3.664 = Ratio of molecular weights, CO_2 to carbon.
0.001 = Conversion factor from kg to metric tons.

(d) Calculation Methodology 4. Calculate the annual CO_2 mass emissions from all fuels combusted in a unit, by using data from continuous emission monitoring systems (CEMS) as specified in (d)(1) through (d)(7). This methodology requires a CO_2 concentration monitor and a stack gas volumetric flow monitor, except as otherwise provided in paragraph (d)(2) of this section.

(1) For a facility that operates CEMS in response to federal, state, provincial, or local regulation, use CO_2 or O_2 concentrations and flue gas flow measurements to determine hourly CO_2 mass emissions using methodologies provided in *Protocols And Performance Specifications For Continuous Monitoring Of Gaseous Emissions From Thermal Power Generation* (Report EPS 1/PG/7 (Revised) December 2005) (or by other relevant document, if superseded).

(2) The operator shall report CO_2 emissions for the reporting year in metric tons based on the sum of hourly CO_2 mass emissions over the year, converted to metric tons.

(3) An oxygen (O_2) concentration monitor may be used in lieu of a CO_2 concentration monitor in a CEMS installed before January 1, 2012, to determine the hourly CO_2 concentrations, if the effluent gas stream monitored by the CEMS consists solely of combustion products (i.e., no process CO_2 emissions or CO_2 emissions from acid gas control are mixed with the combustion products) and if only the following fuels are combusted in the unit: coal, petroleum coke, oil, natural gas, propane, butane, wood bark, or wood residue.

   (A) If the unit combusts waste derived fuels (as defined in the General Provisions and including municipal solid waste), emissions calculations shall not be based on O_2 concentrations.

   (B) If the operator of a facility that combusts biomass fuels uses O_2 concentrations to calculate CO_2 concentrations, annual source testing must demonstrate that calculated CO_2 concentrations when compared to measured CO_2 concentrations meet the Relative Accuracy Test Audit (RATA) requirements in *Protocols And Performance Specifications For Continuous Monitoring Of Gaseous Emissions From Thermal Power Generation* (Report EPS 1/PG/7 (Revised) December 2005) (or by other relevant document, if superseded),

(4) If both biomass fuel (including fuels that are partially biomass) and fossil fuel are combusted during the year, determine and report the biogenic CO_2 mass emissions separately, as described in paragraph (f) of this section.

(5) For any units for which CO_2 emissions are reported using CEMS data, the operator is relieved of the requirement to separately report process emissions from combustion emissions for that unit or to report emissions separately for different fossil fuels for that unit when only fossil fuels are co-fired. In this circumstance, operators shall still report fuel use by fuel type as otherwise required.

(6) If a facility is subject to requirements for continuous monitoring of gaseous emissions, and the operator chooses to add devices to an existing CEMS for the purpose of measuring CO_2 concentrations or flue gas flow, the operator shall select and operate the added devices pursuant to the appropriate requirements for the facility as applicable in Canada.

(7) If a facility does not have a CEMS and the operator chooses to add one in order to measure CO_2 concentrations, the operator shall select and operate the CEMS pursuant to the appropriate requirements or equivalent requirements as applicable in Canada.

Operators who add CEMS under this paragraph are subject to the specifications in paragraphs (d)(1) through (d)(5), if applicable.

(e) Use of the Four CO_2 Calculation Methodologies. Use of the four CO_2 emissions calculation methodologies described in paragraphs (a) through (d) of this section is subject to the following requirements and restrictions:

(1) Calculation Methodology 1 (Equation 20-1).

(A) May be used by a facility that is not subject to the verification requirements by regulation for any type of fuel for which a default high heat value for the fuel (Table 20-1 and 20-1a) and a default CO_2 emission factor (Tables 20-1a, 20-2, 20-3, or 20-5, as applicable) is specified.

(B) May be used for a facility emitting at any level for the combustion of natural gas with a high heat value between 36.3 and 40.98 MJ per cubic meter, and for the combustion of any of the fuels listed in Table 20-1a.

(C) May be used for a facility emitting at any level for the combustion of municipal solid waste in a unit that does not generate steam.

(D) May not be used at a facility emitting at any level for a fuel for which you routinely perform fuel sampling and analysis for the fuel high heat value or can obtain the results of fuel sampling and analysis for the fuel high heat value from the fuel supplier at the minimum frequency specified in WCI.25(a), or at a greater frequency. In such cases, Calculation Method 2 or higher shall be used for those fuels.

(2) Calculation Methodology 2 (Equations 20-2 and 20-3).

(A) May not be used by a facility that is subject to the verification requirements by regulation, except as specified in paragraphs (e)(2)(B) through (E) of this section. Otherwise, Calculation Methodology 2 may be used for any type of fuel combusted for which a default CO_2 emission factor for the fuel is specified in Tables 20-1a, 20-2, 20-3, 20-5, or 20-7, as applicable.

(B) Calculation Methodology 2 may be used for the combustion of natural gas with a high heat value between 36.3 and 40.98 MJ per cubic meter at a facility emitting at any level.

(C) Calculation Methodology 2 may be used at a facility emitting at any level for the combustion of any of the fuels listed in Table 20-1a, and for biomass that has been determined by [the jurisdiction] not to be subject to a compliance obligation under the cap-and-trade program.

(D) Equation 20-3 may be used for the combustion of municipal solid waste only at facilities that are not subject to verification by regulation.

(E) Equation 20-2 may not be used for the combustion of municipal solid waste.

(3) Calculation Methodology 3 (Equations 20-4 through 20-7) may be used for the combustion of any type of fuel, except as specified in paragraph (e)(3)(A) through (E) of this section.

(A) Notwithstanding the provisions in paragraph (e)(1) and (e)(2) of this section, Calculation Methodology 3 must be used at a facility subject to verification for all combustion in any unit with a rated heat input capacity greater than 264 GJ/hr (250mmBtu/hr) and that has operated for more than 1,000 hours in any of the past three years, except when the fuel is natural gas with a high heat value between 36.3 and 40.98 MJ per cubic meter, the fuel is listed in Table 20-1a, or the fuel is biomass that has been determined by [the jurisdiction] not to be subject to a compliance obligation under the cap-and-trade program.

(B) Must be used for all other combustion at a facility subject to verification, except for combustion of fuels for which Calculation Methodology 1 or 2 is permitted, as described in paragraphs (e)(1) and (e)(2) of this section.

(C) May not be used when the use of Calculation Methodology 4 is required.

(D) Equation 20-4 may not be used for the calculation of emissions from combustion of municipal solid waste.

(E) Equation 20-5 may be used for the combustion of municipal solid waste at a facility emitting at any level; however, it must be used for the combustion of municipal solid waste if the facility is subject to verification by regulation, unless Calculation Methodology 4 is required.

(4) Calculation Methodology 4 may be used for a unit combusting any type of fuel. Notwithstanding the provisions in paragraphs (e)(1) through (3) of this section, Calculation Methodology 4 must be used for a combustion unit with a CEMS that is required by any federal, provincial, or local regulation and that includes both a stack gas volumetric flow rate monitor and a CO_2 concentration monitor.

(5) You may elect to use any applicable higher calculation methodology for one or more of the fuels combusted in a unit. For example, if a unit combusts natural gas and distillate fuel oil, you may elect to use Calculation Method 1 for natural gas and Calculation Method 2 for the fuel oil, even though Calculation Method 1 could have been used for both fuels. However, for units that use Calculation Method 4, CO_2 emissions from the combustion of all fuels shall be based solely on CEMS measurements.

(f) CO_2 emissions from combustion of mixtures of biomass or biomass fuel and fossil fuel. Use the procedures of this paragraph (g) to estimate biogenic CO_2 emissions from units that combust a combination of biomass and fossil fuels, including combustion of waste-derived fuels (e.g., municipal solid waste or tires) that are partially biomass. .

(1) If CEMS are not used to measure CO_2 and the facility combusts biomass fuels that do not include waste-derived fuels (e.g., municipal solid waste and tires), use Methods 1, 2, or 3, as applicable, to calculate the annual biogenic CO_2 mass emissions from the combustion of biomass fuels. Determine the mass of biomass combusted using either company records, or, for premixed fuels that contain biomass and fossil fuels (e.g., mixtures containing biodiesel), use best available information to determine the mass of biomass fuels and document the procedure.

(2) If a CEMS is used to measure CO_2 (or O_2 as a surrogate) and the facility combusts biomass fuels that do not include waste-derived fuels (as defined in the General Provisions), use Calculation Methods 1, 2, or 3 to calculate the annual CO_2 mass

emissions from the combustion of fossil fuels. Calculate biomass fuel emissions by subtracting the fossil fuel-related emissions from the total CO_2 emissions determined from the CEMS-based methodology.

(3) If the owner or operator that combusts fuels or fuel mixtures for which the biomass fraction is unknown or cannot be documented (e.g., municipal solid waste, tire-derived fuel), or if the owner or operator combusts a biomass fuel for which a CO_2 emission factor is not provided in Table 20-2, use the following to estimate biogenic CO_2 emissions:

(A) Use Calculation Methods 1, 2, 3, or 4 to calculate the total annual CO_2 mass emissions, as applicable.

(B) Determine the biogenic portion of the CO_2 emissions using ASTM D6866-06a, as specified in this paragraph. This procedure is not required for fuels that contain less than 5 percent biomass by weight or for waste-derived fuels that are less than 30 percent by weight of total fuels combusted in the year for which emissions are being reported, except where the operator wishes to report a biomass fuel fraction of CO_2 emissions.

(C) The operator shall conduct ASTM D6866-06a analysis on a representative fuel or exhaust gas sample at least every three months, and shall collect exhaust gas samples over at least 24 consecutive hours following the standard practice specified by ASTM D7459-08. If municipal solid waste is combusted, the ASTM D6866-06a analysis must be performed on the exhaust gas stream.

(D) The operator shall divide total CO_2 emissions between biomass fuel emissions and non-biomass fuel emissions using the average proportions of the samples analyzed for the year for which emissions are being reported.

(E) If there is a common fuel source to multiple units at the facility, the operator may elect to conduct ASTM D6866-06a testing for only one of the units sharing the common fuel source.

(4) If Equation 20-1 of this section is selected to calculate the annual biogenic mass emissions for wood, wood waste, or other solid biomass-derived fuel, Equation 20-8 of this section may be used to quantify biogenic fuel consumption, provided that all of the required input parameters are accurately quantified. Similar equations and calculation methodologies based on steam generation and boiler efficiency may be used, provided that they are documented.

$$(Fuel)_p = \frac{[H * S] - (HI)_{nb}}{(HHV)_{bio} \ (Eff)_{bio}}$$ **Equation 20-8**

Where:

$(Fuel)_p$	=	Quantity of biomass consumed during the measurement period “p” (metric tons/year or metric tons/month, as applicable).
H	=	Average enthalpy of the boiler steam for the measurement period (GJ/metric ton).
S	=	Total boiler steam production for the measurement period (metric ton/month or metric ton/year, as applicable).

$(HI)_{nb}$ = Heat input from co-fired fossil fuels and non-biomass-derived fuels for the measurement period, based on company records of fuel usage and default or measured HHV values (GJ/month or GJ/year, as applicable).
$(HHV)_{bio}$ = Default or measured high heat value of the biomass fuel (GJ/metric ton).
$(Eff)_{bio}$ = Percent efficiency of biomass-to-energy conversion, expressed as a decimal fraction.

(g) Calculation of CO_2 from sorbent.

(1) When a unit is a fluidized bed boiler, is equipped with a wet flue gas desulfurization system, or uses other acid gas emission controls with sorbent injection, use Equation 20-9 of this section to calculate the CO_2 emissions from the sorbent, if those CO_2 emissions are not monitored by CEMS:

$$CO_2 = S * R * \left(\frac{MW_{CO2}}{MW_S} \right) \quad \textbf{Equation 20-9}$$

Where:

CO_2 = CO_2 emitted from sorbent for the reporting year (metric tons).
S = Limestone or other sorbent used in the reporting year, from company records (metric tons).
R = 1.00, the calcium-to-sulfur stoichiometric ratio.
MW_{CO2} = Molecular weight of carbon dioxide.
MW_S = Molecular weight of sorbent.

(2) The annual CO_2 mass emissions for the unit shall be the sum of the CO_2 emissions from the combustion process and the CO_2 emissions from the sorbent.

§ WCI.24 Calculation of CH_4 and N_2O Emissions

Calculate the annual CH_4 and N_2O mass emissions from stationary fuel combustion sources using the procedures in paragraph (a), (b), or (c), as appropriate.

(a) If the high heat value of the fuel is not measured for CO_2 estimation, calculate CH_4 and N_2O emissions using Equation 20-10 for all fuels except coal. For coal, use Equation 20-11:

$$CH_4 \ or \ N_2O = Fuel \times HHV_D \times EF \times 0.000001 \quad \textbf{Equation 20-10}$$

$$CH_4 \ or \ N_2O = Fuel \times EF_c \times 0.001 \quad \textbf{Equation 20-11}$$

Where:
CH_4 or N_2O = Combustion emissions from specific fuel type, metric tons CH_4 or N_2O per year.
Fuel = Mass or volume of fuel combusted per year (express mass in metric tons for solid fuel, volume in standard cubic meters for gaseous fuel, and volume in kiloliters for liquid fuel).
HHV_D = Default high heat value specified by fuel type provided in Table 20-1, (GJ per metric ton for solid fuel, GJ per kiloliter for liquid fuel, or GJ per cubic meter for gaseous fuel).

EF = Default CH_4 or N_2O emission factor provided in Tables 20-2 or 20-4, as applicable, grams CH_4 or N_2O per GJ.

EF_c = Default CH_4 or N_2O emission factor for coal provided in Table 20-6 (grams CH_4 or N_2O per kg of coal)

0.000001 = Factor to convert grams to metric tons in Equation 20-8.

0.001 = Factor to convert g/kg to metric ton/metric ton in Equation 20-9.

(b) If the high heat value of the fuel is measured or provided by the fuel supplier for CO_2 estimation, calculate CH_4 and N_2O emissions using Equation 20-12 for all fuels except coal. For coal, use Equation 20-13:

$$CH_4 \; or \; N_2O = \sum_{p=1}^{n} Fuel_p \times HHV_p \times EF \times 0.000001 \qquad \textbf{Equation 20-12}$$

$$CH_4 \; or \; N_2O = \sum_{p=1}^{n} Fuel_p \times EF_c \times 0.000001 \qquad \textbf{Equation 20-13}$$

Where:

CH_4 or N_2O = CH_4 or N_2O emissions from a specific fuel type, metric tons CH_4 or N_2O per year.

$Fuel_p$ = Mass or volume of the fuel combusted during the measurement period "p" (express mass in metric tons for solid fuel, volume in standard cubic meters for gaseous fuel, and volume in kiloliters for liquid fuel)..

HHV_p = High heat value measured directly or provided by the fuel supplier for the measurement period, p, specified by fuel type (GJ per metric ton for solid fuel, GJ per kiloliter for liquid fuel, or GJ per cubic meter for gaseous fuel).

EF = Default CH_4 or N_2O emission factor provided in Tables 20-2 or 20-4, as applicable, grams CH_4 or N_2O per GJ.

EF_c = CH_4 or N_2O emission factor for coal, either measured directly or provided by the fuel supplier, grams CH_4 or N_2O per metric ton of coal

0.000001 = Factor to convert grams to metric tons.

(c) For biomass and municipal solid waste combustion where Equation 20-3 or 20-5 are used to calculate CO_2 emissions, use Equation 20-14 of this section to estimate CH_4 and N_2O emissions:

$$CH_4 \; or \; N_2O = Steam \times B \times EF \times 0.000001 \qquad \textbf{Equation 20-14}$$

Where:

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a municipal solid waste (metric tons).

Steam = Total mass of steam generated by municipal solid waste combustion during the reporting year (metric tons steam).

B = Ratio of the boiler's design rated heat input capacity to its design rated steam output (GJ/metric ton steam).

EF = Fuel-specific emission factor for CH_4 or N_2O, from Tables 20-2, 20-4 or 20-6, as applicable (grams CH_4 or N_2O per GJ).

0.000001 = Conversion factor from grams to metric tons.

(d) Use Equation 20-15 of this section for units that use Calculation Methodology 4 and for which heat input is monitored on a year round basis.

$$CH_4 \text{ or } N_2O = 0.001 * (HI)_A * EF$$ **Equation 20-15**

Where:

CH_4 or N_2O	=	Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons).
$(HI)_A$	=	Cumulative annual heat input from the fuel (GJ), derived from the electronic data reports or estimated from the best available information (e.g., fuel feed rate measurements, fuel heating values, engineering analysis).
EF	=	Fuel-specific emission factor for CH_4 or N_2O, from Tables 20-2, 20-4 or 20-6, as applicable (grams CH_4 or N_2O per GJ).
0.001	=	Conversion factor from kg to metric tons.

(1) If only one type of fuel is combusted during normal operation, substitute the cumulative annual heat input from combustion of the fuel into Equation 20-15 of this section to calculate the annual CH_4 or N_2O emissions.

(2) If more than one type of fuel listed is combusted during normal operation, use Equation 20-15 of this section separately for each type of fuel.

(e) When multiple fuels are combusted during the reporting year, sum the fuel-specific results from Equations 20-8, 20-9, 20-10, or 20-11 of this section (as applicable) to obtain the total annual CH_4 and N_2O emissions, in metric tons.

(f) The operator may elect to calculate CH_4 or N_2O emissions using source-specific emission factors derived from source tests conducted at least annually under the supervision of the regulator. Upon approval of a source test plan, the source test procedures in that plan shall be repeated in each future year to update the source specific emission factors annually.

(g) Use of the four CH_4 and N_2O Calculation Methodologies. Use of the four CH_4 and N_2O emissions calculation methodologies described in paragraphs (a) through (d) of this section is subject to the following requirements and restrictions:

(1) WCI.24(a) may not be used by a facility that is subject to the verification requirements of WCI.8, except for stationary combustion units that combust natural gas with a higher heating value between 36.3 and 40.98 MJ per cubic meter. Otherwise, WCI.24(a) may be used for any type of fuel for which a default CH_4 or N_2O emission factor (Tables 20-2, 20-4, 20-6, 20-7) and a default higher heat value (Table 20-1 and 20-1a) is specified.

(2) WCI.24(b) may be used for a unit of any size combusting any type of fuel.

(3) WCI.24(c) may only be used for biomass or municipal solid waste combustion. WCI.24(c) must be used instead of WCI.24(a) for any unit combusting municipal solid waste that generates steam.

(4) WCI.24(d) may be used for a unit of any size combusting any type of fuel, and must be used for any units for which Calculation Methodology 4 is used to estimate CO_2 emissions and heat input is monitored on a year round basis.

§ WCI.25 Sampling, Analysis, and Measurement Requirements

(a) Fuel Sampling Requirements. Fuel sampling must be conducted or fuel sampling results must be received from the fuel supplier at the frequency specified in paragraphs (a)(1) through (a)(4) of this section, subjected to the requirements of WCI.23(e) and WCI.24(g).

(1) Once for each new fuel shipment or delivery for coal.

(2) Once for each new fuel shipment or delivery of fuels, or quarterly for each of the fuels listed in Table 20-1a (when required).

(3) Semiannually for natural gas (when required).

(4) Quarterly for liquid fuels and fossil fuel derived gaseous fuels other than fuels listed in Table 20-1a (when Table 20-1a is used).

(5) Quarterly for gases derived from biomass including landfill gas and biogas from wastewater treatment or agricultural processes.

(6) Monthly for solid fuels other than coal and municipal solid waste, as specified below:

(A) The monthly solid fuel sample shall be a composite sample of weekly samples.

(B) The solid fuel shall be sampled at a location after all fuel treatment operations but before fuel mixing and the samples shall be representative of the fuel chemical and physical characteristics immediately prior to combustion.

(C) Each weekly sub-sample shall be collected at a time (day and hour) of the week when the fuel consumption rate is representative and unbiased.

(D) Four weekly samples (or a sample collected during each week of operation during the month) of equal mass shall be combined to form the monthly composite sample.

(E) The monthly composite sample shall be homogenized and well mixed prior to withdrawal of a sample for analysis.

(F) One in twelve composite samples shall be randomly selected for additional analysis of its discrete constituent samples. This information will be used to monitor the homogeneity of the composite.

(7) For biomass fuels and waste-derived fuels (including municipal solid waste), the following may apply in lieu of WCI.25(a)(5):

(A) If CO_2 emissions are calculated using Equation 20-4 in WCI.23(c)(1), the source-specific carbon content is determined annually.

(B) If CO_2 emissions are calculated using Equation 20-5 in WCI.23(c)(2) (biomass fuels and municipal solid waste only), the operator shall adjust the emission factor, in kg CO_2/MJ not less frequently than every third year, through a stack test measurement of CO_2 and use of the applicable ASME Performance Test Code to determine heat input from all heat outputs, including the steam, flue gases, ash and losses.

(b) Fuel Consumption Monitoring Requirements.

(1) Facilities may determine fuel consumption on the basis of direct measurement or recorded fuel purchase or sales invoices measuring any stock change (measured in MJ, liters, million standard cubic meters, metric tons or bone dry metric tons) using the following equation:

Fuel Consumption in the Report Year = Total Fuel Purchases – Total Fuel Sales + Amount Stored at Beginning of Year – Amount Stored at Year End

(2) Fuel consumption measured in MJ values shall be converted to the required metrics of mass or volume using heat content values that are either provided by the supplier, measured by the facility, or provided in Table 20-1.

(3) All oil and gas flow meters (except for gas billing meters) shall be calibrated prior to the first year for which GHG emissions are reported under this rule, using an applicable flow meter test method listed in by regulation or the calibration procedures specified by the flow meter manufacturer. Fuel flow meters shall be recalibrated either annually or at the minimum frequency specified by the manufacturer.

(4) For fuel oil, tank drop measurements may also be used.

(5) Fuel flow meters that measure mass flow rates may be used for liquid fuels, provided that the fuel density is used to convert the readings to volumetric flow rates. The density shall be measured at the same frequency as the carbon content, using ASTM D1298-99 (Reapproved 2005) "Standard Test Method for Density, Relative Density (Specific Gravity), or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method."

(6) Facilities using Calculation Methods 1 or 2 for CO_2 emissions may use the following default density values for fuel oil, in lieu of using the ASTM method in paragraph (b)(5) of this section: 0.81 kg/liter for No. 1 oil; 0.86 kg/liter for No. 2 oil; 0.97 kg/liter for No. 6 oil. These default densities may not be used for facilities using Calculation Method 3.

(c) Fuel Heat Content Monitoring Requirements. High heat values shall be based on the results of fuel sampling and analysis received from the fuel supplier or determined by the operator, in either case using an applicable analytical method listed by regulation.

(1) For gases, use ASTM D1826-94 (Reapproved 2003), ASTM D3588-98 (Reapproved 2003), ASTM D4891-89 (Reapproved 2006), GPA Standard 2261-00 "Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography." The operator may alternatively elect to use on-line instrumentation that determines heating value accurate to within ± 5.0 percent. Where existing on-line instrumentation provides only low heat value, the operator shall convert the value to high heat value as follows:

$$HHV = LHV \times CF$$ **Equation 20-16**

Where:

HHV = fuel or fuel mixture high heat value (MJ/scm).
LHV = fuel or fuel mixture low heat value (MJ/scm).
CF = conversion factor.

For natural gas, a CF of 1.11 shall be used. For refinery fuel gas and mixtures of refinery fuel gas, a weekly average fuel system-specific CF shall be derived as follows:

(A) By concurrent LHV instrumentation measurements and HHV determined by on-line instrumentation or laboratory analysis as part of the daily carbon content determination; or,

(B) By the HHV/LHV ratio obtained from the laboratory analysis of the daily samples.

(2) For middle distillates and oil, or liquid waste-derived fuels, use ASTM D240-02 (Reapproved 2007), or ASTM D4809-06 (Reapproved 2005).

(3) For solid biomass-derived fuels, use ASTM D5865-07a.

(4) For waste-derived fuels, use ASTM D5865-07a or ASTM D5468-02 (Reapproved 2007). Operators who combust waste-derived fuels that are not pure biomass fuels shall determine the biomass fuel portion of CO_2 emissions using the method specified in WCI.23(f), if applicable

(5) Use Equation 20-17 to calculate the weighted annual average heat content of the fuel, if the measured heat content is used to calculate CO_2 emissions.

$$(HHV)_{annual} = \frac{\sum_{p=1}^{n} (HHV)_p * (Fuel)_p}{\sum_{p=1}^{n} (Fuel)_p} \quad \textbf{Equation 20-17}$$

Where:

$(HHV)_{annual}$ = Weighted annual average high heat value of the fuel (GJ per metric ton for solid fuel, GJ per kiloliter for liquid fuel, or GJ per cubic meter for gaseous fuel).

$(HHV)_p$ = High heat value of the fuel, for measurement period "p" (GJ per metric ton for solid fuel, GJ per kiloliter for liquid fuel, or GJ per cubic meter for gaseous fuel).

$(Fuel)_p$ = Mass or volume of the fuel combusted during measurement period "p" (express mass in metric tons for solid fuel, volume in standard cubic meters for gaseous fuel, and volume in kiloliters for liquid fuel).

n = Number of measurement periods in the year that fuel is burned in the unit.

(d) Fuel Carbon Content Monitoring Requirements. Fuel carbon content and either molecular weight or molar fraction for gaseous fuels shall be based on the results of fuel sampling and analysis received from the fuel supplier or determined by the operator, in either case using an applicable analytical method listed by regulation.

(1) For coal and coke, solid biomass fuels, and waste-derived fuels; use ASTM 5373-08.

(2) For liquid fuels, use the following ASTM methods: For petroleum-based liquid fuels and liquid waste-derived fuels, use ASTM D5291-02 (Reapproved 2007) "Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants," ultimate analysis of oil or computations based on

ASTM D3238-95 (Reapproved 2005) and either ASTM D2502-04 or ASTM D2503-92 (Reapproved 2007).

(3) For gaseous fuels, use ASTM D1945-03 (Reapproved 2006) or ASTM D1946-90 (Reapproved 2006). For gaseous fuels other than natural gas and biogas, daily sampling and analysis to determine the carbon content and molecular weight of the fuel is required if the necessary equipment is in place to make these measurements. Otherwise, weekly sampling and analysis shall be performed. If on-line instrumentation is to be used, the equipment necessary to perform daily sampling and analysis of carbon content and molecular weight for refinery fuel gas must be installed no later than January 1, 2012, and must determine fuel carbon content accurate to ± 5 percent.

(4) Use Equation 20-18 to calculate the weighted annual average carbon content of the fuel, if the measured carbon content is used to calculate CO_2 emissions.

$$(CC)_{annual} = \frac{\sum_{p=1}^{n}(CC)_p * (Fuel)_p}{\sum_{p=1}^{n}(Fuel)_p} \qquad \textbf{Equation 20-18}$$

Where:

$(CC)_{annual}$ = Weighted annual average carbon content of the fuel (percent C by weight for solid fuel, metric ton C per kiloliter for liquid fuel, or kg C per kg fuel for gaseous fuel).

$(CC)_p$ = Carbon content of the fuel, for measurement period "p" (percent C by weight for solid fuel, metric ton C per kiloliter for liquid fuel, or kg C per kg fuel for gaseous fuel).

$(Fuel)_p$ = Mass or volume of the fuel combusted during measurement period "p" (express mass in metric tons for solid fuel, volume in standard cubic meters for gaseous fuel, and volume in kiloliters for liquid fuel).

n = Number of measurement periods in the years that fuel is burned in the unit.

(e) Fuel Analytical Data Capture. When the applicable emissions estimation methodologies in WCI.23 and WCI.24 require periodic collection of fuel analytical data for an emissions source, the operator shall demonstrate every reasonable effort to obtain a fuel analytical data capture rate of 100 percent for each report year.

(1) If the operator is unable to obtain fuel analytical data such that more than 20 percent of emissions from a source cannot be directly accounted for, the emissions from that source shall be considered unverifiable for the report year.

(2) If the fuel analytical data capture rate is at least 80 percent but less than 100 percent for any emissions source identified in WCI.23 and WCI.24, the operator shall use the methods in WCI.26(b) to substitute for the missing values for the period of missing data.

(f) Procedure for Interim Fuel Analytical Data Collection.

(1) In the event of an unforeseen breakdown of fuel analytical data monitoring equipment required for the emissions estimation methodologies in WCI.23 and WCI.24, the regulator may authorize an operator to use an interim data collection procedure if the regulator determines that the operator has satisfactorily demonstrated that:

(A) The breakdown may result in a loss of more than 20 percent of the source's fuel data for the reporting year, such that emissions for the affected source could not be verified under the verification provisions of the regulation;

(B) The fuel analytical data monitoring equipment cannot be promptly repaired or replaced without shutting down a process unit significantly affecting facility operations, or that the monitoring equipment must be replaced and replacement equipment is not immediately available;

(C) The interim procedure will not remain in effect longer than is reasonably necessary for repair or replacement of the malfunctioning data monitoring equipment; and

(D) The request was submitted within 30 calendar days of the breakdown of the fuel analytical data monitoring equipment.

(2) An operator seeking approval of an interim data collection procedure must, within 30 days of the monitoring equipment breakdown, submit a written request to the regulator] that includes all of the following:

(A) The proposed start date and end date of the interim procedure;

(B) A detailed description of what data are affected by the breakdown;

(C) A discussion of the accuracy of data collected during the interim procedure compared with the data collected under the operator's usual equipment-based method;

(D) A demonstration that no feasible alternative procedure exists that would provide more accurate emissions data; and

(E) A demonstration that the proposed interim procedure meets the criteria specified in WCI.25(f)(1).

(3) The regulator may limit the duration of the interim data collection procedure or include other conditions of approval to ensure the criteria in WCI.25(f)(1) are met.

(4) When approving an interim data collection procedure, the regulator shall determine whether the accuracy of data collected under the procedure is reasonably equivalent to data collected from properly functioning monitoring equipment, and if it is not, the relative accuracy to assign for purposes of assessing possible material misstatement under the verification provisions of the regulation.

§ WCI.26 Procedures for estimating missing data.

Whenever a quality-assured value of a required parameter is unavailable (e.g., if a CEMS malfunctions during unit operation or if a required fuel sample is not taken), a substitute data value for the missing parameter shall be used in the calculations.

(a) For all units subject to the requirements of WCI.20 that monitor and report emissions using a CEMS, the missing data backfilling procedures in *Protocols And Performance Specifications*

For Continuous Monitoring Of Gaseous Emissions From Thermal Power Generation (Report EPS 1/PG/7 (Revised) December 2005) (or by other relevant document, if superseded) shall be followed for CO_2 concentration, stack gas flow rate, fuel flow rate, high heating value, and fuel carbon content.

(b) For units that use Calculation Methodologies 1, 2, 3, or 4, perform missing data substitution as follows for each parameter:

(1) For each missing value of the high heating value, carbon content, or molecular weight of the fuel, substitute the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If the "after" value has not been obtained by the time that the GHG emissions must be calculated, you may use the "before" value for missing data substitution or the best available estimate of the parameter, based on all available process data (e.g., electrical load, steam production, operating hours). If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.

(2) For missing records of CO_2 concentration, stack gas flow rate, percent moisture, fuel usage, and sorbent usage, the substitute data value shall be the best available estimate of the parameter, based on all available process data (e.g., electrical load, steam production, operating hours, etc.). You must document and retain records of the procedures used for all such estimates.

§ WCI.27 Definitions

Except as specified in this section, all terms used in this subpart have the same meaning given in the General Provisions.

<u>Emergency generator</u> means a stationary combustion device, such as a reciprocating internal combustion engine or turbine that serves solely as a secondary source of mechanical or electrical power whenever the primary energy supply is disrupted or discontinued during power outages or natural disasters that are beyond the control of the owner or operator of a facility. An emergency generator operates only during emergency situations, for training of personnel under simulated emergency conditions, as part of emergency demand response procedures, or for standard performance testing procedures as required by law or by the generator manufacturer. A generator that serves as a back-up power source under conditions of load shedding, peak shaving, power interruptions pursuant to an interruptible power service agreement, or scheduled facility maintenance shall not be considered an emergency generator.

<u>Emergency equipment</u> means any auxiliary fossil fuel-powered equipment, such as a fire pump, that is used only in emergency situations.

<u>Pipeline quality natural gas</u> means natural gas having a high heat value equal to or greater than 36.1 MJ/m3 or less than 40.98 MJ/m3, and which is at least ninety percent methane by volume, and which is less than five percent carbon dioxide by volume.

<u>Portable</u> means designed and capable of being carried or moved from one location to another. Indications of portability include but are not limited to wheels, skids, carrying handles, dolly, trailer, or platform. Equipment is not portable if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The equipment or a replacement resides at the same location for more than 12 consecutive months.

(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least two years, and operates at that facility for at least three months each year.

(4) The equipment is moved from one location to another in an attempt to circumvent the portable residence time requirements of this definition.

Table 20-1: Default High Heat Value by Fuel Type

Liquid Fuels	**High Heat Value (GJ/kl)**
Asphalt & Road Oil	44.46
Aviation Gasoline	33.52
Diesel	38.3
Aviation Turbo Fuel	37.4
Kerosene	37.68
Propane	25.31
Ethane	17.22
Butane	28.44
Lubricants	39.16
Motor Gasoline - Off-Road	35
Light Fuel Oil	38.8
Residual Fuel Oil (#5 & 6)	42.5
Crude Oil	38.32
Naphtha	35.17
Petrochemical Feedstocks	35.17
Petroleum Coke - Refinery Use	46.35
Petroleum Coke – Upgrader Use	40.57
Solid Fuels	**High Heat Value (GJ/metric ton)**
Anthracite Coal	27.7
Bituminous Coal	26.33
Foreign Bituminous Coal	29.82
Sub-Bituminous Coal	19.15
Lignite	15
Coal Coke	28.83
Solid Wood Waste	18
Spent Pulping Liquor	14
Municipal Solid Waste	11.57
Gaseous Fuels	**High Heat Value (GJ/m3)**
Natural Gas	0.03832
Coke Oven Gas	0.01914
Still Gas – Refineries	0.03608
Still Gas – Upgraders	0.04324
Landfill Gas (captured methane)	0.0359

[1] The default high heat value for "propane" is only for the pure gas species. For the product commercially sold as propane, the value for liquefied petroleum gas in Table 20-1a should be used instead.

Table 20-1a—Fuels for which Calculation Methodologies 1 or 2 may be used at a facility emitting at any level.

Fuel Type	Default High Heat Value	Default CO_2 Emission Factor
Petroleum Products	**GJ/kiloliter**	**kg CO_2 /GJ**
Distillate Fuel Oil No. 1	38.78	69.37
Distillate Fuel Oil No. 2	38.50	70.05
Distillate Fuel Oil No. 4	40.73	71.07
Kerosene	37.68	67.25
Liquefied petroleum gases (LPG)	25.66	59.65
Propane (pure, not mixtures of LPGs)[1]	25.31	59.66
Propylene	25.39	62.46
Ethane	17.22	56.68
Ethylene	27.90	63.86
Isobutane	27.06	61.48
Isobutylene	28.73	64.16
Butane	28.44	60.83
Butylene	28.73	64.15
Natural Gasoline	30.69	63.29
Motor Gasoline	34.87	65.40
Aviation Gasoline	33.52	69.87
Kerosene-Type Jet Fuel	37.66	68.40

[1] The default factors for "propane" are only for the pure gas species. For the product commercially sold as propane, the values for LPG should be used instead.

Table 20-2: Default Emission Factors by Fuel Type

Liquid Fuels	CO_2 Emission Factor (kg /L)	CO_2 Emission Factor (kg /GJ)	CH_4 Emission Factor (g/L)	CH_4 Emission Factor (g/GJ)	N_20 Emission Factor (g/L)	N_20 Emission Factor (g/GJ)
Aviation Gasoline	2.342	69.87	2.2	65.63	0.23	6.862
Diesel	2.663	69.53	0.133	3.473	0.4	10.44
Aviation Turbo Fuel	2.534	67.75	0.08	2.139	0.23	6.150
Kerosene						
- Electric Utilities	2.534	67.25	0.006	0.159	0.031	0.823
- Industrial	2.534	67.25	0.006	0.159	0.031	0.823
- Producer Consumption	2.534	67.25	0.006	0.159	0.031	0.823
- Forestry, Construction, and Commercial/Institutional	2.534	67.25	0.026	0.69	0.031	0.823
Propane						
- Residential	1.51	59.66	0.027	1.067	0.108	4.267
- All other uses	1.51	59.66	0.024	0.948	0.108	4.267
Ethane	0.976	56.68	N/A	N/A	N/A	N/A
Butane	1.73	60.83	0.024	0.844	0.108	3.797
Lubricants	1.41	36.01	N/A	N/A	N/A	N/A
Motor Gasoline – Off-Road	2.289	65.40	2.7	77.14	0.05	1.429

Liquid Fuels	CO_2 Emission Factor (kg /L)	CO_2 Emission Factor (kg /GJ)	CH_4 Emission Factor (g/L)	CH_4 Emission Factor (g/GJ)	N_20 Emission Factor (g/L)	N_20 Emission Factor (g/GJ)
Light Fuel Oil						
- Electric Utilities	2.725	70.23	0.18	4.639	0.031	0.799
- Industrial	2.725	70.23	0.006	0.155	0.031	0.799
- Producer Consumption	2.643	68.12	0.006	0.155	0.031	0.799
- Forestry, Construction, and Commercial/Institutional	2.725	70.23	0.026	0.67	0.031	0.799
Residual Fuel Oil (#5 & 6)						
- Electric Utilities	3.124	73.51	0.034	0.800	0.064	1.506
- Industrial	3.124	73.51	0.12	2.824	0.064	1.506
- Producer Consumption	3.158	74.31	0.12	2.824	0.064	1.506
- Forestry, Construction, and Commercial/Institutional	3.124	73.51	0.057	1.341	0.064	1.820
Naphtha	0.625	17.77	N/A	N/A	N/A	N/A
Petrochemical Feedstocks	0.5	14.22	N/A	N/A	N/A	N/A
Petroleum Coke - Refinery Use	3.826	82.55	0.12	2.589	0.0265	0.572
Petroleum Coke - Upgrader Use	3.494	86.12	0.12	2.958	0.0231	0.569
Biomass and Other Solid Fuels	**CO_2 Emission Factor (kg /kg)**	**CO_2 Emission Factor (kg /GJ)**	**CH_4 Emission Factor (g/kg)**	**CH_4 Emission Factor (g/GJ)**	**N_20 Emission Factor (g/kg)**	**N_20 Emission Factor (g/GJ)**
Landfill Gas	2.989	83.3	0.6	16.7	0.06	1.671
Wood Waste (Env. Canada)[1]	0.95	52.8	0.05	2.778	0.02	1.111
Wood Waste (U.S. EPA)[2]	1.590	88.9	0.51	28.4	0.068	3.79
Spent Pulping Liquor (Env.Canada)	1.428	102.0	0.05	3.571	0.02	1.429
Spent Pulping Liquor (U.S. EPA)	1.394	99.60	0.44	31.65	0.073	5.275
Coal Coke	2.48	86.02	0.03	1.041	0.02	0.694
Tires	N/A	85	N/A	N/A	N/A	N/A
Gaseous Fuels	**CO_2 Emission Factor (kg /m3)**	**CO_2 Emission Factor (kg /GJ)**	**CH_4 Emission Factor (g/m3)**	**CH_4 Emission Factor (g/GJ)**	**N_20 Emission Factor (g/m3)**	**N_20 Emission Factor (g/GJ)**
Coke Oven Gas	1.6	83.60	0.037	1.933	0.035	1.829
Still Gas – Refineries	1.75	48.50	N/A	N/A	0.0222	0.615
Still Gas – Upgraders	2.14	49.49	N/A	N/A	0.0222	0.513

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007, unless otherwise stated

[1] Assumes 50% moisture content of wood waste

[2] Assumes 12% moisture content of wood waste

Table 20-3: Default Carbon Dioxide Emission Factors for Natural Gas by Province

	Marketable Gas (kg/m3)	Marketable Gas (kg/GJ)	Non-Marketable Gas (kg/m3)	Non-Marketable Gas (kg/GJ)
Quebec	1.878	49.01	Not occurring	Not occurring
Ontario	1.879	49.03	Not occurring	Not occurring
Manitoba	1.877	48.98	Not occurring	Not occurring
British Columbia	1.916	50.00	2.151	56.13

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007

Table 20-4: Default Methane and Nitrous Oxide Emission Factors for Natural Gas

	CH_4 (g/m3)	CH_4 (g/GJ)	N_20 (g/m3)	N_20 (g/GJ)
Electric Utilities	0.49	12.79	0.049	1.279
Industrial	0.037	0.966	0.033	0.861
Producer Consumption (Non-marketable)	6.5	169.6	0.06	1.566
Pipelines	1.9	49.58	0.05	1.305
Cement	0.037	0.966	0.034	0.887
Manufacturing Industries	0.037	0.966	0.033	0.861
Residential, Construction, Commercial/Institutional, Agriculture	0.037	0.966	0.035	0.913

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007

Table 20-5: Default Carbon Dioxide Emission Factors for Coal

	Emission Factor (kg CO_2/kg coal)	Emission Factor (kg CO_2/GJ)
Quebec		
- Canadian Bituminous	2.25	85.5
- U.S. Bituminous	2.34	88.9
- Anthracite	2.39	86.3
Ontario		
- Canadian Bituminous	2.25	85.5
- U.S. Bituminous	2.43	81.5
- Sub-bituminous	1.73	90.3
- Lignite	1.48	98.7
- Anthracite	2.39	86.3
Manitoba		
- Canadian Bituminous	2.25	85.5
- U.S. Bituminous	2.43	81.5
- Sub-bituminous	1.73	90.3
- Lignite	1.42	94.7
- Anthracite	2.39	86.3
British Columbia		
- Canadian Bituminous	2.07	78.6
- U.S. Bituminous	2.43	81.5
- Sub-bituminous	1.77	92.4

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007

Table 20-6: Default Methane and Nitrous Oxide Emission Factors for Coal

	CH_4 Emission Factor (g/kg)	N_2O Emission Factor (g/kg)
Electric Utilities	0.022	0.032
Industry and Heat and Steam Plants	0.03	0.02
Residential, Public Administration	4	0.02

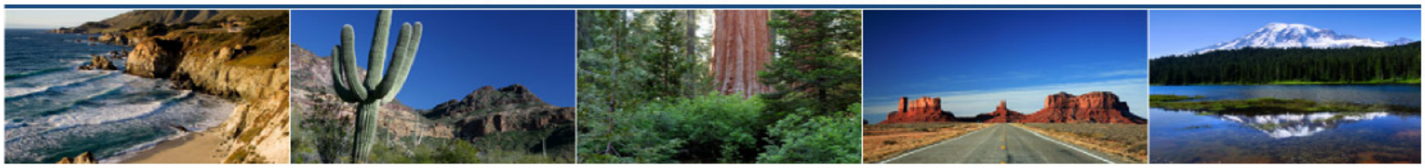
Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007

Table 20-7: Other Emission Factors

	CO_2 Emission Factor (kg/GJ)	CH_4 Emission Factor (g/GJ)	N_2O Emission Factor (g/GJ)
Municipal Solid Waste	85.6	30	4
Peat	103	1	1.5

Source: 2006 IPCC Guidelines for National Greenhouse Gas Inventories, except the CO_2 emission factor for municipal solid waste is from the U.S. EPA from table C-1 of 40 CFR 98 subpart C.

The WCI notes the significant difference in both the black liquor and solid biomass emission factors published by the EPA and Environment Canada (as well as those submitted by industry associations). In lieu of recommending a single emission factor at this time (as there is no certainty as to which is most accurate) the RC is presenting both for information purposes. The RC will be working with experts in the two federal agencies and other organizations to ascertain the most accurate emission factor to use for both Metric and English unit versions of the Essential Requirements of Mandatory Reporting.



§ WCI.30 REFINERY FUEL GAS COMBUSTION

§ WCI.31 Source Category Definition

This source category consists of any combustion device that is located at a petroleum refinery and that combusts refinery fuel gas, still gas, flexigas, or associated gas.

§ WCI.32 Greenhouse Gas Reporting Requirements

In addition to the information required by the regulation, the emissions data report shall include the following information at the facility level:

(a) Annual CO_2, CH_4, and N_2O emissions from refinery fuel gas combustion in metric tons.

(b) Annual fuel consumption in units of standard cubic meters.

(c) Average carbon content of each fuel used to compute CO_2 emissions.

§ WCI.33 Calculation of Greenhouse Gas Emissions

(a) Calculation of CO_2 Emissions. Owners and operators shall calculate daily CO_2 emissions for each fuel gas system using any of the methods specified in paragraphs (a)(1) through (a)(4) of this section. Calculate the total annual CO_2 emissions from combustion of all fuel gas by summing the CO_2 emissions from each fuel gas system.

(1) Use a CEMS that complies with the provisions in section WCI.23(d).

(2) Calculate CO_2 emissions from each refinery fuel gas system and flexigas system using measured carbon content and molecular weight of the gas and Equation 30-1.

$$CO_2 = \sum_{i=1}^{n} Fuel_i \times CC_i \times \frac{MW}{MVC} \times 3.664 \times 0.001$$ **Equation 30-1**

Where:

CO_2 = Carbon dioxide emissions, metric tons/year.
$Fuel_i$ = Daily refinery fuel or flexigas combusted (scm).
CC_i = Daily sample of carbon content of the fuel (kg C/kg fuel).
MW = Daily sample of molecular weight of fuel (kg/kg-mole).
MVC = Molar volume conversion factor (24.06 m^3/kg-mole for STP of 20°C and 1 atmosphere, or 23.67 m^3/kg-mole for STP of 60°F and 1 atmosphere).
3.664 = Conversion factor for carbon to carbon dioxide.
0.001 = Conversion factor for kg to metric tons.
n = Number of days in a year.

(3) For associated gas, low heat content gas, or other fossil fuels; follow the requirements for general stationary source combustion sources in WCI .23(b) or (c), as appropriate for each fuel.

(4) Where individual fuels are mixed prior to combustion, the operator may choose to calculate CO_2 emissions for each fuel prior to mixing instead of using the methods in paragraphs (a)(1) or (a)(2) of this section. In this case, the operator must determine the fuel flow rate and appropriate fuel specific parameters (e.g. carbon content, HHV) of each fuel stream prior to mixing, calculate CO_2 emissions for each fuel stream, and sum the emissions of the individual fuel streams to determine total CO_2 emissions from the mixture. CO_2 emissions for each fuel stream must be estimated using the following methods:

(A) For natural gas and associated gas, use the appropriate methodology specified in section WCI.23(b) or (c).

(B) For refinery fuel gas, flexigas, and low heat content gas, use the methodology in paragraph (a)(2) of this section.

(b) Calculation of CH_4 and N_2O Emissions. Owners and operators shall use the methods specified in section WCI.24 to calculate the annual CH_4 and N_2O emissions.

§ WCI.34 Sampling, Analysis, and Measurement Requirements

(a) Measure the fuel consumption rate daily using methods specified in WCI.25(b).

(b) Daily sampling and analysis to determine the carbon content and molecular weight of the fuel is required if the necessary equipment is in place to make these measurements. Otherwise, weekly sampling and analysis of carbon content and molecular weight shall be performed. The equipment necessary to perform daily sampling and analysis of carbon content and molecular weight for refinery fuel gas must be installed no later than January 1, 2012.

(c)Measure the carbon content for fuel gas and flexigas using either ASTM D1945-03 (Reapproved 2006) or ASTM D1946-90 (Reapproved 2006). Where these methods do not adequately quantify all major hydrocarbons, then an owner or operator may request use of an alternative ASTM or other method to be approved by *the regulator*.

§ WCI.35 Procedures for estimating missing data.

Whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations by following the requirements of WCI.26.

§ WCI.40 ELECTRICITY GENERATION

§ WCI.41 Source Category Definition

An electricity generating unit is any combustion device that combusts solid, liquid, or gaseous fuel for the purpose of producing electricity either for sale or for use onsite. This source category includes cogeneration (combined heat and power) units. This source category does not include portable or emergency generators less than 10 MW in nameplate generating capacity as defined in section WCI.27.

§ WCI.42 Greenhouse Gas Reporting Requirements

For each electricity generating unit, the emissions data report shall include the following information:

(a) Annual greenhouse gas emissions in metric tons, reported as follows:

(1) Total CO_2 emissions for fossil fuels, reported by fuel type.

(2) Total CO_2 emissions for all biomass fuels combined.

(3) Total CH_4 emissions for all fuels combined.

(4) Total N_2O emissions for all fuels combined.

(b) Annual fuel consumption:

(1) For gases, report in units of standard cubic meters.

(2) For liquids, report in units of kiloliters.

(3) For non-biomass solids, report in units of metric tons.

(4) For biomass-derived solid fuels, report in units of bone dry metric tons.

(c) Annual weighted average carbon content of each fuel, if used to compute CO_2 emissions as specified in WCI.43.

(d) Annual weighted average high heating value of each fuel, if used to compute CO_2 emissions as specified WCI.43.

(e) The nameplate generating capacity in megawatts (MW) and net power generated in the reporting year in megawatt hours (MWh).

(f) For each cogeneration unit, indicate whether topping or bottoming cycle and provide useful thermal output as applicable, in MJ. Where steam or heat is acquired from another facility for the generation of electricity, report the provider and amount of acquired steam or heat in MJ. Where supplemental firing has been applied to support electricity generation or industrial output, report this purpose and fuel consumption by fuel type using the units in WCI.42(b).

(g) Process CO_2 emissions from acid gas scrubbers and acid gas reagent.

(h) Fugitive emissions of HFC from cooling units that support power generation.

(i) Fugitive CO_2 emissions from geothermal facilities.

(j) Fugitive CO_2 emissions from coal storage at coal-fired electricity generating facilities shall be reported as specified in section WCI.100.

§ WCI.43 Calculation of Greenhouse Gas Emissions

(a) Calculation of CO_2 Emissions. Operators shall use CEMS to measure CO_2 emissions if required to operate a CEMS by any other federal, provincial, or local regulation and that includes both a stack gas volumetric flow rate monitor and a CO_2 concentration monitor. Operators not required to operate a CEMS by another regulation may use either CEMS or the calculation methods specified in paragraphs (a)(1) through (a)(7). Operators using CEMS to determine CO_2 emissions shall comply with the provisions in section WCI.23(d).

(1) Natural Gas. For electric generating units combusting natural gas, use one of the following methods:

(A) If the high heat value is greater than or equal to 36.3 and less than or equal to 40.98 MJ/scm use either:

(i) The measured carbon content of the fuel and calculation methodology 3 in section WCI.23(c); or

(ii) The measured heat content of the fuel and the calculation methodology 2 in section WCI.23(b), provided the facility is not subject to verification requirements by regulation.

(B) If the high heat value is less than 36.3 or greater than 40.98 MJ/scm, use the measured carbon content of the fuel and the calculation methodology 3 in section WCI.23(c).

(2) Coal or Petroleum Coke. For electric generating units combusting coal or petroleum coke, use the measured carbon content of the fuel and calculation methodology 3 in section WCI.23(c).

(3) Middle Distillates, Gasoline, Residual Oil, or Liquid Petroleum Gases. For electric generating units combusting middle distillates (such as diesel, fuel oil, or kerosene), gasoline, residual oil, or LPG (such as ethane, propane, isobutene, n-butane, or unspecified LPG), use one of the following methods:

(A) The measured carbon content of the fuel and calculation methodology 3 in section WCI.23(c); or

(B) The measured heat content of the fuel and calculation methodology 2 in section WCI.23(b) provided the facility is not subject to verification requirements by regulation.

(4) Refinery Fuel Gas, Flexigas, or Associated Gas. For electric generating units combusting refinery fuel gas, flexigas, or associated gas, use the methods specified in section WCI.30.

(5) Landfill Gas, Biogas, or Biomass. For electric generating units combusting landfill gas, biogas, or biomass, use one of the following methods:

(A) The measured carbon content of the fuel and calculation methodology 3 provided in section WCI.23(c); or

(B) The measured heat content of the fuel and calculation methodology 2 in section WCI.23(b) provided the facility is not subject to verification requirements by regulation.

(6) Municipal Solid Waste. Electric generating units combusting municipal solid waste, may use the measured steam generated, the default emission factor in WCI.20 Table 20-7, and the calculation methodology in section WCI.23(b)(2) provided the facility is not subject to verification requirements by regulation. If the facility is subject to verification requirements by regulation, the operator shall use CEMS to measure CO_2 emissions in accordance with WCI.23(d), or calculate emissions using steam flow and a CO_2 emission factor according to the provisions of WCI.23(c)(2).

(7) Start-up Fuels. The operators of generating facilities that primarily combust biomass-derived fuels but combust fossil fuels during start-up, shut-down, or malfunction operating periods only, shall calculate CO_2 emissions from fossil fuel combustion using one of the following methods:

(A) The default emission factors from Tables 20-1a, 20-2, 20-3, 20-5 or 20-7, and default HHV from Tables 20-1 or 20-1a, as applicable, and calculation methodology 1 provided in section WCI.23(a);

(B) The measured heat content of the fuel and calculation methodology 2 provided in section WCI.23(b);

(C) The measured carbon content of the fuel and calculation methodology 3 provided in section WCI.23(c); or

(D) For combustion of refinery fuel gas, the measured heat content and carbon content of the fuel, and the calculation methodology provided in section WCI.30.

(8) Co-fired Electricity Generating Units. For electricity generating units that combust more than one type of fuel, the operator shall calculate CO_2 emissions as follows.

(A) For co-fired electricity generators that burn only fossil fuels, CO_2 emissions shall be determined using one of the following methods:

(i) A continuous emission monitoring system in accordance with calculation methodology 4 in section WCI.23(d). Operators using this method need not report emissions separately for each fossil fuel.

(ii) For units not equipped with a continuous emission system, calculate the CO_2 emissions separately for each fuel type using the methods specified in paragraphs (a)(1) through (a)(4) of this section.

(B) For co-fired electricity generators that burn biomass-derived fuel with a fossil fuel, CO_2 emissions shall be determined using one of the following methods:

(i) A continuous emission monitoring system in accordance with calculation methodology 4 in section WCI.23(d). Operators using this method shall determine the portion of the total CO_2 emissions attributable to the biomass-derived fuel and portion of the total CO_2 emissions attributable to the fossil fuel using the methods specified in section WCI.23(d)(4).

(ii) For units not equipped with a continuous emission system, calculate the CO_2 emissions separately for each fuel type using the methods specified in paragraphs (a)(1) through (a)(7) of this section.

(b) Calculation of CH_4 and N_2O Emissions. Operators of electricity generating units shall use the methods specified in section WCI.24 to calculate the annual CH_4 and N_2O emissions. For coal combustion, use the default CH_4 emission factor(s) in Table 20-6.

(c) Calculation of CO_2 Emissions from Acid Gas Scrubbing. Operators of electricity generating units that use acid gas scrubbers or add an acid gas reagent to the combustion unit shall calculate the annual CO_2 emissions from these processes using Equation 40-1 if these emissions are not already captured in CO_2 emissions determined using a continuous emissions monitoring system.

$$CO_2 = S \times R \times \left(CO_{2\,MW} / Sorbent_{MW} \right)$$ **Equation 40-1**

Where:

CO_2	=	CO_2 emitted from sorbent for the report year, metric tons;
S	=	Limestone or other sorbent used in the report year, metric tons;
R	=	Ratio of moles of CO_2 released upon capture of one mole of acid gas;
$CO_{2\ MW}$	=	Molecular weight of carbon dioxide (44);
$Sorbent_{MW}$	=	Molecular weight of sorbent (if calcium carbonate, 100).

(d) Calculating Fugitive HFC Emissions from Cooling Units. Operators of electricity generating facilities shall calculate fugitive HFC emissions for each HFC compound used in cooling units that support power generation or are used in heat transfers to cool stack gases using either the methodology in paragraph (d)(1) or (d)(2). The Operator is not required to report GHG emissions from air or water cooling systems or condensers that do not contain HFCs.

(1) Use Equation 40-2 to calculate annual HFC emissions:

$$HFC = HFC_{inventory} + HFC_{purchases/acquisitions} - HFC_{sales/disbursements} + HFC_{\Delta capacity}$$ **Equation 40-2**

Where:

HFC	=	Annual fugitive HFC emission, metric tons;
$HFC_{inventory}$	=	The difference between the quantity of HFC in storage at the beginning of the year and the quantity in storage at the end of the year. Stored HFC includes HFC contained in cylinders (such as 115-pound storage cylinders), gas carts, and other storage containers. It does not include HFC gas held in operating equipment. The change in inventory will be

negative if the quantity of HFC in storage increases over the course of the year.

$HFC_{purchases/acquisitions}$ = The sum of all HFC acquired from other entities during the year either in storage containers or in equipment.

$HFC_{sales/disbursements}$ = The sum of all the HFC sold or otherwise transferred offsite to other entities during the year either in storage containers or in equipment.

$HFC_{\Delta capacity}$ = The net change in the total nameplate capacity (i.e. the full and proper charge) of the cooling equipment. The net change in capacity will be negative if the total nameplate capacity at the end of the year is less than the total nameplate capacity at the beginning of the year.

(2) Use service logs to document HFC usage and emissions from each cooling unit. Service logs should document all maintenance and service performed on the unit during the report year, including the quantity of HFCs added to or removed from the unit, and include a record at the beginning and end of each report year. The operator may use service log information along with the following simplified material balance equations to quantify fugitive HFCs from unit installation, servicing, and retirement, as applicable. The operator shall include the sum of HFC emissions from the applicable equations in the greenhouse gas emissions data report.

$$HFC_{Install} = R_{new} - C_{new}$$

$$HFC_{Service} = R_{recharge} - R_{Recover}$$

$$HFC_{Retire} = C_{retire} - R_{retire}$$

Where:

$HFC_{Install}$ = HFC emitted during initial charging/installation of the unit, kilograms;

$HFC_{Service}$ = HFC emitted during use and servicing of the unit for the report year, kilograms;

HFC_{Retire} = HFC emitted during the removal from service/retirement of the unit, kilograms;

R_{new} = HFC used to fill new unit (omit if unit was pre-charged by the manufacturer), kilograms;

C_{new} = Nameplate capacity of new unit (omit if unit was pre-charged by the manufacturer), kilograms;

$R_{recharge}$ = HFC used to recharge the unit during maintenance and service, kilograms;

$R_{recover}$ = HFC recovered from the unit during maintenance and service, kilograms;

C_{retire} = Nameplate capacity of the retired unit, kilograms; and

R_{retire} = HFC recovered from the retired unit, kilograms.

(e) Fugitive CO_2 Emissions from Geothermal Facilities. Operators of geothermal electricity generating facilities shall calculate the fugitive CO_2 emissions using one of the following methods:

(1) Calculate the fugitive CO_2 emissions using Equation 40-3:

$$CO_2 = 7.14 \times Heat \times 0.001$$ **Equation 40-3**

Where:

CO_2 = CO_2 emissions, metric tons per year;
7.14 = Default fugitive CO_2 emission factor for geothermal facilities, kg per GJ; and
Heat = Heat taken from geothermal steam and/or fluid, GJ/yr.

(2) Calculate CO_2 emissions using source specific emission factor approved by the regulator for this rule..

§ WCI.44 Sampling, Analysis, and Measurement Requirements

(a) CO_2, CH_4 and N_2O Emissions from Fuel Combustion. Operators using CEMS to estimate CO_2 emissions from fuel combustion shall comply with the requirements in section WCI.23(d). Operators using methods other than CEMS shall comply with the applicable fuel sampling, fuel consumption monitoring, heat content monitoring, carbon content monitoring, and calculation methods specified in section WCI.25.

(b) CO_2 Emissions from Acid Gas Scrubbing. Operators of electricity generating units that use acid gas scrubbers or add an acid gas reagent to the combustion unit shall measure the amount of limestone or other sorbent used during the reporting year.

(c) CO_2 Emissions from Geothermal Facilities. Operators of geothermal facilities shall measure the heat recovered from geothermal steam. If using source specific emission factor instead of the default factor, the operator shall conduct an annual test of the CO_2 emission rate using a method approved by the regulator The operator shall submit a test plan to the regulator for approval. Once approved, the annual tests shall be conducted in accordance with the approved test plan under the supervision of the regulator

§ WCI.45 Procedures for estimating missing data.

Whenever a quality-assured value of a required parameter is unavailable (e.g., if a CEMS malfunctions during unit operation or if a required fuel sample is not taken), a substitute data value for the missing parameter shall be used in the calculations.

(a) For all units using CEMS to measure CO_2 emissions, follow the missing data procedures in section WCI.26(a)

(b) For all other missing parameters used to calculate GHG emissions, follow the missing data procedures in section WCI.26(b).

§ WCI.46 Definitions

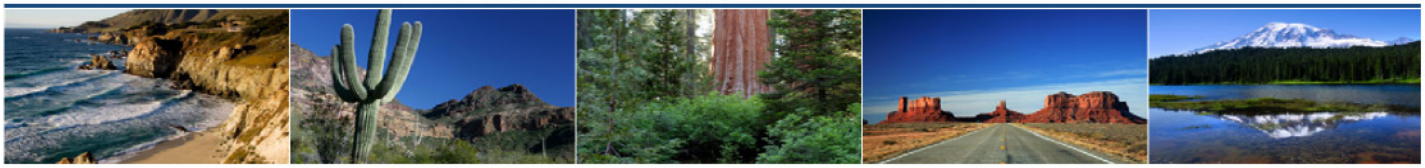
Except as specified in this section, all terms used in this subpart have the same meaning given in the General Provisions.

Bottoming cycle plant means a cogeneration plant in which the energy input to the system is first applied to a useful thermal energy application or process, and at least some of the reject heat emerging from the application or process is then used for electricity production.

Cogeneration unit means a stationary fuel combustion device which simultaneously generates electrical and thermal energy that is (i) used by the operator of the facility where the cogeneration unit is located; or (ii) transferred to another facility for use by that facility.

Cogeneration system means individual cogeneration components including the prime mover (heat engine), generator, heat recovery, and electrical interconnection, configured into an integrated system that provides sequential generation of multiple forms of useful energy (usually electrical and thermal), at least one form of which the facility consumes on-site or makes available to other users for an end-use other than electricity generation.

Topping cycle plant means a cogeneration plant in which the energy input to the plant is first used to produce electricity, and at least some of the reject heat from the electricity production process is then used to provide useful thermal output.



§ WCI.50 ADIPIC ACID MANUFACTURING

§ WCI.51 Source Category Definition

The adipic acid production source category consists of all adipic acid production facilities that use oxidation to produce adipic acid.

§ WCI.52 Greenhouse Gas Reporting Requirements

For the purpose of of the Regulation the annual emissions data report for adipic acid manufacturing shall include the following information at the facility level calculated in accordance this method:

(a) Annual process N_2O emissions from adipic acid production (tonnes).

(b) Annual adipic acid production (tonnes).

(c) Emissions of CO_2, CH_4, and N_2O from stationary combustion must report under WCI.20 (General Stationary Fuel Combustion Sources) following the requirements of WCI.20.

§ WCI.53 Calculation of N_2O Emissions

(a) You must determine annual N_2O emissions from adipic acid production according to paragraphs (a)(1) or (a)(2) of this section.

(1) Use a site-specific emission factor and production data according to paragraphs (b) through (g) of this section.

(2) Request approval by the Director for an alternative method of determining N_2O emissions.

(b) You must conduct an annual performance test or use continuous monitors according to paragraphs (b)(1) through (b)(3) of this section.

(1) You must conduct the test on the waste gas stream from the nitric acid oxidation step of the process using the methods specified in WCI.54 (b) through (d) or use a continuous monitoring system.

(2) You must conduct the performance test under normal process operating conditions and without using N_2O abatement technology or use a continuous monitoring system.

(3) You must measure the adipic acid production rate during the test and calculate the production rate for the test period or the continuous monitoring period in tonnes per hour.

(c) You must determine an N_2O emissions factor to use in Equation 50-2 of this section according to paragraphs (c)(1) or (c)(2) of this section.

(1) You may request Director approval for an alternative method of determining N_2O concentration according to the procedures in paragraphs (a)(2) of this section.

(2) Using the results of the test or continuous monitors in paragraph (b) of this section, you must calculate a facility-specific emissions factor according to Equation 50-1 for performance testing and 50-1a for continuous monitors of this section:

$$EF_{N2O} = \frac{\sum_{1}^{n} \frac{C_{N2O} * 1.826\times10^{-6} * Q}{P}}{n} \qquad \text{(Eq. 50-1)}$$

$$EF_{N2O} = \frac{C_{N2O} * 1.826\times10^{-6} * Q}{P} \qquad \text{(Equation 50-1a)}$$

Where:

EF_{N2O} = Average facility-specific N_2O emissions factor (kg N_2O generated/tonne adipic acid produced).

C_{N2O} = N_2O concentration per test run during the performance test o average hourly concentrations for continuous monitors (ppm N_2O).

$1.828x10^{-6}$ = Conversion factor (kg/dsm^3-ppm N_2O).

Q = Volumetric flow rate of effluent gas per test run during the performance test or hourly readings for continuous monitor (dsm^3/hr).

P = Production rate per test run during the performance test or the average hourly production rate for continuous monitors (tonnes adipic acid produced/hr).

n = Number of test runs.

(d) If applicable, you must determine the destruction efficiency for each N_2O abatement technology used at your facility according to paragraphs (d)(1), (d)(2), (d)(3) or (d)(4)of this section.

(1) Use the manufacturer's specified destruction efficiency.

(2) Estimate the destruction efficiency through process knowledge. Examples of information that could constitute process knowledge include calculations based on material balances, process stoichiometry, or previous test results provided the results are still relevant to the current vent stream conditions. You must document how process knowledge was used to determine the destruction efficiency.

(3) Calculate the destruction efficiency by conducting an additional performance test on the emissions stream following the N_2O abatement technology.

(4) Calculate the destruction efficiency by the use of continuous monitors on the controlled and uncontrolled emissions.

(e) If applicable, you must determine the abatement factor for each N_2O abatement technology used at your facility. The abatement factor is calculated for each adipic acid facility according to Equation 50-2 of this section.

$$AF = \frac{P_{a\ Abate}}{P_a} \qquad \text{(Eq. 50-2)}$$

Where:

AF	=	Abatement factor of N_2O abatement technology (fraction of annual production that abatement technology is operating).
Pa Abate	=	Annual adipic acid production during which N_2O abatement was used (tonne acid produced).
Pa	=	Total annual adipic acid production (tonne acid produced).

(f) You must determine the annual amount of adipic acid produced and the annual adipic acid production during which N_2O abatement is operating.

(g) You must calculate annual adipic acid production process emissions of N_2O by multiplying the emissions factor (determined using Equation 50-1 of this section) by the adipic acid production for each period and accounting for N_2O abatement, according to Equation 50-3 of this section:

$$N_2O = \sum_{i=1}^{N} \frac{EF_{N20i} * P_{ai} * (1-(DF_i * AF_i))}{1000} \qquad \text{(Eq. 50-3)}$$

Where:

N_2O	=	Annual N_2O mass emissions from adipic acid production (tonnes).
EF_{N2O}	=	Facility-specific N_2O emissions factor for the period (kg N_2O generated/tonne adipic acid produced).
P_a	=	Adipic acid produced in the period (tonnes).
DF_N	=	Destruction efficiency of N_2O abatement technology N (abatement device destruction efficiency, percent of N_2O removed from air stream).
AF_N	=	Abatement factor of N_2O abatement technology N (fraction of annual production abatement technology is operating).
1000	=	Conversion factor (kg/tonne).
N	=	Number of different periods in the year. For performance test, the period would be the time between each test (e.g., N is 1 year if performance test conducted annually). For continuous monitors, N would be the number of months in the year (or more) with P_{ai}, EF_{N2Oi}, DF_i and AF_i to be calculated for each month.

(a) You must conduct a new performance test and calculate a new facility-specific emissions factor according to the frequency specified in paragraphs (a)(1) of this section, or use continuous monitors to calculate a facility-specific emissions factor and destruction efficiency according to paragraphs (a)(2) of this section.

(1) Performance Test

(i) Conduct the performance test annually.

(ii) Conduct the performance test when your adipic acid production process is changed either by altering the ratio of cyclohexanone to cyclohexanol or by installing abatement equipment.

(2) Continuous Monitors

(i) Continuous monitors to determine the uncontrolled emissions and the controlled N_2O emissions to derive an N_2O emission factor and abatement system destruction factor.

(ii) The continuous monitors shall be operated in accordance with quality assurance and quality control program approved by the Director.

(b) You must measure the N_2O concentration during the performance test using one of the methods in paragraphs (b)(1) through (b)(3) of this section.

(1) EPA Method 320, Measurement of Vapor Phase Organic and Inorganic Emissions by Extractive Fourier Transform Infrared (FTIR) Spectroscopy in 40 CFR part 63 (U.S.), Appendix A;

(2) ASTM D6348-03 Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy (incorporated by reference, see §98.7); or

(3) An equivalent method or continuous monitors, with Director approval.

(c) You must determine the production rate(s) during the performance test according to paragraph (c)(1) or (c)(2) of this section.

(1) Direct measurement (such as using flow meters or weigh scales).

(2) Existing plant procedures used for accounting purposes.

(d) You must conduct all required performance tests according to the methods in WCI.54(b). For each test, the facility must prepare an emissions factor determination report that must include the items in paragraphs (d)(1) through (d)(3) of this section:

(1) Analysis of samples, determination of emissions, and raw data.

(2) All information and data used to derive the emissions factor.

(3) The production rate(s) during the performance test and how each production rate was determined.

(e) You must determine the monthly adipic acid production quantity and the monthly adipic acid production during which N_2O abatement technology is operating according to the methods in paragraphs (c)(1) or (c)(2) of this section.

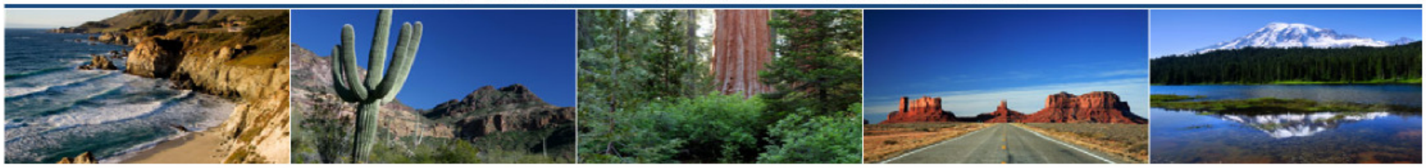
(f) You must determine the annual adipic acid production quantity and the annual adipic production quantity during which N_2O abatement technology is operating by summing the respective monthly adipic acid production quantities.

§ WCI.54 Procedures for Estimating Missing Data

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraphs (a) and (b) of this section.

(a) For each missing value of monthly adipic acid production, the substitute data shall be the best available estimate based on all available process data or data used for accounting purposes (such as sales records).

(b) For missing values related to the performance test, including emission factors, production rate, and N_2O concentration, you must conduct a new performance test according to the procedures in §98.54 (a) through (d).



§ WCI.70 PRIMARY ALUMINUM PRODUCTION

§ WCI.71 Source Category Definition

A primary aluminum production process converts alumina mineral to aluminum metal using the Hall-Héroult manufacturing process, which includes electrolysis in prebake and Søderberg cells and anode baking for prebake cells. Experimental cells or research and development process units are not included.

§ WCI.72 Greenhouse Gas Reporting Requirements

For each facility that includes a primary aluminum production process, the emissions data report must contain the following information:

(a) CO_2 emissions from anode consumption from prebaked and Søderberg electrolysis cells.

(b) CO_2 emissions from anode and cathode baking.

(c) CF_4 and C_2F_6 emissions for anode effects.

(d) CO_2 emissions from green coke calcination.

(e) SF_6 emissions from cover gas consumption.

(f) CO_2, N_2O, and CH_4 emissions from stationary combustion units as specified in WCI.20.

(g) Annual aluminum production.

(h) Type of smelter technology used.

(i) CF_4 and C_2F_6 emissions from anode effects in all prebake and all Søderberg electrolysis cells combined.

(j) Anode effect minutes per cell-day (AE-mins/cell-day), anode effect frequency (AE/cell-day), and anode effect duration (minutes); alternatively, anode effect overvoltage factor (kg CF_4/metric ton Al) , potline overvoltage (mV/cell day), and current efficiency (%).

(k) Smelter-specific slope coefficients (or overvoltage emission factors) and the last date when the smelter-specific slope coefficients (or overvoltage emission factors) were measured.

(l) Method used to measure the frequency and duration of anode effects (or overvoltage).

(m) Annual anode consumption for prebake cells.

(n) Annual CO_2 emissions from the smelter for prebake cells.

(o) Annual paste consumption for Søderberg cells.

(p) Annual CO_2 emissions from the smelter for Søderberg cells.

(q) Smelter-specific inputs to the CO_2 process equations (e.g., levels of Sulphur and ash) that were used in the calculation, on an annual basis.

§ WCI.73 Calculation of GHG Emissions

(a) Calculate CO_2 emissions from anode consumption using either Equation 70-1 or 70-2, as applicable.

(1) For Prebaked Anodes:

$$E_{CO_2} = \sum_{i=1}^{12}[NCC \times MP \times \frac{(100 - S_a - Ash_a)}{100} \times 3.664]_i \qquad \textbf{Equation 70-1}$$

Where:

E_{CO2}	=	Annual CO_2 emissions (metric tons).
NCC	=	Net anode consumption per metric ton of aluminum for month i (metric ton/ metric ton aluminum).
MP	=	Aluminum production for month i (metric ton).
S_a	=	Sulphur content in baked anodes for month i (wt %).
Ash_a	=	Ash content in baked anodes for month i (wt %).
3.664	=	Conversion factor from carbon to CO_2.

(2) For Søderberg Anodes:

$$E_{CO_2} = \sum_{i=1}^{12} \begin{bmatrix} (PC \times MP) - \left(BSM \times \frac{MP}{1000}\right) - \left(\frac{BC}{100} \times PC \times MP \times \left(\frac{S_p + Ash_p + H_p}{100}\right)\right) \\ -\left(\frac{100 - BC}{100} \times PC \times MP \times \frac{S_c + Ash_c}{100}\right) - (CD \times MP) \end{bmatrix}_i \times 3.664 \qquad \textbf{Equation 70-2}$$

Where:

E_{CO2}	=	Annual CO_2 emissions (metric tons).
PC	=	Paste consumption for month i (metric tons paste/metric ton aluminum).
MP	=	Aluminum production for month i (metric tons).
BSM	=	Emissions of benzene-soluble matter (kilograms benzene-soluble matter/metric ton aluminum).
BC	=	Average binder (pitch) content in paste for month i (wt %).
S_p	=	Sulphur content in pitch for month i (wt %).
Ash_p	=	Ash content in pitch (wt %).
H_p	=	Hydrogen content in pitch (wt %).
S_c	=	Sulphur content in calcinated coke (wt %).
Ash_c	=	Ash content in calcinated coke (wt %).
CD	=	Carbon in skimmed dust from Søderberg cells (metric ton C/metric ton aluminum).
3.664	=	Conversion factor from carbon to CO_2.

(b) If anode or cathode baking is performed onsite, calculate CO_2 emissions as specified in paragraphs (b)(1) or (2) as applicable. Total emissions as specified in paragraph (b)(3) if both (b)(1) and (2) are applicable.

(1) Calculate CO_2 emissions from packing coke using Equation 70-3.

$$EC_{CO_2} = \sum_{i=1}^{12} \left(PCC \times BAP \times \frac{100 - Ash_{pc} - S_{pc}}{100} \right)_i \times 3.664$$ **Equation 70-3**

Where:

EC_{CO2} = Annual CO_2 emissions (metric tons pre year).
PCC = Packing coke consumption per metric ton of baked anode for month i (metric tons coke/metric ton anodes).
BAP = Baked anode production for month i (metric tons).
Ash_{pc} = Ash content in packing coke for month i (wt %).
S_{pc} = Sulphur content in packing coke for month i (wt %).
3.664 = Conversion factor from carbon to CO_2.

(2) Calculate CO_2 emissions from pitch coking using Equation 70-4.

$$EP_{CO_2} = \sum_{i=1}^{12} \left(GAW - BAP - \left(\frac{H_p}{100} \times \frac{PC}{100} \times GAW \right) - RT \right)_i \times 3.664$$ **Equation 70-4**

Where:

EP_{CO2} = CO_2 emissions (metric tons pre year).
GAW = Green anode consumption for month i (metric tons).
BAP = Baked anode production for month i (metric tons).
H_p = Hydrogen content in pitch for moth i (wt %).
PC = Pitch content in green anode for month i (wt %).
RT = Recovered tar for month i (metric tons).
3.664 = Conversion factor from carbon to CO_2.

(3) Calculate total CO_2 emissions for anode baking using Equation 70-5.

$$E_{anodebaking} = EC_{CO2} + EP_{CO2}$$ **Equation 70-5**

Where:

$E_{anodebaking}$ = Total annual CO_2 emissions from anode baking (metric tons).
EC_{CO2} = Annual CO_2 emissions from packing coke (metric tons).
EP_{CO2} = Annual CO_2 emissions from pitch coking (metric tons).

(c) Calculate CF_4 emissions using either paragraph (c)(1) or (c)(2) and calculate C_2F_6 emissions using paragraph (c)(3).

(1) Calculate CF_4 emissions from anode effect duration using Equation 70-6.

$$E_{CF_4} = \sum_{i=1}^{12} [S_{CF4} \times AEM \times MP]_i$$ **Equation 70-6**

Where:

E_{CF4} = Annual emissions of CF_4 (metric tons/yr).
S_{CF4} = Slope coefficient ([Metric tons of CF_4/metric ton aluminum]/[AE minutes/cell-days]).

AEM = Anode effect frequency (AE-minutes/cell-day), calculated monthly.
MP = Monthly aluminum production (metric tons).

(2) Calculate CF_4 emissions from overvoltage using Equation 70-7.

$$E_{CF_4} = \sum_{i=1}^{12} [EF_{CF_4} \times MP]_i \quad \textbf{Equation 70-7}$$

Where:
E_{CF4} = Annual emissions of CF_4 (metric tons/yr).
EF_{CF4} = Overvoltage emission factor (Metric tons of CF_4/metric ton aluminum).
MP = Monthly aluminum production (metric tons).

(3) Calculate C_2F_6 emissions from anode effects using Equation 70-8.

$$E_{C_2F_6} = \sum_{i=1}^{12} [E_{CF_4} \times F_{C_2F_6/CF_4}]_i \quad \textbf{Equation 70-8}$$

Where:
E_{C2F6} = Annual emissions of C_2F_6 (metric tons/yr).
E_{CF4} = Monthly emissions of CF_4 (metric tons/yr).
$F_{C2F6/CF4}$ = Weight fraction of C_2F_6/CF_4 (kg C_2F_6/kg CF_4).

(d) Calculate CO_2 emissions from onsite green coke calcination furnaces using Equation 70-9.

$$E_{CO_2} = \sum_{n=1}^{12} \left[\left[GC \times \frac{(100 - H_2O_{gc} - V_{gc} - S_{gc})}{100} - (CC + UCC + DE) \times \frac{(100 - S_{cc})}{100} \right] \times 3.664 \right]_i + \left[GC \times 0.035 \times \frac{44}{16} \right]_i \quad \textbf{Equation 70-9}$$

Where:
E_{CO2} = CO_2 emissions (metric tons pre year).
GC = Green coke feed for month i (metric tons).
H_2O_{gc} = Humidity in green coke feed for month i (wt %).
V_{gc} = Volatiles in green coke feed for month i (wt %).
S_{gc} = Sulphur content in green coke feed in month i (wt %).
S_{cc} = Sulphur content in calcinated coke in month i (wt %).
CC = Calcinated coke produced in month i (metric tons).
UCC = Under-calcinated coke produced in month i (metric tons).
DE = Coke dust emissions for month i (metric tons).
3.664 = Conversion factor from carbon to CO_2.
0.035 = Assumed CH_4 and tar content in coke volatiles, contributing to CO_2 emissions.
44/16 = Conversion factor from methane to CO_2.

(e) Calculate SF_6 emissions from cover gas consumption using one of the following methods:

(1) Calculate the annual SF_6 emissions using inventory records and Equation 70-10:

$$E_{SF6} = S_{Inv-Begin} - S_{Inv-End} + S_{Purchased} - S_{Shipped}$$ **Equation 70-10**

Where:

E_{SF6}	=	SF_6 emissions from cover gas (metric tons).
$S_{Purchased}$	=	Quantity of SF_6 purchased (metric tons).
$S_{Shipped}$	=	Quantity of SF_6 shipped offsite (metric tons).
$S_{Inv-Begin}$	=	Quantity of SF_6 in storage at the beginning of the year, (metric tons).
$S_{Inv-End}$	=	Quantity of SF_6 in storage at the end of the year (metric tons).

(2) Calculate the annual SF_6 emissions using Equation 70-11 and direct measurement of the SF_6 input to electrolysis cells and the SF_6 waste gases collected and transferred off-site:

$$E_{SF6} = \sum_{i=1}^{12} [(Q_{Input} \times C_{Input}) - (Q_{Output} \times C_{Output})]_i$$ **Equation 70-11**

Where:

E_{SF6}	=	SF_6 emissions from cover gas (metric tons).
$Q_{in;put}$	=	Quantity of SF_6 input to the electrolysis cell for month i (metric tons).
C_{Input}	=	Concentration of SF_6 input to the electrolysis cell for month i (metric tons).
Q_{Output}	=	Quantity of SF_6 gas collected during month i (if applicable) (metric tons).
C_{Output}	=	Concentration of SF_6 gas collected and sent off-site during month i (metric tons).

§ WCI.74 Monitoring Requirements

(a) Except as specified in paragraphs (b) through (c) of this section, all parameters must be measured monthly.

(b) Conduct performance tests once every 36 months to determine the slope or Pechiney coefficients for each pot line using the *Protocol for Measurement of Tetrafluoromethane and Hexafluoroethane Emissions from Primary Aluminum Production,* U.S. Environmental Protection Agency and International Aluminum Institute. April 2008. The test must be repeated whenever:

(1) Thirty-six months have passed since the last measurements;

(2) A change occurs in the control algorithm that affects the mix of types of anode effects or the nature of the anode effect termination routine; or

(3) Changes occur in the distribution or duration of anode effects (e.g. when the percentage of manual kills changes or if, over time, the number of anode effects decreases and results in a fewer number of longer anode effects) or, for Rio Tinto Alcan control technology, when the algorithm for bridge movements and anode effect overvoltage accounting changes.

(c) If using the direct measurement approach in WCI.73(e)(2) to calculate SF_6 emissions from cover gas consumption, the quantity of SF_6 gas input to the electrolysis cell month and the quantity and SF_6 concentration of any waste gas collected and sent off-site must be measured.

§ WCI.75 Missing Data Procedures

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraphs (a) or (b) of this section. You must document and keep records of the procedures used for all such estimates.

(a) For each missing value of the carbon content and molecular weight, the substitute data value shall be the arithmetic average of the quality assured values of the parameter immediately preceding and immediately following the missing data incident. If no quality assured data are available prior to the missing data incident, the substitute data value shall be the first quality assured data value obtained after the missing data period.

(b) For missing feedstock and production values, the substitute data value shall be the best available estimate of the parameter, based on all available process data. You must document and retain records of the procedures used for all such estimates.

§ WCI.80 AMMONIA MANUFACTURING

§ WCI.81 Source Category Definition

The ammonia manufacturing source category comprises the process units listed in paragraphs (a) and (b) of this section.

(a) Ammonia manufacturing processes in which ammonia is manufactured from a fossil-based feedstock produced via steam reforming of a hydrocarbon.

(b) Ammonia manufacturing processes in which ammonia is manufactured through the gasification of solid and liquid raw material.

§ WCI.82 Greenhouse Gas Reporting Requirements

For the purpose of the Regulation the annual emissions data report for ammonia acid manufacturing shall include the following information at the facility level calculated in accordance this method:

(a) CO_2 process emissions from steam reforming of a hydrocarbon or the gasification of solid and liquid raw material following the requirements in this subpart.

(b) CO_2, CH_4, and N_2O emissions from each stationary fuel combustion unit. You must report these emissions under WCI.20 (General Stationary Fuel Combustion Sources), by following the requirements of WCI.20.

(c) If a CEMS is used to measure CO_2 emissions, then you must report the relevant information required under WCI.23 for Method 4 Calculation and the following information in this paragraph (a):

Annual quantity of each type of feedstock consumed for ammonia manufacturing (sm^3 of feedstock or kilolitres of feedstock or tonnes of feedstock).

(d) If a CEMS is not used to measure emissions, then you must report the following information:

(1) Whether carbon content for each feedstock is based on reports from the supplier or analysis of carbon content.

(2) If a facility uses gaseous feedstock, the carbon content of the gaseous feedstock(kg C per kg of feedstock).

(3) If a facility uses liquid feedstock, the carbon content of the liquid feedstock, for month n, (kg C per kilolitre of feedstock).

(4) If a facility uses solid feedstock, the carbon content of the solid feedstock, for month n, (kg C per kg of feedstock).

(5) Annual CO_2 emissions associated with the waste recycle stream (tonnes)

(6) Carbon content of the waste recycle stream (kg C per kg of waste recycle stream).

(7) Volume of the waste recycle stream (sm^3)

(e) Annual urea production (tonnes)

§ WCI.83 Calculating GHG emissions

You must calculate and report the annual process CO_2 emissions from each ammonia manufacturing process unit using the procedures in either paragraph (a) or (b) of this section.

(a) Calculate and report under this subpart the process CO_2 emissions by operating and maintaining CEMS according to the Tier 4 Calculation Methodology specified in WCI.23 and all associated requirements for Tier 4 in WCI.20 (General Stationary Fuel Combustion Sources).

(b) Calculate and report under this subpart process CO_2 emissions using the procedures in paragraphs (b)(1) through (b)(6) of this section for gaseous feedstock, liquid feedstock, or solid feedstock, as applicable.

(1) Gaseous feedstock. You must calculate the CO_2 process emissions from gaseous feedstock according to Equation 80-1 of this section:

$$CO_{2,G,k} = \left(\sum_{n=1}^{12} 3.664 * Fdstk_{n,k} * CC_n * \frac{MW}{MVC}\right) * 0.001 \qquad \text{(Eq. 80-1)}$$

Where:

$CO_{2,G,k}$	=	Annual CO2 emissions arising from feedstock consumption (tonnes).
$Fdstk_{n,k}$	=	Volume of the gaseous' feedstock used in month n (sm3 of feedstock).
CC_n	=	Carbon content of the gaseous feedstock, for month n, (kg C per kg of feedstock), determined according to WCI.84(c).
MW	=	Molecular weight of the gaseous feedstock (kg/kg-mole).
MVC	=	Molar volume conversion factor (24.1 sm3 per kg-mole at standard conditions).
3.664	=	Ratio of molecular weights, CO2 to carbon.
0.001	=	Conversion factor from kg to tonnes.
k	=	Processing unit.
n	=	Number of month

(2) Liquid feedstock. You must calculate, from each ammonia manufacturing unit, the CO_2 process emissions from liquid feedstock according to Equation 80-2 of this section:

$$CO_{2,L,k} = \left(\sum_{n=1}^{12} 3.664 * Fdstk_{n,k} * CC_n\right) * 0.001 \qquad \text{(Eq. 80-2)}$$

Where:

$CO_{2,L,k}$	=	Annual CO2 emissions arising from feedstock consumption (tonnes).
$Fdstk_{n,k}$	=	Volume of the liquid feedstock used in month n (kilolitres of feedstock).

CC_n	=	Carbon content of the liquid feedstock, for month n, (kg of C/kilolitre of feedstock) determined according to WCI.84(c).
3.664	=	Ratio of molecular weights, CO_2 to carbon.
0.001	=	Conversion factor from kg to tonnes.
k	=	Processing unit.
n	=	Number of month

(3) Solid feedstock. You must calculate, from each ammonia manufacturing unit, the CO_2 process emissions from solid feedstock according to Equation 80-3 of this section:

$$CO_{2,S,k} = (\sum_{n=1}^{12} 3.664 * Fdstk_{n,k} * CC_n) * 0.001 \qquad \text{(Eq. 80-3)}$$

Where:

$CO_{2,S,k}$	=	Annual CO_2 emissions arising from feedstock consumption (tonnes).
$Fdstk_{n,k}$	=	Mass of the solid feedstock used in month n (kg of feedstock).
CC_n	=	Carbon content of the solid feedstock, for month n, (kg C per kg of feedstock), determined according to WCI.84(c).
3.664	=	Ratio of molecular weights, CO2 to carbon.
0.001	=	Conversion factor from kg to tonnes.
k	=	Processing unit.
n	=	Number of month.

(4) You must calculate the annual process CO_2 emissions from each ammonia processing unit k at your facility summing emissions, as applicable from Equation 80-1, 80-2, and 80-3 of this section using Equation 80-4.

$$E_{CO2_k} = CO_{2,G} + CO_{2,S} + CO_{2,L} \qquad \text{(Eq. 80-4)}$$

Where:

E_{CO2k}	=	Annual CO_2 emissions from each ammonia processing unit k (tonnes).
k	=	Processing unit.

(5) You must determine the combined CO2 emissions from all ammonia processing units at your facility using Equation 80-5 of this section.

$$CO_2 = \sum_{k=1}^{n} E_{CO2_k} \qquad \text{(Eq. 80-5)}$$

Where:

CO_2	=	Annual combined CO_2 emissions from all ammonia processing units (tonnes).
E_{CO2k}	=	Annual CO_2 emissions from each ammonia processing unit (tonnes).
k	=	Processing unit.

n = Total number of ammonia processing units.

(6) If applicable, ammonia manufacturing facilities that utilize the waste recycle stream as a fuel must calculate emissions associated with the waste stream for each ammonia process unit according to Equation 80-6 of this section:

$$CO_2 = \left(\sum_{n=1}^{12} 3.664 * RecycleStream_n * CC_n * \frac{MW}{MVC}\right) * 0.001 \qquad \text{(Eq. 80-6)}$$

Where:

CO2 = Annual CO_2 contained in waste recycle stream (tonnes).

$RecycleStream_n$ = Volume of the waste recycle stream in month n (sm3).

CC_n = Carbon content of the waste recycle stream, for month n, (kg C per kg of waste recycle stream) determined according to WCI.84(f).

MW = Molecular weight of the waste recycle stream (kg/kg-mole).

MVC = Molar volume conversion factor (24.1 sm3 per kg-mole at standard conditions).

3.664 = Ratio of molecular weights, CO_2 to carbon.

0.001 = Conversion factor from kg to tonnes.

n = Number of month

(c) If GHG emissions from an ammonia manufacturing unit are vented through the same stack as any combustion unit or process equipment that reports CO_2 emissions using a CEMS that complies with the Tier 4 Calculation Methodology in WCI.23 (General Stationary Fuel Combustion Sources), then the calculation methodology in paragraph (b) of this section shall not be used to calculate process emissions. The owner or operator shall report under this subpart the combined stack emissions according to the Tier 4 Calculation Methodology in WCI.23 and all associated requirements for Methods 4 in WCI.23.

§ WCI.84 Monitoring and QA/QC Requirements

(a) You must continuously measure the quantity of gaseous or liquid feedstock consumed using a flow meter. The quantity of solid feedstock consumed can be obtained from company records and aggregated on a monthly basis.

(b) You must document the procedures used to ensure the accuracy of the estimates of feedstock consumption.

(c) You must determine monthly carbon contents and the average molecular weight of each feedstock consumed from reports from your supplier. As an alternative to using supplier information on carbon contents, you can also collect a sample of each feedstock on a monthly basis and analyze the carbon content and molecular weight of the fuel using any of the following methods listed in paragraphs (c)(1) through (c)(8) of this section, as applicable.

(1) ASTM D1945-03 Standard Test Method for Analysis of Natural Gas by Gas Chromatography (incorporated by reference, see regulation).

(2) ASTM D1946-90 (Reapproved 2006) Standard Practice for Analysis of Reformed Gas by Gas Chromatography (incorporated by reference, see regulation).

(3) ASTM D2502-04 (Reapproved 2002) Standard Test Method for Estimation of Mean Relative Molecular Mass of Petroleum Oils from Viscosity Measurements (incorporated by reference, see regulation).

(4) ASTM D2503-92 (Reapproved 2007) Standard Test Method for Relative Molecular Mass (Molecular Weight) of Hydrocarbons by Thermoelectric Measurement of Vapor Pressure (incorporated by reference, see regulation).

(5) ASTM D3238-95 (Reapproved 2005) Standard Test Method for Calculation of Carbon Distribution and Structural Group Analysis of Petroleum Oils by the n-d-M Method (incorporated by reference, see regulation).

(6) ASTM D5291-02 (Reapproved 2007) Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants (incorporated by reference, regulation).

(7) ASTM D3176-89 (Reapproved 2002) Standard Practice for Ultimate Analysis of Coal and Coke (incorporated by reference, see regulation).

(8) ASTM D5373-08 Standard Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal (incorporated by reference, see regulation).

(d) Calibrate all oil and gas flow meters (except for gas billing meters) and perform oil tank measurements according to the monitoring and QA/QC requirements for Method 3 in WCI.25.

(e) For quality assurance and quality control of the supplier data, on an annual basis, you must measure the carbon contents of a representative sample of the feedstocks consumed using the appropriate ASTM Method as listed in paragraphs (c)(1) through (c)(8) of this section.

(f) Facilities must continuously measure the quantity of waste gas recycled using a flow meter, as applicable. You must determine the carbon content and the molecular weight of the waste recycle stream by collecting a sample of each waste recycle stream on a monthly basis and analyzing the carbon content using the appropriate ASTM Method as listed in paragraphs (c)(1) through (c)(8) of this section.

(g) If CO_2 from ammonia production is used to produce urea at the same facility, you must determine the quantity of urea produced using methods or plant instruments used for accounting purposes (such as sales records). You must document the procedures used to ensure the accuracy of the estimates of urea produced.

§ WCI.85 Procedures for Estimating Missing Data

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever the monitoring and quality assurance procedures in WCI.84 cannot be followed (e.g., if a meter malfunctions during unit operation), a substitute data value for the missing parameter shall be used in the calculations following paragraphs (a) and (b) of this section. You must document and keep records of the procedures used for all such estimates.

(a) For missing data on monthly carbon contents of feedstock or the waste recycle stream, the substitute data value shall be the arithmetic average of the quality-assured values of that carbon content in the month preceding and the month immediately following the missing data incident. If no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value for carbon content obtained in the month after the missing data period.

(b) For missing feedstock supply rates or waste recycle stream used to determine monthly feedstock consumption or monthly waste recycle stream quantity, you must determine the best available estimate(s) of the parameter(s), based on all available process data.

§ WCI.90 CEMENT MANUFACTURING

§ WCI.91 Source Category Definition

Cement manufacturing is comprised of all processes that are used to manufacture Portland, natural, masonry, pozzolanic, or other hydraulic cements.

§ WCI.92 Greenhouse Gas Reporting Requirements

In addition to the information required by regulation, the annual emissions data report shall contain the following information:

(a) Total emissions of CO_2, CH_4, and N_2O in metric tons.

(b) Annual CO_2 process emissions from calcination (metric tons) and the following information:

(1) Monthly plant specific clinker emission factors (metric tons CO_2/metric tons clinker).

(A) Monthly quantities of clinker produced (metric tons).

(B) Monthly total calcium content of clinker, expressed as calcium oxide (CaO) (weight fraction, tonne CaO/tonne clinker).

(C) Monthly total magnesium content of clinker, expressed as magnesium oxide (MgO) (weight fraction, tonne CaO/tonne clinker).

(D) Monthly non-calcined calcium oxide content of clinker, expressed as CaO (weight fraction, tonne CaO/tonne clinker).

(E) Monthly non-calcined magnesium oxide content of clinker, expressed as MgO (weight fraction, tonne MgO/tonne clinker).

(F) Monthly quantity of non-carbonate raw materials entering the kiln (metric tons).

(2) Quarterly cement kiln dust (CKD) emission factor (metric ton CO_2/metric ton CKD not recycled back to the kiln).

(A) Quarterly quantity of CKD not recycled back to the kiln (metric tons).

(c) CO_2 process emissions from organic carbon oxidation (metric tons) and the following information:

(1) Amount of raw material consumed in the report year (metric tons).

(2) Organic carbon content of raw material (wt. fraction).

(d) CO_2, CH_4, and N_2O emissions from fuel combustion in all kilns combined, following the calculation methods and reporting requirements specified in WCI.93(c) (metric tons).

(e) CO_2, CH_4, and N_2O emissions from all other fuel combustion units combined (kilns excluded), following the calculation methods and reporting requirements specified in WCI.20 (metric tons).

(f) If a continuous emissions monitor is used to measure CO_2 emissions from kilns, then the requirements of paragraphs (b) and (c) of this section do not apply for CO_2. Cement plants that measure CO_2 emissions using CEMS shall report fuel usage by fuel type for kilns.

(g) Operators of cement plants shall also comply with the reporting requirements for any other applicable source category listed by regulation, including but not limited to the following:

(1) Coal fuel storage as specified in WCI.100.

(2) Electricity generating as specified in WCI.40.

(3) Cogeneration systems as specified in WCI.42(f).

(h) Number of times missing data procedures were used to determine clinker production, non-calcined calcium oxide, magnesium oxide content of clinker, CKD not recycled, non-calcined calcium oxide, magnesium oxide content of CKD, organic carbon content, and raw material consumption.

§ WCI.93 Calculation of Greenhouse Gas Emissions From Kilns

(a) Determine CO_2 emissions as specified under either paragraph (a)(1) or (a)(2) of this section.

(1) Calculate the total process and combustion CO_2 emissions from all the kilns using a continuous emissions monitoring system (CEMS) as specified in WCI.23(d) and combustion CO_2 emissions from all the kilns using the calculation methodologies specified in paragraph (c) of this section.

(2) Calculate the sum of CO_2 process emissions from kilns and CO_2 fuel combustion emissions from kilns using the calculation methodologies specified in paragraph (b) and (c) of this section.

(b) Process CO_2 Emissions Calculation Methodology. Calculate total CO_2 process emissions as the sum of emissions from calcination, using the method specified in paragraph (b)(1) of this section; and from organic carbon oxidation, using the method specified in paragraph (b)(2) of this section (Equation 90-1).

$$E_{CO2\text{-}P} = E_{CO2\text{-}C} + E_{CO2\text{-}F} \qquad \textbf{Equation 90-1}$$

Where:

$E_{CO2\text{-}P}$ = Annual process CO_2 emissions, tonne/year.
$E_{CO2\text{-}C}$ = Annual process CO_2 emissions from calcination, tonne/year.
$E_{CO2\text{-}F}$ = Annual process CO_2 emissions from feed oxidation, tonne/year.

(1) Calcination Emissions. Calculate CO_2 process emissions from calcination using Equation 90-2 and a plant-specific clinker emission factor and a plant-specific cement kiln dust (CKD) emission factor as specified in this section.

$$E_{CO2-C} = \sum_{m=1}^{12}\left[Q_{cli,m} \times EF_{cli,m}\right] + \sum_{q}^{4}\left[Q_{CKD,q} \times EF_{CKD,q}\right] \qquad \textbf{Equation 90-2}$$

Where:

E_{CO2-C} = Annual process CO_2 emissions from calcination, metric tons.
$Q_{Cli,m}$ = Quantity of clinker produced in month m, metric tons.
$EF_{Cli,m}$ = CO_2 emission factor for clinker produced in month m, computed as specified in paragraph (b)(1)(A) of this section, metric tons CO_2/metric ton clinker.
$Q_{CKD,q}$ = Quantity CKD not recycled to the kiln in quarter q, metric tons.
$EF_{CKD,q}$ = CO_2 emission factor for CKD not recycled to the kiln in quarter q, computed as specified in paragraph (b)(1)(B) of this section, metric ton CO_2/metric ton CKD.

(A) Clinker Emission Factor. Calculate a plant-specific clinker emission factor (EF_{Cli}) for each month based on monthly measurements of the weight fractions of calcium (as CaO) and magnesium (as MgO) content in the clinker and in the non-carbonate raw materials entering the kiln, using Equation 90-3

$$EF_{Cli} = (CaO_{Cli} - CaO_f) \times 0.785 + (MgO_{Cli} - MgO_f) \times 1.092$$ **Equation 90-3**

EF_{Cli} = Monthly CO_2 emission factor for clinker, tonne CO_2/tonne clinker
CaO_{Cli} = Monthly total calcium content of clinker expressed as calcium oxide, tonne CaO/tonne clinker..
CaO_f = Monthly non-calcined calcium oxide content of clinker, tonne CaO/tonne clinker.
MgO_{Cli} = Monthly total magnesium content of clinker expressed as magnesium oxide, tonne MgO/tonne clinker.
MgO_f = Monthly non-calcined magnesium oxide content of clinker, tonne MgO/tonne clinker.
0.785 = Ratio of molecular weights of CO_2 to CaO
1.092 = Ratio of molecular weights of CO_2 to MgO

(B) CKD Emission Factor. If CKD is generated and not recycled back to the kiln, then calculate a plant-specific CKD emission factor based on quarterly sampling. The CKD emission factor shall be calculated using Equation 90-4.

$$EF_{CKD} = (CaO_{CKD} - CaO_f) \times 0.785 + (MgO_{ckd} - MgO_f) \times 1.092$$

Equation 90-4

Where:

EF_{CKD} = Quarterly CO_2 emission factor for CKD not recycled to the kiln, metric ton CO_2/metric ton CKD.

CaO_{CKD} = Quarterly total calcium oxide content of CKD, tonne CaO/tonne CKD.

CaO_f = Quarterly non-calcined calcium oxide content of CKD, tonne CaO/tonne CKD.

MgO_{CKD} = Quarterly total magnesium oxide content of CKD, tonne MgO/tonne CKD.

MgO_f = Quarterly non-calcined magnesium oxide content of CKD, tonne MgO/tonne CKD.

0.785 = Ratio of molecular weights of CO_2 to CaO

1.092 = Ratio of molecular weights of CO_2 to MgO

(2) Organic Carbon Oxidation Emissions. Calculate CO_2 process emissions from the total organic content in raw materials by using Equation 90-5.

$$E_{CO_2-F} = TOC_{RM} \times RM \times 3.664 \qquad \textbf{Equation 90-5}$$

Where:

$E_{CO2-F\backslash}$ = Annual process CO_2 emissions from raw material oxidation, metric tons.
TOC_{RM} = Total organic carbon content in raw material (wt. fraction), measured using the method in WCI.94(b) or using a default of 0.002 (0.2%).
RM = Amount of raw material consumed (metric tons/yr).
3.664 = The CO_2 to carbon molar ratio.

(c) Fuel Combustion Emissions in Kilns. Calculate CO_2, CH_4, and N_2O emissions from stationary fuel combustion following the calculation methods specified in WCI.20. Cement plants that combust pure biomass-derived fuels and combust fossil fuels only during periods of start-up, shut-down, or malfunction may report CO_2 emissions from fossil fuels using the emission factor methodology in WCI.23(a). "Pure" means that the biomass-derived fuels account for 97 percent of the total amount of carbon in the fuels burned.

§ WCI.94 Sampling, Analysis, and Measurement Requirements

(a) Determine the plant-specific weight fractions of total calcium (as CaO) and total magnesium (as MgO) in clinker and in non-carbonate raw material entering the kiln using ASTM C114-09 Determine the weight fraction of carbonate CO_2 in the CKD and the weight fraction of carbonate CO_2 in the raw material using ASTM C114-07. The monitoring must be conducted monthly from clinker, non-carbonate raw material, and CKD samples drawn from bulk storage.

(b) If not using the default value of 0.002 for TOC_{RM} in Equation 90-5, the total organic carbon contents of raw materials must be determined annually using ASTM Method C114-09 a similar industry standard practice or approved method. The analysis must be conducted on sample material drawn from bulk raw material storage for each category of raw material.

(c) The quantity of clinker produced must be determined by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.

(d) The quantity of CKD not recycled back to the kiln must be determined by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.

(e) The quantity of raw materials consumed (i.e. limestone, sand, shale, iron oxide, alumina, and non-carbonate raw material) must be determined by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.

§ WCI.95 Procedures for Estimating Missing Data

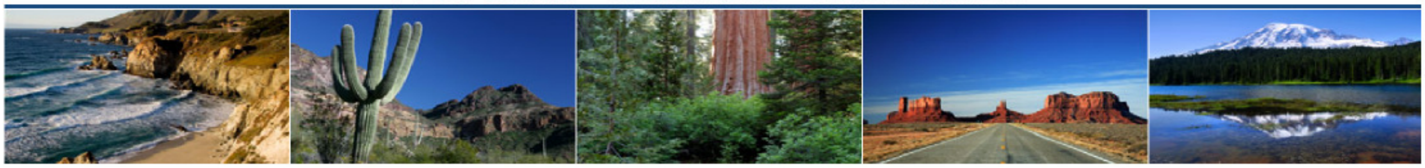
A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations. The owner or operator must document and keep records of the procedures used for all such estimates.

(a) If the CEMS approach is used to determine combined process and combustion CO_2 emissions, the missing data procedures in WCI.20 apply.

(b) For CO_2 process emissions from cement manufacturing facilities calculated according to WCI.93(b), if data on the carbonate content (of clinker or CKD), noncalcined content (of clinker or CKD) or the annual organic carbon content of raw materials are missing, facilities must undertake a new analysis.

(c) For each missing value of monthly clinker production, the substitute data value must be the best available estimate of the monthly clinker production based on information used for accounting purposes, or use the maximum tons per day capacity of the system and the number of days per month.

(d) For each missing value of monthly raw material consumption, the substitute data value must be the best available estimate of the monthly raw material consumption based on information used for accounting purposes (such as purchase records), or use the maximum tons per day raw material throughput of the kiln and the number of days per month.



§ WCI.100 COAL STORAGE

§ WCI.101 Source Category Definition

Coal storage piles are located at any facilities that combust coal. Coal storage piles release fugitive CH_4 emissions. Within natural coal deposits, CH_4 is either trapped under pressure within porous void spaces or adsorbed to the coal. Coal mining, post-mining activities, and coal-handling activities release pressurized CH_4 to the atmosphere; adsorbed CH_4 is also released until the CH_4 in the coal reaches equilibrium with the surrounding atmospheric conditions.

§ WCI.102 Greenhouse Gas Reporting Requirements

The emissions data report shall include the following information at the facility level:

(a) Annual greenhouse gas emissions in metric tons, reported as follows:

(1) Total CH_4 emissions.

(b) Annual coal purchases (tons for U.S.; metric tons for Canada).

(c) Source of coal purchases:

(1) Coal basin.

(2) State/province.

(3) Coal mine type (surface or underground).

§ WCI.103 Calculation of CH_4 Emissions

Note that this methodology for calculation of methane emissions uses emission factors for post-mining operations including all processes occurring after mining at the coal deposit and prior to combustion (e.g., preparation, handling, processing, transportation, storage, etc.) even though coal storage piles are only a subset of the overall post-mining operations. This follows the approach in the Climate Action Reserve (formerly the California Climate Action Registry) reporting protocol, attributing all post-mining fugitive methane emissions to the facility combusting the coal, which is ultimately responsible for the coal having been processed and delivered to the facility.

Calculate fugitive CH_4 emissions from coal storage piles as specified under paragraph (a), (b), or (c) of this section.

(a) For coal purchased from U.S. sources, calculate fugitive CH_4 emissions using Equation 100-1 (English) and Table 100-1, or Equation 100-1 (Metric) and Table 100-2.

(b) For coal purchased from Canadian sources, calculate fugitive CH_4 emissions using Equation 100-1 (Metric) and Table 100-3.

(c) For coal purchased from non-U.S. and non-Canadian sources, owners or operators should use either WCI.103(a) or WCI.103(b), whichever is the most applicable. This chosen approach is subject to approval by the regulator.

$$CH_4 = \sum_i (PC_i \times EF_i) \times 0.04228 \ / \ 2{,}204.6$$ **Equation 100-1 (English Units)**

Where:

CH_4	=	Fugitive emissions from coal storage piles for each coal category *i* (metric tons CH_4 per year);
PC_i	=	Purchased coal for each coal category *i* (tons per year);
EF_i	=	Default CH_4 emission factor for each coal category *i* specified by location and mine type that coal originated from, provided in Table 100-1 (scf CH_4 per ton of coal);
0.04228	=	Methane conversion factor to convert scf to lbs;
2,204.6	=	Factor to convert lbs to metric tons.

$$CH_4 = \sum_i (PC_i \times EF_i) \times 0.6772 \ / \ 1{,}000$$ **Equation 100-1 (Metric Units)**

Where:

CH_4	=	Fugitive emissions from coal storage piles for each coal category *i*, (metric tons CH_4 per year);
PC_i	=	Purchased coal for each coal category *i* (metric tons per year);
EF_i	=	Default CH_4 emission factor for each coal category *i* specified by location and mine type that coal originated from, provided in Table 100-2 or Table 100-3 (m^3 CH_4 per metric ton of coal);
0.6772	=	Methane conversion factor to convert m^3 to kg;
1,000	=	Factor to convert kg to metric tons.

§ WCI.104 Sampling, Analysis, and Measurement Requirements

(a) Coal Purchase Monitoring Requirements.

Facilities may determine the quantity of coal purchased either using records provided by the coal supplier(s) or monitoring coal purchase quantities using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.

§ WCI.105 Procedures for Estimating Missing Data

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraph (a) of this section. You must document and keep records of the procedures used for all such estimates.

(a) For missing feedstock and production values, the substitute data value shall be the best available estimate of the parameter, based on all available process data. You must document and retain records of the procedures used for all such estimates.

Table 100-1. U.S. Default Fugitive Methane Emission Factors from Post-Mining Coal Storage and Handling (CH_4 ft^3 per Short Ton)

Coal Origin		Coal Mine Type	
Coal Basin	**States**	**Surface Post-Mining Factors**	**Underground Post-Mining Factors**
Northern Appalachia	Maryland, Ohio, Pennsylvania, West Virginia North	19.3	45.0
Central Appalachia (WV)	Tennessee, West Virginia South	8.1	44.5
Central Appalachia (VA)	Virginia	8.1	129.7
Central Appalachia (E KY)	East Kentucky	8.1	20.0
Warrior	Alabama, Mississippi	10.0	86.7
Illinois	Illinois, Indiana, Kentucky West	11.1	20.9
Rockies (Piceance Basin)	Arizona, California, Colorado, New Mexico, Utah	10.8	63.8
Rockies (Uinta Basin)		5.2	32.3
Rockies (San Juan Basin)		2.4	34.1
Rockies (Green River Basin)		10.8	80.3
Rockies (Raton Basin)		10.8	41.6
N. Great Plains	Montana, North Dakota, Wyoming	1.8	5.1
West Interior (Forest City, Cherokee Basins)	Arkansas, Iowa, Kansas, Louisiana, Missouri, Oklahoma, Texas	11.1	20.9
West Interior (Arkoma Basin)		24.2	107.6
West Interior (Gulf Coast Basin)		10.8	41.6
Northwest (AK)	Alaska	1.8	52.0
Northwest (WA)	Washington	1.8	18.9

Source: *Inventory of U.S. Greenhouse Gas Emissions and Sinks:1990 – 2005* April 15, 2007, U.S. Environmental Protection Agency. Annex 3, Methodological Descriptions for Additional Source or Sink Categories, Section 3.3, Table A-115, Coal Surface and Post-Mining CH_4 Emission Factors (ft^3 per Short Ton). (Only Post-Mining EFs used from Table). State assignments shown from Table 113 of Annex 3.

Table 100-2. U.S. Default Fugitive Methane Emission Factors from Post-Mining Coal Storage and Handling (CH_4 m^3 per Metric Ton)

Coal Origin		Coal Mine Type	
Coal Basin	**States**	**Surface Post-Mining Factors**	**Underground Post-Mining Factors**
Northern Appalachia	Maryland, Ohio, Pennsylvania, West Virginia North	0.6025	1.4048
Central Appalachia (WV)	Tennessee, West Virginia South	0.2529	1.3892
Central Appalachia (VA)	Virginia	0.2529	4.0490
Central Appalachia (E KY)	East Kentucky	0.2529	0.6244
Warrior	Alabama, Mississippi	0.3122	2.7066
Illinois	Illinois, Indiana, Kentucky West	0.3465	0.6525

Rockies (Piceance Basin)	Arizona, California, Colorado, New Mexico, Utah	0.3372	1.9917
Rockies (Uinta Basin)		0.1623	1.0083
Rockies (San Juan Basin)		0.0749	1.0645
Rockies (Green River Basin)		0.3372	2.5068
Rockies (Raton Basin)		0.3372	1.2987
N. Great Plains	Montana, North Dakota, Wyoming	0.0562	0.1592
West Interior (Forest City, Cherokee Basins)	Arkansas, Iowa, Kansas, Louisiana, Missouri, Oklahoma, Texas	0.3465	0.6525
West Interior (Arkoma Basin)		0.7555	3.3591
West Interior (Gulf Coast Basin)		0.3372	1.2987
Northwest (AK)	Alaska	0.0562	1.6233
Northwest (WA)	Washington	0.0562	0.5900

Source: *Inventory of U.S. Greenhouse Gas Emissions and Sinks:1990 – 2005* April 15, 2007, U.S. Environmental Protection Agency. Annex 3, Methodological Descriptions for Additional Source or Sink Categories, Section 3.3, Table A-115, Coal Surface and Post-Mining CH_4 Emission Factors (ft^3 per Short Ton; converted to m^3 per metric ton). (Only Post-Mining EFs used from Table). State assignments shown from Table 113 of Annex 3.

Table 100-3. Canada Default Fugitive Methane Emission Factors from Post-Mining Coal Storage and Handling (CH_4 m^3 per Metric Ton)

Coal Origin		Coal Mine Type	
Province	**Coalfield**	**Surface Post-Mining Factors**	**Underground Post-Mining Factors**
British Columbia	Comox	0.500	n/a
	Crowness	0.169	n/a
	Elk Valley	0.900	n/a
	Peace River	0.361	n/a
	Province Average	0.521	n/a
Alberta	Battle River	0.067	n/a
	Cadomin-Luscar	0.709	n/a
	Coalspur	0.314	n/a
	Obed Mountain	0.238	n/a
	Sheerness	0.048	n/a
	Smokey River	0.125	0.067
	Wabamun	0.176	n/a
	Province Average	0.263	0.067
Saskatchewan	Estavan	0.055	n/a
	Willow Bunch	0.053	n/a
	Province Average	0.054	n/a
New Brunswick	Province Average	0.060	n/a
Nova Scotia	Province Average	n/a	2.923

Source: *Management of Methane Emissions from Coal Mines: Environmental, Engineering, Economic and Institutional Implications of Options*. Prepared by Brian G. King, Neill and Gunter (Nova Scotia) Limited, Darmouth, Nova Scotia for Environment Canada. Contract Number K2031-3-7062. March 1994. This document is cited by Environment Canada in the NIR 1990-2007 (Final Submission, April 2009), , but post-mining emission factors are not provided, so they were developed for WCI purposes by Province. Surface emission factors were derived from Table 3.1 (Coal production statistics [Column A] and post-mining emissions [Column F]). Underground emission factors were derived from Table 3.2 (Coal production statistics and post-mining emissions).

§ WCI.130 HYDROGEN PRODUCTION

§ WCI.131 Source Category Definition

A hydrogen production process produces hydrogen gas by steam hydrocarbon reforming, partial oxidation of hydrocarbons, or other transformation of hydrocarbon feedstock. The hydrogen produced may be either transferred offsite or used onsite at petrochemical, ammonia production, refineries, and other plants.

§ WCI.132 Greenhouse Gas Reporting Requirements

For each facility, the annual emissions report must contain the following information:

(a) Process CO_2 Emissions. The CO_2 process emissions from the hydrogen production process.

(b) Feedstock Consumption (if estimating emissions using mass balance approach in WCI.133(b)). Annual feedstock consumption by feedstock type (including petroleum coke) reported in units of million standard cubic feet for gases, gallons for liquids, short tons for non-biomass solids, and bone dry short tons for biomass-derived solid fuels.

(c) Production. Annual hydrogen produced (metric tons).

(d) Stationary Combustion Units. Report CO_2, N_2O, and CH_4 emissions as specified in WCI.20.

(e) Unconverted feedstock. Report the amount of carbon in unconverted feedstock for which GHG emissions are calculated and reported by your facility using other calculation methods provided in this regulation. For example, carbon in waste diverted to a fuel system or flare, where the CO_2 and CH_4 emissions are calculated and reported using other methods provided in this regulation. (metric tons CO_2e/year).

§ WCI.133 Calculation of Greenhouse Gas Emissions

The owner or operator shall calculate and report CO_2 process emissions using the methods in paragraphs (a) or (b) of this section.

(a) Continuous Emission Monitoring Systems. The owner or operator may calculate CO_2 process emissions using CEMS. The owner or operator must comply with the requirements in section WCI.20.

(b) Feedstock Material Balance. The owner or operator may calculate CO_2 process emissions using the following method.

(1) Gaseous fuel and feedstock. You must calculate the annual CO_2 process emissions from gaseous fuel and feedstock according to Equation 130-1 of this section:

$$CO_2 = (\sum_{n=1}^{k} \frac{44}{12} * Fdstk_n * CC_n * \frac{MW}{MVC}) * 0.001 \qquad \textbf{Equation 130-1}$$

Where:

CO_2	=	Annual CO_2 process emissions arising from fuel and feedstock consumption (metric tons/yr).
$Fdstk_n$	=	Volume of the gaseous fuel and feedstock used in month n (m^3 at standard conditions of 20°C and 1 atmosphere) of fuel and feedstock).
CC_n	=	Weighted average carbon content of the gaseous fuel and feedstock, from the results of one or more analyses for month n for natural gas or from daily analysis for gasseous feedstocks other than natural gas ((kg carbon per kg of fuel and feedstock).
MW	=	Molecular weight of the gaseous fuel and feedstock (kg/kg-mole).
MVC	=	Molar volume conversion factor (24.06 m^3/kg-mole for STP of 20°C and 1 atmosphere).
k	=	Months in the year.
44/12	=	Ratio of molecular weights, CO_2 to carbon.
0.001	=	Conversion factor from kg to metric tons.

(2) Liquid fuel and feedstock. You must calculate the annual CO_2 process emissions from liquid fuel and feedstock according to Equation 130-2 of this section:

$$CO_2 = (\sum_{n=1}^{k} \frac{44}{12} * Fdstk_n * CC_n) * 0.001 \qquad \textbf{Equation 130-2}$$

Where:

CO_2	=	Annual CO_2 emissions arising from fuel and feedstock consumption (metric tons/yr).
$Fdstk_n$	=	Volume of the liquid fuel and feedstock used in month n (m^3 of fuel and feedstock).
CC_n	=	Weighted Average carbon content of the liquid fuel and feedstock, from the results of daily analyses for month n (kg carbon per m^3 of fuel and feedstock).
k	=	Months in the year.
44/12	=	Ratio of molecular weights, CO_2 to carbon.
0.001	=	Conversion factor from kg to metric tons.

(3) Solid fuel and feedstock. You must calculate the annual CO_2 process emissions from solid fuel and feedstock according to Equation 130-3 of this section:

$$CO_2 = \sum_{n=1}^{k} \frac{44}{12} * (Fdstk_n * CC_n) * 0.001 \qquad \textbf{Equation 130-3}$$

Where:

CO_2	=	Annual CO_2 emissions from fuel and feedstock consumption in metric tons per year month ((metric tons/yr).
$Fdstk_n$	=	Mass of solid fuel and feedstock used in month n (kg of fuel and feedstock).
CC_n	=	Weighted average carbon content of the solid fuel and feedstock, from the results of daily analyses for month n (kg carbon per kg of fuel and feedstock).
k	=	Months in the year.
44/12	=	Ratio of molecular weights, CO_2 to carbon.
0.001	=	Conversion factor from kg to metric tons.

(c) If GHG emissions from a hydrogen production process unit are vented through the same stack as any combustion unit or process equipment that reports CO_2 emissions using a CEMS that complies with WCI.20, then the calculation methodology in paragraph (b) of this section shall not be used to calculate process emissions. The owner or operator shall report the combined stack emissions according to the CEMS methodology in WCI.20.

§ WCI.134 Sampling, Analysis, and Measurement Requirements

(a) Owners or operators using CEMS to estimate CO_2 emissions shall comply with the monitoring requirements in section WCI.20.

(b) Owners or operators using the methods in section WCI.133 (b) or paragraph (c) of this section shall perform the following monitoring:

(1) The owner or operator shall measure the feedstock consumption rate daily Weighted average carbon contents shall be established from the results of daily sampling for month n. For fuels other than gaseous fuels, daily samples may be combined to generate a monthly composite sample for carbon analysis.

(2) The owner or operator shall collect samples of each feedstock consumed and analyze each sample for carbon content using the methods specified in WCI.25(c). For natural gas feedstock not mixed with another feedstock prior to consumption, samples shall be collected and analyzed once per month. For all other feedstocks, samples shall be collected and analyzed daily. The samples shall be collected from a location in the feedstock handling system that provides samples representative of the feedstock consumed in the hydrogen production process.

(3) Owners or operators shall measure the hydrogen produced daily.

(4) Owners or operators shall measure the CO_2 and CO collected daily.

(c) You must use the following methods, as applicable, to determine the carbon content of the feedstocks:

(1) ASTM D2013–07 Standard Practice of Preparing Coal Samples for Analysis.

(2) ASTM D2234/D2234M–07 Standard Practice for Collection of a Gross Sample of Coal.

(3) ASTM D2597–94 (Reapproved 2004) Standard Test Method for Analysis of Demethanized Hydrocarbon Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography.

(4) ASTM D3176–89 (Reapproved 2002), Standard Practice for Ultimate Analysis of Coal and Coke.

(5) ASTM D4057–06 Standard Practice for Manual Sampling of Petroleum and Petroleum Products.

(6) ASTM D4177–95 (Reapproved 2005) Standard Practice for Automatic Sampling of Petroleum and Petroleum Products.

(7) ASTM D6609–08 Standard Guide for Part-Stream Sampling of Coal.

(8) ASTM D6883–04 Standard Practice for Manual Sampling of Stationary Coal from Railroad Cars, Barges, Trucks, or Stockpiles.

(9) ASTM D7430–08ae1 Standard Practice for Mechanical Sampling of Coal.

(10) ASTM UOP539–97 Refinery Gas Analysis by Gas Chromatography.

(11) GPA 2261–00 Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography.

(12) ISO 3170: Petroleum Liquids— Manual sampling—Third Edition.

(13) ISO 3171: Petroleum Liquids— Automatic pipeline sampling—Second Edition.

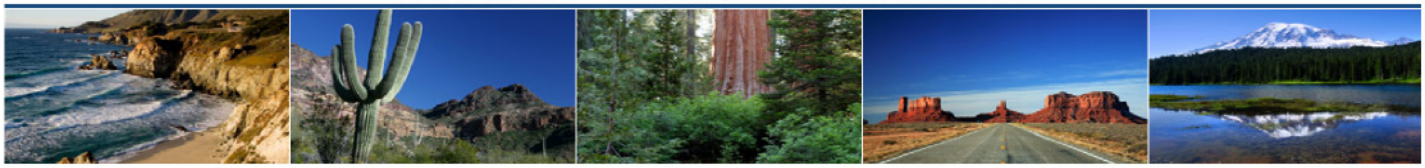
§ WCI.135 Procedures for Estimating Missing Data

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation), a substitute data value for the missing parameter must be used in the calculations as specified in paragraphs (a), (b), and (c) of this section:

(a) For each missing value of the monthly fuel and feedstock consumption, the substitute data value must be the best available estimate of the fuel and feedstock consumption, based on all available process data (e.g., hydrogen production, electrical load, and operating hours). You must document and keep records of the procedures used for all such estimates.

(b) For each missing value of the carbon content or molecular weight of the fuel and feedstock, the substitute data value must be the arithmetic average of the quality-assured values of carbon contents or molecular weight of the fuel and feedstock immediately preceding and immediately following the missing data incident. If no quality-assured data on carbon contents or molecular weight of the fuel and feedstock are available prior to the missing data incident, the substitute data value must be the first quality-assured value for carbon contents or molecular weight of the fuel and feedstock obtained after the missing data period. You must document and keep records of the procedures used for all such estimates.

(c) For missing CEMS data, you must use the missing data procedures in WCI.20.



§ WCI.140 GLASS PRODUCTION

§ WCI.141 Source Category Definition

A glass manufacturing facility manufactures flat glass, container glass, pressed and blown glass, or wool fiberglass by melting a mixture of raw materials to produce molten glass and form the molten glass into sheets, containers, fibers, or other shapes. A glass manufacturing facility uses one or more glass melting furnaces to produce glass. A glass melting furnace that is an experimental furnace or a research and development process unit is not subject to this subpart.

§ WCI.142 Greenhouse Gas Reporting Requirements

For the purpose of the Regulation the annual emissions data report shall include the following information:

(a) Total CO_2 process emissions from all glass melting furnaces.

(b) Total CO_2, CH_4 and N_2O combustion emissions from all glass melting furnaces. You must calculate and report these emissions under WCI.20 (General Stationary Fuel Combustion Sources) by following the requirements of WCI.20.

(c) Total CO_2, CH_4, and N_2O emissions from all stationary fuel combustion units other than glass melting furnaces. You must report these emissions under WCI.23 (General Stationary Fuel Combustion Sources) by following the requirements of WCI.20.

(d) If a CEMS is used to measure CO_2 emissions, then you must report under this method the relevant information required under WCI.23(d) for the Calculation Methodology 4 and the following information:

Annual quantity of glass produced (tonnes).

(e) If a CEMS is not used to determine CO_2 emissions from glass melting furnaces, and process CO_2 emissions are calculated according to the procedures specified in WCI.143(b), then you must report the following information:

(1) Annual quantity of each carbonate-based raw material charged (tonnes)for all furnaces combined.

(2) Annual quantity of glass produced (tonnes) from all furnaces combined.

(3) Total number of glass melting furnaces.

(f) The number of times in the reporting year that missing data procedures were followed to measure monthly quantities of carbonate-based raw materials or mass fraction of the carbonate-based minerals for each glass melting furnace

§ WCI.143 Calculation of GHG Emissions

You must calculate the annual process CO_2 emissions from each glass melting furnace using the procedure in paragraphs (a) and (b) of this section.

(a) For each glass melting furnace that meets the conditions specified in WCI.23(e)(4), you must calculate under this source the combined process and combustion CO_2 emissions by operating and maintaining a CEMS to measure CO_2 emissions according to the method 4 calculation methodology specified in WCI.23(d) and all associated requirements in WCI.20 (General Stationary Fuel Combustion Sources).

(b) For each glass melting furnace that is not subject to the requirements in paragraph (a) of this section, use either the procedure in paragraph (b)(1) of this section or the procedure in paragraphs (b)(2) through (b)(7) of this section, except as specified in paragraph (c) of this section.

(1) Calculate the combined process and combustion CO_2 emissions by operating and maintaining a CEMS to measure CO_2 emissions according to the Calculation Methodology 4 specified in WCI.23(d) (General Stationary Fuel Combustion Sources).

(2) Calculate the process and combustion CO_2 emissions separately using the procedures specified in paragraphs (b)(2)(i) through (b)(2)(vi) of this section.

(i) For each carbonate-based raw material charged to the furnace, obtain from the supplier of the raw material the carbonate-based mineral mass fraction.

(ii) Determine the quantity of each carbonate-based raw material charged to the furnace.

(iii) Apply the appropriate emission factor for each carbonate-based raw material charged to the furnace, as shown in Table 140-1 to this subpart.

(iv) Use Equation 140-1 of this section to calculate process mass emissions of CO2 for each furnace:

$$E_{CO2} = \sum_{i=1}^{n} \left(M_i \times MF_i \times EF_i \times F_i \right) \qquad \text{(Eq. 140-1)}$$

Where:

ECO_2	=	Process emissions of CO_2 from the furnace (tonnes).
n	=	Number of carbonate-based raw materials charged to furnace.
MF_i	=	Annual average mass fraction of carbonate-based mineral i in carbonate-based raw material i (weight fraction).
M_i	=	Annual amount of carbonate-based raw material i charged to furnace (tonnes).
EF_i	=	Emission factor for carbonate-based mineral i (tonnes CO_2 per tonne carbonate-based mineral as shown in Table 140-1.
Fi	=	Fraction of calcination achieved for carbonate-based mineral i, 1.0 for completed calcination (weight fraction).

(v) You must calculate and report the total process CO2 emissions from glass melting furnaces at the facility using Equation 140-2 of this section:

$$CO_2 = \sum_{i=1}^{k} E_{CO_2 i} \qquad \text{(Eq. 140-2)}$$

Where:

CO_2 = Annual process CO_2 emissions from glass manufacturing facility (tonnes).

E_{CO2i} = Annual CO_2 emissions from glass melting furnace i (tonnes).

k = Number of glass melting furnaces.

(vi) Calculate and report under WCI.20 (General Stationary Fuel Combustion Sources) the combustion CO_2 emissions in the glass furnace according to the applicable requirements in WCI.20.

§ WCI.144 Sampling, Analysis, and Measurement Requirements

(a) You must measure annual amounts of carbonate-based raw materials charged to each glass melting furnace from monthly measurements using plant instruments used for accounting purposes, such as calibrated scales or weigh hoppers. Total annual mass charged to glass melting furnaces at the facility shall be compared to records of raw material purchases for the year.

(b) You must measure carbonate-based mineral mass fractions at least annually to verify the mass fraction data provided by the supplier of the raw material; such measurements shall be based on sampling and chemical analysis conducted by a certified laboratory using ASTM D3682-01 (Reapproved 2006) Standard Test Method for Major and Minor Elements in Combustion Residues from Coal Utilization Processes (incorporated by reference, see regulation).

(c) You must determine the annual average mass fraction for the carbonate-based mineral in each carbonate-based raw material by calculating an arithmetic average of the monthly data obtained from raw material suppliers or sampling and chemical analysis.

(d) As an alternative to data provided by the raw material supplier, a value of 1.0 can be used for the monthly mass fraction (MF_i) of carbonate-based mineral i in Equation 140-1 of this section.

(e) You must determine on an annual basis the calcination fraction for each carbonate consumed based on sampling and chemical analysis using an industry consensus standard. This chemical analysis must be conducted using an x-ray fluorescence test or other enhanced testing method published by an industry consensus standards organization (e.g., ASTM, ASME, API, etc.).

§ WCI.145 Procedures for Estimating Missing Data

A complete record of all measured parameters used in the GHG emissions calculations is required (e.g., carbonate raw materials consumed, etc.). If the monitoring and quality assurance procedures in WCI.144 cannot be followed and data is missing, you must use the most appropriate of the missing data procedures in paragraphs (a) and (b) of this section. You must document and keep records of the procedures used for all such missing value estimates.

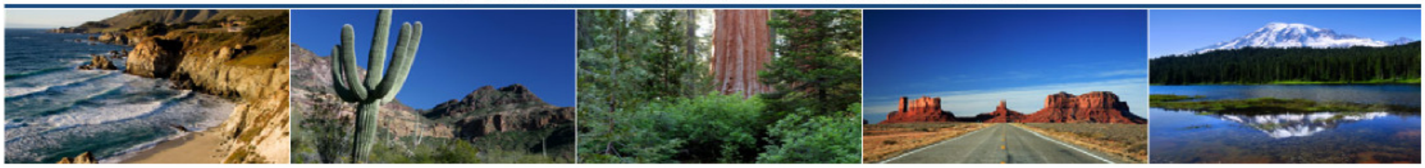
(a) For missing data on the monthly amounts of carbonate-based raw materials charged to any glass melting furnace use the best available estimate(s) of the parameter(s), based on all available process data or data used for accounting purposes, such as purchase records.

(b) For missing data on the mass fractions of carbonate-based minerals in the carbonate-based raw materials assume that the mass fraction of each carbonate based mineral is 1.0.

Table 140-1 —CO_2 Emission Factors for Carbonate-Based Minerals

Carbonate-Based Raw Material – Mineral	CO2 Emission Factor[a]
Limestone – CaCO3	0.43971
Dolomite – CaMg(CO3)2	0.47732
Sodium carbonate/soda ash – Na2CO3	0.41492

[a] Emission factors in units of tonnes of CO2 emitted per tonne of carbonate-based mineral charged to the furnace.



§ WCI.150 IRON AND STEEL MANUFACTURING

§ WCI.151 Source Category Definition

Iron and steel manufacturing comprises five categories: taconite iron ore processing, primary facilities that produce both iron and steel, secondary steelmaking facilities, iron production facilities, and offsite production of metallurgical coke. These processes may occur together in an "integrated" facility or they may occur in separate offsite facilities.

§ WCI.152 Greenhouse Gas Reporting Requirements

In addition to the information required by WCI.3, the annual emissions data report shall contain the following information:

(a) Annual process CO_2 emissions (metric tons) for the following processes:

- (1) Taconite indurating furnace
- (2) Basic oxygen furnace (BOF)
- (3) Coke making operation
- (4) Sinter process
- (5) Electric arc furnace (EAF)
- (6) Argon-oxygen decarburization vessel
- (7) Direct reduction furnace
- (8) Blast furnace

(b) Annual production/usage quantities (metric tons) for the following processes:

- (1) Taconite indurating furnace – fired pellets produced on-site
- (2) BOF – steel produced on-site
- (3) Coke making operation – coke produced and coal charged
- (4) Sinter process – sinter produced
- (5) EAF – steel produced on-site
- (6) Argon-oxygen decarburization vessel – molten steel charged
- (7) Direct reduction furnace – iron produced
- (8) Blast furnace – iron produced

(c) CO_2, N_2O, and CH_4 emissions, not accounted for elsewhere in §WCI.150, from stationary combustion units as specified in §WCI.20. Report these emissions from stationary combustion for each of the following devices:

(1) Taconite indurating furnace

(2) BOF

(3) Coke making operation (coke oven batteries)

(4) Sinter process (sintering furnace)

(5) EAF

(6) Argon-oxygen decarburization vessel

(7) Direct reduction furnace

(8) Blast furnace

(9) Any other stoves, boiler, process heaters, reheat furnaces and other combustion sources.

§ WCI.153 Calculation of CO_2 Emissions

(a) Process CO_2 emissions. Determine process CO_2 emissions as specified under either paragraph (1) or (2) of this section.

(1) Continuous emissions monitoring systems (CEMS) as specified in WCI.23(d).

(2) Calculation methodologies specified in paragraph (b) of this section.

[CEMS and mass balance approach are based on IPCC Tier 3 methods.)

(b) Process CO_2 Emissions Calculation Methodology. Calculate CO_2 process emissions for each taconite indurating furnace, basic oxygen furnace, non-recovery coke oven battery, sinter process, EAF, argon-oxygen decarburization vessel, blast furnace, and direct reduction furnace using the following mass balance approaches specified in paragraphs (b)(1) through (b)(8). Specific process inputs or outputs that contribute less than 1 percent of the total mass of carbon into or out of the process do not have to be included in the paragraphs (b)(1) through (b)(8) mass balances.

(1) Calculate taconite indurating furnace CO_2 emissions using Equation 150-1:

$$E_T = [(T \times C_T) - (P \times C_P) - (R \times C_R)] \times 3.664$$ **Equation 150-1**

Where:

E_T	=	Annual CO_2 emissions from taconite indurating furnace (metric tons);
T	=	Annual mass of greenball (taconite) pellets fed to furnace (metric tons);
C_T	=	Carbon content of greenball (taconite) pellets (metric tons C/metric tons taconite pellets);
P	=	Annual mass of fired pellets producted by the furnace (metric tons);
C_P	=	Carbon content of fired pellets (metric tons C/metric tons fired pellets);

R	=	Annual mass of air pollution control residue collected (metric tons);
C_R	=	Carbon content of air pollution control residue (metric tons C/metric tons residue);
3.664	=	Conversion factor from metric tons of C to metric tons of CO_2.

(2) Calculate basic oxygen process furnace CO_2 emissions using Equation 150-2:

$$E_{BOF} = [(I \times C_I) + (SC \times C_{SC}) + (FL \times C_{FL}) + (CAR \times C_{CAR}) - (ST \times C_{ST}) - (SL \times C_{SL}) - (R \times C_R)] \times 3.664$$

Equation 150-2

Where:

E_{BOF}	=	Annual CO_2 emissions from basic oxygen furnaces (metric tons);
I	=	Annual mass of molten iron charged to furnace (metric tons);
C_I	=	Carbon content of molten iron (metric tons C/metric tons molten iron);
SC	=	Annual mass of ferrous scrap charged to furnace (metric tons);
C_{SC}	=	Carbon content of ferrous scrap (metric tons C/metric tons ferrous scrap);
FL	=	Annual mass for flux materials (e.g., limestone, dolomite, etc.) charged to furnace (metric tons);
C_{FL}	=	Carbon content of flux materials (metric tons C/metric tons flux material);
CAR	=	Annual mass of carbonaceous material (e.g., coal, coke, etc.) charged to furnace (metric tons);
C_{CAR}	=	Carbon content of carbonaceous material (metric tons C/metric tons carbonaceous material);
ST	=	Annual mass of molten raw steel produced by furnace (metric tons);
C_{ST}	=	Carbon content of steel (metric tons C/metric tons steel);
SL	=	Annual mass of slag produced by furnace (metric tons);
C_{SL}	=	Carbon content of slag (metric tons C/metric tons slag);
R	=	Annual mass of air pollution control residue collected (metric tons);
C_R	=	Carbon content of air pollution control residue (metric tons C/metric tons residue);
3.664	=	Conversion factor from metric tons of C to metric tons of CO_2.

(3) Calculate coke oven battery CO_2 emissions using Equation 150-3:

$$E_{coke} = [(CC \times C_{CC}) - (CO \times C_{CO}) - (BY \times C_{BY}) - (R \times C_R) - (COG \times C_{COG})] \times 3.664$$

Equation 150-3

Where:

E_{coke}	=	Annual CO_2 emissions from coke production (metric tons);
CC	=	Annual mass of coking coal charged to battery (metric tons);

C_{CC}	=	Carbon content of coking coal (metric tons C/metric tons coking coal);
CO	=	Annual mass of coke produced (metric tons);
C_{CO}	=	Carbon content of coke (metric tons C/metric tons coke);
BY	=	Annual mass of by-product from by-product coke oven battery (metric tons);
C_{BY}	=	Carbon content of by-product (metric tons C/metric tons by-product);
R	=	Quantity of air pollution control residue collected (metric tons);
C_R	=	Carbon content of air pollution control residue (metric tons C/metric tons residue);
COG	=	Annual mass of coke oven gas transferred off site (metric tons);
C_{COG}	=	Carbon content of coke oven gas transferred off site (metric tons C/metric tons coke oven gas);
3.664	=	Conversion factor from metric tons of C to metric tons of CO_2.

(4) Calculate sinter process CO_2 emissions using Equation 150-4:

$$E_{sinter} = [(CAR \times C_{CAR}) + (FE \times C_{FE}) - (S \times C_S) - (R \times C_R)] \times 3.664$$

Equation 150-4

Where:

E_{sinter}	=	Annual CO_2 emissions from sinter process (metric tons);
CAR	=	Annual mass of carbonaceous material (e.g., coal, coke, etc.) charged to furnace (metric tons);
C_{CAR}	=	Carbon content of carbonaceous material (metric tons C/metric tons carbonaceous material);
FE	=	Annual mass of sinter feed material (metric tons);
C_{FE}	=	Carbon content of sinter feed material (metric tons C/metric tons sinter feed material);
S	=	Annual mass of sinter produced (metric tons);
C_S	=	Carbon content of sinter produced (metric tons C/metric tons sinter);
R	=	Quantity of air pollution control residue collected (metric tons);
C_R	=	Carbon content of air pollution control residue (metric tons C/metric tons residue);
3.664	=	Conversion factor from metric tons of C to metric tons of CO_2.

(5) Calculate electric arc furnace (EAF) CO_2 emissions using Equation 150-5:

$$E_{EAF} = [(I \times C_I) + (SC \times C_{SC}) + (FL \times C_{FL}) + (EL \times C_{EL}) + (CAR \times C_{CAR}) - (ST \times C_{ST}) - (SL \times C_{SL}) - (R \times C_R)] \times 3.664$$

Equation 150-5

Where:

E_{EAF}	=	Annual CO_2 emissions from EAF (metric tons);
I	=	Annual mass of direct reduced iron (if any) charged to furnace (metric tons);

C_I	=	Carbon content of direct reduced iron (metric tons C/metric tons direct reduced iron);
SC	=	Annual mass of ferrous scrap charged to furnace (metric tons);
C_{SC}	=	Carbon content of ferrous scrap (metric tons C/metric tons ferrous scrap);
FL	=	Annual mass for flux materials (e.g., limestone, dolomite, etc.) charged to furnace (metric tons);
C_{FL}	=	Carbon content of flux materials (metric tons C/metric tons flux material);
EL	=	Annual mass for carbon electrodes consumed (metric tons);
C_{EL}	=	Carbon content of carbon electrodes (metric tons C/metric tons carbon electrode);
CAR	=	Annual mass of carbonaceous material (e.g., coal, coke, etc.) charged to furnace (metric tons);
C_{CAR}	=	Carbon content of carbonaceous material (metric tons C/metric tons carbonaceous material);
ST	=	Annual mass of molten raw steel produced by furnace (metric tons);
C_{ST}	=	Carbon content of steel (metric tons C/metric tons steel);
SL	=	Annual mass of slag produced by furnace (metric tons);
C_{SL}	=	Carbon content of slag (metric tons C/metric tons slag);
R	=	Annual mass of air pollution control residue collected (metric tons);
C_R	=	Carbon content of air pollution control residue (metric tons C/metric tons residue);
3.664	=	Conversion factor from metric tons of C to metric tons of CO_2.

(6) Calculate argon-oxygen decarburization vessel CO_2 emissions using Equation 150-6:

$$E_{AOD} = \left[Steel \times \left(C_{in} - C_{out}\right) - \left(R \times C_R\right)\right] \times 3.664$$ **Equation 150-6**

Where:

E_{AOD}	=	Annual CO_2 emissions from argon-oxygen decarburization vessels (metric tons);
Steel	=	Annual mass of molten steel charged to vessel (metric tons);
C_{in}	=	Carbon content of molten steel before decarburization (metric tons C/metric tons molten steel);
C_{out}	=	Carbon content of molten steel after decarburization (metric tons C/metric tons molten steel);
R	=	Annual mass of air pollution control residue collected (metric tons);
C_R	=	Carbon content of air pollution control residue (metric tons C/metric tons residue);
3.664	=	Conversion factor from metric tons of C to metric tons of CO_2.

(7) Calculate direct reduction furnace CO_2 emissions using Equation 150-7:

$$E_{DR} = \left[\left(Ore \times C_{Ore}\right) + \sum\left(CAR \times C_{CAR}\right) + \sum\left(OT \times C_{OT}\right) - \left(I \times C_I\right) - \left(NM \times C_{NM}\right) - \left(R \times C_R\right)\right] \times 3.664$$

Equation 150-7

Where:

E_{DR} = Annual CO_2 emissions from direct reduction furnace (metric tons);
Ore = Annual mass of iron ore or iron ore pellets fed to the furnace (metric tons);
C_{Ore} = Carbon content of iron ore or iron ore pellets (metric tons C/metric tons iron ore or iron ore pellets);
CAR = Annual mass of non-fuel carbonaceous materials (e.g., coal, coke, by-products, etc.) charged to furnace (metric tons);
C_{CAR} = Carbon content of non-fuel carbonaceous materials (metric tons C/metric tons non-fuel carbonaceous material);
OT = Annual mass of other materials charged to furnace (metric tons);
C_{OT} = Carbon content of other materials (metric tons C/metric tons other materials);
I = Annual mass of iron produced (metric tons);
C_I = Carbon content of iron (metric tons C/metric tons iron);
NM = Annual mass for non-metallic materials produced (metric tons);
C_{NM} = Carbon content of non-metallic materials (metric tons C/metric tons non-metallic minerals);
R = Annual mass of air pollution control residue collected (metric tons);
C_R = Carbon content of air pollution control residue (metric tons C/metric tons residue);
3.664 = Conversion factor from metric tons of C to metric tons of CO_2.

(8) Calculate blast furnace CO_2 emissions using Equation 150-8:

$$E_{BF} = \left[(Ore \times C_{Ore}) + \sum (CAR \times C_{CAR}) + \sum (F \times C_F) + \sum (OT \times C_{OT}) - (I \times C_I) - (NM \times C_{NM}) - (BG \times C_{BG}) - (R \times C_R) \right] \times 3.664$$

Equation 150-8

Where:

E_{BF} = Annual CO_2 emissions from blast furnace (metric tons);
Ore = Annual mass of iron ore or iron ore pellets fed to the furnace (metric tons);
C_{Ore} = Carbon content of iron ore or iron ore pellets (metric tons C/metric tons iron ore or iron ore pellets);
CAR = Annual mass of non-fuel carbonaceous materials (e.g., coal, coke, by-products, etc.) charged to furnace (metric tons);
C_{CAR} = Carbon content of non-fuel carbonaceous materials (metric tons C/metric tons non-fuel carbonaceous material);
F = Annual mass for flux materials (e.g., limestone, dolomite, etc.) charged to furnace (metric tons);
C_F = Carbon content of flux materials (metric tons C/metric tons flux material);
OT = Annual mass of other materials charged to furnace (metric tons);
C_{OT} = Carbon content of other materials (metric tons C/metric tons other materials);
I = Annual mass of iron produced (metric tons);
C_I = Carbon content of iron (metric tons C/metric tons iron);
NM = Annual mass for non-metallic materials produced (metric tons);

C_{NM} = Carbon content of non-metallic materials (metric tons C/metric tons non-metallic minerals);
BG = Annual mass for blast furnace gas transferred off-site (metric tons);
C_{BG} = Carbon content of blast furnace gas (metric tons C/metric tons blast furnace gas);
R = Annual mass of air pollution control residue collected (metric tons);
C_R = Carbon content of air pollution control residue (metric tons C/metric tons residue);
3.664 = Conversion factor from metric tons of C to metric tons of CO_2.

(9) Calculate total CO_2 emissions using Equation 150-9:

$$E_{CO2} = E_T + E_{BOF} + E_{coke} + E_{sinter} + E_{EAF} + E_{AOD} + E_{DR} + E_{BF}$$ **Equation 150-9**

Where:

E_{CO2} = Total CO_2 emissions (metric tons);
E_T = Emissions from taconite indurating furnace (metric tons);
E_{BOF} = Emissions from basic oxygen furnace (BOF) (metric tons);
E_{coke} = Emissions from coke production (metric tons);
E_{sinter} = Emissions from sinter production (metric tons);
E_{EAF} = Emissions from electric arc furnace (EAF) (metric tons);
E_{AOD} = Emissions from argon-oxygen decarburization vessels (metric tons);
E_{DR} = Emissions from direct reduction furnace (metric tons);
E_{BF} = Emissions from blast furnace (metric tons);

§ WCI.154 Calculation of CH_4 Emissions

(a) Process CH_4 emissions. Determine process CH_4 emissions as specified under either paragraph (1) or paragraph (2) of this section.

(1) Continuous emissions monitoring systems (CEMS) as specified in WCI.23(d).

(2) Site-specific emission factors.

§ WCI.155 Sampling, Analysis, and Measurement Requirements

The annual mass of each material used in the §WCI.153 mass balance methodologies shall be determined using plant instruments used for accounting purposes, including either direct measurement of the quantity of material used in the process or by calculations using process operating information.

The average carbon content of each material used shall be determined as specified under paragraph (a) or (b) of this section.

(a) Obtain carbon content by collecting and analyzing at least three representative samples of the material each year using one of the following methods:

(1) For iron ore, taconite pellets, and other iron-bearing materials, use ASTM E1915-07a "Standard Test Methods for Analysis of Metal Bearing Ores and Related Materials by Combustion Infrared-Absorption Spectrometry".

(2) For iron and ferrous scrap, use ASTM E1019-08 "Standard Test Methods for Determination of Carbon, Sulphur, Nitrogen, and Oxygen in Steel, Iron, Nickel, and Cobalt Alloys by Various Combustion and Fusion Techniques".

(3) For coal, coke, and other carbonaceous materials (e.g., electrodes, etc.), use ASTM D5373-08 "Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal" or ASTM D5142 -09 Standard Test Methods for Proximate Analysis of the Analysis Sample of Coal and Coke by Instrumental Procedures, for petroleum liquid based fuels and liquid waste-derived fuels.

(4) For steel, use one of the methods described in subparagraph (i) through (iv):

(i) ASM CS-104 UNS No. G10460 "Carbon Steel of Medium Carbon Content".

(ii) ISO/TR 15349-1: 1998 "Unalloyed steel – Determination of low carbon content, Part 1: Infrared absorption method after combustion in an electric resistance furnace (by peak separation) (1998-10-15) – First Edition".

(iii) ISO/TR 15349-3: 1998 "Unalloyed steel – Determination of low carbon content, Part 3: Infrared absorption method after combustion in an electric resistance furnace (with preheating) (1998-10-15) – First Edition".

(iv) ASTM E415-08 "Standard Test Method for Atomic Emission Vacuum Spectrometric Analysis of Carbon and Low-Alloy Steel".

(5) For flux (i.e., limestone or dolomite) and slag, use ASTM C25-06 "Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime".

(6) For fuels, determine carbon content and molecular weight (if applicable) using the applicable methods listed in §WCI.20.

(7) For steel production by-products (e.g., blast furnace gas, coke oven gas, coal tar, light oil, sinter off gas, slag dust, etc.), use an online instrument that determines carbon content to within 5%.

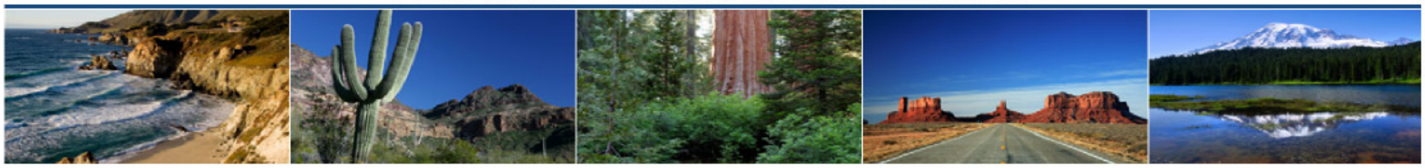
(b) Obtain carbon content from material vendor or supplier.

§ WCI.156 Procedures for Estimating Missing Data

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever the monitoring and quality assurance procedures in WCI.84 cannot be followed (e.g., if a meter malfunctions during unit operation), a substitute data value for the missing parameter shall be used in the calculations following paragraphs (a) and (b) of this section. You must document and keep records of the procedures used for all such estimates.

(a) For missing data on monthly carbon contents of feedstock or the waste recycle stream, the substitute data value shall be the arithmetic average of the quality-assured values of that carbon content in the month preceding and the month immediately following the missing data incident. If no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value for carbon content obtained in the month after the missing data period.

(b) For missing feedstock supply rates or waste recycle stream used to determine monthly feedstock consumption or monthly waste recycle stream quantity, you must determine the best available estimate(s) of the parameter(s), based on all available process data.



§ WCI.160 LEAD PRODUCTION

§ WCI.161 Source Category Definition

The lead production category includes two primary production processes used to produce lead from lead concentrates (i.e., the sintering/smelting process and the direct smelting process). In addition, secondary production or recycling of lead (primarily from scrapped lead acid batteries) is included in the category.

§ WCI.162 Greenhouse Gas Reporting Requirements

In addition to the information required by regulation the annual emissions data report shall contain the following information:

(a) Annual emissions of CO_2 at the facility level (metric tons).

(b) Annual quantities of each material used (metric tons).

(c) Carbon content of each material used (metric tons C/metric ton reducing agent).

(d) Inferred waste-based carbon-containing material emission factor (if waste-based reducing agent quantification method used).

(e) If you use the missing data procedures in WCI.165(b), you must report how the monthly mass of carbon-containing materials with missing data was determined and the number of months the missing data procedures were used.

(f) CO_2, CH_4, and N_2O emissions from each stationary fuel combustion unit. You must report these emissions under WCI.20 (General Stationary Fuel Combustion Sources), by following the requirements of WCI.20.

§ WCI.163 Calculation of CO_2 Emissions

Calculate total CO_2 emissions as specified under paragraph (a) or (b) of this section.

(a) Determine facility CO_2 emissions using continuous emissions monitoring systems (CEMS) as specified in WCI.23(d).

(b) Calculate total CO_2 emissions using Equation 160-1. Specific materials that contribute less than 1 percent of the total carbon into the process are being considered to not be included in the calculation using Equation 160-1.

$$E_{Pb} = \sum_{x} (RA_x \times C_x) \times 3.664 \qquad \textbf{Equation 160-1}$$

Where:

E_{Pb}	=	Annual CO_2 emissions from lead production (metric tons);
RA_x	=	Annual quantity of material *x* used (metric tons);
C_x	=	Carbon content of material *x* (metric tons C/metric tons of *x*);
3.664	=	Conversion factor from metric tons of C to metric tons of CO_2.

§ WCI.164 Sampling, Analysis, and Measurement Requirements

The annual mass of each material introduced into the smelting furnace shall be determined by summing the monthly mass for the material determined for each month of the calendar year. The monthly mass may be determined using plant instruments used for accounting purposes, including either direct measurement of the quantity of the material placed in the unit or by calculations using process operating information.

The average carbon content of each material introduced into the smelting furnace shall be determined as specified under paragraph (a), (b), or (c) of this section.

(a) Obtain carbon content by collecting and analyzing at least three representative samples of the material each year using one of the following methods:

(1) For solid carbonaceous reducing agents and carbon electrodes, use ASTM D5373-08 "Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal".

(2) For liquid reducing agents, use one of the methods described in subparagraph (i) through (iv):

(i) ASTM D2502-04 (Reapproved 2002) "Standard Test Method for Estimation of Molecular Weight (Relative Molecular Mass) of Petroleum Oils from Viscosity Measurements".

(ii) ASTM D2503-92 (Reapproved 2002) "Standard Test Method for Relative Molecular Mass (Relative Molecular Weight) of Hydrocarbons by Thermoelectric Measurement of Vapor Pressure".

(iii) ASTM D3238-95 (Reapproved 2005) "Standard Test Method for Calculation of Carbon Distribution and Structural Group Analysis of Petroleum Oils by the n-d-M Method".

(iv) ASTM D5291-02 (Reapproved 2007) "Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants".

(3) For gaseous reducing agents, use one of the methods described in subparagraph (i) or (ii):

(i) ASTM D1945-03 "Standard Test Method for Analysis of Natural Gas by Gas Chromatography".

(ii) ASTM D1946-90 "Standard Practice for Analysis of Reformed Gas by Gas Chromatography".

(4) For waste-based carbon-containing material, determine carbon content by operating the smelting furnace both with and without the waste-reducing agents while keeping the composition of other material introduced constant.

i. To ensure representativeness of waste-based carbon-containing material variability, the specific testing plan (e.g. number of test runs, other process variables to keep constant, timing of runs) for these trials must be approved by the jurisdiction

(b) Obtain carbon content from material vendor or supplier.

§ WCI.165 Procedures for Estimating Missing Data

A complete record of all measured parameters used in the GHG emissions calculations in WCI.163 is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in the paragraphs (a) and (b) of this section. You must document and keep records of the procedures used for all such estimates.

a) For each missing data for the carbon content for the smelting furnaces at your facility that estimate annual process CO_2 emissions using the carbon mass balance procedure in WCI.163, 100 percent data availability is required. You must repeat the test for average carbon contents of inputs according to the procedures in WCI.164 if data are missing.

b) For missing records of the monthly mass of carbon-containing materials, the substitute data value must be based on the best available estimate of the mass of the material from all available process data or data used for accounting purposes (such as purchase records).

§ WCI.170 LIME MANUFACTURING

§ WCI.171 Source Category Definition

Lime manufacturing is comprised of all processes that are used to manufacture a lime product (e.g., calcium oxide, high calcium quicklime, calcium hydroxide, hydrated lime, dolomitic quick lime, dolomitic hydrate, or other products) by calcination of limestone or other highly calcareous materials such as dolomite, aragonite, chalk, coral, marble, and shell.

This source category includes all lime manufacturing plants unless the plant is located at a kraft pulp mill, soda pulp mill, sulfite pulp mill, or only processes sludge containing calcium carbonate from water softening processes. The lime manufacturing source category consists of marketed and non-marketed lime manufacturing facilities.

Lime kilns at pulp and paper manufacturing facilities must report emissions under WCI.210 (Pulp and Paper Manufacturing).

§ WCI.172 Greenhouse Gas Reporting Requirements

In addition to the information required by regulation, the annual emissions data report shall contain the following information:

(a) Total emissions of CO_2, CH_4, and N_2O in metric tons.

(b) CO_2 process emissions from lime production (metric tons) for all kilns combined and the following information:

(1) For lime production:

(A) The emission factor (kg CO_2/metric ton) for each lime type for each month.

(B) The quantity of each type of lime produced (metric tons) each month.

(C) The calcium oxide (CaO) content (weight fraction) of each lime type for each month.

(D) The magnesium oxide (MgO) content (weight fraction) of each lime type for each month.

(2) For the production of calcined byproducts and wastes:

(A) The emission factor (kg CO_2/metric ton) for each calcined byproduct/waste type for each quarter.

(B) The quantity of each type of calcined byproduct/waste type produced each quarter.

(C) The calcium oxide (CaO) content (weight fraction) of each calcined byproduct/waste type for each quarter.

(D) The magnesium oxide (MgO) content (weight fraction) of each calcined byproduct/waste type for each quarter.

(3) Number of times during the reporting year that missing data procedures were followed to measure lime production.

(c) CO_2, CH_4, and N_2O emissions from fuel combustion in all kilns combined, following the calculation methods and reporting requirements specified in WCI.173(c) (metric tons).

(d) CO_2, CH_4, and N_2O emissions from all other fuel combustion units combined (kilns excluded), following the calculation methods and reporting requirements specified in WCI.20 (metric tons).

(e) If a continuous emissions monitor is used to measure CO_2 emissions from kilns, then the requirements of paragraphs (b) of this section do not apply for CO_2.

(f) Operators of lime plants shall also comply with the reporting requirements for any other applicable source category listed by regulation, including but not limited to the following:

(1) Coal fuel storage as specified in WCI.100.

(2) Electricity generating as specified in WCI.40.

(3) Cogeneration systems as specified in WCI.42(f).

§ WCI.173 Calculation of greenhouse Gas Emissions from Kilns

(a) Determine process CO_2 emissions as specified under either paragraph (a)(1) or (a)(2) of this section.

(1) Continuous emissions monitoring systems (CEMS) as specified in WCI.23(d).

(2) Calculate the sum of CO_2 process emissions from kilns and CO_2 fuel combustion emissions from kilns using the calculation methodologies specified in paragraph (b) and (c) of this section**.**

(b) Process CO_2 Emissions Calculation Methodology. Calculate total CO_2 process emissions as the sum of emissions from lime production, using the method specified in paragraph (b)(1) of this section.

(1) CO_2 Process Emissions. Calculate CO_2 emissions from the production of each type of lime using Equation 170-1 and a plant-specific lime emission factor and a plant-specific calcined byproduct/waste emission factor as specified in this section.

$$CO_2 = \sum_{i}^{12} \sum_{j}^{y} \left[QL_{ij} \times EF_{QL_{ij}} \right] + \sum_{k}^{4} \sum_{l}^{z} \left[CBW_{kl} \times EF_{CBW_{kl}} \right] \qquad \textbf{Equation 170-1}$$

Where:

CO_2	=	CO_2 emissions in metric tons/yr.
QL	=	Monthly quantity of lime produced, metric tons.
EF_{QL}	=	Monthly lime emission factor, metric tons CO_2/metric ton lime computed as specified in paragraph (b)(2) of this section.
CBW	=	Monthly quantity of calcined byproduct/waste, including LKD, scrubber sludge and other calcined wastes produced, metric tons.

EF_{CBW}	=	Monthly calcined byproduct/waste emission factor, computed as specified in paragraph (b)(3) of this section.
i	=	Month.
j	=	Lime type.
k	=	Quarter.
l	=	Calcined byproduct/waste type.
y	=	Total number of lime types.
z	=	Total number of calcined byproduct/waste types.

(2) Monthly Lime Emission Factor. Calculate a plant-specific lime emission factor (EF_{QL}) for each type of lime and month based on the percent of measured CaO and MgO content in lime and using Equation 170-2.

$$EF_{QL} = (CaO\ \ content \times Molecular\ \ ratio\ \ of\ CO_2 / CaO) + (MgO\ \ content \times Molecular\ \ ratio\ \ CO_2 / MgO)$$

Equation 170-2

Where:

CaO Content (by weight)	=	Total CaO content of Lime.
Molecular ratio of CO_2/CaO	=	0.785.
MgO Content (by weight)	=	Total MgO content of Lime.
Molecular ratio of CO_2/MgO	=	1.092.

(3) Quarterly Calcined Byproduct/Waste Emission Factor. The calcined byproduct/waste emission factor shall be calculated using Equation 170-3.

$$EF_{CBW} = [(CaO\ \ content) \times Molecular\ \ ratio\ \ of\ \ CO_2 / CaO] + [(MgO\ \ Content) \times Molecular\ \ ratio\ \ of\ \ CO_2 / MgO]$$

Equation 170-3

Where:

EF_{CBW}	=	Calcined byproduct/waste emission factor.
CaO Content (by weight)	=	Total CaO content of calcined byproduct/waste.
Molecular ratio of CO_2/CaO	=	0.785.
MgO Content (by weight)	=	Total MgO content of calcined byproduct/waste.
Molecular ratio of CO_2/MgO	=	1.092.

(c) Fuel Combustion Emissions in Kilns. Calculate CO_2, CH_4, and N_2O emissions from stationary fuel combustion emissions following the calculation methods specified in WCI.20. Operators of lime manufacturing plants that primarily combust biomass-derived fuels and combust fossil fuels only during periods of start-up, shut-down, or malfunction may report CO_2 emissions from fossil fuels using the emission factor methodology in WCI.23(a). "Pure" means that the biomass-derived fuels account for 97 percent of the total amount of carbon in the fuels burned.

§ WCI.174 Sampling, Analysis, and Measurement Requirements

(a) You must determine the chemical composition (percent total CaO and percent total MgO) of each type of lime and each type of calcined byproduct/waste according to paragraph (a)(1) and (a)(2) of this section. Samples for analysis of the calcium oxide and magnesium oxide content of each lime type and each calcined byproduct/waste type should be collected during the same month or quarter as the production data. At least one sample must be collected monthly for each lime type produced during the month and for each calcined byproduct/waste type produced.

(1) ASTM C25-06 Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime.
(2) The National Lime Association's CO_2 Emissions Calculation Protocol for the Lime Industry English Units Version, February 5, 2008 Revision – National Lime Association.

(b) The quantity of lime produced and sold is to be estimated monthly using direct measurements (such as rail and truck scales) of lime sales for each lime type, and adjusted to take into account the difference in beginning- and end-of-period inventories of each lime type. The inventory period shall be annual at a minimum.

(c) The quantity of calcined byproduct/waste sold is to be estimated monthly using direct measurements (such as rail and truck scales) of calcined byproduct/waste sales for each calcined byproduct/waste type, and adjusted to take into account the difference in beginning- and end-of-period inventories of each calcined byproduct/waste type. The inventory period shall be annual at a minimum. The quantity of calcined byproduct/waste not sold is to be determined no less often than annually for each calcined/byproduct waste type using direct measurements (such as rail and truck scales), or a calcined byproduct/waste generation rate (i.e. calcined byproduct produced as a factor of lime production).

(d) Follow the quality assurance/quality control procedures (including documentation) in National Lime Association's CO_2 Emissions Calculation Protocol for the Lime Industry English Units Version, February 5, 2008 Revision – National Lime Association.

§ WCI.175 Procedures for Estimating Missing Data

A complete record of all measured parameters used in the GHG emissions calculations is required (e.g., oxide content, quantity of lime products, etc.). Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraphs (a) or (b) of this section. You must document and keep records of the procedures used for all such estimates.

(a) For each missing value of the quantity of lime produced (by lime type), and quantity of byproduct/waste produced and sold, the substitute data value shall be the best available estimate based on all available process data or data used for accounting purposes.
(b) For missing values related to the CaO and MgO content, you must conduct a new composition test.

§ WCI.180 CARBONATES USE

§ WCI.181 Source Category Definition

This source category includes any equipment that uses carbonates listed in Table 180-1 in manufacturing processes that emit carbon dioxide. Table 180-1 includes the following carbonates: limestone, dolomite, ankerite, magnesite, siderite, rhodochrosite, or sodium carbonate. Facilities are considered to emit CO_2 if they consume at least 1,800 tonnes per year of carbonates heated to a temperature sufficient to allow the calcination reaction to occur.

This source category does not include equipment that uses carbonates or carbonate containing minerals that are consumed in the production of cement, copper and nickel, electricity generation, ferroalloys, glass, iron and steel, lead, lime, phosphoric acid, pulp and paper, soda ash, sodium bicarbonate, sodium hydroxide, or zinc.

This source category does not include carbonates used in sorbent technology used to control emissions from stationary fuel combustion equipment. Emissions from carbonates used in sorbent technology are reported under WCI.20 (Stationary Fuel Combustion Sources).

§ WCI.182 Greenhouse Gas Reporting Requirements

For the purpose of the Regulation the annual emissions data report for carbonate use shall include the following information at the facility level calculated in accordance this method:

(a) Annual CO_2 emissions from miscellaneous carbonate use (tonnes).

(b) Annual mass of each carbonate type consumed (tonnes).

(c) If you followed the calculation method of WCI.183(a), you must report the following information:

(1) Annual carbonate consumption by carbonate type (tonnes).

(2) Annual calcination fractions used in calculations.

(d) If you followed the calculation method of WCI.183(b), you must report the following information:

(1) Annual carbonate input by carbonate type (tonnes).

(2) Annual carbonate output by carbonate type (tonnes).

(e) Number of times in the reporting year that missing data procedures were followed to measure carbonate consumption, carbonate input or carbonate output (months).

§ WCI.183 Calculating GHG emissions.

You must determine CO_2 process emissions from carbonate use in accordance with the procedures specified in either paragraphs (a) or (b) of this section.

(a) Calculate the process emissions of CO_2 using calcination fractions with Equation 180-1 of this section.

$$E_{CO2} = \sum_{i=1}^{n} (M_i \times EF_i \times F_i)$$

Equation 180-1

Where:

ECO_2 = Annual CO_2 mass emissions from consumption of carbonates (tonnes).

M_i = Annual mass of carbonate type i consumed (tonnes).

EF_i = Emission factor for the carbonate type i, as specified in Table 180-1 to this Subpart, tonnes CO_2/tonne carbonate consumed.

F_i = Fraction calcination achieved for each particular carbonate type i (weight fraction). As an alternative to measuring the calcination fraction, a value of 1.0 can be used.

n = Number of carbonate types.

(b) Calculate the process emissions of CO_2 using actual mass of output carbonates with Equation 180-2 of this section.

$$E_{CO2} = \left[\sum_{k=1}^{m} (M_k \times EF_k) - \sum_{j=1}^{n} (M_j \times EF_j) \right]$$

Equation 180-2

Where:

ECO_2 = Annual CO_2 mass emissions from consumption of carbonates (tonnes).
M_k = Annual mass of input carbonate type k (tonnes).
EF_k = Emission factor for the carbonate type k, as specified in Table 180-1 of this method (tonnes CO_2/tonne carbonate input).
M_j = Annual mass of output carbonate type j (tonnes).
EF_j = Emission factor for the output carbonate type j, as specified in Table 180-1 of this method (tonnes CO_2/tonne carbonate input).
m = Number of input carbonate types.
n = Number of output carbonate types.

§ WCI.184 Monitoring and QA/QC requirements.

(a) The annual mass of carbonate consumed (for Equation 180-1 of this subpart) or carbonate inputs (for Equation 180-2 of this subpart) must be determined annually from monthly measurements using the same plant instruments used for accounting purposes including purchase records or direct measurement, such as weigh hoppers or weigh belt feeders.

(b) The annual mass of carbonate outputs (for Equation 180-2 of this subpart) must be determined annually from monthly measurements using the same plant instruments used for accounting purposes including purchase records or direct measurement, such as weigh hoppers or belt weigh feeders.

(c) If you follow the procedures of WCI.183(a), as an alternative to assuming a calcination fraction of 1.0, you can determine on an annual basis the calcination fraction for each carbonate consumed based on sampling and chemical analysis using a suitable method such as using an x-ray fluorescence standard method or other enhanced industry consensus standard method published by an industry consensus standard organization (e.g., ASTM, ASME, etc.).

§ WCI.185 Procedures for estimating missing data.

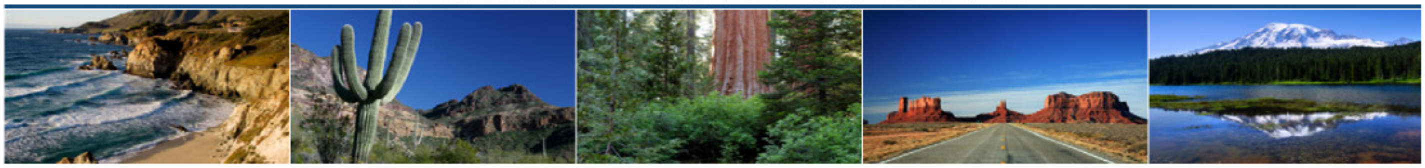
(a) A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraph (b) of this section. You must document and keep records of the procedures used for all such estimates.

(b) For each missing value of monthly carbonate consumed, monthly carbonate output, or monthly carbonate input, the substitute data value must be the best available estimate based on the all available process data or data used for accounting purposes.

§ WCI.186 Data reporting requirements.

Table 180-1 —CO_2 Emission Factors for Common Carbonates

Mineral Name - Carbonate	CO_2 Emission Factor (tonnes CO_2/tonne carbonate)
Limestone - $CaCO_3$	0.43971
Magnesite - $MgCO_3$	0.52197
Dolomite - $CaMg(CO_3)_2$	0.47732
Siderite - $FeCO_3$	0.37987
Ankerite - $Ca(Fe,Mg,Mn)(CO_3)_2$	0.47572
Rhodochrosite - $MnCO_3$	0.38286
Sodium Carbonate/Soda Ash – Na_2CO_3	0.41492
Others	Facility specific factor to be determined through analysis or supplier information



§ WCI.200 PETROLEUM REFINERIES

§ WCI.201 Source Category Definition

(a) A petroleum refinery consists of all processes used to produce gasoline, aromatics, kerosene, distillate fuel oils, residual fuel oils, lubricants, asphalt, or other products through distillation of petroleum or through redistillation, cracking, rearrangement or reforming of unfinished petroleum derivatives.

(b) For the purposes of this subpart, facilities that distill only pipeline transmix (off-spec material created when different specification products mix during pipeline transportation) are not petroleum refineries, regardless of the products produced.

(c) This source category consists of the following sources at petroleum refineries: catalytic cracking units; fluid coking units; delayed coking units; catalytic reforming units; coke calcining units; asphalt blowing operations; blowdown systems; storage tanks; process equipment components (compressors, pumps, valves, pressure relief devices, flanges, and connectors) in gas service; marine vessel, barge, tanker truck, and similar loading operations; flares; sulphur recovery plants; and non-merchant hydrogen plants (i.e., hydrogen plants that are owned or under the direct control of the refinery owner and operator).

§ WCI.202 Greenhouse Gas Reporting Requirements

In addition to the information required by WCI.3, the annual emissions report must contain the following information reported at the facility level:

(a) Catalyst Regeneration. Report CO_2, CH_4, and N_2O emissions.

(b) Process Vents. Report CO_2, N_2O, and CH_4 emissions.

(c) Asphalt Production. Report CO_2 and CH_4 emissions.

(d) Sulphur Recovery. Report CO_2 emissions.

(e) Stationary Combustion Units Other than Flares and Control Devices. Report CO_2, N_2O, and CH_4 emissions as specified in WCI.30 for combustion of refinery fuel gas, still gas, flexigas, or associated gas and WCI.20 for combustion of all other fuels.

(f) Flares and Other Control Devices. Report CO_2, N_2O, and CH_4 emissions.

(g) Above-Ground Storage Tanks. Report CH_4 emissions.

(h) Wastewater Treatment. Report CH_4 and N_2O emissions from anaerobic treatment and CH_4 emissions from oil-water separators.

(i) Equipment Leaks. Report CH_4 emissions.

(j) Feedstock Consumption: Report feedstock consumption by type for all feedstocks which result in GHG emissions in the reporting year (including petroleum coke) in units of cubic meters for gases, kilolitres for liquids, metric tons for non-biomass solids, and bone dry short tons or metric tons for biomass-derived solid fuels.

(k) Fuel Consumption: Report fuel consumption by fuel type consumed in the reporting year in units of cubic meters for gases, kilolitres for liquids, metric tons for non-biomass solids, and bone dry short tons or metric tons for biomass-derived solid fuels.

(l) Coke calcining units. Report CO_2, N_2O, and CH_4 emissions.

(m) Uncontrolled blowdown systems. Report CH_4 emissions.

(n) Loading Operations. Report CH_4 emissions.

(o) Delayed Coking Units. Report CH_4 emissions.

§ WCI.203 Calculation of Greenhouse Gas Emissions

The operator shall calculate GHG emissions using the methods in paragraphs (a) through (i) of this section. If a continuous emissions monitor is used to measure CO_2 emissions from process vents, asphalt production, sulphur recovery, or other control devices then the operator shall calculate the CO_2 emissions from these processes using a continuous emissions monitoring system (CEMS) as specified in WCI.23(d).

(a) Catalyst Regeneration. Operators shall calculate the CO_2, CH_4, and N_2O process emissions resulting from catalyst regeneration using the methods in paragraph (a)(1), (a)(2) and (a)(3), respectively.

(1) For units equipped with CEMS, operators shall calculate CO_2 process emissions resulting from catalyst regeneration using CEMS in accordance with WCI.20. In the absence of CEMS data, the operator shall use the methods in paragraphs (a)(1)(A) through (a)(1)(C).

(A) The operator shall calculate process CO_2 emissions from the continuous regeneration of catalyst material in fluid catalytic cracking units (FCCU) and fluid cokers using Equations 200-1, 200-2, and 200-3.

$$CO_2 = \sum_{i=1}^{n} CR_i \times CF \times 3.664 \times 0.001 \qquad \textbf{Equation 200-1}$$

Where:

CO_2	=	CO_2 emissions (metric tons/yr)
n	=	Number of weeks of operation in the report year (or number of days of operation if equipment is in place to make continuous measurements)
CR_i	=	Weekly coke burn rate in kg/week (or daily average coke burn rate in kg/day if equipment is in place to make continuous measurements)
CF	=	Carbon fraction in coke burned
3.664	=	Ratio of molecular weights, CO_2 to carbon

0.001	=	Conversion factor from kg to metric tons

Either continuously monitor the volumetric flow rate of exhaust gas from the fluid catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels or calculate the volumetric flow rate of this exhaust gas stream using Equation 200-2 of this section.

$$Q_r = \frac{\left(79 * Q_a + (100 - \%O_{oxy}) * Q_{oxy}\right)}{100 - \%CO_2 - \%CO - \%O_2}$$

Equation 200-2

Where:

Q_r	=	Volumetric flow rate of exhaust gas from regenerator before entering the emission control system (dSm^3/min)
Q_a	=	Volumetric flow rate of air to regenerator, as determined from control room instrumentation (dSm^3/min)
$\%Q_{oxy}$	=	Oxygen concentration in oxygen enriched air stream, percent by volume – dry basis
Q_{oxy}	=	Volumetric flow rate of O_2 enriched air to regenerator as determined from catalytic cracking unit control room instrumentation (dSm^3/min)
$\%CO_2$	=	Carbon dioxide concentration in regenerator exhaust, percent by volume – dry basis
$\%CO$	=	CO concentration in regenerator exhaust, percent by volume – dry basis. When no auxiliary fuel is burned and a continuous CO monitor is not required, assume %CO to be zero
$\%O_2$	=	O_2 concentration in regenerator exhaust, percent by volume – dry basis

Calculate the coke burn rate using Equation 200-3:

$$CR_i = K_1 Q_r \times (\%CO_2 + \%CO) + K_2 Q_a - K_3 Q_r \times \left[\%CO/2 + \%CO_2 + \%O_2\right] + K_3 Q_{oxy} \times (\%O_{oxy})$$

Equation 200-3

Where:

CR_i	=	Weekly coke burn rate in kg/week (or daily coke burn rate in kg/day if equipment is in place to make continuous measurements)
K_1, K_2, K_3	=	Material balance and conversion factors (K_1, K_2, and K_3 from Table 200-1
Q_r	=	Volumetric flow rate of exhaust gas before entering the emission control system (dSm^3/min)
Q_a	=	Volumetric flow rate of air to regenerator as determined from control room instrumentation (dSm^3/min)
$\%CO_2$	=	CO_2 concentration in regenerator exhaust, percent by volume – dry basis

%CO	=	CO concentration in regenerator exhaust, percent by volume – dry basis
$\%O_2$	=	O_2 concentration in regenerator exhaust, percent by volume – dry basis
Q_{oxy}	=	Volumetric flow rate of O_2 enriched air to regenerator as determined from control room instrumentation (dSm^3/min)
$\%O_{oxy}$	=	O_2 concentration in O_2 enriched air stream inlet to regenerator, percent by volume – dry basis

(B) The operator shall calculate process CO_2 emissions resulting from continuous catalyst regeneration in operations other than FCCUs and fluid cokers (e.g. catalytic reforming) using Equation 200-4.

$$CO_2 = CC_{irc} \times (CF_{spent} - CF_{regen}) \times H \times 3.664$$ **Equation 200-4**

Where:

CO_2	=	CO_2 emissions (metric tons/yr)
CC_{irc}	=	Average catalyst regeneration rate (metric tons/hr)
CF_{spent}	=	Weight carbon fraction on spent catalyst
CF_{regen}	=	Weight carbon fraction on regenerated catalyst (default = 0)
H	=	Hours regenerator was operational (hr/yr)
3.664	=	Ratio of molecular weights, CO_2 to carbon

(C) The operator shall calculate process CO_2 emissions resulting from periodic catalyst regeneration using Equations 200-5

$$CO_2 = \sum_{1}^{n} \left[\left(CB_Q \right)_n \times CC \times 3.664 \times 0.001 \right]$$ **Equation 200-5**

Where:

CO_2	=	Annual CO_2 emissions (metric tons/year).
CB_Q	=	Coke burn-off quantity per regeneration cycle from engineering estimates (kg coke/cycle).
n	=	Number of regeneration cycles in the calendar year.
CC	=	Carbon content of coke based on measurement or engineering estimate (kg C per kg coke); default = 0.94.
3.664	=	ratio of molecular weights, CO_2 to carbon
0.001	=	Conversion factor (metric ton/kg).

(2) Calculate CH_4 emissions using either unit specific measurement data, a unit-specific emission factor based on a source test of the unit, or Equation 200-6 of this section.

$$CH_4 = \left(CO_2 * \frac{EmF_2}{EmF_1} \right)$$ **Equation 200-6**

Where:

CH_4	=	Annual methane emissions from coke burn-off (metric tons CH_4/year).
CO_2	=	Emission rate of CO_2 from coke burn-off calculated in paragraph (a)(1) of this section, as applicable (metric tons/year).
EmF_1	=	Default CO_2 emission factor for petroleum coke of 97 kg CO_2/GJ
EmF_2	=	Default CH_4 emission factor of 2.8 x 10^{-3} kg CH_4/GJ).

(3) Calculate N_2O emissions using either unit specific measurement data, a unit-specific emission factor based on a source test of the unit, or Equation 200-7 of this section.

$$N_2O = \left(CO_2 * \frac{EmF_3}{EmF_1} \right)$$ **Equation 200-7**

Where:

N_2O	=	Annual nitrous oxide emissions from coke burn-off (mt N_2O/year).
CO_2	=	Emission rate of CO_2 from coke burn-off calculated in paragraphs (a)(1) of this section, as applicable (metric tons/year).
EmF_1	=	Default CO_2 emission factor for petroleum coke of 97 kg CO_2/GJ .
EmF_3	=	Default N_2O emission factor of 5.7 x10^{-4} kg N_2O/GJ.

(b) **Process Vents.** Except for process emissions reported under other requirements of this regulation, the operator shall calculate process emissions of CO_2, CH_4, and N_2O from process vents using Equation 200-8 for each process vent that can be reasonably expected to contain greater than 2 percent by volume CO_2 or greater than 0.5 percent by volume of CH_4 or greater than 0.01 percent by volume (100 parts per million) of N_2O.

$$E_x = \sum_{i=1}^{n} VR_i \times F_{xi} \times (MW_x / MVC) \times VT_i \times 0.001$$ **Equation 200-8**

Where:

E_x	=	Annual emissions of x (metric tons/yr), where x = CO_2, N_2O, or CH_4
VR_i	=	Average volumetric flow rate for venting event i from measurement data, process knowledge or engineering estimates (Sm^3/unit time)

F_{xi} = Molar fraction of x in vent gas stream during event i from measurement data, process knowledge or engineering estimates.
MW_x = Molecular weight of x (kg/kg-mole)
MVC = Molar volume conversion (24.06 m^3/kg-mole for STP of 20°C and 1 atmosphere, or 23.67 m^3/kg-mole for STP of 15.6°C and 1 atmosphere)
VT_i = Time duration of venting event i, in same units of time as VR_i
n = Number of venting events in report year
0.001 = Conversion factor from kg to metric tons

(c) **Asphalt Production**. The operator shall calculate CO_2 and CH_4 process emissions from asphalt blowing activities using either process vent method specified in paragraph (b) or according to the applicable provisions in paragraphs (c)(1) and (c)(2) of this section.

(1) For uncontrolled asphalt blowing operations or asphalt blowing operations controlled by vapor scrubbing, calculate CO_2 and CH_4 emissions using Equations 200-9 and 200-10 of this section, respectively.

$$CO_2 = (Q_{AB} \times EF_{AB.CO2}) \qquad \textbf{Equation 200-9}$$

Where:

CO_2 = Annual CO_2 emissions from uncontrolled asphalt blowing (metric tons CO_2/year).
Q_{AB} = Quantity of asphalt blown (million barrels per year, MMbbl/year).
$EF_{AB,CO2}$ = Emission factor for CO_2 from uncontrolled asphalt blowing from facility-specific test data (metric tons CO_2/MMbbl asphalt blown); default = 1,100.

$$CH_4 = (Q_{AB} \times EF_{AB,CH4}) \qquad \textbf{Equation 200-10}$$

Where:
CH_4 = Annual methane emissions from uncontrolled asphalt blowing (metric tons CH_4/year).
Q_{AB} = Quantity of asphalt blown (million barrels per year, MMbbl/year).
$EF_{AB,CH4}$ = Emission factor for CH_4 from uncontrolled asphalt blowing from facility-specific test data (metric tons CH_4/MMbbl asphalt blown); default = 580.

(2) For asphalt blowing operations controlled by thermal oxidizer or flare, calculate CO_2 and CH_4 emissions using Equations 200-11 and 200-12 of this section, respectively, provided these emissions are not already included in the flare emissions calculated in paragraph (e) of this section or in the stationary combustion unit emissions required under WCI.20.

$$CO_2 = 0.98 \times (Q_{AB} \times CEF_{AB} \times 3.664) \qquad \textbf{Equation 200-11}$$

Where:

CO_2 = Annual CO_2 emissions from controlled asphalt blowing (metric tons CO_2/year).

0.98	=	Assumed combustion efficiency of thermal oxidizer or flare.
Q_{AB}	=	Quantity of asphalt blown (MMbbl/year).
CEF_{AB}	=	Carbon emission factor from asphalt blowing from facility-specific test data (metric tons C/MMbbl asphalt blown); default = 2,750.
3.664	=	ratio of molecular weights, carbon dioxide to carbon

$$CH_4 = 0.02 \times (Q_{AB} \times EF_{AB,CH4})$$ **Equation 200-12**

Where:

CH_4	=	Annual methane emissions from controlled asphalt blowing (metric tons CH_4/year).
0.02	=	Fraction of methane uncombusted in thermal oxidizer or flare based on assumed 98% combustion efficiency.
Q_{AB}	=	Quantity of asphalt blown (million barrels per year, MMbbl/year).
$EF_{AB,CH4}$	=	Emission factor for CH_4 from uncontrolled asphalt blowing from facility-specific test data (metric tons CH_4/MMbbl asphalt blown); default = 580.

(d) **Sulphur Recovery**. The operator shall calculate CO_2 process emissions from sulphur recovery units (SRUs) using Equation 200-13. For the molar fraction (MF) of CO_2 in the sour gas, use either a default factor of 0.20 or a source specific molar fraction value approved by the regulator and derived from source tests conducted at least once per calendar year under the supervision of the regulator.

$$CO_2 = FR \times MW_{CO2} / MVC \times MF \times 0.001$$ **Equation 200-13**

Where:

CO_2	=	Emissions of CO_2 (metric tons/yr)
FR	=	Volumetric flow rate of acid gas to SRU (Sm^3/year)
MW_{CO2}	=	Molecular weight of CO_2 (44 kg/kg-mole)
MVC	=	Molar volume conversion (24.06 m^3/kg-mole for STP of 20°C and 1 atmosphere, or 23.67 m^3/kg-mole for STP of 15.6°C and 1 atmosphere)
MF	=	Molar fraction (%) of CO_2 in sour gas (default MF = 20% expressed as 0.20)
0.001	=	Conversion factor from kg to metric tons

(e) **Flares and Other Control Devices**.

(1) The operator shall calculate and report CO_2, CH_4 and N_2O emissions resulting from the combustion of flare pilot and purge gas using the appropriate method(s) specified in section WCI.20.

(2) The operator shall calculate and report CO_2 emissions resulting from the combustion of hydrocarbons routed to flares for destruction as follows:

(i) Heat value or carbon content measurement. If you have a continuous higher heating value monitor or gas composition monitor on the flare or if you monitor these parameters at least weekly, you must use the measured heat value or carbon content value in calculating the CO_2 emissions from the flare using the applicable methods in paragraphs (e)(2)(i)(A) and (e)(2)(i)(B).

(A) If you monitor gas composition, calculate the CO_2 emissions from the flare using Equation 200-14 of this section. If daily or more frequent measurement data are available, you must use daily values when using Equation 200-14 of this section; otherwise, use weekly values.

$$CO_2 = 0.98 \times 0.001 \times \left(\sum_{p=1}^{n} \left[3.664 \times (Flare)_p \times \frac{(MW)_p}{MVC} \times (CC)_p \right] \right) \quad \textbf{Equation 200-14}$$

Where:

CO_2	=	Annual CO_2 emissions for a specific fuel type (metric tons/year).
0.98	=	Assumed combustion efficiency of a flare.
0.001	=	Unit conversion factor (metric tons per kilogram, mt/kg).
n	=	Number of measurement periods. The minimum value for n is 52 (for weekly measurements); the maximum value for n is 366 (for daily measurements during a leap year).
p	=	Measurement period index.
3.664	=	Ratio of molecular weights, carbon dioxide to carbon
$(Flare)_p$	=	Volume of flare gas combusted during measurement period (Sm^3/period). If a mass flow meter is used, measure flare gas flow rate in kg/period and replace the term "$(MW)_p$/MVC" with "1".
$(MW)_p$	=	Average molecular weight of the flare gas combusted during measurement period (kg/kg-mole). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.
MVC	=	Molar volume conversion (24.06 m^3/kg-mole for STP of 20°C and 1 atmosphere, or 23.67 m^3/kg-mole for STP of 15.6°C and 1 atmosphere).
$(CC)_p$	=	Average carbon content of the flare gas combusted during measurement period (kg C per kg flare gas). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.

(B) If you monitor heat content but do not monitor gas composition, calculate the CO_2 emissions from the flare using Equation 200-15 of this section. If daily or more frequent measurement data are available, you must use daily values when using Equation 200-15 of this section; otherwise, use weekly values.

$$CO_2 = 0.98 \times 0.001 \times \sum_{p=1}^{n} \left[(Flare)_p \times (HHV)_p \times EmF \right]$$ **Equation 200-15**

Where:

CO_2	=	Annual CO_2 emissions for a specific fuel type (metric tons/year).
0.98	=	Assumed combustion efficiency of a flare.
0.001	=	Unit conversion factor (metric tons per kilogram, mt/kg).
n	=	Number of measurement periods. The minimum value for n is 52 (for weekly measurements); the maximum value for n is 366 (for daily measurements during a leap year).
p	=	Measurement period index.
$(Flare)_p$	=	Volume of flare gas combusted during measurement period (Sm^3/period). If a mass flow meter is used, you must also measure molecular weight and convert the mass flow to a volumetric flow as follows: Flare[m^3] = 0.000001 × Flare[kg] × MVC/$(MW)_p$, where MVC is the molar volume conversion (24.06 m^3/kg-mole for STP of 20°C and 1 atmosphere, or 23.67 m^3/kg-mole for STP of 15.6°C and 1 atmosphere) and $(MW)_p$ is the average molecular weight of the flare gas combusted during measurement period (kg/kg-mole).
$(HHV)_p$	=	Higher heating value for the flare gas combusted during measurement period (GJ per m^3,). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.
EmF	=	Default CO_2 emission factor of 57 kilograms CO_2/GJ (HHV basis).

(ii) Alternative Method for Startup, Shutdown, and Malfunctions. For startup, shutdown, and malfunctions during which you were unable to measure the parameters required by Equations 200-14 and 200-15 of this section, you must determine the quantity of gas discharged to the flare separately for each start-up, shutdown, or malfunction, and calculate the CO_2 emissions as specified in paragraphs (e)(1)(iii)(A) and (e)(1)(iii)(B) of this section.

(A) For periods of start-up, shutdown, or malfunction, use engineering calculations and process knowledge to estimate the carbon content of the flared gas for each start-up, shutdown, or malfunction event.

(B) Calculate the CO_2 emissions using Equation 200-16 of this section.

$$CO_2 = 0.98 \times 0.001 \times \left(\sum_{p=1}^{n} \left[3.664 \times (Flare_{SSM})_p \times \frac{(MW)_p}{MVC} \times (CC)_p \right] \right)$$ **Equation 200-16**

Where:

CO_2	=	Annual CO_2 emissions for a specific fuel type (metric tons/year).
0.98	=	Assumed combustion efficiency of a flare.
0.001	=	Unit conversion factor (metric tons per kilogram, mt/kg).
n	=	Number of start-up, shutdown, and malfunction events during the reporting year.
p	=	Start-up, shutdown, and malfunction event index.
$(Flare_{SSM})_p$	=	Volume of flare gas combusted during indexed start-up, shutdown, or malfunction event from engineering calculations, (m^3/event).
$(MW)_p$	=	Average molecular weight of the flare gas, from the analysis results or engineering calculations for the event (kg/kg-mole).
MVC	=	Molar volume conversion (24.06 m^3/kg-mole for STP of 20°C and 1 atmosphere, or 23.67 m^3/kg-mole for STP of 15.6°C and 1 atmosphere)
$(CC)_p$	=	Average carbon content of the flare gas, from analysis results or engineering calculations for the event (kg C per kg flare gas).
3.664	=	Ratio of molecular weights, carbon dioxide to carbon

(3) The operator shall calculate and report CH_4 and N_2O emissions resulting from the combustion of hydrocarbons routed to flares for destruction using the methods specified in paragraphs (e)(3)(A) and (e)(3)(B):

(A) Calculate CH_4 using Equation 200-17 of this section.

$$CH_4 = \left(CO_2 \times \frac{EmF_{CH4}}{EmF} \right) + CO_2 \times \frac{0.02}{0.98} \times \frac{16}{44} \times f_{CH4} \qquad \textbf{Equation 200-17}$$

Where:

CH_4	=	Annual methane emissions from flared gas (metric tons CH_4/year).
CO_2	=	Emission rate of CO_2 from flared gas calculated in paragraph (e)(1) and (e)(2) of this section (metric tons/year).
EmF_{CH4}	=	Default CH_4 emission factor for Petroleum Products of 2.8×10^{-3} kg/GJ
EmF	=	Default CO_2 emission factor for flare gas of 57 kilograms CO_2/GJ (HHV basis).
0.02/0.98	=	Correction factor for flare combustion efficiency.
16/44	=	Correction factor ratio of the molecular weight of CH_4 to CO_2
f_{CH4}	=	Weight fraction of carbon in the flare gas prior to combustion that is contributed by methane from measurement values or engineering calculations (kg C in methane in flare gas/kg C in flare gas); default is 0.4.

(B) Calculate N_2O emissions using Equation 200-18 of this section.

$$N_2O = \left(CO_2 \times \frac{EmF_{N2O}}{EmF} \right) \quad \textbf{Equation 200-18}$$

Where:

N_2O = Annual nitrous oxide emissions from flared gas (metric tons N_2O/year).

CO_2 = Emission rate of CO_2 from flared gas calculated in paragraph (b)(1) and (b)(2) of this section (metric tons/year).

EmF_{N2O} = Default N_2O emission factor for Petroleum Products of 5.7×10^{-4} kg/GJ .

EmF = Default CO_2 emission factor for flare gas of 57 kilograms CO_2/GJ (HHV basis).

(4) The operator who uses methods other than flares (e.g. incineration, combustion as a supplemental fuel in heaters or boilers) to destroy low Btu gases (e.g. coker flue gas, gases from vapor recovery systems, casing vents and product storage tanks) shall calculate CO_2 emissions using Equation 200-19. The operator shall determine CC_A and MW_A quarterly using methods specified in WCI.20 and use the annual average values of CC_A and MW_A to calculate CO_2 emissions.

$$CO_2 = GV_A \times CC_A \times MW_A / MVC \times 3.664 \times 0.001 \quad \textbf{Equation 200-19}$$

Where:

CO_2 = CO_2 emissions (metric tons/year)
GV_A = Volume of gas A destroyed annually (m^3/year)
CC_A = Carbon content of gas A (kg C/kg fuel)
MW_A = Molecular weight of gas A
MVC = Molar volume conversion (24.06 m^3/kg-mole for STP of 20°C and 1 atmosphere, or 23.67 m^3/kg-mole for STP of 15.6°C and 1 atmosphere)
3.664 = Ratio of molecular weights, CO_2 to carbon
0.001 = Conversion factor – kg to metric tons

(f) **Storage Tanks.** For storage tanks other than those processing unstabilized crude oil except as provided in paragraph (f)(3) of this section, calculate CH_4 emissions using the applicable methods in paragraphs (f)(1) and (f)(2) of this section.

(1) For storage tanks other than those processing unstabilized crude oil, you must either calculate CH_4 emissions from storage tanks that have a vapor-phase methane concentration of 0.5 volume percent or more using tank-specific methane composition data (from measurement data or product knowledge) and the AP-42 emission estimation methods provided in Section 7.1 of the AP-42: "Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources", including TANKS Model (Version 4.09D) or similar programs, or estimate CH_4 emissions from storage tanks using Equation 200-20 of this section.

$$CH_4 = (0.1 \times Q_{Ref}) \quad \textbf{Equation 200-20}$$

Where:

CH_4	=	Annual methane emissions from storage tanks (metric tons/year).
0.1	=	Default emission factor for storage tanks (metric ton CH_4/MMbbl).
Q_{Ref}	=	Quantity of crude oil plus the quantity of intermediate products received from off site that are processed at the facility (MMbbl/year).

(2) For storage tanks that process unstabilized crude oil, calculate CH_4 emissions from the storage of unstabilized crude oil using either tank-specific methane composition data (from measurement data or product knowledge) and direct measurement of the gas generation rate or by using Equation 200-21 of this section.

$$CH_4 = (995{,}000 \times Q_{un} \times \Delta P) \times MF_{CH4} \times \frac{16}{MVC} \times 0.001 \quad \textbf{Equation 200-21}$$

Where:

CH_4	=	Annual methane emissions from storage tanks (metric tons/year).
Q_{un}	=	Quantity of unstabilized crude oil received at the facility (MMbbl/year).
ΔP	=	Pressure differential from the previous storage pressure to atmospheric pressure (pounds per square inch, psi).
MF_{CH4}	=	Mole fraction of CH_4 in vent gas from the unstabilized crude oil storage tank from facility measurements (kg-mole CH_4/kg-mole gas); use 0.27 as a default if measurement data are not available.
995,000	=	Correlation Equation factor (scf gas per MMbbl per psi)
16	=	Molecular weight of CH_4 (kg/kg-mole).
MVC	=	Molar volume conversion (849.5 scf/kg-mole).
0.001	=	Conversion factor (metric ton/kg).

(3) You do not need to calculate CH_4 emissions from storage tanks that meet any of the following descriptions:

(i) Units permanently attached to conveyances such as trucks, trailers, rail cars, barges, or ships;

(ii) Pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere;
(iii) Bottoms receivers or sumps;
(iv) Vessels storing wastewater; or
(v) Reactor vessels associated with a manufacturing process unit.

(g) **Industrial Wastewater Processing**.

(1) The operator shall calculate CH_4 emissions from anaerobic wastewater treatment (such as anaerobic reactor, digester, or lagoon) using Equation 200-22 or Equation 200-23.

$$CH_4 = Q \times COD_{qave} \times B \times MCF \times 0.001 \qquad \textbf{Equation 200-22}$$

$$CH_4 = Q \times BOD_{5qave} \times B \times MCF \times 0.001 \qquad \textbf{Equation 200-23}$$

Where:

CH_4	=	Emission of methane (metric tons/yr)
Q	=	Volume of wastewater treated (m^3/yr)
COD_{qave}	=	Average of quarterly determinations of chemical oxygen demand of the wastewater (kg/m^3)
BOD_{5qave}	=	Average of quarterly determinations of five-day biochemical oxygen demand of the wastewater (kg/m^3)
B	=	Methane generation capacity (B = 0.25 kg CH_4/kg COD and 0.06 kg CH_4/kg BOD_5)
MCF	=	Methane correction factor for anaerobic decay (0-1.0) from Table 200-2
0.001	=	Conversion factor – kg to metric tons

(2) For anaerobic processes from which biogas is recovered and not emitted, you must adjust the CH_4 emissions calculated in paragraph (g)(1) by the amount of CH_4 collected.

(3) The operator shall calculate N_2O emissions from wastewater treatment using Equation 200-24.

$$N_2O = Q \times N_{qave} \times EF_{N2O} \times 1.571 \times 0.001 \qquad \textbf{Equation 200-24}$$

Where:

N_2O	=	Emissions of N_2O (metric tons/yr)

Q	=	Volume of wastewater treated (m^3/yr)
N_{qave}	=	Average of quarterly determinations of N in effluent (kg N/m^3)
EF_{N2O}	=	Emission factor for N_2O from discharged wastewater (0.005 kg N_2O-N/kg N)
1.571	=	Conversion factor – kg N_2O-N to kg N_2O
0.001	=	Conversion factor – kg to metric tons

(4) **Oil-Water Separators.** The operator shall calculate CH_4 emissions from oil-water separators using Equation 200-25. For the CF_{NMHC} conversion factor, operators shall use either a default factor of 0.6 or species specific conversion factors determined by analysis using a sampling and analysis methodology approved by regulator.

$$CH_4 = EF_{sep} \times V_{water} \times CF_{NMHC} \times 0.001 \qquad \textbf{Equation 200-25}$$

Where:

CH_4	=	Emission of methane (metric tons/yr)
EF_{sep}	=	NMHC (non methane hydrocarbon) emission factor (kg/m^3) from Table 200-3.
V_{water}	=	Volume of waste water treated by the separator (m^3/yr)
CF_{NMHC}	=	NMHC to CH_4 conversion factor
0.001	=	Conversion factor from kg to metric tons

(h) **Equipment leaks**. **C**alculate CH_4 emissions using the method specified in either paragraph (h)(1) or (h)(2) of this section.

(1) Use process-specific methane composition data (from measurement data or process knowledge) and any of the emission estimation procedures provided in the Protocol for Equipment Leak Emissions Estimates (EPA-453/R-95-017, NTIS PB96-175401).

(2) Use Equation 200-26 of this section.

$$CH_4 = (0.4 \times N_{CD} + 0.2 \times N_{PU1} + 0.1 \times N_{PU2} + 4.3 \times N_{H2} + 6 \times N_{FGS}) \qquad \textbf{Equation 200-26}$$

Where:

CH_4	=	Annual methane emissions from equipment leaks (metric tons/year)
N_{CD}	=	Number of atmospheric crude oil distillation columns at the facility.
N_{PU1}	=	Cumulative number of catalytic cracking units, coking units (delayed or fluid), hydrocracking, and full-range distillation columns (including depropanizer and debutanizer distillation columns) at the facility.
N_{PU2}	=	Cumulative number of hydrotreating/hydrorefining units, catalytic reforming units, and visbreaking units at the facility.

N_{H2} = Total number of hydrogen plants at the facility.

N_{FGS} = Total number of fuel gas systems at the facility.

(i) **Coke Calcining.** The operator shall calculate GHG emissions according to the applicable provisions in paragraphs (i)(1) through (i)(3) of this section.

(1) If you operate and maintain a CEMS that measures CO_2 emissions according to WCI.20, you must calculate and report CO_2 emissions for coke calcining by following the CEMS Calculation Methodology specified in WCI.20. If the coke calcining unit is not equipped with CEMS must either install a CEMS that complies with the CEMS requirements in WCI.20, or follow the requirements of paragraph (i)(2) of this section.

(2) Calculate the CO_2 emissions from the coke calcining unit using Equation 200-27 of this section.

$$CO_2 = 3.664 \times \left(M_{in} \times CC_{GC} - (M_{out} + M_{dust}) \times CC_{MPC} \right) \quad \textbf{Equation 200-27}$$

Where:

CO_2 = Annual CO_2 emissions (metric tons/year).

M_{in} = Annual mass of green coke fed to the coke calcining unit from facility records (metric tons/year).

CC_{GC} = Average mass fraction carbon content of green coke from facility measurement data (metric ton carbon/metric ton green coke).

M_{out} = Annual mass of marketable petroleum coke produced by the coke calcining unit from facility records (metric tons petroleum coke/year).

M_{dust} = Annual mass of petroleum coke dust collected in the dust collection system of the coke calcining unit from facility records (metric ton petroleum coke dust/year)

CC_{MPC} = Average mass fraction carbon content of marketable petroleum coke produced by the coke calcining unit from facility measurement data (metric ton carbon/metric ton petroleum coke).

3.664 = Ratio of molecular weights, carbon dioxide to carbon

(3) For all coke calcining units, use the CO_2 emissions from the coke calcining unit calculated in paragraphs (i)(1) or (i)(2), as applicable, and calculate CH_4 and N_2O using the following methods:

(i) Calculate CH_4 emissions using either unit specific measurement data, a unit-specific emission factor based on a source test of the unit, or Equation 200-28 of this section.

$$CH_4 = \left(CO_2 * \frac{EmF_2}{EmF_1} \right)$$ **Equation 200-28**

Where:

CH_4 = Annual methane emissions (metric tons CH_4/year).

CO_2 = Emission rate of CO_2 calculated in paragraphs (i)(1) and (i)(2) of this section, as applicable (metric tons/year).

EmF_1 = Default CO_2 emission factor for petroleum coke (97 kg CO_2/GJ).

EmF_2 = Default CH_4 emission factor of 2.8 x 10^{-3} kg CH_4/GJ).

(ii) Calculate N_2O emissions using either unit specific measurement data, a unit-specific emission factor based on a source test of the unit, or Equation 200-29 of this section.

$$N_2O = \left(CO_2 * \frac{EmF_3}{EmF_1} \right)$$ **Equation 200-29**

Where:

N_2O = Annual nitrous oxide emissions (metric tons N_2O/year).

CO_2 = Emission rate of CO_2 from paragraphs (i)(1) and (i)(2) of this section, as applicable (metric tons/year).

EmF_1 = Default CO_2 emission factor for petroleum coke (97 kg CO_2/GJ)

EmF_3 = Default N_2O emission factor of 5.7 x 10^{-4} kg N_2O/GJ.

(j) **Uncontrolled Blowdown Systems**. For uncontrolled blowdown systems, you must use the methods for process vents in paragraph (b) of this section.

(k) **Loading Operations**. For crude oil, intermediate, or product loading operations for which the equilibrium vapor-phase concentration of methane is 0.5 volume percent or more, calculate CH_4 emissions from loading operations using product-specific, vapor-phase methane composition data (from measurement data or process knowledge) and the emission estimation procedures provided in Section 5.2 of the AP-42: "Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources." For loading operations in which the equilibrium vapor-phase concentration of methane is less than 0.5 volume percent, you may assume zero methane emissions.

(l) **Delayed coking units.** Calculate the CH_4 emissions from the depressurization of the coking unit vessel (i.e., the "coke drum") to atmosphere using either of the methods provided in paragraphs (l)(1) or (l)(2), provided no water or steam is added to the vessel once it is vented to the atmosphere. You must use the method in paragraph (l)(1) of this section if you add water or steam to the vessel after it is vented to the atmosphere.

(1) Use the process vent method in paragraph (b) of this section and also calculate the CH_4 emissions from the subsequent opening of the vessel for coke cutting operations using Equation 200-30 of this section. If you have coke drums or

vessels of different dimensions, use Equation 200-30 for each set of coke drums or vessels of the same size and sum the resultant emissions across each set of coke drums or vessels to calculate the CH_4 emissions for all delayed coking units.

$$CH_4 = \left(N \times H \times \frac{(P_{CV} + 101.325)}{101.325} \times f_{void} \times \frac{\pi \times D^2}{4} \times \frac{16}{MVC} \times MF_{CH4} \times 0.001 \right) \quad \textbf{Equation 200-30}$$

Where:

CH_4	=	Annual methane emissions from the delayed coking unit vessel opening (metric tons/year).
N	=	Cumulative number of vessel openings for all delayed coking unit vessels of the same dimensions during the year.
H	=	Height of coking unit vessel (Meters).
P_{CV}	=	Gauge pressure of the coking vessel when opened to the atmosphere prior to coke cutting or, if the alternative method provided in paragraph (l)(2) of this section is used, gauge pressure of the coking vessel when depressurization gases are first routed to the atmosphere (kilopascals)
101.325	=	Assumed atmospheric pressure (kilopascals, kPa)
f_{void}	=	Volumetric void fraction of coking vessel prior to steaming based on engineering judgement (m^3 gas/m^3 of vessel);
D	=	Diameter of coking unit vessel (Meters).
16	=	Molecular weight of CH_4 (kg/kg-mole).
MVC	=	Molar volume conversion (24.06 m^3/ kg-mole for STP of 20°C and 1 atmosphere, or 23.67 m^3/kg-mole for STP of 15.6°C and 1 atmosphere).
MF_{CH4}	=	Average mole fraction of methane in coking vessel gas based on the analysis of at least two samples per year, collected at least four months apart (kg-mole CH_4/kg-mole gas, wet basis);
0.001	=	Conversion factor (metric ton/kg).

(2) Calculate the CH_4 emissions from the depressurization vent and subsequent opening of the vessel for coke cutting operations using Equation 200-18 of this section and the pressure of the coking vessel when the depressurization gases are first routed to the atmosphere. If you have coke drums or vessels of different dimensions, use Equation 200-30 for each set of coke drums or vessels of the same size and sum the resultant emissions across each set of coke drums or vessels to calculate the CH_4 emissions for all delayed coking units.

§ WCI.204 Sampling, Analysis, and Measurement Requirements

(a) Catalyst Regeneration.

(1) For FCCUs and fluid coking units, the operators shall measure the following parameters:

(A) The daily oxygen concentration in the oxygen enriched air stream inlet to the regenerator.

(B) Continuous measurements of the volumetric flow rate of air and oxygen enriched air entering the regenerator.

(C) Weekly periodic measurements of the CO_2, CO and O_2 concentrations in the regenerator exhaust gas (or continuous measurements if the equipment necessary to make continuous measurements is already in place).

(D) Daily determinations of the carbon content of the coke burned.

(E) The number of days of operation.

(2) For periodic catalyst regeneration, the operators shall measure the following parameters.

(A) The mass of catalyst regenerated in each regeneration cycle.

(B) The weight fraction of carbon on the catalyst prior to and after catalyst regeneration.

(3) For continuous catalyst regeneration in operations other than FCCUs and fluid cokers, the operators shall measure the following parameters.

(A) The hourly catalyst regeneration rate.

(B) The weight fraction of carbon on the catalyst prior to and after catalyst regeneration.

(C) The number of hours of operation.

(b) Process vents. Operators shall measure the following parameters for each process vent.

(1) The vent flow rate for each venting event from measurement data, process knowledge or engineering estimates.

(2) The molar fraction of CO_2, N_2O, and CH_4 in the vent gas stream during each venting event from measurement data, process knowledge or engineering estimates.

(3) The duration of each venting event.

(c) Asphalt Production. Operators shall measure the mass of asphalt blown.

(d) Sulphur Recovery. The operator shall measure the volumetric flow rate of acid gas to the SRU. If using source specific molar fraction value instead of the default factor, the operator shall conduct an annual test of the CO_2 content using methods approved by the Director. The operator shall submit a test plan to the regulator for approval. Once approved, the annual tests shall be conducted in accordance with the approved test plan under the supervision of the Director.

(e) Flares and Other Control Devices. The operator shall measure the following:

(1) If you have a continuous flow monitor on the flare, you must use the measured flow rates when the monitor is operational and the flow rate is within the calibrated range of the measurement device to calculate the flare gas flow. If you do not have a continuous flow monitor on the flare and for periods when the monitor is not

operational or the flow rate is outside the calibrated range of the measurement device, you must use engineering calculations, company records, or similar estimates of volumetric flare gas flow.

(2) If using the method specified in WCI.203(e)(2)(i)(A), monitor the high heat value of the flare gas daily if the flare is already equipped with the necessary measurement devices (at least weekly if not).

(3) If using the method specified in WCI.203(e)(2)(i)(B), monitor the carbon content of the flare gas daily if the flare is already equipped with the necessary measurement devices (at least weekly if not).

(f) Storage Tanks. The operator shall measure the annual throughput of crude oil, naphtha, distillate oil, asphalt, and gas oil for each storage tank using flow meters.

(g) Wastewater Treatment. Operators shall measure the following parameters.

(1) You must collect samples representing wastewater influent to the anaerobic wastewater treatment process, following all preliminary and primary treatment steps (e.g., after grit removal, primary clarification, oil-water separation, dissolved air flotation, or similar solids and oil separation processes). You must collect and analyze samples for COD or BOD_5 concentration once each calendar week.

(2) You must measure the flowrate of wastewater entering anaerobic wastewater treatment process once each calendar week. The flow measurement location must correspond to the location used to collect samples analyzed for COD or BOD_5 concentration.

(3) The quarterly nitrogen content of the wastewater.

(4) Oil-Water Separators. Operators shall measure the daily volume of waste water treated by the oil-water separators .

(h) Coke Calcining. Determine the mass of petroleum coke as required using measurement equipment used for accounting purposes. Determine the carbon content of petroleum coke as using any one of the following methods:

(1) ASTM D3176-89 (Reapproved 2002) Standard Practice for Ultimate Analysis of Coal and Coke.

(2) ASTM D5291-02 (Reapproved 2007) Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants.

(3) ASTM D5373-08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal

§ WCI.205 Procedures for Estimating Missing Data.

A complete record of all measured parameters used in the GHG emissions calculations is required (e.g., concentrations, flow rates, fuel heating values, carbon content values). Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a CEMS malfunctions during unit operation or if a required fuel sample is not taken), a substitute data value for the missing parameter shall be used in the calculations.

(a) For stationary combustion sources, use the missing data procedures in WCI.20.

(b) For each missing value of the heat content, carbon content, or molecular weight of the fuel, substitute the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If the "after" value is not obtained by the end of the reporting year, you may use the "before" value for the missing data substitution. If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.

(c) For missing CO_2, CO, O_2, CH_4, or N_2O concentrations, gas flow rate, and percent moisture, the substitute data values shall be the best available estimate(s) of the parameter(s), based on all available process data (e.g., processing rates, operating hours, etc.). The owner or operator shall document and keep records of the procedures used for all such estimates.

Table 200-1. Coke burn rate material balance and conversion factors

	(kg min)/(hr dSm^3%)	(lb min)/(hr dscf %)
K_1	0.2982	0.0186
K_2	2.0880	0.1303
K_3	0.0994	0.0062

Table 200-2. Default MCF Values for Industrial Wastewater

Type of Treatment and Discharge Pathway or System	Comments	MCF	Range
Untreated			
Sea, river and lake discharge	Rivers with high organic loading may turn anaerobic, however this is not considered here	0.1	0 - 0.2
Treated			
Aerobic treatment plant	Well maintained, some CH_4 may be emitted from settling basins	0	0 – 0.1
Aerobic treatment plant	Not well maintained, overloaded	0.3	0.2 – 0.4
Anaerobic digester for sludge	CH_4 recovery not considered here	0.8	0.8 – 1.0
Anaerobic reactor	CH_4 recovery not considered here	0.8	0.8 – 1.0
Anaerobic shallow lagoon	Depth less than 2 Meters	0.2	0 – 0.3
Anaerobic deep lagoon	Depth more than 2 Meters	0.8	0.8 – 1.0

For CH_4 generation capacity (B) in kg CH_4/kg COD, use default factor of 0.25 kg CH_4/kg COD.

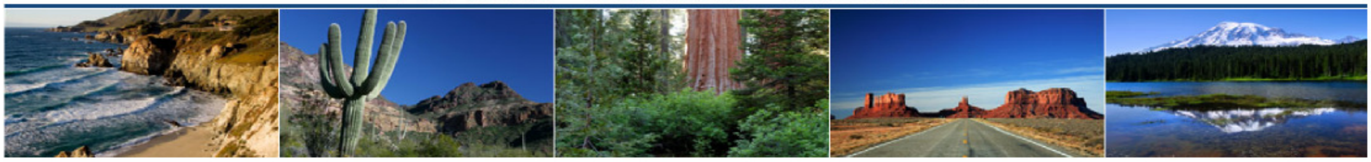
The emission factor for N_2O from discharged wastewater (EF_{N2O}) is 0.005 kg N_2O-N/kg-N.

MCF = methane conversion factor (the fraction of waste treated anaerobically).
COD = chemical oxygen demand (kg COD/m^3).

Table 200-3. Emission Factors for Oil/Water Separators	
Separator Type	**Emission factor (EF_{sep})[a] kg NMHC/m^3 wastewater treated**
Gravity type - uncovered	1.11e-01
Gravity type - covered	3.30e-03
Gravity type – covered and connected to destruction device	0
DAF[b] of IAF[c] - uncovered	4.00e-03[d]
DAF or IAF - covered	1.20e-04[d]
DAF or Iaf – covered and connected to a destruction device	0

[a] EFs do not include ethane
[b] DAF = dissolved air flotation type
[c] IAF = induced air flotation device
[d] EFs for these types of separators apply where they are installed as secondary treatment systems

Table 200-4. Data for Preparing the Asphalt Chemical Database	
Parameter	**Database Entry**
Liquid Molecular Weight	1000
Vapor Molecular Weight	105
Liquid Density (lb/gal. at 60 ^oF)	8.0925
Antoine's Equation Constants (using K)	A = 75350.06
	B = 9.00346



§ WCI.210 PULP AND PAPER MANUFACTURING

§ WCI.211 Source Category Definition

The pulp and paper manufacturing source category consists of facilities that produce market pulp (i.e., stand-alone pulp facilities), manufacture pulp and paper (i.e., integrated facilities), produce paper products from purchased pulp, produce secondary fiber from recycled paper, convert paper into paperboard products (e.g., containers), or operate coating and laminating processes

§ WCI.212 Greenhouse Gas Reporting Requirements

In addition to the information required by WCI.3, the annual emissions report must contain the following information:

(a) Annual CO_2, biogenic CO_2, CH_4, and N_2O process emissions from all recovery units and kilns combined in metric tons, as specified in WCI.213.

(b) Annual CO_2 emissions from addition of makeup chemicals ($CaCO_3$, Na_2CO_3) in the chemical recovery areas of chemical pulp mills.

(c) CO_2, N_2O, and CH_4 emissions from stationary combustion units in metric tons, as specified in WCI.23.

(d) Annual consumption of carbonate in metric tons.

(e) Annual black liquor production in metric tons.

(f) Annual N_2O, and CH_4 emissions from onsite wastewater treatment plants in metric tons, as specified in WCI.200 (if required by regulation)

§ WCI.213 Calculation of GHG Emissions

Calculate emissions from each unit (i.e., kraft or soda chemical recovery furnace, sulfite chemical recovery combustion unit, stand-alone semichemical recovery combustion unit, or kraft or soda pulp mill lime kiln) as specified under paragraphs (a) through (d) of this section. CH_4 and N_2O emissions must be calculated as the sum of emissions from combustion of fossil fuels and combustion of biomass in spent liquor solids.

(a) Calculate fossil-fuel based CO_2 emissions from direct measurement of fossil fuels consumed and the methodology for stationary combustion sources specified by WCI.20 for the appropriate fuel type. For kraft or soda pulp mill lime kilns, if WCI.20 allows the use of default emission factors, use the default CO_2 emission factors listed in Table 210-1.

(b) Calculate fossil-fuel based CH_4 and N_2O emissions from direct measurement of fossil fuels consumed, default HHV, and default emission factors according to the methodology specified by WCI.20. For kraft or soda pulp mill lime kilns, use the default CH_4 and N_2O emission factors listed in Table 210-1.

(c) Calculate biogenic CO_2 emissions and emissions of CH_4 and N_2O from biomass as specified under subparagraphs (1) through (3).

(1) For kraft or soda chemical recovery furnaces, calculate emissions using Equation 210-1:

$$Emissions = Solids \times HHV \times EF$$

Equation 210-1

Where:

Emissions = Biogenic CO_2 emissions and emissions of CH_4 and N_2O from biomass (spent liquor solids) combustion (metric tons/year).
Solids = Mass of spent liquor solids combusted (metric tons/year).
HHV = Annual high heat value of spent liquor solids (GJ/kg).
EF = Default emission factor for CO_2, CH_4, and N_2O from Table 210-2 (kg/GJ)

(2) For sulfite or stand-alone semichemical chemical recovery combustion units, calculate CO_2 emissions using Equation 210-2:

$$E_{CO2} = 3.664 \times Solids \times CC$$

Equation 210-2

Where:

E_{CO2} = Biogenic CO_2 emissions from spent liquor solids combustion (metric tons/year).
3.664 = Ratio of molecular weights, CO_2 to carbon.
Solids = Mass of spent liquor solids combusted (metric tons/year).
CC = Annual carbon content of spent liquor solids (percent by weight, expressed as a decimal fraction).

(3) For sulfite or stand-alone semichemical chemical recovery combustion units, calculate emissions of CH_4 and N_2O from biomass using Equation 210-1.

(d) For make-up chemical use, calculate CO_2 emissions by using direct or indirect measurement of the quantity of chemicals added and ratios of the molecular weights of CO_2 and make-up chemicals using Equation 210-3:

$$CO_2 = \left(\left[M_{CaCO3} \times \frac{44}{100}\right] + \left[M_{Na2CO3} \times \frac{44}{105.99}\right]\right)$$

Equation 210-3

Where:

CO_2 = CO_2 emissions from make-up chemicals (metric tons/year).
M_{CaCO3} = Make-up quantity of $CaCO_3$ used for reporting year (metric tons/year).
M_{Na2CO3} = Make-up quantity of Na_2CO_3 used for reporting year (metric tons/year).
44 = Molecular weight of CO_2.
100 = Molecular weight of $CaCO_3$.
105.99 = Molecular weight of Na_2CO_3.

§ WCI.214 Monitoring Requirements

At least annually, determine the following fuel properties. If measurements are performed more frequently than annually, then fuel properties must be based on the average of the representative measurements made during the year.

(a) Determine high heat values of black liquor using Technical Association of the Pulp and Paper Industry (TAPPI) T684 om-06 "Gross High Heating Value of Black Liquor".

(b) Determine annual mass of spent liquor solids using one of the methods specified in subparagraph (1) or (2)

(1) Measure mass of annual spent liquor solids using TAPPI T650 om-05 "Solids Content of Black Liquor".

(2) Determine mass of annual spent liquor solids based on records of measurements made with an online measurement system that determines the mass of spent liquor solids fired in a chemical recovery furnace or chemical recovery combustion unit. Measure the quantity of black liquor produced each month.

(c) Determine carbon content using ASTM D5373-08 "Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal".

§ WCI.215 Procedures for Estimating Missing Data

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation or if a required sample is not taken), a substitute data value for the missing parameter shall be used in the calculations, according to the requirements of paragraphs (a) through (c) of this section:

a) There are no missing data procedures for measurements of heat content and carbon content of spent pulping liquor. A re-test must be performed if the data from any annual measurements are determined to be invalid.
b) For missing measurements of the mass of spent liquor solids or spent pulping liquor flow rates, use the lesser value of either the maximum mass or fuel flow rate for the combustion unit, or the maximum mass or flow rate that the fuel meter can measure.
c) For the use of makeup chemicals (carbonates), the substitute data value shall be the best available estimate of makeup chemical consumption, based on available data (e.g., past accounting records, production rates). The owner or operator shall document and keep records of the procedures used for all such estimates.

Tables 210-1 and Table 210-2 (Option A)

Canada-specific emission factors for fossil fuel and biomass-based CO_2, CH_4 and N_2O may be supplied by the WCI to replace the U.S. based Tables 210-1 and 210-2 (Option B)

Table 210-1 (Option B-EPA Rule). Kraft Lime Kiln and Calciner Emissions Factors for Fossil Fuel-Based CO_2, CH_4, and N_2O

	Fossil Fuel-Based Emissions Factors (kg/GJ HHV)					
	Kraft Lime Kilns			Kraft Calciners		
Fuel	**CO_2**	**CH_4**	**N_2O**	**CO_2**	**CH_4**	**N_2O**
Residual Oil	72.7	0.0026	0	72.7	0.0026	0.00028
Distillate Oil	69.7			69.7		0.00038
Natural Gas	53.1			53.1		0.00009
Biogas	0			0		0.00009

Table 210-2 (Option B-EPA Rule). Kraft Pulping Liquor Emissions Factors for Biomass-Based CO_2, CH_4, and N_2O.

	Biomass-Based Emissions Factors (kg/GJ HHV)		
Wood Furnish	**CO_2[a]**	**CH_4**	**N_2O**
North American Softwood	89.5	0.028	0.0047
North American Hardwood	88.8		
Bagasse	90.5		
Bamboo	88.8		
Straw	90.2		

[a] Includes emissions from both the recovery furnace and pulp mill lime kiln.

§ WCI.220 SODA ASH MANUFACTURING

§ WCI.221 Source Category Definition

A soda ash manufacturing facility is any facility with a manufacturing line that produces soda ash by one of the methods in paragraphs (a) through (c) of this section:

(a) Calcining trona.

(b) Calcining sodium sesquicarbonate.

(c) Using a liquid alkaline feedstock process that directly produces CO_2.

In the context of the soda ash manufacturing sector, “calcining” means the thermal/chemical conversion of the bicarbonate fraction of the feedstock to sodium carbonate.

§ WCI.222 Greenhouse Gas Reporting Requirements

In addition to the information required by regulation, each annual report must contain the following information

(a) CO_2 process emissions from the soda ash manufacturing facility.

(b) CO_2, CH_4 and N_2O combustion emissions must be calculated and reported under WCI.20 (General Stationary Combustion) by following the requirements of WCI.20.

(c) If a CEMS is used to measure CO_2 emissions, then you must report under this method the relevant information required under WCI.20.

(d) Annual consumption of trona or liquid alkaline feedstock for each manufacturing line (metric tons).

(e) Annual production of soda ash (metric tons).

(f) Annual quantity of generated CO_2 recycled to carbonation towers (tons), if applicable.

(g) Number of times missing data procedures were used.

§ WCI.223 Calculation of Greenhouse Gas Emissions

Calculate and report the annual process CO_2 emissions from each soda ash manufacturing line using the procedures specified in paragraph (a) or (b) of this section.

(a) For each soda ash manufacturing line that meets the conditions specified in WCI.23(e), calculate and report under this method the combined process and combustion CO_2 emissions by operating and maintaining a CEMS to measure CO_2 emissions according to the Method 4 Calculation Methodology specified in WCI.23(d) and all associated requirements.

(b) For each soda ash manufacturing line that is not subject to the requirements in paragraph (a) of this section, calculate and report the process CO_2 emissions from the soda ash manufacturing line by using the procedure in either paragraphs (b)(1), (b)(2), or (b)(3) of this section; and the combustion CO_2 emissions using the procedure in paragraph (b)(4) of this section.

(1) Calculate and report under this method the combined process and combustion CO_2 emissions by operating and maintaining a CEMS to measure CO_2 emissions according to the Method 4 Calculation Methodology specified in WCI.23(d) and all associated requirements for Method 4 in WCI.23(d) (General Stationary Combustion).

(2) Use either Equation 220-1 or Equation 220-2 of this section to calculate annual CO_2 process emissions from each manufacturing line that calcines trona to produce soda ash:

$$E_k = \sum_{n=1}^{12} [(IC_T)_n * (T_t)_n] * \frac{0.097}{1} \quad \text{(Eq. 220-1)}$$

$$E_k = \sum_{n=1}^{12} [(IC_{sa})_n * (T_{sa})_n] * \frac{0.138}{1} \quad \text{(Eq. 220-2)}$$

Where:

E_k	=	Annual CO_2 process emissions from each manufacturing line, k (metric tons).
$(IC_T)_n$	=	Inorganic carbon content (percent by weight, expressed as a decimal fraction) in trona input, from the carbon analysis results for month n. This represents the ratio of trona to trona ore.
$(IC_{sa})_n$	=	Inorganic carbon content(percent by weight, expressed as a decimal fraction) in soda ash output, from the carbon analysis results for month n. This represents the purity of the soda ash produced.
$(T_t)_n$	=	Mass of trona input in month n (metric tons).
$(T_{sa})_n$	=	Mass of soda ash output in month n (metric tons).
0.097/1	=	Ratio of metric ton of CO_2 emitted for each metric ton of trona.
0.138/1	=	Ratio of metric ton of CO_2 emitted for each metric ton of soda ash produced.

(3) Site-specific emission factor method. Use Equations 220-3, 220-4, and 220-5 of this section to determine annual CO_2 process emissions from manufacturing lines that use the liquid alkaline feedstock process to produce soda ash. You must conduct an annual performance test and measure CO_2 emissions and flow rates at all process vents from the mine water stripper/evaporator for each manufacturing line and calculate CO_2 emissions as described in paragraphs (b)(3)(i) through (b)(3)(iv) of this section.

(i) During the performance test, you must measure the process vent flow from each process vent during the test and calculate the average rate for the test period in metric tons per hour.

(ii) Using the test data, you must calculate the hourly CO_2 emission rate using Equation 220-3 of this section:

$$ER_{CO2} = [(C_{co2} * 10000) * 4.16 x 10^{-8} * 44] * (Q * 60) * 0.001 \qquad \text{(Eq. 220-3)}$$

Where:

ER_{CO2} = CO_2 mass emission rate (metric tons/hour).

C_{CO2} = Hourly CO_2 concentration (per cent CO_2) as determined by WCI.224(c).

10000 = Conversion factor from per cent to parts per million

4.16 x 10-8 = Conversion factor from ppm to kg-mole/dsm3 (kg-mole/dsm3/ppm).

44 = kg per kg-mole of carbon dioxide.

Q = Stack gas volumetric flow rate per minute (dsm3 per minute).

60 = Minutes per hour

0.001 = Conversion factor from kg to metric tons (metric tons/kg)

(iii) Using the test data, you must calculate a CO_2 emission factor for the process using Equation 220-4 of this section:

$$EF_{CO2} = \frac{ER_{CO2}}{V_t} \qquad \text{(Eq. 220-4)}$$

Where:

EF_{CO2} = CO_2 emission factor (metric tons CO_2/metric ton of process vent flow from mine water stripper/evaporator).

ER_{CO2} = CO_2 mass emission rate (metric tons/hour).

V_t = Process vent mass flow rate from mine water stripper/evaporator during annual performance test (metric tons/hour).

(iv) Calculate annual CO_2 process emissions from each manufacturing line using Equation 220-5 of this section:

$$E_k = EF_{CO2} * V_a * H \qquad \text{(Eq. 220-5)}$$

Where:

Ek = Annual CO2 process emissions for each manufacturing line, k (metric tons).

EF_{CO2}	=	CO_2 emission factor (metric tons CO_2/metric ton of process vent flow from mine water stripper/evaporator).
V_a	=	Annual process vent mass flow rate from mine water stripper/evaporator (metric tons/hour).
H	=	Annual operating hours for the each manufacturing line.

(4) Calculate and report under WCI.20 (General Stationary Fuel Combustion Sources) the combustion CO_2, CH_4, and N_2O emissions in the soda ash manufacturing line according to the applicable requirements of WCI.20.

§ WCI.224 Sampling, Analysis, and Measurement Requirements

Section WCI.223 provides four different procedures for emission calculations. The appropriate paragraphs (a) through (d) of this section should be used for the procedure chosen.

(a) If you determine your emissions using WCI.223(b)(2) Equation 220-1 of this subpart) you must:

(1) Determine the monthly inorganic carbon content of the trona from a weekly composite analysis for each soda ash manufacturing line, using a modified version of ASTM E359-00(Reapproved 2005)e1, Standard Test Methods for Analysis of Soda Ash (Sodium Carbonate). ASTM E359-00(Reapproved 2005)e1 is designed to measure the total alkalinity in soda ash not in trona. The modified method of ASTM E359-00 adjusts the regular ASTM method to express the results in terms of trona. Although ASTM E359-00(Reapproved 2005) uses manual titration, suitable autotitrators may also be used for this determination.

(2) Measure the mass of trona input produced by each soda ash manufacturing line on a monthly basis using belt scales or methods used for accounting purposes.

(3) Document the procedures used to ensure the accuracy of the monthly measurements of trona consumed.

(b) If you calculate CO_2 process emissions based on soda ash production (WCI.223(b)(2)Equation 220-2 of this method), you must:

(1) Determine the inorganic carbon content of the soda ash (i.e., soda ash purity) using ASTM E359-00(Reapproved 2005)e1 Standard Test Methods for Analysis of Soda Ash (Sodium Carbonate). Although ASTM E359-00(Reapproved 2005) uses manual titration, suitable autotitrators may also be used for this determination.

(2) Measure the mass of soda ash produced by each soda ash manufacturing line on a monthly basis using belt scales, by weighing the soda ash at the truck or rail load out points of your facility, or methods used for accounting purposes.

(3) Document the procedures used to ensure the accuracy of the monthly measurements of soda ash produced.

(c) If you calculate CO_2 emissions using the site-specific emission factor method in WCI.223(b)(3), you must:

(1) Conduct an annual performance test that is based on representative performance (i.e., performance based on normal operating conditions) of the affected process.

(2) Sample the stack gas and conduct three emissions test runs of 1 hour each.

(3) Conduct the stack test using EPA Method 3A at 40 CFR part 60, appendix A-2 to measure the CO2 concentration, Method 2, 2A, 2C, 2D, or 2F at 40 CFR part 60, appendix A-1 or Method 26 at 40 CFR part 60, appendix A-2 to determine the stack gas volumetric flow rate. All QA/QC procedures specified in the reference test methods and any associated performance specifications apply. For each test, the facility must prepare an emission factor determination report that must include the items in paragraphs (c)(3)(i) through (c)(3)(iii) of this section.

   (i) Analysis of samples, determination of emissions, and raw data.

   (ii) All information and data used to derive the emissions factor(s).

   (iii) You must determine the average process vent flow rate from the mine water stripper/evaporator during each test and document how it was determined.

(4) You must also determine the annual vent flow rate from the mine water stripper/evaporator from monthly information using the same plant instruments or procedures used for accounting purposes (i.e., volumetric flow meter).

WCI.225 Procedures for estimating missing data

For the emission calculation methodologies in WCI.223(b)(2)and (b)(3), a complete record of all measured parameters used in the GHG emissions calculations is required (e.g., inorganic carbon content values, etc.). Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in the paragraphs (a) through (d) of this section. You must document and keep records of the procedures used for all such missing value estimates.

(a) For each missing value of the weekly composite of inorganic carbon content of either soda ash or trona, the substitute data value shall be the arithmetic average of the quality-assured values of inorganic carbon contents from the week immediately preceding and the week immediately following the missing data incident. If no quality-assured data on inorganic carbon contents are available prior to the missing data incident, the substitute data value shall be the first quality-assured value for carbon contents obtained after the missing data period.

(b) For each missing value of either the monthly soda ash production or the trona consumption, the substitute data value shall be the best available estimate(s) of the parameter(s), based on all available process data or data used for accounting purposes.

(c) For each missing value collected during the performance test (hourly CO_2 concentration, stack gas volumetric flow rate, or average process vent flow from mine water stripper/evaporator during performance test), you must repeat the annual performance test following the calculation and monitoring and QA/QC requirements under WCI.223(b)(3) and WCI.224(c).

(d) For each missing value of the monthly process vent flow rate from mine water stripper/evaporator, the substitute data value shall be the best available estimate(s) of the parameter(s), based on all available process data or the lesser of the maximum capacity of the system or the maximum rate the meter can measure.

§ WCI.230 ELECTRICITY TRANSMISSION (AND EMISSIONS FROM ELECTRICAL EQUIPMENT IN ELECTRICITY GENERATION)

§ WCI.231 Source Category Definition

Sulfur hexafluoride (SF_6) are perflurorocarbons (PFCs) are used as gaseous dielectric mediums for electric power distribution equipment, including transmission and distribution systems, substations, high-voltage circuit breakers, switches, and other electrical equipment. This category includes fugitive emissions from equipment that is located at a facility that the operator is responsible for maintaining in proper working order.

§ WCI.232 Greenhouse Gas Reporting Requirements

For each facility, the emissions data report shall include the following information:

(a) Annual greenhouse gas emissions in metric tons, reported as follows:

(1) Fugitive SF_6 emitted from equipment.

(2) Fugitive PFCs emitted from equipment

§ WCI.233 Calculation of SF_6 Emissions

SF_6 emissions must be calculated using either a mass-balance or direct measurement approach. Section (a) describes the mass balance approach; section (b) describes the direct measurement approach.

(a) Mass Balance Approach.

(1) Calculate the annual SF_6 emissions using a mass balance approach that tracks and systematically accounts for all operator uses of SF_6, as follows. Any quantity of SF_6 that cannot be accounted for is then assumed to have been emitted into the atmosphere.

(2) Calculate the change in inventory of SF_6 in storage using Equation 230-1.

$$\Delta S_{Inv} = S_{Inv-Begin} - S_{Inv-End}$$ **Equation 230-1**

Where:

ΔS_{Inv} = Change in inventory of SF_6 in storage, kilograms ("Storage" includes cylinders, gas carts, and other storage containers, but excludes equipment. Value will be negative if quantity of SF_6 increases during the year);

$S_{Inv-Begin}$ = Quantity of SF_6 in storage at the beginning of the year, kilograms;

$S_{Inv-End}$ = Quantity of SF_6 in storage at the end of the year, kilograms.

(3) Calculate the sum of all SF_6 acquired from other entities during the year either in storage containers or in equipment using Equation 230-2.

Equation 230-2

$$S_{PA} = S_{Cyl} + S_{Equip} + S_{\mathrm{Re}\,cyc-ret}$$

Where:

S_{PA}	=	Sum of all SF_6 acquired from other entities during the year either in storage containers or in equipment, kilograms;
S_{Cyl}	=	Quantity of SF_6 purchased from producers or distributors in cylinders, kilograms;
S_{Equip}	=	Quantity of SF_6 provided by equipment manufacturers with/inside equipment, kilograms;
$S_{Recyc\text{-}ret}$	=	Quantity of SF_6 returned to site after off-site recycling, kilograms.

(4) Calculate the sum of all SF_6 sold or otherwise disbursed during the year either in storage containers or in equipment using Equation 230-3.

$$S_{SD} = S_{Sales} + S_{\mathrm{Re}\,turns} + S_{Destruct} + S_{\mathrm{Re}\,cyc-off}$$

Equation 230-3

Where:

S_{SD}	=	Sum of all SF_6 sold or otherwise disbursed during the year either in storage containers or in equipment, kilograms;
S_{Sales}	=	Quantity of SF_6 sold to other entities (including gas left in equipment that is sold), kilograms;
$S_{Returns}$	=	Quantity of SF_6 returned to suppliers, kilograms;
$S_{Destruct}$	=	Quantity of SF_6 sent to destruction facilities, kilograms;
$S_{Recyc\text{-}off}$	=	Quantity of SF_6 sent off-site for recycling, kilograms.

(5) Calculate the net increase in nameplate capacity of equipment using Equation 230-4.

$$\Delta S_{Cap} = S_{Cap-new} - S_{Cap-retire}$$

Equation 230-4

Where:

ΔS_{Cap}	=	Net increase in total nameplate capacity of equipment using SF_6 in storage, kilograms ("Total nameplate capacity" refers to the full and proper charge of the equipment rather than to the actual charge, which may reflect leakage.);
$S_{Cap\text{-}new}$	=	Total nameplate capacity (proper full charge) of new equipment, kilograms;
$S_{Cap\text{-}retire}$	=	Total nameplate capacity (proper full charge) of retired or sold equipment, kilograms.

(6) Calculate total annual emissions using Equation 230-5.

$$S = \left(\Delta S_{Inv} + S_{PA} - S_{SD} - \Delta S_{Cap}\right) / 1{,}000 \qquad \textbf{Equation 230-5}$$

Where:

S	=	Annual SF_6 emissions, metric tons;
ΔS_{Inv}	=	Change in inventory of SF_6 in storage, kilograms ("Storage" includes cylinders, gas carts, and other storage containers, but excludes equipment. Value will be negative if quantity of SF_6 increases during the year);
S_{PA}	=	Sum of all SF_6 acquired during the year either in storage containers or in equipment, kilograms;
S_{SD}	=	Sum of all SF_6 sold or otherwise disbursed during the year either in storage containers or in equipment, kilograms;
ΔS_{Cap}	=	Net increase in total nameplate capacity of equipment using SF_6 in storage, kilograms ("Total nameplate capacity" refers to the full and proper charge of the equipment rather than to the actual charge, which may reflect leakage.);
1,000	=	Factor to convert kilograms to metric tons.

(b) Direct Measurement Approach.

SF_6 emissions are estimated by directly measuring the mass of SF_6 added to electrical equipment during operation (operation phase) and the amount of SF_6 collected from any decommissioned equipment (decommissioning phase).

In the operation phase, SF_6 added to equipment can be measured using one of two methods: automated mass-flow measurement or weigh-scale measurement. In automated mass-flow measurement, mass-flow meters attached to electrical equipment directly measure the amount of SF_6 added to equipment. In weigh-scale measurement, an SF_6 cylinder is measured before and after its contents are added to electrical equipment, the difference being equal to the SF_6 added to the equipment. Annual SF_6 emissions for both methods are calculated according to Equation 230-6.

$$S_O = \sum_{i}^{N} s_i \qquad \textbf{Equation 230-6}$$

Where:

S_O	=	Annual SF_6 emissions during operation phase, kilograms;
N	=	Number of SF_6 additions in a given year;
s_i	=	SF_6 added to equipment during 'i'th addition, kilograms.

Annual SF_6 emissions during the decommissioning phase are calculated according to Equation 230-7.

$$S_D = \sum_{i}^{N} (NC_i - S_i) \qquad \textbf{Equation 230-7}$$

Where:

S_D = Annual SF_6 emissions during decommissioning phase, kilograms;

N = Number of equipment decommissioned in a given year;

NC_i = Nameplate capacity of 'i'th decommissioned equipment, kilograms;

S_i = SF_6 collected from 'i'th decommissioned equipment, kilograms.

Total annual SF_6 emissions are calculated as the sum of SF_6 emissions from equipment operation and decommissioning, according to Equation 230-8.

Equation 230-8

$$S = \frac{S_O + S_D}{1{,}000}$$

Where:

S = Annual SF_6 emissions during, metric tons;
S_O = Annual SF_6 emissions during operation phase, kilograms;
S_D = Annual SF_6 emissions during decommissioning phase, kilograms.

(c) The methods in either paragraph (a) or (b) of this section shall be used to estimate emissions of PFCs from power transformers, substituting the relevant PFC(s) for SF6 in equation 230-5 or 230-8.

§ WCI.234 Sampling, Analysis, and Measurement Requirements

Calibration of equipment used to measure the mass of SF_6 used for top-ups to electrical equipment must be conducted as specified in paragraphs (a) and (b) of this section.

a) For automated mass-flow measurement, equipment must be calibrated according to regulation.

b) For weigh-scale measurement, equipment must be calibrated every 6 months by weighing objects of pre-determined mass and zeroing the weigh scale accordingly.

§ WCI.235 Procedures for Estimating Missing Data

A complete record of all measured parameters used in the GHG emissions calculations is required. Replace missing data, if needed, based on data from equipment with a similar nameplate capacity for SF6 and PFC, and from similar equipment repair, replacement, and maintenance operations.

§ WCI.240 ZINC PRODUCTION

§ WCI.241 Source Category Definition

The zinc production category includes three primary production processes used to produce zinc (i.e., electro-thermic distillation, pyrometallurgical, and electrolytic). In addition, secondary zinc production is also included in this category.

§ WCI.242 Greenhouse Gas Reporting Requirements

In addition to the information required by regulation, the annual emissions data report shall contain the following information:

(a) Annual emissions of CO_2 at the facility level (metric tons).

(b) Annual quantities of each carbon-containing input material used (metric tons).

(c) Carbon content of each carbon-containing input material used (metric tons C/metric ton reducing agent).

(d) Inferred waste-based carbon-containing material emission factor (if waste-based reducing agent quantification method used).

(e) If you use the missing data procedures in WCI.245(b), you must report how the monthly mass of carbon-containing materials with missing data was determined and the number of months the missing data procedures were used.

(f) CO_2, CH_4, and N_2O emissions from each stationary fuel combustion unit. You must report these emissions under WCI.20 (General Stationary Fuel Combustion Sources), by following the requirements of WCI.20.

§ WCI.243 Calculation of CO_2 Emissions

Calculate total CO_2 emissions as specified under paragraph (a) or (b) of this section.

(a) Determine facility CO_2 emissions using continuous emissions monitoring systems (CEMS) as specified in WCI.23(d).

(b) Calculate total CO_2 emissions using Equation 240-1. Specific materials that contribute less than 1 percent of the total carbon into the process are being considered to not be included in the calculation using Equation 240-1.

$$E_{CO_2} = \sum_i (Q_i \times C_i) \times 3.664 \qquad \textbf{Equation 240-1}$$

Where:

E_{CO2} = Annual CO_2 emissions from carbon-containing materials (metric tons);

Q_i = Annual quantity of carbon-containing material *i* (metric tons);

C_i = Carbon content of carbon-containing material *i* (metric tons C/metric ton process input);

3.664 = Stoichiometric conversion factor from C to CO_2.

§ WCI.244 Sampling, Analysis, and Measurement Requirements

The annual mass of each solid carbon-containing input material consumed shall be determined by summing the monthly mass for the material determined for each month of the calendar year. The monthly mass may be determined using facility instruments, procedures, or records used for accounting purposes, including either direct measurement of the quantity of the material consumed or by calculations using process operating information.

The average carbon content of each material consumed shall be determined as specified under paragraph (a) or (b) of this section.

(a) Obtain carbon content by collecting and analyzing at least three representative samples of the material each year using one of the following methods:

(1) For zinc-bearing materials, use ASTM E1941-04 "Standard Test Method for Determination of Carbon in Refractory and Reactive Metals and Their Alloys".
(2) For carbonaceous reducing agents and carbon electrodes, use ASTM D5373-08 "Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal".
(3) For flux materials (i.e., limestone or dolomite), use ASTM C25-06 "Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime".
(4) For waste-based carbon-containing material, determine carbon content by operating the smelting furnace both with and without the waste-reducing agents while keeping the composition of other material introduced constant.
    i. To ensure representativeness of waste-based reducing agent variability, the specific testing plan (e.g. number of test runs, other process variables to keep constant, timing of runs) for these trials must be approved by the jurisdiction

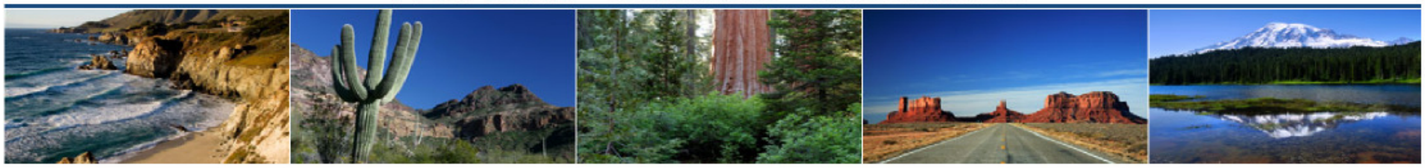
(b) Obtain carbon content from material vendor or supplier.

§ WCI.245 Procedures for Estimating Missing Data

For the carbon input procedure in WCI.243, a complete record of all measured parameters used in the GHG emissions calculations is required (e.g., raw materials carbon content values, etc.). Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraphs (a) and (b) of this section. You must document and keep records of the procedures used for all such estimates.

a) For missing records of the carbon content of inputs for facilities that estimate emissions using the carbon input procedure in WCI.243; 100 percent data availability is required. You must repeat the test for average carbon contents of inputs according to the procedures in WCI.245(b) if data are missing.

b) For missing records of the annual mass of carbon-containing inputs using the carbon input procedure in WCI.243, the substitute data value must be based on the best available estimate of the mass of the input material from all available process data or information used for accounting purposes, such as purchase records.



§ WCI.260 Nickel and Copper Metal Production

§ WCI.261 Source Category Definition

The nickel and copper metal production category includes process-related sources at nickel and copper metal smelting and refining facilities. Metals addressed in other categories (i.e., iron and steel, ferroalloys, aluminum, magnesium, lead, and zinc) are not included in this category.

The nickel and copper metal production category includes three main processes that produce CO_2 emissions: removal of impurities from nickel or copper ore concentrate using carbonate flux reagents (i.e., limestone [$CaCO_3$] or dolomite [$CaCO_3 \cdot MgCO_3$]), the use of other reducing agents to extract metals from their oxides (e.g., metallurgical coke, coal, natural gas, etc.), and the use of material (e.g., coke) for slag cleaning and the consumption of graphite or carbon electrodes in electric arc furnaces. It is important to distinguish between fuels used for combustion and fuels used as reducing agents; only fuels used as reducing agents should be included in the base metal production category. Fuels used for combustion are reported in WCI.020.

§ WCI.262 Greenhouse Gas Reporting Requirements

In addition to the information required by the Reporting Regulation, the annual emissions data report shall contain the following information:

(a) Annual emissions of CO_2 at the facility level (metric tons).

(b) Annual quantities of each carbonate flux reagent used (metric tons).

(c) Fractional purity of each carbonate flux reagent used (metric tons carbonate/metric tons raw material).

(d) Annual quantities of other reducing agents used (metric tons).

(e) Carbon content of other reducing agent used or material used for slag cleaning (metric tons C/metric ton reducing agent or material for slag cleaning).

(f) Annual quantity of ore processed (metric tons).

(g) Carbon content of ore processed (metric tons C/metric ton ore).

§ WCI.263 Calculation of CO_2 emissions

Calculate total CO_2 emissions as specified under paragraph (a) through (d) of this section.

(a) Calculate CO_2 emissions from carbonate flux reagents using Equation 260-1.

$$E_{cf} = Q_{ls} \times f_{ls} \times \left(\frac{44}{100}\right) + Q_d \times f_d \times \left(\frac{88}{184}\right)$$ **Equation 260-1**

Where:

E_{cf} = Annual CO_2 emissions from carbonate flux reagents (metric tons);

Q_{ls} = Annual quantity of limestone consumed (metric tons);

f_{ls} = Fractional purity of limestone (metric tons $CaCO_3$/metric tons of raw material);

44/100 = Stoichiometric conversion factor from $CaCO_3$ to CO_2;

Q_d = Annual quantity of dolomite consumed (metric tons);

f_d = Fractional purity of dolomite (metric tons $CaCO_3 \cdot MgCO_3$/metric tons of raw material);

88/184 = Stoichiometric conversion factor from $CaCO_3 \cdot MgCO_3$ to CO_2.

(b) Calculate CO_2 emissions from other reducing agents or material used in slag cleaning using Equation 260-2.

Equation 260-2

Where:

E_{ra} = Annual CO_2 emissions from other reducing agents or material used for slag cleaning (metric tons);

Q_a = Annual quantity of other reducing agents or material used for slag cleaning (metric tons);

C_a = Carbon content of other reducing agents or material used for slag cleaning (metric tons C/metric ton of reducing agent or material used for slag cleaning);

3.664 = Stoichiometric conversion factor from C to CO_2.

(c) Calculate CO_2 emissions from release of carbon from metal ores using Equation 260-3.

$$E_{ore} = Q_{ore} \times C_{ore} \times 3.664$$ **Equation 260-3**

Where:

E_{ore} = Annual process CO_2 emissions from metal ore, tonnes

Q_{ore} = Annual quantity of nickel or copper metal ore consumed (metric tons);

C_{ore} = Carbon content of nickel or copper metal ore (metric tons C/metric ton of nickel or copper ore);

3.664 = Stoichiometric conversion factor from C to CO_2.

(d) Calculate CO_2 emissions from carbon electrode consumption in electric arc furnaces (EAFs) using Equation 260-4.

$$E_{ce} = Q_{ce} \times C_{ce} \times 3.664$$ **Equation 260-4**

Where:

E_{ce}	=	Annual CO_2 emissions from carbon electrode consumption in EAFs (metric tons);
Q_{ce}	=	Quantity of carbon electrodes consumed (metric tons);
C_{ce}	=	Carbon content of carbon electrodes (metric tons C/metric ton carbon electrodes);
3.664	=	Stoichiometric conversion factor from C to CO_2.

§ WCI.264 Sampling, analysis, and measurement requirements

The annual mass of each solid carbon-containing input material consumed shall be determined using facility instruments, procedures, or records used for accounting purposes, including either direct measurement of the quantity of the material consumed or by calculations using process operating information.

The average carbon content of each material consumed shall be determined as specified under paragraph (a) or (b) of this section.

(a) Obtain carbon content by collecting and analyzing at least three representative samples of the material each year using one of the following methods:

(1) For coal and coke, use ASTM D5373-08 “Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal and Coke”.

(2) For petroleum-based liquid fuels and liquid waste-derived fuels, use ASTM D5291-02 (Reapproved 2007) “Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants”, ultimate analysis of oil or computations based on ASTM D3238-95 (Reapproved 2005) and either ASTM D2502-04 or ASTM D2503-92 (Reapproved 2007).

(3) For gaseous fuels, use ASTM D1945-03 or ASTM D1946-90 (Reapproved 2006).

(4) For carbonate flux reagents (i.e., limestone and dolomite), use ASTM C25-06 “Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime”.

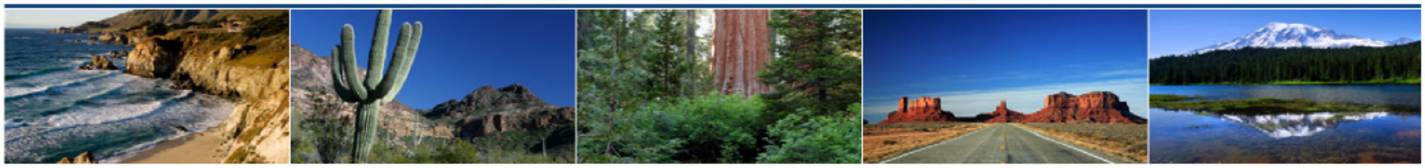
(b) Obtain carbon contents of the material, including carbon electrodes, from the vendor or supplier.

§ WCI.265 Procedures for Estimating Missing Data

For the carbon input procedure in WCI.263, a complete record of all measured parameters used in the GHG emissions calculations is required (e.g., raw materials carbon content values, etc.). Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraphs (a) and (b) of this section. You must document and keep records of the procedures used for all such estimates.

(a) For missing records of the carbon content of inputs for facilities that estimate emissions using the carbon input procedure in WCI.263; 100 percent data availability is required. You must repeat the test for average carbon contents of inputs according to the procedures in WCI.264 if data are missing.

(b) For missing records of the annual mass of carbon-containing inputs using the carbon input procedure in WCI.263, the substitute data value must be based on the best available estimate of the mass of the input material from all available process data or information used for accounting purposes, such as purchase records.



§ WCI.270 FERROALLOY PRODUCTION

§ WCI.271 Source Category Definition

Ferroalloy production consists of any facility that uses pyrometallurgical techniques to produce any of the following metals: ferrochromium, ferromanganese, ferromolybdenum, ferronickel, ferrosilicon, ferrotitanium, ferrotungsten, ferrovanadium, silicomanganese, or silicon metal.

§ WCI.272 Greenhouse Gas Reporting Requirements

In addition to the information required by regulation, the annual emissions data report shall contain the following information:

(a) Annual process CO2 emissions (metric tons) from each electric arc furnace (EAF) used in the production of any ferroalloy listed in §WCI.271.

(b) Annual process CH4 emissions (metric tons) from each electric arc furnace (EAF) used in the production of any ferroalloy listed in Table 270-1 (i.e., ferrosilicon [65%, 75%, or 90%] or silicon metal.

(c) CO2, N2O, and CH4 emissions from stationary combustion units as specified in §WCI.23.

(d) Annual facility ferroalloy product production capacity (metric tons).

(e) Annual production for each ferroalloy product from each EAF (metric tons).

(f) Total number of EAFs at facility used for production of ferroalloy products.

(g) Identification number of each EAF

(h) Annual material quantity for each material included for the calculation of annual process CO2 emissions for each EAF.

(i) Annual average of the carbon content determinations for each material included for the calculation of annual process CO2 emissions for each EAF.

(j) Method used for determination of carbon content for each material reported (e.g., supplier provided information, representative samples analyses, etc.)

(k) If missing data procedures used (§WCI.275), how monthly mass of carbon-containing inputs and output with missing data was determined and the number of months the missing data procedures were used.

§ WCI.273 Calculation of GHG Emissions

(a) Process CO2 emissions. Determine process CO_2 emissions as specified under either paragraph (1) or (2) of this section.

(1) Continuous emissions monitoring systems (CEMS) as specified in §WCI.23(d).

(2) Calculation methodologies specified in paragraph (b) of this section.

(b) Process CO_2 Emissions Calculation Methodology. Calculate electric arc furnace (EAF) CO_2 emissions using the mass balance approach specified in paragraphs (b)(1) and (b)(2). Specific process inputs or outputs that contribute less than 1 percent of the total carbon into or out of the process do not have to be includes in the paragraph (b)(1) and (b)(2) mass balances

(1) Calculate EAF CO_2 emissions using Equation 270-1:

$$E_{EAF} = \left[(RA \times C_{RA}) + (EL \times C_{EL}) + (Ore \times C_{Ore}) + (FL \times C_{FL}) - (PR \times C_{PR}) - (NP \times C_{NP})\right] \times 3.664$$

Equation 270-1

Where:

E_{EAF} = Annual CO_2 emissions from EAF (metric tons);
RA = Annual mass of reducing agent charged or introduced to EAF (metric tons);
C_{RA} = Carbon content of reducing agent (metric tons C/metric tons reducing agent);
EL = Annual mass of carbon electrodes consumed (metric tons);
C_{EL} = Carbon content of carbon electrodes (metric tons C/metric tons carbon electrode);
Ore = Annual mass of ore charged to EAF (metric tons);
C_{Ore} = Carbon content of ore (metric tons C/metric tons carbon electrode);
FL = Annual mass of flux materials charged or introduced to EAF (metric tons);
C_{FL} = Carbon content of flux materials (metric tons C/metric tons flux material);
PR = Annual mass of alloy product tapped from EAF (metric tons);
C_{PR} = Carbon content of alloy product (metric tons C/metric tons alloy product);
NP = Annual mass of outgoing non-product material removed from EAF (metric tons);
C_{NP} = Carbon content of outgoing non-product material (metric tons C/metric tons non-product);
3.664 = Conversion factor from metric tons of C to metric tons of CO_2.

(2) Determine combined annual CO_2 emissions from all EAFs at the facility using Equation 270-2:

$$E_{CO2-Fac} = \sum_{1}^{k} E_{EAF-k}$$ **Equation 270-2**

Where:

$E_{CO2\text{-}Fac}$ = Annual process CO_2 emissions from EAFs at facility used for the production of any ferroalloy listed in listed in §WCI.271 (metric tons).
$E_{EAF\text{-}k}$ = Annual process CO_2 emissions calculated from EAF *k* using Equation 270-1 (metric tons).
k = Total number of EAFs at facility used for the production of any ferroalloy listed in §WCI.271 (metric tons).

(c) Process CH_4 Emissions Calculation Methodology. For any ferroalloy listed in Table 270-1, calculate emissions using procedure specified in paragraphs (c)(1) and (c)(2).

(1) For each EAF, calculate annual CH_4 emissions using Equation 270-3:

$$E_{CH4} = \sum_{1}^{i} \left(M_i \times EF_i \right) \qquad \textbf{Equation 270-3}$$

Where:

E_{CH4} = Annual process CH_4 emissions from an individual EAF (metric tons).
M_i = Annual mass of alloy product *i* produced in the EAF (metric tons).
EF_i = CH_4 emission factor for alloy product *i* from Table 270-1 (metric ton CH_4/ metric ton of alloy product *i*).

(2) Determine combined annual CH_4 emissions from all EAFs at the facility using Equation 270-4:

$$E_{CH4-Fac} = \sum_{1}^{j} E_{CH4-j} \qquad \textbf{Equation 270-4}$$

Where:

$E_{CH4-Fac}$ = Annual process CH_4 emissions from EAFs at facility used for the production of ferroalloys listed in Table 270-1 (metric tons).
E_{CH4-j} = Annual process CH_4 emissions calculated from EAF *j* using Equation 270-3 (metric tons).
j = Total number of EAFs at facility used for the production of ferroalloys listed in Table 270-1.

§ WCI.274 Sampling, Analysis, and Measurement Requirements

The annual mass of each material used in the §WCI.273 mass balance methodologies shall be determined using plant instruments used for accounting purposes, including either direct measurement of the quantity of material used in the process or by calculations using process operating information.

The average carbon content of each material used shall be determined as specified under paragraph (a) or (b) of this section.

(a) Obtain carbon content by collecting and analyzing at least three representative samples of the material each year using one of the following methods:

(1) For metal ore and alloy product, use ASTM E1941-04 “Standard Test Method for Determination of Carbon in Refractory and Reactive Metals and Their Alloys”.

(2) For carbonaceous reducing agents and carbon electrodes, use ASTM D5373-08 “Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal”.

(3) For flux materials (e.g., limestone, dolomite, etc.), use ASTM C25-06 “Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime”.

(b) Obtain carbon content from material vendor or supplier.

§ WCI.275 Missing Data Procedures

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraphs (a) or (b) of this section. Records must be documented and kept of the procedures used for all such estimates.

(a) If CO_2 emissions for EAFs are estimated using the carbon mass balance in §WCI.273(b)(1), 100 percent data availability is required for the carbon content of the input and output materials. The test for average carbon contents according to §WCI.274 must be repeated if data are missing.

(b) For each missing value of monthly mass of carbon-containing inputs and outputs, the substitute data value must be based on the best available estimate of the mass of inputs and outputs from all available process data or data used for accounting purposes.

(c) If CH_4 emissions for EAFs are required to be calculated, the estimate is based on an annual quantity of certain alloy products, so 100 percent data availability is required.

Table 270-1 —Electric Arc Furnace (EAF) CH_4 Emission Factors.

	CH4 Emission Factor (metric ton CH_4 per metric ton product)		
	EAF Operation		
Alloy product produced in EAF	**Batch-Charging**	**Sprinkle-Charging[a]**	**Sprinkle-Charging and >750°C[b]**
Silicon metal	0.0015	0.0012	0.0007
Ferrosilicon 90%	0.0014	0.0011	0.0006
Ferrosilicon 75%	0.0013	0.0010	0.0005
Ferrosilicon 65%	0.0013	0.0010	0.0005

[a] Sprinkle-charging is charging intermittently every minute.

[b] Temperature measured in off-gas channel downstream of the furnace hood.

§ WCI.280 MOBILE EQUIPMENT AT FACILITIES

§ WCI.281 Source Category definition

The mobile equipment at facilities category includes:

(a) Mobile equipment used for the on-site transportation or movement of substances, materials or products, and

(b) Other mobile equipment such as tractors, mobile cranes, log transfer equipment, mining machinery, graders, backhoes and bulldozers, and other industrial equipment,

but does not include an on road vehicle, an aircraft or a marine vessel.

For clarity, an on-road vehicle means a motor vehicle that:

(a) Can exceed a speed of 40 kilometers per hour on a level paved surface, and

(b) Has features customarily associated with safe and practical highway use such as a reverse gear (unless the vehicle is a motorcycle), a differential and safety features required by federal or provincial laws,

but does not include a vehicle that exhibits features that render its use on a highway unsafe, impractical or highly unlikely, such as tracked road contact or inordinate size.

Mobile equipment that is part of normal facility operations that are operated by contractors is also included as it is managed or controlled by the facility.

§ WCI.282 Greenhouse Gas Reporting Requirements

In addition to the information required by the British Columbia Reporting Regulation, the annual emissions data report shall contain the following information:

(a) Total emissions of CO_2, CO_2 from biomass, CH_4, and N_2O at the facility level by fuel type (including differentiation of biodiesel and ethanol from conventional fuel types) (metric tons).

(b) Annual and quarterly quantities of fuel used by fuel type (including differentiation of biodiesel and ethanol from conventional fuel types) (litres) from the sum of mobile equipment at the facility.

§ WCI.283 Calculation of CO_2 Emissions

Calculate the annual CO_2 mass emissions from mobile equipment using the procedures in paragraph (a),(b), or (c), as appropriate.

(a) If fossil fuel quantities are measured, calculate total CO_2 emissions using Equation 280-1.

$$E_{i,CO2} = Q_i \times EF_i$$

Equation 280-1

Where:

$E_{i,CO2}$ = Quarterly CO_2 emissions from mobile equipment for fuel *i* (metric tons);

Q_i = Quarterly quantity of fuel *i* used in mobile equipment (litres);

EF_i = Emission factor for the fuel (metric tons CO_2e/litre, required emission factors provided in WCI.020).

(b) If fossil fuel quantities are not measured, use hours of operation for each mobile equipment to calculate total CO_2 emissions using Equations 280-2 and 280-3.

$$E_{i,k,CO2} = (h_{i,k} \times hp_{i,k} \times LF_{i,k} \times BSFC_{i,k}) \times EF_{i,CO2}$$ **Equation 280-2**

$$E_{Total,i,CO2} = \sum_k E_{i,k,CO2}$$ **Equation 280-3**

Where:

$E_{i,k,CO2}$ = Quarterly CO_2 emissions from mobile equipment *k* for fuel *i* (metric tons);

$h_{i,k}$ = Quarterly hours of operation for mobile equipment *k* for fuel *i* (hours);

$hp_{i,k}$ = Rated equipment horsepower for mobile equipment *k* for fuel *i* (horsepower);

$LF_{i,k}$ = Load factor for mobile equipment *k* for fuel *i* (unitless; ranges between 0 and 1);

$BSFC_{i,k}$ = Brake-specific fuel consumption for mobile equipment *k* for fuel *i* (litres/horsepower-hour);

$EF_{i,CO2}$ = Emission factor for fuel *i* (metric tons CO_2e/litre, required emission factors provided in WCI.020);

$E_{Total,i,CO2}$ = Total quarterly CO_2 emissions for fuel *i* (metric tons).

(c) CO_2 Emissions Calculation Methodology for Mixtures of Biomass Fuel and Fossil Fuel. Calculate biomass and non-biomass CO_2 emissions as specified in paragraph (1) of this section.

(1) The owner or operator that combusts fuels or fuel mixtures where there is a mixture of biofuel (i.e. biodiesel and ethanol) and other fuels shall determine the portion of the biofuel used by broad fuel category (i.e. gasoline and diesel) and use the appropriate emission factors for each of the biofuel and the conventional fuel. When reporting emissions, CO_2 from the biomass component of biofuels shall be reported separately from CO_2 from fossil fuels.

§ WCI.284 Calculation of CH_4 and N_2O Emissions

Calculate the annual CH_4 and N_2O mass emissions from mobile equipment using the procedures in paragraph (a) or (b), as appropriate. Annual emissions for each fuel type and GHG are calculated as the sum of the quarterly emissions. Annual emissions are reported by fuel and by GHG.

(a) If fossil fuel quantities are measured, calculate total CH_4 and N_2O emissions using Equation 280-4 and the emission factors provided in WCI.020.

$$E_{i,g} = Q_i \times EF_{i,g} \times \left(\frac{1}{10^6}\right) \qquad \textbf{Equation 280-4}$$

Where:

$E_{i,g}$ = Quarterly emissions of greenhouse gas *g* (CH_4 or N_2O) from mobile equipment for fuel *i* (metric tons);

Q_i = Quarterly quantity of fuel *i* (litres);

$EF_{i,g}$ = Greenhouse gas *g* (CH_4 or N_2O) mobile equipment emission factor for fuel *i* (grams/litre) (required emission factors provided in WCI.020);

$(1/10^6)$ = Conversion factor from grams to metric tons.

(b) If fossil fuel quantities are not measured, use hours of operation for each mobile equipment to calculate total CH_4 or N_2O emissions using Equations 280-5 and 280-6.

$$E_{i,k,g} = \left(h_{i,k} \times hp_{i,k} \times LF_{i,k} \times BSFC_{i,k}\right) \times EF_{i,g} \times \left(\frac{1}{10^6}\right) \qquad \textbf{Equation 280-5}$$

$$E_{Total,i,g} = \sum_k E_{i,k,g} \qquad \textbf{Equation 280-6}$$

Where:

$E_{i,k,g}$ = Quarterly greenhouse gas *g* (CH_4 or N_2O) emissions from mobile equipment *k* for fuel *i* (metric tons);

$h_{i,k}$ = Quarterly hours of operation for mobile equipment *k* for fuel *i* (hours);

$hp_{i,k}$ = Rated equipment horsepower for mobile equipment *k* for fuel *i* (horsepower);

$LF_{i,k}$ = Load factor for mobile equipment *k* for fuel *i* (unitless; ranges between 0 and 1);

$BSFC_{i,k}$ = Brake-specific fuel consumption for mobile equipment *k* for fuel *i* (litres/horsepower-hour);

$EF_{i,g}$ = Emission factor for greenhouse gas *g* (CH_4 or N_2O) for fuel *i* (grams/litre, required emission factors provided in WCI.020);

$(1/10^6)$	=	Conversion factor from grams to metric tons;
$E_{Total,i,g}$	=	Total quarterly emissions greenhouse gas *g* (CH_4 or N_2O) for fuel *i* (metric tons).

§ WCI.285 Sampling, Analysis, and Measurement Requirements

Fuel use and emission factors shall be determined as specified under paragraphs (a),(b) and (c) of this section.

(a) For biofuels, the portion(s) of ethanol or biodiesel from vendor specifications.

(b) For conventional fuels and biofuels, required emission factors listed in WCI.020.

(c) Fuel volumes used shall be determined by vendor receipts, dipstick measurement or other appropriate means on a quarterly basis, starting on January 1 of the calendar year.

§ WCI.300 PETROCHEMICAL MANUFACTURING

§ WCI.301 Source Category Definition

(a) The petrochemical manufacturing source category consists of any facility that manufacturers petrochemicals, including acrylonitrile, carbon black, propylene, ethylene, ethylene dichloride, ethylene oxide, or methanol, from feedstocks derived from petroleum, or petroleum and natural gas liquids.

(b) A process that produces a petrochemical as a byproduct is not part of the petrochemical production source category.

(c) A facility that makes methanol, hydrogen, and/or ammonia from synthesis gas should report under this section if the annual mass of methanol produced exceeds the individual annual mass production levels of both hydrogen recovered as product and ammonia. The facility should report under WCI.130 (Hydrogen Production) if the annual mass of hydrogen recovered as product exceeds the individual annual mass production levels of both methanol and ammonia. The facility should report under WCI.80 (Ammonia Manufacturing) if the annual mass of ammonia produced exceeds the individual annual mass production levels of both hydrogen recovered as product and methanol.

(d) A direct chlorination process that is operated independently of an oxychlorination process to produce ethylene dichloride is not part of the petrochemical production source category.

(e) A process that produces a petrochemical from bio-based feedstock is not part of the petrochemical production source category.

§ WCI.302 Greenhouse Gas Reporting Requirements

In addition to the information required by WCI.3, the annual emissions report must contain the following information:

(a) CO_2, N_2O, and CH_4 emissions from combustion of fuels in the stationary combustion units in metric tons, as specified in WCI.20.

(b) CO_2, N_2O, and CH_4 emissions from flares in metric tons for facilities complying with either WCI.303(a)(2) or WCI.303(c).

(c) CO_2, N_2O, and CH_4 process emissions from vents in metric tons for facilities complying with WCI.303(a)(3).

(d) CO_2, N_2O, and CH_4 process emissions from equipment leaks in metric tons for facilities complying with WCI.303(a)(4).

(e) CO_2 process emissions in metric tons for facilities complying with WCI.303(b).

(f) CO_2, N_2O, and CH_4 process emissions from ethylene production facilities in metric tons for facilities complying with WCI.303(c).

(g) Annual consumption of feedstock by type for all feedstocks that result in GHG emissions in cubic meters for gases and liquids, metric tons for solid fuels.

§ WCI.303 Calculation of GHG Emissions

Calculate GHG emissions using one of the methods in paragraphs (a), (b), or (c):

(a) **Method 1:** Calculate the GHG emissions from petrochemical production processes using the methods specific in paragraphs (a)(1) through (a)(3) of this section.

(1) For flares, calculate CO_2, CH_4 and N_2O emissions using the methods specified in WCI.203(e).

(2) For combustion devices other than flares, calculate CO_2, CH_4 and N_2O emissions resulting from the combustion of fuels and process off-gas as specified in paragraphs (a)(2)(i) through (a)(2)(iii):

(i) Calculate CO_2 emissions from fuels and process off-gas in accordance with the methods in specified in WCI.23.

(ii) Calculate CH_4 and N_2O emissions from combustion of fuels using the applicable methods in WCI.24. Use the appropriate default emission factors for CH_4 and N_2O from Tables 20-2, 20-4, 20-6, and 20-7.

(iii) Calculate CH_4 and N_2O emissions from process off-gas using the applicable method in WCI.24. Use the emission factors of 2.8×10^{-3} kg/GJ for CH_4 and 5.7×10^{-4} kg/GJ for N_2O.

(3) Calculate the emissions from process vents using the method specified in WCI.203(b) for each process vent that can be reasonably expected to contain greater than 2 percent by volume CO_2 or greater than 0.5 percent by volume of CH_4 or greater than 0.01 percent by volume (100 parts per million) of N_2O.

(4) Calculate the emissions from equipment leaks using the method specified in WCI.203(h)(1).

(b) **Method 2:** Calculate the emissions of CO_2 from each process unit, for each calendar month as described in paragraphs (b)(1) through (b)(5) of this section.

(1) For each gaseous and liquid feedstock and product, measure the volume or mass used or produced each calendar month with a flow meter. Alternatively, for liquids, you may calculate the volume used or collected in each month based on measurements of the liquid level in a storage tank at least once per month (and just prior to each change in direction of the level of the liquid). Fuels used for combustion purposes are not considered to be feedstocks. The emissions from the combustion of fuels (other than process off-gas) in stationary combustion units must be calculated in accordance with the methods specified in WCI.23 for CO_2 and the methods specified in WCI.24 for CH_4 and N_2O.

(2) For each solid feedstock and product, measure the mass used or produced each calendar month.

(3) Collect a sample of each feedstock and product at least once per month and determine the carbon content of each sample. Alternatively, you may use the results of analyses conducted by a fuel or feedstock supplier, provided the sampling and analysis is conducted at least once per month. If multiple valid carbon content measurements are made during the monthly measurement period, average them arithmetically.

(4) If you determine that the monthly average concentration of a specific compound in a feedstock or product is greater than 99.5 percent by volume (or mass for liquids and solids), then as an alternative to the sampling and analysis specified in paragraph (b)(3) of this section, you may calculate the carbon content assuming 100 percent of that feedstock or product is the specific compound during periods of normal operation. You must maintain records of any determination made in accordance with this paragraph (b)(4) along with all supporting data, calculations, and other information. This alternative may not be used for products during periods of operation when off-specification product is produced. You must reevaluate determinations made under this paragraph (b)(4) after any process change that affects the feedstock or product composition. You must keep records of the process change and the corresponding composition determinations. If the feedstock or product composition changes so that the average monthly concentration falls below 99.5 percent, you are no longer permitted to use this alternative method.

(5) Calculate the CO_2 mass emissions for each petrochemical process unit using Equations 300-2 through 300-5 of this section.

(i) <u>Gaseous feedstocks and products</u>. Use Equation 300-1 of this section to calculate the net annual carbon input or output from gaseous feedstocks and products. Note that the result will be a negative value if there are no gaseous feedstocks in the process but there are gaseous products.

$$C_g = \sum_{n=1}^{12} [\sum_{i=1}^{j\ or\ k} [(F_{gf})_{i,n} * (CC_{gf})_{i,n} * \frac{(MW_f)_i}{MVC} - (P_{gp})_{i,n} * (CC_{gp})_{i,n} * \frac{(MW_p)_i}{MVC}]]$$

Equation 300-1

Where:

C_g	=	Annual net contribution to calculated emissions from carbon (C) in gaseous materials (kilograms/year, kg/yr).
$(F_{gf})_{i,n}$	=	Volume of gaseous feedstock i introduced in month “n” (m^3).
$(CC_{gf})_{i,n}$	=	Average carbon content of the gaseous feedstock i for month “n” (kg C per kg of feedstock).
$(MW_f)_i$	=	Molecular weight of gaseous feedstock i (kg/kg-mole).
MVC	=	Molar volume conversion factor (24.06 m^3/kg-mole for STP of 20°C and 1 atmosphere, or 23.67 m^3/kg-mole for STP of 15.6°C and 1 atmosphere).
$(P_{gp})_{i,n}$	=	Volume of gaseous product i produced in month “n” (m^3).
$(CC_{gp})_{i,n}$	=	Average carbon content of gaseous product i, including streams containing CO_2 recovered for sale or use in another process, for month “n” (kg C per kg of product).
$(MW_p)_i$	=	Molecular weight of gaseous product i (kg/kg-mole).

j = Number of feedstocks.
k = Number of products.

(ii) Liquid feedstocks and products. Use Equation 300-2 of this section to calculate the net carbon input or output from liquid feedstocks and products. Note that the result will be a negative value if there are no liquid feedstocks in the process but there are liquid products.

$$C_l = \sum_{n=1}^{12} [\sum_{i=1}^{j\ or\ k} [(F_{lf})_{i,n} * (CC_{lf})_{i,n} - (P_{lp})_{i,n} * (CC_{lp})_{i,n}]] \quad \textbf{Equation 300-2}$$

Where:

C_l = Annual net contribution to calculated emissions from carbon in liquid materials, including liquid organic wastes (kg/yr).
$(F_{lf})_{i,n}$ = Volume or mass of liquid feedstock i introduced in month "n" (m^3 of feedstock).
$(CC_{lf})_{i,n}$ = Average carbon content of liquid feedstock i for month "n" (kg C per m^3).
$(P_{lp})_{i,n}$ = Volume or mass of liquid product i produced in month "n" (m^3).
$(CC_{lp})_{i,n}$ = Average carbon content of liquid product i, including organic liquid wastes, for month "n" (kg C per m^3 of product).
j = Number of feedstocks.
k = Number of products.

(iii) Solid feedstocks and products. Use Equation 300-3 of this section to calculate the net annual carbon input or output from solid feedstocks and products. Note that the result will be a negative value if there are no solid feedstocks in the process but there are solid products.

$$C_s = \sum_{n=1}^{12} \left\{ \sum_{i=1}^{j\ or\ k} \left[(F_{sf})_{i,n} * (CC_{sf})_{i,n} - (P_{sp})_{i,n} * (CC_{sp})_{i,n} \right] \right\} \quad \textbf{Equation 300-3}$$

Where:

C_s = Annual net contribution to calculated emissions from carbon in solid materials (kg/yr).
$(F_{sf})_{i,n}$ = Mass of solid feedstock i introduced in month "n" (kg).
$(CC_{sf})_{i,n}$ = Average carbon content of solid feedstock i for month "n" (kg C per kg of feedstock).
$(P_{sp})_{i,n}$ = Mass of solid product i produced in month "n" (kg).
$(CC_{sp})_{i,n}$ = Average carbon content of solid product i in month "n" (kg C per kg of product).
j = Number of feedstocks.
k = Number of products.

(iv) Annual emissions. Use the results from Equations 300-1 through 300-3 of this section, as applicable, in Equation 300-4 of this section to calculate annual CO_2 emissions.

$$CO_2 = 0.001 * 3.664 * (C_g + C_l + C_s)$$ **Equation 300-4**

Where:

CO_2	=	Annual CO_2 mass emissions from process operations and process off-gas combustion (metric tons/year).
0.001	=	Conversion factor from kg to metric tons.
3.664	=	Ratio of molecular weight, carbon dioxide to carbon.

(c) **<u>Method 3:</u>** (Optional combustion methodology for ethylene production processes) For ethylene production processes, calculate CO_2, CH_4, and N_2O emissions as specified in paragraphs (c)(1) and (c)(2):

(1) For each flare, calculate CO_2, CH_4, and N_2O emissions using the methodology for flares specified in WCI.203(e).

(2) For all other combustion units, calculate the CO_2 emissions from combustion of fuel that contains ethylene process off-gas using either calculation methodology 3 or calculation methodogy 4 in WCI.23(c) and (d), respectively. Calculate CH_4 and N_2O emissions using the applicable method in WCI.24 and the emission factors of 2.8×10^{-3} kg/GJ for CH_4 and 5.7×10^{-4} kg/GJ for N_2O. You are not required to use the same calculation method for each stationary combustion unit that burns ethylene process off-gas.

§ WCI.304 Monitoring Requirements

(a) If you calculate emissions using the method specified in WCI.303(a):

(1) **Flares.** You must comply with the monitoring requirements for flares specified in WCI.204(e).

(2) **Process Vents.** You must comply with the monitoring requirements for process vents specified in WCI.204(b).

(b) If you calculate emissions using the method specified in WCI.303(b):

(1) **Feedstock Consumption.** You must measure the feedstock consumption using the same plant instruments used for accounting purposes, such as weigh hoppers, belt weigh feeders, or flow meters.

(2) **Product Production.** You must measure the amount of product produced using the same plant instruments used for accounting purposes, such as weigh hoppers, belt weigh feeders, or flow meters.

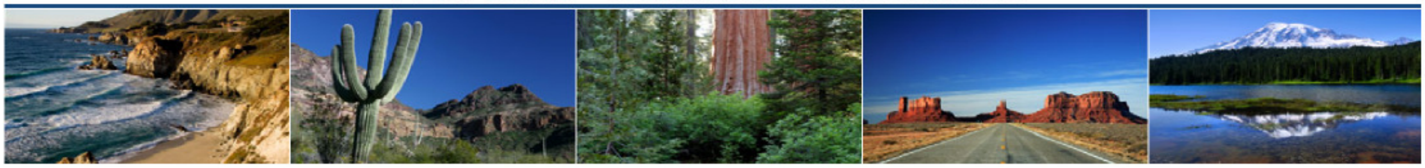
(3) **Carbon Content.** Except as allowed by WCI.303(b)(4), the carbon content of each feedstock and product must be measured at least once per month.

§ WCI.305 Procedures for Estimating Missing Data

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraphs (a) or (b) of this section. You must document and keep records of the procedures used for all such estimates.

(a) For each missing value of the carbon content and molecular weight, the substitute data value shall be the arithmetic average of the quality assured values of the parameter immediately preceding and immediately following the missing data incident. If no quality assured data are available prior to the missing data incident, the substitute data value shall be the first quality assured data value obtained after the missing data period.

(b) For missing feedstock and production values, the substitute data value shall be the best available estimate of the parameter, based on all available process data. You must document and retain records of the procedures used for all such estimates.



§ WCI.310 NITRIC ACID MANUFACTURING

§ WCI.311 Source Category Definition

A nitric acid production facility uses one or more trains to produce weak nitric acid (30 to 70 percent in strength). A nitric acid train produces weak nitric acid through the catalytic oxidation of ammonia.

§ WCI.312 Greenhouse Gas Reporting Requirements

For the purpose of the Regulation the annual emissions data report shall include the following information at the facility level calculated in accordance this method

(a) You must report facility wide N_2O process emissions as required by this method.

(b) Annual nitric acid production from the nitric acid facility (tonnes, 100 percent acid basis).

(c) You must report under WCI.20 (General Stationary Fuel Combustion Sources) the emissions of CO_2, CH_4, and N_2O from each stationary combustion unit by following the requirements of WCI.20.

§ WCI.313 Calculation of GHG emissions

(a) You must determine annual N_2O process emissions from each nitric acid train according to paragraphs (a)(1) or (a)(2) of this section.

(1) Use a site-specific emission factor and production data according to paragraphs (b) through (h) of this section.

(2) Request Director approval for an alternative method of determining N_2O emissions according to paragraphs.

(b) You must conduct an annual performance test according to paragraphs (b)(1) through (b)(3) of this section.

(1) You must measure N_2O emissions from the absorber tail gas vent for each nitric acid train using the methods specified in WCI.314(b) through (d).

(2) You must conduct the performance test under normal process operating conditions and without using N_2O abatement technology (if applicable).

(3) You must measure the production rate during the performance test and calculate the production rate for the test period in metric tons (100 percent acid basis) per hour.

(c) You must determine an N_2O emissions factor to use in Equation 310-3 of this section according to paragraphs (c)(1) or (c)(2) of this section.

(1) You may request Director approval for an alternative method of determining N_2O concentration according to the procedures in paragraphs (a)(2) of this section. Alternative methods include the use of N_2O CEMs.

(2) Using the results of the performance test in paragraph (b) of this section, you must calculate an average site-specific emission factor for each nitric acid train "t" according to Equation 310-1 of this section:

$$EF_{N2Ot} = \frac{\sum_{1}^{n} \frac{C_{N2O} * 1.14 \times 10^{-7} * Q}{P}}{n} \qquad \text{(Eq. 310-1)}$$

Where:

EF_{N2Ot}	=	Average site-specific N_2O emissions factor for nitric acid train "t" (kg N_2O generated/tonne nitric acid produced, 100 percent acid basis).
C_{N2O}	=	N_2O concentration for each test run during the performance test (ppm N_2O).
1.828×10^{-6}	=	Conversion factor (kg/dsm^3-ppm N_2O).
Q	=	Volumetric flow rate of effluent gas for each test run during the performance test (dsm^3/hr).
P	=	Production rate for each test run during the performance test (tonnes nitric acid produced per hour, 100 percent acid basis).
n	=	Number of test runs.

(d) If applicable, you must determine the destruction efficiency for each N_2O abatement technology according to paragraphs (d)(1), (d)(2), or (d)(3) of this section.

(1) Use the manufacturer's specified destruction efficiency.

(2) Estimate the destruction efficiency through process knowledge. Examples of information that could constitute process knowledge include calculations based on material balances, process stoichiometry, or previous test results provided the results are still relevant to the current vent stream conditions. You must document how process knowledge (if applicable) was used to determine the destruction efficiency.

(3) Calculate the destruction efficiency by conducting an additional performance test on the emissions stream following the N_2O abatement technology.

(e) If applicable, you must determine the abatement factor for each N_2O abatement technology. The abatement factor is calculated for each nitric acid train according to Equation 310-2 of this section.

$$AF_{N\,t} = \frac{P_{a\,t\,Abate}}{P_{a\,t}} \qquad \text{(Eq. 310-2)}$$

Where:

$AF_{N\,t}$	=	Abatement factor of N_2O abatement technology at nitric acid train "t" (fraction of annual production that abatement technology is operating).
$P_{a\,t}$	=	Total annual nitric acid production from nitric acid train "t" (tonne acid produced, 100 percent acid basis).

$P_{a\,t\,Abate}$ = Annual nitric acid production from nitric acid train "t" during which N_2O abatement was used (tonne acid produced, 100 percent acid basis).

(f) You must determine the annual amount of nitric acid produced and the annual amount of nitric acid produced while each N_2O abatement technology is operating from each nitric acid train (100 percent basis).

(g) You must calculate N_2O emissions for each nitric acid train by multiplying the emissions factor (determined in Equation 310-1 of this section) by the annual nitric acid production and accounting for N_2O abatement, according to Equation 310-3 of this section:

$$E_{N_2Ot} = \sum_{N=1}^{z} \frac{EF_{N20t} * P_{a\,t} * (1-(DF_{N\,t} * AF_{N\,t}))}{1000} \qquad \text{(Eq. 310-3)}$$

Where:

E_{N2Ot} = N_2O mass emissions per year for nitric acid train "t" (tonnes).

EF_{N2Ot} = Average site-specific N_2O emissions factor for nitric acid train "t" (kg N_2O generated/tonne acid produced, 100 percent acid basis).

$P_{a\,t}$ = Annual nitric acid production from the train "t" (tonne acid produced, 100 percent acid basis).

$DF_{N\,t}$ = Destruction efficiency of N_2O abatement technology N that is used on nitric acid train "t" (percent of N_2O removed from air stream).

$AF_{N\,t}$ = Abatement factor of N_2O abatement technology for nitric acid train "t" (fraction of annual production that abatement technology is operating).

1000 = Conversion factor (kg/tonne).

z = Number of different N_2O abatement technologies.

(h) You must determine the annual nitric acid production emissions combined from all nitric acid trains at your facility using Equation 310-4 of this section:

$$N_2O = \sum_{t=1}^{m} E_{N2Ot} \qquad \text{(Eq. 310-4)}$$

Where:

N_2O = Annual process N_2O emissions from nitric acid production facility (tonnes)

E_{N2Ot} = N_2O mass emissions per year for nitric acid train "t" (tonnes).

m = Number of nitric acid trains.

§ WCI.314 Sampling, Analysis, and Measurement Requirements

(a) You must conduct a new performance test and calculate a new site-specific emissions factor according to a test plan as specified in paragraphs (a)(1) through (a)(3) of this section.

(1) Conduct the performance test annually.

(2) Conduct the performance test when your nitric acid production process is changed, specifically when abatement equipment is installed.

(3) If you requested Director approval for an alternative method of determining N_2O concentration under WCI.313(a)(2), you must conduct the performance test if your request has not been approved by the Director within 150 days of the end of the reporting year in which it was submitted.

(b) You must measure the N_2O concentration during the performance test using one of the methods in paragraphs (b)(1) through (b)(3) of this section.

(1) EPA Method 320 at 40 CFR part 63, appendix A, Measurement of Vapor Phase Organic and Inorganic Emissions by Extractive Fourier Transform Infrared (FTIR) Spectroscopy.

(2) ASTM D6348-03 Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy.

(3) An equivalent method, with Director approval.

(c) You must determine the production rate(s) (100 percent basis) from each nitric acid train during the performance test according to paragraphs (c)(1) or (c)(2) of this section.

(1) Direct measurement of production and concentration (such as using flow meters, weigh scales, for production and concentration measurements).

(2) Existing plant procedures used for accounting purposes (i.e. dedicated tank-level and acid concentration measurements).

(d) You must conduct all performance tests in conjunction with the applicable methods approved by the Director. For each test, the facility must prepare an emission factor determination report that must include the items in paragraphs (d)(1) through (d)(3) of this section.

(1) Analysis of samples, determination of emissions, and raw data.

(2) All information and data used to derive the emissions factor(s).

(3) The production rate during each test and how it was determined.

(e) You must determine the monthly nitric acid production and the monthly nitric acid production during which N_2O abatement technology is operating from each nitric acid train according to the methods in paragraphs (c)(1) or (c)(2) of this section.

(f) You must determine the annual nitric acid production and the annual nitric acid production during which N_2O abatement technology is operating for each train by summing the respective monthly nitric acid production quantities.

§ WCI.315 Procedures for Estimating Missing Data

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraphs (a) and (b) of this section.

(a) For each missing value of nitric acid production, the substitute data shall be the best available estimate based on all available process data or data used for accounting purposes (such as sales records).

(b) For missing values related to the performance test, including emission factors, production rate, and N_2O concentration, you must conduct a new performance test according to the procedures in WCI.314 (a) through (d).

§ WCI.340 PHOSPHORIC ACID PRODUCTION

§ WCI.341 Source Category Definition

The phosphoric acid production source category consists of facilities that use a wet-process phosphoric acid process line to produce phosphoric acid by reacting phosphate rock with acid.

§ WCI.342 Greenhouse Gas Reporting Requirements

In addition to the information required by regulation, the annual emissions data report shall contain the following information:

(a) Annual CO_2 process emissions from all wet-process phosphoric acid production lines, as specified in WCI.343 (metric tons).

(b) CO_2, N_2O, and CH_4 emissions from stationary combustion units, as specified in WCI.23 (metric tons).

(c) Annual phosphoric acid production (metric tons).

(d) Annual phosphoric acid permitted production capacity (metric tons).

(e) Annual arithmetic average percent inorganic carbon in phosphate rock from monthly records (%).

(f) Annual phosphate rock consumption from monthly records (metric tons).

(g) Number of times missing data procedures were used to estimate phosphate rock consumption (months) and inorganic carbon contents of the phosphate rock (month).

§ WCI.343 Calculation of CO_2 Emissions

(a) Calculate CO_2 process emissions using Equation 340-1 and the measured inorganic carbon content and feedstock input of the phosphate rock.

$$CO_2 = \sum_{i=1}^{12} \frac{FS_i \times CF_i \times 3.664}{c} \qquad \textbf{Equation 340-1}$$

Where:

CO_2 = Annual carbon dioxide emitted (metric tons/year).
FS_i = Feedstock consumption in month *i* (metric tons/month).
CF_i = Carbonate content of feedstock (kg C/metric ton feedstock) for month *i*.
3.664 = Ratio of molecular weights, CO_2 to carbon.
c = Conversion factor (1,000 kg/metric ton).

§ WCI.344 Sampling, Analysis, and Measurement Requirements

The monthly mass of phosphate rock consumed shall be determined using either existing plant procedures that are used for accounting purposes (such as sales records) or data from existing monitoring equipment that is used to measure total mass flow of phosphorus-bearing feed.

The monthly inorganic carbon content shall be obtained as specified under paragraphs (a) and (b) of this section.

(a) Obtain a monthly grab sample of phosphate rock directly from the rock being fed to the process line according to the following requirements:

(1) Follow the applicable standard method in "Phosphate Mining States Methods Used and Adopted by the Association of Fertilizer and Phosphate Chemists AFPC Manual 10th Edition 2009 – Version 1.9".

(2) If phosphate rock is obtained from more than one origin in a month, a sample must be obtained from each origin of rock or a composite representative sample must be obtained.

(b) Determine the inorganic carbon content of each monthly grab sample of phosphate rock (consumed in the production of phosphoric acid) using the applicable standard method in "Phosphate Mining States Methods Used and Adopted by the Association of Fertilizer and Phosphate Chemists AFPC Manual 10th Edition 2009 – Version 1.9".

§ WCI.345 Missing Data Procedures

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraphs (a) or (b) of this section. Records must be documented and kept of the procedures used for all such estimates.

(a) A substitute data value must be determined by calculated the arithmetic average of the quality-assured values of inorganic carbon contents of phosphate rock of origin *i* from samples immediately preceding and immediately following the missing data incident. If no quality-assured data on inorganic carbon contents of phosphate rock of origin *i* are available prior to the missing data incident, then the substitute data value shall be the first quality-assured value of inorganic carbon contents for phosphate rock of origin *i* obtained after the missing data period.

(b) For each missing value of monthly mass consumption of phosphate rock (by origin), the substitute data value shall be the best available estimate based on all available process data or data used for accounting purposes.

Western Climate Initiative

Proposed Harmonization of Essential Requirements for Mandatory Reporting (ERs) in Canadian Jurisdictions with the WCI ERs and the U.S. EPA GHG Reporting Program

Stakeholder Conference Call

September 27, 2010

Background

- Final WCI Essential Requirements – July 2009
- Final U.S. EPA Mandatory Reporting Rule (“EPA Rule”) – September 2009
- U.S. facilities emitting >25,000 tonne CO_{2e} are subject to both programs (WCI has a 10,000 tonne threshold)
- Proposed harmonized ERs for U.S. jurisdictions – May 2010
  - Format is the same as EPA Rule
  - Final harmonized ERs expected Fall 2010

Proposed Harmonized ERs for Canadian Jurisdictions

- Released September 8, 2010
- Maintain consistency across all WCI jurisdictions
- Follow same format as original WCI ERs
- Allow review and input by stakeholders

Canadian Harmonization Principles

- Same level of reporting accuracy as U.S. facilities
- Quantification methods sufficient for GHG reporting under cap-and-trade program
- Suitable for use in Canada
  - Metric units
  - Canadian emission factors
- Facilitate harmonization with Environment Canada CEPA Section 46 (or future regulatory) reporting

Canadian Harmonization Approach

- Revise existing WCI ERs to conform with harmonized ERs for U.S. jurisdictions
  - Made content in WCI ERs “methodologically consistent” with ERs for U.S. jurisdictions
    - Harmonized ERs for US jurisdictions follow markup of EPA Rule
    - Harmonized ERs for Canadian jurisdictions keep WCI ER format
- Assure harmonization with Environment Canada’s reporting programs
- Require fewer data elements to be reported in Canadian jurisdictions due to 3rd party verification
- Add missing data procedures following EPA Rule
- Identify sources subject to “reporting only”

Sources Subject to Reporting Only

- Electricity Generation (WCI.20) – fugitive HFC emissions from cooling
- Coal Storage (WCI.100)
- Petroleum Refineries (WCI.200)
  - GHG emissions from asphalt blowing
  - CH_4 emissions from equipment leaks and storage tanks
  - CH_4 emissions from crude oil, intermediate, and product loading operations
- Mobile Equipment at Facilities (WCI.280)

On-Going Canadian Harmonization

- Natural Gas Transmission and Distribution (WCI.350)
- Petroleum and Natural Gas Production and Gas Processing (WCI.360)
- Underground Coal Mines (WCI.250)
- Magnesium Production (WCI.290)

- Electricity Imports (WCI.060) being reviewed by WCI Electricity Committee
- Other recently released EPA methods will be reviewed by WCI Reporting Committee (e.g. Carbon Dioxide Injection and Geologic Sequestration)

Western Climate Initiative

Questions?

Significant Changes to WCI ERs for Canadian Jurisdictions

- Table in documentation itemizes changes by source category
- Next few slides summarize the most significant changes, in addition to missing data procedures and reporting-only requirements
  - New, expanded sampling, analysis, and measurement requirements
  - Different sampling frequency
  - Different quantification method (or tier)
  - Changes for biomass combustion

Significant Changes – General Stationary Combustion (WCI.20)

- Several changes to harmonize with EPA Rule Subpart C:
  - Exemption for portable equipment, emergency generators and flares, etc.
- Must report annual weighted carbon content (CC) and high heat value (HHV)
- Very large combustion sources must either measure fuel CC or install CEMS, if:
  - >250 million BTU/hour heat input
  - Operated >1,000 hours/year
  - Excluding units that only use fuels in Table 20-1a
- Clarifications on:
  - Methods based on type of fuels
  - Sampling frequencies, requirements
  - Biogenic emissions from mixtures

Significant Changes – GSC (WCI.20) – Cont.

Parameter[a]	Fuel Type and Applicable CO_2 Quantification Method						
	Natural Gas	Fuels in Table 20-1a (e.g., distillates, LPG)	Coal	Solid Biomass	MSW	Other Fuels (e.g., liquid fuels, gas derived from fossil fuels, biogas)	Units ≥ 250 mmBTU/hr
Method 1	✔	✔					
Method 2	✔	✔		✔[b]			
Method 3	✔	✔	✔	✔	✔[b]	✔	✔[c]
Method 4	✔	✔	✔	✔	✔	✔	✔[c]

[a] Method 1 = Emission factors

Method 2 = HHV testing

Method 3 = Carbon content

Method 4 = CEMS

[b] Applies to steam and default factor (method 2) or efficiency testing (method 3)

[c] Except for natural gas, biomass and fuels in Table 20-1a

Significant Changes – Petroleum Refineries (WCI.200) and Refinery Fuel Gas (WCI.30)

- Added flexibility in methods for some sources
  - Flares
  - Startup and shutdown conditions and malfunctions
  - Process vents
- Modified existing and added new methods based on EPA Rule Subpart Y
  - Sources for which GHG emissions must be estimated (also added to definitions)
  - CH_4 and N_2O for some activities
  - Storage tanks
  - Industrial waste water
  - Equipment leaks
  - Emissions from combustion of refinery fuel gas (RFG)

Significant Changes – Iron and Steel (WCI.150)

- More specific breakdown of methods for upstream process-by-process approach
  - Coke oven batteries (COB)
  - Blast furnace
  - Basic oxygen furnace (BOF)
  - Electric arc furnace (EAF)
  - Others (sinter, direct reduction furnace, taconite, argon oxygen decarburization)
- Coke oven gas and blast furnace gas now reported upstream instead of at combustion unit
- All process and combustion emissions reported in the same method

Significant Changes – Petrochemical Manufacturing (WCI.300)

- Clarified and expanded definition of facility
- Changed methods refer to petroleum refinery methods (WCI.200)
  - Flares, equipment leaks, process vents
  - Continues to use GSC (WCI.20) for non-flare combustion sources
- Added new optional methods
  - To be consistent with EPA Subpart Y
  - Mass balance for gaseous, liquid, and solid feedstock(s) and products

Significant Changes – Cont.

- Cement Manufacturing (WCI.90)
  - Additional Reporting
    - Monthly emission factors
    - Organic carbon oxidation emissions
  - Adopted USEPA equations
  - Removed requirement for plant-specific clinker kiln dust (CKD)
- Lime Manufacturing (WCI.170)
  - Changed reporting for byproducts and waste from monthly to quarterly
  - Change byproduct sampling from quarterly to monthly
  - Added reporting for other combustion sources even when CEMS are used

Significant Changes – Cont.

- Adipic Acid (WCI.50) and Nitric Acid (WCI.310) Manufacturing
  - Added option to use continuous monitors with recording of monthly results
  - More specific monitoring requirements
- Hydrogen Production (WCI.130)
  - Added requirement to report amount of carbon in unconverted feedstock
  - Modified equations to separate calculations for liquid, gaseous, and solid fuels and feedstocks
- Pulp and Paper Manufacturing (WCI.210)
  - Changed to use methods in GSC (WCI.20) for fossil-fuel combustion
  - Added method based on HHV of spent liquor solids for biogenic emissions
  - Added method for estimating CO_2 from make-up chemical use

Significant Changes – Cont.

- Copper and Nickel Production (WCI.260)
  - Entirely new section based on method developed by Environment Canada
  - Clarified sampling frequency for CC
- Lead Manufacturing (WCI.160)
  - Added reporting for inferred waste-based carbon-containing material emission factor
  - Clarified sampling frequency for CC and methods
- Zinc Manufacturing (WCI.240)
  - Added requirement for CC of input materials if missing data procedures used
  - Clarified equation variables

Significant Changes – Cont.

- Primary Aluminum Manufacturing (WCI.70)
  - Added some reporting requirements to be consistent with EPA Subpart F
  - Changed from daily to monthly production data reporting when estimating CF_4 and C_2F_6 emissions
- Soda Ash Manufacturing (WCI.220)
  - Added more options for estimating emissions when CEMS not used
  - Expanded sampling, analysis, and measurement requirements
- Mobile Equipment at Facilities (WCI.280)
  - Entirely new section based on method developed by British Columbia
  - CO_2 calculations based on either fuel quantities and emission factors, or hours of operation, horsepower, load factor, and fuel economy

New WCI ERs Based on EPA Rule

- Ammonia Manufacturing (WCI.80) – based on Subpart G
- HCFC-22 Production (WCI.120) – based on Subpart O
- Glass Production (WCI.140) – based on Subpart N
- Carbonates Use (WCI.180) – based on Subpart U
- Electricity Transmission (WCI.230) – based on Subpart DD and existing methodology used in Canada
- Ferroalloy Production (WCI.270) – based on Subpart K
- Phosphoric Acid Production (WCI.340) – based on Subpart Z

Next Steps

Who?	What?	When? (2010)
Stakeholders	Submit comments on proposed Canadian harmonization package #1	Oct. 12
WCI	Finalize Canadian harmonization package #1	To be determined
WCI	Propose Canadian harmonization package #2 (magnesium, oil and gas, transmission and distribution, underground coal mines)	Early Oct.
Stakeholders	Submit comments on proposed Canadian harmonization package #2	To be determined
WCI	Finalize Canadian harmonization package #2	End of Nov.

Links and Contacts

- Proposed harmonized ERs in Canadian jurisdictions

  http://www.westernclimateinitiative.org/news-and-updates/122-wci-proposes-harmonized-reporting-requirements-for-canadian-jurisdictions

- Submit comments

  http://www.westernclimateinitiative.org/public-comments/document/33

- Contact
  - Dennis Paradine, dennis.paradine@gov.bc.ca or
  - Eric Loi, eric.loi@ontario.ca

Western Climate Initiative

WCI Regional Program Design

WCI Stakeholder Meeting
Montréal, QC
September 15, 2010

Program Design Overview

- Program Design released July 27, 2010
  http://westernclimateinitiative.org/the-wci-cap-and-trade-program/program-design
- Comprehensive strategy to reduce greenhouse gases and spur a clean-energy economy
  - Reduce emissions to 15% below 2005 levels by 2020
- Culmination of two years of work since WCI released initial design recommendations in 2008
- WCI Partners include *Arizona, British Columbia, California, Manitoba, Montana, New Mexico, Ontario, Oregon, Québec, Utah, and Washington*

Program Design Overview

- Based on extensive analysis and stakeholder consultation
- Includes an emissions cap and other core policies that are affordable, gradual, and support economic growth. The program:
  - Uses a market-based approach to cap most emissions
  - Encourages reductions throughout the economy
  - Expands energy efficiency programs
  - Encourages additional renewable energy sources
  - Tackles transportation emissions

Program Design Overview

- Economically- and geographically-broad cap covers nearly 90% of the region's emissions, providing flexibility to achieve least-cost emission reductions
- Provides a roadmap to inform Partners in their development of implementing regulations
- Jurisdictions with caps beginning in 2012 will include most of the region's emissions
  - The WCI program accommodates jurisdictions with alternative schedules

Program Benefits

- Reduces costly impacts that climate change will have on water resources, natural ecosystems, air quality, and environment-dependent industries like agriculture and tourism
- Provides incentives for clean-energy technologies
- Creates green jobs
- Increases energy security
- Protects public health

Document Organization

- Design Summary
  - Program highlights
  - Summary of major policy recommendations (see following slides)
- Supporting Documentation
  - Issue-specific recommendations and papers
- Detailed Design
  - Operational components

Major Policy Recommendations / Findings

- Relying on high-quality emissions data
  - State reporting rules being harmonized with EPA requirements, where they are adequate for C&T purposes
  - Working with federal governments on 1-window reporting
- Setting program emission limits
  - Annual allowance budgets decline linearly from emissions expected in first year of program (2012 for some sources, 2015 for others) to the 2020 reduction goal for each Partner
  - Use of offsets and allowances from other systems limited to 49% of the total reductions expected from the program
  - Early reduction allowances are optional

Major Policy Recommendations / Findings

- Enhancing flexibility and managing costs
  - Three cost containment mechanisms are being considered as options for Partners, in addition to the standard mechanisms included in the 2008 Design Recommendations (banking, offsets, broad scope, etc.)
  - Strategic allowance reserve
  - Contingent allowance reserve
  - Use of issued allowances with future vintages

Major Policy Recommendations / Findings

- Maintaining competitiveness and preventing emissions leakage (industries other than power)
  - Could be accomplished through the free distribution of allowances to industries with a high risk of leakage
  - Distribution in such cases should be standardized (e.g., through the use of common output-based benchmarks)
- Addressing electricity sector issues
  - Imports and leakage
  - RECs will have no compliance role
  - Allowance set-asides are an option for Partners who want to maintain the GHG reduction value of voluntary RE

Major Policy Recommendations / Findings

- Designing for high-quality offsets
  - Recommendations for WCI offset project criteria and other offset essential elements finalized in June
  - Recommendations under development for the process of approving offset projects and issuing offset credits
- Designing fair and transparent allowance auctions
  - Program Design contains several recommendations, closely aligned with RGGI auction design
  - Work is in progress to finalize recommendations on the remaining auction design elements
  - These are enumerated in the Program Design

Major Policy Recommendations / Findings

- Ensuring a well-functioning allowance market
  - Several recommendations were finalized in a separate update released in July, including recommendations on the treatment of offsets, participation by and registration of intermediaries, the role of derivatives and OTC transactions, reporting requirements, and public disclosure
  - Recommendations have yet to be issued on holding limits, market oversight, and centralized reporting of OTC derivative contracts

Major Policy Recommendations / Findings

- Linking programs
  - Prior to linking, WCI jurisdictions will have the opportunity to review each jurisdiction's program to assess its consistency with the Program Design
  - Distinctions made between unilateral linking, bilateral linking, and accepting offsets that are not part of a C&T program

Major Policy Recommendations / Findings

- Coordinating program administration
  - Three areas are highlighted in the Program Design, which the WCI Partners continue to investigate
  - Establishment and maintenance of an allowance tracking system
  - Compliance, verification, and enforcement (e.g., provisions for technical and compliance assistance, and a common requirement to surrender three additional compliance instruments for each excess tonne)
  - Regional administrative organization

Next Steps

- Complete outstanding WCI program design issues
- Put in place administrative systems and infrastructure
- Continue advancing core policies and programs
- Work closely with federal governments and other regional organizations to promote national and international action and ensure coordination

Western Climate Initiative

Le Programme Détaillé de la WCI

Réunion des détenteurs d’enjeux
Montréal, Québec
15 Septembre 2010

Vue d'ensemble

- Le Programme Détaillé de plafond/échanges de la WCI a été publié le 27 Juillet 2010
  http://westernclimateinitiative.org/the-wci-cap-and-trade-program/program-design
- Stratégie complète pour réduire les émissions de GES et pour promouvoir les énergies propres
  - Réduire les émissions de 15% par rapport à 2015 en 2020
- Deux années de travail depuis la publication du Modèle Recommandé en 2008
- Les partenaires de la WCI sont: AZ, BC, CA, MB, MT, NM, ON, OR, QC, UT et WA

Vue d'ensemble

- Le Programme Détaillé est fondé sur des analyses approfondies et sur la consultation des détenteurs d'enjeux
- Le Programme Détaillé inclut un plafond d'émission et d'autres politiques qui sont abordables, graduelles et soutiennent la croissance de l'économie :

  approche marché, réductions réparties dans toute l'économie, efficacité énergétique, énergies renouvelables, secteur des transports

    - uti

Vue d’ensemble

- Les émissions couvertes par le programme de la WCI représentent 90% des émissions de la région
- Le programme sert de guide aux partenaires dans l’élaboration de leur réglementation
- Les juridictions qui vont mettre en oeuvre le programme en 2012 couvrent la majorité des émissions de la WCI
- Le programme de la WCI est conçu de façon à permettre l’arrivée d’autres juridictions dans le programme

Les avantages du programme

- Réduction des impacts des changements climatiques sur les ressources en eau, les écosystèmes naturels, la qualité de l'air, les industries dépendantes de l'environnement comme l'agriculture et le tourisme
- Favorise le développement des technologies énergétiques propres
- Création d'emplois verts
- Accroître notre sécurité énergétique
- Impact positif sur la santé publique

Les composantes du document

- Sommaire du Programme
  - Les faits saillants du programme
  - Sommaire des pricipales politiques recommandées
- La Documentation
  - Les documents produits par les groupes de travail de la WCI qui ont servi à l'élaboration des recommandations
- Programme Détaillé
  - Les composantes opérationnelles
    - » Semblable à un réglement modèle

Les principales recommandations

- Programme fondé sur des données d'émission de grande qualité
  - **États-Unis** : Harmonisation des règlements de déclaration des États avec les exigences de l'EPA
  - **Canada** : Travail avec le gouvernement fédéral pour une déclaration unique
- Quantité totale d'émissions permises
  - Les budgets de droits d'émission vont décroître de façon linéaire à partir de la mise en place du programme (2012 pour certains secteurs et 2015 pourd'autres) jusqu'à l'atteinte de la cible de réduction en 2020
  - L'utilisation de CC ou de droits d'émission provenant d'autres programmes reconnus est limitée à 49% de la réduction totale
  - L'octroi de droits d'émission pour des réductions hâtives est optionnel

Les principales recommandations

- Permettre la flexibilité et le contrôle des prix
  - Trois mécanismes de contrôle des prix sont présentement considérés par les juridictions, en addition aux mécanismes déjà prévus dans le Modèle Recommandé de 2008 (mise en banque, les crédits compensatoires, une couverture étendue, etc.)
  - Une réserve de droits d'émission stratégique
  - Une réserve de droits d'émission pour les imprévus
  - L'utilisation lors de la période de conformité de droits d'émission futurs déjà détenus

Les principales recommandations

- Maintenir la compétitivité des entreprises et prévenir les fuites
  - Pourrait être accompli au moyen d'une distribution gratuite des droits d'émission aux entreprises qui pourraient faire l'objet de fuites
  - Cette distribution devra être standardisée, c'est-à-dire en utilisant une base de production commune (output-based benchmarks)
- Le secteur de la production d'électricité
  - Importation et fuite (voir la présentation du 8 septembre)
  - Les Certificats d'Énergie Renouvelable (REC) ne pourront être utilisés lors de la période de conformité
  - La mise de coté de droits d'émission est une option qui peut être utilisée par les juridictions qui voudraient maintenir la valeur des réductions qui proviennent de la production d'énergie renouvelable volontaire

Les principales recommandations

- Des crédits compensatoires (CC) de grande qualité
  - Les recommandations entourant les critères pour développer les CC de la WCI et les autres éléments essentiels sont terminées depuis juin 2010
  - Les recommandations entourant le processus d'approbation des CC et leur création sont présentement en élaboration
- Une vente à l'enchère transparente et équitable
  - Le Programme Détaillé comporte plusieurs recommandations qui sont semblables au processus de vente à l'enchère du RGGI
  - Finaliser les recommandations sur les éléments restants à développer
  - Celles-ci sont énumérées dans le Programme Détaillé

Les principales recommandations

- Assurer un marché efficace des droits d'émission
  - Plusieurs recommandations ont été finalisées dans une mise à jour publiée en juillet, incluant des recommandations sur le traitement des CC, les participants et l'enregistrement des intermédiaires , le rôle des dérivés et des transactions de gré à gré, les exigences de déclaration, et la divulgation d'information au public
  - Les recommandations suivantes seront finalisées:

    la limite de possession, la supervision du marché et la déclaration des transactions de gré à gré de dérivés à un organisme central

Les principales recommandations

- Les liens entre les programmes
  - Avant de créer des liens entre les programmes, les partenaires de la WCI auront l'opportunité de réviser les programmes des autres partenaires pour s'assurer qu'ils sont conformes au Programme Détaillé
  - Des distinction seront faites entre un lien unilatéral, un lien bilatéral et l'acceptation de CC qui ne font pas partie d'un programme de plafonds/échanges.

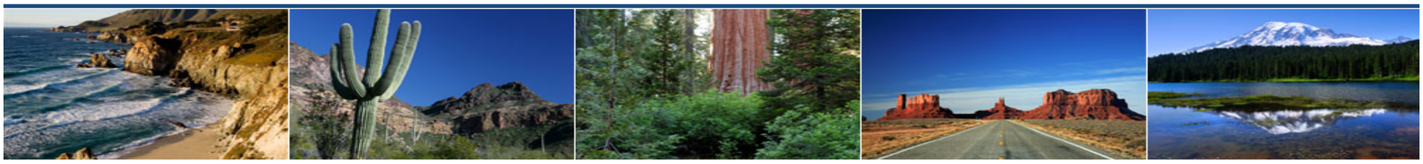
Les principales recommandations

- Coordonner l’administration du programme
  - Trois priorités du Programme Détaillé sur lesquels les partenaires vont continuer de travailler :
  - La création et l’entretien d’un système de suivi des droits d’émission
  - La conformité, la vérification et l’observance (la fourniture d’assistance technique et l’exigence de remettre trois droits d’émission pour chacune des tonnes de GES émises en trop lors de la période de conformité)
  - La création d’une organisation administrative régionale

Prochaines étapes

- Résoudre les problèmes complexes soulevés dans le Programme Détaillé de la WCI
- Mettre en place le système administratif et l'infrastructure
- Poursuivre le développement des politiques et programmes
- Travailler en étroite collaboration avec les autorités fédérales et les autres organisations régionales afin de promouvoir des actions nationales et internationales et d'assurer leur coordination

Western Climate Initiative



Second Harmonization Package -

Harmonization of Essential Requirements for Mandatory Reporting in Canadian Jurisdictions with the WCI Essential Requirements for Mandatory Reporting and the EPA Greenhouse Gas Reporting Program

October 29, 2010

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1 Second Harmonization Package

On September 8, 2010, the WCI proposed the "Harmonization of Essential Requirements for Mandatory Reporting in Canadian Jurisdictions with the WCI Essential Requirements for Mandatory Reporting and the EPA Greenhouse Gas Reporting Program" (the 'ERs'). This second WCI harmonization package builds upon the previous package and proposes methods for electronics manufacturing, underground coal mining, magnesium production, natural gas transmission and distribution, and petroleum and natural gas systems. The specific language for the changes is set forth in the Appendices. Unlike for the first harmonization package no summary of changes is presented as all methods are being newly proposed by the WCI for use in Canada.

Methods for the first three sectors (magnesium, electronics and underground coal) were developed using the U.S. EPA's final or proposed Part 98 Subparts as a base, and then converted into the WCI Canadian format. For the latter two sectors (petroleum and natural gas systems, and natural gas transmission and distribution), the EPA's proposed Subpart W and the June 7, 2010 "WCI Comments and Recommendations for the Proposed Mandatory Reporting of Greenhouse Gas Emissions from Petroleum and Natural Gas Operations" were together used as a base upon which sampling, analysis and measurement requirements, definitions, and emission factors appropriate for use in Canada were incorporated. Some consequential changes to WCI.20 (general stationary combustion) are being contemplated as a result of this process. The format of the harmonized Canadian ERs follows the original WCI format, a format that had already been used in guidance documents and regulations in several Canadian WCI jurisdictions.

The proposed WCI ERs are methodologically consistent with those of the U.S. EPA (or as proposed by the WCI) but are appropriate for use in the Canadian jurisdictions. At such a point when the U.S. EPA finalizes Subpart W, the WCI will develop cap and trade quality requirements for sources covered by Subpart W for use in U.S. jurisdictions. This may mean modifications will be required to the current proposed Canadian language covering the same sources. No evaluation has yet been conducted with respect to "reporting only" sources within the scope of the methods in the second harmonization package.

2 Future Changes to the Proposal

Further EPA rule revisions, such as conforming changes to Subpart A (General provisions) and Subpart H (cement), have been or are expected to be finalized to go into effect later this year. As a result, some consequential modifications to the proposed ERs in the first harmonization package may be required. In addition, stakeholder comments received on the first harmonization package are currently under review, and may result in changes to those proposed Canadian ERs.

3 Stakeholder Comments

This section to be completed after the public consultation period is over.

APPENDICES

§ WCI.110 MAGNESIUM PRODUCTION

§ WCI.111 Source Category Definition

Electronics manufacturing facilities include, but are not limited to, facilities that manufacture semiconductors, liquid crystal displays (LCDs), micro-electro-mechanical systems (MEMS), and photovoltaic cells (PV). The electronics source category consists of any of the processes listed in paragraphs (a) through (f) of this section that are located at electronics manufacturing facilities.

(a) Processes in which the etching process uses plasma-generated fluorine atoms and other reactive fluorine-containing fragments, which chemically react with exposed thin-films (e.g., dielectric, metals) and silicon to selectively remove portions of material.

(b) Processes in which chambers used for depositing thin films are cleaned periodically using plasma-generated fluorine atoms and other reactive fluorine-containing fragments from fluorinated and other gases.

(c) Processes in which wafers are cleaned using plasma-generated fluorine atoms or other reactive fluorine-containing fragments to remove residual material from wafer surfaces.

(d) Processes in which some fluorinated compounds can be transformed in the plasma processes into different fluorinated compounds which are then exhausted, unless abated, into the atmosphere.

(e) Processes in which the chemical vapor deposition process or other manufacturing processes use N_2O.

(f) Processes in which fluorinated GHGs are used as heat transfer fluids to cool process equipment, control temperature during device testing, and solder semiconductor devices to circuit boards.

§ WCI.112 Greenhouse Gas Reporting Requirements

In addition to the information required by regulation, the annual emissions data report shall contain the following information:

(a) Annual emissions of N_2O and fluorinated GHGs. The fluorinated GHGs that are emitted from electronics production processes include, but are not limited to, those listed in Table 110-1 of this subpart. The process that must be reported include: fluorinated GHGs from plasma etching, fluorinated GHGs from chamber cleaning, fluorinated GHGs from wafer cleaning, N_2O from chemical vapor deposition and other manufacturing processes, and fluorinated GHGs from heat transfer fluid use.

(b) CO_2, N_2O, and CH_4 emissions from stationary combustion units as specified in §WCI.23.

(c) The method of emissions calculation used in §WCI.113.

(d) Production in terms of substrate surface area (e.g., silicon, PV-cell, LCD).

(e) Emission factors used for process utilization and by-product formation rates and the source for each factor for each fluorinated GHG and N_2O.

(f) Where process categories for semiconductor facilities as defined in §WCI.113(a)(1)(i) through (a)(1)(iii) are not used, descriptions of individual processes or process categories used to estimate emissions.

(g) For each fluorinated GHG and N_2O, annual gas consumed during the reporting year and facility-wide gas-specific heel-factors used.

(h) The apportioning factors for each process category (i.e., fractions of each gas fed into each individual process or process category used to calculate fluorinated GHG and N_2O emissions) and a description of the engineering model used for apportioning gas usage per §WCI.114(b). If the method used to develop the apportioning factors permits the development of facility-wide consumption estimates that are independent of the estimates calculated in Equation 110-6 of this subpart (e.g., that are based on wafer passes for each individual process or process category), report the independent facility-wide consumption estimate for each fluorinated GHG and N_2O.

(i) Fraction of each gas fed into each process type that is fed into tools with abatement systems.

(j) Description of all abatement systems through which fluorinated GHGs or N_2O flow at the facility, including the number of devices of each manufacturer, model numbers, manufacturers guaranteed destruction or removal efficiencies, if any, and record of destruction or removal efficiency measurements over its in-use life. The inventory of abatement systems shall also include a description of the associated tools and/or processes for which these systems treat exhaust.

(k) For each abatement system through which fluorinated GHGs or N_2O flow at the facility, for which controlled emissions are reported, the following:

(1) Certification that each abatement system used at the facility is installed, maintained, and operated in accordance with manufacturers' specifications.

(2) The uptime and the calculations to determine uptime for that reporting year.

(3) The default destruction or removalefficiency value or properly measured destruction or removal efficiencies for each abatement system used in that reporting year to reflect controlled emissions.

(4) There the default destruction or removal efficiency value is used to report controlled emissions, certification that the abatement systems for which controlled emissions are being reported are specifically designed for fluorinated GHG and N_2O abatement.

(5) Where properly measured destruction or removal efficiencies or class averages of destruction or removal efficiencies are used to report controlled emissions, the following:

(i) A description of the class including the abatement system manufacturer and model number, and the fluorinated GHG and N_2O in the process effluent stream;
(ii) The total number of systems in that class for the reporting year.
(iii) The total number of systems for which destruction or removal efficiency was measured in that class for the reporting year.

(iv) A description of the calculation used to determine the class average, including all inputs of the calculation.

(v) A description of method of randomly selecting class members for testing.

(l) For heat transfer fluid emissions, inputs in the mass-balance equation, Equation 110-8 of this subpart for each fluorinated GHG.

(m) Example calculations for fluorinated GHG, N_2O, and heat transfer fluid emissions.

§ WCI.113 Calculation of GHG Emissions

(a) For each fluorinated GHG and each process type used at the facility (i.e., plasma etching, chamber cleaning, or wafer cleaning) as appropriate, calculate annual facility-level emissions using Equations 110-1 and 110-2 of this section and according to the procedures in paragraph (a)(1), (a)(2), or (a)(3) of this section.

$$processtypeE_i = \sum_{j=1}^{N} E_{ij} \qquad \textbf{Equation 110-1}$$

Where:

$processtypeE_i$	=	Annual emissions of input gas *i* from the processes type (metric tons);
E_{ij}	=	Annual emissions of input gas *i* from individual process *j* or process category *j* (metric tons); and
N	=	Total number of individual processes *j* or process categories *j*, which depend on the electronics manufacturing facility and emission calculation methodology.

$$processtypeBE_k = \sum_{j=1}^{N}\sum_{i} BE_{kij} \qquad \textbf{Equation 110-2}$$

Where:

$processtypeBE_k$	=	Annual emissions of by-product gas *k* from the processes type (metric tons);
BE_{kij}	=	Annual emissions of by-product *k* formed from input gas *i* during individual process *j* or process category *j* (metric tons); and
N	=	Total number of individual processes *j* or process categories *j*, which depend on the electronics manufacturing facility and emission calculation methodology.

(1) Semiconductor facilities that fabricate devices on wafers measuring 300 mm or less in diameter shall calculate annual facility-level emissions of each fluorinated GHG used at a facility for each fluorinated GHG-using process type, either from all individual processes at that facility in accordance with §WCI.114(c), or from process categories as defined in this paragraph (a)(1).

(i) All etching process categories for which annual fluorinated GHG emissions shall be calculated are defined in this paragraph (a)(1)(i).

(A) Oxide etch means any process using fluorinated GHG reagents to selectively remove SiO_2, SiO_x-based or fully organic-based thin-film material that has been deposited on a wafer during semiconductor device manufacturing.

(B) Nitride etch means any process using fluorinated GHG reagents to selectively remove SiN, SiON, Si_3N_4, SiC, SiCO, SiCN, etc. (represented by the general chemical formula, $Si_wO_xN_yX_z$ where w, x, y and z are zero or integers and X can be some other element such as carbon) that has been deposited on a wafer during semiconductor manufacturing.

(C) Silicon etch also often called polysilicon etch means any process using fluorinated GHG reagents to selectively remove silicon during semiconductor manufacturing.

(D) Metal etch means any process using fluorinated GHG reagents associated with removing metal films (such as aluminum or tungsten) that have been deposited on a wafer during semiconductor manufacturing.

(ii) All chamber cleaning processcategories for which annual fluorinated GHG emissions shall be calculated are defined in this paragraph (a)(1)(ii).

(A) In situ plasma means cleaning thin-film production chambers, after processing one or more wafers, with a fluorinated GHG cleaning reagent that is dissociated into its cleaning constituents by a plasma generated inside the chamber where the film was produced.

(B) Remote plasma system means cleaning thin-film production chambers, after processing one or more wafers, with a fluorinated GHG cleaning reagent dissociated by a remotely located (e.g., upstream) plasma source.

(C) In situ thermal means cleaning thin-film production chambers, after processing one or more wafers, with a fluorinated GHG cleaning reagent that is thermally dissociated into its cleaning constituents inside the chamber where the thin-film (or thin films) was (were) produced.

(iii) All wafer cleaning process categories for which annual fluorinated GHG emissions shall be calculated are defined in this paragraph (a)(1)(iii) .

(A) Bevel cleaning means any process using fluorinated GHG reagents with plasma to clean the edges of wafers during semiconductor manufacture.

(B) Ashing means any process using fluorinated GHG reagents with plasma to remove photoresist materials during wafer manufacture.

(2) Semiconductor facilities that fabricate devices on wafers measuring greater than 300 mm in diameter shall calculate annual facility-level emissions of each fluorinated GHG used at a facility for all individual processes at that facility in accordance with §WCI.114(c).

(3) All other electronics facilities shall calculate annual facility-level emissions of each fluorinated GHG used at a facility for each process type, including etching and chemical vapor deposition chamber cleaning.

(b) For each fluorinated GHG and each individual process, process category, or process type used at the facility as appropriate, calculate annual facility-level emissions using Equations 110-3 and 110-4 of this section, and according to the procedures in either paragraph (b)(1), (b)(2), or (b)(3) of this section.

$$E_{ij} = C_{ij}(1 - U_{ij})(1 - a_{ij} \times d_{kj}) \times 0.001$$

Equation 110-3

Where:

E_{ij}	=	Annual emissions of input gas *i* from individual process, process category, or process type *j* (metric tons);
C_{ij}	=	Amount of input gas *i* consumed in individual process, process category, or process type *j*, as calculated in Equation 110-6 (kg) of this section and apportioned pursuant to §WCI.114(b);
U_{ij}	=	Process utilization for input gas *i* during individual process, process category, or process type *j*;
a_{ij}	=	Fraction of input gas *i* used in individual process, process category, or process type *j* with abatement systems;
d_{ij}	=	Fraction of input gas *i* destroyed in abatement systems connected to individual process, process category, or process type *j*, accounting for uptime as specified in §WCI.114(e)(2). This is zero unless the facility adheres to requirements in §WCI.114(e); and
0.001	=	Conversion factor from kg to metric tons.

$$BE_{ijk} = B_{ijk} \times C_{ij} \times (1 - a_{ij} \times d_{kj}) \times 0.001$$

Equation 110-4

Where:

BE_{ijk}	=	Annual emissions of by-product *k* formed from input gas *i* during individual process, process category, or process type *j* (metric tons);
B_{ijk}	=	Amount of gas *k* created as a by-product per amount of input gas *i* (kg) consumed in individual process, process category, or process type *j* (kg);
C_{ij}	=	Amount of input gas *i* consumed in individual process, process category, or process type *j*, as calculated in Equation 110-6 (kg) of this section and apportioned pursuant to §WCI.114(b);
a_{ij}	=	Fraction of input gas *i* used in individual process, process category, or process type *j* with abatement systems;
d_{kj}	=	Fraction of by-product gas k destroyed in abatement systems connected to individual process, process category, or process type j, accounting for uptime as specified in §WCI.114(e)(2). This is zero unless the facility adheres to requirements in §WCI.114(e); and
0.001	=	Conversion factor from kg to metric tons.

(1) Semiconductor facilities that fabricate devices on wafers measuring 300 mm or less in diameter shall use the procedures in either paragraph (b)(1)(i) or (b)(1)(ii) of this section.

(i) Except as provided in paragraph (b)(1)(ii), use default process category emission factors for process utilization and by-product formation rates shown in Tables 110-2, 110-3, and 110-4 of this subpart as appropriate.

(ii) Recipe-specific measurements may be used instead of the process category default factors provided that the methods in §WCI.114(c) are followed.

(2) Semiconductor facilities that fabricate devices on wafers measuring greater than 300 mm in diameter shall use recipe-specific measurements and follow methods in §WCI.114(c) to calculate emissions from each fluorinated GHG-using process type. Equations 110-1 through 110-4 shall be used to calculate fluorinated GHG emissions from all fluorinated GHG-using process recipes.

(3) All other electronics facilities shall use the default process type-specific emission factors for process utilization and by-product formation rates shown in Tables 110-5, 110-6, and 110-7 of this subpart for MEMS, LCD, and PV manufacturing, respectively.

(c) Calculate annual facility-level N_2O emissions from electronics manufacturing processes, using Equation 110-5 of this section and the methods in this paragraph (c).

(1) Use a factor for N_2O utilization for chemical vapor deposition processes pursuant to either paragraph (c)(1)(i) or (c)(1)(ii) of this section.

(i) Develop a facility-specific N_2O utilization factor averaged over all N_2O-using recipes used for chemical vapor deposition processes in accordance with §WCI.114(d).

(ii) If a facility-specific N_2O utilization factor for chemical vapor deposition processes is not available, a value of 20 percent must be used as the default utilization factor for N_2O from chemical vapor deposition processes.

(2) Use a factor for N_2O utilization for other manufacturing processes pursuant to either paragraph (c)(2)(i) or (c)(2)(ii) of this section.

(i) Develop a facility-specific N_2O utilization factor averaged over all N_2O-using recipes used for manufacturing processes other than chemical vapor deposition processes in accordance with §WCI.114(d).

(ii) If a facility-specific N_2O utilization factor for manufacturing processes other than chemical vapor deposition is not available, a value of 0 percent must be used as a default utilization factor for N_2O from manufacturing processes other than chemical vapor deposition.

(3) If a facility employs abatement systems and wishes to quantify and document N2O emission reductions due to these systems, it must adhere to the requirements in §WCI.114(e).

(4) Calculate annual facility-level N2O emissions for all processes at the facility using Equation 110-5 of this section.

$$E(N_2O) = \sum_j C_{N_2O,j}\left(1 - U_{N_2O,j}\right)\left(1 - a_{N_2O,j} \times d_{N_2O,j}\right) \times 0.001$$

Equation 110-5

Where:

$E(N_2O)$	=	Annual emissions of N_2O (metric tons/year);
$C_{N2O,j}$	=	Amount of N_2O consumed for N_2O-using process *j*, as calculated in Equation 110-6 of this section and apportioned to N_2O-using process *j* (kg);
$U_{N2O,j}$	=	Process utilization for N_2O-using process *j*;
$a_{N2O,j}$	=	Fraction of N_2O used in N_2O-using process *j* with abatement systems;
$d_{N2O,j}$	=	Fraction of N_2O for N_2O-using process *j* destroyed by abatement systems connected to process *j*, accounting for uptime as specified in §WCI.114(e)(2). This is zero unless the facility adheres to requirements in §WCI.114(e); and
0.001	=	Conversion factor from kg to metric tons.

(d) Calculate gas consumption for each fluorinated GHG and N_2O used at the facility using facility-wide gas-specific heel factors, as determined in §WCI.114(a), and using Equation 110-6 of this section.

$$C_i = \left(I_{Bi} - I_{Ei} + A_i - D_i\right) \times 0.001$$

Equation 110-6

Where:

C_i	=	Annual consumption of input gas *i* (metric tons/year);
I_{Bi}	=	Inventory of input gas *i* stored in cylinders or other containers at the beginning of the year, including heels (kg);
I_{Ej}	=	Inventory of input gas *i* stored in cylinders or other containers at the end of the year, including heels (kg);
A_i	=	Acquisitions of gas *i* during the year through purchases or other transactions, including heels in cylinders or other containers returned to the electronics manufacturing facility (kg);
D_i	=	Disbursements under exceptional circumstances of gas *i* through sales or other transactions during the year, including heels in cylinders or other containers returned by the electronics manufacturing facility to the chemical supplier, calculated using Equation 110-7 of this section (kg); and
0.001	=	Conversion factor from kg to metric tons.

(e) Calculate disbursements of gas *i* using Equation 110-7 of this section.

$$D_i = h_i \times N_i \times F_i + X_i$$

Equation 110-7

Where:

D_i	=	Disbursements of gas *i* through sales or other transactions during the year, including heels in cylinders or other containers returned by the electronics manufacturing facility to the gas distributor (kg);
h_i	=	Facility-wide gas-specific heel factor for input gas *i* (%), as determined in §98.94(b) of this subpart;
N_i	=	Number of cylinders or other containers returned to the gas distributor containing the standard heel of gas *i*;
F_i	=	Full capacity of cylinders or other containers containing gas *i* (kg); and
X_i	=	Disbursements under exceptional circumstances of gas *i* through sales or other transactions during the year. These include returns of containers whose contents have been weighed due to an exceptional circumstance as specified in §WCI.114(a)(5) of this subpart (kg).

(f) For facilities that use fluorinated heat transfer fluids, you shall report the annual emissions of fluorinated GHG heat transfer fluids using the mass balance approach described in Equation 110-8 of this section.

$$E_i = \rho_i\left(I_{ib} + P_i - N_i + R_i - I_{ie} - D_i\right)\times 0.001$$

Equation 110-8

Where:

E_i	=	Emissions of fluorinated GHG heat transfer fluid *i*, (metric tons/year);
ρ_i	=	Density of fluorinated heat transfer fluid *i* (kg/liter);
I_{ib}	=	Inventory of fluorinated heat transfer fluid *i* (in containers, not equipment) at the beginning of the reporting year (liters). The inventory at the beginning of the reporting year must be the same as the inventory at the end of the previous reporting year;
P_i	=	Acquisitions of fluorinated heat transfer fluid *i* during the current reporting year (liters). Includes amounts purchased from chemical suppliers, amounts purchased from equipment suppliers with or inside of equipment, and amounts returned to the facility after off-site recycling;
N_i	=	Total nameplate capacity (full and proper charge) of equipment that uses fluorinated heat transfer fluid *i* and that is newly installed during the reporting year (liters);
R_i	=	Total nameplate capacity (full and proper charge) of equipment that uses fluorinated heat transfer fluid *i* and that is removed from service during the current reporting year (liters);
I_{ie}	=	Inventory of fluorinated heat transfer fluid *i* (in containers, not equipment) at the end of current reporting year (liters);
D_i	=	Disbursements of fluorinated heat transfer fluid *i* during the current reporting year (liters). Includes amounts returned to chemical suppliers, sold with or inside of equipment, and sent off site for verifiable recycling or destruction. Disbursements should include only amounts that are properly stored and transported so as to prevent emissions in transit; and
0.001	=	Conversion factor from kg to metric tons.

§ WCI.114 Sampling, Analysis, and Measurement Requirements

(a) For purposes of Equation 110-6 of this section, you must estimate facility-wide gas-specific heel factors for each cylinder/container type for each gas used according to the procedures in paragraphs (a)(1) through (a)(6) of this section.

(1) Base the facility-wide gas-specific heel factors on the residual weight or pressure of a gas cylinder/container that the facility uses to change out that cylinder/container for each cylinder/container type for each gas used.

(2) The residual weight or pressure used for §WCI.114(a)(1) shall be determined by monitoring the mass or the pressure of your cylinders/containers. If monitoring the pressure, convert the pressure to mass using the ideal gas law, as displayed in Equation 110-9 of this section, with an appropriately selected *Z* value.

$$pV = ZnRT \qquad \textbf{Equation 110-9}$$

Where:

p	=	Absolute pressure of the gas (Pa);
V	=	Volume of the gas (m^3);
Z	=	Compressibility factor;
n	=	Amount of substance of the gas (moles);
R	=	Gas constant (8.314 Joule/Kelvin mole); and
T	=	Absolute temperature (K).

(3) Use the facility-wide gas-specific cylinder/container residual mass, determined from §WCI.114(a)(1) and (a)(2), to calculate the unused gas for each container, which when expressed as fraction of the initial mass in the cylinder/container is the heel factor.

(4) The initial mass used to calculate the facility-wide gas-specific heel factor may be based on the weight of the gas provided in the gas supplier documents; however, the facilities remain responsible for the accuracy of these masses and weights under this subpart.

(5) In the exceptional circumstance that a cylinder/container is changed at a residual mass or pressure that differs by more than 20 percent from the facility-wide gas-specific determined values, that cylinder shall be weighed, or the pressure of that cylinder shall be measured with a pressure gauge, in place of using a heel factor.

(6) Recalculate facility-wide gas-specific heel factors applied at the facility in the event that the residual weight or pressure of the gas cylinder/container that the facility uses to change out that cylinder/container differs by more than 1 percentage point from that used to calculate the previous gas-specific heel factor.

(b) Semiconductor facilities shall apportion fluorinated GHG consumption by process category, as defined in §WCI.113(a)(1)(i) through (a)(1)(iii), or by individual process using a facility-specific engineering model based on wafer passes.

(c) If factors for fluorinated GHG process utilization and by-product formation rates are used other than the defaults provided in Tables 110-2 through 110-4 of this subpart, the factors must have been measured using the "International SEMATECH Manufacturing Initiative's Guideline for Environmental Characterization of Semiconductor Process Equipment" (December 2006). Factors for fluorinated GHG process utilization and by-product formation rates measured by manufacturing equipment suppliers may be used if the conditions in paragraphs (c)(1) and (c)(2) of this section are met.

(1) The manufacturing equipment supplier has measured the GHG emission factors for process utilization and by-product formation rates using the "International SEMATECH Manufacturing Initiative's Guideline for Environmental Characterization of Semiconductor Process Equipment" (December 2006).

(2) The conditions under which the measurements were made are representative of the facility's fluorinated GHG emitting processes.

(d) If N_2O utilization factors other than those defaults provided in §WCI.113(c)(1)(ii) or (c)(2)(ii) are used, factors that have been measured using the "International SEMATECH Manufacturing Initiative's Guideline for Environmental Characterization of Semiconductor Process Equipment" (December 2006) must be used. Utilization factors measured by manufacturing equipment suppliers may be used if the conditions in paragraphs (d)(1) and (d)(2) of this section are met.

(1) The manufacturing equipment supplier has measured the N_2O utilization factors using the "International SEMATECH Manufacturing Initiative's Guideline for Environmental Characterization of Semiconductor Process Equipment" (December 2006).

(2) The conditions under which the measurements were made are representative of the facility's N_2O emitting processes.

(e) If the facility employs abatement systems and wishes to reflect emission reductions due to these systems in appropriate calculations in §WCI.113, the facility must adhere to the procedures in paragraphs (e)(1) and (e)(2) of this section. If the facility uses the default destruction or removal efficiency of 60 percent, the facility must adhere to procedures in paragraph (e)(3) of this section. If the facility uses either a properly measured destruction or removal efficiency, or a class average of properly measured destruction or removal efficiencies during a reporting year, the facility must adhere to procedures in paragraph (e)(4) of this section.

(1) The facility must certify and document that the systems are properly installed, operated, and maintained according to manufacturers' specifications by adhering to the procedures in paragraphs (e)(1)(i) and (e)(1)(ii) of this section.

(i) Proper installation must be verified by certifying the systems are installed in accordance with the manufacturers' specifications.

(ii) Proper operation and maintenance must be verified by certifying the systems are operated and maintained in accordance with the manufacturers' specifications.

(2) The facility must take into account and report the uptime of abatement systems when using destruction or removal efficiencies to reflect emission reductions. Abatement system uptime is expressed as the sum of an abatement system's operational productive, standby, and engineering times divided by the total operations time of its associated manufacturing tool(s) as referenced in SEMI Standard E-10-0340 "Specification for Definition and Measurement of Equipment Reliability, Availability, and Maintainability" (2004).

(3) To report controlled emissions using the default destruction or removal efficiency, the facility must certify and document that the abatement systems at the facility for which it is reporting controlled emissions are specifically designed for fluorinated GHG and N_2O abatement and you shall use a default destruction or removal efficiency of 60 percent for those abatement systems.

(4) If the facility does not use the default destruction or removal efficiency value to report controlled emissions, the facility must use either a properly measured destruction or removal efficiency, or a class average of properly measured destruction or removal efficiencies during a reporting year, determined in accordance with procedures in paragraphs (e)(4)(i) through (e)(4)(v) of this section.

(i) Destruction or removal efficiencies must be properly measured in accordance with EPA's "Protocol for Measuring Destruction or Removal Efficiency of Fluorinated Greenhouse Gas Abatement Equipment in Electronics Manufacturing" (March 2010).

(ii) A facility must annually select and properly measure the destruction or removal efficiency for a random sample of abatement systems to include in a random sampling abatement system testing program (RSASTP) in accordance with procedures in paragraphs (f)(3)(ii)(A) and (f)(3)(ii)(B) of this section.

(A) Each reporting year a random sample of three or 20 percent of installed abatement systems, whichever is greater, for each abatement system class shall be tested. In instances where 20 percent of the total number of abatement systems in each class does not equate to a whole number, the number of systems to be tested shall be determined by rounding up to the nearest integer.

(B) The facility must select the random sample each reporting year for the RSASTP without repetition of systems in the sample, until all systems in each class are properly measured in a 5-year period.

(iii) If a facility has measured the destruction or removal efficiency of a particular abatement system during the previous two-year period, the facility shall calculate emissions from that system using the destruction or removal efficiency most recently measured for that particular system.

(iv) If an individual abatement system has not yet undergone proper destruction or removal efficiency testing during the previous two-year period, the facility may apply a simple average of the properly measured destruction or removal efficiencies for all systems of that class, in accordance with the RSASTP. The facility shall maintain or exceed the RSASTP schedule and regime if it wishes to apply class average destruction or removal efficiency factors to abatement systems that have not been properly measured as per the RSASTP.

(v) In instances where redundant abatement systems are used, the facility may account for the total abatement system uptime calculated for a specific exhaust stream during the reporting year.

(f) Facilities must adhere to the QA/QC procedures of this paragraph when estimating fluorinated GHG and N_2O emissions from all electronics manufacturing processes:

(1) Facilities must follow the QA/QC procedures in the "International SEMATECH Manufacturing Initiative's Guideline for Environmental Characterization of Semiconductor Process Equipment" (December 2006) when estimating facility-specific, recipe-specific fluorinated GHG and N2O utilization and by-product formation rates.

(2) Facilities must follow the QA/QC procedures in EPA's "Protocol for Measuring Destruction or Removal Efficiency of Fluorinated Greenhouse Gas Abatement Equipment in Electronics Manufacturing" (March 2010) when estimating abatement systems destruction or removal efficiency.

(3) Facilities must certify that gas consumption is tracked to a high degree of precision as part of normal facility operations ensuring that the inventory at the beginning of the reporting is the same as the inventory at the end of the previous year.

(g) Facilities must adhere to the QA/QC procedures of this paragraph when estimating fluorinated GHG emissions from heat transfer fluid use and annual gas consumption for each fluorinated GHG and N_2O used at the facility:

(1) Facilities must review all inputs to Equations 110-6 and 110-8 of this section to ensure that all inputs and outputs to the facility's system are accounted for.

(2) Facilities must not enter negative inputs into the mass balance Equations 110-6 and 110-8 of this section and shall ensure that no negative emissions are calculated.

(3) Facilities must ensure that the beginning of year inventory matches the end of year inventory from the previous year.

(h) All instruments (e.g., mass spectrometers and fourier transform infrared measuring systems) used to determine the concentration of fluorinated GHG and N_2O in process streams shall be calibrated just prior to destruction or removal efficiency, gas utilization, or by-product formation measurement through analysis of certified standards with known concentrations of the same chemicals in the same ranges (fractions by mass) as the process samples. Calibration gases prepared from a high-concentration certified standard using a gas dilution system that meets the requirements specified in Method 205, 40 CFR part 51, Appendix M may also be used.

(i) All flowmeters, weigh scales, pressure gauges, and thermometers used to measure quantities that are monitored under this section or used in calculations under §WCI.113 shall have an accuracy and precision of one percent of full scale or better.

§ WCI.115 Missing Data Procedures

(a) Except as provided in paragraph §WCI.115(b), a complete record of all measured parameters used in the fluorinated GHG and N_2O emissions calculations in §WCI.113 and§WCI.114 is required.

(b) If a facility uses heat transfer fluids and is missing data for one or more of the parameters in Equation 110-8 of this subpart, the facility must estimate heat transfer fluid emissions using the arithmetic average of the emission rates for the year immediately preceding the period of missing data and the months immediately following the period of missing data. Alternatively, you may estimate missing information using records from the heat transfer fluid supplier. The facility must document the method used and values estimated for all missing data values.

Table 110-1. Examples of Fluorinated GHGs Used by the Electronics Industry

Product Type	Fluorinated GHGs used during manufacturing
Electronics	CF_4, C_2F_6, C_3F_8, c-C_4F_8, c-C_4F_8O, C_4F_6, C_5F_8, CHF_3, CH_2F_2, NF_3, SF6,and HTFs [CF_3-(O-CF(CF_3)-CF_2)$_n$-(O-CF2)$_m$-O-CF_3, C_nF_{2n+2}, C_nF_{2n+1}(O)C_mF_{2m+1}, $C_nF_{2n}O$, (C_nF2$_{n+1}$)$_3$N].

Table 110-2. Default Emission Factors for Refined Process Categories for Semiconductor Manufacturing for 150 mm Wafer Size

Refined Process Category	Process Gas *i*										
	CF_4	C_2F_6	CHF_3	CH_2F_2	C_3F_8	c-C_4F_8	NF_3	SF_6	C_4F_6	C_5F_8	C_4F_8O
PATTERNING/ETCHING											
Oxide etch											
$1\text{-}U_i$	0.2-0.8	0.2-0.7	0.2-0.7	0.02-0.3	NA	0.1-0.3	0.1-0.4	0.1-0.4	0.05-0.2	0.05-0.3	NA
BCF_4	NA	0.05-0.5	0.01-0.8	0.05-0.1	NA	0.01-0.3	NA	NA	0.02-0.4	0.02-0.4	NA
BC_2F_6	NA	NA	NA	NA	NA	0.01-0.3	NA	NA	0.02-0.3	0.02-0.3	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Nitride etch											
$1\text{-}U_i$	0.2-0.8	0.2-0.7	0.2-0.7	0.02-0.3	NA	0.1-0.3	0.1-0.4	0.1-0.4	0.05-0.2	0.05-0.3	NA
BCF_4	NA	0.05-0.5	0.01-0.8	0.05-0.1	NA	0.01-0.3	NA	NA	0.02-0.4	0.02-0.4	NA
BC_2F_6	NA	NA	NA	NA	NA	0.01-0.3	NA	NA	0.02-0.3	0.02-0.3	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Silicon etch											
$1\text{-}U_i$	0.2-0.8	0.2-0.7	0.2-0.7	0.02-0.3	NA	0.1-0.3	0.1-0.4	0.1-0.4	0.05-0.2	0.05-0.3	NA
BCF_4	NA	0.05-0.5	0.01-0.8	0.05-0.1	NA	0.01-0.3	NA	NA	0.02-0.4	0.02-0.4	NA
BC_2F_6	NA	NA	NA	NA	NA	0.01-0.3	NA	NA	0.02-0.3	0.02-0.3	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Metal etch											
$1\text{-}U_i$	0.2-0.8	0.2-0.7	0.2-0.7	0.02-0.3	NA	0.1-0.3	0.1-0.4	0.1-0.4	0.05-0.2	0.05-0.3	NA
BCF_4	NA	0.05-0.5	0.01-0.8	0.05-0.1	NA	0.01-0.3	NA	NA	0.02-0.4	0.02-0.4	NA
BC_2F_6	NA	NA	NA	NA	NA	0.01-0.3	NA	NA	0.02-0.3	0.02-0.3	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
CHAMBER CLEANING											
In situ plasma cleaning											
$1\text{-}U_i$	0.8-0.95	0.4-0.8	NA	NA	0.2-0.6	0.05-0.3	0.05-0.3	NA	NA	0.05-0.2	0.05-0.2

Refined Process Category	Process Gas *i*										
	CF_4	C_2F_6	CHF_3	CH_2F_2	C_3F_8	c-C_4F_8	NF_3	SF_6	C_4F_6	C_5F_8	C_4F_8O
BCF_4	NA	0.05-0.2	NA	NA	0.05-0.2	0.05-0.2	0.05-0.2	NA	NA	0.05-0.2	0.05-0.2
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.02-0.08
Remote plasma cleaning											
$1-U_i$	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BCF_4	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
In situ thermal cleaning											
$1-U_i$	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BCF_4	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
WAFER CLEANING											
Bevel cleaning											
$1-U_i$	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BCF_4	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Ashing											
$1-U_i$	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BCF_4	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Notes: NA denotes not applicable based on currently available information.

Table 110-3. Default Emission Factors for Refined Process Categories for Semiconductor Manufacturing for 200 mm Wafer Size

Refined Process Category	Process Gas *i*										
	CF_4	C_2F_6	CHF_3	CH_2F_2	C_3F_8	$c\text{-}C_4F_8$	NF_3	SF_6	C_4F_6	C_5F_8	C_4F_8O
PATTERNING/ETCHING											
Oxide etch											
$1\text{-}U_i$	0.2-0.8	0.2-0.7	0.2-0.7	0.02-0.3	NA	0.1-0.3	0.1-0.4	0.1-0.4	0.05-0.5	0.05-0.3	NA
BCF_4	NA	0.05-0.5	0.01-0.8	0.05-0.1	NA	0.01-0.3	NA	NA	0.02-0.4	0.02-0.4	NA
BC_2F_6	NA	NA	NA	NA	NA	0.01-0.3	NA	NA	0.02-0.3	0.02-0.3	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Nitride etch											
$1\text{-}U_i$	0.2-0.8	0.2-0.7	0.1-0.7	0.02-0.3	NA	0.05-0.3	0.1-0.4	0.1-0.4	0.05-0.2	0.05-0.3	NA
BCF_4	NA	0.05-0.5	0.01-0.8	0.05-0.1	NA	0.02-0.3	NA	NA	0.02-0.4	0.02-0.4	NA
BC_2F_6	NA	NA	NA	NA	NA	0.005-0.3	NA	NA	0.02-0.3	0.02-0.3	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Silicon etch											
$1\text{-}U_i$	0.2-0.8	0.2-0.7	0.2-0.7	0.02-0.3	NA	0.1-0.3	0.1-0.4	0.1-0.4	0.05-0.2	0.05-0.3	NA
BCF_4	NA	0.05-0.5	0.01-0.8	0.05-0.1	NA	0.01-0.3	NA	NA	0.02-0.4	0.02-0.4	NA
BC_2F_6	NA	NA	NA	NA	NA	0.01-0.3	NA	NA	0.02-0.3	0.02-0.3	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Metal etch											
$1\text{-}U_i$	0.2-0.8	0.2-0.7	0.2-0.7	0.02-0.3	NA	0.1-0.3	0.1-0.4	0.1-0.4	0.05-0.2	0.05-0.3	NA
BCF_4	NA	0.05-0.5	0.01-0.8	0.05-0.1	NA	0.01-0.3	NA	NA	0.02-0.4	0.02-0.4	NA
BC_2F_6	NA	NA	NA	NA	NA	0.01-0.3	NA	NA	0.02-0.3	0.02-0.3	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
CHAMBER CLEANING											
In situ plasma cleaning											
$1\text{-}U_i$	0.8-0.95	0.4-0.8	NA	NA	0.2-0.6	005-0.3	0.05-0.2	NA	NA	0.05-0.2	0.05-0.2

Refined Process Category	Process Gas *i*										
	CF_4	C_2F_6	CHF_3	CH_2F_2	C_3F_8	$c\text{-}C_4F_8$	NF_3	SF_6	C_4F_6	C_5F_8	C_4F_8O
BCF_4	NA	0.05-0.2	NA	NA	0.05-0.2	0.05-0.2	0.05-0.1	NA	NA	0.05-0.2	0.05-0.2
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.02-0.08
Remote plasma cleaning											
$1\text{-}U_i$	NA	NA	NA	NA	NA	NA	0.005-0.03	NA	NA	NA	NA
BCF_4	NA	NA	NA	NA	NA	NA	0.0001-0.2	NA	NA	NA	NA
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
In situ thermal cleaning											
$1\text{-}U_i$	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BCF_4	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
WAFER CLEANING											
Bevel cleaning											
$1\text{-}U_i$	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BCF_4	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Ashing											
$1\text{-}U_i$	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BCF_4	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Notes: NA denotes not applicable based on currently available information.

Table 110-4. Default Emission Factors for Refined Process Categories for Semiconductor Manufacturing for 300 mm Wafer Size

Refined Process Category	Process Gas *i*										
	CF_4	C_2F_6	CHF_3	CH_2F_2	C_3F_8	c-C_4F_8	NF_3	SF_6	C_4F_6	C_5F_8	C_4F_8O
PATTERNING/ETCHING											
Oxide etch											
$1\text{-}U_i$	0.2-0.8	0.2-0.7	0.2-0.4	0.1-0.8	NA	0.05-0.3	0.1-0.4	0.1-0.4	0.05-0.3	0.05-0.3	NA
BCF_4	NA	0.05-0.5	0.005-0.03	0.001-0.01	NA	0.005-0.1	NA	NA	0.02-0.4	0.02-0.4	NA
BC_2F_6	NA	NA	NA	NA	NA	0.005-0.1	NA	NA	0.02-0.3	0.02-0.3	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Nitride etch											
$1\text{-}U_i$	0.2-0.8	0.2-0.7	0.2-0.4	0.1-0.8	NA	0.08-0.3	0.1-0.4	0.1-0.4	0.05-0.2	0.05-0.3	NA
BCF_4	NA	0.05-0.5	0.003-0.1	0.01-0.1	NA	0.02-0.3	NA	NA	0.05-0.4	0.05-0.4	NA
BC_2F_6	NA	NA	NA	NA	NA	0.02-0.3	NA	NA	0.05-0.4	0.05-0.4	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Silicon etch											
$1\text{-}U_i$	0.2-0.8	0.2-0.7	0.2-0.7	0.02-0.3	NA	0.1-0.3	0.1-0.4	0.1-0.4	0.05-0.2	0.05-0.3	NA
BCF_4	NA	0.05-0.5	0.01-0.8	0.05-0.1	NA	0.01-0.3	NA	NA	0.02-0.4	0.02-0.4	NA
BC_2F_6	NA	NA	NA	NA	NA	0.01-0.3	NA	NA	0.02-0.3	0.02-0.3	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Metal etch											
$1\text{-}U_i$	0.2-0.8	0.2-0.7	0.2-0.7	0.02-0.3	NA	0.1-0.3	0.1-0.4	0.1-0.4	0.05-0.2	0.05-0.3	NA
BCF_4	NA	0.05-0.5	0.01-0.8	0.05-0.1	NA	0.01-0.3	NA	NA	0.02-0.4	0.02-0.4	NA
BC_2F_6	NA	NA	NA	NA	NA	0.01-0.3	NA	NA	0.02-0.3	0.02-0.3	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
CHAMBER CLEANING											
In situ plasma cleaning											
$1\text{-}U_i$	NA	NA	NA	NA	NA	NA	0.1-0.4	NA	NA	NA	NA

Refined Process Category	Process Gas *i*										
	CF_4	C_2F_6	CHF_3	CH_2F_2	C_3F_8	c-C_4F_8	NF_3	SF_6	C_4F_6	C_5F_8	C_4F_8O
BCF_4	NA	NA	NA	NA	NA	NA	0.001-0.6	NA	NA	NA	NA
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Remote plasma cleaning											
$1\text{-}U_i$	NA	NA	NA	NA	NA	NA	0.002-0.03	NA	NA	NA	NA
BCF_4	NA	NA	NA	NA	NA	NA	0.001-0.05	NA	NA	NA	NA
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
In situ thermal cleaning											
$1\text{-}U_i$	NA	NA	NA	NA	NA	NA	0.1-0.4	NA	NA	NA	NA
BCF_4	NA	NA	NA	NA	NA	NA	0.005-.05	NA	NA	NA	NA
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
WAFER CLEANING											
Bevel cleaning											
$1\text{-}U_i$	0.3-0.8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BCF_4	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Ashing											
$1\text{-}U_i$	0.3-0.8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BCF_4	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Notes: NA denotes not applicable based on currently available information.

Table 110-5. Default Emission Factors for MEMS Manufacturing

Process Type Factors	Process Gas *i*											
	CF_4	C_2F_6	CHF_3	CH_2F_2	C_3F_8	c-C_4F_8	NF_3 Remote	NF_3	SF_6	C_4F_6[a]	C_5F_8[a]	C_4F_8O[a]
Etch 1-U_i	0.7	0.4[1]	0.4[1]	0.06[1]	NA	0.2[1]	NA	0.2	0.2	0.1	0.2	NA
Etch BCF_4	NA	0.4[1]	0.07[1]	0.08[1]	NA	0.2	NA	NA	NA	0.3[1]	0.2	NA
Etch BC_2F_6	NA	NA	NA	NA	NA	0.2	NA	NA	NA	0.2[1]	0.2	NA
CVD 1-U_i	0.9	0.6	NA	NA	0.4	0.1	0.02	0.2	NA	NA	0.1	0.1
CVD BCF_4	NA	0.1	NA	NA	0.1	0.1	0.02[2]	0.1[2]	NA	NA	0.1	0.1
CVD BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.4

Notes: NA denotes not applicable based on currently available information.

[1] Estimate includes multi-gas etch processes.

[2] Estimate reflects presence of low-k, carbide and multi-gas etch processes that may contain a C-containing fluorinated GHG additive.

Table 110-6. Default Emission Factors for LCD Manufacturing

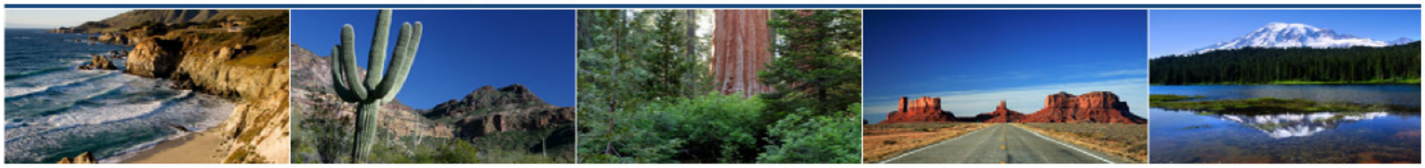
Process Type Factors	Process Gas *i*								
	CF_4	C_2F_6	CHF_3	CH_2F_2	C_3F_8	c-C_4F_8	NF_3 Remote	NF_3	SF_6
Etch 1-U_i	0.6	NA	0.2	NA	NA	0.1	NA	NA	0.3
Etch BCF_4	NA	NA	0.07	NA	NA	0.009	NA	NA	NA
Etch $BCHF_3$	NA	NA	NA	NA	NA	0.02	NA	NA	NA
Etch BC_2F_6	NA	NA	0.05	NA	NA	NA	NA	NA	NA
CVD 1-U_i	NA	NA	NA	NA	NA	NA	0.03	0.3	0.9

Notes: NA denotes not applicable based on currently available information.

Table 110-7. Default Emission Factors for PV Manufacturing

Process Type Factors	Process Gas *i*								
	CF_4	C_2F_6	CHF_3	CH_2F_2	C_3F_8	$c\text{-}C_4F_8$	NF_3 Remote	NF_3	SF_6
Etch $1\text{-}U_i$	0.7	0.4	0.4	NA	NA	0.2	NA	NA	0.4
Etch BCF_4	NA	0.2	NA	NA	NA	0.1	NA	NA	NA
Etch BC_2F_6	NA	NA	NA	NA	NA	0.1	NA	NA	NA
CVD $1\text{-}U_i$	NA	0.6	NA	NA	0.1	0.1	NA	0.3	0.4
CVD BCF_4	NA	0.2	NA	NA	0.2	0.1	NA	NA	NA

Notes: NA denotes not applicable based on currently available information.



This proposed WCI Essential Requirement would be for use in WCI Canadian jurisdictions. At such a point when the U.S. EPA finalizes Subpart W, the WCI will develop cap and trade quality requirements for sources covered by Subpart W for use in U.S. jurisdictions. This may mean modifications will be required to the current proposed Canadian language covering the same sources.

§ WCI.250 UNDERGROUND COAL MINES

§ WCI.251 Source Category Definition

The underground coal mine source category consists of active underground coal mines, and any underground mines under development that have operational pre-mining degasification systems. An underground coal mine is a mine at which coal is produced by tunneling into the earth to the coalbed, which is then mined with underground mining equipment such as cutting machines and continuous, longwall, and shortwall mining machines, and transported to the surface.

(a) Underground coal mines are categorized as active if any one of the following five conditions apply:

  (1) Mine development is underway.

  (2) Coal has been produced within the last 90 days.

  (3) Mine personnel are present in the mine workings.

  (4) Mine ventilation fans are operative.

  (5) The mine operates on an intermittent basis.

(b) The underground coal mine source category includes the following:

  (1) Each ventilation well or shaft, including both those wells and shafts where gas is emitted and those where gas is sold, used onsite, or otherwise destroyed (including by flaring).

  (2) Each degasification system well or shaft, including degasification systems deployed before, during, or after mining operations are conducted in a mine area. This includes both those wells and shafts where gas is emitted, and those where gas is sold, used onsite, or otherwise destroyed (including by flaring).

(c) The underground coal mine source category does not include abandoned or closed mines, surface coal mines, or post-coal mining activities (i.e., storage or transportation of coal).

§ WCI.252 Greenhouse Gas Reporting Requirements

In addition to the information required by regulation, the annual emissions data report shall contain the following information:

(a) Quarterly CH_4 destruction at all ventilation and degasification system destruction devices or point of offsite transport (metric tons CH_4).

(b) Quarterly CH_4 emissions (net) from all ventilation and degasification systems (metric tons CH_4).

(c) Quarterly CO_2 emissions from onsite destruction of coal mine gas CH_4, where the gas is not a fuel input for energy generation or use (e.g., flaring) (metric tons CO_2).

§ WCI.253 Calculation of GHG Emissions

(a) For each ventilation shaft, vent hole, or centralized point into which CH_4 from multiple shafts and/or vent holes are collected, calculate the quarterly CH_4 liberated from the ventilation system using Equation 250-1 of this section. Measure CH_4 content, flow rate, temperature, pressure, and moisture content of the gas using the procedures outlined in §WCI.254.

$$CH_{4V} = n \times \left(V \times MCF \times \frac{C}{100\%} \times 0.6775 \times \frac{288.71K}{T} \times \frac{P}{1\ atm} \times 1{,}440 \right)$$

Equation 250-1

Where:

CH_{4V}	=	Quarterly CH_4 liberated from a ventilation monitoring point (metric tons CH_4);
V	=	Daily volumetric flow rate for the quarter (cubic meters) based on sampling or a flow rate meter. If a flow rate meter is used and the meter automatically corrects for temperature and pressure, replace "288.71K/T × P/1 atm" with "1";
MCF	=	Moisture correction factor for the measurement period, volumetric basis;
	=	1 when V and C are measured on a dry basis or if both are measured on a wet basis.
	=	1 - $(f_{H2O})_n$ when V is measured on a wet basis and C is measured on a dry basis.
	=	$1/[1-(f_{H2O})]$ when V is measured on a dry basis and C is measured on a wet basis.
(f_{H2O})	=	Moisture content of the CH_4 emitted during the measurement period, volumetric basis (cubic meter water per cubic meter emitted gas);
C	=	Daily CH_4 concentration of ventilation gas for the quarter (%, wet basis);
n	=	Number of days in the quarter where active ventilation of mining operations is taking place at the monitoring point;
0.6775	=	Density of CH_4 at 288.71 K (15.56 °C) and 1 atm (kg/m^3);
288.71K	=	288.71 Kelvin;
T	=	Temperature at which flow is measured (K) for the quarter;
P	=	Pressure at which flow is measured (atm); and
1,440	=	Conversion factor (min/day).

(1) Unless required to be modified to meet existing regulatory inspection schedules, the quarterly periods are:

(i) January 1 – March 31.

(ii) April 1 – June 30.

(iii) July 1 – September 30.

(iv) October 1 – December 31.

(2) Daily values of V, MCF, C, T, and P must be based on measurements taken at least once each quarter with no fewer than 6 weeks between measurements. If measurements are taken more frequently than once per quarter, then use the average value for all measurements taken. If continuous measurements are taken, then use the average value over the time period of continuous monitoring.

(3) If a facility has more than one monitoring point, the facility must calculate total CH4 liberated from ventilation systems ($CH_{4VTotal}$) as the sum of the CH_4 from all ventilation monitoring points in the mine, as follows in Equation 250-2:

$$CH_{4VTotal} = \sum_{i=1}^{m} \left(CH_{4V}\right)_i$$

Equation 250-2

Where:

$CH_{4VTotal}$ = Total quarterly CH_4 liberated from ventilation systems (metric tons CH_4);
CH_{4V} = Quarterly CH_4 liberated from each ventilation monitoring point (metric tons CH_4 and
m = Number of ventilation monitoring points.

(b) For each monitoring point in the degasification system (this could be at each degasification well and/or vent hole, or at more centralized points into which CH_4 from multiple wells and/or vent holes are collected), calculate the weekly CH_4 liberated from the mine using CH_4 measured weekly or more frequently (including by CEMS) according to §WCI.254(c), CH_4 content, flow rate, temperature, pressure, and moisture content, and Equation 250-3 of this section.

$$CH_{4D} = \sum_{i=1}^{n} \left(V_i \times MCF_i \times \frac{C_i}{100\%} \times 0.6775 \times \frac{288.71K}{T_i} \times \frac{P_i}{1\,atm} \times 1{,}440 \right)$$

Equation 250-3

Where:

CH_{4D} = Weekly CH_4 liberated from a monitoring point (metric tons CH_4);
V_i = Daily measured total volumetric flow rate for the days in the week when the degasification system is in operation at that monitoring point, based on sampling or a flow rate meter (cubic meters). If a flow rate meter is used and the meter automatically corrects for temperature and pressure, replace"288.71K/T × P/1 atm" with "1";
MCF_i = Moisture correction factor for the measurement period, volumetric basis;
= 1 when V_i and C_i are measured on a dry basis or if both are measured on a wet basis.
= $1-(f_{H2O})_i$ when V_i is measured on a wet basis and C_i is measured on a dry basis.
= $1/[1-(f_{H2O})_i]$ when V_i is measured on a dry basis and C_i is measured on a wet basis.

$(f_{H2O})_i$	=	Moisture content of the CH_4 emitted during the measurement period, volumetric basis (cubic meter water per cubic meter emitted gas);
C_i	=	Daily CH_4 concentration of gas for the days in the week when the degasification system is in operation at that monitoring point (%, wet basis);
n	=	Number of days in the week that the system is operational at that measurement point.
0.6775	=	Density of CH_4 at 288.71 K (15.56 ℃) and 1 atm (kg/m^3);
288.71K	=	288.71 Kelvin;
T_i	=	Daily temperature at which flow is measured (K);
P_i	=	Daily pressure at which flow is measured (atm); and
1,440	=	Conversion factor (min/day).

(1) Daily values for V, MCF, C, T, and P must be based on measurements taken at least once each calendar week with at least 3 days between measurements. If measurements are taken more frequently than once per week, then use the average value for all measurements taken that week. If continuous measurements are taken, then use the average values over the time period of continuous monitoring when the continuous monitoring equipment is properly functioning.

(2) Quarterly total CH4 liberated from degasification systems for the mine should be determined as the sum of CH4 liberated determined at each of the monitoring points in the mine, summed over the number of weeks in the quarter, as follows in Equation 250-4:

$$CH_{4DTotal} = \sum_{i=1}^{m} \sum_{j=1}^{w} \left(CH_{4D}\right)_{i,j}$$

Equation 250-4

Where: :

$CH_{4DTotal}$	=	Quarterly CH_4 liberated from all degasification monitoring points (metric tons CH_4);
CH_{4D}	=	Weekly CH_4 liberated from a degasification monitoring point (metric tons CH_4);
m	=	Number of monitoring points; and
w	=	Number of weeks in the quarter during which the degasification system is operated.

(c) If gas from degasification system wells or ventilation shafts is sold, used onsite, or otherwise destroyed (including by flaring), calculate the quarterly CH_4 destroyed for each destruction device and each point of offsite transport to a destruction device, using Equation 250-5 of this section. You must measure CH_4 content and flow rate according to the provisions in §WCI.254.

$$CH_{4Destroyed} = CH_4 \times DE$$

Equation 250-5

Where:

$CH_{4Destroyed}$ = Quarterly CH_4 destroyed (metric tons);
CH_4 = Quarterly CH_4 routed to the destruction device or offsite transfer point (metric tons); and
DE = Destruction efficiency (lesser of manufacturer's specified destruction efficiency and 0.99). If the gas is transported off-site for destruction, use DE = 1.

(d) Calculate total CH_4 destroyed as the sum of the methane destroyed at all destruction devices (onsite and offsite), using Equation 250-6 of this section.

$$CH_{4DestroyedTotal} = \sum_{i=1}^{d} \left(CH_{4Destroyed}\right)_d$$

Equation 250-6

Where:

$CH_{4DestroyedTotal}$ = Quarterly total CH_4 destroyed at the mine (metric tons CH_4);
$CH_{4Destroyed}$ = Quarterly CH_4 destroyed from each destruction device or offsite transfer point; and
d = Number of onsite destruction devices and points of offsite transport.

(e) Calculate the quarterly measured net CH4 emissions to the atmosphere using Equation 250-7 of this section.

$$CH_{emitted\ (net)} = CH_{4VTotal} + CH_{4DTotal} - CH_{4DestroyedTotal}$$

Equation 250-7

Where:

$CH_{4emitted\ (net)}$ = Quarterly CH_4 emissions from the mine (metric tons).
$CH_{4VTotal}$ = Quarterly sum of the CH_4 liberated from all mine ventilation monitoring points (CH_{4V}), calculated using Equation 250-2 of this section (metric tons).
$CH_{4DTotal}$ = Quarterly sum of the CH_4 liberated from all mine degasification monitoring points (CH_{4D}), calculated using Equation 250-4 of this section (metric tons).
$CH_{4DestroyedTotal}$ = Quarterly sum of the measured CH_4 destroyed from all mine ventilation and degasification systems, calculated using Equation 250-6 of this section (metric tons).

(f) For the methane collected from degasification and/or ventilation systems that is destroyed on site and is not a fuel input for energy generation or use (those emissions are monitored and reported under §WCI.20), estimate the CO_2 emissions using Equation 250-8 of this section.

$$CO_2 = CH_{4\,Destroyed\ on\ site} \times \left(\frac{44}{16}\right)$$

Equation 250-8

Where:

CO_2	=	Total quarterly CO_2 emissions from CH_4 destruction (metric tons);
$CH_{4Destroyedonsite}$	=	Quarterly sum of the CH_4 destroyed, calculated as the sum of CH_4 destroyed for each onsite, non-energy use, as calculated individually in Equation 250-5 of this section (metric tons); and
44/16	=	Ratio of molecular weights of CO_2 to CH_4.

§ WCI.254 Sampling, Analysis, and Measurement Requirements

Emissions may be estimated by monitoring as specified under paragraphs (a) through (g).

(a) For CH_4 liberated from ventilation systems, CH_4 must be monitored from each ventilation well and shaft, from a centralized monitoring point, or from a combination of the two options. Operators are allowed flexibility for aggregating emissions from more than one ventilation well or shaft, as long as emissions from all are addressed, and the methodology for calculating total emissions documented. Monitor using one of the following options:

(1) Collect quarterly or more frequent grab samples (with no fewer than 6 weeks between measurements) and make quarterly measurements of flow rate, temperature, and pressure. The sampling and measurements must be made at the same locations as MSHA inspection samples are taken, and should be taken when the mine is operating under normal conditions. Follow MSHA sampling procedures as set forth in the MSHA Handbook "General Coal Mine Inspection Procedures and Inspection Tracking System Handbook Number PH–08–V–1", January 1, 2008 or appropriate equivalent in Canada. Record the date of sampling, airflow, temperature, and pressure measured, the hand-held methane and oxygen readings (percent), the bottle number of samples collected, and the location of the measurement or collection.

(2) Obtain results of the quarterly (or more frequent) testing performed by appropriate equivalent to MSHA in Canada (if any).

(3) Monitor emissions through the use of one or more continuous emission monitoring systems (CEMS). If operators use CEMS as the basis for emissions reporting, they must provide documentation on the process for using data obtained from their CEMS to estimate emissions from their mine ventilation systems.

(b) For CH_4 liberated at degasification systems, CH_4 must be monitored from each well and gob gas vent hole, from a centralized monitoring point, or from a combination of the two options. Operators are allowed flexibility for aggregating emissions from more than one well or gob gas vent hole, as long as emissions from all are addressed, and the methodology for calculating total emissions documented. Monitor both gas volume and methane concentration by one of the following two options:

(1) Monitor emissions through the use of one or more continuous emissions monitoring systems (CEMS).

(2) Collect weekly (once each calendar week, with at least three days between measurements) or more frequent samples, for all degasification wells and gob gas vent holes. Determine weekly or more frequent flow rates and methane composition from these degasification wells and gob gas vent holes. Methane composition should be determined either by submitting samples to a lab for analysis, or from the use of methanometers at the degasification well site. Follow the sampling protocols for sampling of methane emissions from ventilation shafts, as described in §WCI.254(a)(1).

(c) Monitoring must adhere to one of the following standards:

(1) ASTM D1945–03 "Standard Test Method for Analysis of Natural Gas by Gas Chromatography"

(2) ASTM D1946–90 (Reapproved 2006) "Standard Practice for Analysis of Reformed Gas by Gas Chromatography"

(3) ASTM D4891–89 (Reapproved 2006) "Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion"

(4) ASTM UOP539–97 "Refinery Gas Analysis by Gas Chromatography"

(d) All fuel flow meters, gas composition monitors, and heating value monitors that are used to provide data for the GHG emissions calculations shall be calibrated prior to the first reporting year, using the applicable methods specified in paragraphs (d)(1) through (7) of this section. Alternatively, calibration procedures specified by the flow meter manufacturer may be used. Fuel flow meters, gas composition monitors, and heating value monitors shall be recalibrated either annually or at the minimum frequency specified by the manufacturer, whichever is more frequent. For fuel, flare, or sour gas flow meters, the operator shall operate, maintain, and calibrate the flow meter using any of the following test methods or follow the procedures specified by the flow meter manufacturer. Flow meters must meet the accuracy requirements specified by regulation in the jurisdiction.

(1) ASME MFC–3M–2004 "Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi"

(2) ASME MFC–4M–1986 (Reaffirmed 1997) "Measurement of Gas Flow by Turbine Meters"

(3) ASME MFC–6M–1998 "Measurement of Fluid Flow in Pipes Using Vortex Flowmeters"

(4) ASME MFC–7M–1987 (Reaffirmed 1992) "Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles"

(5) ASME MFC–11M–2006 "Measurement of Fluid Flow by Means of Coriolis Mass Flowmeters"

(6) ASME MFC–14M–2003 "Measurement of Fluid Flow Using Small Bore Precision Orifice Meters"

(7) ASME MFC–18M–2001 "Measurement of Fluid Flow using Variable Area Meters"

(e) For CH_4 destruction, CH_4 must be monitored at each onsite destruction device and each point of offsite transport for combustion using continuous monitors of gas routed to the device or point of offsite transport.

(f) All temperature and pressure monitors must be calibrated using the procedures and frequencies specified by the manufacturer.

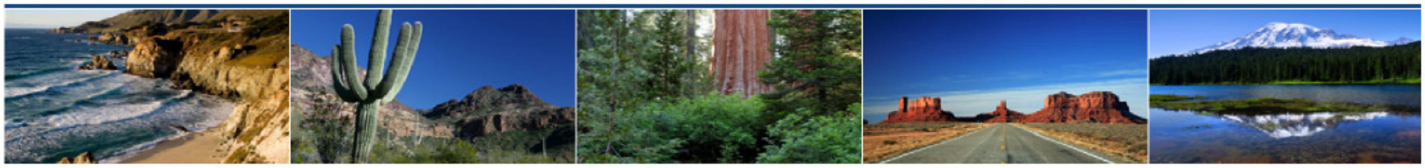
(g) If applicable, the owner or operator shall document the procedures used to ensure the accuracy of gas flow rate, gas composition, temperature, and pressure measurements. These

(h) procedures include, but are not limited to, calibration of fuel flow meters, and other measurement devices. The estimated accuracy of measurements, and the technical basis for the estimated accuracy shall be recorded.

§ WCI.255 Missing Data Procedures

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation or if a required fuel sample is not taken), a substitute data value for the missing parameter shall be used in the calculations, in accordance with the following.

For each missing value of CH_4 concentration, flow rate, temperature, and pressure for ventilation and degasification systems, the substitute data value shall be the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.



§ WCI.290 MAGNESIUM PRODUCTION

§ WCI.291 Source Category Definition

Magnesium production and processing source category consists of any process in which magnesium metal is produced through smelting (including electrolytic smelting), refining, or remelting operations or in which molten magnesium is used in alloying, casting, drawing, extruding, forming, or rolling operations.

Two important sector-specific definitions are the following:

(a) *Cover gas* means SF_6, HFC–134a, fluorinated ketone (FK 5–1–12) or other gas used to protect the surface of molten magnesium from rapid oxidation and burning in the presence of air. The molten magnesium may be the surface of a casting or ingot production operation or the surface of a crucible of molten magnesium that feeds a casting operation.

(b) *Carrier gas* means the gas with which cover gas is mixed to transport and dilute the cover gas thus maximizing its efficient use. Carrier gases typically include CO_2, N_2, and/or dry air.

§ WCI.292 Greenhouse Gas Reporting Requirements

In addition to the information required by regulation, the annual emissions data report shall contain the following information:

(a) Annual emissions of the following gases in metric tons per year resulting from their use as cover gases or carrier gases in magnesium production or processing:

   (1) Sulfur hexafluoride (SF_6).

   (2) HFC–134a.

   (3) FK 5–1–12 (a fluorinated ketone).

   (4) Carbon dioxide (CO_2).

   (5) Any other GHGs (as defined by regulation).

(b) CO_2, N_2O, and CH_4 emissions from stationary combustion units as specified in §WCI.23.

(c) Types of production processes at the facility (e.g., primary, secondary, die casting, etc.).

(d) Amount of magnesium produced or processed in metric tons for each process type, including the output of primary and secondary magnesium production processes and the input to magnesium casting processes.

(e) For any missing data, the length of time the data were missing for each cover gas or carrier gas, the method used to estimate emissions in their absence, and the quantity of emissions thereby estimated.

(f) If applicable, an explanation of any change greater than 30 percent in the facility's cover gas usage rate (e.g., installation of new melt protection technology or leak discovered in the cover gas delivery system that resulted in increased emissions).

(g) Description of any new melt protection technologies adopted to account for reduced or increased GHG emissions in any given year.

§ WCI.293 Calculation of GHG Emissions

(a) Calculate the mass of each GHG emitted from magnesium production or processing over the calendar year using either Equation 290-1 or Equation 290-2 of this section, as appropriate. Both of these equations equate emissions of cover gases or carrier gases to consumption of cover gases or carrier gases.

(1) To estimate emissions of cover gases or carrier gases by monitoring changes in container masses and inventories, emissions of each cover gas or carrier gas shall be estimated using Equation 290-1 of this section:

$$E_x = \left(I_{B,x} - I_{E,x} + A_x - D_x\right) \times 0.001$$

Equation 290-1

Where:

E_x	=	Emissions of each cover gas or carrier gas *x* over the reporting year (metric tons);
$I_{B,x}$	=	Inventory of each cover gas or carrier gas *x* stored in cylinders or other containers at the beginning of the year, including heels (kg);
$I_{E,x}$	=	Inventory of each cover gas or carrier gas *x* stored in cylinders or other containers at the end of the year, including heels (kg);
A_x	=	Acquisitions of each cover gas or carrier gas *x* during the year through purchases or other transactions, including heels in cylinders or other containers returned to the magnesium production or processing facility (kg);.
D_x	=	Disbursements of each cover gas or carrier gas *x* to sources and locations outside the facility through sales or other transactions during the year, including heels in cylinders or other containers returned by the magnesium production or processing facility to the gas supplier (kg);
0.001	=	Conversion factor from kg to metric tons; and
x	=	Each cover gas or carrier gas that is a GHG.

(2) To estimate emissions of cover gases or carrier gases by monitoring changes in the masses of individual containers as their contents are used, emissions of each cover gas or carrier gas shall be estimated using Equation 290-2 of this section:

$$E_x = \sum_{p=1}^{n} Q_p \times 0.001$$

Equation 290-2

Where:

E_x = Emissions of each cover gas or carrier gas *x* over the reporting year (metric tons);
Q_p = Mass of the cover or carrier gas consumed (kg) over the container-use period *p* as estimated using Equation 290-3;
n = Number of container-use periods in the year;
= Inventory of each cover gas or carrier gas *x* stored in cylinders or other containers at the beginning of the year, including heels (kg);
0.001 = Conversion factor from kg to metric tons; and
x = Each cover gas or carrier gas that is a GHG.

(b) For purposes of Equation 290-2 of this section, the mass of the cover gas used over the period *p* for an individual container shall be estimated by using Equation 290-3 of this section:

$$Q_p = M_B - M_E$$

Equation 290-3

Where: :

Q_p = Mass of the cover or carrier gas consumed (kg) over the container-use period *p* (e.g., one month, etc.);
M_B = Mass of the container's contents (kg) at the beginning of period *p*; and
M_E = Mass of the container's contents (kg) at the end of period *p*.

(c) If a facility has mass flow controllers (MFC) and the capacity to track and record MFC measurements to estimate total gas usage, the mass of each cover or carrier gas monitored may be used as the mass of cover or carrier gas consumed (Q_p), in kg for period *p* in Equation 290-2 of this section.

§ WCI.294 Sampling, Analysis, and Measurement Requirements

Emissions (consumption) of cover gases and carrier gases may be estimated by monitoring as specified under paragraphs (a) through (c). Emissions must be estimated at least annually.

(a) Monitor the changes in container weights and inventories using Equation 290-1 of this subpart as follows:

(1) All quantities required by Equation 290-1 of this subpart must be measured using scales or load cells with an accuracy of 1 percent of full scale or better, accounting for the tare weights of the containers.

(2) Gas masses or weights provided by the gas supplier (e.g., for the contents of containers containing new gas or for the heels remaining in containers returned to the gas supplier) if the supplier provides documentation verifying that accuracy standards are met. However, the facility remains responsible for the accuracy of these masses or weights under this subpart.

(b) Monitor the changes in individual container weights as the contents of each container are used using Equations 290-2 and 290-3 of this subpart. The container identities and masses must be monitored and recorded as follows:

(1) Track the identities and masses of containers leaving and entering storage with check-out and check-in sheets and procedures. The masses of cylinders returning to storage shall be measured immediately before the cylinders are put back into storage.

(2) All the quantities required by Equations 290-2 and 290-3 of this subpart must be measured using scales or load cells with an accuracy of 1 percent of full scale or better, accounting for the tare weights of the containers.

(3) Gas masses or weights provided by the gas supplier (e.g., for the contents of cylinders containing new gas or for the heels remaining in cylinders returned to the gas supplier) if the supplier provides documentation verifying that accuracy standards are met. However, the facility remains responsible for the accuracy of these masses or weights under this subpart.

(c) Monitoring the mass flow of the pure cover gas or carrier gas into the gas distribution system. When estimating emissions by monitoring the mass flow of the pure cover gas or carrier gas into the gas distribution system, gas flow meters, or mass flow controllers, with an accuracy of 1 percent of full scale or better must be used.

All flow meters, scales, and load cells used to measure quantities that are to be reported under this subpart shall be calibrated using calibration procedures specified by the flow meter, scale, or load cell manufacturer. Calibration shall be performed prior to the first reporting year. After the initial calibration, recalibration shall be performed at the minimum frequency specified by the manufacturer.

§ WCI.295 Missing Data Procedures

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraphs (a) or (b) of this section. Records must be documented and kept of the procedures used for all such estimates.

(a) A complete record of all measured parameters used in the GHG emission calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter will be used in the calculations as specified in paragraph (b) of this section.

(b) Replace missing data on the emissions of cover or carrier gases by multiplying magnesium production during the missing data period by the average cover or carrier gas usage rate from the most recent period when operating conditions were similar to those for the period for which the data are missing. Calculate the usage rate for each cover or carrier gas using Equation 290-4 of this section:

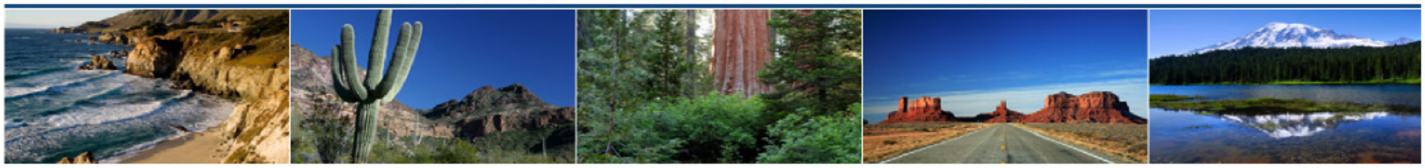
$$R_x = \left(\frac{C_x}{Mg}\right) \times 0.001$$

Equation 290-4

Where:

R_x	=	Usage rate of a particular cover gas or carrier gas *x* over the period of comparable operation (metric tons gas/metric ton Mg);
C_x	=	Consumption of a particular cover gas or carrier gas *x* over the period of comparable operation (kg);
Mg	=	Magnesium produced or fed into the process over the period of comparable operation (metric tons);
0.001	=	Conversion factor from kg to metric tons; and
x	=	Each cover gas or carrier gas that is a GHG.

(c) If the precise before and after weights are not available, it should be assumed that the container was emptied in the process (i.e., quantity purchased should be used, less heel).



This proposed WCI Essential Requirement would be for use in WCI Canadian jurisdictions. When the U.S. EPA finalizes Subpart W, the WCI will develop cap and trade quality requirements for sources covered by Subpart W for use in U.S. jurisdictions. This may mean modifications will be required to the current proposed Canadian language covering the same sources.

§ WCI.350 NATURAL GAS TRANSMISSION AND DISTRIBUTION

§ WCI.351 Source Category Definition

This source category consists of the following:

(a) Onshore natural gas transmission compression. Onshore natural gas transmission compression means any fixed combination of compressors that move natural gas at elevated pressure from production fields or natural gas processing facilities, in transmission pipelines, to natural gas distribution pipelines, or into storage. In addition, transmission compressor station includes equipment for liquids separation, natural gas dehydration, and tanks for the storage of water and hydrocarbon liquids.

(b) Underground natural gas storage. Underground natural gas storage means subsurface storage, including but not limited to, depleted gas or oil reservoirs and salt dome caverns utilized for storing natural gas that has been transferred from its original location for the primary purpose of load balancing (the process of equalizing the receipt and delivery of natural gas); natural gas underground storage processes and operations (including, but not limited to, compression, dehydration and flow measurement); and all the wellheads connected to the compression units located at the facility.

(c) Liquefied natural gas (LNG) storage. LNG storage means onshore LNG storage vessels located above ground, equipment for liquefying natural gas, compressors to capture and re-liquefy boil-off-gas, re-condensers, and vaporization units for re-gasification of the liquefied natural gas.

(d) LNG import and export equipment. LNG import equipment means all onshore or offshore equipment that receives imported LNG via ocean transport, stores LNG, re-gasifies LNG, and delivers re-gasified natural gas to a natural gas transmission or distribution system. LNG export equipment means all onshore or offshore equipment that receives natural gas, liquefies natural gas, stores LNG, and transfers the LNG via ocean transportation to any location, including locations in the United States.

(e) Natural gas distribution. Natural gas distribution consists of all natural gas equipment downstream of the station yard inlet shut-off valves of natural gas transmission pipelines at stations where pressure reduction and/or measuring and/or odorizing first occurs for eventual delivery of natural gas to consumers, or as otherwise separated from natural gas transmission by provincial or federal laws or regulations.

(f) Natural gas transmission pipelines. Natural gas transmission pipelines means a high pressure pipeline (and associated equipment) transporting sellable quality natural gas from production or natural gas processing to natural gas distribution pressure let-down, metering, regulating stations where the natural gas is typically odorized before delivery to customers, or as otherwise separated from natural gas transmission by provincial or federal laws or regulations.

§ WCI.352 Greenhouse Gas Reporting Requirements

Where greenhouse gases are not emitted from a specific emission source identified in paragraphs (a) to (g) then the reported emissions for the specific source shall be reported as zero.

In addition to the information required by regulation, the annual emissions data report shall contain the following information:

(a) CO_2 and CH_4 emissions from each industry source, including those in paragraph (b) through (g) of this section. In addition, N_2O emissions from flares and stationary combustion equipment identified for each industry source, including those specified in paragraph (b) through (g) of this section.

(b) For onshore natural gas transmission compression, report emissions from the following sources:

(1) Venting (from the following sources):

(i) Reciprocating compressor rod packing.

(ii) Centrifugal compressor wet seal degassing.

(iii) Blowdown vent stacks.

(iv) Natural gas pneumatic high bleed devices.

(v) Natural gas pneumatic low bleed device venting.

(vi) Other venting emission sources.*

(2) Fugitive emissions from connectors, block valves, control valves, compressor blowdown valves, pressure relief valves, orifice meters, other meters, regulators, open ended lines, reciprocating compressor rod packing and other fugitive emission sources.*

(3) Flares.

(4) Stationary combustion sources combusting field gas; stationary combustion sources combusting fuels other than field gas must report under WCI.20 (General Stationary Combustion Sources).

(c) For underground natural gas storage, report emissions from the following sources:

(1) Venting (from the following sources):

(i) Reciprocating compressor rod packing.

(ii) Centrifugal compressor wet seal degassing.

(iii) Natural gas pneumatic high bleed devices.

(iv) Natural gas pneumatic low bleed devices.

(v) Other venting emission sources.*

(2) Fugitive emissions from connectors, block valves, control valves, compressor blowdown valves, pressure relief valves, orifice meters, other meters, regulators, open ended lines and other fugitive emission sources.*

(3) Flares.

(4) Stationary combustion sources combusting field gas; stationary combustion sources combusting fuels other than field gas must report under WCI.20 (General Stationary Combustion Sources).

(d) For LNG storage, report emissions from the following sources:

(1) Venting (from the following sources):

(i) Reciprocating compressor rod packing.

(ii) Centrifugal compressor wet seal degassing.

(iii) Other venting emission sources.*

(2) Fugitive emissions from valves; pump seals; connectors; vapor recovery compressors, reciprocating compressor rod packing, centrifugal compressor dry seals and other fugitive sources.*

(3) Flares.

(4) Stationary combustion sources combusting field gas; stationary combustion sources combusting fuels other than field gas must report under WCI.20 (General Stationary Combustion Sources).

(e) LNG import and export equipment, report emissions from the following sources:

(1) Venting (from the following sources):

(i) Reciprocating compressor rod packing.

(ii) Centrifugal compressor wet seal degassing.

(iii) Blowdown vent stacks.

(iv) Other venting emission sources.*

(2) Fugitive emissions from valves, pump seals, connectors, vapor recovery compressors, centrifugal compressor dry seals reciprocating compressor rod packing and other fugitive sources.*

(3) Flares.

(4) Stationary combustion sources combusting field gas; stationary combustion sources combusting fuels other than field gas must report under WCI.20 (General Stationary Combustion Sources).

(f) For natural gas distribution, report emissions from the following sources:

(1) Above ground meter regulators and gate station fugitive emissions from connectors, block valves, control valves, pressure relief valves, orifice meters, other meters, regulators, farm taps, and open ended lines.

(2) Below ground meter regulators and vault fugitives.

(3) Pipeline fugitives.

(4) Service line fugitives.

(5) Stationary combustion sources combusting field gas; stationary combustion sources combusting fuels other than field gas must report under WCI.20 (General Stationary Combustion Sources).

(6) Other venting emission sources.*

(7) Other fugitive emission sources.*

(g) For natural gas transmission pipelines

(1) Above ground meter regulators and gate station fugitive emissions from connectors, block valves, control valves, pressure relief valves, orifice meters, other meters, regulators, farm taps, and open ended lines.

(2) Below ground meter regulators and vault fugitives.

(3) Pipeline fugitives.

(4) Other venting emission sources.*

(5) Other fugitive emission sources.*

(h) Facility and company-specific emission factors used in place of Tables 350-1 to 350-5

(i) Report activity data for each aggregated source type as follows:

(1) Count of natural gas pneumatic high bleed devices.

(2) Count of natural gas pneumatic low bleed devices.

(3) Count of natural gas driven pneumatic pumps.

(4) For each dehydrator unit report the following:

(i) Glycol dehydrators:

(A) The number of glycol dehydrators operated

(ii) Desiccant dehydrators:

(A) The number of desiccant dehydrators operated.

(5) For each compressor blowdown vent stack report the following for each compressor:

(i) Type of compressor whether reciprocating or centrifugal.
(ii) Compressor capacity in horse powers.
(iv) Number of blowdowns per year.

(6) For fugitive emissions sources using emission factors for estimating emissions report the following:

(i) Component count for each fugitive emissions source.

(j) Report emissions separately for portable equipment for the following source types (aggregate emissions by source type:

(1) Dehydrators, compressors, electrical generators, steam boilers, and heaters.

** other venting emission or other fugitive sources not specificially listed are not required to be reported if a source type is reasonably estimated to be below 0.5% of total operation emissions.*

*** where a quantification method is not provided for a specific source (such as for other venting and other fugitive sources, best practices must be used to estimate emissions*

§ WCI.353 Calculation of Greenhouse Gas Emissions

If greenhouse gases are not emitted from one or more of the following emission sources, the reporter will not need to calculate emissions from the emission source(s) in question and reported emissions for the emission source(s) will be zero.

(a) Natural gas pneumatic high bleed device venting and natural gas driven pneumatic pump venting.

(1) Calculate emissions from a natural gas pneumatic high bleed flow control device venting and natural gas driven pneumatic pump venting as follows:

(i) Estimate gas consumption for all high bleed natural gas powered devices and pneumatic pumps using a statistically defensible emission factor that is reviewed every three to five years.

(ii) Calculate CH_4 and CO_2 emissions from high bleed pneumatic devices and pumps using Equation 350-1 of this section.

$$E_{GHGi} = V_{NG} * M_i * MW_i / MVC * 0.001 \qquad \text{Equation 350-1}$$

Where:

E_{GHGi}	=	emissions of GHG i (i = CH_4 or CO_2) in metric tons
V_{NG}	=	volume of natural gas consumed by metered high bleed pneumatic devices and pumps (m^3/year)
M_i	=	mole fraction of CH_4 or CO_2 in natural gas supply
MW_i	=	molecular weight of GHG_i
MVC	=	molar volume conversion factor
0.001	=	conversion factor – kg to metric tons

(2) If in 2011 the statistically defensible emission factor is not available use the following method to estimate emissions from high bleed devices and natural gas driven pneumatic pumps that are not equipped with meters must be calculated using the following methods.

(i) For high bleed devices, calculate vented emissions using manufacturer data.

(A) Obtain from the manufacturer specific pneumatic device model natural gas bleed rate during normal operation.

(B) Calculate the natural gas emissions for each continuous bleed device using Equation 350-2 of this section.

$$E_{s,n} = B_s * T \qquad \text{Equation 350-2}$$

Where:

$E_{s,n}$ = Annual natural gas emissions at standard conditions, in m^3.

B_s = Natural gas driven pneumatic device bleed rate volume at standard conditions in m^3 per minute, as provided by the manufacturer.

T = Amount of time in minutes that the pneumatic device has been operational through the reporting period.

(C) If manufacturer data for a specific device is not available, then use data for a similar device model, size and operational characteristics (or published default values) to estimate emissions.

(ii) Calculate emissions from natural gas driven pneumatic pump venting as follows:

(A) Obtain from the manufacturer specific pump model natural gas emission (or manufacturer "gas consumption") per unit volume of liquid circulation rate at pump speeds and operating pressures.

(B) Maintain a log of the amount of liquid pumped annually from individual pumps.

(C) Calculate the natural gas emissions for each pump using Equation 350-3 of this section.

$$E_{s,n} = F_s * V \qquad \text{Equation 350-3}$$

Where:

$E_{s,n}$ = Annual natural gas emissions at standard conditions in m^3 per year.

F_s = Natural gas driven pneumatic pump gas emission in "emission per volume of liquid pumped at operating pressure" in m^3/liter at standard conditions, as provided by the manufacturer.

V = Volume of liquid pumped annually in liters/year.

(D) If manufacturer data for a specific pump in Equation 350-3 is not available, then use data for a similar pump model, size and operational characteristics (or published default values) to estimate emissions.

(iii) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (j) and (k) of this section.

(b) <u>Natural gas pneumatic low bleed device venting</u>. Calculate emissions from natural gas pneumatic low continuous bleed device venting using Equation 350-4 of this section.

$$Mass_{s,i} = Count * EF * GHG_i * Conv_i * 24*365 \qquad \text{Equation 350-4}$$

Where:

$Mass_{s,i}$ = Annual total mass GHG emissions in metric tons per year at standard conditions from all natural gas pneumatic low bleed device venting, for GHG_i.

Count = Total number of natural gas pneumatic low bleed devices.

EF = Population emission factors for natural gas pneumatic low bleed device venting listed in Tables 350-1 and 350-2 of this section for onshore natural gas transmission and underground natural gas storage facilities, respectively.

GHG_i = 1.

$Conv_i$ = Conversion from m^3 to metric tons CO_2e; 0.01427 for CH_4, and 0.001832 for CO_2 at stp off 15 degrees celsius and 1 atmostphere

24 * 365 = Conversion to yearly emissions estimate.

(c) Blowdown vent stacks. Calculate blowdown vent stack emissions as follows:

(1) Calculate the total volume (including, but not limited to, pipelines, compressor case or cylinders, manifolds, suction and discharge bottles and vessels) between isolation valves.

(2) Retain logs of the number of blowdowns for each equipment type.

(3) Calculate the total annual venting emissions using Equation 350-5 of this section:

$$E_{a,n} = N * V_v \qquad \text{Equation 350-5}$$

Where:

$E_{a,n}$ = Annual natural gas venting emissions at ambient conditions from blowdowns in m^3.

N = Number of blowdowns for the equipment in reporting year.

V_v = Total volume of blowdown equipment chambers (including, but not limited to, pipelines, compressors and vessels) between isolation valves in m^3.

(4) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (i) of this section.

(5) Calculate both CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (j) and (k) of this section.

(6) Blowdowns that are directed to flares use the WCI.353(d) Flare stacks calculation method rather than WCI.353(c) Blowdown vent stacks calculation method.

(d) Flare stacks. Calculate emissions from a flare stack as follows:

(1) If you have a continuous flow measurement device on the flare, you must use the measured flow volumes to calculate the flare gas emissions. If you do not have a continuous flow measurement device on the flare, you can install a flow measuring device on the flare or use engineering calculations, company records, or similar estimates of volumetric flare gas flow.

(2) If you have a continuous gas composition analyzer on gas to the flare, you must use these compositions in calculating emissions. If you do not have a continuous gas composition analyzer on gas to the flare, you must use the appropriate gas compositions for each stream of hydrocarbons going to the flare as follows:

(i) When the stream going to flare is natural gas, use the GHG mole percent in feed natural gas for all streams upstream of the de-methanizer and GHG mole percent in facility specific residue gas to transmission pipeline systems for all emissions sources downstream of the de-methanizer overhead for onshore natural gas processing facilities.

(ii) When the stream going to the flare is a hydrocarbon product stream, such as ethane or butane, then use a representative composition from the source for the stream.

(3) Determine flare combustion efficiency from manufacturer. If not available, assume that flare combustion efficiency is 98 percent.

(4) Calculate GHG volumetric emissions at actual conditions using Equations 350-6, 350-7, 350-8, and 350-9 of this section.

$$E_{a,CH4} = V_a * (1-\eta) * X_{CH4} \quad \text{Equation 350-6}$$

$$E_{a,CO2}(non-combustion) = V_a * X_{CO2} \quad \text{Equation 350-7}$$

$$E_{a,CO2}(combusted) = \sum_j \eta * V_a * Y_j * R_j \quad \text{Equation 350-8}$$

$$E_{a,CO2}(total) = E_{a,CO2}(combusted) + E_{a,CO2}(un-combusted) \quad \text{Equation 350-9}$$

Where:

$E_{a,CH4}$	=	Contribution of annual uncombusted CH_4 emissions from flare stack in m^3, under ambient conditions.
$E_{a,CO2}$ (non-combusted)	=	Contribution of annual CO_2 emissions from CO_2 in the inlet gas passing through the flare, in m^3, under ambient conditions.

$E_{a,CO2}$ (combusted)	=	Contribution of annual emissions from combustion from flare stack in m^3, under ambient conditions
$E_{a,I}$ (total)	=	Total annual emissions from flare stack in m^3, under ambient conditions
V_a	=	Volume of natural gas sent to flare in m^3, during the year.
η	=	Percent of natural gas combusted by flare (default is 98 percent).
X_i	=	Concentration of GHG *i* in gas to the flare.
Y_j	=	Concentration of natural gas hydrocarbon constituents *j* (such as methane, ethane, propane, butane, and pentanes plus).
R_j	=	Number of carbon atoms in the natural gas hydrocarbon constituent *j*; 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes plus).

(5) Calculate GHG volumetric emissions at standard conditions using calculations in paragraph (i) of this section.

(6) Calculate both CH_4 and CO_2 mass emissions from volumetric CH_4 and CO_2 emissions using calculation in paragraph (k) of this section.

(7) Calculate N_2O emissions using the emission factors for Gas Flares listed in Table 350-6 of this section.

(8) This emissions source excludes any emissions calculated under other emissions sources in this section.

(e) Centrifugal compressor wet seal degassing vents. Calculate emissions from centrifugal compressor wet seal degassing vents as follows:

(1) For each centrifugal compressor determine the volume of vapors from wet seal oil degassing tank sent to an atmospheric vent or flare using a temporary or permanent flow measurement meter such as, but not limited to, a vane anemometer according to methods set forth in WCI.354(b).

(2) Estimate annual emissions using meter flow measurement using Equation 350-10 of this section.

$$E_{a,i} = MT * T * M_i * (1 - B) \qquad \text{Equation 350-10}$$

Where:

$E_{a,i}$ = Annual GHG i (either CH_4 or CO_2) volumetric emissions at ambient conditions.

MT = Meter reading of gas emissions per unit time.

T = Total time the compressor associated with the wet seal(s) is operational in the reporting year.

M_i = Mole percent of GHG i in the degassing vent gas; use the appropriate gas compositions in paragraph (j)(2) of this section.

B = Percentage of centrifugal compressor wet seal degassing vent gas sent to vapor recovery or fuel gas or other beneficial use as determined by keeping logs of the number of operating hours for the vapor recovery system and the amount of vent gas that is directed to the fuel gas system.

(3) Calculate CH_4 and CO_2 volumetric emissions at standard conditions using paragraph (i) of this section.

(4) Calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (k) of this section.

(5) Calculate emissions from degassing vent vapors to flares as follows:

(i) Use the degassing vent vapor volume and gas composition as determined in paragraphs (e)(1) through (3) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (d) of this section to determine degassing vent vapor emissions from the flare.

(f) Reciprocating compressor rod packing venting. Calculate annual CH_4 and CO_2 emissions from each reciprocating compressor rod packing venting as follows:

(1) Estimate annual emissions using a meter flow measurement using Equation 350-11 of this section.

$$E_{a,i} = MT * T * M_i \qquad \text{Equation 350-11}$$

Where:

$E_{a,i}$ = Annual GHG i (either CH_4 or CO_2) volumetric emissions at ambient conditions.

MT = Meter volumetric reading of gas emissions per unit time, under ambient conditions.

T = Total time the compressor associated with the venting is operational in the reporting year.

M_i = Mole percent of GHG i in the vent gas; use the appropriate gas compositions in paragraph (j)(2) of this section.

(2) If the rod packing case is connected to an open ended vent line then use one of the following two methods to calculate emissions**.**

(i) Measure emissions from all vents (including (as a singular case) emissions manifolded to common vents) including rod packing, unit isolation valves, and blowdown valves using bagging according to methods set forth in WCI.354(c).

(ii) Use a temporary meter such as, but not limited to, a vane anemometer or a permanent meter such as, but not limited to, an orifice meter to measure emissions from all vents (including (as a singular case) emissions manifolded to a common vent) including rod packing vents, unit isolation valves, and blowdown valves according to methods set forth in WCI.354(b).

(3) If the rod packing case is not equipped with a vent line use the following method to estimate emissions:

(i) You must use the methods described in WCI.354(a) to conduct a progressive sample leak detection of fugitive emissions from the packing case into an open distance piece, or from the compressor crank case breather cap or vent with a closed distance piece.

(ii) Measure emissions using a high flow sampler, or calibrated bag, or appropriate meter according to methods set forth in WCI.354(d).

(4) Conduct one measurement for each compressor in each of the operational modes that occurs during a reporting period:

(i) Operating.

(ii) Standby pressurized.

(iii) Not operating, depressurized.

(5) Calculate CH_4 and CO_2 volumetric emissions at standard conditions using calculations in paragraph (i) of this section.

(6) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in paragraphs (j) and (k) of this section.

(g) <u>Leak detection and leaker emission factors</u>. The methods described in WCI.354(a) must be used to conduct a progressive sample leak detection of fugitive emissions from all sources listed in WCI.352(b)(2), (c)(2), (d)(2), (e)(2), (f)(1) and (g)(1). If fugitive emissions are detected for sources listed in this paragraph, calculate emissions using Equation 350-18 of this section for each source with fugitive emissions.

$$E_{s,i} = Count * EF * GHG_i * T \qquad \text{Equation 350-12}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from each fugitive source.

Count = Total number of this type of emission source found to be leaking.

EF	=	Leaker emission factor for specific sources listed in Table 350-1 through Table 350-5 of this section.
GHG_i	=	the concentration of CO_2 in the feed natural gas or 1 for CH_4.
T	=	Total time the specific source associated with the fugitive emission was leaking in the reporting year, in hours.

(1) Calculate GHG mass emissions in carbon dioxide equivalent at standard conditions using calculations in paragraph (k) of this section.

(2) Onshore natural gas transmission compression facilities shall use the appropriate default leaker emission factors listed in Table 350-1 of this section for fugitive emissions detected from connectors; block valves; control valves; compressor blowdown valves; pressure relief valves; orifice meters; other meters; regulators; and open ended lines.

(3) Underground natural gas storage facilities for storage stations shall use the appropriate default leaker emission factors listed in Table 350-2 of this section for fugitive emissions detected from connectors; block valves; control valves; compressor blowdown valves; pressure relief valves; orifice meters; other meters; regulators; and open ended lines.

(4) LNG storage facilities shall use the appropriate default leaker emission factors listed in Table 350-3 of this section for fugitive emissions detected from valves; pump seals; connectors; and other.

(5) LNG import and export facilities shall use the appropriate default leaker emission factors listed in Table 350-4 of this section for fugitive emissions detected from valves; pump seals; connectors; and other.

(6) Natural gas distribution facilities for above ground meter regulator and gate stations shall use the appropriate default leaker emission factors listed in Table 350-5 of this section for fugitive emissions detected from connectors; block valves; control valves; pressure relief valves; orifice meters; other meters; regulators; and open ended lines.

(h) Population count and emission factors. This paragraph applies to emissions sources listed in WCI.352(b)(1)(v), (c)(i)(iv), (c)(2), (d)(2), (e)(2), (f)(2), (f)(3), (f)(4), g(2) and g(3) on streams with gas content greater than 10 percent CH_4 plus CO_2 by weight. Emissions sources in streams with gas content less than 10 percent CH_4 plus CO_2 by weight do not need to be reported. Calculate emissions from all sources listed in this paragraph using Equation 350-13 of this section.

$$E_{s,i} = Count * EF * GHG_i * T \qquad \text{Equation 350-13}$$

Where:

$E_{s,I}$	=	Annual total volumetric GHG emissions at standard conditions from each fugitive source.

Count = Total number of this type of emission source at the facility.

EF = Population emission factor for specific sources listed in Table 350-1 through Table 350-5 of this section.

GHG_i = GHG_i equals the concentration of CO_2 in produced natural gas or feed natural gas and 1 for CH_4.

T = Total time the specific source associated with the fugitive emission was operational in the reporting year, in hours.

(1) Calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (k) of this section.

(2) Underground natural gas storage facilities for storage wellheads shall use the appropriate default population emission factors listed in Table 350-2 of this section for fugitive emissions from connectors; valves; pressure relief valves; and open ended lines.

(3) LNG storage facilities shall use the appropriate default population emission factors listed in Table 350-3 of this section for fugitive emissions from vapor recovery compressors.

(4) LNG import and export facilities shall use the appropriate default population emission factor listed in Table 350-4of this section for fugitive emissions from vapor recovery compressors.

(5) Natural gas distribution facilities shall use the appropriate default population emission factors listed in Table 350-5 of this section for fugitive emissions from below grade M&R stations; gathering pipelines; mains; and services.

(i) Volumetric emissions. Calculate volumetric emissions at standard conditions as specified in paragraphs (i)(1) or (2) of this section.

(1) Calculate natural gas volumetric emissions at standard conditions by converting ambient temperature and pressure of natural gas emissions to standard temperature and pressure (15 degrees celsius and 1 atmophere (101.325 kPA)) natural gas using Equation 350-14 of this section.

$$E_{s,n} = \frac{E_{a,n} \times (273.15 + T_s) \times P_a}{(273.15 + T_a) \times P_s}$$

Equation 350-14

Where:

$E_{s,n}$ = Natural gas volumetric emissions at standard temperature and pressure (STP) conditions.

$E_{a,n}$ = Natural gas volumetric emissions at ambient conditions.

T_s = Temperature at standard conditions. (^oC).

T_a = Temperature at actual emission conditions. (^oC).

P_s = Absolute pressure at standard conditions (kPa).

P_a = Absolute pressure at ambient conditions (kPa).

(2) Calculate GHG volumetric emissions at standard conditions by converting ambient temperature and pressure of GHG emissions to standard temperature and pressure using Equation 350-15 this section.

$$E_{s,i} = \frac{E_{a,i} \times (273.15 + T_s) \times P_a}{(273.15 + T_a) \times P_s}$$

Equation 350-15

Where:

$E_{s,i}$ = GHG i volumetric emissions at standard temperature and pressure (STP) conditions.

$E_{a,i}$ = GHG i volumetric emissions at actual conditions.

T_s = Temperature at standard conditions. (^oC).

T_a = Temperature at actual emission conditions. (^oC).

P_s = Absolute pressure at standard conditions (kPa).

P_a = Absolute pressure at ambient conditions (kPa).

(j) GHG volumetric emissions. Calculate GHG volumetric emissions at standard conditions as specified in paragraphs (j)(1) and (2) of this section.

(1) Estimate CH_4 and CO_2 emissions from natural gas emissions using Equation 350-16 of this section.

$$E_{s,i} = E_{s,n} * M_i$$

Equation 350-16

Where:

$E_{s,i}$ = GHG i (either CH_4 or CO_2) volumetric emissions at standard conditions.

$E_{s,n}$ = Natural gas volumetric emissions at standard conditions.

M_i = Mole percent of GHG i in the natural gas.

(2) For Equation 350-16 of this section, the mole percent, M_i, shall be the annual average mole percent for each facility, as specified in paragraphs (j)(2)(i) through (vii) of this section.

(i) GHG mole percent in transmission pipeline natural gas that passes through the facility for onshore natural gas transmission compression facilities.

(ii) GHG mole percent in natural gas stored in underground natural gas storage facilities.

(iii) GHG mole percent in natural gas stored in LNG storage facilities.

(iv) GHG mole percent in natural gas stored in LNG import and export facilities.

(v) GHG mole percent in local distribution pipeline natural gas that passes through the facility for natural gas distribution facilities.

(k) GHG mass emissions. Calculate GHG mass emissions in carbon dioxide equivalent at standard conditions by converting the GHG volumetric emissions into mass emissions using Equation 350-17 of this section.

$$Mass_{s,i} = E_{s,i} * \rho_i * GWP * 10^{-3}$$ Equation 350-17

Where:

$Mass_{s,i}$ = GHG i (either CH_4 or CO_2) mass emissions at standard conditions in metric tons CO_2e.

$E_{s,i}$ = GHG i (either CH_4 or CO_2) volumetric emissions at standard conditions, in m^3.

ρ_i = Density of GHG i, 1.871 kg/m^3 for CO_2 and 0.681 kg/m^3 for CH_4 at stp off 15 degrees celsius and 1 atmosphere.

GWP = Global warming potential, 1 for CO_2 and 21 for CH_4.

(l) Other vented or fugitive emissions

All vented or fugitive emissions not covered by quantification methods in WCI.353 must be calculated by methodologies consistent with those here or as presented in the Canadian Gas Association Methodology Manual.

§ WCI.354 Sampling, Analysis, and Measurement Requirements

Instruments used for sampling, analysis and measurement must be operated and calibrated according to legislative, manufacturer's, or other written specifications or requirements. All sampling, analysis and measurement must be conducted only by, or under the direct supervision of individuals with demonstrated understanding and experience in the application (and principles related) of the specific sampling, analysis and measurement technique in use.

(a) If a documented leak detection or integrity management standard or requirement that is required by legislation or regulation such as CSA Z662-07 Oil & Gas Pipeline Systems or the [CGA reference for fugitive emissions], the documented standard or requirement must be followed – including service schedules for different components - with reporting as required for input to the calculation methods herein.

If there is no such legal requirement, then progressive sampling is required using one of the methods outlined below in combination with best industry practices for use of the method– including service schedules for different components - to determine the count of leaks (and time leaking) required in WCI.363(o) and (n)(3)(i), as applicable. Progressive sampling means establishing a statistically valid baseline sample of leaks under normal operating conditions for the 2011 and 2012 calendar years, with subsequent sampling determined based random or spot sampling, modeling or measurement of leaks under normal operating conditions. A minimum of 18 months and a maximum of 36 months is allowed between surveys. This interval is determined based on whether there are indications of leaks. If a leak found and immediately repaired, the existing schedule may be maintained.

Leak detection for fugitive emissions must be performed for all identified equipment in operation or on standby mode during a reporting period.

(1) Optical gas imaging instrument. Use an optical gas imaging instrument for fugitive emissions detection in accordance with 40 CFR part 60, subpart A, §60.18 (i)(1) and (2) *Alternative work practice for monitoring equipment leaks* (or per relevant standard in Canada). In addition, the optical gas imaging instrument must be operated to image the source types required by this proposed reporting rule in accordance with the instrument manufacturer's operating parameters. The optical gas imaging instrument must comply with the following requirements:

(i) Provide the operator with an image of the potential leak points for each piece of equipment at both the detection sensitivity level and within the distance used in the daily instrument check described in the relevant best practices. The detection sensitivity level depends upon the frequency at which leak monitoring is to be performed.

(ii) Provide a date and time stamp for video records of every monitoring event.

(2) Bubble tests

(3) Portable organic vapour analyzer. Use a portable organic vapour analyzer in accordance with US EPA Method 21 or as outlined in the [CGA reference for fugitive emissions] or the CAPP Best Management Practices for Fugitive Emissions

(4) Other methods as outlined in the [CGA reference for fugitive emissions] or the CAPP Best Management Practices for Fugitive Emisisons may be used as necessary for operational circumstances

(b) All flow meters, composition analyzers and pressure gauges that are used to provide data for the GHG emissions calculations shall use measurement methods, maintenance practices, and calibration methods, prior to the first reporting year and in each subsequent reporting year using an appropriate standard method published by a consensus standards organization such as, but not limited to, Canadian Standards Association (CSA), Canadian Gas Association, Canadian Energy Pipeline Association (CEPA), ASTM International, American National Standards Institute (ANSI) and manufacturer's standards. If a consensus based standard is not available, you must use manufacturer instructions to calibrate the meters, analyzers, and pressure gauges.

(c) Use calibrated bags (also known as vent bags) only where the emissions are at near-atmospheric pressures such that it is safe to handle and can capture all the emissions, below the maximum temperature specified by the vent bag manufacturer, and the entire emissions volume can be encompassed for measurement.

(1) Hold the bag in place enclosing the emissions source to capture the entire emissions and record the time required for completely filling the bag. If the bag inflates in less than one second, assume one second inflation time.

(2) Perform three measurements of the time required to fill the bag, report the emissions as the average of the three readings.

(3) Estimate natural gas volumetric emissions at standard conditions using calculations in WCI.353(i).

(4) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in WCI.353(j) and (k).

(d) Use a high volume sampler to measure emissions within the capacity of the instrument.

(1) A technician following (and competent to follow) manufacturer instructions shall conduct measurements, including equipment manufacturer operating procedures and measurement methodologies relevant to using a high volume sampler, including, but not limited to, positioning the instrument for complete capture of the fugitive emissions without creating backpressure on the source.

(2) If the high volume sampler, along with all attachments available from the manufacturer, is not able to capture all the emissions from the source then you shall use anti-static wraps or other aids to capture all emissions without violating operating requirements as provided in the instrument manufacturer's manual.

(3) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in WCI.353(j) and (k).

(4) Calibrate the instrument at 2.5 percent methane with 97.5 percent air and 100 percent CH_4 by using calibrated gas samples and by following manufacturer's instructions for calibration.

(Proposed to be added as WCI.025(g) – general stationary combustion)
Measurement and Metering Act of Canada standards (or other appropriate standards if the Measurement and Metering Act is not applicable) are deemed to be sufficient rigor for the sampling, analysis and measurement for the combustion of pipeline quality natural gas (including for derivation of standard gas composition) for facilities covered by WCI.350 – Natural Gas Transmission and Distribution. If a required meter is not covered by the Measurement and Metering Act, it must exist and meet the requirements of the applicable greenhouse gas reporting regulation for the jurisdiction.

§ WCI.355 Procedures for Estimating Missing Data

A complete record of all estimated and/or measured parameters used in the GHG emissions calculations is required. If data are lost or an error occurs during annual emissions estimation or measurements, you must repeat the estimation or measurement activity for those sources as soon as possible, including in the subsequent reporting year if missing data are not discovered until after December 31 of the reporting year, until valid data for reporting is obtained. Data developed and/or collected in a subsequent reporting year to substitute for missing data cannot be used for that subsequent year's emissions estimation. Where missing data procedures are used for the previous year, at least 30 days must separate emissions estimation or measurements for the previous year and emissions estimation or meausrements for the current year of data collection.

Directions on the use of Tables 350-1 to 350-5

(1) Starting with [2012] calendar year emissions, for each component listed in the Tables 350-1 to 350-5

(i) If facility specific emission factors for a component type are available they must be used

(ii) If facility specific emissions factors for a component type are not available, n operator must use company specific emission factors

(iii) If a specific component type cannot be safely or reasonably accessed to develop valid facility or company-specific emission factors, estimates in the default Tables 350-1 to 350-5 may be used. Similarly, equipment or facilities that have low utilization (e.g. some booster stations) may continue to use the default tables.

(iv) If a facility-specific emission factor has been used in a previous reporting year, it must continue to be used until updated. If a company-specific emission factor has been used in a previous reporting year, it must continue to be used until updated or a facility-specific emission factor is used in its place.

(v) Any changes from facility-specific factors to company-specific or table factors, or from company specific factors to the defaults in Tables 350-1 to 350-5 must be approved by the jurisdiction and substantiated by proof that the new approach is more accurate for the facility or facilities in question.

(vi) Documentation on the method used to update the emission factors, input data and sampling used, and the like must be kept by the operator and provided to the jurisdiction or verifier upon request.

(2) For 2011 calendar year emissions,

(i) An operator may use the default factors specified below, company or facility-specific emissions factors (if such emission factors are available). If the default factors in Tables 350-1 to 350-5 are used, an explanation as to why company or facility specific emission factors are cannot be used must be provided to the jurisdiction.

(3) All emission factors must be developed using Canadian Gas Association standard methods, or other methods if Canadian Gas Association methods are not available. Facility and company-specific emission factors must be updated at a minimum on a three year cycle, with the first update to the original facility and company-specific emission factors for the 2015 reporting period, at the latest.

(4) Updated emission factors can only be incorporated for reporting purposes at the start of a reporting period and not during a calendar year.

(5) The default emission factors provided in Tables 350-1 to 350-5 below are industry average emission factors for Canada as of the 2010 calendar year. The factors will be updated every 3-5 years based on new data, methods and statistically valid samples of the entire industry and developed in collaboration with industry groups.

[Except where noted, the following emission factors are from the CGA Methodology Manual version (2007). As the emission factors are updated by the CGA from time to time, the intention is to update the emission factors here]

TABLE 350-1 –DEFAULT METHANE EMISSION FACTORS FOR TRANSMISSION

Transmission	Emission Factor (sm^3/hour/component)
Leaker Emission Factors - All Components, Gas Service	
Connector	6.56 E-4
Block Valve	6.07 E-3
Control Valve	2.42 E-2
Compressor Blowdown Valve	2.319
Pressure Relief Valve	2.38 E-1
Orifice Meter	7.14 E-2
Other Meter	1.46 E-5
Regulator	1.17 E-2
Open-ended Line	1.35 E-1
Population Emission Factors - Other Components, Gas Service	
Low-Bleed Pneumatic Device Vents	7.28 E-2

TABLE 350-2 –DEFAULT METHANE EMISSION FACTORS FOR UNDERGROUND STORAGE*

Underground Storage	Emission Factor (sm^3/hour/component)
Leaker Emission Factors - Storage Station, Gas Service	
Connector	2.7 E-2
Block Valve	5.72 E-2
Control Valve	1.12 E-1
Compressor Blowdown Valve	1.87
Pressure Relief Valve	5.64 E-1
Orifice Meter	1.30 E-2
Other Meter	2.83 E-4
Regulator	2.92 E-2
Open-ended Line	1.70 E-1
Population Emission Factors - Storage Wellheads, Gas Service	
Connector	2.83 E-4
Valve	2.83 E-3
Pressure Relief Valve	4.81 E-3
Open-ended Line	8.5 E-4
Population Emission Factors - Other Components, Gas Service	
Low-Bleed Pneumatic Device Vents	7.28 E-2

*Emission factors are conversions of those contained in the U.S. EPA Subpart W.

TABLE 350-3 –DEFAULT METHANE EMISSION FACTORS FOR LIQUEFIED NATURAL GAS (LNG) STORAGE*

LNG Storage	Emission Factor (sm^3/hour/component)
Leaker Emission Factors - LNG Storage Components, LNG Service	
Valve	3.37 E -2
Pump Seal	1.13 E-1
Connector	9.6 E-3
Other[1]	5.01 E-2
Population Emission Factors - LNG Storage Compressor, Gas Service	
Vapor Recovery Compressor	1.93 E-1

[1] "other" equipment type should be applied for any equipment type other than connectors, pumps, or valves.

* Emission factors are conversions of those contained in the U.S. EPA Subpart W.

TABLE 350-4–DEFAULT METHANE EMISSION FACTORS FOR LNG TERMINALS*

LNG Terminals	Emission Factor (sm^3/hour/component)
Leaker Emission Factors - LNG Terminals Components, LNG Service	
Valve	3.37 E -2
Pump Seal	1.13 E-1
Connector	9.6 E-3
Other	5.01 E-2
Population Emission Factors - LNG Terminals Compressor, Gas Service	
Vapor Recovery Compressor	1.93 E-1

*Emission factors are conversions of those contained in the U.S. EPA Subpart W.

TABLE 350-5 –DEFAULT METHANE EMISSION FACTORS FOR DISTRIBUTION

Distribution	Emission Factor (sm^3/hour/component)
Leaker Emission Factors - Above Grade M&R Stations Components, Gas Service	
Connector	1.21 E-4
Block Valve	8.23 E-4
Control Valve	2.86 E-6
Pressure Relief Valve	5.79 E-3
Orifice Meter	4.42 E-3
Regulator	9.61 E-4
Open-ended Line	8.92 E-2
Population Emission Factors - Below Grade M&R Stations Components, Gas Service[1]	
Below Grade M&R Station, Inlet Pressure > 300 psig	3.68 E-2
Below Grade M&R Station, Inlet Pressure 100 to 300 psig	5.66 E-3
Below Grade M&R Station, Inlet Pressure < 100 psig	2.83 E-3
Population Emission Factors - Distribution Mains, Gas Service[2]*	
Unprotected Steel	3.56 E-1
Protected Steel	9.91 E-3
Plastic	3.20 E-2
Cast Iron	7.72 E-1
Population Emission Factors - Distribution Services, Gas Service[2*]	
Unprotected Steel	5.38 E-3
Protected Steel	5.66 E-4
Plastic	2.83 E-5
Copper	8.50 E-4

[1] Emission Factor is in units of " sm^3/hour/station"

[2] Emission Factor is in units of "sm^3/hour/service"

*Emission factors are conversions of those contained in the U.S. EPA Subpart W.

TABLE 350-6 –DEFAULT NITROUS OXIDE EMISSION FACTORS FOR GAS FLARING

Gas Flaring	Emission Factor (metric tons/MMscf gas production or receipts)
Population Emission Factors - Gas Flaring	
Gas Production	5.90E-07
Sweet Gas Processing	7.10E-07
Sour Gas Processing	1.50E-06
Conventional Oil Production[1]	1.00E-04
Heavy Oil Production[2]	7.30E-05

[1] Emission Factor is in units of "metric tons/barrel conventional oil production"

[2] Emission Factor is in units of "metric tons/barrel heavy oil production"

TABLE 350-7 –DETECTION SENSITIVITY LEVELS

Monitoring Frequency	Detection sensitivity level
Bi-Monthly	60
Semi-Quarterly	85
Monthly	100

§ WCI.356 Definitions

Blowdown vent stack emissions mean natural gas released due to maintenance and/or blowdown operations including but not limited to compressor blowdown and emergency shut-down (ESD) system testing.

Calibrated bag means a flexible, non-elastic, anti-static bag of a calibrated volume that can be affixed to a emitting source such that the emissions inflate the bag to its calibrated volume.

Centrifugal compressor means any equipment that increases the pressure of a process natural gas by centrifugal action, employing rotating movement of the driven shaft.

Centrifugal compressor dry seals mean a series of rings around the compressor shaft where it exits the compressor case that operates mechanically under the opposing forces to prevent natural gas from escaping to the atmosphere.

Centrifugal compressor dry seals emissions mean natural gas released from a dry seal vent pipe and/or the seal face around the rotating shaft where it exits one or both ends of the compressor case.

Centrifugal compressor wet seal degassing venting emissions means emissions that occur when the high-pressure oil barriers for centrifugal compressors are depressurized to release absorbed natural gas. High-pressure oil is used as a barrier against escaping gas in centrifugal compressor shafts. Very little gas escapes through the oil barrier, but under high pressure, considerably more gas is absorbed by the oil. The seal oil is purged of the absorbed gas (using heaters, flash tanks, and degassing techniques) and recirculated. The separated gas is commonly vented to the atmosphere.

Component, for the purposes of WCI.350 and WCI.360 only, means but is not limited to each metal to metal joint or seal of non-welded connection separated by a compression gasket, screwed thread (with or without thread sealing compound), metal to metal compression, or fluid barrier through which natural gas or liquid can escape to the atmosphere.

Compressor means any machine for raising the pressure of a natural gas by drawing in low pressure natural gas and discharging significantly higher pressure natural gas.

Flare combustion means unburned hydrocarbons including CH_4, CO_2, N_2O emissions resulting from the incomplete combustion of gas in flares.

Flare combustion efficiency means the fraction of natural gas, on a volume or mole basis, that is combusted at the flare burner tip.

Fugitive emissions means the same as defined in the relevant greenhouse gas reporting regulation.

Fugitive emissions detection means the process of identifying emissions from equipment, components, and other point sources.

Gas conditions mean the actual temperature, volume, and pressure of a gas sample.

High-Bleed Pneumatic Devices are automated flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream which is regulated by the process condition flows to a valve actuator controller where it vents (bleeds) to the atmosphere at a rate in excess of six standard cubic feet per hour.

Liquefied natural gas (LNG) means natural gas (primarily methane) that has been liquefied by reducing its temperature to -162 degrees Celsius at atmospheric pressure.

LNG boiloff gas means natural gas in the gaseous phase that vents from LNG storage tanks due to ambient heat leakage through the tank insulation and heat energy dissipated in the LNG by internal pumps.

Low-Bleed Pneumatic Devices mean automated flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream which is regulated by the process condition flows to a valve actuator controller where it vents (bleeds) to the atmosphere at a rate equal to or less than six standard cubic feet per hour.

Natural gas driven pneumatic pump means a pump that uses pressurized natural gas to move a piston or diaphragm, which pumps liquids on the opposite side of the piston or diaphragm.

Operating pressure means the containment pressure that characterizes the normal state of gas or liquid inside a particular process, pipeline, vessel or tank.

Pipeline quality natural gas means natural gas having a high heat value equal to or greater than 36.1 MJ/m3 or less than 40.98 MJ/m3, and which is at least ninety percent methane by volume, and which is less than five percent carbon dioxide by volume.

Portable means the same as defined in WCI.27 and WCI.361(a)(2)

Pump means a device used to raise pressure, drive, or increase flow of liquid streams in closed or open conduits.

Pump seals means any seal on a pump drive shaft used to keep methane and/or carbon dioxide containing light liquids from escaping the inside of a pump case to the atmosphere.

Pump seal emissions means hydrocarbon gas released from the seal face between the pump internal chamber and the atmosphere.

Reciprocating compressor means a piece of equipment that increases the pressure of a process natural gas by positive displacement, employing linear movement of a shaft driving a piston in a cylinder.

Reciprocating compressor rod packing means a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that escapes to the atmosphere.

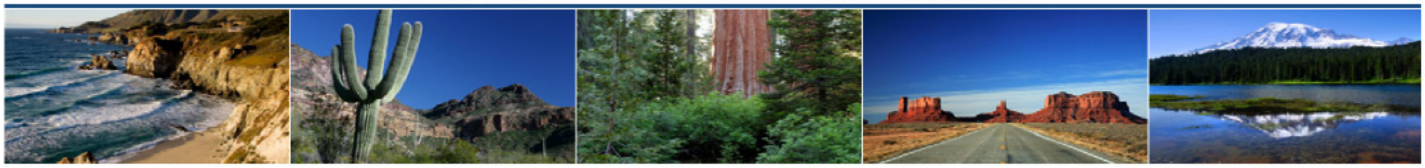
Re-condenser means heat exchangers that cool compressed boil-off gas to a temperature that will condense natural gas to a liquid.

Reservoir means a porous and permeable underground natural formation containing significant quantities of hydrocarbon liquids and/o r gases. A reservoir is characterized by a single natural pressure system.

Vapor recovery system means any equipment located at the source of potential gas emissions to the atmosphere or to a flare, that is composed of piping, connections, and, if necessary, flow-inducing devices, and that is used for routing the gas back into the process as a product and/or fuel.

Vaporization unit means a process unit that performs controlled heat input to vaporize LNG to supply transmission and distribution pipelines or consumers with natural gas.

Vented emissions means the same as defined in the relevant greenhouse gas reporting regulation, including but not limited to process designed flow to the atmosphere through seals or vent pipes, equipment blowdown for maintenance, and direct venting of gas used to power equipment (such as pneumatic devices).



This proposed WCI Essential Requirement would be for use in WCI Canadian jurisdictions. When the U.S. EPA finalizes Subpart W, the WCI will develop cap and trade quality requirements for sources covered by Subpart W for use in U.S. jurisdictions. This may mean modifications will be required to the current proposed Canadian language covering the same sources.

§WCI.360 PETROLEUM AND NATURAL GAS PRODUCTION AND GAS PROCESSING

§ WCI.361 Source Category Definition

(a) This source category consists of the following:

(1) Offshore petroleum and natural gas production. Offshore petroleum and natural gas production is any platform structure, affixed temporarily or permanently to offshore submerged lands, that houses equipment to extract hydrocarbons from the ocean or lake floor and that transfers such hydrocarbons to storage, transport vessels, or onshore. In addition, offshore production includes secondary platform structures and storage tanks associated with the platform structure.

(2) Onshore petroleum and natural gas production. Onshore petroleum and natural gas production equipment means all structures associated with wells (including but not limited to compressors, generators, or storage facilities), piping (including but not limited to flowlines or intra-facility gathering lines), and portable non-self-propelled equipment (including but not limited to well drilling and completion equipment, workover equipment, gravity separation equipment, auxiliary non-transportation-related equipment, and leased, rented or contracted equipment) used in the production, extraction, recovery, lifting, stabilization, separation or treating of petroleum and/or natural gas (including condensate). This also includes associated storage or measurement and all systems engaged in gathering produced gas from multiple wells, all EOR operations using CO_2, and all petroleum and natural gas production located on islands, artificial islands or structures connected by a causeway to land, an island, or artificial island.

(3) Onshore natural gas processing. Natural gas processing plants are designed to separate and recover natural gas liquids (NGLs) or other non-methane gases and liquids from a stream of produced natural gas to meet onshore natural gas transmission pipeline quality specifications through equipment performing one or more of the following processes: oil and condensate removal, water removal, separation of natural gas liquids, sulfur and carbon dioxide removal, fractionation of NGLs, or other processes, and also the capture of CO_2 separated from natural gas streams for delivery outside the facility. In addition, field gathering and/or boosting stations that gather and process natural gas from multiple wellheads, and compress and transport natural gas (including but not limited to flowlines or intra-facility gathering lines or compressors) as feed to the natural gas processing plants may be considered a part of the processing plant if emissions are not

calculated under onshore petroleum and natural gas production. Gathering and boosting stations that send the natural gas to an onshore natural gas transmission compression facility, or natural gas distribution facility, or to an end user are also considered within onshore natural gas processing for the purposes of emissions calculation. All residue gas compression equipment operated by a processing plant, whether inside or outside the processing plant fence, are considered part of the natural gas processing plant.

(b) This source category does not include natural gas transmission and distribution (i.e., onshore natural gas transmission compression, underground natural gas storage, liquefied natural gas (LNG) storage, LNG import and export equipment, and natural gas distribution). These are included in §WCI.350 (Natural Gas Transmission and Distribution).

§ WCI.362 Greenhouse Gas Reporting Requirements

Where greenhouse gases are not emitted from a specific emission source identified in paragraphs (a) to (g) then the reported emissions for the specific source shall be reported as zero.

In addition to the information required by regulation, the annual emissions data report shall contain the following information:

(a) CO_2 and CH_4 (and N_2O, if applicable) emissions (in metric tonnes) from each industry segment specified in paragraph (b) through (d) of this section. Onshore and offshore petroleum and natural gas production facilities must report emissions for the province.

(b) For offshore petroleum and natural gas production, report emissions from all "stationary fugitive" and "stationary vented" sources identified in the Minerals Management Service (MMS) Gulfwide Offshore Activity Data System (GOADS) study (2005 Gulfwide Emission Inventory Study MMS 2007-067). *[WCI.363(p), reserved]*

(c) For onshore petroleum and natural gas production, report emissions from the following source types:

(1) Natural gas pneumatic high bleed device venting. *[WCI.363(a)]*

(2) Natural gas driven pneumatic pump venting. *[WCI.363(a)]*

(3) Natural gas pneumatic low bleed device venting. *[WCI.363(b)]*

(4) Acid gas removal venting and incineration *[WCI.363(c)]*

(5) Dehydrator vent stacks. *[WCI.363(d)]*

(6) Well venting for liquids unloading. *[WCI.363(e)]*

(7) Gas well venting during conventional or unconventional well completions, except where vent gas is sent to a flare. *[WCI.363(f)]*

(8) Gas well venting during conventional well workovers, except where vent gas is sent to a flare. *[WCI.363(f)]*

(9) Blowdown vent stacks. *[WCI.363(g)]*

(10) Storage tanks. *[WCI.363(h)]*

(11) Well testing venting and flaring. *[WCI.363(i)]*

(12) Associated gas venting and flaring. *[WCI.363(j)]*

(13) Centrifugal compressor wet seal degassing venting. *[WCI.363(l)]*

(14) Reciprocating compressor rod packing venting. *[WCI.363(m)]*

(15) Fugitive emissions from reciprocating compressor rod packing. *[WCI.363(m)]*

(16) Gathering pipeline fugitives. *[WCI.363(o)]*

(17) Fugitive emissions from valves, connectors, open ended lines, pressure relief valves, compressor starter gas vents, pumps, flanges, and other fugitive sources* (such as instruments, loading arms, pressure relief valves, stuffing boxes, compressor seals, dump lever arms, and breather caps for crude services). *[WCI.363(o) or best practices if specific methods not identified]*

(18) EOR injection pump blowdown. *[WCI.363(t)]*

(19) Hydrocarbon liquids dissolved CO_2 from flashing. *[WCI.363(u)]*

(20) Produced water dissolved CO_2. *[WCI.363(v)]*

(21) Coal bed methane produced water emissions. *[WCI.363(v)]*

(22) Other venting emission sources* *[best practices]*

(d) For onshore natural gas processing, report emissions from the following sources:

(1) Acid gas removal venting or incineration. *[WCI.363(c)]*

(2) Dehydrator vent stacks. *[WCI.363(d)]*

(3) Blowdown vent stacks. *[WCI.363(g)]*

(4) Storage tanks. *[WCI.363(h)]*

(5) Flare stacks. *[WCI.363(k)]*

(6) Centrifugal compressor wet seal degassing venting. *[WCI.363(l)]*

(7) Reciprocating compressor rod packing venting. *[WCI.363(m)]*

(8) Fugitive emissions from reciprocating compressor rod packing. *[WCI.363(m)]*

(9) Gathering pipeline fugitives. *[WCI.363(o)]*

(10) Fugitive emissions from: valves, connectors, open ended lines, pressure relief valves, meters, centrifugal compressor dry and wet seals and other fugitive sources* *[WCI.363(n) or best practices if specific methods not identified]*

(11) Other venting emission sources**[best practices]*

(e) CO_2, CH_4, and N_2O emissions from each flare. *[including WCI.363(k)]*

(f) CO_2, CH_4, and N_2O from each stationary fuel combustion source type combusting field gas *[WCI.363(w)]* and fuels other than field gas. Stationary combustion sources that combust fuels other than field gas must report under §WCI.20 (General Stationary Combustion Sources).

(g) CO_2, CH_4, and N_2O from each portable equipment combustion source type combusting field gas *[WCI.363(w)]* and fuels other than field gas. Portable equipment combustion sources that combust fuels other than field gas must report under §WCI.20 (General Stationary Combustion Sources).

(h) Facility and company-specific emission factors used in place of Tables 360-1 to 360-2

(i) Report activity data for each aggregated source type as follows (for each individual facility or aggregate of facilities reported):

(1) Count of natural gas pneumatic high bleed devices.

(2) Count of natural gas pneumatic low bleed devices.

(3) Count of natural gas driven pneumatic pumps.

(4) For each dehydrator unit report the following:
(i) Glycol dehydrators:

(A) The number of glycol dehydrators operated.
(ii) Desiccant dehydrators:
(A) The number of desiccant dehydrators operated.

(5) Count of wells vented to the atmosphere for liquids unloading

(6) Count of wells venting during well completions:
(i) Number of conventional completions.
(ii) Number of completions employing hydraulic fracturing.

(7) Count of wells venting during well workovers:
(i) number of conventional well workovers involving well venting to the atmosphere.
(ii) number of unconventional well workovers involving well venting to the atmosphere.

(8) For each compressor blowdown vent stack report the following for each compressor:
   (i) Type of compressor whether reciprocating or centrifugal.
   (ii) Compressor capacity in horse powers.
   (iii) Number of blowdowns per year.

(9) Count of wells tested in the reporting period.

(10) Count of wells venting or flaring associated natural gas in the reporting period.

(11) Count of wells being unloaded for liquids in the reporting year.

(12) Count of wells completed (worked over) in the reporting year

(13) For fugitive emissions sources where emission factors are used for estimating emissions, report the following:
   (i) Component count for each fugitive emissions source.

(j) Report emissions separately for portable equipment for the following source types (aggregated by source type):

(1) dehydrators, compressors, electrical generators, steam boilers, and heaters.

** other venting emission or other fugitive sources not specifically listed are not required to be reported if a source type is reasonably estimated to be below 0.5% of total operation emissions.*

*** where a quantification method is not provided for a specific source (such as for other venting and other fugitive sources, best practices must be used to estimate emissions*

§ WCI.363 Calculating GHG Emissions

Zero emissions shall be reported for a given emission source where a quantification method is not applicable to the reporting operation's activities, or the greenhouse gas calculation equates to zero emissions.

(a) <u>Natural gas pneumatic high bleed device venting and natural gas driven pneumatic pump venting.</u> Calculate emissions from a natural gas pneumatic high bleed flow control device venting and natural gas drived pneumatic pump venting as follows:

(1) Calculate vented emissions from a natural gas pneumatic high bleed control devices or pneumatic pump as follows:
   (i) Measure gas consumption for all high bleed natural gas powered devices and pneumatic pumps using a meter or meters that meet accuracy requirements specified by relevant oil and gas metering requirements in the jurisdiction (even if a meter is not prescribed for this circumstance in the relevant requirements). In Year 1, reporters are required to meter gas consumption for at least 50% of all high bleed devices and pneumatic pumps. Metering of gas consumption for all high bleed

devices and pneumatic pumps is required in Year 2. Common meters may be used where possible.
[timing of meter installation with relation to planned downtime and statistically relevant samples are being considered]

(ii) Calculate CH_4 and CO_2 emissions from high bleed pneumatic devices and pumps using Equation 360-1.

$$E_{GHGi} = V_{NG} \times M_i \times \left(\frac{MW_i}{MVC} \right) \times 0.001 \qquad \textbf{Equation 360-1}$$

Where:

E_{GHGi}	=	emissions of GHG *i* (CH_4 or CO_2) (metric tons)
V_{NG}	=	volume of natural gas consumed by metered high bleed pneumatic devices and pumps (m^3/year).
M_i	=	mole fraction of CH_4 or CO_2 in natural gas supply.
MW_i	=	molecular weight of GHG *i*.
MVC	=	molar volume conversion factor.
0.001	=	conversion factor from kg to metric tons.

(2) In Year 1, emissions from high bleed devices and natural gas driven pneumatic pumps that are not equipped with meters must be calculated using the following methods.

(i) For high bleed devices, calculate vented emissions using manufacturer data.

(A) Obtain from the manufacturer specific pneumatic device model natural gas bleed rate during normal operation.

(B) Calculate the natural gas emissions for each continuous bleed device using Equation 360-2.

$$E_{s,n} = B_s \times T \qquad \textbf{Equation 360-2}$$

Where:

$E_{s,n}$ = Annual natural gas emissions at standard conditions (m^3).
B_s = Natural gas driven pneumatic device bleed rate volume at standard conditions, as provided by the manufacturer (m^3 per minute).
T = Amount of time that the pneumatic device has been operational through the reporting period (minutes).

(C) If manufacturer data for a specific device is not available, then use data for a similar device model, size and operational characteristics to estimate emissions.

(ii) Calculate emissions from natural gas driven pneumatic pump venting as follows:

(A) Obtain from the manufacturer specific pump model natural gas emission (or manufacturer "gas consumption") per unit volume of liquid circulation rate at pump speeds and operating pressures.

(B) Maintain a log of the amount of liquid pumped annually from individual pumps.

(C) Calculate the natural gas emissions for each pump using Equation 360-3.

$$E_{s,n} = F_s \times V \qquad \textbf{Equation 360-3}$$

Where:

$E_{s,n}$ = Annual natural gas emissions at standard conditions (m^3/year).
F_s = Natural gas driven pneumatic pump gas emission in "emission per volume of liquid pumped at operating pressure" at standard conditions, as provided by the manufacturer (m^3/liter).
V = Volume of liquid pumped annually (liters/year).

(D) If manufacturer data for a specific pump in Equation 360-3 is not available, then use data for a similar pump model, size and operational characteristics to estimate emissions.

(iii) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (r) and (s) of this section.

(b) Natural gas pneumatic low bleed device venting. Calculate emissions from natural gas pneumatic low continuous bleed device venting using Equation 360-4.

$$Mass_{s,i} = Count \times EF \times GHG_i \times Conv_i \times 24 \times 365$$

Equation 360-4

Where:

$Mass_{s,i}$	=	Annual total mass GHG emissions at standard conditions from all natural gas pneumatic low bleed device venting, for GHG i (metric tons/year).
Count	=	Total number of natural gas pneumatic low bleed devices.
EF	=	Population emission factors for natural gas pneumatic low bleed device venting listed in Table 360-1.
GHG_i	=	Concentration of GHG i (CH_4 or CO_2), in produced natural gas.
$Conv_i$	=	Conversion from m^3 to metric tons CO2e for GHG i; (0.01427 for CH_4, and 0.001832 for CO_2).
24 × 365	=	Conversion to yearly emissions estimate.

(c) Acid gas removal (AGR) venting or incineration process. Except for AGRs where the acid gases are re-injected into the oil/gas field, calculate CO_2 emissions only (not CH_4) for AGR (including but not limited to processes such as amine, membrane, molecular sieve or other absorbents and adsorbents) using Equation 360-5.

$$Mass_{a,CO2} = (V_1 \times \%Vol_1) - (V_2 \times \%Vol_2)$$

Equation 360-5

Where:

$E_{a,CO2}$	=	Annual volumetric CO_2 emissions at ambient condition (m^3/year).
V_1	=	Metered total annual volume of natural gas flow into AGR unit at ambient condition (m^3/year).
$\%Vol_1$	=	Volume weighted CO_2 content of natural gas into the AGR unit.
V_2	=	Metered total annual volume of natural gas flow out of the AGR unit at ambient condition (m^3/year).
$\%Vol_2$	=	Volume weighted CO_2 content of natural gas out of the AGR unit.

(1) If a continuous gas analyzer is installed, then the continuous gas analyzer results must be used. If continuous gas analyzer is not available, monthly gas samples must be taken to determine $\%Vol_1$ and $\%Vol_2$ according to methods set forth in WCI.364(b).

(2) Calculate CO_2 volumetric emissions at standard conditions using calculations in paragraph (q) of this section.

(3) Mass CO_2 emissions shall be calculated from volumetric CO_2 emissions using calculations in paragraphs (r) and (s) of this section.

(d) Dehydrator vent stacks. For dehydrator vent stacks without vapor recovery or thermal control devices, calculate annual mass CH_4 and CO_2 emissions at standard temperature and pressure (STP) conditions using a simulation software package of similar accuracy to GRI-GLYCalc Version 4.0 .

(1) A minimum of the following parameters must be used for characterizing emissions from dehydrators:
   (i) Feed natural gas flow rate.
   (ii) Feed natural gas water content.
   (iii) Outlet natural gas water content.
   (iv) Absorbent circulation pump type (natural gas pneumatic/air pneumatic/electric).
   (v) Absorbent circulation rate.
   (vi) Absorbent type: including, but not limited to, triethylene glycol (TEG), diethylene glycol (DEG) or ethylene glycol (EG).
   (vii) Use of stripping natural gas.
   (viii) Use of flash tank separator (and disposition of recovered gas).
   (ix) Hours operated.
   (x) Wet natural gas temperature, pressure, and composition.

(2) Calculate annual emissions from dehydrator vent stacks to flares or regenerator fire-box/fire tubes as follows:
   (i) Use the dehydrator vent stack volume and gas composition as determined in paragraph (d)(1) of this section.
   (ii) Use the calculation methodology of flare stacks in paragraph (k) of this section to determine dehydrator vent stack emissions from the flare or regenerator combustion gas vent.

(3) Dehydrators that use desiccant shall calculate emissions from the amount of gas vented from the vessel every time it is depressurized for the desiccant refilling process using Equation 360-6.

$$E_{s,n} = \left(\frac{H \times D^2 \times \pi \times P_2 \times \%G \times 365}{4 \times P_1 \times T} \right)$$

Equation 360-6

Where:

$E_{s,n}$	=	Annual natural gas emissions at standard conditions.
H	=	Height of the dehydrator vessel (m^3).
D	=	Inside diameter of the vessel (m^3).
P_1	=	Atmospheric pressure (kPa).
P_2	=	Pressure of the gas (kPa).
π	=	pi (3.14).
%G	=	Percent of packed vessel volume that is gas.
365	=	Conversion from days to years.
T	=	Time between refilling (days).

(i) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (r) and (s) of this section.

(e) Well venting for liquids unloading.

(1) The emissions for well venting for liquids unloading shall be determined using the following calculation methodology:

Calculate emissions from each well venting for liquids unloading using Equation 360-7.

$$E_{s,n} = \left(\left[7.854 \times 10^{-5}\right] \times CD^2 \times WD \times \left[\frac{SP}{101.325}\right] \times V \right) + \left(SFR \times HR\right)$$

Equation 360-7

Where:

$E_{s,n}$	=	Annual natural gas emissions at standard conditions, in m^3/year.
7.854×10^{-5}	=	$(\pi/4)/(10000)$
CD	=	Casing diameter (cm).
WD	=	Well depth (m).
SP	=	Shut-in pressure (kPa-gage).
V	=	Number of vents per year.
SFR	=	Sales flow rate of gas well (m^3/hr).
HR	=	Hours that the well was left open to the atmosphere during unloading.

Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (r) and (s) of this section.

(f) Gas well venting during conventional or unconventional well completions and workovers. Calculate emissions from gas conventional or uncoventional (from hydraulic fracturing) well venting during well completions and workovers for each gas well using Equation 360-8. Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (r) of this section. Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (r) and (s) of this section.

$$E_{a,n} = T \times FR$$

Equation 360-8

Where:

$E_{a,n}$	=	Annual natural gas vented emissions at ambient conditions (m^3).
T	=	Cumulative amount of time in hours of well venting during the year.
FR	=	Flow rate under ambient conditions, as required in paragraph (f)(1) of this section (m^3/hr).

(1) The flow rate for gas well venting during well completions and workovers from hydraulic fracturing shall be determined using either of the calculation methodologies described in this paragraph (f)(1). The same calculation methodology must be used for the entire volume for the reporting year.

(i) Calculation Methodology 1. For each well completion and each well workover, a recording flow meter shall be installed on the vent line during each well unloading event according to methods set forth in WCI.364(b). The average flow rate in cubic feet per minute of venting is calculated for each well completion and each well workover.

(ii) Calculation Methodology 2. For each well completion and each well workover, record the pressures measured before and after the well choke according to methods set forth in WCI.364(b). The average flow rate in cubic feet per minute of venting across the choke is calculated for each well completion and each well workover.

(iii) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (q) of this section.

(iv) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (r) and (s) of this section.

(2) Calculate annual emissions from gas well venting during well completions and workovers to flares as follows:

(i) Use the gas well venting volume during well completions and workovers as determined in paragraph (f)(1) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (k) of this section to determine gas well venting during well completions and workovers emissions from the flare.

(f.1) Gas well venting during conventional well completions and workovers.

Reserved *[paragraph (f) indicated to be appropriate for use in Canada for conventional gas wells]*

(g) Blowdown vent stacks. Calculate blowdown vent stack emissions as follows:

(1) Calculate the total volume (including, but not limited to, pipelines, compressor case or cylinders, manifolds, suction and discharge bottles and vessels) between isolation valves.

(2) Retain logs of the number of blowdowns for each equipment type.

(3) Calculate the total annual venting emissions using Equation 360-10:

$$E_{a,n} = N \times V_v$$

Equation 360-10

Where:

$E_{a,n}$	=	Annual natural gas venting emissions at ambient conditions from blowdowns (m^3).
N	=	Number of blowdowns for the equipment in reporting year.
V_v	=	Total volume of blowdown equipment chambers (including, but not limited to, pipelines, compressors and vessels) between isolation valves (m^3).

(4) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (q) of this section.

(5) Calculate both CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (r) and (s) of this section.

(h) Onshore production and processing storage tanks. For emissions from atmospheric pressure storage tanks receiving produced liquids from onshore petroleum and natural gas production faciliites (including stationary liquid storage not owned or operated by the reporter) and onshore natural gas processing facilities, calculate annual CH_4 and CO_2 emissions as specified in paragraphs (h)(1) or (h)(2). For atmospheric storage tanks vented to flares, use the calculation methodology for flare stacks in paragraph (k) of this section. Storage tanks equipped with vapor recovery units (VRU) are exempt from the requirements of this paragraph.

(1) CH_4 and CO2 emissions at storage tank batteries where the oil production rate is 10 barrels per day or greater shall be calculated using Equation 360-11

.

$$E_{GHGi} = GOR \times PR \times \left(\frac{1}{MVC}\right) \times MW_g \times MF_i \times 0.001$$

Equation 360-11

Where:

E_{GHGi}	=	Annual emissions of greenhouse gas *i* (CO_2 or CH_4) (metric tons/year).
GOR	=	Gas Oil Ratio (m^3/bbl).
PR	=	oil production rate (bbl/measurement period).
MVC	=	molar volume conversion.
MW_g	=	molecular weight of the gas (kg/kg-mole).
MF_i	=	mass fraction of greenhouse gas *i* (CO_2 or CH_4) in gas (kg *i* /kg gas).
0.001	=	conversion factor (metric tons/kg).

(2) Methane and carbon dioxide emissions at storage tank batteries where the oil production rate is less than 10 barrels per day shall calculate methane emissions the using the latest

software package for E&P Tank. A minimum of the following parameters must be used to characterize emissions from liquid transfer to atmospheric pressure storage tanks.

(i) Separator oil composition.
(ii) Separator temperature.
(iii) Separator pressure.
(iv) Sales oil API gravity.
(v) Sales oil production rate.
(vi) Sales oil Reid vapor pressure.
(vii) Ambient air temperature.
(viii) Ambient air pressure.

(i) Well testing venting and flaring. Calculate well testing venting and flaring emissions as follows:

(1) Determine the gas to oil ratio (GOR) of the hydrocarbon production from each well tested.

(2) Estimate venting emissions using Equation 360-12.

$$E_{a,n} = GOR \times FR \times D$$

Equation 360-12

Where:

$E_{a,n}$	=	Annual volumetric natural gas emissions from well testing ambient conditions (m^3).
GOR	=	Gas to oil ratio (m^3 of gas per barrel of oil); oil here defined as hydrocarbon liquids produced of all API gravities.
FR	=	Flow rate in barrels of oil per day for the well being tested.
D	=	Number of days during the year the well is tested.

(3) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (q) of this section.

(4) Calculate both CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (r) and (s) of this section.

(5) Calculate emissions from well testing to flares as follows:

(i) Use the well testing emissions volume and gas composition as determined in paragraphs (i)(1) through (3) of this section.
(ii) Use the calculation methodology of flare stacks in paragraph (k) of this section to determine well testing emissions from the flare.

(j) Associated gas venting and flaring. Calculate associated gas venting and flaring emissions as follows:

(1) Determine the GOR ratio of the hydrocarbon production from each well whose associated natural gas is vented or flared.

(2) Estimate venting emissions using the Equation 360-13.

$$E_{a,n} = GOR \times V$$

Equation 360-13

Where:

$E_{a,n}$	=	Annual volumetric natural gas emissions from associated gas venting under ambient conditions (m^3).
GOR	=	Gas to oil ratio (m^3 of gas per barrel of oil); oil here defined as hydrocarbon liquids produced of all API gravities.
V	=	Total volume of oil produced in barrels in the reporting year.

(3) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (q) of this section.

(4) Calculate both CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (r) and (s) of this section.

(5) Calculate emissions from associated natural gas to flares as follows:
  (i) Use the associated natural gas volume and gas composition as determined in paragraph (j)(1) through (3) of this section.
  (ii) Use the calculation methodology of flare stacks in paragraph (k) of this section to determine associated gas emissions from the flare.

(k) Flare stacks. Calculate emissions from a flare stack as follows:

(1) If there is a continuous flow measurement device on the flare, measured flow volumes must be used to calculate the flare gas emissions. If there is not a continuous flow measurement device on the flare, a flow measuring device can be installed on the flare or engineering calculations, company records, or similar estimates of volumetric flare gas flow can be used.

(2) If there is a continuous gas composition analyzer on the gas to the flare, these compositions must be used in calculating emissions. If there is not a continuous gas composition analyzer on the gas to the flare, the appropriate gas compositions for each stream of hydrocarbons going to the flare must be used as follows:
  (i) When the stream going to flare is natural gas, use the GHG mole percent in feed natural gas for all streams upstream of the de-methanizer and GHG mole percent in facility specific residue gas to transmission pipeline systems for all emissions sources downstream of the de-methanizer overhead for onshore natural gas processing facilities.

(ii) When the stream going to the flare is a hydrocarbon product stream, such as ethane or butane, then use a representative composition from the source for the stream.

(3) Determine flare combustion efficiency from manufacturer. If not available, assume that flare combustion efficiency is 98 percent.

(4) Calculate GHG volumetric emissions at actual conditions using Equations 360-14a, 360-14b, 360-15, and 360-16.

$$E_{a,CH4} = V_a \times (1-\eta) \times X_{CH4}$$

Equation 360-14a

$$E_{a,CO2}(noncombusted) = V_a \times X_{CO2}$$

Equation 360-14b

$$E_{a,CO2}(combusted) = \sum_j \eta \times V_a \times Y_j \times R_j$$

Equation 360-15

$$E_{a,CO2}(total) = E_{a,CO2}(noncombusted) + E_{a,CO2}(combusted)$$

Equation 360-16

Where:

$E_{a,CH4}$	=	Contribution of annual uncombusted CH_4 emissions from flare stack under ambient conditions (m^3).
$E_{a,CO2}$ (noncombusted)	=	Contribution of annual CO_2 emissions from CO_2 in the inlet gas passing through the flare uncombusted under ambient conditions (m^3).
$E_{a,CO2}$ (combusted)	=	Contribution of annual CO_2 emissions from combustion from flare stack under ambient conditions (m^3)
$E_{a,I}$ (total)	=	Total annual emissions from flare stack under ambient conditions (m^3)
V_a	=	Volume of natural gas sent to flare during the year (m^3).
η	=	Percent of natural gas combusted by flare (default is 98 percent).
X_i	=	Concentration of GHG i in gas to the flare.
Y_j	=	Concentration of natural gas hydrocarbon constituents j (i.e., methane, ethane, propane, butane, and pentanes plus).
R_j	=	Number of carbon atoms in the natural gas hydrocarbon constituent j (i.e., 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes plus).

(5) Calculate GHG volumetric emissions at standard conditions using calculations in paragraph (q) of this section.

(6) Calculate both CH_4 and CO_2 mass emissions from volumetric CH_4 and CO_2 emissions using calculation in paragraph (s) of this section.

(7) Calculate N_2O emissions using the emission factors for Gas Flaring listed in Table 360-3.

(8) This emissions source excludes any emissions calculated under other emissions sources in WCI.363.

(l) Centrifugal compressor wet seal degassing vents. Calculate emissions from centrifugal compressor wet seal degassing vents as follows:

(1) For each centrifugal compressor determine the volume of vapors from wet seal oil degassing tank sent to an atmospheric vent or flare using a temporary or permanent flow measurement meter such as, but not limited to, a vane anemometer according to methods set forth in WCI.364(b).

(2) Estimate annual emissions using meter flow measurement using Equation 360-17.

$$E_{a,i} = MT \times T \times M_i \times (1 - B)$$

.

Equation 360-17

Where:

$E_{a,i}$	=	Annual volumetric emissions of GHG i (either CH_4 or CO_2) at ambient conditions.
MT	=	Meter reading of gas emissions per unit time.
T	=	Total time the compressor associated with the wet seal(s) is operational in the reporting year.
M_i	=	Mole percent of GHG i in the degassing vent gas; use the appropriate gas compositions in paragraph (r)(2) of this section.
B	=	Percentage of centrifugal compressor wet seal degassing vent gas sent to vapor recovery or fuel gas or other beneficial use as determined by keeping logs of the number of operating hours for the vapor recovery system and the amount of vent gas that is directed to the fuel gas system.

(3) Calculate CH_4 and CO_2 volumetric emissions at standard conditions using paragraph (q) of this section.

(4) Calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (s) of this section.

(5) Calculate emissions from degassing vent vapors to flares as follows:
  (i) Use the degassing vent vapor volume and gas composition as determined in paragraphs (l)(1) through (3) of this section.
  (ii) Use the calculation methodology of flare stacks in paragraph (k) of this section to determine degassing vent vapor emissions from the flare.

(m) Reciprocating compressor rod packing venting. Calculate annual CH_4 and CO_2 emissions from each reciprocating compressor rod packing venting as follows:

(1) Estimate annual emissions using a meter flow measurement using Equation 360-18.

$$E_{a,i} = MT \times T \times M_i$$

Equation 360-18

Where:

$E_{a,i}$	=	Annual volumetric emissions of GHG i (either CH_4 or CO_2) at ambient conditions.
MT	=	Meter volumetric reading of gas emissions per unit time, under ambient conditions.
T	=	Total time the compressor associated with the venting is operational in the reporting year.
M_i	=	Mole percent of GHG i in the vent gas; use the appropriate gas compositions in paragraph (r)(2) of this section.

(2) If the rod packing case is connected to an open ended vent line then use one of the following two methods to calculate emissions.
  (i) Measure emissions from all vents (including emissions manifolded to common vents) including rod packing, unit isolation valves, and blowdown valves using bagging according to methods set forth in WCI.364(c).
  (ii) Use a temporary meter such as, but not limited to, a vane anemometer or a permanent meter such as, but not limited to, an orifice meter to measure emissions from all vents (including emissions manifolded to a common vent) including rod packing vents, unit isolation valves, and blowdown valves according to methods set forth in WCI.364(b).

(3) If the rod packing case is not equipped with a vent line use the following method to estimate emissions:
  (i) Use the methods described in WCI.364(a) to conduct a progressive sample leak detection of fugitive emissions from the packing case into an open distance piece, or from the compressor crank case breather cap or vent with a closed distance piece.
  (ii) Measure emissions using a high flow sampler, or calibrated bag, or appropriate meter according to methods set forth in WCI.364(d).

(4) Conduct one measurement for each compressor in each of the operational modes that occurs during a reporting period:
  (i) Operating.
  (ii) Standby pressurized.
  (iii) Not operating, depressurized.

(5) Calculate CH_4 and CO_2 volumetric emissions at standard conditions using calculations in paragraph (q) of this section.

(6) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in paragraphs (r) and (s) of this section.

(n) Leak detection and leaker emission factors. The methods described in WCI.364(a) must be used to conduct a progressive sample leak detection of fugitive emissions from all sources listed in §WCI.362(d)(10). If fugitive emissions are detected for sources listed in this paragraph, calculate emissions using Equation 360-19 for each source with fugitive emissions.

$$E_{s,i} = Count \times EF \times GHG_i \times T$$

Equation 360-19

Where:

$E_{s,i}$	=	Annual total volumetric GHG emissions at standard conditions from each fugitive source.
Count	=	Total number of this type of emission source found to be leaking.
EF	=	Leaker emission factor for specific sources listed in Table 360-1 or Table 360-2.
GHG_i	=	For onshore natural gas processing facilities, concentration of GHG i, CH_4 or CO_2, in the total hydrocarbon of the feed natural gas.
T	=	Total time the specific source associated with the fugitive emission was leaking in the reporting year, in hours.

(1) Calculate GHG mass emissions in carbon dioxide equivalent at standard conditions using calculations in paragraph (s) of this section.

(2) Onshore natural gas processing facilities shall use the appropriate default leaker emission factors listed in Table 360-2 for fugitive emissions detected from valves; connectors; open ended lines; pressure relief valves; meters; and centrifugal compressor dry seals.

(o) Population count and emission factors. This paragraph applies to emissions sources listed in §WCI.362(c)(2), (c)(16), (c)(17), (c)(21), and (d)(9) on streams with gas content greater than 10 percent CH_4 plus CO_2 by weight. Emissions sources in streams with gas content less than 10 percent CH_4 plus CO_2 by weight do not need to be reported. Calculate emissions from all sources listed in this paragraph using Equation 360-20.

$$E_{s,i} = Count \times EF \times GHG_i \times T$$

Equation 360-20

Where:

$E_{s,i}$	=	Annual total volumetric GHG emissions at standard conditions from each fugitive source.
Count	=	Total number of this type of emission source at the facility.
EF	=	Population emission factor for specific sources listed in Table 360-1 or Table 360-2.
GHG_i	=	for onshore petroleum and natural gas production facilities and onshore natural gas processing facilities, concentration of GHG i, CH_4 or CO_2, in produced natural gas or feed natural gas.
T	=	Total time the specific source associated with the fugitive emission was operational in the reporting year, in hours.

(1) Calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (s) of this section.

(2) Onshore petroleum and natural gas production facilities shall use the appropriate default population emission factors listed in Table 360-1 for fugitive emissions from valves; connectors; open ended lines; pressure relief valves; compressor starter gas vent; pump; flanges; other; and CBM well water production. Where facilities conduct EOR operations the emissions factor listed in Table 360-1 shall be used to estimate all streams of gases, including recycle CO_2 stream. In cases where the stream is almost all CO_2, the emissions factors in Table 360-1 shall be assumed to be for CO_2 instead of natural gas.

(3) Onshore natural gas processing facilities shall use the appropriate default population emission factor listed in Table 360-2 for fugitive emissions from gathering pipelines.

(p) Offshore petroleum and natural gas production facilities in both provincial and federal waters.
[reserved]

(q) Volumetric emissions. Calculate volumetric emissions at standard conditions as specified in paragraphs (q)(1) or (2).

(1) Calculate natural gas volumetric emissions at standard conditions by converting ambient temperature and pressure of natural gas emissions to standard temperature and

pressure (15 degrees Celsius and 1 atmosphere in Canada) natural gas using Equation 360-21.

$$E_{s,n} = \frac{E_{a,n} \times (273.15 + T_s) \times P_a}{(273.15 + T_a) \times P_s}$$

Equation 360-21

Where:

$E_{s,n}$	=	Natural gas volumetric emissions at standard temperature and pressure (STP) conditions.
$E_{a,n}$	=	Natural gas volumetric emissions at ambient conditions.
T_s	=	Temperature at standard conditions (^{o}C).
T_a	=	Temperature at actual emission conditions (^{o}C).
P_s	=	Absolute pressure at standard conditions (kPa).
P_a	=	Absolute pressure at ambient conditions (kPa).

(2) Calculate GHG volumetric emissions at standard conditions by converting ambient temperature and pressure of GHG emissions to standard temperature and pressure using Equation 360-22.

$$E_{s,i} = \frac{E_{a,i} \times (273.15 + T_s) \times P_a}{(273.15 + T_a) \times P_s}$$

Equation 360-21

Where:

$E_{s,i}$	=	GHG i volumetric emissions at standard temperature and pressure (STP) conditions.
$E_{a,i}$	=	GHG i volumetric emissions at actual conditions.
T_s	=	Temperature at standard conditions (^{o}C).
T_a	=	Temperature at actual emission conditions (^{o}C).
P_s	=	Absolute pressure at standard conditions (kPa).
P_a	=	Absolute pressure at ambient conditions (kPa).

(r) GHG volumetric emissions. Calculate GHG volumetric emissions at standard conditions as specified in paragraphs (r)(1) and (2).

(1) Estimate CH_4 and CO_2 emissions from natural gas emissions using Equation 360-23.

$$E_{s,i} = E_{s,n} \times M_i$$

Equation 360-23

Where:

$E_{s,i}$ = GHG i (CH_4 or CO_2) volumetric emissions at standard conditions.
$E_{s,n}$ = Natural gas volumetric emissions at standard conditions.
M_i = Mole percent of GHG i in the natural gas.

(2) For Equation 360-23 of this section, the mole percent, M_i, shall be the annual average mole percent for each facility, as specified in paragraphs (r)(2)(i) and (ii) of this section.

(i) GHG mole percent in produced natural gas for onshore petroleum and natural gas production facilities. If you have a continuous gas composition analyzer for produced natural gas, you must use these values in calculating emissions. If you do not have a continuous gas composition analyzer, then the known composition for the company or operator for the specific field must be used as taken according to methods set forth in WCI.364(b).

(ii) GHG mole percent in feed natural gas for all emissions sources upstream of the de-methanizer and GHG mole percent in facility specific residue gas to transmission pipeline systems for all emissions sources downstream of the de-methanizer overhead for onshore natural gas processing facilities. If you have a continuous gas composition analyzer on feed natural gas, you must use these values in calculating emissions. If you do not have a continuous gas composition analyzer, then the known composition for the company or operator for the specific field must be used as taken according to methods set forth in WCI.364(b).

(s) <u>GHG mass emissions</u>. Calculate GHG mass emissions in carbon dioxide equivalent at standard conditions by converting the GHG volumetric emissions into mass emissions using Equation 360-24.

$$Mass_{s,i} = E_{s,i} \times \rho_i \times GWP_i \times 10^{-3}$$

Equation 360-24

Where:
$Mass_{s,i}$ = GHG i (CH_4 or CO_2) mass emissions at standard conditions (metric tons CO_2e).
$E_{s,i}$ = GHG i (CH_4 or CO_2) volumetric emissions at standard conditions (m^3).
ρ_i = Density of GHG i, (1.871 kg/m^3 for CO_2 and 0.681 kg/m^3 for CH_4).
GWP_i = Global warming potential of GHG i (1 for CO_2 and 21 for CH_4).

(t) <u>EOR injection pump blowdown</u>. Calculate pump blowdown emissions as follows:

(1) Calculate the total volume in cubic meters (including, but not limited to, pipelines, compressors and vessels) between isolation valves.

(2) Retain logs of the number of blowdowns per reporting period.

(3) Calculate the total annual venting emissions using Equation 360-25.

$$Mass_{c,i} = N \times V_v \times R_c \times GHG_i \times 10^{-3}$$

Equation 360-25

Where:

$Mass_{c,i}$	=	Annual EOR injection gas venting emissions at critical conditions "c" from blowdowns (metric tons).
N	=	Number of blowdowns for the equipment in reporting year.
V_v	=	Total volume of blowdown equipment chambers (including, but not limited to, pipelines, compressors, manifolds and vessels) between isolation valves (m^3).
R_c	=	Density of critical phase EOR injection gas in kg/m^3. Use an appropriate standard method published by a consensus-based standards organization to determine density of super critical EOR injection gas.
GHG_i	=	Mass fraction of GHG_i in critical phase injection gas.

(u) Hydrocarbon liquids dissolved CO_2. Calculate dissolved CO_2 in hydrocarbon liquids as follows:

(1) Determine the amount of CO_2 retained in hydrocarbon liquids after flashing in tankage at STP conditions. Quarterly samples must be taken according to methods set forth in WCI.364(b) to determine retention of CO_2 in hydrocarbon liquids immediately downstream of the storage tank. Use the average of the quarterly analysis for the reporting period.

(2) Estimate emissions using Equation 360-26.

$$Mass_{s,CO2} = S_{hl} \times V_{hl}$$

Equation 360-26

Where:

$Mass_{s,CO2}$	=	Annual CO_2 emissions from CO_2 retained in hydrocarbon liquids beyond tankage (metric tons).
S_{hl}	=	Amount of CO_2 retained in hydrocarbon liquids under standard conditions (metric tons per barrel).
V_{hl}	=	Total volume of hydrocarbon liquids produced (barrels per year).

(v) Produced water dissolved CO_2. Calculate dissolved CO_2 in produced water that is not re-injected as follows:

(1) Determine the amount of CO_2 retained in produced water at STP conditions. Quarterly samples must be taken according to methods set forth in WCI.364(b) to determine retention of CO_2 in produced water immediately downstream of the separator where

hydrocarbon liquids and produced water are separated. Use the average of the quarterly analysis for the reporting period.

(2) Estimate emissions using the Equation 360-27.

$$Mass_{s,CO2} = S_{pw} \times V_{pw}$$

Equation 360-27

Where:

$Mass_{s, CO2}$	=	Annual CO_2 emissions from CO_2 retained in produced water beyond tankage (metric tons).
S_{pw}	=	Amount of CO_2 retained in produced water under standard conditions (metric tons per barrel).
V_{pw}	=	Total volume of produced water produced (barrels per year).

(3) EOR operations that route produced water from separation directly to re-injection into the hydrocarbon reservoir in a closed loop system without any leakage to the atmosphere are exempt from paragraph (v) of this section.

(w) Field gas combustion. For combustion units that combust field gas, you must comply with following requirements:

(1) Measure the higher heating value of the field gas annually.

(2) If the measured higher heating value is equal to or greater than 36,1 MJ/m^3 and less than 40.98 MJ/m^3, then calculate the CO_2, CH_4, and N_2O emissions using the methods in WCI.20 (General Stationary Combustion Sources) following the methods required for pipeline quality natural gas.

(3) If the measured higher heating value is less than 36,1 MJ/m^3 or greater than 40.98 MJ/m^3, then calculate the CO_2, CH_4, and N_2O emissions using either the Tier 3 or Tier 4 methodology in WCI.20 (General Stationary Combustion Sources). Sampling, analysis and measurement requirements (including for gas composition) required for WCI.360 in WCI.025(f) applies in place of those indicated for Equation 20-7.

§ WCI.364 Sampling, Analysis, and Measurement Requirements

Instruments used for sampling, analysis and measurement must be operated and calibrated according to legislative, manufacturer's, or other written specifications or requirements. All sampling, analysis and measurement must be conducted only by, or under the direct supervision of individuals with demonstrated understanding and experience in the application (and principles related) of the specific sampling, analysis and measurement technique in use.

(a) If a documented leak detection or integrity management standard or requirement that is required by legislation orregulation such as CSA Z662-07 Oil & Gas Pipeline Systems or the CAPP Best Management Practices for Fugitive Emisisons, the documented standard or requirement must be followed – including service schedules for different components - with reporting as required for input to the calculation methods herein.

If there is no such legal requirement, then progressive sampling is required using one of the methods outlined below in combination with best industry practices for use of the method– including service schedules for different components - to determine the count of leaks (and time leaking) required in WCI.363(o) and (n)(3)(i), as applicable. Progressive sampling means establishing a statistically valid baseline sample of leaks under normal operating conditions for the 2011 and 2012 calendar years, with subsequent sampling determined based random or spot sampling modelling or measurement of leaks under normal operating conditions. A minimum of 18 months and a maximum of 36 months is allowed between surveys. This interval is determined based on whether there are indications of leaks. If a leak found and immediately repaired, the existing schedule may be maintained.

Leak detection for fugitive emissions must be performed for all identified equipment in operation or on standby mode during a reporting period.

(1) Optical gas imaging instrument. Use an optical gas imaging instrument for fugitive emissions detection in accordance with 40 CFR part 60, subpart A, §60.18 (i)(1) and (2) *Alternative work practice for monitoring equipment leaks* (or per relevant standard in Canada). In addition, the optical gas imaging instrument must be operated to image the source types required by this proposed reporting rule in accordance with the instrument manufacturer's operating parameters. The optical gas imaging instrument must comply with the following requirements:

(i) Provide the operator with an image of the potential leak points for each piece of equipment at both the detection sensitivity level and within the distance used in the daily instrument check described in the relevant best practices. The detection sensitivity level depends upon the frequency at which leak monitoring is to be performed.

(ii) Provide a date and time stamp for video records of every monitoring event.

(2) Bubble tests

(3) Portable organic vapour analyzer. Use a portable organic vapour analyzer in accordance with US EPA Method 21 or as outlined in the CAPP Best Management Practices for Fugitive Emisisons

(4) Other methods as outlined in the CAPP Best Management Practices for Fugitive Emisisons may be used as necessary for operational circumstances

(b) All flow meters, composition analyzers and pressure gauges that are used to provide data for the GHG emissions calculations shall use measurement methods, maintenance practices, and calibration methods, prior to the first reporting year and in each subsequent reporting year using an appropriate standard method published by a consensus standards organization such as, but not limited to, ASTM International, Canadian Standards Assocation (CSA), American National Standards Institute (ANSI), the relevant provincial or national oil and gas regulator, Measurement Canada, Canadian Association of Petroleum Producers (CAPP) and American Petroleum Institute (API). If a consensus based standard is not available, manufacturer instructions must be used to calibrate the meters, analyzers, and pressure gauges.

(c) Use calibrated bags (also known as vent bags) only where the emissions are at near-atmospheric pressures such that it is safe to handle and can capture all the emissions, below the maximum temperature specified by the vent bag manufacturer, and the entire emissions volume can be encompassed for measurement.

(1) Hold the bag in place enclosing the emissions source to capture the entire emissions and record the time required for completely filling the bag. If the bag inflates in less than one second, assume one second inflation time.

(2) Perform three measurements of the time required to fill the bag, report the emissions as the average of the three readings.

(3) Estimate natural gas volumetric emissions at standard conditions using calculations in WCI.363(r).

(4) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in WCI.363(r) and (s).

(d) Use a high volume sampler to measure emissions within the capacity of the instrument.

(1) A technician following manufacturer instructions shall conduct measurements, including equipment manufacturer operating procedures and measurement methodologies relevant to using a high volume sampler, including, but not limited to, positioning the instrument for complete capture of the fugitive emissions without creating backpressure on the source.

(2) If the high volume sampler, along with all attachments available from the manufacturer, is not able to capture all the emissions from the source, then anti-static wraps or other aids must be used to capture all emissions without violating operating requirements as provided in the instrument manufacturer's manual.

(3) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in WCI.363(r) and (s).

(4) Calibrate the instrument at 2.5 percent methane with 97.5 percent air and 100 percent CH_4 by using calibrated gas samples and by following manufacturer's instructions for calibration.

(e) Onshore Production and Processing Storage Tanks.

(1) A pressurized sample of produced liquids shall be collected from the separator at a location upstream of the storage tank. This point would typically be at the final separation device before produced oil transitions from separator outlet pressure to atmospheric pressure and enters a production storage tank. This may require the installation of a sampling valve at the appropriate location. Sampling protocol specific to the collection of separator liquid can be found in the following publications:
   (i) Appendix C Sampling Protocol section (page 33) of the *E&P TANK Version 2.0 User's Manual*.
   (ii) Wyoming Department of Environmental Quality Air Quality Division guidance document *Oil and Gas Production Facilities, Chapter 6, Section 2 Permitting Guidance (revised August 2001), Appendix D Sampling and Analysis of Hydrocarbon Liquids and Natural Gas.*
   (iii) Gas Processors Association (GPA) Standard 2174-93, *Obtaining Liquid Hydrocarbon Samples for Analysis by Gas Chromatography*.

(2) The sample collection pressure shall be determined at the time of collection and again prior to processing in the laboratory to insure that sample integrity has been maintained. Liquid temperature should also be determined and recorded at the time of collection.

(3) Sampling and laboratory based determination of GOR shall be conducted at prescribed intervals and at a time when operational parameters of the storage tank battery are representative and consistent with normal operating conditions. Sampling shall be annual for oil production rates between 11 and 100 barrels/day, semi-annual for oil production rates between 101 and 500 barrels/day, and quarterly for oil production rates greater than 500 barrels/day.

(4) An additional sample shall be collected and analyzed if:
   (i) The oil production rate at the storage tank battery changes more than 20 percent for time periods in excess of one week (e.g., in cases where a well or wells feeding the storage tank battery stop or start production).
   (ii) The separator operating pressures change by more than 10 percent.

(5) The volume (barrels) of liquid produced during the sampling interval shall be determined using a calibrated liquid meter or industry standard method to an accuracy of ±5%.

[proposed to be added as WCI.025(f) – General Stationary Combustion]
For field gas combustion or general stationary combustion of natural gas within facilities covered by WCI.360, legislative or regulatory requirements, such as those required by the Petroleum and Natural Gas Act of British Columbia are sufficient for the points of measurement that are metered. For British Columbia, combustion sources specifically covered by the Petroleum and Natural Gas Act are to be calculated in the manner prescribed by the Act, its regulations, guidelines and policies. Combustion sources not covered by the Act must be metered according to the following sampling and measurement requirements.

(1) *For combustion emission sources where meters are not required by legislation or regulation a calculated shrinkage value is sufficient but must be assigned using engineering estimation techniques to the various sources, if required for reporting.*

(2) *For field or pipeline quality natural gas combustion emission sources where metering is not required by law or regulation and shrinkage is not calculated, engineering estimation techniques that consolidate to common meter points such as that at the input to a processing plant used for financial purposes are sufficient. As required, fuel use must be allocated (using equipment specifications, operating hours, and flow rates) to specific emission sources.*

(3) *For upstream sources, a meter is required at each installation or at a point where fuel use can allocated to multiple combustion sources such that the aggregated of all combustion sources are metered.*

All combustion estimates must be calculated in such a manner that ensures that fugitive, flaring and venting emissions as calculated under WCI.360 are uniquely reported and that no double-counting of emissions in one or more categories occurs.

Carbon content and molecular weight of the field gas determined annually by a company or operator for a specific field for operational and regulatory purposes must be used as inputs to Equation 20-7 When this is data is not available, the generic emission factors provided in Table 360-4 (to be developed) must be used by a company or operator for the specific field in question.

[proposed to be added to WCI.025(b)(1)]

For facilities that are covered by WCI.360 (Petroleum and Natural Gas Production and Gas Processing) but are less than 10,000 tonnes in individual size, an operator may calculate fuel consumption for propane and diesel without correcting for the difference in inventory at the beginning and end of the year.

§ WCI.365 *Procedures for Estimating Missing Data*

A complete record of all estimated and/or measured parameters used in the GHG emissions calculations is required. If data are lost or an error occurs during annual emissions estimation or measurements, you must repeat the estimation or measurement activity for those sources as soon as possible, including in the subsequent reporting year if missing data are not discovered until after December 31 of the reporting year, until valid data for reporting is obtained. Data developed and/or collected in a subsequent reporting year to substitute for missing data cannot be used for that subsequent year's emissions estimation. Where missing data procedures are used for the previous year, at least 30 days must separate emissions estimation or measurements for the previous year and emissions estimation or meausrements for the current year of data collection.

§ WCI.366 Definitions

Absorbent circulation pump means a pump commonly powered by natural gas pressure that circulates the absorbent liquid between the absorbent regenerator and natural gas contactor.

Acid Gas means hydrogen sulfide ($H2S$) and carbon dioxide ($CO2$) contaminants that are separated from sour natural gas by an acid gas removal.

Acid Gas Removal unit (AGR) means a process unit that separates hydrogen sulfide and/or carbon dioxide from sour natural gas using liquid or solid absorbents or membrane separators.

Acid gas removal vent stack emissions mean the acid gas separated from the acid gas absorbing medium (e.g., an amine solution) and released with methane and other light hydrocarbons to the atmosphere or a flare.

Air injected flare means a flare in which air is blown into the base of a flare stack to induce complete combustion of low Btu natural gas (i.e., high non-combustible component content).

Blowdown vent stack emissions mean natural gas released due to maintenance and/or blowdown operations including but not limited to compressor blowdown and emergency shut-down (ESD) system testing.

Calibrated bag means a flexible, non-elastic, anti-static bag of a calibrated volume that can be affixed to a emitting source such that the emissions inflate the bag to its calibrated volume.

Centrifugal compressor means any equipment that increases the pressure of a process natural gas by centrifugal action, employing rotating movement of the driven shaft.

Centrifugal compressor dry seals mean a series of rings around the compressor shaft where it exits the compressor case that operates mechanically under the opposing forces to prevent natural gas from escaping to the atmosphere.

Centrifugal compressor dry seals emissions mean natural gas released from a dry seal vent pipe and/or the seal face around the rotating shaft where it exits one or both ends of the compressor case.

Centrifugal compressor wet seal degassing venting emissions means emissions that occur when the high-pressure oil barriers for centrifugal compressors are depressurized to release absorbed natural gas. High-pressure oil is used as a barrier against escaping gas in centrifugal compressor shafts. Very little gas escapes through the oil barrier, but under high pressure, considerably more gas is absorbed by the oil. The seal oil is purged of the absorbed gas (using heaters, flash tanks, and degassing techniques) and recirculated. The separated gas is commonly vented to the atmosphere.

Coal Bed Methane (CBM) means natural gas which is extracted from underground coal deposits or "beds."

Component, for the purposes of WCI.350 and WCI.360 only, means but is not limited to each metal to metal joint or seal of non-welded connection separated by a compression gasket, screwed thread (with or without thread sealing compound), metal to metal compression, or fluid barrier through which natural gas or liquid can escape to the atmosphere.

Compressor means any machine for raising the pressure of a natural gas by drawing in low pressure natural gas and discharging significantly higher pressure natural gas.

Condensate means hydrocarbon and other liquid separated from natural gas that condenses due to changes in the temperature, pressure, or both, and remains liquid at storage conditions, includes both water and hydrocarbon liquids.

Dehydrator means a device in which a liquid absorbent (including but not limited to desiccant, ethylene glycol, diethylene glycol, or triethylene glycol) directly contacts a natural gas stream to absorb water vapor.

Dehydrator vent stack emissions means natural gas released from a natural gas dehydrator system absorbent (typically glycol) reboiler or regenerator, including stripping natural gas and motive natural gas used in absorbent circulation pumps. De-methanizer means the natural gas processing unit that separates methane rich residue gas from the heavier hydrocarbons (e.g., ethane, propane, butane, pentane-plus) in feed natural gas stream).

Desiccant means a material used in solid-bed dehydrators to remove water from raw natural gas by adsorption. Desiccants include activated alumina, palletized calcium chloride, lithium chloride and granular silica gel material. Wet natural gas is passed through a bed of the granular or pelletized solid adsorbent in these dehydrators. As the wet gas contacts the surface of the particles of desiccant material, water is adsorbed on the surface of these desiccant particles. Passing through the entire desiccant bed, almost all of the water is adsorbed onto the desiccant material, leaving the dry gas to exit the contactor.

E&P Tank means the most current version of an exploration and production field tank emissions equilibrium program that estimates flashing, working and standing losses of hydrocarbons, including methane, from produced crude oil and gas condensate. Equal or successors to E&P Tank Version 2.0 for Windows Software. Copyright (C) 1996-1999 by The American Petroleum Institute and The Gas Research Institute.

Engineering estimation, for the purposes of WCI.350 and WCI.360, means an estimate of emissions based on engineering principles applied to measured and/or approximated physical parameters such as dimensions of containment, actual pressures, actual temperatures, and compositions.

Enhanced Oil Recovery (EOR) means the use of certain methods such as water flooding or gas injection into existing wells to increase the recovery of crude oil from a reservoir. In the context of this rule, EOR applies to injection of critical phase carbon dioxide into a crude oil reservoir to enhance the recovery of oil.

Field means the surface area underlaid or appearing to be underlaid by one or more pools, and the subsurface regions vertically beneath that surface area;

Flare combustion means unburned hydrocarbons including CH4, CO2, N2O emissions resulting from the incomplete combustion of gas in flares.

Flare combustion efficiency means the fraction of natural gas, on a volume or mole basis, that is combusted at the flare burner tip.

Fugitive emissions means the same as defined in the relevant greenhouse gas reporting regulation

Fugitive emissions detection means the process of identifying emissions from equipment, components, and other point sources.

Gas conditions mean the actual temperature, volume, and pressure of a gas sample.

Gas gathering/booster stations mean centralized stations where produced natural gas from individual wells is co-mingled, compressed for transport to processing plants, transmission and distribution systems, and other gathering/booster stations which co-mingle gas from multiple production gathering/booster stations. Such stations may include gas dehydration, gravity separation of liquids (both hydrocarbon and water), pipeline pig launchers and receivers, and gas powered pneumatic devices.

Gas to oil ratio (GOR) means the ratio of the volume of gas at standard temperature and pressure that is produced from a volume of oil when depressurized to standard temperature and pressure.

High-Bleed Pneumatic Devices are automated flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream which is regulated by the process condition flows to a valve actuator controller where it vents (bleeds) to the atmosphere at a rate in excess of six standard cubic feet per hour.

Liquefied natural gas (LNG) means natural gas (primarily methane) that has been liquefied by reducing its temperature to -260 degrees Fahrenheit at atmospheric pressure.

LNG boiloff gas means natural gas in the gaseous phase that vents from LNG storage tanks due to ambient heat leakage through the tank insulation and heat energy dissipated in the LNG by internal pumps.

Low-Bleed Pneumatic Devices mean automated flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream which is regulated by the process condition flows to a valve actuator controller where it vents (bleeds) to the atmosphere at a rate equal to or less than six standard cubic feet per hour.

Natural gas driven pneumatic pump means a pump that uses pressurized natural gas to move a piston or diaphragm, which pumps liquids on the opposite side of the piston or diaphragm.

Offshore means seaward of the terrestrial borders of the Canada, including waters subject to the ebb and flow of the tide, as well as adjacent bays, lakes or other normally standing waters, and extending to the outer boundaries of the jurisdiction and control of Canada.

Operating pressure means the containment pressure that characterizes the normal state of gas or liquid inside a particular process, pipeline, vessel or tank.

Portable means the same as defined in WCI.27 and WCI.361(a)(2)

Pump means a device used to raise pressure, drive, or increase flow of liquid streams in closed or open conduits.

Pump seals means any seal on a pump drive shaft used to keep methane and/or carbon dioxide containing light liquids from escaping the inside of a pump case to the atmosphere.

Pump seal emissions means hydrocarbon gas released from the seal face between the pump internal chamber and the atmosphere.

Reciprocating compressor means a piece of equipment that increases the pressure of a process natural gas by positive displacement, employing linear movement of a shaft driving a piston in a cylinder.

Reciprocating compressor rod packing means a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that escapes to the atmosphere.

Re-condenser means heat exchangers that cool compressed boil-off gas to a temperature that will condense natural gas to a liquid.

Reservoir means a porous and permeable underground natural formation containing significant quantities of hydrocarbon liquids and/o r gases. A reservoir is characterized by a single natural pressure system.

Sales oil means produced crude oil or condensate measured at the production lease automatic custody transfer (LACT) meter or custody transfer meter tank gauge.

Sour natural gas means natural gas that contains significant concentrations of hydrogen sulfide and/or carbon dioxide that exceed the concentrations specified for commercially saleable natural gas delivered from transmission and distribution pipelines.

Sweet Gas is natural gas with low concentrations of hydrogen sulfide (H_2S) and/or carbon dioxide (CO_2) that does not require (or has already had) acid gas treatment to meet pipeline corrosion-prevention specifications for transmission and distribution.

Transmission pipeline means high pressure cross country pipeline transporting sellable quality natural gas from production or natural gas processing to natural gas distribution pressure let-down, metering, regulating stations where the natural gas is typically odorized before delivery to customers.

Turbine meter means a flow meter in which a gas or liquid flow rate through the calibrated tube spins a turbine from which the spin rate is detected and calibrated to measure the fluid flow rate.

Vapor recovery system means any equipment located at the source of potential gas emissions to the atmosphere or to a flare, that is composed of piping, connections, and, if necessary, flow-inducing devices, and that is used for routing the gas back into the process as a product and/or fuel.

Vaporization unit means a process unit that performs controlled heat input to vaporize LNG to supply transmission and distribution pipelines or consumers with natural gas.

Vented emissions means means the same as defined in the relevant greenhouse gas reporting regulation, including but not limited to process designed flow to the atmosphere through seals or vent pipes, equipment blowdown for maintenance, and direct venting of gas used to power equipment (such as pneumatic devices).

Well completions means a process that allows for the flow of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and test the reservoir flow characteristics. This process includes high-rate back-flow of injected water and sand used to fracture and prop-open fractures in low permeability gas reservoirs.

Well workover means the performance of one or more of a variety of remedial operations on producing oil and gas wells to try to increase production. This process also includes high-rate back-flow of injected water and sand used to re-fracture and prop-open new fractures in existing low permeability gas reservoirs.

Wellhead means the piping, casing, tubing and connected valves protruding above the Earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve.

Wet natural gas means natural gas in which water vapor exceeds the concentration specified for commercially saleable natural gas delivered from transmission and distribution pipelines. This input stream to a natural gas dehydrator is referred to as "wet gas".

Directions on the use of Tables 360-1 to 360-2

(1) Starting with [2012] calendar year emissions, for each component listed in the Tables 360-1 to 360-2:

(i) If facility specific emission factors for a component type are available they must be used.

(ii) If facility specific emissions factors for a component type are not available, an operator must use company specific emission factors.

(iii) If a specific component type cannot be safely or reasonably accessed to develop valid facility or company-specific emission factors, estimates in the default tables 360-1 to 360-2 may be used. Similarly, equipment or facilities that have low utilization (e.g. some booster stations) may continue to use the default tables.

(iv) If a facility-specific emission factor has been used in a previous reporting year, it must continue to be used until updated. If a company-specific emission factor has been used in a previous reporting year, it must continue to be used until updated or a facility-specific emission factor is used in its place.

(v) Any changes from facility-specific factors to company-specific or the defaults in Tables 360-1 to 360-2, or from company specific factors to the defaults in Tables 360-1 to 360-2 must be approved by the jurisdiction and substantiated by evidence that the new approach is more accurate for the facility or facilities in question.

(vi) Documentation on the method used to update the emission factors, input data, sampling methodology and other relevant information must be kept by the operator and provided to the jurisdiction or verifier upon request.

(2) For 2011 calendar year emissions:

(i) An operator may use the default factors specified below, company or facility-specific emissions factors (if such emission factors are available). If the default factors in Tables 360-1 to 360-2 are used, an explanation as to why company or facility specific emission factors are cannot be used must be provided to the jurisdiction.

(3) All emission factors must be developed using Canadian Association of Petroleum Producer of Canadian Gas Association standard methods, or other methods if Canadian Association of Petroleum Producer or Canadian Gas Association methods are not available. Facility and company-specific emission factors must be updated at a minimum on a three year cycle, with the first update to the original facility and company-specific emission factors for the 2015 reporting period, at the latest.

(4) All emission factors must be developed using Canadian Association of Petroleum Producer of Canadian Gas Association standard methods, or other methods if Canadian Association of Petroleum Producer or Canadian Gas Association methods are not

available. Facility and company-specific emission factors must be updated at a minimum on a three year cycle, with the first update to the original facility and company-specific emission factors for the 2015 reporting period, at the latest.

(5) Updated emission factors can only be incorporated for reporting purposes at the start of a reporting period and not during a calendar year.

(6) The default emission factors provided in Tables 360-1 to 360-2 below are published emission factors for Canada as of the 2010 calendar year. The factors will be updated every 3-5 years based on new data, methods and statistically valid samples of the entire industry and developed in collaboration with industry groups.

Important note on Tables 360-1 and 360-2

Specific stakeholder comment is sought on two alternatives being considered for the provision of default emission factors for use in WCI.363(b),(n) and (o). The first approach would use existing equations 360-4, 360-19 and 360-20 in combination with the structure provided in Tables 360-1 and 360-2, below (as converted to metric units) and data processed from Tables 6-21 and 6-22 (below) from API Compendium of GHG Emission Methodologies for the Oil and Gas Industry, August 2009 (http://www.api.org/ehs/climate/new/upload/2009_GHG_COMPENDIUM.pdf).

The second approach would use the data in Tables 6-21 and 6-22, but instead keep the data in the published version, obviating the need to first convert the total hydrocarbon content factors to a volume of methane basis. As the emission factors are updated by CAPP or the API from time to time, the intention would be to update the emission factors here as well. The second approach would necessitate modifying Equations 360-4,-19 and -20 per the following example:

*Es,i,j =sum(Count * EF * Xj) * t /1000*

Where:
Es,i = Annual emissions at standard conditions for each source
Count = number of components of type i
EF = population emission factor for component type i [kg/source/h]
X = mass fraction of CH4 in stream j
t = hours per year [hours]

TABLE 360-1 –DEFAULT WHOLE GAS EMISSION FACTORS FOR ONSHORE PRODUCTION

Onshore production	Emission Factor (scf/hour/component)
Population Emission Factors - All Components, Gas Service	
Valve	0.08
Connector	0.01
Open-ended Line	0.04
Pressure Relief Valve	0.17
Low-Bleed Pneumatic Device Vents	2.75
Gathering Pipelines[1]	2.81
CBM Well Water Production[2]	0.11
Population Emission Factors - All Components, Light Crude Service[3]	
Valve	0.04
Connector	0.01
Open-ended Line	0.04
Pump	0.01
Other[5]	0.24
Population Emission Factors - All Components, Heavy Crude Service[4]	
Valve	0.001
Flange	0.001
Connector (other)	0.0004
Open-ended Line	0.01
Other[5]	0.003

[1] Emission Factor is in units of "scf/hour/mile"

[2] Emission Factor is in units of "scf methane/gallon", in this case the operating factor is "gallons/year" and do not multiply by methane content

[3] Hydrocarbon liquids greater than or equal to 20˚API are considered "light crude"

[4] Hydrocarbon liquids less than 20˚API are considered "heavy crude"

[5] ”Others” category includes instruments, loading arms, pressure relief valves, stuffing boxes, compressor seals, dump lever arms, and vents.

TABLE 360-2 –DEFAULT TOTAL HYDROCARBON EMISSION FACTORS FOR PROCESSING

Processing	Before De-methanizer Emission Factor (scf/hour/component)	After De-methanizer Emission Factor (scf/hour/component)
Leaker Emission Factors - Reciprocating Compressor Components, Gas Service		
Valve	15.88	18.09
Connector	4.31	9.10
Open-ended Line	17.90	10.29
Pressure Relief Valve	2.01	30.46
Meter	0.02	48.29
Leaker Emission Factors - Centrifugal Compressor Components, Gas Service		
Valve	0.67	2.51
Connector	2.33	3.14
Open-ended Line	17.90	16.17
Dry Seal	105	105
Leaker Emission Factors - Other Components, Gas Service		
Valve		6.42
Connector		5.71
Open-ended Line		11.27
Pressure Relief Valve		2.01
Meter		2.93
Population Emission Factors - Other Components, Gas Service		
Gathering Pipelines[1]		2.81

[1] Emission Factor is in units of "scf/hour/mile"

TABLE 360-3 –DEFAULT NITROUS OXIDE EMISSION FACTORS FOR GAS FLARING

Gas Flaring	Emission Factor (metric tons/MMscf gas production or receipts)
Population Emission Factors - Gas Flaring	
Gas Production	5.90E-07
Sweet Gas Processing	7.10E-07
Sour Gas Processing	1.50E-06
Conventional Oil Production[1]	1.00E-04
Heavy Oil Production[2]	7.30E-05

[1] Emission Factor is in units of "metric tons/barrel conventional oil production"

[2] Emission Factor is in units of "metric tons/barrel heavy oil production"

Table 6-21. Additional Natural Gas Facility Average Emission Factors

Component – Service	Emission Factor [a], kg THC/comp/hr	Emission Factor, tonnes THC/component-hr	Uncertainty [b] (± %)
Valves - fuel gas	2.81E-03	2.81E-06	±17
Valves - light liquid	3.52E-03	3.52E-06	±19
Valves - gas/vapor - all	2.46E-03	2.46E-06	±15
Valves - gas/vapor - sour	1.16E-03	1.16E-06	±31
Valves - gas/vapor - sweet	2.81E-03	2.81E-06	±17
Connectors - fuel gas	8.18E-04	8.18E-07	±32
Connectors - light liquid	5.51E-04	5.51E-07	+111/-90
Connectors - gas/vapor - all	7.06E-04	7.06E-07	±31
Connectors - gas/vapor - sour	1.36E-04	1.36E-07	±72
Connectors - gas/vapor - sweet	8.18E-04	8.18E-07	±32
Control valves - fuel gas	1.62E-02	1.62E-05	±27
Control valves - light liquid	1.77E-02	1.77E-05	±45
Control valves - gas/vapor - all	1.46E-02	1.46E-05	±23
Control valves - gas/vapor - sour	9.64E-03	9.64E-06	±4
Control valves - gas/vapor - sweet	1.62E-02	1.62E-05	±27
Pressure relief valves - fuel gas and gas/vapor	1.70E-02	1.70E-05	±98
Pressure relief valves - light liquid	5.39E-03	5.39E-06	±80
Pressure regulators - fuel gas and gas/vapor	8.11E-03	8.11E-06	+238/-72
Pressure regulators - gas/vapor - sour	4.72E-05	4.72E-08	+126/-74
Pressure regulators - gas/vapor - sweet	8.39E-03	8.39E-06	+239/-72
Open ended lines - fuel gas	4.67E-01	4.67E-04	+172/-58
Open ended lines - light liquid	1.83E-02	1.83E-05	+127/-79
Open ended lines - gas/vapor - all	4.27E-01	4.27E-04	+161/-62
Open ended lines - gas/vapor - sour	1.89E-01	1.89E-04	+127/-79
Open ended lines - gas/vapor - sweet	4.67E-01	4.67E-04	+172/-58
Chemical injection pumps - fuel gas and gas/vapor	1.62E-01	1.62E-04	±60
Compressor seals - fuel gas and gas/vapor	7.13E-01	7.13E-04	±36
Compressor starts - fuel gas	6.34E-03	6.34E-06	±25
Controllers - fuel gas and gas/vapor	2.38E-01	2.38E-04	±27
Pump seals - light liquid	2.32E-02	2.32E-05	+136/-74

Footnotes and Sources:
[a] Clearstone Engineering Ltd.. *A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry*, Volume 5, September 2004.
[b] Uncertainty based on 95% confidence interval from the data used to develop the original emission factor.

Table 6-22. Additional Oil Facility Average Emission Factors

Component – Service	Emission Factor [a], kg THC/comp/hr	Emission Factor, tonnes THC/component-hr	Uncertainty [b] (± %)
Valves - fuel gas and gas/vapor	1.51E-03	1.51E-06	±79
Valves - heavy liquid	8.40E-06	8.40E-09	±19
Valves - light liquid	1.21E-03	1.21E-06	±19
Connectors - fuel gas and gas/vapor	2.46E-03	2.46E-06	±15
Connectors - heavy liquid	7.50E-06	7.50E-09	+111/-90
Connectors - light liquid	1.90E-04	1.90E-07	+111/-90
Control valves - fuel gas and gas/vapor	1.46E-02	1.46E-05	±21
Control valves - light liquid	1.75E-02	1.75E-05	±44
Pressure relief valves - fuel gas and gas/vapor	1.63E-02	1.63E-05	±80
Pressure relief valves - heavy liquid	3.20E-05	3.20E-08	±80
Pressure relief valves - light liquid	7.50E-02	7.50E-05	±80
Pressure regulators - fuel gas and gas/vapor	6.68E-03	6.68E-06	+238/-72
Open ended lines - fuel gas and gas/vapor	3.08E-01	3.08E-04	+129/-78
Open ended lines - light liquid	3.73E-03	3.73E-06	+127/-79
Chemical injection pumps - fuel gas and gas/vapor	1.62E-01	1.62E-04	±60
Compressor seals - fuel gas and gas/vapor	8.05E-01	8.05E-04	±36
Compressor starts - fuel gas	6.34E-03	6.34E-06	±25
Controllers - fuel gas and gas/vapor	2.38E-01	2.38E-04	±27
Pump seals - heavy liquid	3.20E-05	3.20E-08	+136/-74
Pump seals - light liquid	2.32E-02	2.32E-05	+136/-74

Footnotes and Sources:

[a] Clearstone Engineering Ltd.. *A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry,* Volume 5, September 2004.

[b] Uncertainty based on 95% confidence interval from the data used to develop the original emission factor.

TABLE 360-3 –DEFAULT EMISSION FACTORS FOR SPECIFIC FIELDS [IN DEVELOPMENT]

Western Climate Initiative

Second Harmonization Package

Proposed Harmonization of Essential Requirements for Mandatory Reporting (ERs) in Canadian Jurisdictions with the WCI ERs and the U.S. EPA GHG Reporting Program

Stakeholder Conference Call

November 8, 2010

Background

- Final WCI Essential Requirements – July 2009
- Final U.S. EPA Mandatory Reporting Rule ("EPA Rule") – September 2009
- U.S. facilities emitting >25,000 tonne CO_{2e} are subject to both programs (WCI has a 10,000 tonne threshold)
- Proposed harmonized ERs for U.S. jurisdictions – May 2010
  - Format is the same as EPA Rule
  - Final harmonized ERs expected Fall 2010

Proposed Harmonized ERs for Canadian Jurisdictions

- First Harmonization Package released September 8, 2010
- Maintain consistency across all WCI jurisdictions
- Follow same format as original WCI ERs
- Stakeholder comments and EPA modifications are currently being reviewed

- Second Harmonization Package released October 29, 2010

Canadian Harmonization Principles

- Same level of reporting accuracy as U.S. facilities
- Quantification methods sufficient for GHG reporting under cap-and-trade program
- Suitable for use in Canada
  - Metric units
  - Canadian emission factors
- Facilitate harmonization with Environment Canada CEPA Section 46 (or future regulatory) reporting

Canadian Harmonization Approach

- Revise existing WCI ERs to conform with harmonized ERs for U.S. jurisdictions
  - Made content in WCI ERs "methodologically consistent" with ERs for U.S. jurisdictions
    - Harmonized ERs for US jurisdictions follow markup of EPA Rule
    - Harmonized ERs for Canadian jurisdictions keep WCI ER format
- Assure harmonization with Environment Canada's reporting programs
- Require fewer data elements to be reported in Canadian jurisdictions due to 3rd party verification
- Add missing data procedures following EPA Rule
- Identify sources subject to "reporting only"

Sources Subject to Reporting Only

- Under review for sources within the second harmonization package

On-Going Canadian Harmonization

- Second Harmonization Package includes:
  - Electronics Manufacturing (WCI. 110)
  - Underground Coal Mines (WCI.250)
  - Magnesium Production (WCI.290)
  - Natural Gas Transmission and Distribution (WCI.350)
  - Petroleum and Natural Gas Production and Gas Processing (WCI.360)
- First Harmonization Package stakeholder comments are currently being reviewed
- Other recently released EPA methods will be reviewed by WCI Reporting Committee (e.g. Carbon Dioxide Injection and Geologic Sequestration)

Western Climate Initiative

Questions?

Significant Changes to WCI ERs for Canadian Jurisdictions

- New sources for the WCI
- Methods are based on proposed or final EPA Subparts and Canada-specific circumstances
- Next few slides summarize the most significant items for each method
- All methods
  - incorporate missing data procedures
  - reduce amount of data to be reported (from EPA) due to third party verification

Significant Changes – General Stationary Combustion (WCI.20)

- Consequential changes to incorporate sampling, analysis and measurement for Petroleum and Natural Gas Systems, and Natural Gas Transmission and Distribution
  - *Measurement and Metering Act of Canada* for T&D
  - Existing legislation and regulation for upstream sources (e.g. *Petroleum and Natural Gas Act of B.C.*)
  - Use of known field gas composition in place of specific sampling and measurement
  - Inventory adjustment not required for propane and diesel for smaller upstream sources.

Electronics Manufacturing, Underground Coal Mines and Magnesium Production

- Electronics Manufacturing (WCI.110) based on final EPA Subpart I
- Underground Coal Mines (WCI.250) based on final EPA Subpart FF
  - Reduced disaggregation of data reporting
  - Allowed for use of Canadian standards
- Magnesium Production (WCI.290) based on final EPA Subpart T

Significant Items – Natural Gas Transmission and Distribution (WCI.350)

- Based on **proposed** EPA Subpart W, WCI submission to the EPA and Canada-specific circumstances
- Definitions modified for use in Canada
- Incorporated Canadian Gas Association emission factors. Phase in of company/facility-specific emission factors.
- Expanded equipment for leak detection and incorporates progressive sampling

Significant Items – Petroleum and Natural Gas Systems (WCI.360)

- Based on **proposed** EPA Subpart W, WCI submission to the EPA and Canada-specific circumstances
- Definitions modified for use in Canada
- Incorporates method for field gas combustion
- Merged conventional and unconventional completions/workovers
- Deferred methods for offshore oil and gas
- Bracketed text on metering of high bleed pneumatics/pumps
- Expanded leak detection equipment, incorporates progressive sampling
- Suggested CAPP/API emission factors. Phase in of company/facility-specific emission factors.

Next Steps

Who?	What?	When? (2010)
Stakeholders	Submit comments on proposed Canadian harmonization package #2	Nov. 24
WCI	Finalize Canadian harmonization package #1	late Nov.
WCI	Finalize Canadian harmonization package #2	Early Dec.

Links and Contacts

- Proposed harmonized ERs in Canadian jurisdictions

  http://www.westernclimateinitiative.org/news-and-updates/124-second-harmonization-package-for-reporting-requirements-for-canadian-jurisdictions-posted-for-stakeholder-comment

- Submit comments

  http://www.westernclimateinitiative.org/public-comments/document/34

- Contact
  - Dennis Paradine, dennis.paradine@gov.bc.ca or Eric Loi, eric.loi@ontario.ca

October 29, 2010 Second Harmonization Package – Harmonization of Reporting in Canadian Jurisdictions with the WCI and EPA

List of Commenters

Canadian Association of Petroleum Producers

Canadian Energy Pipeline Association

Canadian Gas Association

Encana Corporation

Husky Energy

Ludvigsen, Phillip

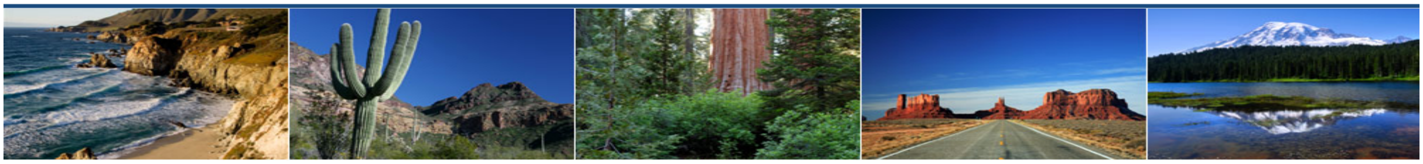
Ontario Forest Industries Association

Shell Canada

Spectra Energy

Terasen Gas

Western Climate Initiative



Harmonization of Essential Requirements for Mandatory Reporting in U.S. Jurisdictions with EPA Mandatory Reporting Rule

November 12, 2010

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1 Introduction

On July 16, 2009, The WCI published the Final Essential Requirements for Mandatory Reporting (the “ERs”) to be implemented by the WCI Partner jurisdictions. On September 22, 2009, U.S. EPA adopted its final Mandatory Reporting Rule (the “EPA rule”) for greenhouse gas emissions. Many U.S. facilities in the WCI region will be subject to both reporting programs. Specifically, most facilities with emissions of CO_2e greater than or equal to 25,000 metric tons per year in WCI states will be subject to both programs.

The WCI Partners were concerned that the existence of two different reporting systems in a WCI state could result in the imposition of duplicative or conflicting reporting obligations on facilities subject to both programs. Unless steps were taken to reconcile the WCI ERs with the EPA rule, a facility in a WCI state and with CO_2e emissions of 25,000 metric tons per year or greater could be required to prepare and submit two reports containing different data values in different formats to two jurisdictions.

In order to avoid the imposition of this burden on reporting facilities, the Partners directed the WCI Reporting Committee to develop amended ERs that are harmonized with the EPA rule.

Both the EPA rule and the WCI ERs require the filing of initial reports for the 2010 reporting year by Spring 2011 (March 31, 2011, and April 1, 2011, respectively). The goal of the Reporting Committee is to issue amended ERs in time for implementation in the 2011 reporting year. The adoption and implementation of interim measures to harmonize existing reporting requirements with the EPA rule has been left to the discretion of individual WCI jurisdictions.

This document and its Appendices explain the WCI’s approach to harmonizing the ERs and the EPA rule in U.S. jurisdictions (the “harmonized ERs”). As explained below, the WCI also has proposed amended ERs that are methodologically consistent with the harmonized ERs but appropriate for use in the Canadian Partner jurisdictions.

On May 28, 2010, the WCI made this document available for stakeholder review and comment. The stakeholder comment period closed on June 28, 2010. A summary of the comments received and WCI’s response is set forth in section 5 below. Changes made to the harmonized ERs other than as a result of stakeholder comments are summarized in section 6 below.

2 Harmonization Principles

2.1 For U.S. Jurisdictions

In developing harmonized ERs for use in U.S. jurisdictions, the WCI Reporting Committee adhered to the following principles:

1. A U.S. facility should be able to comply with both the MRR and a WCI jurisdiction's reporting requirements by following a single set of monitoring, recordkeeping and reporting requirements.

2. The quantification methods included in the harmonized ERs must be sufficiently reliable and accurate to be employed in a greenhouse gas (GHG) cap-and-trade program.

The most straightforward way to follow the first principle would be to adopt the EPA rule without change. Unfortunately, it is not possible to do so and also adhere to the second principle. As EPA has acknowledged, the EPA rule, unlike the WCI ERs, has not been specifically designed to meet the needs of a cap-and-trade program:

> A key difference between the Federal mandatory GHG reporting rule and the RGGI and WCI programs is that the Federal mandatory GHG rule is solely a reporting requirement. It does not in any way regulate GHG emissions or require any emissions reductions.

74 Fed. Reg. 16448, 16460 (2009); see also 74 Fed. Reg. 56260, 56369 (2009) (EPA rule designed to gather data needed to "inform future climate change policies").

Fortunately, in nearly all cases where the Reporting Committee determined that a modification to the EPA rule was necessary for implementation of a cap-and-trade program or to achieve other WCI objectives, the modification could be implemented without requiring any alteration to the EPA program. For example, Subpart C of EPA's general stationary combustion rule establishes essentially the same four-tiered approach as section WCI.20 of the ERs. In some cases, WCI.20 requires the use of a higher tier than the EPA rule. Because the EPA rule generally *allows* the use of higher tier for any facility, however, a facility may use the methodology required by WCI.20 and still submit a report conforming to the EPA rule.

In a few cases, the Reporting Committee identified additional data elements that the EPA rule does not require but that WCI jurisdictions will need for cap-and-trade or other purposes.[1] In order to avoid imposing a requirement to file a supplemental report addressing these data elements, the Reporting Committee has been working with EPA and the National Data Exchange to secure changes to the EPA GHG reporting schema that will allow submission of reports containing these data elements directly to EPA. In addition, EPA has indicated that it may be possible to make adjustments to the online reporting tool it is developing for the federal GHG reporting program to accommodate state and regional reporting requirements.

[1] For example, gathering data related to cogeneration.

WCI intends to follow the same principles with regard to future additions or amendments to the EPA rule, such as the recently re-proposed Subpart W for the oil and gas industry, and the recently proposed revisions to Subpart A and several source category subparts (prepublication version posted on EPA web site July 20, 2010). WCI will review each proposed revision to assess its suitability for cap-and-trade before incorporating it into the harmonized ERs.

2.2 For Canadian Jurisdictions

In developing harmonized ERs for use in Canadian jurisdictions that modify the existing ERs, the WCI Reporting Committee is adhering to the following principles:

1. A Canadian facility should apply the same functions, equations, sampling protocols and measurement criteria as U.S. facilities subject to the U.S. version of the harmonized ERs. This means that the harmonized ERs will achieve the same level of reporting accuracy for Canadian and U.S. facilities, but the U.S. version may require more data elements to be reported to harmonize with the EPA rule.

2. The quantification methods included in the harmonized ERs must remain sufficiently reliable and accurate to be employed in a greenhouse gas (GHG) cap-and-trade program.

3. The WCI reporting system must remain suitable for use in Canadian jurisdictions. For example, it must allow reporting in metric as well as English units and must where necessary include Canada-specific emission factors.

4. The harmonized ERs should facilitate harmonization with Canadian federal reporting. Some Canadian jurisdictions are working with Environment Canada to develop a one-window reporting tool for provincial and national GHG reporting requirements.

3 Harmonization Approach

3.1 For U.S. Jurisdictions

The WCI proposes to achieve harmonization in U.S. jurisdictions by adopting incorporation-by-reference rules that modify the EPA rule in a manner consistent with the harmonization principles set forth in section 2.1. The new WCI ERs for U.S. jurisdictions, which are attached to this document as appendices, therefore take the form of a markup of the EPA rule. The partners anticipate that each U.S. Partner will adopt an incorporation-by-reference rule consistent with this markup.

The WCI chose this approach for U.S. jurisdictions, rather than attempting to amend the existing WCI ERs to achieve harmonization, for the following reasons:

- Although the WCI ERs and EPA rule for the most part follow similar approaches to GHG quantification, they vary widely in organization and formatting and in the details of the monitoring, recordkeeping and reporting requirements imposed. It would therefore be extraordinarily difficult to amend the ERs to conform to the EPA rule without inadvertently introducing inconsistencies between the two programs. Any inconsistency would subject U.S. facilities to the risk of noncompliance with one program or the other.

- An incorporation-by-reference rule will make it much easier for a facility subject to both WCI and EPA requirements to assure itself that it is complying with both programs.

3.2 For Canadian Jurisdictions

For the Canadian jurisdictions, the key requirement is that the WCI reporting system as a whole require the use of comparable methodologies and produce comparable results for facilities of the same type, so that a “ton is a ton” in both the U.S. and Canada. For Canadian jurisdictions it is not nearly as important to avoid small differences between the ERs and the EPA rule as it is for the U.S. jurisdictions, where differences create a risk of inadvertent non-compliance.

Canadian Partners have invested substantial resources in developing regulations to implement the existing WCI ERs. In addition, the provinces face technical and legal issues with the incorporation by reference of the EPA rule that do not apply to the states. The WCI therefore has proposed amendments to the existing WCI ERs to assure that they conform in substance with the U.S. version of the harmonized ERs as well as the interest provinces have in harmonizing their reporting programs with Environment Canada’s.

3.3 Verification

Consistent with the Design Recommendations for the WCI Regional Cap-and-Trade Program, the harmonized ERs will continue to require third party verification of emission reports by entities and facilities included in the cap. A version of the verification rule, WCI.8, revised to cross reference the U.S. version of the harmonized ERs is included as an appendix.

Because the EPA rule does not require third-party verification, it generally requires reporting of substantially more data than the existing WCI ERs. In the absence of third-party verification, EPA must require the submission of sufficient data to enable the agency to implement its own audit program. In order to assure consistency with the first harmonization principle—allowing compliance with both programs through preparation of a single report—the WCI markup of the EPA rule does not attempt to reduce the amount of data required in a report for U.S. jurisdictions.

The amount of data to be reported for Canadian jurisdictions will be modified to reflect that third party verification is required for emissions reports at a certain threshold of emissions, so less data is required to be reported to the Canadian jurisdictions as compared to that which is required to be reported to the EPA for their internal verification.

3.4 Missing Data Procedures

The EPA rule includes procedures in each subpart for replacing missing data resulting from monitoring failures. With the exception of methodologies for facilities subject to 40 C.F.R. Part 75 (the acid rain program), these missing data procedures do not appear to be sufficiently rigorous to support a cap-and-trade system. There is no limitation on the amount of data that may be missing, and replacement methods appear to be both inadequate (for example, many use only one or two available data points) and inequitable (for example, Part 75 power plants have to apply punitive methods, while other facilities do not).

In order to move forward with a harmonization proposal in time to allow implementation for the 2011 reporting year, the proposed harmonized ERs retain the EPA missing data procedures. Before implementation of the cap-and-trade program, however, the WCI intends to revisit this issue. The WCI is investigating how the EPA missing data procedures can be modified to be more consistent with the needs of a cap-and-trade program while adhering to the harmonization principles in section 2.1 and intends to propose and implement the necessary modifications in time for the 2012 reporting year.

As a partial measure to address the possibility of gaming, the harmonized ERs include a provision making it clear that the use of a missing data procedure does not excuse a facility's failure to follow the monitoring requirements of the rule.

4 Summary of Changes to EPA Rule

The following table summarizes the changes to the EPA rule that the WCI is proposing to implement in WCI jurisdictions. The specific language for the changes is set forth in the Appendices.

The table also identifies potential differences in approach that may be employed by the Canadian WCI jurisdictions.

§	Change to EPA Rule	Rationale
Subpart A—General Provisions		
98.1	Added new (c) substituting jurisdiction for EPA and EPA administrator throughout rule.	Clarifies who is responsible for administering the incorporated-by-reference version of the EPA rule. Since the EPA rule does not provide for delegation, EPA will remain responsible for administering the original 40 C.F.R. Part 98 requirements.
98.1 and passim[2]	Added new (d) providing for identification of data that will be reported for informational purposes only, will not be subject to cap and trade and will not be counted towards the threshold for verification. Added "reporting only" label to certain EPA subparts and specific quantification methods.	Not all quantification methods specified by the harmonized ERs are suitable for a cap-and-trade system. The "reporting only" label provides notice to stakeholders on WCI's current view on which emissions should not be subject to the cap-and-trade program.
98.1	Added new (e) to authorize a WCI jurisdiction to allow submission of a report to EPA to meet the requirements of the harmonized ERs.	As discussed above, WCI is working with EPA to allow reporting entities to use EPA's system to meet the requirements of both the EPA rule and the harmonized ERs.

[2] Occurring in various places.

§	Change to EPA Rule	Rationale
98.2 passim	Changed threshold for reporting from 25,000 metric tons to 10,000 metric tons.	Consistent with WCI design recommendation for reporting. EPA has indicated that it may be able to accommodate reports by facilities with emissions below the EPA rule threshold.
98.2(a)(3)(iii)	Changed heat input threshold for fuel combustion units from 30 mmBtu/hr to 12 mmBtu/hr.	The 30 mmBtu/hr threshold is designed to provide facilities whose only regulated GHG source is fuel combustion an easy method for determining whether they are above the 25,000 metric tons emission threshold. For WCI's 10,000 metric tons threshold, the equivalent heat input threshold is 12 mmBtu/hr.
98.2(b)(2)	Added exclusions from the applicability determination for certain emissions from the combustion of biomass.	Consistent with WCI Design Recommendations and existing WCI.1(b)(2).
98.2(i)	Modified to change threshold for off-ramp to 10,000, rather than 25,000, metric tons per year and to establish additional off-ramp for facilities required to report to WCI jurisdiction but not EPA (i.e. emissions between 10,000 and 25,000 metric tons per year) that subsequently fall below 10,000- metric-tons-per-year threshold.	Consistent with existing WCI.1(e)(2).

§	Change to EPA Rule	Rationale
98.3(g), 98.3(g)(5)(iv)	Added requirement to submit records within 20 days of a request from a WCI jurisdiction.	Failure of EPA rule to specify a time period for responding may make enforcement difficult. Modified from 10-day response time in existing WCI.4(b) in response to stakeholder comments.
98.3(h)	Added a new (2) requiring facilities subject to WCI but not EPA reporting requirements to submit correction only if cumulative errors exceed 5 % of total CO2e emissions.	Consistent with WCI.2(f). This change cannot be applied to facilities subject to the EPA rule, since EPA requires the correction of any errors.
98.3(i)(6)	Added requirement to obtain jurisdictional approval of monitoring plan provisions that allow postponement of measurement device calibrations.	See Section 5.2.2.
98.3	Added a method for calculating weighted averages as new (j).	In some cases, the harmonized ERs require more frequent sampling than the EPA rule. This subsection provides a method for reducing the data obtained from the additional samples to fit the EPA reporting system, and produces more accurate emissions estimates.
98.3	Added new (k) requiring a jurisdiction's approval before a facility may switch from a CEMS to a mass- or fuel-based monitoring method or vice versa.	This provision is designed to prevent facilities from using changes in monitoring methods to create an artificial reduction in GHG emissions.

§	Change to EPA Rule	Rationale
98.3	Added a modified version of the de minimis provision in WCI.2(d) as new (l). Instead of allowing the use of any alternative method approved by the verifier, as in the current ERs, the modified version requires the use of a method permitted by 40 C.F.R. Part 98 for the facility. So, for example, a facility subject to verification could use Tiers 1 or 2, rather than Tier 3, for up to 3 percent of its combustion emissions.	The EPA rule does not include a de minimis provision. Allowing U.S. facilities to employ methods that are not specified by the EPA rule therefore would be inconsistent with harmonization. In some cases, however, the harmonized ERs require the use of a higher tier than would otherwise be required by the EPA rule. In these cases, it is consistent with harmonization to allow the use of the lower tier for emissions determined to be de minimis.
98.3	Added new (m) to make it clear the missing data procedures included in the EPA rule (and therefore the harmonized ERs) do not excuse facilities from possible enforcement action for failure to conduct the monitoring required by the rule.	See section 3.4.
Subpart C—General Stationary Combustion		
98.32(b), 98.33(f)	Added requirement to report fugitive HFC emissions from cooling units.	Consistent with existing WCI.42(h) and WCI.42(d).
98.33(a)(2)(iii)	Limit availability of Equation C-2c (ratio of heat input to steam method) to municipal solid waste and solid biomass, rather than allowing its use for any other solid fuel listed in Table C-1.	Consistent with existing WCI.23(b)(2).

§	Change to EPA Rule	Rationale
98.33(a) (4)(iv)	Require CEMS installed after beginning of first reporting year subject to rule to include a CO2 monitor, rather than an oxygen monitor.	Although it may make sense not to require the retrofit of grandfathered CEMS with a CO2 monitor, there is no reason for newly installed CEMS not to include such a monitor. See also discussion in Section 5.3.2.
98.33(b) (1)	For any fuel with a variable HHV and carbon content, limit use of Tier 1 (default emission factors and HHV) to units that are both (1) below both EPA's 250 mmBtu/hr heat input threshold and (2) located at facilities that are not subject to verification (i.e., emissions < 25,000 metric tons/yr). Fuels with standard HHVs and carbon contents that may use Tier 1 in accordance with the EPA rule are listed in new Table C-1a.	See Section 5.3.1.
98.33(b)(1)(iii)	Allow the use of Tier 1 for a biomass fuel only when the fuel has been determined by the jurisdiction not to be subject to a compliance obligation.	Tier 1 is not sufficiently accurate for the combustion of fuels subject to a cap-and-trade program. EPA's approach of allowing Tier 1 for *all* biomass fuels is therefore not suitable for WCI jurisdictions.
98.33(b) (2)	Limit use of Tier 2 (default emission factors and measured HHV) to units that are both (1) below both EPA's 250 mmBtu/hr heat input threshold and (2) located at facilities that are not subject to verification (i.e., emissions < 25,000 metric tons/yr), except for facilities that burn pipeline quality natural gas or distillate fuel oil.	Consistent with existing WCI.23(e)(2).

§	Change to EPA Rule	Rationale
98.33(b)(3)	Require the use of Tier 3 (measured carbon content) for all units at a facility subject to verification (i.e. emissions > 25,000 metric tons/yr), except for certain listed fuels with standardized and uniform composition. Require Tier 3 for the combustion of *all* fuels that are not listed in Table C-1, not just for unlisted fuels that provide 10% or more of a unit's annual heat input.	Revised from existing WCI.23(e)(3) to allow Tier 1 or Tier 2 for certain fuels where uniformity of composition gives high accuracy for Tier 1. Exempting unlisted fuels that provide less than 10 % of a unit's heat input could result in a significant gap in a facility's reported emissions. Corrected markup to reflect this intent.
98.33(c)	Add new (6) to allow an operator use a source-specific emission factor to calculate CH4 and N2O emissions.	Consistent with existing WCI.24(d). Since this is optional, it does not conflict with harmonization principle 1.
98.33(e)(2)	Require the use of 98.33(e)(3) for the combustion of any fossil fuel/biomass mixture containing an undeterminable quantity of fossil fuels, not just MSW.	The method specified in 98.33(e)(2) assumes that the amount of fossil fuel in a fossil fuel/biomass mixture can be determined and that a mass balance approach is therefore possible. Its use therefore must be limited to fuels where the amount of fossil fuel in a mixture can in fact be determined. Other mixtures must as a practical matter be subject to 98.33(e)(3).
98.34(b)(3)(ii)(E)	Require installation of equipment necessary to perform daily sampling and analysis of carbon content and molecular weight for refinery fuel gas by beginning of first reporting year subject to harmonized ERs.	Consistent with existing WCI.34.

§	Change to EPA Rule	Rationale
98.36(b), (d)	Added provisions requiring reporting of nameplate capacity and net power generated for EGUs and cogeneration data, as well as certain fuel data if not reported under 40 C.F.R. Part 75.	Consistent with existing WCI.40.
98.36(e)(3), (e)(4)	Changed time to respond to requests for data needed for verification from 30 to 20 days.	Consistent with new requirement in 98.3(g). See above.
Subpart D—Electricity Generation		
98.46	Corrected cross-reference.	Clarification.
Subpart E—Adipic Acid Production		
No change.		
Subpart F—Aluminum Production		
98.64(a)	Changed to require re-measurement of smelter-specific slope coefficients every 36 months, rather than every 10 years. Inserted additional conditions that would trigger the obligation to re-measure the coefficients before the expiration of the 36-month period.	Consistent with WCI.74(b).
98.64(a), (d)	Changed to require the use of smelter-specific measurements rather than the default values specified in table F-1.	Consistent with WCI.74.
98.64(b)	Changed minimum measurement frequency from annually to monthly for all parameters.	Consistent with WCI.74(a).
Subpart G—Ammonia Production		
No change.		

§	Change to EPA Rule	Rationale
Subpart H—Cement Production		
No change to EPA rule for U.S. jurisdictions. Unlike the EPA rule, existing WCI.090 allows emissions to be calculated on a facility-wide basis. The harmonized ERs for U.S. jurisdictions will retain the EPA requirement to calculate emissions for each kiln in order to assure harmonization. Canadian jurisdictions, however, may continue to allow facility-based calculations.		
Subpart K—Feroalloy Production		
No change.		
Subpart N—Glass Production		
Passim	Changed to apply to batch as well as continuous processes.	Consistent with draft WCI method. This change may require facilities not subject to the EPA rule to report but should not result in a facility subject to both the WCI and EPA programs being subject to inconsistent reporting obligations.
Subpart O—HCFC-22 Production and HFC-23 Destruction		
No change.		
Subpart P—Hydrogen Production		
98.160(a)	Changed to apply subpart to production of hydrogen for use on site as well as hydrogen sold as a product.	Consistent with WCI.131. This change may require facilities not subject to the EPA rule to report but should not result in a facility subject to both the WCI and EPA programs being subject to inconsistent reporting obligations.
98.163(b), 98.164(b)(2)-(4)	Require daily, rather than monthly or weekly, analysis of carbon feedstocks other than natural gas. As an alternative, allow analysis of a composite of up to 30 weighted samples.	Consistent with WCI.134(b)(1). Higher frequency sampling is required to ensure accuracy adequate for a cap-and-trade program. See also Section 5.2.6.

<table>
<tr><th>§</th><th>Change to EPA Rule</th><th>Rationale</th></tr>
<tr><td>98.166(b)</td><td>Added (7) requiring reporting of carbon in unconverted feedstock for which GHG emissions are calculated and reported by the facility using other methods.</td><td>In order to avoid possible double counting of emissions, WCI.133, Equation 130-1 allows subtraction of carbon “accounted for elsewhere” from the amount of feedstock, before calculation of the mass balance. EPA’s equations P-1, P-2 and P-3 do not allow for such a deduction. The equations themselves cannot be modified in the harmonized ERs, because that would require reporting different emissions to EPA and a U.S. WCI jurisdiction. The harmonized ERs therefore provide for the reporting of carbon accounted for elsewhere in bulk, which can then be subtracted from a facility’s total emissions by the WCI data system.</td></tr>
<tr><td colspan="3">Subpart Q—Iron and Steel Production</td></tr>
<tr><td colspan="3">No change to EPA rule for U.S. jurisdictions.

The EPA rule requires the reporting of CO2 from the combustion of coke oven gases at the point of combustion under Subpart C. Existing WCI.153 requires the reporting of emissions attributable to coke oven gases and blast furnace gases at the point of generation using a mass balance method. U.S. jurisdictions will employ the EPA method in order to assure harmonization. Canadian jurisdictions may continue to employ existing WCI.153. It is anticipated that the methods will produce substantially similar results.

Jurisdictions also may choose not to allow the use of the site-specific emission factor method established by 98.173(b)(2) for process emissions.</td></tr>
<tr><td colspan="3">Subpart R—Lead Production</td></tr>
<tr><td colspan="3">No change.</td></tr>
<tr><td colspan="3">Subpart S—Lime Production</td></tr>
<tr><td colspan="3">No change.</td></tr>
</table>

§	Change to EPA Rule	Rationale
Subpart V—Nitric Acid Production		
No change.		
Subpart X—Petrochemical Production		
No change.		
Subpart Y—Petroleum Refineries		
98.253(b)(1)(iii) 98.256(e)(8)	Amended to allow use of alternative equation Y-3 for flare emissions only during periods of startup, shutdown or malfunction.	The more accurate methods specified in equations Y-1 and Y-2 should be used for periods of normal operations.
98.253(c)(2) 98.256(f)(9)	Require calculation of emissions from catalytic cracking units that do not use CEMS and have rated capacities less than 10,000 barrels per stream day using this method (no less than hourly monitoring of O2, CO2 and CO), rather than 98.173(c)(3), which is deleted.	The EPA TSD for this sector states that the method specified in 98.173(c)(3) for units that do not have the necessary monitors is highly uncertain.
98.253(h), (l), (m), (n)	Identified as reporting only.	WCI does not believe the methods specified in these sections are sufficiently accurate to support a cap-and-trade program.
98.253(i)	Rather than allowing the use of default factors in Equation Y-18 for CO2 emissions from delayed coking units, require (1) the volumetric void fraction of the coking vessel prior to steaming to be based on engineering calculations and (2) the mole fraction of methane in coking vessel gas to be based on two samples per year.	Greater accuracy required for cap-and-trade.

§	Change to EPA Rule	Rationale
98.253(k) 98.256(m)	Require the use the same method for process vents (paragraph (j)) and uncontrolled blowdown systems.	Consistent with WCI.200.
98.254	New (m) added to require installation of equipment needed for daily sampling of carbon content and molecular weight of gaseous fuels (other than natural gas and biogas) by no later than first reporting year of harmonized ERs.	Needed to ensure Tier 3 calculations of emissions from refinery gas are sufficiently accurate for cap-and-trade.
98.257(m)	New (b) added to require retention of records of the method used to demonstrate that the thresholds in §98.253(j) are not exceeded.	Needed for third-party verification.
Subpart Z—Phosphoric Acid Production		
No change.		
Subpart AA—Pulp and Paper		
98.273(a)(1), (b)(1), (c)(1)	Require use of applicable Subpart C methodology rather than specifying the use of Tier 1 for combustion at chemical recovery furnaces and pulp mill lime kilns.	Consistent with WCI.212(c). There does not appear to be any reason to treat combustion at these sources differently from combustion elsewhere. Note: Although Subpart C generally allows the use of higher tiers, even when a lower tier is specified for a particular unit or fuel, section 98.273 could be read as *requiring* the use of Tier 1. WCI is seeking clarification of the correct interpretation of section 98.273 in order to assure that the proposed changes are consistent with harmonization principle 1.

§	Change to EPA Rule	Rationale
Subpart CC—Soda Ash Manufacturing		
98.294(d), 98.296(a)(5), (b)(12)	Added requirement to determine CO2 recycled to carbonation tower.	Consistent with WCI.232(f).
Subpart GG—Zinc Production		
No change.		

5 Stakeholder Comments and Response

5.1 General Comments

Several commenters expressed concern or support for implementation of a cap-and-trade program in New Mexico, or addressed other concerns specific to New Mexico's current proposed rulemaking for cap and trade. These issues were not within the scope of the WCI harmonized Essential Requirements, but the comments have been transmitted to the New Mexico Environment Department for their consideration.

One commenter expressed general support for the principles of harmonization, for working with EPA to ensure that additional data elements can be submitted, for third-party verification, and for the emissions reporting threshold.

5.2 General Provisions

5.2.1 Time to Respond to Requests for Information [§98.3(g)]

Several commenters objected that the 10-day time period allowed for response to jurisdictional requests for information is not long enough to allow for retrieval and aggregation of the data. Commenter-recommended time periods ranged from 20 to 60 days. One commenter also recommended that the period start with receipt of the request in writing.

Each of the WCI Jurisdictions have data request procedures currently in-place which have been established to effectively deal with data access issues. The current WCI language in this section is, by necessity, generic to some extent, in order to allow WCI Jurisdictions the flexibility to utilize their existing data request procedures. Thus it is not advisable to be overly specific as to the form in which a formal data request is made. In regard to the time allowed for responding to a data request, we note that this data must be compiled and maintained by the reporter as part of the required GHG Monitoring Plan. We do not believe that 30 days would be needed to respond, but we agree to lengthen the response period to 20 calendar days after receipt of the request, to allow for staff absences and other potential difficulties in assembling the data.

For consistency, we have also modified the response period for requests for information in Subpart C [§98.36(e)(3) and §98.36(e)(4)] to 20 days.

5.2.2 Calibration Deadline [§98.3(i)(6)]

Several commenters objected to the requirement that initial calibrations be performed if there is any unplanned outage of sufficient duration to complete the calibration, noting a number of potential logistical difficulties including an inability to estimate the outage duration at the beginning of an unplanned outage such as a malfunction or emergency repair.

We had added this language to ensure that the initial calibration was conducted at the earliest opportunity. However, we recognize the difficulty in estimating the duration of an unplanned outage. Therefore, we agree to strike this provision. We have added a provision allowing for postponement, subject to jurisdictional approval, in cases where units operate continuously with infrequent outages.

> (6) For units and processes that operate continuously with infrequent outages, it may not be possible to meet the April 1, 2010 deadline for the initial calibration of a flow meter or other measurement device without removing the device from service and shipping it to a remote location, thereby disrupting normal process operation. In such cases, the owner or operator may postpone the initial calibration until the next scheduled maintenance outage, and may similarly postpone the subsequent recalibrations. Such postponements, <u>including the date for the next planned shutdown,</u> shall be documented in the monitoring plan that is required under § 98.3(g)(5) <u>and submitted before December 31, 2011 to the [jurisdiction] for approval</u>.

Reporters understand from the outset of reporting that an initial calibration is required, thus they should be able to plan accordingly to ensure that the required personnel and equipment are available or can be accessed in a timely fashion.

5.2.3 Approval for Method Switching [§98.3(k)]

A commenter objected to the requirement for jurisdictional approval for a reporter to switch between alternative methods allowed under the rule. This provision was seen as introducing an unnecessary bureaucratic delay.

It is an established fact that different calculation methods (e.g., fuel based, mass balance-based, and CEMS) by their very nature each generate unique and slightly different emissions estimates. The requirement that a facility obtain jurisdictional approval prior to switching methods is designed to ensure that changes in emissions estimates are real and the result of facility operational changes rather than simply changes in calculation methodology. Allowing a facility to "*select and change the calculation method at any time*" as the commenter suggests would not promote data consistency, but rather would incentivize method switching to generate the most favorable emissions data. Therefore, we will retain this provision.

5.2.4 Reporting Threshold [§98.2]

Two comments objected to retention of the 10,000-metric-ton-per-year reporting threshold for the WCI reporting program. One commenter argued that "[r]etaining the lower reporting threshold will result in confusion among the regulated community because it is different than the EPA reporting threshold and will result in added cost." This commenter also argued that retention of the WCI threshold was not necessary to fulfill the second harmonization principle because "the lower threshold does not relate to a quantification method that is sufficiently reliable and accurate to be employed in a cap-and-trade program." Another commenter simply stated under the heading "Reporting Threshold" that it "supports uniformity in emissions accounting standards used across reporting programs and across jurisdictions."

The 10,000 ton per year design threshold was a Partner design recommendation and was not subject to reconsideration as part of the harmonization effort. It should be noted, however, that the possibility of "confusion among the regulated community" as a result of the lower threshold is minimal, because facilities in U.S. WCI jurisdictions with emissions at or above 10,000 but below 25,000 metric tons per year will be subject *only* to the WCI reporting program.

5.2.5 Third-Party Verification [§98.3(f)]

One commenter objects to the WCI third-party verification requirement "unless and until there is a uniform federal law requiring such." The commenter also maintains that the verification provisions of the harmonized ERs are ambiguous.

Third-party verification is a Partner design recommendation and was not reconsidered in the development of the harmonized ERs. WCI has attempted to clarify the applicability of the third-party verification requirements by substituting a reference to WCI.8 for the EPA self-certification and audit language in 98.3(f). It should be noted that the harmonized ERs are intended to serve as a guide for U.S. WCI jurisdictions to use in developing incorporation-by-reference rules and not as model rule language. Thus the precise manner by which incorporated EPA requirements are integrated with WCI-only requirements, such as third-party verification, will be up to the individual jurisdictions.

Another commenter was concerned that because it will not be possible to complete third-party verification by the EPA March 31, 2010, reporting deadline, the verification requirement "will place emitters in the problematic position of reporting different data to EPA and WCI."

This concern is misplaced. Under the harmonized ERs, U.S. facilities subject to third-party verification will submit their reports on the same date, March 31, 2010, to both EPA and the WCI state. Under WCI.8, they will then have to submit a verification statement for that report to the WCI state by September 1. (This date may be moved forward in the future.) Any errors discovered as a result of the verification process would have to be corrected with a revised report under both the EPA and WCI programs (see section 98.3(h)). Thus, the data reported to both programs will remain consistent.

5.2.6 Sampling Frequency [§98.3(j)]

One commenter objected in general to the increased sampling frequency and the related weighted average calculation method imposed in section 98.3(j). According to this commenter:

> [T]he increased sampling frequency requirements and the weighted average calculations impose an additional cost burden on those businesses [in] the WCI Partner jurisdictions. This increased cost does not necessarily result in increased accuracy of the estimated greenhouse gas emissions. The WCI has not presented a cost-benefit analysis that justifies the increased sampling frequency or the weighted average calculations.

In the few instances (Subparts P and Y) where the harmonized ERs impose a sampling frequency greater than that imposed in EPA's rule, they do so in order to conform the quantification methodology to the original WCI ERs. Those ERs in turn reflect the WCI's judgment on the minimum sampling frequency needed for reliable emissions determinations. In the case of Subpart P, WCI has added a provision allowing facilities to composite up to 30 weighted samples in order to allow for monthly analysis, which should reduce the cost burden.

Use of weighted average data results in more accurate emissions data since the fuel composition is mass or volume "weighted" by the amount of fuel consumed to more accurately reflect the amount of total carbon entering the combustion process during a specific time period. The calculation of a weighted average is a simple matter.

We note that for some calculation methodologies [e.g., §98.33(a)(2)(ii)(A)], 40 C.F.R. 98 specifies arithmetic averaging of parameters measured at greater than the required frequency. Accordingly, we have modified the requirement for weighted averaging to avoid conflict with the EPA rule, but weighted averaging will still be required in those cases where the EPA rule is silent on this issue.

5.2.7 Data Substitution [§98.3(m)]

Two commenters objected to section 98.3(m), which states that notwithstanding the data substitution procedures "failure to conduct monitoring in accordance with the schedules established in this Article shall constitute a violation."

One commenter notes that "EPA has long recognized that data collection systems have down time associated with various monitoring system problems" and suggests that WCI consider a maximum data substitution rate as an alternative.

Unless the monitoring obligations of the harmonized ERs are directly enforceable regardless of whether there is a data substitution method available, facilities (with the exception of Acid Rain facilities, as noted below) will have no incentive to comply with those requirements. They can decide that it is simply less expensive or even advantageous for purposes of compliance with their cap-and-trade obligations to omit samples or temporarily shut down monitoring equipment. A maximum data substitution rate would not provide a complete solution to this problem.

The inclusion of this language does not mean that every monitoring failure will be subject to enforcement action. As always, state agencies administering the ERs will exercise enforcement discretion and will consider factors such as whether the failure was deliberate or accidental, whether it could have been avoided and whether the facility acted expeditiously to correct the failure in deciding whether an enforcement action is appropriate.

Another commenter noted that the data substitution procedures for Acid Rain facilities *are* punitive and therefore provide a disincentive for failing to monitor. This commenter suggested amending 98.3(m) as follows:

> Notwithstanding the missing data procedures specified in this Article, the failure to conduct monitoring in accordance with the schedules established in this Article shall constitute a violation, <u>except in respect of electricity generating units subject to 40 CFR Part 75</u>.

We note that the data substitution procedures for Acid Rain facilities may or may not be punitive in a cap-and-trade context, depending on whether the data substitution occurs in a period when baselines are being set.

We believe the intent of this provision can be more accurately stated with rewording as follows:

> Notwithstanding the missing data procedures specified in this Article, the failure to conduct monitoring in accordance with this Article shall constitute a violation.

5.2.8 First Jurisdictional Deliverers

One commenter noted that the reporting requirements for electricity importers were not included in the EPA rule markup. This commenter stated that "First Jurisdictional Deliverers will presumably be required to submit a separate report in addition to the WCI/ EPA report."

The WCI.60 Imported Electricity quantification method is part of the WCI program design. WCI members are exploring how to integrate electricity import reporting into the federal (or jurisdictional) reporting systems for both the U.S. and Canada.

5.3 General Stationary Combustion (Subpart C)

5.3.1 Tier 3 or 4 for Facilities Subject to Cap [98.33(b)(1) and 98.33(b)(2)]

Two commenters objected to the WCI's decision not to allow combustion units at facilities subject to third-party verification to use Tier 1 or Tier 2 methodologies. According to one commenter:

> In general, only relatively small facilities (i.e., with maximum rated heat input capacity of 250 mmBtu/hr or less) are eligible to use these tiers. Such facilities are likely to be only modest players in a cap-and-trade system, yet the most significantly impacted by the cost and administrative burdens of employing the more rigorous Tier 3 or 4 methodologies to calculate their GHG emissions. We do not believe WCI has adequately justified that use of Tier 1 or 2 quantification methods by these facilities would adversely impact a cap-and-trade program.

The WCI has determined that all facilities above 25,000 metric tons per year need to be included in the cap-and-trade system for the system to achieve the WCI's emission reduction goals. In order for the cap-and-trade system to function, emission reports from covered facilities must be accurate. For facilities burning fuels with highly variable high heating values and carbon contents, Tier 3 is required.

However, we recognize that if a facility is burning a standard fuel with a predictable HHV and carbon content, an acceptable level of accuracy may be achieved using the Tier 1 or Tier 2 methodology. We have therefore revised §98.33(b) to allow the use of Tier 1 or Tier 2 by any facility for the following fuels as listed in new Table C-1a, if combusted in a unit with maximum rated heat input capacity of 250 mmBtu/hr or less:

- Distillate fuel #1, 2 and 4
- Kerosene (normal and jet)

- LPG (commercial "propane")
- Pure propane (C3H8)
- Pure propylene (C3H6)
- Pure ethane (C2H6)
- Pure ethylene (C2H4)
- Pure isobutene (C4H8)
- Pure butane (C4H10)
- Pure butylene (C4H8)
- Gasoline (including. aviation, natural, motor)

If the facility is subject to verification requirements, then Tier 2 is required for combustion of pipeline quality natural gas, because the gas supplier is normally able to provide HHV information, and billing for natural gas is often based on heat content.

In addition, one commenter objected to the general requirement to use Tier 2 if the facility can obtain HHV values from the fuel supplier. We agree that the "can obtain" provision is too broad in that it does not include any limits on costs for HHV sampling that might be imposed by a fuel supplier. We have therefore restored the EPA rule language, which requires use of Tier 2 if the facility routinely receives HHV data from the supplier.

5.3.2 CO_2 CEMS [98.33(a)(4)(iv)]

One commenter objected to the requirement in 40 CFR 98.33(a)(4)(iv) to install a CO_2, rather than just an oxygen, sensor in all new CEMS.

After further investigation, the Reporting Committee remains unconvinced that the use of an oxygen sensor together with EPA methods for converting oxygen to CO_2 will produce results reliable enough for a cap-and-trade program. The requirement to include a CO_2 sensor in all new CEMS therefore has been retained in the final harmonized U.S. ERs. The Committee, however, is continuing its investigation of this issue and may publish a supplement to the harmonized ERs if a change is determined to be necessary.

The final ERs continue to allow the use of oxygen sensors in existing CEMS. In order to generate data on the relative accuracy of using oxygen sensors to determine CO_2 emissions, however, the ERs have been amended to include optional language allowing individual WCI jurisdictions to impose a requirement to include CO_2 analysis in RATA testing for existing CEMS.

5.4 Petroleum Refineries

5.4.1 Refinery Fuel Gas [98.254(m) and 98.34(b)(3)(ii)(E)]

One commenter objected to the requirement in 40 CFR 98.34(b)(3)(ii)(E) and 98.254(m) to monitor refinery fuel gas composition on a daily basis.

This requirement is consistent with established GHG sampling protocols (e.g. EU ETS). Refineries typically have multiple independent fuel gas systems and this fuel which is derived from many process units within the refinery can exhibit significant short term compositional variation. In most refineries, refinery fuel gas also represents the major fuel combusted at the refinery. Thus the compositional variability and importance of this fuel require an accurate quantification methodology.

5.4.2 Flares

One commenter objected to restriction of the use of Equation Y-3 only for flare emissions during startups, shutdowns and malfunctions during which measurement of the parameters required by Equations Y-1 and Y-2 were impossible.

Equation Y-3 gives a much less accurate estimate of emissions than Equations Y-1 and Y-2. In cases of normal operation of flares reporters are required to determine HHV or composition of the material flared and use Equation Y-1 or Y-2, but use of Equation Y-3 is allowed when use of the more accurate methods is impossible. These requirements are designed to promote data consistency across reporting entities while still providing an alternative methodology in cases of "unforeseen malfunctions and start-up and shut-down" when operators are unable to measure the required parameters – flow and composition.

5.5 Other

5.5.1 Fugitive Transmission And Distribution Emissions And The Cap

One commenter indicated that fugitive emissions from gas transmission and distribution systems should be excluded from the cap/trading system due to inherent difficulties in ensuring accurate measurements at a reasonable cost. The 'Proposed Harmonization of Essential Requirements for Mandatory Reporting in U.S. Jurisdictions with EPA Mandatory Reporting Rule' document does not directly consider gas transmission and distribution systems as these are part of the EPA's proposed Subpart W (Petroleum and Natural Gas Systems' quantification method (to which the Western Climate Initiative has made comment). The 'Proposed Harmonization' document does, however, outline emission sources which are considered to be 'reporting only'. During the future harmonization process for Subpart W, the WCI will consider whether these transmission and distribution fugitive emissions should be considered to the reporting only or included within the cap.

5.5.2 Canadian Operations Should Be Able To Use Equations, Emission Factors, Etc. In Use In Canada

One oil and gas industry commenter indicated that Canadian facilities should not have to use all of the same functions, equations, sampling protocols and measurement criteria as U.S. facilities. Since it is essential that the quantification methods derive the same measured emissions in both Canada and the U.S., in most cases these quantification methods need to be the same, recognizing that standard emission factors do vary between the jurisdictions. For oil and gas operations, however, it is recognized that there can be different standard quantification methods in use in Canada and the States, and the WCI's Oil and Gas Subcommittee is considering cases where existing measurement systems (e.g. those in the B.C. Oil and Gas Commission Measurement for Upstream Oil and Gas Operations manual) can be used to quantify/sample specific emission sources in place of those outlined in the EPA's Subpart W proposal.

6 Other Changes to the Proposal

6.1 Amendments to EPA Rule

On July 12, 2010, EPA published a final rule adding four additional quantification subparts the EPA rule. 75 Fed. Reg. 39736. Due to time constraints, the WCI is not including these subparts in the final harmonized ERs. The July 12, 2010, rule revisions, however, included conforming changes to Subpart A that will go into effect this year. To ensure the harmonized ERs are consistent with the EPA rule, Subpart A of the harmonized ERs has been updated to reflect these changes.

6.2 Verification Deadlines

Deadlines for the submission of verification statements were added to the U.S. version of WCI.8. These deadlines were established by WCI.2, which is not included in U.S. harmonized ERs.

6.3 Accreditation

WCI.8(c)(2)(C) was amended to allow jurisdictions to develop their own accreditation programs for verification bodies that meet specified standards.

6.4 Pipeline Quality Natural Gas

A definition of pipeline quality natural gas was added to Subpart C in order to clarify when the use of Tier 1 or 2 is permitted for natural gas fuels.

6.5 Method Selection for Combustion of MSW and Biomass Fuels

Section 98.33(b)(1)(ii) of the EPA rule, which allows the use of Tier 1 for the combustion of municipal solid waste (MSW) in all non-steam-producing units, was marked for deletion in the proposal. The Reporting Committee proposed this change in order to achieve consistency with the ERs, which would have allowed the use of Tier 1 for these units only if located at facilities that are not subject to verification.

On further analysis, however, the Reporting Committee concluded that Tier 1 is the only viable quantification method for non-steam-producing MSW combustion units without CEMS. The highly variable, heterogeneous content of MSW would make it extremely difficult if not impossible to conduct the sampling required under Tier 2 to determine the high heating value or under Tier 3 to determine carbon content. Eliminating section 98.3(b)(1)(iii) could be construed as requiring the installation of a CEMS for all non-steam-producing MSW combustion units, which was not the Reporting Committee's intention. In addition, the Committee noted that section 98.34(d) requires quarterly radiocarbon analysis to determine the biogenic portion of CO_2 emissions from all MSW combustion units, regardless of the method used to determine total CO_2 emissions. Section 98.33(b)(1)(ii) therefore has been restored in the final harmonized ERs.

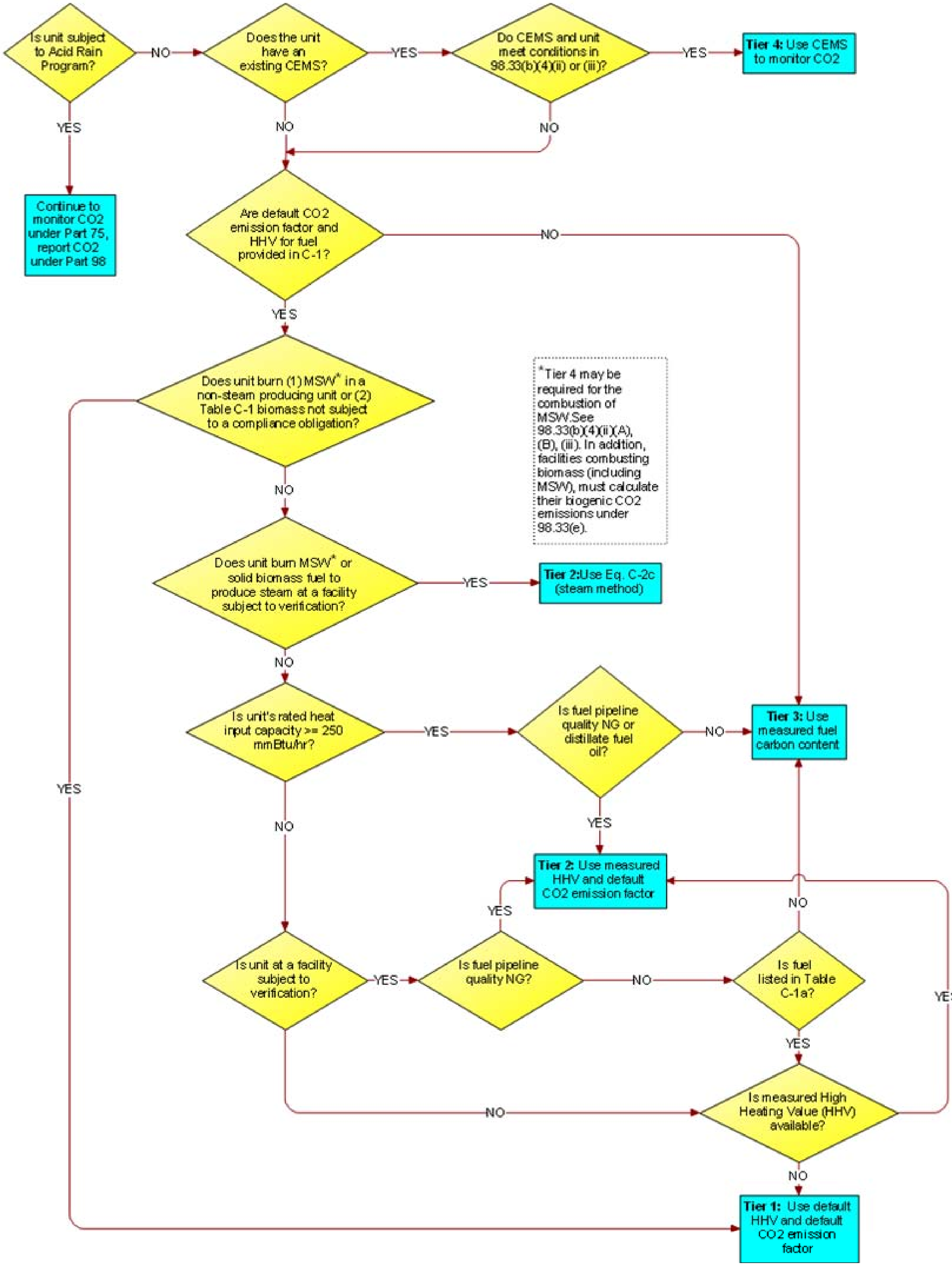
Section 98.33(b)(1)(iii) of the EPA rule, which allows the use of Tier 1 for all biomass fuels listed in Table C-1, was also marked for deletion in the proposal to achieve consistency with the original ERs. The verification rule, however, contemplates that CO_2 emissions from biomass fuels determined by the jurisdiction to be carbon neutral will not be subject to the cap-and-trade program. The Committee concluded that the additional cost of using a higher tier would not be justified for combustion emissions that are not subject to cap-and-trade. Section 98.33(b)(1)(iii) therefore has been restored with the proviso that it applies only to the combustion of biomass fuels that have been determined by the jurisdiction not to be subject to a compliance obligation.

6.6 Clarification of GSC Tier Selection Language

The Reporting Committee concluded that after some of the other changes identified above, the tier selection language for Tiers 2 and 3 required clarification. Specifically, rule language needed to make it clear that (a) Tier 2 is always allowed for the combustion of a Table C-1 fuel at a facility not subject to verification and (b) Tier 3 is required for the combustion of Table C-1 fuels at a facility that is subject to verification, unless Tier 1 or 2 is specifically authorized by another section. The Committee added new section 98.33(b)(2)(iv) and revised section 98.33(b)(3)(ii) to make this clear.

6.7 Flowchart

The Reporting Committee developed the following flowchart to clarify the CO_2 combustion method selection process under the harmonized U.S. ERs. The flowchart may be used in a jurisdiction's rule language or guidance material.


Is unit subject to Acid Rain Program?
NO
Does the unit have an existing CEMS?
YES
Do CEMS and unit meet conditions in 98.33(b)(4)(ii) or (iii)?
YES
Tier 4: Use CEMS to monitor CO2
YES
Continue to monitor CO2 under Part 75, report CO2 under Part 98
NO
NO
Are default CO2 emission factor and HHV for fuel provided in C-1?
NO
YES
Does unit burn (1) MSW* in a non-steam producing unit or (2) Table C-1 biomass not subject to a compliance obligation?
*Tier 4 may be required for the combustion of MSW. See 98.33(b)(4)(ii)(A), (B), (iii). In addition, facilities combusting biomass (including MSW), must calculate their biogenic CO2 emissions under 98.33(e).
NO
Does unit burn MSW* or solid biomass fuel to produce steam at a facility subject to verification?
YES
Tier 2: Use Eq. C-2c (steam method)
NO
Is unit's rated heat input capacity >= 250 mmBtu/hr?
YES
Is fuel pipeline quality NG or distillate fuel oil?
NO
Tier 3: Use measured fuel carbon content
YES
YES
NO
Tier 2: Use measured HHV and default CO2 emission factor
YES
NO
Is unit at a facility subject to verification?
YES
Is fuel pipeline quality NG?
NO
Is fuel listed in Table C-1a?
YES
YES
NO
Is measured High Heating Value (HHV) available?
NO
Tier 1: Use default HHV and default CO2 emission factor

Subpart A—General Provisions

§ 98.1 Purpose and scope.

(a) This part establishes mandatory greenhouse gas (GHG) reporting requirements for owners and operators of certain facilities that directly emit GHG as well as for certain fossil fuel suppliers and industrial GHG suppliers. For suppliers, the GHGs reported are the quantity that would be emitted from combustion or use of the products supplied.[1]

(b) Owners and operators of facilities and suppliers that are subject to this part must follow the requirements of this subpart and all applicable subparts of this part. If a conflict exists between a provision in subpart A and any other applicable subpart, the requirements of the applicable subpart shall take precedence.

(c) Except as otherwise specifically provided:

(1) Wherever the term "Administrator" is used in the rules incorporated by reference in this Article,[2] the term [director/secretary/administrator] of the [jurisdiction] shall be substituted.

(2) Wherever the term "EPA" is used in the rules incorporated by reference in this Article, the term [jurisdiction] shall be substituted.

(d) The following emissions data shall be submitted for information only and may not be subject to cap-and-trade requirements:[3]

(1) Data submitted by a source category designated as "reporting only." This provision does not apply to emissions from general stationary combustion at a source in a "reporting only" category.

(2) Emissions data calculated with a methodology identified as "reporting only."

(3) Data submitted by a facility not subject to verification under WCI.8.

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[1] WCI jurisdictions will require reporting by fuel suppliers for reporting year 2012 and later and may in part rely on EPA methods

[2] "Article" is a placeholder for a jurisdiction-specific cross reference to whatever subdivision of its administrative code contains the WCI's Essential Requirements for Mandatory Reporting in their entirety. Any WCI methodologies that are not sufficiently accurate for cap-and-trade purposes, such as the coal storage method, should be designated "reporting only" in the jurisdiction's rules.

[3] The identification of data as "reporting only" will be subject to review possible revision before the adoption of a cap-and-trade program. On adoption of a cap-and-trade program, the jurisdiction will want to substitute a citation to the rules implementing the program for the words "cap-and-trade requirements." Any WCI methodologies that are not sufficiently accurate for cap-and-trade purposes, such as the coal storage method, should also be designated "reporting only" in the jurisdiction's rules.

(e) On approval by [jurisdiction], reports that conform to this Article and that are submitted to the EPA GHG reporting system shall be deemed to satisfy, in whole or in part,[4] the requirement to submit a report to [jurisdiction] under this Article.[5]

§ 98.2 Who must report?

(a) The GHG reporting requirements and related monitoring, recordkeeping, and reporting requirements of this part apply to the owners and operators of any facility that is located in the United States and that meets the requirements of either paragraph (a)(1), (a)(2), or (a)(3) of this section; and any supplier that meets the requirements of paragraph (a)(4) of this section:

(1) A facility that contains any source category that is listed in Table A-3 of this subpart in any calendar year starting in ~~2010~~2011. For these facilities, the annual GHG report must cover stationary fuel combustion sources (subpart C), miscellaneous use of carbonates (subpart U), and all applicable source categories listed in Table A-3 and Table A-4 of this subpart.

(2) A facility that contains any source category that is listed in Table A-4 of this subpart that emits 25,000 metric tons CO2e or more per year in combined emissions from stationary fuel combustion units, miscellaneous uses of carbonate, and all applicable source categories that are listed in Table A-3 and Table A-4 of this subpart. For these facilities, the annual GHG report must cover stationary fuel combustion sources (subpart C), miscellaneous use of carbonates (subpart U), and all applicable source categories listed in Table A-3 and Table A-4 of this subpart.

(3) A facility that in any calendar year starting in 2010 meets all three of the conditions listed in this paragraph (a)(3). For these facilities, the annual GHG report must cover emissions from stationary fuel combustion sources only.

(i) The facility does not meet the requirements of either paragraph (a)(1) or (a)(2) of this section.

(ii) The aggregate maximum rated heat input capacity of the stationary fuel combustion units at the facility is ~~30~~ 12 mmBtu/hr or greater.[6]

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[4] Supplemental reports may be needed for facilities subject to both EPA reporting requirements and WCI-only quantification methodologies, e.g. facilities that include coal storage (subject to WCI.100).
[5] Applies in U.S. jurisdictions only. Procedures for approval will be established by the jurisdiction.
[6] 30 mmBtu/hr * 10,000/25,000.

(iii) The facility emits ~~25,000~~10,000 metric tons CO2e or more per year in combined emissions from all stationary fuel combustion sources.

(4) A supplier that is listed in Table A-5 of this subpart. For these suppliers, the annual GHG report must cover all applicable products for which calculation methodologies are provided in the subparts listed in Table A-5 of this subpart.

(5) Research and development activities are not considered to be part of any source category defined in this part.

(b) To calculate GHG emissions for comparison to the ~~25,000~~10,000 metric ton CO2e per year emission threshold in paragraph (a)(2) of this section, the owner or operator shall calculate annual CO2e emissions, as described in paragraphs (b)(1) through (b)(4) of this section.

(1) Calculate the annual emissions of CO2, CH4, N2O, and each fluorinated GHG in metric tons from all applicable source categories listed in paragraph (a)(2) of this section. The GHG emissions shall be calculated using the calculation methodologies specified in each applicable subpart and available company records. Include emissions from only those gases listed in Table A– 1 of this subpart.

(2) For each general stationary fuel combustion unit, calculate the annual CO2 emissions in metric tons using any of the four calculation methodologies specified in § 98.33(a). Calculate the annual CH4 and N2O emissions from the stationary fuel combustion sources in metric tons using the appropriate equation in § 98.33(c). ~~Exclude carbon dioxide emissions from the combustion of biomass, but include emissions of CH4 and N2O from biomass combustion.~~

(i) For stationary combustion units, carbon dioxide emissions from the combustion of biomass fuels shall be included in determining whether a facility is subject to the reporting requirements of this Article with the following exceptions:

(1) Until such time as [jurisdiction] has made a determination regarding the carbon neutrality of any biomass fuels, a maximum of 15,000 metric tons of carbon dioxide emissions from the combustion of pure solid biomass fuel may be excluded from calculation of GHG emissions for comparison to the 10,000 metric ton CO2e per year emission threshold in paragraph (a)(2) of this section, provided that total GHG emissions including emissions from solid biomass fuel are less than 25,000 metric tons CO2e.

(2) After such time as [jurisdiction] has made a determination regarding the carbon neutrality of any biomass fuels, the carbon dioxide emissions from the combustion of those fuels may be excluded from calculation of GHG emissions for determining whether the 10,000 metric tons CO2e per year emission threshold in paragraph (a)(1) of this section has been met.

(ii) The exceptions in paragraphs (b)(2)(i) of this section shall not apply in determining whether a facility is subject to the reporting requirements of 40 C.F.R. Part 98.

(3) For miscellaneous uses of carbonate, calculate the annual CO2 emissions in metric tons using the procedures specified in subpart U of this part.

(4) Sum the emissions estimates from paragraphs (b)(1), (b)(2), and (b)(3) of this section for each GHG and calculate metric tons of CO2e using Equation A– 1 of this section.

$$CO_2e = \sum_{i=1}^{n} GHG_i \times GWP_i \qquad \text{(Eq. A-1)}$$

Where:

CO2e = Carbon dioxide equivalent, metric tons/year.

GHGi = Mass emissions of each greenhouse gas listed in Table A–1 of this subpart, metric tons/year.

GWPi = Global warming potential for each greenhouse gas from Table A–1 of this subpart.

n = The number of greenhouse gases emitted.

(5) For purpose of determining if an emission threshold has been exceeded, include in the emissions calculation any CO2 that is captured for transfer off site.

(c) To calculate GHG emissions for comparison to the ~~25,000~~10,000 metric ton CO2e/year emission threshold for stationary fuel combustion under paragraph (a)(3) of this section, calculate CO2, CH4, and N2O emissions from each stationary fuel combustion unit by following the methods specified in paragraph (b)(2) of this section. Then, convert the emissions of each GHG to metric tons CO2e per year using Equation A–1 of this section, and sum the emissions for all units at the facility.

(d) To calculate GHG quantities for comparison to the 25,000 metric ton CO_2 per year threshold for importers and exporters of coal-to-liquid products under paragraph (a)(4)(i) of this section, calculate the mass in metric tons per year of CO_2 that would result from the complete combustion or oxidation of the quantity of coal-to-liquid products that are imported during the reporting year and that are exported during the reporting year. Calculate the emissions using the methodology specified in subpart LL of this part.

(e) To calculate GHG quantities for comparison to the 25,000 metric ton CO_2e per year threshold for importers and exporters of petroleum products under paragraph (a)(4)(ii) of this section, calculate the mass in metric tons per year of CO_2 that would result from the complete combustion or oxidation of the volume of petroleum products and natural gas liquids that are imported during the reporting year and that are exported during the reporting year. Calculate the emissions using the methodology specified in subpart MM of this part.

(f) To calculate GHG quantities for comparison to the 25,000 metric ton CO_2e per year threshold under paragraph (a)(4) of this section for importers and exporters of industrial greenhouse gases and for importers and exporters of CO_2, the owner or operator shall calculate the mass in metric tons per year of CO_2e imports and exports as described in paragraphs (f)(1) through (f)(3) of this section.

(1) Calculate the mass in metric tons per year of CO_2, N_2O, and each fluorinated GHG that is imported and the mass in metric tons per year of CO_2, N_2O, and each fluorinated GHG that is exported during the year. Include only those gases listed in Table A–1 of this subpart.

(2) Convert the mass of each imported and each GHG exported from paragraph (f)(1) of this section to metric tons of CO_2e using Equation A–1 of this section.

(3) Sum the total annual metric tons of CO_2e in paragraph (f)(2) of this section for all imported GHGs. Sum the total annual metric tons of CO_2e in paragraph (f)(2) of this section for all exported GHGs.

(g) If a capacity or generation reporting threshold in paragraph (a)(1) of this section applies, the owner or operator shall review the appropriate records and perform any necessary calculations to determine whether the threshold has been exceeded.

(h) An owner or operator of a facility or supplier that does not meet the applicability requirements of paragraph (a) of this section is not subject to this rule. Such owner or operator would become subject to the rule and reporting requirements § 98.3(b)(3), if a facility or supplier exceeds the applicability requirements of paragraph (a) of this section at a later time. Thus, the owner or operator should reevaluate the applicability to this part (including the revising of any relevant emissions calculations or other calculations) whenever there is any change that could cause a facility or supplier to meet the applicability requirements of paragraph (a) of this section. Such changes include but are not limited to process modifications, increases in operating hours, increases in production, changes in fuel or raw material use, addition of equipment, and facility expansion.

(i) Except as provided in this paragraph, once a facility or supplier is subject to the requirements of this part, the owner or operator must continue for each year thereafter to comply with all requirements of this part, including the requirement to submit annual GHG reports, even if the facility or supplier does not meet the applicability requirements in paragraph (a) of this section in a future year.[7]

(1) [Reserved] ~~If reported emissions are less than 25,000 metric tons CO2e per year for five consecutive years, then the owner or operator may discontinue complying with this part provided that the owner or operator submits a notification to the Administrator that announces the cessation of reporting and explains the reasons for the reduction in emissions. The notification shall be submitted no later than March 31 of the year immediately following the fifth consecutive year of emissions less than 25,000 tons CO2e per year. The owner or operator must maintain the corresponding records required under § 98.3(g) for each of the five consecutive years and retain such records for three years following the year that reporting was discontinued. The owner or operator must resume reporting if annual emissions in any future calendar year increase to 25,000 metric tons CO2e per year or more.~~

(2) If the operations of a facility change such that emissions fall below ~~reported emissions are less than 15,000~~ 10,000 metric tons CO2e per year ~~for three consecutive years~~, then the following reporting requirements shall apply:

(i) If, prior to the emission reduction, the facility was required to report under both this Article and 40 C.F.R. Part 98, then the owner or operator shall continue to submit emission reports until reported emissions are below 10,000 metric tons CO_2e per year for a

[7] As modified, section 98.2(i) of this Article covers only the circumstances under which a facility may cease reporting to the jurisdiction under this Article. There are circumstances under which a facility might be eligible to cease reporting to EPA but must continue to report to the jurisdiction. To determine whether these circumstances apply, the owner or operator should consult 40 C.F.R. § 98.2(i).

minimum of three consecutive years. If reported emissions are less than 10,000 metric tons CO_2 per year for three consecutive years then the owner or operator may discontinue complying with this ~~part~~ Article provided that the owner or operator submits a notification to the Administrator that announces the cessation of reporting and explains the reasons for the reduction in emissions. The notification shall be submitted no later than March 31 of the year immediately following the third consecutive year of emissions less than ~~15,000~~10,000 tons CO2e per year. The owner or operator must maintain the corresponding records required under § 98.3(g) for each of the three consecutive years and retain such records for three years following the year that reporting was discontinued. The owner or operator must resume reporting if annual emissions in any future calendar year increase to ~~25,000~~10,000 metric tons CO2e per year or more.

(ii) If prior to the emission reduction, the facility was required to report under this Article but was not required to report under 40 C.F.R. Part 98, then in lieu of submitting a report under this Article the owner or operator shall submit to [jurisdiction] a signed statement certifying that emissions were less than 10,000 metric tons CO2e during the prior year. After certifying that emissions are below 10,000 metric tons CO2e per year for three consecutive years under this paragraph, the owner or operator shall be exempted from further reporting until CO2e emissions again exceed 10,000 metric tons in any future calendar year.

(3) If the operations of a facility or supplier are changed such that all applicable GHG-emitting processes and operations listed in paragraphs (a)(1) through (a)(4) of this section cease to operate, then the owner or operator is exempt from reporting in the years following the year in which cessation of such operations occurs, provided that the owner or operator submits a notification to the Administrator that announces the cessation of reporting and certifies to the closure of all GHG emitting processes and operations. This paragraph (i)(~~2~~3) does not apply to seasonal or other temporary cessation of operations. This paragraph (i)(3) does not apply to facilities with municipal solid waste landfills or industrial waste landfills, or to underground coal mines. The owner or operator must resume reporting for any future

calendar year during which any of the GHG-emitting processes or operations resume operation.[8]

(j) Table A–2 of this subpart provides a conversion table for some of the common units of measure used in part 98.

§ 98.3 What are the general monitoring, reporting, recordkeeping and verification requirements of this part?

The owner or operator of a facility or supplier that is subject to the requirements of this part must submit GHG reports to the Administrator, as specified in this section.

(a) General. Except as provided in paragraph (d) of this section, follow the procedures for emission calculation, monitoring, quality assurance, missing data, recordkeeping, and reporting that are specified in each relevant subpart of this part.

(b) Schedule. The annual GHG report must be submitted no later than March 31 of each calendar year for GHG emissions in the previous calendar year. As an example, for a facility that is subject to the rule in calendar year 2010, the first report must be submitted on March 31, 2011.

(1) [Reserved]

(2) For a new facility or supplier that begins operation on or after January 1, 2010 and becomes subject to the rule in the year that it becomes operational, report emissions beginning with the first operating month and ending on December 31 of that year. Each subsequent annual report must cover emissions for the calendar year, beginning on January 1 and ending on December 31.

(3) For any facility or supplier that becomes subject to this rule because of a physical or operational change that is made after January 1, 2010, report emissions for the first calendar year in which the change occurs, beginning with the first month of the change and ending on December 31 of that year. For a facility or supplier that becomes subject to this rule solely because of an increase in hours of operation or level of production, the first month of the change is the month in which the increased hours of operation or level of production, if maintained for the remainder of the year, would cause the facility or supplier to exceed the applicable threshold. Each subsequent annual report must cover emissions for the calendar year, beginning on January 1 and ending on December 31.

[8] This provision may require modification to meet the needs of the cap-and-trade program.

(c) Content of the annual report. Except as provided in paragraph (d) of this section, each annual GHG report shall contain the following information:

(1) Facility name or supplier name (as appropriate) and physical street address including the city, state, and zip code.

(2) Year and months covered by the report.

(3) Date of submittal.

(4) For facilities, report annual emissions of CO_2, CH_4, N_2O, and each fluorinated GHG (as defined in § 98.6) as follows:

(i) Annual emissions (excluding biogenic CO_2) aggregated for all GHG from all applicable source categories listed in Tables A-3 and Table A-4 of this subpart and expressed in metric tons of CO_2e calculated using Equation A-1 of this subpart.

(ii) Annual emissions of biogenic CO_2 aggregated for all applicable source categories in listed in Tables A-3 and Table A-4 of this subpart.

(iii) Annual emissions from each applicable source category listed in Tables A-3 and Table A-4 of this subpart, expressed in metric tons of each GHG listed in paragraphs (c)(4)(iii)(A) through (c)(4)(iii)(E) of this section.

(A) Biogenic CO_2.

(B) CO_2 (excluding biogenic CO_2).

(C) CH_4.

(D) N_2O.

(E) Each fluorinated GHG (including those not listed in Table A–1 of this subpart).

(iv) Emissions and other data for individual units. processes, activities, and operations as specified in the ‘‘Data reporting requirements’’ section of each applicable subpart of this part.

(5) For suppliers, report annual quantities of CO_2, CH_4, N_2O, and each fluorinated GHG (as defined in § 98.6) that would be emitted from combustion or use of the products supplied, imported, and exported during the year. Calculate and report quantities at the following levels:

(i) Total quantity of GHG aggregated for all GHG from all applicable supply categories in subparts KK through PP of this part and expressed in metric tons of CO_2e calculated using Equation A–1 of this subpart.

(ii) Quantity of each GHG from each applicable supply category in subparts KK through PP of this part, expressed in metric tons of each GHG. For fluorinated GHG, report emissions of all fluorinated GHG, including those not listed in Table A–1 of this subpart.

(iii) Any other data specified in the ‘‘Data reporting requirements’’ section of each applicable subpart of this part.

(6) A written explanation, as required under § 98.3(e), if you change emission calculation methodologies during the reporting period.

(7) A brief description of each “best available monitoring method” used according to paragraph (d) of this section, the parameter measured using the method, and the time period during which the “best available monitoring method” was used, if applicable.

(8) Each data element for which a missing data procedure was used according to the procedures of an applicable subpart and the total number of hours in the year that a missing data procedure was used for each data element.

(9) A signed and dated certification statement provided by the designated representative of the owner or operator, according to the requirements of § 98.4(e)(1).

(d) Special provisions for reporting year 2010.

(1) Best available monitoring methods. During January 1, 2010 through March 31, 2010, owners or operators may use best available monitoring methods for any parameter (e.g., fuel use, daily carbon content of feedstock by process line) that cannot reasonably be measured according to the monitoring and QA/QC requirements of a relevant subpart. The owner or operator must use the calculation methodologies and equations in the ‘‘Calculating GHG Emissions’’ sections of each relevant subpart, but may use the best available monitoring method for any parameter for which it is not reasonably feasible to acquire, install, and operate a required piece of monitoring equipment by January 1, 2010. Starting no later than April 1, 2010, the owner or operator must discontinue using best available methods and begin following all applicable monitoring and QA/QC requirements of this part, except as provided in paragraphs (d)(2) and (d)(3) of this section. Best available monitoring methods means any of the following methods specified in this paragraph:

(i) Monitoring methods currently used by the facility that do not meet the specifications of an relevant subpart.

(ii) Supplier data.

(iii) Engineering calculations.

(iv) Other company records.

(2) Requests for extension of the use of best available monitoring methods. The owner or operator may submit a request to the Administrator to use one or more best available monitoring methods beyond March 31, 2010.

(i) Timing of request. The extension request must be submitted to EPA no later than 30 days after the effective date of the GHG reporting rule.

(ii) Content of request. Requests must contain the following information:

(A) A list of specific item of monitoring instrumentation for which the request is being made and the locations where each piece of monitoring instrumentation will be installed.

(B) Identification of the specific rule requirements (by rule subpart, section, and paragraph numbers) for which the instrumentation is needed.

(C) A description of the reasons why the needed equipment could not be obtained and installed before April 1, 2010.

(D) If the reason for the extension is that the equipment cannot be purchased and delivered by April 1, 2010, include supporting documentation such as the date the monitoring equipment was ordered, investigation of alternative suppliers and the dates by which alternative vendors promised delivery, backorder notices or unexpected delays, descriptions of actions taken to expedite delivery, and the current expected date of delivery.

(E) If the reason for the extension is that the equipment cannot be installed without a process unit shutdown, include supporting documentation demonstrating that it is not practicable to isolate the equipment and install the monitoring instrument without a full process unit shutdown. Include the date of the most recent process unit shutdown, the frequency of shutdowns for this process unit, and the date of the next planned shutdown during which the monitoring equipment can be installed. If there has been a shutdown or if there is a planned process unit shutdown between promulgation of this part and April 1, 2010, include a justification of why the equipment could not be obtained and installed during that shutdown.

(F) A description of the specific actions the facility will take to obtain and install the equipment as soon as reasonably feasible and the expected date by which the equipment will be installed and operating.

(iii) Approval criteria. To obtain approval, the owner or operator must demonstrate to the Administrator's satisfaction that it is not reasonably feasible to acquire, install, and operate a required piece of monitoring equipment by April 1, 2010. The use of best available methods will not be approved beyond December 31, 2010.

(3) Abbreviated emissions report for facilities containing only general stationary fuel combustion sources. In lieu of the report required by paragraph (c) of this section, the owner or operator of an existing facility that is in operation on January 1, 2010 and that meets the conditions of § 98.2 (a)(3) may submit an abbreviated GHG report for the facility for GHGs emitted in 2010. The abbreviated report must be submitted by March 31, 2011. An owner or operator that submits an abbreviated report must submit a full GHG report according to the requirements of paragraph (c) of this section beginning in calendar year 2011. The abbreviated facility report must include the following information:

(i) Facility name and physical street address including the city, state and zip code.

(ii) The year and months covered by the report.

(iii) Date of submittal.

(iv) Total facility GHG emissions aggregated for all stationary fuel combustion units calculated according to any method specified in § 98.33(a) and expressed in metric tons of CO2, CH4, N2O, and CO2e.

(v) Any facility operating data or process information used for the GHG emission calculations.

(vi) A signed and dated certification statement provided by the designated representative of the owner or operator, according to the requirements of paragraph (e)(1) of this section.

(e) Emission calculations. In preparing the GHG report, you must use the calculation methodologies specified in the relevant subparts, except as specified in paragraph (d) of this section. For each source category, you must use the same calculation methodology throughout a reporting period unless you provide a written explanation of why a change in methodology was required.

(f) Verification. Owner or operators subject to the verification requirements of WCI.8 shall obtain verification services and submit a verification statement meeting the requirements of WCI.8, if applicable.~~To verify the completeness and accuracy of reported GHG emissions, the Administrator may review the certification statements described in paragraphs (c)(8) and (d)(3)(vi) of this section and any other credible evidence, in conjunction with a comprehensive review of the GHG reports and periodic audits of selected reporting facilities. Nothing in this section prohibits the Administrator from using additional information to verify the completeness and accuracy of the reports.~~

(g) Recordkeeping. An owner or operator that is required to report GHGs under this part must keep records as specified in this paragraph. Retain all required records for at least ~~3~~ 7 years. The records shall be kept in an electronic or hard-copy format (as appropriate) and recorded in a form that is suitable for expeditious inspection and review. Upon request by the Administrator, the records required under this section must be made available to EPA within 20 days after the request. Records may be retained off site if the records are readily available for expeditious inspection and review. For records that are electronically generated or maintained, the equipment or software necessary to read the records shall be made available, or, if requested by EPA, electronic records shall be converted to paper documents. You must retain the following records, in addition to those records prescribed in each applicable subpart of this part:

(1) A list of all units, operations, processes, and activities for which GHG emission were calculated.

(2) The data used to calculate the GHG emissions for each unit, operation, process, and activity, categorized by fuel or material type. These data include but are not limited to the following information in this paragraph (g)(2):

(i) The GHG emissions calculations and methods used.

(ii) Analytical results for the development of site-specific emissions factors.

(iii) The results of all required analyses for high heat value, carbon content, and other required fuel or feedstock parameters.

(iv) Any facility operating data or process information used for the GHG emission calculations.

(3) The annual GHG reports.

(4) Missing data computations. For each missing data event, also retain a record of the duration of the event, actions taken to restore malfunctioning monitoring equipment, the cause of the event, and the actions taken to prevent or minimize occurrence in the future.

(5) For sources subject to reporting under 40 C.F.R. Part 98, ~~A~~ a written GHG Monitoring Plan.[9]

(i) At a minimum, the GHG Monitoring Plan shall include the elements listed in this paragraph (g)(5)(i).

(A) Identification of positions of responsibility (i.e., job titles) for collection of the emissions data.

(B) Explanation of the processes and methods used to collect the necessary data for the GHG calculations.

(C) Description of the procedures and methods that are used for quality assurance, maintenance, and repair of all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported under this part.

(ii) The GHG Monitoring Plan may rely on references to existing corporate documents (e.g., standard operating procedures, quality assurance programs under appendix F to 40 CFR part 60 or appendix B to 40 CFR part 75, and other documents) provided that the elements required by paragraph (g)(5)(i) of this section are easily recognizable.

(iii) The owner or operator shall revise the GHG Monitoring Plan as needed to reflect changes in production processes, monitoring instrumentation, and quality assurance procedures; or to improve procedures for the maintenance and repair of monitoring systems to reduce the frequency of monitoring equipment downtime.

(iv) Upon request by the Administrator, the owner or operator shall make all information that is collected in conformance with the GHG Monitoring Plan available for review during an audit within 20 days after the request. Electronic storage of the information in the plan is permissible, provided that the information can be made available in hard copy upon request during an audit.

[9] WCI jurisdictions may elect to require a GHG Monitoring Plan from all sources. This provision is optional for Canadian jurisdictions.

(6) The results of all required certification and quality assurance tests of continuous monitoring systems, fuel flow meters, and other instrumentation used to provide data for the GHGs reported under this part.

(7) Maintenance records for all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported under this part.

(h) Annual GHG report revisions.

(1) The owner or operator of a facility subject to reporting under both this Article and 40 C.F.R. Part 98 shall submit a revised report within 45 days of discovering or being notified by EPA of errors in an annual GHG report. The revised report must correct all identified errors. The owner or operator shall retain documentation for ~~3~~ 7 years to support any revisions made to an annual GHG report.

(2) The owner or operator of a facility subject to reporting under this Article but not 40 C.F.R. Part 98 shall submit a revised report within 30 days of finding that a report contains an error, or accumulation of errors, greater than 5 percent of the total CO_2e emissions reported. To the extent possible, the revised report must correct all identified errors. A revised report will be accepted only if approved by [jurisdiction]. The owner or operator shall retain documentation for 7 years to support any revisions made to an annual GHG report.

(i) Calibration accuracy requirements. The owner or operator of a facility or supplier that is subject to the requirements of this part must meet the calibration accuracy requirements of this paragraph (i).

(1) Except as provided in paragraphs (i)(4) through (i)(6) of this section, flow meters and other devices (e.g., belt scales) that measure data used to calculate GHG emissions shall be calibrated using the procedures specified in this paragraph and each relevant subpart of this part. All measurement devices must be calibrated according to the manufacturer's recommended procedures, an appropriate industry consensus standard, or a method specified in a relevant subpart of this part. All measurement devices shall be calibrated to an accuracy of 5 percent. For facilities and suppliers that are subject to this part on January 1, 2010, the initial calibration shall be conducted by April 1, 2010. For facilities and suppliers that become subject to this part after April 1, 2010, the initial calibration shall be conducted by the date

that data collection is required to begin. Subsequent calibrations shall be performed at the frequency specified in each applicable subpart.[10]

(2) For flow meters, perform all calibrations at measurement points that are representative of normal operation of the meter. Except for the orifice, nozzle, and venturi flow meters described in paragraph (i)(3) of this section, calculate the calibration error at each measurement point using Equation A–2 of this section. The terms ‘‘R’’ and ‘‘A’’ in Equation A–2 must be expressed in consistent units of measure (e.g., gallons/minute, ft 3/min). The calibration error at each measurement point shall not exceed 5.0 percent of the reference value.

$$CE = \frac{R - A}{R} \times 100 \qquad \text{(Eq. A-2)}$$

Where:

CE = Calibration error (%)

R = Reference value

A = Flow meter response to the reference value

(3) For orifice, nozzle, and venturi flow meters, the initial quality assurance consists of in-situ calibration of the differential pressure (delta-P), total pressure, and temperature transmitters. Calibrate each transmitter at a zero point and at least one upscale point. Fixed reference points, such as the freezing point of water, may be used for temperature transmitter calibrations. Calculate the calibration error of each transmitter at each measurement point, using Equation A–3 of this subpart. The terms ‘‘R’’, ‘‘A’’, and ‘‘FS’’ in Equation A–3 of this subpart must be in consistent units of measure (e.g., milliamperes, inches of water, psi, degrees). For each transmitter, the CE value at each measurement point shall not exceed 2.0 percent of full-scale. Alternatively, the results are acceptable if the sum of the calculated CE values for the three transmitters at each calibration level (i.e., at the zero level and at each upscale level) does not exceed 5.0 percent.

[10] Canadian jurisdictions may grant an exemption for the combustion of solid biomass or biomass fuels determined to be carbon neutral.

$$CE = \frac{R - A}{FS} \times 100 \qquad \text{(Eq. A-3)}$$

Where:

CE = Calibration error (%)

R = Reference value

A = Transmitter response to the reference value

FS = Full-scale value of the transmitter

(4) Fuel billing meters are exempted from the calibration requirements of this section, provided that the fuel supplier and any unit combusting the fuel do not have any common owners and are not owned by subsidiaries or affiliates of the same company.

(5) For a flow meter or other measurement device that has been previously calibrated in accordance with this part, an initial calibration is not required by the date specified in paragraph (i)(1) of this section if, as of the date required for the initial calibration, the previous calibration is still active (i.e., the device is not yet due for recalibration because the time interval between successive calibrations, as required by this part, has not elapsed).

(6) For units and processes that operate continuously with infrequent outages, it may not be possible to meet the April 1, 2010 deadline for the initial calibration of a flow meter or other measurement device without removing the device from service and shipping it to a remote location, thereby disrupting normal process operation. In such cases, the owner or operator may postpone the initial calibration until the next scheduled maintenance outage, and may similarly postpone the subsequent recalibrations. Such postponements shall be documented in the monitoring plan that is required under § 98.3(g)(5) and submitted before December 31, 2011 to the [jurisdiction] for approval.

(j) Where a rule in this Article requires sampling of a parameter on a more frequent basis than the corresponding rule in 40 C.F.R. Part 98, the following shall apply unless in conflict with any other provision in 40 C.F.R. Part 98:

(1) The samples must be spaced apart as evenly as possible over time, taking into account the operating schedule of the relevant unit or facility.

(2) You must calculate and report a weighted average of the values derived from the samples by using the following formula:

$$V_E = \frac{\sum_{j=1}^{n} (V_j \times M_j)}{\sum_{j=1}^{n} M_j}$$

Where:

V_E = The value of the parameter to be reported under 40 C.F.R. Part 98 for period E.

j = Each period during period E for which a sample is required by [jurisdiction] under the applicable rule in this Article.

n = The number of periods j in period E.

Vj = The value of the sample for period j.

Mj = The mass of the sampled material processed or otherwise used by the relevant unit or facility in period j.

(3) You must keep records of the date and result for each sample and mass measurement used in the equation in subsection (2) and of the calculation of each weighted average included in your report.

(k)Where this Article specifies a choice between use of a fuel-based or mass balance-based calculation or use of a continuous emissions monitoring system (CEMS) to calculate CO2 emissions, the operator shall make this choice and continue to use the method chosen for all future emissions data reports, unless the use of the alternative calculation method is approved in advance by [the jurisdiction].[11]

(l) The owner or operator may elect to designate as de minimis one or more sources or pollutants that collectively emit no more than 3 percent of the facility's total CO2e emissions, but not to exceed 20,000 metric tons CO2e. Where this Article otherwise requires the use of a more stringent method for monitoring and reporting emissions than the method required by 40

[11] Approval may be granted by rule or by other general authorization. A case-by-case approval process may not be required.

C.F.R. Part 98, the owner or operator may elect to use any other method allowed under 40 C.F.R. Part 98 for the sources or pollutants designated as de minimis.[12]

(m) Notwithstanding the missing data procedures specified in this Article, the failure to conduct monitoring in accordance with this Article shall constitute a violation.

§ 98.4 Authorization and responsibilities of the designated representative.[13]

(a) General. Except as provided under paragraph (f) of this section, each facility, and each supplier, that is subject to this part, shall have one and only one designated representative, who shall be responsible for certifying, signing, and submitting GHG emissions reports and any other submissions for such facility and supplier respectively to the Administrator under this part. If the facility is required under any other part of title 40 of the Code of Federal Regulations to submit to the Administrator any other emission report that is subject to any requirement in 40 CFR part 75, the same individual shall be the designated representative responsible for certifying, signing, and submitting the GHG emissions reports and all such other emissions reports under this part.

(b) Authorization of a designated representative. The designated representative of the facility or supplier shall be an individual selected by an agreement binding on the owners and operators of such facility or supplier and shall act in accordance with the certification statement in paragraph (i)(4)(iv) of this section.

(c) Responsibility of the designated representative. Upon receipt by the Administrator of a complete certificate of representation under this section for a facility or supplier, the designated representative identified in such certificate of representation shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator of such facility or supplier in all matters pertaining to this part, notwithstanding any agreement between the designated representative and such owners and operators. The owners and operators shall be bound by any decision or order issued to the designated representative by the Administrator or a court.

(d) Timing. No GHG emissions report or other submissions under this part for a facility or supplier will be accepted until the Administrator has received a complete certificate of

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[12] Canadian jurisdictions may include de minimis provisions consistent with WCI.2(d).

[13] In Canadian jurisdictions, the responsibilities specified in this section will ordinarily fall on the "operator's representative" as defined in Canadian law.

representation under this section for a designated representative of the facility or supplier. Such certificate of representation shall be submitted at least 60 days before the deadline for submission of the facility's or supplier's initial emission report under this part.

(e) Certification of the GHG emissions report. Each GHG emission report and any other submission under this part for a facility or supplier shall be certified, signed, and submitted by the designated representative or any alternate designated representative of the facility or supplier in accordance with this section and § 3.10 of this chapter.

(1) Each such submission shall include the following certification statement signed by the designated representative or any alternate designated representative: ''I am authorized to make this submission on behalf of the owners and operators of the facility or supplier, as applicable, for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(2) The Administrator will accept a GHG emission report or other submission for a facility or supplier under this part only if the submission is certified, signed, and submitted in accordance with this section.

(f) Alternate designated representative. A certificate of representation under this section for a facility or supplier may designate one alternate designated representative, who shall be an individual selected by an agreement binding on the owners and operators, and may act on behalf of the designated representative, of such facility or supplier. The agreement by which the alternate designated representative is selected shall include a procedure for authorizing the alternate designated representative to act in lieu of the designated representative.

(1) Upon receipt by the Administrator of a complete certificate of representation under this section for a facility or supplier identifying an alternate designated representative.

(i) The alternate designated representative may act on behalf of the designated representative for such facility or supplier.

(ii) Any representation, action, inaction, or submission by the alternate designated representative shall be deemed to be a representation, action, inaction, or submission by the designated representative.

(2) Except in this section, whenever the term ‘‘designated representative’’ is used in this part, the term shall be construed to include the designated representative or any alternate designated representative.

(g) Changing a designated representative or alternate designated representative. The designated representative or alternate designated representative identified in a complete certificate of representation under this section for a facility or supplier received by the Administrator may be changed at any time upon receipt by the Administrator of another later signed, complete certificate of representation under this section for the facility or supplier. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous designated representative or the previous alternate designated representative of the facility or supplier before the time and date when the Administrator receives such later signed certificate of representation shall be binding on the new designated representative and the owners and operators of the facility or supplier.

(h) Changes in owners and operators. In the event an owner or operator of the facility or supplier is not included in the list of owners and operators in the certificate of representation under this section for the facility or supplier, such owner or operator shall be deemed to be subject to and bound by the certificate of representation, the representations, actions, inactions, and submissions of the designated representative and any alternate designated representative of the facility or supplier, as if the owner or operator were included in such list. Within 90 days after any change in the owners and operators of the facility or supplier (including the addition of a new owner or operator), the designated representative or any alternate designated representative shall submit a certificate of representation that is complete under this section except that such list shall be amended to reflect the change. If the designated representative or alternate designated representative determines at any time that an owner or operator of the facility or supplier is not included in such list and such exclusion is not the result of a change in the owners and operators, the designated representative or any alternate designated representative shall submit, within 90 days of making such determination, a certificate of representation that is complete under this section except that such list shall be amended to include such owner or operator.

(i) Certificate of representation. A certificate of representation shall be complete if it includes the following elements in a format prescribed by the Administrator in accordance with this section:

(1) Identification of the facility or supplier for which the certificate of representation is submitted.

(2) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the designated representative and any alternate designated representative.

(3) A list of the owners and operators of the facility or supplier identified in paragraph (i)(1) of this section, provided that, if the list includes the operators of the facility or supplier and the owners with control of the facility or supplier, the failure to include any other owners shall not make the certificate of representation incomplete.

(4) The following certification statements by the designated representative and any alternate designated representative:

(i) ‘‘I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of the facility or supplier, as applicable.’’

(ii) ‘‘I certify that I have all the necessary authority to carry out my duties and responsibilities under 40 CFR part 98 on behalf of the owners and operators of the facility or supplier, as applicable, and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions.’’

(iii) ‘‘I certify that the owners and operators of the facility or supplier, as applicable, shall be bound by any order issued to me by the Administrator or a court regarding the facility or supplier.’’

(iv) ‘‘If there are multiple owners and operators of the facility or supplier, as applicable, I certify that I have given a written notice of my selection as the ‘designated representative’ or ‘alternate designated representative’, as applicable, and of the agreement by which I was selected to each owner and operator of the facility or supplier.’’

(5) The signature of the designated representative and any alternate designated representative and the dates signed.

(j) Documents of agreement. Unless otherwise required by the Administrator, documents of agreement referred to in the certificate of representation shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(k) Binding nature of the certificate of representation. Once a complete certificate of representation under this section for a facility or supplier has been received, the Administrator will rely on the certificate of representation unless and until a later signed, complete certificate of representation under this section for the facility or supplier is received by the Administrator.

(l) Objections Concerning a Designated Representative

(1) Except as provided in paragraph (g) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission, of the designated representative or alternate designated representative shall affect any representation, action, inaction, or submission of the designated representative or alternate designated representative, or the finality of any decision or order by the Administrator under this part.

(2) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any designated representative or alternate designated representative.

(m) Delegation by designated representative and alternate designated representative.

(1) A designated representative or an alternate designated representative may delegate his or her own authority, to one or more individuals, to submit an electronic submission to the Administrator provided for or required under this part, except for a submission under this paragraph.

(2) In order to delegate his or her own authority, to one or more individuals, to submit an electronic submission to the Administrator in accordance with paragraph (m)(1) of this section, the designated representative or alternate designated representative must submit electronically to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(i) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of such designated representative or alternate designated representative.

(ii) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such individual (referred to as an ‘‘agent’’).

(iii) For each such individual, a list of the type or types of electronic submissions under paragraph (m)(1) of this section for which authority is delegated to him or her.

(iv) For each type of electronic submission listed in accordance with paragraph (m)(2)(iii) of this section, the facility or supplier for which the electronic submission may be made.

(v) The following certification statements by such designated representative or alternate designated representative:

(A) ‘‘I agree that any electronic submission to the Administrator that is by an agent identified in this notice of delegation and of a type listed, and for a facility or supplier designated, for such agent in this notice of delegation and that is made when I am a designated representative or alternate designated representative, as applicable, and before this notice of delegation is superseded by another notice of delegation under § 98.4(m)(3) shall be deemed to be an electronic submission certified, signed, and submitted by me.’’

(B) ‘‘Until this notice of delegation is superseded by a later signed notice of delegation under § 98.4(m)(3), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under § 98.4(m) is terminated.’’

(vi) The signature of such designated representative or alternate designated representative and the date signed.

(3) A notice of delegation submitted in accordance with paragraph (m)(2) of this section shall be effective, with regard to the designated representative or alternate designated representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of another such notice that was signed later by such designated representative or alternate designated representative, as applicable. The later

signed notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(4) Any electronic submission covered by the certification in paragraph (m)(2)(iv)(A) of this section and made in accordance with a notice of delegation effective under paragraph (m)(3) of this section shall be deemed to be an electronic submission certified, signed, and submitted by the designated representative or alternate designated representative submitting such notice of delegation.

§ 98.5 How is the report submitted?

Each GHG report and certificate of representation for a facility or supplier must be submitted electronically in accordance with the requirements of § 98.4 and in a format specified by the Administrator.

§ 98.6 Definitions.

[No change.]

§ 98.7 What standardized methods are incorporated by reference into this part?

[No change.]

§ 98.8 What are the compliance and enforcement provisions of this part?

[No change.]

§ 98.9 Addresses.

[No change.]

Tables A-1 through A-5

[No change.]

Subpart C—General Stationary Combustion

§98.30 Definition of the source category.

(a) Stationary fuel combustion sources are devices that combust solid, liquid, or gaseous fuel, generally for the purposes of producing electricity, generating steam, or providing useful heat or energy for industrial, commercial, or institutional use, or reducing the volume of waste by removing combustible matter. Stationary fuel combustion sources include, but are not limited to, boilers, simple and combined-cycle combustion turbines, engines, incinerators, and process heaters.

(b) This source category does not include:

(1) Portable equipment, as defined in §98.6.

(2) Emergency generators and emergency equipment, as defined in §98.6.

(3) Irrigation pumps at agricultural operations.

(4) Flares, unless otherwise required by provisions of another subpart of 40 CFR part 98 to use methodologies in this subpart.

(5) Electricity generating units that are subject to subpart D of this part.

(c) For a unit that combusts hazardous waste (as defined in 40 CFR 261.3), reporting of GHG emissions is not required unless either of the following conditions apply:

(1) Continuous emission monitors (CEMS) are used to quantify CO_2 mass emissions.

(2) Any fuel listed in Table C-1 of this subpart is also combusted in the unit. In this case, report GHG emissions from combustion of all fuels listed in Table C-1 of this subpart.

§98.31 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains one or more stationary fuel combustion sources and the facility meets the applicability requirements of either §§98.2(a)(1), 98.2(a)(2), or 98.2(a)(3).

§98.32 GHGs to report.

(a) You must report CO_2, CH_4, and N_2O mass emissions from each stationary fuel combustion unit.

(b) [Reporting only] Units that generate electricity either for sale or for use onsite must also report fugitive HFC emissions from cooling units by following the requirements of §98.33(f).

§98.33 Calculating GHG emissions.

You must calculate CO_2 emissions according to paragraph (a) of this section, and calculate CH_4 and N_2O emissions according to paragraph (c) of this section.

Subpart C—General Stationary Combustion

(a) CO_2 emissions from fuel combustion. Calculate CO_2 emissions by using one of the four calculation methodologies in this paragraph (a) subject to the conditions, requirements, and restrictions set forth in paragraph (b) of this section. If you co-fire biomass fuels with fossil fuels, report CO_2 emissions from the combustion of biomass separately using the methods in paragraph (e) of this section.

(1) Tier 1 Calculation Methodology. Calculate the annual CO_2 mass emissions for each type of fuel by using Equation C-1 of this section.

$$CO_2 = 1x\,10^{-3} * Fuel * HHV * EF \qquad \text{(Eq. C-1)}$$

Where:

CO_2 = Annual CO_2 mass emissions for the specific fuel type (metric tons).

Fuel = Mass or volume of fuel combusted per year, from company records as defined in §98.6 (express mass in short tons for solid fuel, volume in standard cubic feet for gaseous fuel, and volume in gallons for liquid fuel).

HHV = Default high heat value of the fuel, from Table C-1 of this subpart (mmBtu per mass or mmBtu per volume, as applicable).

EF = Fuel-specific default CO_2 emission factor, from Table C-1 of this subpart (kg CO_2/mmBtu).

1×10^{-3} =
Conversion factor from kilograms to metric tons.

(2) Tier 2 Calculation Methodology. Calculate the annual CO_2 mass emissions for each type of fuel by using either Equation C2a or C2c of this section, as appropriate.

(i) Equation C-2a of this section applies to any type of fuel listed in Table C-1 of the subpart, except for municipal solid waste (MSW). For MSW combustion, use Equation C-2c of this section.

$$CO_2 = 1x10^{-3} * Fuel * HHV * EF \qquad \text{(Eq. C-2a)}$$

Where:

CO_2 = Annual CO_2 mass emissions for a specific fuel type (metric tons).

Fuel = Mass or volume of the fuel combusted during the year, from company records as defined in §98.6 (express mass in short tons for solid fuel, volume in standard cubic feet for gaseous fuel, and volume in gallons for liquid fuel).

HHV = Annual average high heat value of the fuel from all valid samples for the year (mmBtu per mass or volume). The average HHV shall be calculated according to the requirements of paragraph (a)(2)(ii) of this section.

EF = Fuel-specific default CO_2 emission factor, from Table C-1 of this subpart (kg CO_2/mmBtu).

1×10^{-3} = Conversion factor from kilograms to metric tons.

(ii) The minimum number of HHV samples for determining annual average HHV is specified (e.g., monthly, quarterly, semi-annually, or by lot) in §98.34. The method for computing the annual average HHV is a function of how frequently you perform or receive from the fuel supplier the results of fuel sampling for HHV. The method is specified in paragraph (a)(2)(ii)(A) or (a)(2)(ii)(B) of this section, as applicable.

(A) If the results of fuel sampling are received monthly or more frequently, then the annual average HHV shall be calculated using Equation C-2b of this section. If multiple HHV determinations are made in any month, average the values for the month arithmetically.

$$(HHV)_{annual} = \frac{\sum_{i=1}^{n} (HHV)_i * (Fuel)_i}{\sum_{i=1}^{n} (Fuel)_i} \qquad \text{(Eq. C-2b)}$$

Where:

$(HHV)_{annual}$	=	Weighted annual average high heat value of the fuel (mmBtu per mass or volume).
$(HHV)_i$	=	High heat value of the fuel, for month "i" (mmBtu per mass or volume).
$(Fuel)_i$	=	Mass or volume of the fuel combusted during month "i" (express mass in short tons for solid fuel, volume in standard cubic feet for gaseous fuel, and volume in gallons for liquid fuel).
n	=	Number of months in the year that fuel is burned in the unit.

(B) If the results of fuel sampling are received less frequently than monthly, then the annual average HHV shall be computed as the arithmetic average HHV for all values for the year (including valid samples and substitute data values under 98.35).

(iii) For units that combust municipal solid waste (MSW) and that produce steam, use Equation C-2c of this section. Equation C-2c of this section may also be used for any ~~other~~ solid biomass fuel listed in Table C-1 of this subpart provided that steam is generated by the unit.

$$CO_2 = 1 \times 10^{-3}\, Steam * B * EF \qquad \text{(Eq. C-2c)}$$

Where:

CO_2	=	Annual CO_2 mass emissions from MSW or solid fuel combustion (metric tons).
Steam	=	Total mass of steam generated by MSW or solid fuel combustion during the reporting year (lb steam).
B	=	Ratio of the boiler's maximum rated heat input capacity to its design rated steam output capacity (mmBtu/lb steam).
EF	=	Fuel-specific default CO_2 emission factor, from Table C-1 of this subpart (kg CO_2/mmBtu)[1].
1×10^{-3}	=	Conversion factor from kilograms to metric tons.

(3) Tier 3 Calculation Methodology. Calculate the annual CO_2 mass emissions for each fuel by using either Equation C3, C4, or C5 of this section, as appropriate.

(i) For a solid fuel, use Equation C-3 of this section.

[1] The ER required development of a site-specific emission factor for MSW. For harmonization with the MRR, this requirement was deleted. However, jurisdictions may allow or require testing to develop a site-specific emission factor as an alternative to the default emission factors in Table C-1.

$$CO_2 = \frac{44}{12} * \text{Fuel} * \text{CC} * 0.91 \qquad \text{(Eq. C-3)}$$

Where:

CO_2 = Annual CO_2 mass emissions from the combustion of the specific solid fuel (metric tons).

Fuel = Annual mass of the solid fuel combusted, from company records as defined in §98.6 (short tons).

CC = Annual average carbon content of the solid fuel (percent by weight, expressed as a decimal fraction, e.g., 95% = 0.95). The annual average carbon content shall be determined using the same procedures as specified for HHV in paragraph (a)(2)(ii) of this section.

44/12 = Ratio of molecular weights, CO_2 to carbon.

0.91 = Conversion factor from short tons to metric tons.

(ii) For a liquid fuel, use Equation C-4 of this section.

$$CO_2 = \frac{44}{12} * \text{Fuel} * \text{CC} * 0.001 \qquad \text{(Eq. C-4)}$$

Where:

CO_2 = Annual CO_2 mass emissions from the combustion of the specific liquid fuel (metric tons).

Fuel = Annual volume of the liquid fuel combusted (gallons). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to §98.3(i). Fuel billing meters may be used for this purpose. Tank drop measurements may also be used.

CC = Annual average carbon content of the liquid fuel (kg C per gallon of fuel). The annual average carbon content shall be determined using the same procedures as specified for HHV in paragraph (a)(2)(ii) of this section.

44/12 = Ratio of molecular weights, CO_2 to carbon.

0.001 = Conversion factor from kg to metric tons.

(iii) For a gaseous fuel, use Equation C-5 of this section.

$$CO_2 = \frac{44}{12} * Fuel * CC * \frac{MW}{MVC} * 0.001 \qquad \text{(Eq. C-5)}$$

Where:

CO_2	=	Annual CO_2 mass emissions from combustion of the specific gaseous fuel (metric tons).
Fuel	=	Annual volume of the gaseous fuel combusted (scf). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to §98.3(i). Fuel billing meters may be used for this purpose.
CC	=	Annual average carbon content of the liquid fuel (kg C per gallon of fuel). The annual average carbon content shall be determined using the same procedures as specified for HHV in paragraph (a)(2)(ii) of this section.
MW	=	Annual average molecular weight of the gaseous fuel (kg/kg-mole). The annual average carbon content shall be determined using the same procedures as specified for HHV in paragraph (a)(2)(ii) of this section.
MVC	=	Molar volume conversion factor (849.5 scf per kg-mole at standard conditions, as defined in §98.6).
44/12	=	Ratio of molecular weights, CO_2 to carbon.
0.001	=	Conversion factor from kg to metric tons.

(iv) Fuel flow meters that measure mass flow rates may be used for liquid fuels, provided that the fuel density is used to convert the readings to volumetric flow rates. The density shall be measured at the same frequency as the carbon content, using ASTM D1298-99 (Reapproved 2005) "Standard Test Method for Density, Relative Density (Specific Gravity), or API Gravity of Crude Petroleum and

Liquid Petroleum Products by Hydrometer Method" (incorporated by reference, see §98.7).

(v) The following default density values may be used for fuel oil, in lieu of using the ASTM method in paragraph (a)(3)(iv) of this section: 6.8 lb/gal for No. 1 oil; 7.2 lb/gal for No. 2 oil; 8.1 lb/gal for No. 6 oil.

(4) Tier 4 Calculation Methodology. Calculate the annual CO_2 mass emissions from all fuels combusted in a unit, by using quality-assured data from continuous emission monitoring systems (CEMS).

(i) This methodology requires a CO_2 concentration monitor and a stack gas volumetric flow rate monitor, except as otherwise provided in paragraph (a)(4)(iv) of this section. Hourly measurements of CO_2 concentration and stack gas flow rate are converted to CO_2 mass emission rates in metric tons per hour.

(ii) When the CO_2 concentration is measured on a wet basis, Equation C-6 of this section is used to calculate the hourly CO_2 emission rates:

$$CO_2 = 5.18x10^{-7} * C_{CO2} * Q \qquad \text{(Eq. C-6)}$$

Where:

CO_2 = CO_2 mass emission rate (metric tons/hr).
C_{CO2} = Hourly average CO_2 concentration (% CO_2).

Q = Hourly average stack gas volumetric flow rate (scfh).

5.18×10^{-7} = Conversion factor (metric tons/scf/% CO_2).

(iii) If the CO_2 concentration is measured on a dry basis, a correction for the stack gas moisture content is required. You shall either continuously monitor the stack gas moisture content as described in §75.11(b)(2) of this chapter or, for certain types of fuel, use a default moisture percentage from §75.11(b)(1) of this chapter. For each unit operating hour, a moisture correction must be applied to Equation C-6 of this section as follows:

$$CO_2^* = CO_2\left(\frac{100 - \%H_2O}{100}\right) \qquad \text{(Eq. C-7)}$$

Where:

CO_2^* = Hourly CO_2 mass emission rate, corrected for moisture (metric tons/hr).

CO_2 = Hourly CO_2 mass emission rate from Equation C-6 of this section, uncorrected (metric tons/hr).

$\%H_2O$ = Hourly moisture percentage in the stack gas (measured or default value, as appropriate).

(iv) An oxygen (O_2) concentration monitor may be used in lieu of a CO_2 concentration monitor in a CEMS installed before January 1, 2012,[2] to determine the hourly CO_2 concentrations, in accordance with Equation F-14a or F-14b (as applicable) in appendix F to 40 CFR part 75, if the

[2] A jurisdiction may want to modify this date depending on the effective date of the jurisdiction's reporting regulations.

effluent gas stream monitored by the CEMS consists solely of combustion products (i.e., no process CO_2 emissions are mixed with the combustion products) and if only fuels that are listed in Table 1 in section 3.3.5 of appendix F to 40 CFR part 75 are combusted in the unit. If the O_2 monitoring option is selected, the F-factors used in Equations F-14a and F-14b shall be determined according to section 3.3.5 or section 3.3.6 of appendix F to 40 CFR part 75, as applicable. If Equation F-14b is used, the hourly moisture percentage in the stack gas shall be either a measured value in accordance with §75.11(b)(2) of this chapter, or, for certain types of fuel, a default moisture value from §75.11(b)(1) of this chapter. An operator without a CO_2 monitor who uses a CEMS and O_2 concentrations to calculate and report a unit's CO_2 emissions, and who regularly conducts a Relative Accuracy Test Audit (RATA) for the unit, must include in the RATA at least annually the monitoring of CO2 concentration and flow, and the calculation of CO_2 mass. The operator must retain these results and make them available to [the jurisdiction] upon request.[3]

(v) Each hourly CO_2 mass emission rate from Equation C-6 or C-7 of this section is multiplied by the operating

[3] The additional language is optional.

time to convert it from metric tons per hour to metric tons. The operating time is the fraction of the hour during which fuel is combusted (e.g., the unit operating time is 1.0 if the unit operates for the whole hour and is 0.5 if the unit operates for 30 minutes in the hour). For common stack configurations, the operating time is the fraction of the hour during which effluent gases flow through the common stack.

(vi) The hourly CO_2 mass emissions are then summed over each calendar quarter and the quarterly totals are summed to determine the annual CO_2 mass emissions.

(vii) If both biomass and fossil fuel are combusted during the year, determine and report the biogenic CO_2 mass emissions separately, as described in paragraph (e) of this section.

(5) Alternative methods for units with continuous monitoring systems. Units not subject to the Acid Rain Program that report data to EPA according to 40 CFR part 75 may use the alternative methods in this paragraph in lieu of using any of the four calculation methodology tiers.

(i) For a unit that combusts only natural gas and/or fuel oil, is not subject to the Acid Rain Program, monitors and reports heat input data year-round according to appendix D to 40 CFR part 75, but is not required by the applicable 40 CFR part 75 program to report CO_2 mass emissions data, calculate the annual CO_2 mass emissions for the purposes of this part as follows:

(A) Use the hourly heat input data from appendix D to 40 CFR part 75, together with Equation G-4 in appendix G to 40 CFR part 75 to determine the hourly CO_2 mass emission rates, in units of tons/hr;

(B) Use Equations F-12 and F-13 in appendix F to 40 CFR part 75 to calculate the quarterly and cumulative annual CO_2 mass emissions, respectively, in units of short tons; and

(C) Divide the cumulative annual CO_2 mass emissions value by 1.1 to convert it to metric tons.

(ii) For a unit that combusts only natural gas and/or fuel oil, is not subject to the Acid Rain Program, monitors and reports heat input data year-round according to 40 CFR 75.19 of this chapter but is not required by the applicable 40 CFR part 75 program to report CO_2 mass emissions data, calculate the annual CO_2 mass emissions for the purposes of this part as follows:

(A) Calculate the hourly CO_2 mass emissions, in units of short tons, using Equation LM-11 in 40 CFR 75.19(c)(4)(iii).

(B) Sum the hourly CO_2 mass emissions values over the entire reporting year to obtain the cumulative annual CO_2 mass emissions, in units of short tons.

(C) Divide the cumulative annual CO_2 mass emissions value by 1.1 to convert it to metric tons.

(iii) For a unit that is not subject to the Acid Rain Program, uses flow rate and CO_2 (or O_2) CEMS to report heat input data year-round according to 40 CFR part 75, but is not required by the applicable 40 CFR part 75 program to report CO_2 mass emissions data, calculate the annual CO_2 mass emissions as follows:

(A) Use Equation F-11 or F-2 (as applicable) in appendix F to 40 CFR part 75 to calculate the hourly CO_2 mass emission rates from the CEMS data. If an O_2 monitor is used, convert the hourly average O_2 readings to CO_2 using Equation F-14a or F-14b in appendix F to 40 CFR part 75 (as applicable), before applying Equation F-11 or F-2.

(B) Use Equations F-12 and F-13 in appendix F to 40 CFR part 75 to calculate the quarterly and cumulative annual CO_2 mass emissions, respectively, in units of short tons.

(C) Divide the cumulative annual CO_2 mass emissions value by 1.1 to convert it to metric tons.

(D) If both biomass and fossil fuel are combusted during the year, determine and report the biogenic CO_2 mass emissions separately, as described in paragraph (e) of this section.

(b) Use of the four tiers. Use of the four tiers of CO_2 emissions calculation methodologies described in paragraph (a) of this section is subject to the following conditions, requirements, and restrictions:

(1) The Tier 1 Calculation Methodology:

(i) May be used for any fuel listed in Table C-1 of this subpart that is combusted in a unit with a maximum rated heat input capacity of 250 mmBtu/hr or less at a facility that is not subject to verification, and may be used for any fuel listed in Table C-1a of this subpart that is combusted in a unit with a maximum rated heat input capacity of 250 mmBtu/hr or less at any facility.

(ii) May be used for MSW in a unit of any size that does not produce steam, if the use of Tier 4 is not required.

(iii) May be used for solid, gaseous, or liquid biomass fuels in a unit of any size provided that the fuel is listed in Table C-1 of this subpart and has been determined by [the jurisdiction] not to be subject to a compliance obligation under the cap-and-trade program.[4]

(iv) May not be used if you routinely perform fuel sampling and analysis for the fuel high heat value (HHV) or routinely receives the results of HHV sampling and analysis from the fuel supplier at the minimum frequency specified in §98.34(a), or at a greater frequency. In such cases, Tier 2 or higher shall be used.

(2) The Tier 2 Calculation Methodology:

(i) May be used for the combustion of any type of fuel in a unit with a maximum rated heat input capacity of 250 mmBtu/hr or less at any facility provided that the fuel is pipeline quality natural gas or is listed in ~~Table C-1~~ Table C-1a of this subpart.

(ii) May be used in a unit with a maximum rated heat input capacity greater than 250 mmBtu/hr for the combustion of pipeline quality natural gas and distillate fuel oil.

(iii) May be used for MSW or solid biomass fuel[5] in a unit of any size that produces steam, if Equation C-2c is employed and if the use of Tier 4 is not required.

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[4] Under the WCI design recommendations, biomass determined to be carbon neutral may be excluded from the cap-and-trade program.

The added language in this paragraph is optional. A jurisdiction may choose to require a higher tier for any or all biomass fuels.

[5] Consistent with 98.33(a)(2)(iii).

(iv) May be used for the combustion of any fuel listed in Table C-1 at a facility that is not subject to verification or to 40 C.F.R. Part 98.

(3) The Tier 3 Calculation Methodology:

(i) May be used for a unit of any size that combusts any type of fuel listed in Table C-1 of this subpart (except for MSW), unless the use of Tier 4 is required.

(ii) Shall be used for the combustion of a fuel listed in Table C-1 of this subpart in a unit ~~with~~ that has a maximum rated heat input capacity greater than 250 mmBtu/hr or is located a a facility subject to verification ~~that combusts any type of fuel listed in Table C-1 of this subpart (except MSW)~~, unless either of the following conditions apply:

(A) The use of Tier 1 or 2 is permitted, as described in paragraphs (b)(1)~~(iii)~~ and (b)(2)~~(ii)~~ of this section.

(B) The use of Tier 4 is required.

(iii) Shall be used for a fuel not listed in Table C-1 of this subpart ~~if the fuel is combusted in a unit with a maximum rated heat input capacity greater than 250 mmBtu/hr~~ provided that ~~both of the following conditions apply:~~

~~(A)~~ The use of Tier 4 is not required.

~~(B) The fuel provides 10% or more of the annual heat input to the unit or, if §98.36(c)(3)applies, to a group of units served by common supply pipe.~~ [Reserved]

(4) The Tier 4 Calculation Methodology:

(i) May be used for a unit of any size, combusting any type of fuel.

(ii) Shall be used if the unit meets all six of the conditions specified in paragraphs (b)(4)(ii)(A) through (b)(4)(ii)(F) of this section:

(A) The unit has a maximum rated heat input capacity greater than 250 mmBtu/hr, or if the unit combusts municipal solid waste and has a maximum rated input capacity greater than 250 tons per day of MSW.

(B) The unit combusts solid fossil fuel or MSW, either as a primary or secondary fuel.

(C) The unit has operated for more than 1,000 hours in any calendar year since 2005.

(D) The unit has installed CEMS that are required either by an applicable Federal or State regulation or the unit's operating permit.

(E) The installed CEMS include a gas monitor of any kind or a stack gas volumetric flow rate monitor, or both and the monitors have been certified, either in accordance with the requirements of 40 CFR part 75, part 60 of this chapter, or an applicable State continuous monitoring program.

(F) The installed gas or stack gas volumetric flow rate monitors are required, either by an applicable Federal or State regulation or by the unit's operating permit, to undergo periodic quality assurance testing in accordance with either appendix B to 40 CFR part 75, appendix F to 40 CFR part 60, or an applicable State continuous monitoring program.

(iii) Shall be used for a unit with a maximum rated heat input capacity of 250 mmBtu/hr or less and for a unit that combusts municipal solid waste with a maximum rated input capacity of 250 tons of MSW per day or less, if the unit meets all of the following three conditions:

(A) The unit has both a stack gas volumetric flow rate monitor and a CO_2 concentration monitor.

(B) The unit meets the conditions specified in paragraphs (b)(4)(ii)(B) through (b)(4)(ii)(D) of this section.

(C) The CO_2 and stack gas volumetric flow rate monitors meet the conditions specified in paragraphs (b)(4)(ii)(E) and (b)(4)(ii)(F) of this section.

(5) The Tier 4 Calculation Methodology shall be used beginning on:

(i) January 1, 2010, for a unit that is required to report CO_2 mass emissions beginning on that date, if all of the monitors needed to measure CO_2 mass emissions have been installed and certified by that date.

(ii) January 1, 2011, for a unit that is required to report CO_2 mass emissions beginning on January 1, 2010, if all of the monitors needed to measure CO_2 mass emissions have not been installed and certified by January 1, 2010. In this case, you may use Tier 2 or Tier 3 to report GHG emissions for 2010.

(6) You may elect to use any applicable higher tier for one or more of the fuels combusted in a unit. For example, if a 100 mmBtu/hr unit combusts natural gas and distillate fuel oil, you may elect to use Tier 1 for natural gas and Tier 3 for the fuel oil, even though Tier 1 could have been used for both fuels. However, for units that use either the Tier 4 or the alternative calculation methodology specified in paragraph (a)(5) of this section, CO_2 emissions from the combustion of all fuels shall be based solely on CEMS measurements.

(c) Calculation of CH_4 and N_2O emissions from stationary combustion sources. You must calculate annual CH_4 and N_2O mass emissions only for units that are required to report CO_2 emissions using the calculation methodologies of this subpart and for only those fuels that are listed in Table C-2 of this subpart.

(1) Use Equation C-8 of this section to estimate CH_4 and N_2O emissions for any fuels for which you use the Tier 1 or Tier 3 calculation methodologies for CO_2. Use the same values for fuel combustion that you use for the Tier 1 or Tier 3 calculation.

$$CH_4 \ or \ N_2O = 1 \, x \, 10^{-3} * Fuel * HHV * EF \qquad \text{(Eq. C-8)}$$

Where:

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons).

Fuel = Mass or volume of the fuel combusted, either from company records or directly measured by a fuel flow meter, as applicable (mass or volume per year).

HHV = Default high heat value of the fuel from Table C-1 of this subpart (mmBtu per mass or volume).

EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 of this subpart (kg CH_4 or N_2O per mmBtu).

1×10^{-3} = Conversion factor from kilograms to metric tons.

(2) Use Equation C-9a of this section to estimate CH_4 and N_2O emissions for any fuels for which you use the Tier 2 Equation C-2a of this section to estimate CO_2 emissions. Use the same values for fuel combustion and HHV that you use for the Tier 1 or Tier 3 calculation.

$$CH_4 \text{ or } N_2O = 1 \text{ x } 10^{-3} * HHV * EF * Fuel \qquad \text{(Eq. C-9a)}$$

Where:

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons).

Fuel = Mass or volume of the fuel combusted during the reporting year.

HHV = High heat value of the fuel, averaged for all valid measurements for the reporting year (mmBtu per mass or volume).

EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 of this subpart (kg CH_4 or N_2O per mmBtu).

1 x 10^{-3} = Conversion factor from kilograms to metric tons.

(3) Use Equation C-9b of this section to estimate CH_4 and N_2O emissions for any fuels for which you use Equation C-2c of this section to calculate the CO_2 emissions. Use the same values for steam generation and the ratio "B" that you use for Equation C-2c.

$$CH_4 \text{ or } N_2O = 1 \text{ x } 10^{-3} \text{ Steam} * B * EF \qquad \text{(Eq. C-9b)}$$

Where:

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a solid fuel (metric tons).

Steam = Total mass of steam generated by solid fuel combustion during the reporting year (lb steam).

B = Ratio of the boiler's maximum rated heat input capacity to its design rated steam output (mmBtu/lb steam).

EF = Fuel-specific emission factor for CH_4 or N_2O, from Table C-2 of this subpart (kg CH_4 or N_2O per mmBtu).

1×10^{-3} = Conversion factor from kilograms to metric tons.

(4) Use Equation C-10 of this section for units in the Acid Rain Program, units that monitor and report heat input on a year-round basis according to 40 CFR part 75, and units that use the Tier 4 Calculation Methodology.

$$CH_4 \text{ or } N_2O = 0.001 * (HI)_A * EF \qquad \text{(Eq. C-10)}$$

Where:

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons).

$(HI)_A$ = Cumulative annual heat input from the fuel, derived from the electronic data reports required under §75.64 of this chapter or, for Tier 4 units, from the best available information as described in paragraph (c)(4)(ii) of this section(mmBtu).

EF = Fuel-specific emission factor for CH_4 or N_2O, from Table C-2 of this section (kg CH_4 or N_2O per mmBtu).

0.001 = Conversion factor from kg to metric tons.

(i) If only one type of fuel listed in Table C-2 of this subpart is combusted during normal operation, substitute the cumulative annual heat input from combustion of the fuel into Equation C-10 of this section to calculate the annual CH_4 or N_2O emissions.

(ii) If more than one type of fuel listed in Table C-2 of this subpart is combusted during normal operation, use Equation C-10 of this section separately for each type of fuel. If flow rate and diluent gas monitors are used to measure the unit heat input, use the best available information (e.g., fuel feed rate measurements, fuel heating values, engineering analysis) to estimate the annual heat input from each type of fuel.

(5) When multiple fuels are combusted during the reporting year, sum the fuel-specific results from Equations C-8, C-9a, C-9b, or C-10 of this section (as applicable) to obtain the total annual CH_4 and N_2O emissions, in metric tons.

(6) The operator may elect to calculate CH_4 or N_2O emissions using source-specific emission factors derived from source tests conducted at least annually under the supervision of [jurisdiction]. Upon approval of a source test plan, the source test procedures in that plan shall be repeated in each future year to update the source specific emission factors annually.

(d) Calculation of CO_2 from sorbent.

(1) When a unit is a fluidized bed boiler, is equipped with a wet flue gas desulfurization system, or uses other acid gas emission controls with sorbent

injection, use Equation C-11 of this section to calculate the CO_2 emissions from the sorbent, if those CO_2 emissions are not monitored by CEMS:

$$CO_2 = 0.91 * S * R * \left(\frac{MW_{CO2}}{MW_S}\right) \qquad \text{(Eq. C-11)}$$

Where:

CO_2 = CO_2 emitted from sorbent for the reporting year (metric tons).

S = Limestone or other sorbent used in the reporting year, from company records (short tons).

R = 1.00, the calcium-to-sulfur stoichiometric ratio.

MW_{CO2} = Molecular weight of carbon dioxide (44).

MW_S = Molecular weight of sorbent (100 if calcium carbonate).

0.91 = Conversion factor from short tons to metric tons

(2) The annual CO_2 mass emissions for the unit shall be the sum of the CO_2 emissions from the combustion process and the CO_2 emissions from the sorbent.

(e) CO_2 emissions from combustion of biomass. Use the procedures of this paragraph (e) to estimate biogenic CO_2 emissions from units that combust a combination of biomass and fossil fuels. Reporting of CO_2 emissions from combustion of biomass is required only for those biomass fuels listed in Table C-1 of this section, unless emissions are measured using CEMS.

(1) If CEMS are not used to measure CO_2, use Equation C-1 or C-2c of this subpart to calculate the annual CO_2 mass emissions from the combustion of biomass (except MSW) for a unit of any size. Determine the mass of biomass combusted using one of the following procedures in this paragraph (e)(1), as appropriate.

(i) Use company records.

(ii) Follow the procedures in paragraph (e)(5) of this section.

(iii) For premixed fuels that contain biomass and fossil fuels (e.g., mixtures containing biodiesel), use best available information to determine the mass of biomass fuels and document the procedure used in the GHG Monitoring Plan required by §98.3(g)(5).

(2) If a CO_2 CEMS (or a surrogate O_2 monitor) and a stack gas flow rate monitor are used to determine the annual CO_2 mass emissions either according to 40 CFR part 75, the Tier 4 Calculation Methodology, or the alternative calculation methodology specified in paragraph (a)(5)(iii); and if both fossil fuel and biomass (except for MSW) are combusted in the unit during the reporting year, you may use the following procedure to determine the annual biogenic CO_2 mass emissions. If MSW or a fossil fuel/biomass mixture containing an undeterminable quantity

of fossil fuels is combusted in the unit, follow the procedures in paragraph (e)(3) of this section.

(i) For each operating hour, use Equation C-12 of this section to determine the volume of CO_2 emitted.

$$V_{CO2h} = \frac{(\%CO_2)_h}{100} * Q_h * t_h \qquad \text{(Eq. C-12)}$$

Where:

V_{CO2h} = Hourly volume of CO_2 emitted (scf).

$(\%CO_2)_h$ = Hourly average CO_2 concentration, measured by the CO_2 concentration monitor, or, if applicable, calculated from the hourly average O_2 concentration ($\%CO_2$).

Q_h = Hourly average stack gas volumetric flow rate, measured by the stack gas volumetric flow rate monitor (scfh).

t_h = Source operating time (decimal fraction of the hour during which the source combusts fuel, i.e., 1.0 for a full operating hour, 0.5 for 30 minutes of operation, etc.).

100 = Conversion factor from percent to a decimal fraction.

(ii) Sum all of the hourly V_{CO2h} values for the reporting year, to obtain V_{total}, the total annual volume of CO_2 emitted.

(iii) Calculate the annual volume of CO_2 emitted from fossil fuel combustion using Equation C-13 of this section. If two or more types of fossil fuel are combusted during the year, perform a separate calculation with Equation C-13 of this section for each fuel and sum the results.

$$V_{ff} = \frac{Fuel * F_c * HHV}{10^6} \qquad \text{(Eq. C-13)}$$

Where:

V_{ff} = Annual volume of CO_2 emitted from combustion of a particular fossil fuel (scf).

Fuel = Total quantity of the fossil fuel combusted in the reporting year, from company records, as defined in §98.6 (lb for solid fuel, gallons for liquid fuel, and scf for gaseous fuel).

F_c = Fuel-specific carbon based F-factor, either a default value from Table 1 in section 3.3.5 of appendix F to 40 CFR part 75 or a site-specific value determined under section 3.3.6 of appendix F to 40 CFR part 75 (scf CO_2/mmBtu).

HHV = High heat value of the fossil fuel, from fuel sampling and analysis (annual average value in Btu/lb for solid fuel, Btu/gal for liquid fuel and Btu/scf for gaseous fuel, sampled as specified (e.g., monthly, quarterly, semi-annually, or by lot) in §98.34(a)(2)). The average HHV shall be calculated according to the requirements of paragraph (a)(2)(ii) of this section.

10^6 = Conversion factor, Btu per mmBtu.

(iv) Subtract V_{ff} from V_{total} to obtain V_{bio}, the annual volume of CO_2 from the combustion of biomass. If a CEMS is being used to measure the combined combustion and process emissions from a unit that is subject to another subpart of part 98, then also subtract CO_2 process emissions from V_{total} to determine V_{bio}. The CO_2 process emissions must be calculated according to the requirements of the applicable subpart.

(v) Calculate the biogenic percentage of the annual CO_2 emissions,expressed as a decimal fraction, using Equation C-14 of this section:

$$\%\ Biogenic = \frac{V_{bio}}{V_{total}} \qquad \text{(Eq. C-14)}$$

(vi) Calculate the annual biogenic CO_2 mass emissions, in metric tons, by multiplying the results obtained from Equation C-14 of this section by the annual CO_2 mass emissions in metric tons, as determined:

(A) Under paragraph (a)(4)(vi) of this section, for units using the Tier 4 Calculation Methodology.

(B) Under paragraph (a)(5)(iii)(B) of this section, for units using the alternative calculation methodology specified in paragraph (a)(5)(iii).

(C) From the electronic data report required under §75.64 of this chapter, for units in the Acid Rain Program and other units using CEMS to monitor and report CO_2 mass emissions according to 40 CFR part 75. However, before calculating the annual biogenic CO_2 mass emissions, multiply the cumulative annual CO_2 mass emissions by 0.91 to convert from short tons to metric tons.

(3) For a unit that combusts MSW, the annual biogenic CO_2 emissions shall be calculated using the procedures in this paragraph (3).

(i) If the Tier 1 or Tier 2 Calculation Methodology is used to quantify CO_2 mass emissions:

(A) Use Equation C-1 or C-2c of this subpart, as appropriate, to calculate the annual CO_2 mass emissions from MSW combustion.

(B) Determine the relative proportions of biogenic and non-biogenic CO_2 emissions on a quarterly basis using the method specified in §98.34(d).

(C) Determine the annual biogenic CO_2 mass emissions from MSW combustion by multiplying the annual CO_2 mass emissions by the annual average biogenic decimal fraction obtained from §98.34(d).

(ii) If the unit uses Tier 4 to quantify CO_2 emissions:

(A) Follow the procedures in paragraphs (e)(2)(i) and (ii) of this section, to determine V_{total}.

(B) If any fossil fuel was combusted during the year, follow the procedures in paragraph (e)(2)(iii) of this section, to determine V_{ff}.

(C) Subtract V_{ff} from V_{total}, to obtain V_{MSW} , the annual volume of CO_2 emissions from MSW combustion.

(D) Determine the annual volume of biogenic CO_2 emissions (V_{bio}) from MSW combustion as follows. Multiply the annual volume of CO_2 emissions from MSW combustion (V_{MSW})

by the annual average biogenic decimal fraction obtained from ASTM D6866-08 and ASTM D7459-08.

(E) Calculate the biogenic percentage of the annual CO_2 emissions from the unit, using Equation C-14 of this section. For the purposes of this calculation, the term "V_{bio}" in the numerator of Equation C-14 of this section shall be the results of the calculation performed under paragraph (e)(3)(ii)(D) of this section.

(F) Calculate the annual biogenic CO_2 mass emissions according to paragraph (e)(2)(vi)(A) of this section.

(4) As an alternative to the procedures in paragraph (e)(2) of this section, use ASTM Methods D7459-08 and D6866-08 to determine the biogenic portion of the annual CO_2 emissions, as described in §98.34(e). If this option is selected, the results of each determination shall be expressed as a decimal fraction (e.g., 0.30, if 30 percent of the CO_2 is biogenic), and the values shall be averaged over the reporting year. The annual biogenic CO_2 mass emissions shall be calculated by multiplying the the total annual CO_2 mass emissions by the annual average biogenic fraction obtained from ASTM D6866-08 and ASTM D7459-08.

(5) If Equation C-1 of this section is selected to calculate the annual biogenic mass emissions for wood, wood waste, or other solid biomass-derived fuel, Equation C-15

of this section may be used to quantify biogenic fuel consumption, provided that all of the required input parameters are accurately quantified. Similar equations and calculation methodologies based on steam generation and boiler efficiency may be used, provided that they are documented in the GHG Monitoring Plan required by §98.3(g)(5).

$$(Fuel)_p = \frac{[H * S] - (HI)_{nb}}{2000\,(HHV)_{bio}\,(Eff)_{bio}} \quad \text{(Eq. C-15)}$$

Where:

$(Fuel)_p$	=	Quantity of biomass consumed during the measurement period "p" (tons/year or tons/month, as applicable).
H	=	Average enthalpy of the boiler steam for the measurement period (Btu/lb).
S	=	Total boiler steam production for the measurement period (lb/month or lb/year, as applicable).
$(HI)_{nb}$	=	Heat input from co-fired fossil fuels and non-biomass-derived fuels for the measurement period, based on company records of fuel usage and default or measured HHV values (Btu/month or Btu/year, as applicable).
$(HHV)_{bio}$	=	Default or measured high heat value of the biomass fuel (Btu/lb).
$(Eff)_{bio}$	=	Percent efficiency of biomass-to-energy conversion, expressed as a decimal fraction.
2000	=	Conversion factor (lb/ton).

(f) [Reporting only] Calculating fugitive HFC emissions from cooling units.[6] Operators of electricity generating facilities shall calculate fugitive HFC emissions for each HFC compound used in cooling units that support power generation or are used in heat transfers to cool stack gases using either the methodology in paragraph (f)(1) or (f)(2). The Operator is not required to report GHG emissions from air or water cooling systems or condensers that do not contain HFCs.

(1) Use Equation C-16 to calculate annual HFC emissions:

$$HFC = HFC_{inventory} + HFC_{purchases/acquisitions} - HFC_{sales/disbursements} + HFC_{\Delta capacity} \qquad \text{Eqn. C-16}$$

Where:

HFC = Annual fugitive HFC emission, metric tons;

$HFC_{inventory}$ = The difference between the quantity of HFC in storage at the beginning of the year and the quantity in storage at the end of the year. Stored HFC includes HFC contained in cylinders (such as 115-pound storage cylinders), gas carts, and other storage containers. It does not include HFC gas held in operating equipment. The change in inventory will be negative if the quantity of HFC in storage increases over the course of the year.

$HFC_{purchases/acquisitions}$ = The sum of all HFC acquired from other entities during the year either in storage containers or in equipment.

$HFC_{sales/disbursements}$ = The sum of all the HFC sold or otherwise transferred offsite to other entities during the year either in storage containers or in equipment.

[6] Taken from WCI.43(d).

$HFC_{\Delta capacity}$ = The net change in the total nameplate capacity (i.e. the full and proper charge) of the cooling equipment). The net change in capacity will be negative if the total nameplate capacity at the end of the year is less than the total nameplate capacity at the beginning of the year.

(2) Use service logs to document HFC usage and emissions from each cooling unit. Service logs should document all maintenance and service performed on the unit during the report year, including the quantity of HFCs added to or removed from the unit, and include a record at the beginning and end of each report year. The operator may use service log information along with the following simplified material balance equations to quantify fugitive HFCs from unit installation, servicing, and retirement, as applicable. The operator shall include the sum of HFC emissions from the applicable equations in the greenhouse gas emissions data report.

$$HFC_{Install} = R_{new} - C_{new}$$

$$HFC_{Service} = R_{recharge} - R_{Recover}$$

$$HFC_{Retire} = C_{retire} - R_{retire}$$

Where:

$HFC_{Install}$ = HFC emitted during initial charging/installation of the unit, kilograms;

$HFC_{Service}$ = HFC emitted during use and servicing of the unit for the report year, kilograms;

HFC_{Retire} = HFC emitted during the removal from service/retirement of the unit, kilograms;

R_{new} = HFC used to fill new unit (omit if unit was pre-charged by the manufacturer), kilograms;

C_{new} = Nameplate capacity of new unit (omit if unit was pre-charged by the manufacturer), kilograms;

$R_{recharge}$ = HFC used to recharge the unit during maintenance and service, kilograms;

$R_{recover}$ = HFC recovered from the unit during maintenance and service, kilograms;

C_{retire} = Nameplate capacity of the retired unit, kilograms; and

R_{retire} = HFC recovered from the retired unit, kilograms.

§98.34 Monitoring and QA/QC requirements.

The CO_2 mass emissions data for stationary fuel combustion sources shall be monitored as follows:

(a) For the Tier 2 Calculation Methodology:

(1) All fuel samples shall be taken at a location in the fuel handling system that provides a sample representative of the fuel combusted. The fuel sampling and analysis may be performed by either the owner or operator or the supplier of the fuel.

(2) The minimum required frequency of the HHV sampling and analysis for each type of fuel is specified in this paragraph. When the specified frequency is based on a specified time period (i.e., weekly, monthly, quarterly, or semiannually), fuel sampling and analysis is required only for those periods in which the unit operates.

(i) For natural gas, semiannual sampling and analysis is required (i.e., twice in a calendar year, with consecutive samples taken at least four months apart).

(ii) For coal and fuel oil, analysis of at least one representative sample from each fuel lot is required. For the purposes of this section, a fuel lot is defined as a shipment or delivery of a single fuel (e.g., ship load, barge load, group of trucks, group of railroad cars, etc.).

(iii) For liquid fuels other than fuel oil, for fossil fuel-derived gaseous fuels, and for biogas; sampling and analysis is required at least once per calendar quarter. To the extent practicable, consecutive quarterly samples shall be taken at least 30 days apart.

(iv) For solid fuels other than coal and MSW, weekly sampling is required to obtain composite samples, which are then analyzed monthly.

(3) If different types of fuel (e.g., different ranks of coal or different grades of fuel oil) are blended prior to combustion, use one of the following procedures in this paragraph.

(i) Use a weighted HHV value in the emission calculations, based on the relative proportions of each fuel in the blend.

(ii) Take a representative sample of the blend and analyze it for HHV.

(4) If, for a particular type of fuel, HHV sampling and analysis is performed more often than the minimum frequency specified in paragraphs (a)(2)of this section, the results of all valid fuel analyses shall be used in the GHG emission calculations.

(5) If, for a particular type of fuel, valid HHV values are obtained at less than the minimum frequency specifed in paragraphs (a)(2) of this section, appropriate substitute data values shall be used in the emissions calculations, in accordance with missing data procedures of §98.35.

(6) Use any applicable fuel sampling and analysis methods in this paragraph (a)(6) to determine the high heat values. Alternatively, for gaseous fuels, the HHV may be calculated using chromatographic analysis together with standard heating values of the fuel constituents, provided that the gas chromatograph is operated, maintained, and calibrated according to the manufacturer's instructions.

(i) ASTM D4809-06 Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method) (incorporated by reference, see §98.7).

(ii) ASTM D240-02 (Reapproved 2007) Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (incorporated by reference, see §98.7).

(iii) ASTM D1826-94 (Reapproved 2003) Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter (incorporated by reference, see §98.7).

(iv) ASTM D3588-98 (Reapproved 2003) Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels (incorporated by reference, see §98.7).

(v) ASTM D4891-89 (Reapproved 2006) Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion (incorporated by reference, see §98.7).

(vi) GPA Standard 2172–09 Calculation of Gross Heating Value, Relative Density, Compressibility and Theoretical Hydrocarbon Liquid Content for Natural Gas Mixtures for Custody Transfer (incorporated by reference, see §98.7).

(vii) GPA Standard 2261–00, Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography (incorporated by reference, see §98.7).

(viii) ASTM D5865-07a, Standard Test Method for Gross Calorific Value of Coal and Coke (incorporated by reference, see §98.7).

(b) For the Tier 3 Calculation Methodology:

(1) Calibrate each oil and gas flow meter according to §98.3(i) and the provisions of paragraph (b).

(i) Perform calibrations using any of the test methods and procedures in this paragraph (b)(1)(i):

(A) An applicable flow meter test method listed in paragraphs (b)(4)(i) through (b)(4)(viii) of this section.

(B) The calibration procedures specified by the flow meter manufacturer.

(C) An industry-accepted or industry standard calibration practice.

(ii) In addition to the initial calibration required by §98.3(i), recalibrate each fuel flow meter (except for qualifying billing meters under paragraph (b)(1)(iii) of this section) either annually, at the minimum frequency specified by the manufacturer, or at the interval specified by the industry consensus standard practice used.

(iii) Fuel billing meters are exempted from the initial and ongoing calibration requirements of this paragraph, provided that the fuel supplier and the unit combusting the fuel do not have any common owners and are not owned by subsidiaries or affiliates of the same company.

(iv) For the initial calibration of an orifice, nozzle, or venturi meter; in-situ calibration of the transmitters is sufficient. A primary element inspection (PEI) shall be performed at least once every three years.

(v) For the continuously-operating units and processes described in §98.3(i)(6), the required flow meter recalibrations and, if necessary, the PEIs may be postponed until the next scheduled maintenance outage.

(vi) If a mixture of fuels is transported by a common pipe (e.g., still gas and supplementary natural gas), you must either separately meter each of the fuels prior to mixing using flow meters calibrated according to §98.3(i), or use flow meters calibrated according to §98.3(i) to measure the mixed fuel at the common pipe and to separately meter an appropriate subset of the fuels prior to mixing. If the latter option is chosen, quantify the fuels that are not measured prior to mixing by subtracting out the fuels measured prior to mixing from the fuel measured at the common pipe.

(2) Oil tank drop measurements (if used to determine liquid fuel use volume) shall be performed according to any an appropriate method published by a consensus-based standards organization (e.g., the American Petroleum Institute).

(3) The carbon content and, if applicable, molecular weight of the fuels shall be determined according to the procedures in paragraph (b)(3).

(i) All fuel samples shall be taken at a location in the fuel handling system that provides a sample representative of the fuel combusted. The fuel sampling and analysis may be performed by either the owner or operator or by the supplier of the fuel.

(ii) At a minimum, fuel samples shall be collected at the frequency specified in this paragraph. When sampling is required at a specified time interval (e.g., weekly, monthly, quarterly, or semiannually), fuel sampling and analysis is required for only those specified periods in which the unit operates.

(A) For natural gas, semiannual sampling and analysis is required (i.e., twice in a calendar year, with consecutive samples taken at least four months apart).

(B) For coal and fuel oil, analysis of at least one representative sample from each fuel lot is required. For the purposes of this section, a fuel lot is defined as a shipment or delivery of a single fuel (e.g., ship load, barge load, group of trucks, group of railroad cars, etc.).

(C) For other liquid fuels other than fuel oil, for fossil fuel-derived gaseous fuels, and for biogas; sampling and analysis is required at least once per calendar quarter. To the extent practicable, consecutive quarterly samples shall be taken at least 30 days apart.

(D) For solid fuels other than coal, weekly sampling is required to obtain composite samples, which are then analyzed monthly.

(E) For gaseous fuels other than natural gas and biogas (e.g., refinery gas), daily sampling and analysis to determine the carbon content and molecular weight of the fuel is required if the necessary equipment is in place to make these measurements. Otherwise, weekly sampling and analysis shall be performed. The equipment necessary to perform daily sampling and analysis of carbon content and molecular weight for refinery fuel gas must be installed no later than January 1, 2012.

(iii) If, for a particular type of fuel, sampling and analysis for carbon content and molecular weight is performed more often than the minimum frequency specified in paragraph (b)(3) of this section, the results of all valid fuel analyses shall be used in the GHG emission calculations.

(iv) If, for a particular type of fuel, sampling and analysis for carbon content and molecular weight is performed at less than the minimum frequency specifed in paragraph (b)(3) of this section, appropriate substitute data values shall be used in the emissions calculations, in accordance with the missing data procedures of §98.35.

(v) The procedures of paragraphs (a)(3) of this section apply to carbon content and molecular weight determinations.

(4) Use any applicable standard method from the following list to quality assure the data from each fuel flow meter.

(i) AGA Report No. 3, Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids, Part 1: General Equations and Uncertainty Guidelines (1990) and Part 2: Specification and Installation Requirements (2000)(incorporated by reference, see §98.7).

(ii) AGA Transmission Measurement Committee Report No. 7, Measurement of Gas by Turbine Meters (2006) (incorporated by reference, see §98.7).

(iii) ASME MFC-3M-2004 Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi (incorporated by reference, see §98.7).

(iv) ASME MFC-4M-1986 (Reaffirmed 1997), Measurement of Gas Flow by Turbine Meters (incorporated by reference, see §98.7).

(v) ASME MFC-5M-1985 (Reaffirmed 1994), Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters (incorporated by reference, see §98.7).

(vi) ASME MFC-6M-1998 Measurement of Fluid Flow in Pipes Using Vortex Flowmeters (incorporated by reference, see §98.7).

(vii) ASME MFC–7M–1987 (Reaffirmed 1992), Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles (incorporated by reference, see §98.7).

(viii) ASME MFC–9M–1988 (Reaffirmed 2001), Measurement of Liquid Flow in Closed Conduits by Weighing Method (incorporated by reference, see §98.7).

(5) Use any applicable methods from the following list to determine the carbon content and molecular weight (for gaseous fuel) of the fuel. Alternatively, the results of chromatographic analysis of the fuel may be used, provided that the gas chromatograph is operated, maintained, and calibrated according to the manufacturer's instructions.

(i) ASTM D1945-03 Standard Test Method for Analysis of Natural Gas by Gas Chromatography (incorporated by reference, see §98.7).

(ii) ASTM D1946-90 (Reapproved 2006) Standard Practice for Analysis of Reformed Gas by Gas Chromatography (incorporated by reference, see §98.7).

(iii) ASTM D2502-04 (Reapproved 2002) Standard Test Method for Estimation of Molecular Weight (Relative Molecular Mass) of Petroleum Oils from Viscosity Measurements (incorporated by reference, see §98.7).

(iv) ASTM D2503-92 (Reapproved 2007) Standard Test Method for Relative Molecular Mass (Relative Molecular Weight) of Hydrocarbons by Thermoelectric Measurement of Vapor Pressure (incorporated by reference, see §98.7).

(v) ASTM D3238-95 (Reapproved 2005) Standard Test Method for Calculation of Carbon Distribution and Structural Group Analysis of Petroleum Oils by the n-d-M Method (incorporated by reference, see §98.7).

(vi) ASTM D5291-02 (Reapproved 2007) Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants (incorporated by reference, see §98.7).

(vii) ASTM D5373-08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal (incorporated by reference, see §98.7).

(c) For the Tier 4 Calculation Methodology, the CO_2 and flow rate monitors must be certified prior to the applicable deadline specified in §98.33(b)(5).

(1) For initial certification, you may use any one of the following three procedures in this paragraph.

(i) §75.20(c)(2) and (4) and appendix A to 40 CFR part 75.

(ii) The calibration drift test and relative accuracy test audit (RATA) procedures of Performance Specification 3 in appendix B to part 60 (for the CO_2 concentration monitor) and Performance Specification 6 in appendix B to part 60 (for the continuous emission rate monitoring system (CERMS)).

(iii) The provisions of an applicable State continuous monitoring program.

(2) If an O_2 concentration monitor is used to determine CO_2 concentrations, the applicable provisions of 40 CFR part 75, 40 CFR part 60, or an applicable State continuous monitoring program shall be followed for initial certification and on-going quality assurance, and all required RATAs of the monitor shall be done on a percent CO_2 basis.

(3) For ongoing quality assurance, follow the applicable procedures in either appendix B to 40 CFR part 75, appendix F to 40 CFR part 60, or an applicable State continuous monitoring program. If appendix F to 40 CFR part 60 is selected for on-going quality assurance, perform daily calibration drift assessments for both the CO_2 monitor (or surrogate O_2 monitor) and the flow rate monitor, conduct cylinder gas audits of the CO_2 concentration monitor in three of the four quarters of each year (except for non-

operating quarters), and perform annual RATAs of the CO_2 concentration monitor and the CERMS.

(4) For the purposes of this part, the stack gas volumetric flow rate monitor RATAs required by appendix B to 40 CFR part 75 and the annual RATAs of the CERMS required by appendix F to 40 CFR part 60 need only be done at one operating level, representing normal load or normal process operating conditions, both for initial certification and for ongoing quality assurance.

(5) If, for any source operating hour, quality assured data are not obtained with a CO_2 monitor (or surrogate O_2 monitor), flow rate monitor, or (if applicable) moisture monitor, use appropriate substitute data values in accordance with the missing data provisions of §98.35.

(d) When municipal solid waste (MSW) is combusted in a unit, determine the biogenic portion of the CO_2 emissions from MSW combustion using ASTM D6866-08 Standard Test Methods for Determining the Biobased Content of Solid, Liquid, and Gaseous Samples Using Radiocarbon Analysis (incorporated by reference, see §98.7) and ASTM D7459-08 Standard Practice for Collection of Integrated Samples for the Speciation of Biomass (Biogenic) and Fossil-Derived Carbon Dioxide Emitted from Stationary Emissions Sources (incorporated by reference, see §98.7). Perform the ASTM

D7459-08 sampling and the ASTM D6866-08 analysis at least once in every calendar quarter in which MSW is combusted in the unit. Collect each gas sample during normal unit operating conditions while MSW is the only fuel being combusted for at least 24 consecutive hours or for as long as is necessary to obtain a sample large enough to meet the specifications of ASTM D6866-08. Separate CO_2 emissions into the biogenic and non-biogenic fraction using the average proportion of biogenic emissions of all samples analyzed during the reporting year. Express the results as a decimal fraction (e.g., 0.30, if 30 percent of the CO_2 from MSW combustion is biogenic). If there is a common fuel source of MSW that feeds multiple units at the facility, performing the testing at only one of the units is sufficient.

(e) For units that use CEMS to measure the total CO_2 mass emissions and combust a combination of biogenic fuels (other than MSW) with a fossil fuel, ASTM D6866-08 and ASTM D7459-08 may be used to determine the biogenic portion of the CO_2 emissions. Perform the ASTM D7459-08 sampling and the ASTM D6866-08 analysis at least once in every calendar quarter in which biogenic and non-biogenic fuels are co-fired in the unit. The relative proportions of the biogenic and non-biogenic fuels during the sampling shall be representative of the average fuel blend for a typical operating year. Collect each gas sample using ASTM D7459-08 during normal unit operation for at least 24 consecutive hours or for as long as is necessary to obtain a sample large enough to meet the specifications of ASTM D6866-08.

(f) Whenever company records are used in the calculation of CO_2 emissions, the records required under §98.3(g) shall include both the company records and an explanation of how those records are used to estimate the following parameters:

(1) Fuel consumption, when the Tier 1 and Tier 2 Calculation Methodologies are used.

(2) Fuel consumption, when solid fuel is combusted and the Tier 3 Calculation Methodology is used.

(3) Fossil fuel consumption when §98.33(e) applies to a unit that uses CEMS to quantify CO_2 emissions and that combusts both fossil and biomass fuels.

(4) Sorbent usage, when §98.33(d) applies.

(5) Quantity of steam generated by a unit when §98.33(a)(2) applies.

(6) Biogenic fuel consumption under §98.33(e)(5).

(g) As part of the GHG Monitoring Plan required under §98.3(g)(5), you must document the procedures used to ensure the accuracy of the estimates of fuel usage, sorbent usage, steam production, and boiler efficiency (as applicable) in paragraph (f) of this section, including but not limited to calibration of weighing equipment, fuel flow meters, steam flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices shall also be recorded, and the technical basis for these estimates shall be provided.

§98.35 Procedures for estimating missing data.

Required in U.S. jurisdictions only. Canadian jurisdictions may impose data substitution procedures that differ from the following.

Whenever a quality-assured value of a required parameter is unavailable (e.g., if a CEMS malfunctions during unit operation or if a required fuel sample is not taken), a substitute data value for the missing parameter shall be used in the calculations.

(a) For all units subject to the requirements of the Acid Rain Program, and all other stationary combustion units subject to the requirements of this part that monitor and report emissions and heat input data in accordance with 40 CFR part 75, the missing data substitution procedures in 40 CFR part 75 shall be followed for CO_2 concentration, stack gas flow rate, fuel flow rate, high heating value, and fuel carbon content.

(b) For units that use the Tier 1, Tier 2, Tier 3, and Tier 4 Calculation Methodologies, perform missing data substitution as follows for each parameter:

(1) For each missing value of the high heating value, carbon content, or molecular weight of the fuel, substitute the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If the "after" value has not been obtained by the time that the GHG emissions report is due, you may use the "before" value for missing data substitution or the best available estimate of the parameter, based on all available process data (e.g., electrical load, steam production, operating hours). If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.

(2) For missing records of CO_2 concentration, stack gas flow rate, percent moisture, fuel usage, and sorbent usage, the substitute data value shall be the best available estimate of the parameter, based on all available process data (e.g., electrical load, steam production,

operating hours, etc.). You must document and retain records of the procedures used for all such estimates.

§98.36 Data reporting requirements.

Canadian jurisdictions may allow or require aggregation of emissions data up to the facility level.

(a) In addition to the facility-level information required under §98.3, the annual GHG emissions report shall contain the unit-level or process-level emissions data in paragraphs (b) through (d) of this section (as applicable) and the emissions verification data in paragraph (e) of this section.

(b) Units that use the four tiers. You shall report the following information for stationary combustion units that use the Tier 1, Tier 2, Tier 3, or Tier 4 methodology in §98.33(a) to calculate CO_2 emissions, except as otherwise provided in paragraphs (c) and (d) of this section:

(1) The unit ID number.

(2) A code representing the type of unit.

(3) Maximum rated heat input capacity of the unit, in mmBtu/hr for boilers and process heaters only and relevant units of measure for other combustion sources.

(4) Each type of fuel combusted in the unit during the report year.

(5) The tier used to calculate the CO_2 emissions for each type of fuel combusted (i.e., Tier 1, 2, 3, or 4).

(6) For a unit that uses Tiers 1, 2, and 3; the CO_2, CH_4, and N_2O emissions for each type of fuel combusted, expressed in metric tons of each gas and in metric tons of CO_2e.

(7) For a unit that uses Tier 4:

(i) For units that burn fossil fuels only, the annual CO_2 emissions for all fuels combined. Reporting CO_2 emissions by type of fuel is not required.

(ii) For units that burn both fossil fuels and biomass, the annual CO_2 emissions from combustion of all fossil fuels combined and the annual CO_2 emissions from combustion of all biomass fuels combined. Reporting CO_2 emissions by type of fuel is not required.

(iii) Annual CH_4 and N_2O emissions for each type of fuel combusted expressed in metric tons of each gas and in metric tons of CO_2e.

(8) Annual CO_2 emissions from sorbent (if calculated using Equation C-11 of this subpart), expressed in metric tons.

(9) Annual GHG emissions from all fossil fuels burned in the unit (i.e., the sum of the CO_2 , CH_4, and N_2O emissions), expressed in metric tons of CO_2e.

(10) Customer meter number for units that combust natural gas.

(11) For units that generate electricity, nameplate generating capacity (MW) and net power generated (MWh) during the reporting year.

(12) For each cogeneration unit, indicate whether topping or bottoming cycle and provide useful thermal output as applicable, in mmBtu. Where steam or heat is acquired from another facility for the generation of electricity, report the provider and amount of acquired steam or heat in mmBtu. Where supplemental firing has been applied to support electricity generation or industrial output, report this purpose and fuel consumption by fuel type using the following units:[7]

(i) For gases, report in units of million standard cubic feet.
(ii) For liquids, report in units of gallons.
(iii) For non-biomass solids, report in units of short tons.
(iv) For biomass-derived solid fuels, report in units of bone dry short tons.

(c) Reporting alternatives for units using the four Tiers. You may use any of the applicable reporting alternatives of this paragraph to simplify the unit-level reporting required under paragraph (b) of this section:

[7] Taken from WCI.42(b).

Subpart C—General Stationary Combustion

(1) Aggregation of units. If a facility contains two or more units (e.g., boilers or combustion turbines), each of which has a maximum rated heat input capacity of 250 mmBtu/hr or less, you may report the combined GHG emissions for the group of units in lieu of reporting GHG emissions from the individual units, provided that the use of Tier 4 is not required or elected for any of the units and the units use the same tier for any common fuels combusted. If this option is selected, the following information shall be reported instead of the information in paragraph (b) of this section:

(i) Group ID number, beginning with the prefix "GP".

(ii) An identification number for each unit in the group.

(iii) Cumulative maximum rated heat input capacity of the group (mmBtu/hr).

(iv) The highest maximum rated heat input capacity of any unit in the group (mmBtu/hr).

(v) Each type of fuel combusted in the group of units during the reporting year.

(vi) Annual CO_2, CH_4, and N_2O mass emissions aggregated for each type of fuel combusted in the group of units during the year, expressed in metric tons of each gas and in metric tons of CO_2e. If any of the units burn both fossil fuels and biomass, report also the annual CO_2 emissions from combustion of all fossil fuels combined and annual CO_2 emissions from combustion of all biomass fuels combined, expressed in metric tons.

(vii) The tier used to calculate the CO_2 mass emissions for each type of fuel combusted in the units (i.e., Tier 1, Tier 2, or Tier 3).

(viii) The calculated CO_2 mass emissions (if any) from sorbent.

(ix) Annual GHG emissions from all fossil fuels burned in the group (i.e., the sum of the CO_2 , CH_4, and N_2O emissions), expressed in metric tons of CO2e.

(2) Monitored common stack or duct configurations. When the flue gases from two or more stationary combustion units at a facility are discharged through a common stack or duct before exiting to the atmosphere and if CEMS are used to continuously monitor CO_2 mass emissions at the common stack or duct according to the Tier 4 Calculation Methodology, you may report the combined emissions from the units sharing the common stack or duct, in lieu of separately reporting the GHG emissions from the individual units. The following information shall be reported instead of the information in paragraph (b) of this section:

(i) Common stack or duct identification number, beginning with the prefix "CS".

(ii) Identification numbers of the units sharing the common stack or duct.

(iii) Maximum rated heat input capacity of each unit sharing the common stack or duct (mmBtu/hr).

(iv) Each type of fuel combusted in the units during the year.

(v) The methodology used to calculate the CO_2 mass emissions, i.e., Tier 4.

(vi) If the any of the units burn both fossil fuels and biomass, annual CO_2 mass emissions, annual CO_2 emissions from combustion of fossil fuels, and annual CO_2 emissions from combustion of biomass measured at the common stack or duct, expressed in metric tons.

(vii) The annual CH_4 and N_2O emissions from the units sharing the common stack or duct, expressed in metric tons of each gas and in metric tons of CO_2e.

(viii) Annual GHG emissions from all fossil fuels burned in the group (i.e., the sum of the CO_2 , CH_4, and N_2O emissions), expressed in metric tons of CO2e.

(3) <u>Common pipe configurations</u>. When two or more liquid-fired or gaseous-fired stationary combustion units at a facility combust the same type of fuel and the fuel is

fed to the individual units through a common supply line or pipe, you may report the combined emissions from the units served by the common supply line, in lieu of separately reporting the GHG emissions from the individual units, provided that the total amount of fuel combusted by the units is accurately measured at the common pipe or supply line using a fuel flow meter that is calibrated in accordance with §98.34(a). If a portion of the fuel measured at the common pipe is diverted to a chemical or industrial process where it is used but not combusted, you may subtract the diverted fuel from the fuel measured at the common pipe prior to performing the GHG emissions calculations, provided that the amount of fuel diverted is also measured with a calibrated flow meter per §98.3(i). If the common pipe option is selected, the applicable tier shall be used based on the maximum rated heat input capacity of the largest unit served by the common pipe configuration. The following information shall be reported instead of the information in paragraph (b) of this section:

(i) Common pipe identification number, beginning with the prefix “CP”.

(ii) The identification numbers of the units served by the common pipe.

(iii) Maximum rated heat input capacity of each unit served by the common pipe (mmBtu/hr).

(iv) The fuels combusted in the units during the reporting year.

(v) The methodology used to calculate the CO_2 mass emissions (i.e., Tier 1, Tier 2, or Tier 3).

(vi) If the any of the units burns both fossil fuels and biomass, the annual CO_2 mass emissions from combustion of all fossil fuels and annual CO_2 emissions from combustion of all biomass fuels from the units served by the common pipe, expressed in metric tons.

(vii) Annual CH_4 and N_2O emissions from the units served by the common pipe, expressed in metric tons of each gas and in metric tons of CO_2e.

(viii) Annual GHG emissions from all fossil fuels burned in units served by the common pipe (i.e., the sum of the CO_2, CH_4, and N_2O emissions), expressed in metric tons of CO_2e.

(d) Units subject to 40 CFR part 75.

(1) For stationary combustion units that are either subject to the Acid Rain Program or not in the Acid Rain Program but monitor and report CO_2 mass emissions year-round according to 40 CFR part 75, you shall report the following unit-level information:

(i) Unit or stack identification numbers. Use exact same unit, common stack, or multiple stack identification numbers that represent the monitored locations (e.g., 1, 2, CS001, MS1A, etc.) that are reported under §75.64 of this chapter.

(ii) Annual CO_2, CH_4, and N_2O emissions at each monitored location, expressed in metric tons of CO_2e.

(iii) Identification of the Part 75 methodology used to determine the CO_2 mass emissions.

(iv) Annual fuel consumption, if not reported under 40 CFR part 75.

(A) For gases, report in units of thousands of standard cubic feet.

(B) For liquids, report in units of gallons.

(C) For non-biomass solids, report in units of short tons.

(D) For biomass solid fuels, report in units of bone dry short tons or bone dry metric tons.

(v) Average carbon content of each fuel, if used to compute CO_2 emissions but not reported under 40 CFR part 75.

(vi) Average high heating value of each fuel, if used to compute CO_2 emissions but not reported under 40 CFR part 75.

(vii) For units that burn both fossil fuels and biomass, the annual CO2 emissions from combustion of all fossil fuels combined and the annual CO2 emissions from combustion of all biomass fuels combined. Reporting CO2 emissions by type of fuel is not required.

(viii) For units that generate electricity, nameplate generating capacity (MW) and net power generated (MWh) during the reporting year.

(ix) For each cogeneration unit, indicate whether topping or bottoming cycle and provide useful thermal output as applicable, in mmBtu. Where steam or heat is acquired from another facility for the generation of electricity, report the provider and amount of acquired steam or heat in mmBtu. Where supplemental firing has been applied to support electricity generation or industrial output, report this purpose and fuel consumption by fuel type using the units in WCI.42(b).

(2) For units that use the alternative CO_2 mass emissions calculation methods for units with continuous monitoring systems provided in §98.33(a)(5), you shall report the following unit-level information:

(i) Unit, stack, or pipe ID numbers. Use exact same unit, common stack, or multiple stack identification numbers that represent the monitored locations (e.g., 1, 2, CS001, MS1A, etc.) that are reported under §75.64 of this chapter.

(ii) For units that use the alternative methods specified in §98.33(a)(5)(i) and (ii) to monitor and report heat input data year-round according to appendix D to 40 CFR part 75 or 40 CFR 75.19:

(A) Each type of fuel combusted in the unit during the reporting year.

(B) The methodology used to calculate the CO_2 mass emissions for each fuel type.

(C) A code or flag to indicate whether heat input is calculated according to appendix D to 40 CFR part 75 or 40 CFR 75.19.

(D) Annual CO_2, CH_4, and N_2O emissions at each monitored location, across all fuel types, expressed in metric tons of CO_2e.

(iii) For units with continuous monitoring systems that use the alternative method for units with continuous monitoring systems in §98.33(a)(5)(iii) to monitor heat input year-round according to 40 CFR part 75:

(A) Fuel combusted during the reporting year.

(B) Methodology used to calculate the CO_2 mass emissions.

(C) A code or flag to indicate that the heat input data is derived from CEMS measurements.

(D) The total annual CO_2, CH_4, and N_2O emissions at each monitored location, expressed in metric tons of CO_2e.

(iv) The information required in paragraphs (d)(1)(iv) through (d)(1)(ix) of this section, as applicable.

(e) Verification data. You must keep on file, in a format suitable for inspection and auditing, sufficient data to verify the reported GHG emissions. This data and information must, where indicated in this paragraph (e), be included in the annual GHG emissions report.

(1) The applicable verification data specified in this paragraph (e) are not required to be kept on file or reported for units that meet any one of the three following conditions:

(i) Are subject to the Acid Rain Program.

(ii) Use the alternative methods for units with continuous monitoring systems provided in §98.33(a)(5).

(iii) Are not in the Acid Rain Program, but are required monitor and report CO_2 mass emissions and heat input data year-round, in accordance with 40 CFR part 75.

(2) For stationary combustion sources using the Tier 1, Tier 2, Tier 3, and Tier 4 Calculation Methodologies in

Subpart C—General Stationary Combustion

§98.33(a) to quantify CO_2 emissions, the following additional information shall be kept on file and included in the GHG emissions report, where indicated:

(i) For the Tier 1 Calculation Methodology, report the total quantity of each type of fuel combusted in the unit or group of aggregated units (as applicable) during the reporting year, in short tons for solid fuels, gallons for liquid fuels and standard cubic feet for gaseous fuels.

(ii) For the Tier 2 Calculation Methodology, report:

(A) The total quantity of each type of fuel combusted in the unit or group of aggregated units (as applicable) during each month of the reporting year. Express the quantity of each fuel combusted during the measurement period in short tons for solid fuels, gallons for liquid fuels, and scf for gaseous fuels.

(B) The frequency of the HHV determinations (e.g., once a month, once per fuel lot).

(C) The high heat values used in the CO_2 emissions calculations for each type of fuel combusted, in mmBtu per short ton for solid fuels, mmBtu per gallon for liquid fuels, and mmBtu per scf for gaseous fuels. Specify the date on which each fuel sample was taken. Indicate whether each HHV is a measured value of a substitute data value.

(D) If Equation C-2c of this subpart is used to calculate CO_2 mass emissions, report the total quantity (i.e., pounds) of steam produced from MSW or solid fuel combustion during the year, and the ratio of the maximum rate heat input capacity to the design rated steam output capacity of the unit, in mmBtu per lb of steam.

(iii) For the Tier 2 Calculation Methodology, keep records of the methods used to determine the HHV for each type of fuel combusted and the date on which each fuel sample was taken.

(iv) For the Tier 3 Calculation Methodology, report:

(A) The quantity of each type of fuel combusted in the unit or group of units (as applicable) during the year, in short tons for solid fuels, gallons for liquid fuels, and scf for gaseous fuels.

(B) The frequency of carbon content and, if applicable, molecular weight determinations for each type of fuel for the reporting year (e.g., daily, weekly, monthly, semiannually, once per fuel lot).

(C) The carbon content and, if applicable, gas molecular weight values used in the emission calculations (including both valid and substitute data values). Report all measured values if the fuel is sampled monthly or less frequently. Otherwise, for daily and weekly sampling, report monthly average values determined using the calculation procedures in Equation C-2b for each variable. Express carbon content as a decimal fraction for solid fuels, kg C per gallon for liquid fuels, and kg C per kg of fuel for gaseous fuels. Express the gas molecular weights in units of kg per kg-mole.

(D) The total number of valid carbon content determinations and, if applicable, molecular weight determinations made during the reporting year, for each fuel type.

(E) The number of substitute data values used for carbon content and, if applicable, molecular weight used in the annual GHG emissions calculations.

(v) For the Tier 3 Calculation Methodology, keep records of the following:

(A) For liquid and gaseous fuel combustion, the dates and results of the initial calibrations and periodic recalibrations of the required fuel flow meters.

(B) For fuel oil combustion, the method from §98.34(b) used to make tank drop measurements (if applicable).

(C) The methods used to determine the carbon content for each type of fuel combusted.

(D) The methods used to calibrate the fuel flow meters).

(vi) For the Tier 4 Calculation Methodology, report:

(A) The total number of source operating hours in the reporting year.

(B) The cumulative CO_2 mass emissions in each quarter of the reporting year, i.e., the sum of the hourly values calculated from Equation C-6 or C-7 of this subpart (as applicable), in metric tons.

(C) For CO_2 concentration, stack gas flow rate, and (if applicable) stack gas moisture content, the percentage of source operating hours in which a substitute data value of each parameter was used in the emissions calculations.

(vii) For the Tier 4 Calculation Methodology, keep records of:

(A) Whether the CEMS certification and quality assurance procedures of 40 CFR part 75, 40 CFR part 60, or an applicable State continuous monitoring program were used.

(B) The dates and results of the initial certification tests of the CEMS.

(C) The dates and results of the major quality assurance tests performed on the CEMS during the reporting year, i.e., linearity checks, cylinder gas audits, and relative accuracy test audits (RATAs).

(viii) If CO_2 emissions that are generated from acid gas scrubbing with sorbent injection are not captured using CEMS, report:

(A) The total amount of sorbent used during the report year, in short tons.

(B) The molecular weight of the sorbent.

(C) The ratio ("R") in Equation C-11 of this subpart.

(ix) For units that combust both fossil fuel and biomass, when CEMS are used to quantify the annual CO_2 emissions and biogenic CO_2 is determined according to §98.33(e)(2), you shall report the following additional information, as applicable:

(A) The annual volume of CO_2 emitted from the combustion of all fuels, i.e., V_{total}, in scf.

(B) The annual volume of CO_2 emitted from the combustion of fossil fuels, i.e., V_{ff}, in scf. If more than one type of fossil fuel was combusted, report the combustion volume of CO_2 for each fuel separately as well as the total.

(C) The annual volume of CO_2 emitted from the combustion of biomass, i.e., V_{bio}, in scf.

(D) The carbon-based F-factor used in Equation C-13 of this subpart, for each type of fossil fuel combusted, in scf CO_2 per mmBtu.

(E) The annual average HHV value used in Equation C-13 of this subpart, for each type of fossil fuel combusted, in Btu/lb, Btu/gal, or Btu/scf, as appropriate.

(F) The total quantity of each type of fossil fuel combusted during the reporting year, in lb, gallons, or scf, as appropriate.

(G) Annual biogenic CO_2 mass emissions, in metric tons.

(x) When ASTM methods D7459-08 and D6866-08 are used to determine the biogenic portion of the annual CO_2 emissions from MSW combustion, report:

(A) The results of each quarterly sample analysis, expressed as a decimal fraction (e.g., if the biogenic fraction of the CO_2 emissions from MSW combustion is 30 percent, report 0.30).

(B) Annual combined biomass and fossil fuel CO_2 emissions from MSW combustion, in metric tons of CO_2e.

(C) The quantities V_{ff}, V_{total}, and V_{MSW} from §98.33(e)(4)(ii), if CEMS are used to measure CO_2 emissions.

(D) The annual volume of biogenic CO_2 emissions from MSW combustion, in metric tons.

(xi) When ASTM methods D7459-08 and D6866-08 are used to determine the biogenic portion of the annual CO_2 emissions from a unit that co-fires biogenic (other than MSW) and non-biogenic fuels, you shall report the results of each quarterly sample analysis, expressed as a decimal fraction (e.g., if the biogenic fraction of the CO_2 emissions is 30 percent, report 0.30).

(3) Within ~~30~~20 days of receipt of a written request from the Administrator, you shall submit explanations of the following:

(i) An explanation of how company records are used to quantify fuel consumption, if the Tier 1 or Tier 2 Calculation Methodology is used to calculate CO_2 emissions.

(ii) An explanation of how company records are used to quantify fuel consumption, if solid fuel is combusted and the Tier 3 Calculation Methodology is used to calculate CO_2 emissions.

(iii) An explanation of how sorbent usage is quantified.

(iv) An explanation of how company records are used to quantify fossil fuel consumption in units that uses CEMS to quantify CO_2 emissions and combusts both fossil fuel and biomass.

(v) An explanation of how company records are used to measure steam production, when it is used to calculate CO_2 mass emissions under §98.33(a)(2)(iii) or to quantify solid fuel usage under §98.33(c)(3).

(4) Within ~~30~~20 days of receipt of a written request from the Administrator, you shall submit the verification data and information described in paragraphs (e)(2)(iii), (e)(2)(v), and (e)(2)(vii) of this section.

§98.37 Records That Must be Retained.

In addition to the requirements of §98.3(g), you must retain the applicable records specified in §§98.34(f) and (g), 98.35(b), and 98.36(e).

§98.38 Definitions.

Except as specified in this section, all~~All~~ terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

"Bottoming cycle plant" means a cogeneration plant in which the energy input to the system is first applied to a useful thermal energy application or process, and at least some of the reject heat emerging from the application or process is then used for electricity production.

"Cogeneration unit" means a stationary fuel combustion device which simultaneously generates electrical and thermal energy that is (i) used by the operator of the facility where the cogeneration unit is located; or (ii) transferred to another facility for use by that facility.

"Cogeneration system" means individual cogeneration components including the prime mover (heat engine), generator, heat recovery, and electrical interconnection, configured into an integrated system that provides sequential generation of multiple forms of useful energy (usually electrical and thermal), at least one form of which the facility consumes on-site or makes available to other users for an end-use other than electricity generation.

"Pipeline quality natural gas" means natural gas having a high heat value greater than 970 Btu/scf and equal to or less than 1,100 Btu/scf, and which is at least ninety percent methane by volume and less than five percent carbon dioxide by volume.

"Topping cycle plant" means a cogeneration plant in which the energy input to the plant is first used to produce electricity, and at least some of the reject heat from the electricity production process is then used to provide useful thermal output.

Canadian jurisdictions will substitute tables that contain Canada-specific emission factors for Tables C-1 and C-2 below:

Table C-1 of Subpart C—Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel

Fuel Type	Default High Heat Value	Default CO_2 Emission Factor
Coal and Coke	**mmBtu/short ton**	**kg CO_2 /mmBtu**
Anthracite	25.09	103.54
Bituminous	24.93	93.40
Subbituminous	17.25	97.02
Lignite	14.21	96.36
Coke	24.80	102.04
Mixed (Commercial sector)	21.39	95.26
Mixed (Industrial coking)	26.28	93.65
Mixed (Industrial sector)	22.35	93.91
Mixed (Electric Power sector)	19.73	94.38
Natural Gas	**mmBtu/scf**	**kg CO_2 /mmBtu**
Pipeline (Weighted U.S. Average)	1.028×10^{-3}	53.02
Petroleum Products	**mmBtu/gallon**	**kg CO_2 /mmBtu**
Distillate Fuel Oil No. 1	0.139	73.25
Distillate Fuel Oil No. 2	0.138	73.96
Distillate Fuel Oil No. 4	0.146	75.04
Residual Fuel Oil No. 5	0.140	72.93
Residual Fuel Oil No. 6	0.150	75.10
Still Gas	0.143	66.72
Kerosene	0.135	75.20
Liquefied petroleum gases (LPG)	0.092	62.98
Propane	0.091	61.46
Propylene	0.091	65.95
Ethane	0.096	62.64
Ethylene	0.100	67.43
Isobutane	0.097	64.91
Isobutylene	0.103	67.74
Butane	0.101	65.15
Butylene	0.103	67.73
Naphtha (<401 deg F)	0.125	68.02
Natural Gasoline	0.110	66.83
Other Oil (>401 deg F)	0.139	76.22
Pentanes Plus	0.110	70.02
Petrochemical Feedstocks	0.129	70.97
Petroleum Coke	0.143	102.41
Special Naphtha	0.125	72.34
Unfinished Oils	0.139	74.49
Heavy Gas Oils	0.148	74.92
Lubricants	0.144	74.27
Motor Gasoline	0.125	70.22
Aviation Gasoline	0.120	69.25

Subpart C—General Stationary Combustion

Table C-1 of Subpart C—Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel

Fuel Type	Default High Heat Value	Default CO_2 Emission Factor
Kerosene-Type Jet Fuel	0.135	72.22
Asphalt and Road Oil	0.158	75.36
Crude Oil	0.138	74.49
Fossil Fuel-derived Fuels (Solid)	**mmBtu/short ton**	**kg CO_2 /mmBtu**
Municipal Solid Waste[1]	9.95	90.7
Tires	26.87	85.97
Fossil Fuel-derived Fuels (Gaseous)	**mmBtu/scf**	**kg CO_2 /mmBtu**
Blast Furnace Gas	0.092×10^{-3}	274.32
Coke Oven Gas	0.599×10^{-3}	46.85
Biomass Fuels - Solid	**mmBtu/short Ton**	**kg CO_2 /mmBtu**
Wood and Wood Residuals	15.38	93.80
Agricultural Byproducts	8.25	118.17
Peat	8.00	111.84
Solid Byproducts	25.83	105.51
Biomass Fuels - Gaseous	**mmBtu/scf**	**kg CO_2 /mmBtu**
Biogas (Captured methane)	0.841×10^{-3}	52.07
Biomass Fuels - Liquid	**mmBtu/gallon**	**kg CO_2 /mmBtu**
Ethanol (100%)	0.084	68.44
Biodiesel (100%)	0.128	73.84
Rendered Animal Fat	0.125	71.06
Vegetable Oil	0.120	81.55

[1]Allowed only for units that do not generate steam and use Tier 1.

Table C-1a of Subpart C—Fuels for which Tier 1 or Tier 2 Calculation Methodologies May Be Used

Fuel Type	Default High Heat Value	Default CO_2 Emission Factor
Petroleum Products	**mmBtu/gallon**	**kg CO_2 /mmBtu**
Distillate Fuel Oil No. 1	0.139	73.25
Distillate Fuel Oil No. 2	0.138	73.96
Distillate Fuel Oil No. 4	0.146	75.04
Kerosene	0.135	75.20
Liquefied petroleum gases (LPG)[8]	0.092	62.98
Propane	0.091	61.46
Propylene	0.091	65.95
Ethane	0.096	62.64
Ethylene	0.100	67.43
Isobutane	0.097	64.91
Isobutylene	0.103	67.74
Butane	0.101	65.15
Butylene	0.103	67.73

[8] Commercially sold as "propane", including grades such as HD5.

Table C-1a of Subpart C—Fuels for which Tier 1 or Tier 2 Calculation Methodologies May Be Used

Fuel Type	Default High Heat Value	Default CO_2 Emission Factor
Natural Gasoline	0.110	66.83
Motor Gasoline	0.125	70.22
Aviation Gasoline	0.120	69.25
Kerosene-Type Jet Fuel	0.135	72.22

Table C-2 of Subpart C—Default CH_4 and N_2O Emission Factors for Various Types of Fuel.

Fuel Type	Default CH_4 Emission Factor (kg CH_4 /mmBtu)	Default N_2O Emission Factor (kg N_2O/mmBtu)
Coal and Coke (All fuel types in Table C-1)	1.1×10^{-2}	1.6×10^{-03}
Natural Gas	1.0×10^{-03}	1.0×10^{-04}
Petroleum (All fuel types in Table C-1)	3.0×10^{-03}	6.0×10^{-04}
Municipal Solid Waste	3.2×10^{-02}	4.2×10^{-03}
Tires	3.2×10^{-02}	4.2×10^{-03}
Blast Furnace Gas	2.2 x 10-05	1.0×10^{-04}
Coke Oven Gas	4.8 x 10-04	1.0×10^{-04}
Biomass Fuels - Solid (All fuel types in Table C-1)	3.2×10^{-02}	4.2×10^{-03}
Biogas	3.2×10^{-03}	6.3×10^{-04}
Biomass Fuels – Liquid (All fuel types in Table C-1)	1.1×10^{-03}	1.1×10^{-04}

Note: Those employing this table are assumed to fall under the IPCC definitions of the "Energy Industry" or "Manufacturing Industries and Construction". In all fuels except for coal the values for these two categories are identical. For coal combustion, those who fall within the IPCC "Energy Industry" category may employ a value of 1 g of CH_4/MMBtu.

[1]Allowed only for units that do not generate steam and use Tier 1.

Table C-2 of Subpart C—Default CH_4 and N_2O Emission Factors for Various Types of Fuel.

Fuel Type	Default CH_4 Emission Factor (kg CH_4 /mmBtu)	Default N_2O Emission Factor (kg N_2O/mmBtu)
Coal and Coke (All fuel types in Table C-1)	1.1×10^{-2}	1.6×10^{-03}
Natural Gas	1.0×10^{-03}	1.0×10^{-04}
Petroleum (All fuel types in Table C-1)	3.0×10^{-03}	6.0×10^{-04}
Municipal Solid Waste	3.2×10^{-02}	4.2×10^{-03}
Tires	3.2×10^{-02}	4.2×10^{-03}
Blast Furnace Gas	2.2×10^{-05}	1.0×10^{-04}
Coke Oven Gas	4.8×10^{-04}	1.0×10^{-04}

Fuel Type	Default CH_4 Emission Factor (kg CH_4 /mmBtu)	Default N_2O Emission Factor (kg N_2O/mmBtu)
Biomass Fuels - Solid (All fuel types in Table C-1)	3.2×10^{-02}	4.2×10^{-03}
Biogas	3.2×10^{-03}	6.3×10^{-04}
Biomass Fuels – Liquid (All fuel types in Table C-1)	1.1×10^{-03}	1.1×10^{-04}

Note: Those employing this table are assumed to fall under the IPCC definitions of the "Energy Industry" or "Manufacturing Industries and Construction". In all fuels except for coal the values for these two categories are identical. For coal combustion, those who fall within the IPCC "Energy Industry" category may employ a value of 1 g of CH_4/MMBtu.

Subpart D—Electricity Generation

§98.40 Definition of the source category.

(a) The electricity generation source category comprises electricity generating units that are subject to the requirements of the Acid Rain Program and any other electricity generating units that are required to monitor and report to EPA CO_2 emissions year-round according to 40 CFR part 75.

(b) This source category does not include portable equipment, emergency equipment, or emergency generators, as defined in §98.6.[1]

§98.41 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains one or more electricity generating units and the facility meets the requirements of §98.2(a)(1).

§98.42 GHGs to report[2].

(a) For each electricity generating unit that is subject to the requirements of the Acid Rain Program or is otherwise required to monitor and report to EPA CO_2 emissions year-round according to 40 CFR part 75, you must

[1] Retain for U.S. rules. Canadians will decide whether or not to retain for their jurisdictions.

[2] Reporting of fugitive CO2 by geothermal facilities is in the ERMRs but not in the MRR. Flag for Partners decision on whether or not to retain reporting by geothermal facilities. If geothermal is retained, it may be clearer to publish the requirement as a separate WCI subpart rather than be included in MRR subpart D.

report under this subpart the annual mass emissions of CO_2, N_2O, and CH_4 by following the requirements of this subpart.

(b) For each electricity generating unit that is not subject to the Acid Rain Program or otherwise required to monitor and report to EPA CO_2 emissions year-round according to 40 CFR part 75, you must report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO_2, CH_4, and N_2O by following the requirements of subpart C.

(c) For each stationary fuel combustion unit that does not generate electricity, you must report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO_2, CH_4, and N_2O by following the requirements of subpart C of this part.

§98.43 Calculating GHG emissions.

Continue to monitor and report CO_2 mass emissions as required under §75.13 or section 2.3 of apppendix G to 40 CFR part 75, and §75.64. Calculate CO_2, CH_4, and N_2O emissions as follows:

(a) Convert the cumulative annual CO_2 mass emissions reported in the fourth quarter electronic data report required under §75.64 from units of short tons to metric tons. To convert tons to metric tons, divide by 1.1023.

(b) Calculate and report annual CH_4 and N_2O mass emissions under this subpart by following the applicable method specified in §98.33(c).

§98.44 Monitoring and QA/QC requirements

Follow the applicable quality assurance procedures for CO_2 emissions in appendices B, D, and G to 40 CFR part 75.

§98.45 Procedures for estimating missing data.

Follow the applicable missing data substitution procedures in 40 CFR part 75 for CO_2 concentration, stack gas flow rate, fuel flow rate, high heating value, and fuel carbon content.

§98.46 Data reporting requirements.

The annual report shall comply with the data reporting requirements specified in §98.36(d~~b~~)[3] and, if applicable, §98.36(c)(2) or (c)(3).

§98.47 Records that must be retained.

You shall comply with the recordkeeping requirements of §§98.3(g) and 98.37.

§98.48 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

[3] This corrects an error in the MRR that EPA is in the process of correcting.

Subpart F—Aluminum Production

§98.60 Definition of the source category.

(a) A primary aluminum production facility manufactures primary aluminum using the Hall-Héroult manufacturing process. The primary aluminum manufacturing process comprises the following operations:

(1) Electrolysis in prebake and Søderberg cells.

(2) Anode baking for prebake cells.

(b) This source category does not include experimental cells or research and development process units.

§98.61 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains an aluminum production process and the facility meets the requirements of either §98.2(a)(1) or (a)(2).

§98.62 GHGs to report.

You must report:

(a) Perfluoromethane (CF_4), and perfluoroethane (C_2F_6) emissions from anode effects in all prebake and Søderberg electolysis cells.

(b) CO_2 emissions from anode consumption during electrolysis in all prebake and Søderberg electolysis cells.

(c) CO_2 emissions from on-site anode baking.

(d) You must report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO_2, N_2O, and CH_4 emissions from each stationary fuel combustion unit by following the requirements of subpart C.

§98.63 Calculating GHG emissions.

(a) The annual value for PFC emissions shall be estimated from the sum of monthly values using Equation F-1 of this section:

$$E_{PFC} = \sum_{m=1}^{m=12} E_m \qquad \text{(Eq. F-1)}$$

Where:

E_{PFC} = Annual PFC emissions from aluminum production (metric tons PFC).

E_m = PFC emissions from aluminum production for the month “m” (metric tons PFC).

(b) Use Equation F-2 of this section to estimate CF_4 emissions from anode effect duration or Equation F-3 of this section to estimate CF_4 emissions from overvoltage, and use Equation F-4 of this section to estimate C_2F_6 emissions from anode effects from each prebake and Søderberg electolysis cell.

$$E_{CF4} = S_{CF4} \times AEM \times MP \times 0.001 \qquad \text{(Eq. F-2)}$$

Where:

E_{CF4} = Monthly CF_4 emissions from aluminum production (metric tons CF_4).

S_{CF4} = The slope coefficient ((kg CF_4/metric ton Al)/(AE-Mins/cell-day)).

AEM = The anode effect minutes per cell-day (AE-Mins/cell-day).

MP = Metal production (metric tons Al), where AEM and MP are calculated monthly.

$$E_{CF4} = EF_{CF4} \times MP \times 0.001 \qquad \text{(Eq. F-3)}$$

Where:

E_{CF4} = Monthly CF_4 emissions from aluminum production (metric tons CF_4).

EF_{CF4} = The overvoltage emission factor (kg CF_4/metric ton Al).

MP = Metal production (metric tons Al), where MP is calculated monthly.

$$E_{C2F6} = E_{CF4} \times F_{C2F6/CF4} \times 0.001 \qquad \text{(Eq. F-4)}$$

Where:

E_{C2F6} = Monthly C_2F_6 emissions from aluminum production (metric tons C_2F_6).

E_{CF4} = CF_4 emissions from aluminum production(kg CF_4).

$F_{C2F6/CF4}$ = The weight fraction of C_2F_6/CF_4 (kg C_2F_6/kg CF_4).

0.001 = Conversion factor from kg to metric tons, where E_{CF4} is calculated monthly.

(c) You must calculate and report the annual process CO_2 emissions from anode consumption during electrolysis and anode baking of prebake cells using either the procedures in paragraph (d) of this section or the procedures in paragraphs (e) and (f) of this section.

(d) Calculate and report under this subpart the process CO_2 emissions by operating and maintaining CEMS according to the Tier 4 Calculation Methodology in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(e) Use the following procedures to calculate CO_2 emissions from anode consumption during electrolysis:

(1) For Prebake cells: you must calculate CO_2 emissions from anode consumption using Equation F-5 of this section:[1]

$$E_{CO2} = NAC \times MP \times ([100 - S_a - Ash_a] / 100) \times (44/12) \quad \text{(Eq. F-5)}$$

Where:

E_{CO2}	=	Annual CO_2 emissions from prebaked anode consumption (metric tons CO_2).
NAC	=	Net annual prebaked anode consumption per metric ton Al (metric tons C/metric tons Al).
MP	=	Annual metal production (metric tons Al).
S_a	=	Sulfur content in baked anode (percent weight).
Ash_a	=	Ash content in baked anode(percent weight).
44/12	=	Ratio of molecular weights, CO_2 to carbon.

(2) For Søderberg cells you must calculate CO_2 emissions using Equation F-6 of this section:[2]

$$E_{CO2} = (PC \times MP - [CSM \times MP] / 1000 - BC / 100 \times PC \times MP \times [S_p + Ash_p + H_p] / 100 - [100 - BC] / 100 \times PC \times MP \times [S_c + Ash_c] / 100 - MP \times CD) \times (44/12) \quad \text{(Eq. F-6)}$$

Where:

E_{CO2}	=	Annual CO_2 emissions from paste consumption (metric ton CO_2).
PC	=	Annual paste consumption (metric ton/metric ton Al).
MP	=	Annual metal production (metric ton Al).

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[1]The WCI equivalents for equations F-5, F-6 and F-8 in the existing ERs for aluminum production include a deduction for impurities in the baked anode, pitch and packing coke respectively. Allowing such a deduction, however, would be inconsistent with harmonization, since it would require reporting different amounts for these processes to EPA and the WCI. WCI solicits stakeholder input on the significance of this omission.

[2]WCI discussed removing the factor for carbon removed as skimmed dust (CD) since it is not included in the WCI methodology. It has been retained to assure harmonization.

CSM = Annual emissions of cyclohexane soluble matter (kg/metric ton Al).

BC = Binder content of paste (percent weight).

S_p = Sulfur content of pitch (percent weight).

Ash_p = Ash content of pitch (percent weight).

H_p = Hydrogen content of pitch (percent weight).

S_c = Sulfur content in calcined coke (percent weight).

Ash_c = Ash content in calcined coke (percent weight).

CD = Carbon in skimmed dust from Søderberg cells (metric ton C/metric ton Al).

44/12 = Ratio of molecular weights, CO_2 to carbon.

(e) Use the following procedures to calculate CO_2 emissions from anode baking of prebake cells:

(1) Use Equation F-7 of this section to calculate emissions from pitch volatiles combustion.

$$E_{CO2PV} = (GA - H_w - BA - WT) \times (44/12) \qquad \text{(Eq. F-7)}$$

Where:

E_{CO2PV} = Annual CO_2 emissions from pitch volatiles combustion (metric tons CO_2).

GA = Initial weight of green anodes (metric tons).

H_w = Annual hydrogen content in green anodes (metric tons).

BA = Annual baked anode production (metric tons).

WT = Annual waste tar collected (metric tons).

44/12 = Ratio of molecular weights, CO_2 to carbon.

(2) Use Equation F-8 of this section to calculate emissions from bake furnace packing material.

$$E_{CO2PC} = PCC \times BA \times ([100 - S_{pc} - Ash_{pc}] / 100) \times (44/12) \qquad \text{(Eq. F-8)}$$

Where:

E_{CO2PC} = Annual CO_2 emissions from bake furnace packing material (metric tons CO_2).

PCC = Annual packing coke consumption (metric tons/metric ton baked anode).

BA = Annual baked anode production (metric tons).
S_{pc} = Sulfur content in packing coke (percent weight).
Ash_{pc} = Ash content in packing coke (percent weight).
44/12 = Ratio of molecular weights, CO_2 to carbon.

(f) If process CO_2 emissions from anode consumption during electrolysis or anode baking of prebake cells are vented through the same stack as any combustion unit or process equipment that reports CO_2 emissions using a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Fuel Combustion Sources), then the calculation methodology in paragraphs (d) and (e) of this section shall not be used to calculate those process emissions. The owner or operation shall report under this subpart the combined stack emissions according to the Tier 4 Calculation Methodology in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

§98.64 Monitoring and QA/QC requirements.

(a) Effective one year after publication of the rule for smelters with no prior measurement or effective three years after publication for facilities with historic measurements, the smelter-specific slope coefficients used in Equations F-2, F-3, and F-4 of this subpart must be measured in accordance with the recommendations of the

Subpart F—Aluminum Production

EPA/IAI Protocol for Measurement of Tetrafluoromethane (CF_4) and Hexafluoroethane (C_2F_6) Emissions from Primary Aluminum Production (2008), except the minimum frequency of measurement shall be every ~~10 years~~ 36 months ~~unless~~ and when a change occurs in the control algorithm that affects the mix of types of anode effects or the nature of the anode effect termination routine or when changes occur in the distribution or duration of anode effects (i.e., when the percentage of manual kills changes or if the number of anode effects decreases and results in a fewer number of longer anode effects) or for Rio Tinto Alcan control technology (i.e., when the algorithm for bridge movements and anode effect overvoltage accounting changes). Facilities which operate at less than 0.2 anode effect minutes per cell day or operate with less than 1.4mV anode effect overvoltage ~~can~~ must use ~~either~~ smelter-specific slope coefficients ~~or the technology specific default values in Table F-1 of this subpart~~.

(b) The minimum frequency of the measurement and analysis is ~~annually except as follows: Monthly – anode effect minutes per cell day (or anode effect overvoltage and current efficiency), production~~monthly.

(c) Sources ~~may~~ must use ~~either~~ smelter-specific values from annual measurements of parameters needed to complete the equations in §98.63 (e.g., sulfur, ash, and hydrogen contents)~~ or the default values shown in Table F-2 of this subpart~~.

§98.65 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation or if a required sample measurement is not taken), a substitute data value for the missing parameter shall be used in the calculations, according to the following requirements:

(a) Where anode or paste consumption data are missing, CO_2 emissions can be estimated from aluminum production using Tier 1 method per Equation F-8 of this section.

$$ECO_2 = EF_p \times MP_p + EF_s \times MP_s \qquad \text{(Eq. F-8)}$$

Where:

ECO_2 = CO_2 emissions from anode and/or paste consumption, metric tons CO_2.

EF_p = Prebake technology specific emission factor (1.6 metric tons CO_2/metric ton aluminum produced).

MP_p = Metal production from prebake process (metric tons Al).

EF_s = Søderberg technology specific emission factor (1.7 metric tons CO_2/metric ton Al produced).

MP_s = Metal production from Søderberg process (metric tons Al).

(b) For other parameters, use the average of the two most recent data points after the missing data.

§98.66 Data reporting requirements.

In addition to the information required by §98.3(c), you must report the following information at the facility level:

(a) Annual aluminum production in metric tons.

(b) Type of smelter technology used.

(c) The following PFC-specific information on an annual basis:

(1) Perfluoromethane emissions and perfluoroethane emissions from anode effects in all prebake and all Søderberg electolysis cells combined.

(2) Anode effect minutes per cell-day (AE-mins/cell-day), anode effect frequency (AE/cell-day), anode effect duration (minutes). (Or anode effect overvoltage factor ((kg CF_4/metric ton Al)/(mV/cell day)), potline overvoltage (mV/cell day), current efficiency (%).)

(3) Smelter-specific slope coefficients (or overvoltage emission factors) and the last date when the smelter-specific-slope coefficients (or overvoltage emission factors) were measured.

(d) Method used to measure the frequency and duration of anode effects (or overvoltage).

(e) The following CO_2-specific information for prebake cells:

(1) Annual anode consumption.

(2) Annual CO_2 emissions from the smelter.

(f) The following CO_2-specific information for Søderberg cells:

(1) Annual paste consumption.

(2) Annual CO_2 emissions from the smelter.

(g) Smelter-specific inputs to the CO_2 process equations (e.g., levels of sulfur and ash) that were used in the calculation, on an annual basis.

(h) Exact data elements required will vary depending on smelter technology (e.g., point-feed prebake or Søderberg) and process control technology (e.g., Pechiney or other).

§98.67 Records that must be retained.

In addition to the information required by §98.3(g), you must retain the following records:

(a) Monthly aluminum production in metric tons.

(b) Type of smelter technology used.

(c) The following PFC-specific information on a monthly basis:

Subpart F—Aluminum Production

(1) Perfluoromethane and perfluoroethane emissions from anode effects in prebake and Søderberg electolysis cells.

(2) Anode effect minutes per cell-day (AE-mins/cell-day), anode effect frequency (AE/cell-day), anode effect duration (minutes). (Or anode effect overvoltage factor ((kg CF_4/metric ton Al)/(mV/cell day)), potline overvoltage (mV/cell day), current efficiency (%).))

(3) Smelter-specific slope coefficients and the last date when the smelter-specific-slope coefficients were measured.

(d) Method used to measure the frequency and duration of anode effects (or to measure anode effect overvoltage and current efficiency).

(e) The following CO_2-specific information for prebake cells:

(1) Annual anode consumption.

(2) Annual CO_2 emissions from the smelter.

(f) The following CO_2-specific information for Søderberg cells:

(1) Annual paste consumption.

(2) Annual CO_2 emissions from the smelter.

(g) Smelter-specific inputs to the CO_2 process equations (e.g., levels of sulfur and ash) that were used in the calculation, on an annual basis.

(h) Exact data elements required will vary depending on smelter technology (e.g., point-feed prebake or Søderberg) and process control technology (e.g., Pechiney or other).

§98.68 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Table F-1 of Subpart F—Slope and Overvoltage Coefficients for the Calculation of PFC Emissions from Aluminum Production

Technology	**CF_4 Slope Coefficient [(kg CF_4/metric ton Al)/(AE-Mins/cell-day)]**	**CF_4 Overvoltage Coefficient [(kg CF_4/metric ton Al)/(mV)]**	**Weight Fraction C_2F_6/CF_4 [(kg C_2F_6/kg CF_4)]**
CWPB	0.143	1.16	0.121
SWPB	0.272	3.65	0.252
VSS	0.092	NA	0.053
HSS	0.099	NA	0.085

Table F-2 of Subpart F—Default Data Sources for Parameters Used for CO_2 Emissions

CO_2 Emissions from Prebake Cells (CWPB and SWPB)	
Parameter	Data Source
MP: metal production (metric tons Al)	Individual facility records
NAC: net annual prebaked anode consumption per metric ton Al (metric tons C/metric tons Al)	Individual facility records
S_a: sulfur content in baked	2.0

anode (percent weight)	
Ash_a: ash content in baked anode(percent weight)	0.4
CO_2 Emissions from Søderberg Cells (VSS and HSS)	
Parameter	Data Source
MP: metal production (metric tons Al)	Individual facility records
PC: annual paste consumption (metric ton/metric ton Al)	Individual facility records
CSM: annual emissions of cyclohexane soluble matter (kg/metric ton Al)	HSS: 4.0 VSS: 0.5
BC: binder content of paste (percent weight)	Dry Paste: 24 Wet Paste: 27
S_p: sulfur content of pitch (percent weight)	0.6
Ash_p: ash content of pitch (percent weight)	0.2
H_p: hydrogen content of pitch (percent weight)	3.3
S_c: sulfur content in calcined coke (percent weight)	1.9
Ash_c: ash content in calcined coke (percent weight)	0.2
CD: carbon in skimmed dust from Søderberg cells (metric ton C/metric ton Al)	0.01
CO_2 Emissions from Pitch Volatiles Combustion (VSS and HSS)	
Parameter	Data Source
GA: initial weight of green anodes (metric tons)	Individual facility records
H_w: annual hydrogen content in green anodes (metric tons)	0.005 × GA
BA: annual baked anode production (metric tons)	Individual facility records
WT: annual waste tar collected (metric tons) (a) Riedhammer furnaces (b) all other furnaces	(a) 0.005 × GA (b) insignificant
CO_2 Emissions from Bake Furnace Packing Materials (CWPB	

and SWPB)	
Parameter	Data Source
PCC: annual packing coke consumption (metric tons/metric ton baked anode)	0.015
BA: annual baked anode production (metric tons)	Individual facility records
S_{pc}: sulfur content in packing coke (percent weight)	2
Ash_{pc}: ash content in packing coke (percent weight)	2.5

Subpart N—Glass Production

§98.140 Definition of the source category.

(a) A glass manufacturing facility manufactures flat glass, container glass, pressed and blown glass, or wool fiberglass by melting a mixture of raw materials to produce molten glass and form the molten glass into sheets, containers, fibers, or other shapes. A glass manufacturing facility uses one or more continuous or batch glass melting furnaces to produce glass.[1]

(b) A glass melting furnace that is an experimental furnace or a research and development process unit is not subject to this subpart.

§98.141 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a glass production process and the facility meets the requirements of either §98.2(a)(1) or (2).

§98.142 GHGs to report.

You must report:

(a) CO_2 process emissions from each continuous or batch glass melting furnace.

[1]EPA's definition of a glass manufacturing facility is limited to only continuous glass melting furnaces. WCI has requested that batch furnaces be included as well. Expanded definition included in §98.140(a). All references in Subpart N to "continuous glass melting furnace" have been changed to "continuous or batch glass melting furnace" or "continuous and batch glass melting furnace", depending upon the specific text.

(b) CO_2 combustion emissions from each continuous or batch glass melting furnace.

(c) CH_4 and N_2O combustion emissions from each continuous or batch glass melting furnace. You must calculate and report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

(d) CO_2, CH_4, and N_2O emissions from each stationary fuel combustion unit other than continuous or batch glass melting furnaces. You must report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

§98.143 Calculating GHG emissions.

You must calculate and report the annual process CO_2 emissions from each continuous or batch glass melting furnace using the procedure in paragraphs (a) and (b) of this section.

(a) For each continuous or batch glass melting furnace that meets the conditions specified in §98.33(b)(4)(ii) or (iii), you must calculate and report under this subpart the combined process and combustion CO_2 emissions by operating and maintaining a CEMS to measure CO_2 emissions according to the Tier 4 Calculation Methodology specified in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(b) For each continuous or batch glass melting furnace that is not subject to the requirements in paragraph (a) of this section, calculate and report the process and combustion CO_2 emissions from the glass melting furnace by using either the procedure in paragraph (b)(1) of this section or the procedure in paragraphs (b)(2) through (b)(7) of this section, except as specified in paragraph (c) of this section.

(1) Calculate and report under this subpart the combined process and combustion CO_2 emissions by operating and maintaining a CEMS to measure CO_2 emissions according to the Tier 4 Calculation Methodology specified in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(2) Calculate and report the process and combustion CO_2 emissions separately using the procedures specified in paragraphs (b)(2)(i) through (b)(2)(vi) of this section.

(i) For each carbonate-based raw material charged to the furnace, obtain from the supplier of the raw material the carbonate-based mineral mass fraction.

(ii) Determine the quantity of each carbonate-based raw material charged to the furnace.

(iii) Apply the appropriate emission factor for each carbonate-based raw material charged to the furnace, as shown in Table N-1 to this subpart.

(iv) Use Equation N-1 of this section to calculate process mass emissions of CO_2 for each furnace:

$$E_{CO2} = \sum_{i=1}^{n} MF_i \bullet (M_i \bullet \frac{2000}{2205}) \bullet EF_i \bullet F_i \qquad \text{(Eq. N-1)}$$

Where:

E_{CO2}	=	Process emissions of CO_2 from the furnace (metric tons).
n	=	Number of carbonate-based raw materials charged to furnace.
MF_i	=	Annual average mass fraction of carbonate-based mineral i in carbonate-based raw material i (percentage, expressed as a decimal).
M_i	=	Annual amount of carbonate-based raw material i charged to furnace (tons).
2000/2205	=	Conversion factor to convert tons to metric tons.
EF_i	=	Emission factor for carbonate-based raw material i (metric ton CO_2 per metric ton carbonate-based raw material as shown in Table N-1 to this subpart).
F_i	=	Fraction of calcination achieved for carbonate-based raw material i, assumed to be equal to 1.0 (percentage, expressed as a decimal).

(v) You must calculate the total process CO_2 emissions from continuous and batch glass melting furnaces at the facility using Equation N-2 of this section:

$$CO_2 = \sum_{i=1}^{k} E_{CO_2 i} \qquad \text{(Eq. N-2)}$$

Where:

CO_2 = Annual process CO_2 emissions from glass manufacturing facility (metric tons).

E_{CO2i} = Annual CO_2 emissions from glass melting furnace i (metric tons).

k = Number of continuous and batch glass melting furnaces.

(vi) Calculate and report under subpart C of this part (General Stationary Fuel Combustion Sources) the combustion CO_2 emissions in the glass furnace according to the applicable requirements in subpart C.

(c) As an alternative to data provided by the raw material supplier, a value of 1.0 can be used for the mass fraction (MF_i) of carbonate-based mineral i in Equation N-1 of this section.

§98.144 Monitoring and QA/QC requirements.

(a) You must measure annual amounts of carbonate-based raw materials charged to each continuous or batch glass melting furnace from monthly measurements using plant instruments used for accounting purposes, such as calibrated scales or weigh hoppers. Total annual mass charged to glass melting furnaces at the facility shall be compared to records of raw material purchases for the year.

(b) You must measure carbonate-based mineral mass fractions at least annually to verify the mass fraction data provided by the supplier of the raw material; such measurements shall be based on sampling and chemical analysis conducted by a certified laboratory using ASTM D3682-01 (Reapproved 2006) Standard Test Method for Major and Minor Elements in Combustion Residues from Coal Utilization Processes (incorporated by reference, see §98.7).

(c) You must determine the annual average mass fraction for the carbonate-based mineral in each carbonate-based raw material by calculating an arithmetic average of the monthly data obtained from raw material suppliers or sampling and chemical analysis.

(d) You must determine on an annual basis the calcination fraction for each carbonate consumed based on sampling and chemical analysis using an industry consensus standard. This chemical analysis must be conducted using an x-ray fluorescence test or other enhanced testing method published by an industry consensus standards organization (e.g., ASTM, ASME, API, etc.).

§98.145 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required (e.g., carbonate raw materials consumed, etc.). If the monitoring and quality assurance procedures in §98.144 cannot be followed and data is missing, you must use the most appropriate of the missing data procedures in paragraphs (a) and (b) of this section. You must document and keep records of the procedures used for all such missing value estimates.

(a) For missing data on the monthly amounts of carbonate-based raw materials charged to any continuous or batch glass melting furnace use the best available estimate(s) of the parameter(s), based on all available process data or data used for accounting purposes, such as purchase records.

(b) For missing data on the mass fractions of carbonate-based minerals in the carbonate-based raw materials assume that the mass fraction of each carbonate based mineral is 1.0.

§98.146 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) and (b) of this section, as applicable.

Subpart N—Glass Production

(a) If a CEMS is used to measure CO_2 emissions, then you must report under this subpart the relevant information required under §98.37 for the Tier 4 Calculation Methodology and the following information specified in paragraphs (a)(1) and (a)(2) of this section:

(1) Annual quantity of each carbonate-based raw material charged to each continuous or batch glass melting furnace and for all furnaces combined (tons).

(2) Annual quantity of glass produced (tons).

(b) If a CEMS is not used to determine CO_2 emissions from continuous or batch glass melting furnaces, and process CO_2 emissions are calculated according to the procedures specified in §98.143(b), then you must report the following information as specified in paragraphs (b)(1) through (b)(9) of this section:

(1) Annual process emissions of CO_2 (metric tons) for each continuous or batch glass melting furnace and for all furnaces combined.

(2) Annual quantity of each carbonate-based raw material charged (tons) to each continuous or batch glass melting furnace and for all furnaces combined.

(3) Annual quantity of glass produced (tons) from each continuous or batch glass melting furnace and from all furnaces combined.

(4) Carbonate-based mineral mass fraction (percentage, expressed as a decimal) for each carbonate-based raw material charged to a continuous or batch glass melting furnace.

(5) Results of all tests used to verify the carbonate-based mineral mass fraction for each carbonate-based raw material charged to a continuous or batch glass melting furnace, as specified in paragraphs (b)(5)(i) through (b)(5)(iii) of this section.

(i) Date of test.

(ii) Method(s) and any variations used in the analyses.

(iii) Mass fraction of each sample analyzed.

(6) The fraction of calcination achieved for each carbonate-based raw material, if a value other than 1.0 is used to calculate process mass emissions of CO_2.

(7) Method used to determine fraction of calcination (percentage, expressed as a decimal).

(8) Total number of continuous or batch glass melting furnaces.

(9) The number of times in the reporting year that missing data procedures were followed to measure monthly quantities of carbonate-based raw materials any continuous

or batch glass melting furnace or mass fraction of the carbonate-based minerals (months).

§98.147 Records that must be retained.

In addition to the information required by §98.3(g), you must retain the records listed in paragraphs (a), (b), and (c) of this section.

(a) If a CEMS is used to measure emissions, then you must retain the records required under §98.37 for the Tier 4 Calculation Methodology and the following information specified in paragraphs (a)(1) and (a)(2) of this section:

(1) Monthly glass production rate for each continuous or batch glass melting furnace (tons).

(2) Monthly amount of each carbonate-based raw material charged to each continuous or batch glass melting furnace (tons).

(b) If process CO_2 emissions are calculated according to the procedures specified in §98.143(b), you must retain the records in paragraphs (b)(1) through (b)(5) of this section.

(1) Monthly glass production rate for each continuous or batch glass melting furnace (metric tons).

(2) Monthly amount of each carbonate-based raw material charged to each continuous or batch glass melting furnace (metric tons).

(3) Data on carbonate-based mineral mass fractions provided by the raw material supplier for all raw materials consumed annually and included in calculating process emissions in Equation N-1 of this subpart.

(4) Results of all tests used to verify the carbonate-based mineral mass fraction for each carbonate-based raw material charged to a continuous or batch glass melting furnace, including the data specified in paragraphs (b)(4)(i) through (b)(4)(v) of this section.

(i) Date of test.

(ii) Method(s), and any variations of the methods, used in the analyses.

(iii) Mass fraction of each sample analyzed.

(iv) Relevant calibration data for the instrument(s) used in the analyses.

(v) Name and address of laboratory that conducted the tests.

(5) The fraction of calcination achieved for each carbonate-based raw material (percentage, expressed as a decimal), if a value other than 1.0 is used to calculate process mass emissions of CO_2.

(c) All other documentation used to support the reported GHG emissions.

§98.148 Definitions.

Subpart N—Glass Production

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Table N-1 of Subpart N—CO_2 Emission Factors for Carbonate-Based Raw Materials

Carbonate-Based Raw Material – Mineral	CO_2 Emission Factor[a]
Limestone – $CaCO_3$	0.440
Dolomite – $CaMg(CO_3)_2$	0.477
Sodium carbonate/soda ash – Na_2CO_3	0.415

[a] Emission factors in units of metric tons of CO_2 emitted per metric ton of carbonate-based raw material charged to the furnace.

Subpart P—Hydrogen Production

§98.160 Definition of the source category.

(a) A hydrogen production source category consists of facilities that produce hydrogen gas for use onsite or sold as a product to other entities.

(b) This source category comprises process units that produce hydrogen by reforming, gasification, oxidation, reaction, or other transformations of feedstocks.

(c) This source category includes merchant hydrogen production facilities located within a petroleum refinery if they are not owned by, or under the direct control of, the refinery owner and operator.

§98.161 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a hydrogen production process and the facility meets the requirements of either §98.2(a)(1) or (a)(2).

§98.162 GHGs to report.

You must report:

(a) CO_2 process emissions from each hydrogen production process unit.

(b) CO_2, CH_4 and N_2O combustion emissions from each hydrogen production process unit. You must calculate and report these combustion emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

(c) CO_2, CH_4, and N_2O emissions from each stationary combustion unit other than hydrogen production process units. You must calculate and report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

(d) For CO_2 collected and transferred off site, you must follow the requirements of subpart PP of this part.

§98.163 Calculating GHG emissions.

You must calculate and report the annual process CO_2 emissions from each hydrogen production process unit using the procedures specified in either paragraph (a) or (b) of this section.

(a) Continuous Emissions Montoring Systems (CEMS). Calculate and report under this subpart the process CO_2 emissions by operating and maintaining CEMS according to the Tier 4 Calculation Methodology specified in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(b) Fuel and feedstock material balance approach. Calculate and report process CO_2 emissions as the sum of the annual emissions associated with each fuel and feedstock used for hydrogen production by following paragraphs (b)(1) through (b)(3) of this section.

(1) Gaseous fuel and feedstock. You must calculate the annual CO_2 process emissions from gaseous fuel and feedstock according to Equation P-1 of this section:

$$CO_2 = \left(\sum_{n=1}^{k} \frac{44}{12} * Fdstk_n * CC_n * \frac{MW}{MVC}\right) * 0.001 \quad \text{(Eq. P-1)}$$

Where:

CO_2	=	Annual CO_2 process emissions arising from fuel and feedstock consumption (metric tons/yr).
$Fdstk_n$	=	Volume of the gaseous fuel and feedstock used in month n(scf (at standard conditions of 68 °F and atmospheric pressure) of fuel and feedstock).
CC_n	=	Weighted ~~A~~average carbon content of the gaseous fuel and feedstock, from the results of one or more analyses for month n for natural gas or from daily analysis for gasseous feedstocks other than natural gas(kg carbon per kg of fuel and feedstock).
MW	=	Molecular weight of the gaseous fuel and feedstock (kg/kg-mole).
MVC	=	Molar volume conversion factor (849.5 scf per kg-mole at standard conditions).
k	=	Months in the year.
44/12	=	Ratio of molecular weights, CO_2 to carbon.
0.001	=	Conversion factor from kg to metric tons.

(2) Liquid fuel and feedstock. You must calculate the annual CO_2 process emissions from liquid fuel and feedstock according to Equation P-2 of this section:

$$CO_2 = (\sum_{n=1}^{k} \frac{44}{12} * Fdstk_n * CC_n) * 0.001 \qquad \text{(Eq. P-2)}$$

Where:

CO_2 = Annual CO_2 emissions arising from fuel and feedstock consumption (metric tons/yr).

$Fdstk_n$ = Volume of the liquid fuel and feedstock used in month n (gallons of fuel and feedstock).

CC_n = Weighted a~~A~~verage carbon content of the liquid fuel and feedstock, from the results of daily ~~one or more~~ sampling~~analyses~~ for month n (kg carbon per gallon of fuel and feedstock). Daily liquid samples may be combined to generate a monthly composite sample for carbon analysis.

k = Months in the year.

44/12 = Ratio of molecular weights, CO_2 to carbon.

0.001 = Conversion factor from kg to metric tons.

(3) Solid fuel and feedstock. You must calculate the annual CO_2 process emissions from solid fuel and feedstock according to Equation P-3 of this section:

$$CO_2 = \sum_{n=1}^{k} \frac{44}{12} * (Fdstk_n * CC_n) * 0.001 \qquad \text{(Eq.P-3)}$$

Where:

CO_2 = Annual CO_2 emissions from fuel and feedstock consumption in metric tons per year (metric tons/yr).

$Fdstk_n$ = Mass of solid fuel and feedstock used in month n (kg of fuel and feedstock).

CC_n = Weighted ~~A~~average carbon content of the solid fuel and feedstock, from the results of daily~~one or more~~ sampling~~analyses~~ for month n (kg carbon per kg of fuel and feedstock). Daily solid samples may be combined to generate a monthly composite sample for carbon analysis.

k = Months in the year.

44/12 = Ratio of molecular weights, CO_2 to carbon.
0.001 = Conversion factor from kg to metric tons.

(c) If GHG emissions from a hydrogen production process unit are vented through the same stack as any combustion unit or process equipment that reports CO_2 emissions using a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Fuel Combustion Sources), then the calculation methodology in paragraph (b) of this section shall not be used to calculate process emissions. The owner or operator shall report under this subpart the combined stack emissions according to the Tier 4 Calculation Methodology in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

§98.164 Monitoring and QA/QC requirements.

The GHG emissions data for hydrogen production process units must be quality-assured as specified in paragraphs (a) or (b) of this section, as appropriate for each process unit:

(a) If a CEMS is used to measure GHG emissions, then the facility must comply with the monitoring and QA/QC procedures specified in §98.34(c).

(b) If a CEMS is not used to measure GHG emissions, then you must:

(1) Calibrate all oil and gas flow meters (except for gas billing meters), solids weighing equipment, and oil tank drop measurements (if used to determine liquid fuel and feedstock use volume) according to the calibration accuracy requirements in §98.3(i) of this part .

(2) Determine the carbon content and the molecular weight monthly ~~annually~~ for ~~of standard gaseous hydrocarbon fuels and feedstocks having consistent composition (e.g.,~~ natural gas~~)~~. For other gaseous fuels and feedstocks (e.g., biogas, refinery gas, or process gas), daily ~~weekly~~ sampling and analysis is required to determine the carbon content and molecular weight of the fuel and feedstock.

(3) Determine the carbon content of fuel oil, naphtha, and other liquid fuels and feedstocks at least ~~monthly~~daily~~,~~. ~~except annually for standard liquid hydrocarbon fuels and feedstocks having consistent composition, or upon delivery for liquid fuels delivered by bulk transport (e.g., by truck or rail).~~ Daily weighted liquid samples may be combined to generate a monthly composite sample for carbon analysis.

(4) Determine the carbon content of coal, coke, and other solid fuels and feedstocks at least ~~monthly,~~daily

~~except annually for standard solid hydrocarbon fuels and feedstocks having consistent composition, or upon delivery for solid fuels delivered by bulk transport (e.g., by truck or rail)~~. Daily weighted solid samples may be combined to generate a monthly composite sample for carbon analysis.

(5) You must use the following applicable methods to determine the carbon content for all fuels and feedstocks, and molecular weight of gaseous fuels and feedstocks.

(i) ASTM D1945-03 Standard Test Method for Analysis of Natural Gas by Gas Chromatography (incorporated by reference, see §98.7).

(ii) ASTM D1946-90 (Reapproved 2006), Standard Practice for Analysis of Reformed Gas by Gas Chromatography (incorporated by reference, see §98.7).

(iii) ASTM D2013-07 Standard Practice of Preparing Coal Samples for Analysis (incorporated by reference, see §98.7).

(iv) ASTM D2234/D2234M-07 Standard Practice for Collection of a Gross Sample of Coal (incorporated by reference, see §98.7).

(v) ASTM D2597-94 (Reapproved 2004) Standard Test Method for Analysis of Demethanized Hydrocarbon Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography (incorporated by reference, see §98.7).

(vi) ASTM D3176-89 (Reapproved 2002), Standard Practice for Ultimate Analysis of Coal and Coke (incorporated by reference, see §98.7).

(vii) ASTM D3238-95 (Reapproved 2005), Standard Test Method for Calculation of Carbon Distribution and Structural Group Analysis of Petroleum Oils by the n-d-M Method (incorporated by reference, see §98.7).

(viii) ASTM D4057-06 Standard Practice for Manual Sampling of Petroleum and Petroleum Products (incorporated by reference, see §98.7).

(ix) ASTM D4177-95 (Reapproved 2005) Standard Practice for Automatic Sampling of Petroleum and Petroleum Products (incorporated by reference, see §98.7).

(x) ASTM D5291-02 (Reapproved 2007), Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants (incorporated by reference, see §98.7).

(xi) ASTM D5373-08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal (incorporated by reference, see §98.7).

(xii) ASTM D6609-08 Standard Guide for Part-Stream Sampling of Coal (incorporated by reference, see §98.7).

(xiii) ASTM D6883-04 Standard Practice for Manual Sampling of Stationary Coal from Railroad Cars, Barges, Trucks, or Stockpiles (incorporated by reference, see §98.7).

(xiv) ASTM D7430-08ae1 Standard Practice for Mechanical Sampling of Coal (incorporated by reference, see §98.7).

(xv) ASTM UOP539-97 Refinery Gas Analysis by Gas Chromatography (incorporated by reference, see §98.7).

(xvi) GPA 2261–00 Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography (incorporated by reference, see §98.7).

(xvii) ISO 3170: Petroleum Liquids -- Manual sampling – Third Edition (incorporated by reference, see §98.7).

(xviii) ISO 3171: Petroleum Liquids -- Automatic pipeline sampling – Second Edition (incorporated by reference, see §98.7).

(c) For units using the calculation methodologies described in this section, the records required under §98.3(g) must include both the company records and a detailed explanation of how company records are used to estimate the following:

(1) Fuel and feedstock consumption, when solid fuel and feedstock is combusted and a CEMS is not used to measure GHG emissions.

(2) Fossil fuel consumption, when, pursuant to §98.33(e), the owner or operator of a unit that uses CEMS to quantify CO_2 emissions and that combusts both fossil and biogenic fuels separately reports the biogenic portion of the total annual CO_2 emissions.

(3) Sorbent usage, if the methodology in §98.33(d) is used to calculate CO_2 emissions from sorbent.

(d) The owner or operator must document the procedures used to ensure the accuracy of the estimates of fuel and feedstock usage and sorbent usage (as applicable) in paragraph (b) of this section, including, but not limited to, calibration of weighing equipment, fuel and feedstock flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.

<u>§98.165 Procedures for estimating missing data.</u>

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation), a substitute data value for the missing parameter must be used in the calculations as specified in paragraphs (a), (b), and (c) of this section:

(a) For each missing value of the monthly fuel and feedstock consumption, the substitute data value must be the best available estimate of the fuel and feedstock consumption, based on all available process data (e.g., hydrogen production, electrical load, and operating hours). You must document and keep records of the procedures used for all such estimates.

(b) For each missing value of the carbon content or molecular weight of the fuel and feedstock, the substitute data value must be the arithmetic average of the quality-assured values of carbon contents or molecular weight of the fuel and feedstock immediately preceding and immediately following the missing data incident. If no quality-assured data on carbon contents or molecular weight of the fuel and feedstock are available prior to the missing data incident, the substitute data value must be the first quality-assured value for carbon contents or molecular weight of the fuel and feedstock obtained after the missing data period. You must document and keep records of the procedures used for all such estimates.

(c) For missing CEMS data, you must use the missing data procedures in §98.35.

§98.166 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) or (b) of this section, as appropriate:

(a) If a CEMS is used to measure CO_2 emissions, then you must report the relevant information required under §98.36 for the Tier 4 Calculation Methodology and the following information in this paragraph (a):

(1) Unit identification number and annual CO_2 process emissions.

(2) Annual quantity of hydrogen produced (metric tons) for each process unit and for all units combined.

(3) Annual quantity of ammonia produced (metric tons), if applicable, for each process unit and for all units combined.

(b) If a CEMS is not used to measure CO_2 emissions, then you must report the following information for each hydrogen production process unit:

(1) Unit identification number and annual CO_2 process emissions (2) Monthly consumption of each fuel and feedstock used for hydrogen production and its type (scf of

gaseous fuels and feedstocks, gallons of liquid fuels and feedstocks, kg of solid fuels and feedstocks).

(3) Annual quantity of hydrogen produced (metric tons).

(4) Annual quantity of ammonia produced, if applicable (metric tons).

(5) Monthly or daily analyses of carbon content for each fuel and feedstock used in hydrogen production (kg carbon/kg of gaseous and solid fuels and feedstocks, (kg carbon per gallon of liquid fuels and feedstocks).

(6) Monthly or daily analyses of the molecular weight of gaseous fuels and feedstocks (kg/kg-mole) used, if any.~~.~~

(7) Amount of carbon in unconverted feedstock for which GHG emissions are calculated and reported by your facility using other calculation methods provided in this regulation. For example, carbon in waste diverted to a fuel system or flare, where the CO_2 and CH_4 emissions are calculated and reported using other methods provided in this regulation. (metric tons CO_2e/year).

(c) Quarterly quantity of CO_2 collected and transferred off site in either gas, liquid, or solid forms (kg), following the requirements of subpart PP of this part.

(d) Annual quantity of carbon other than CO_2 collected and transferred off site in either gas, liquid, or solid forms (kg carbon).

§98.167 Records that must be retained.

In addition to the information required by §98.3(g), you must retain the records specified in paragraphs (a) through (b) of this section for each hydrogen production facility.

(a) If a CEMS is used to measure CO_2 emissions, then you must retain under this subpart the records required for the Tier 4 Calculation Methodology in §98.37.

(b) If a CEMS is not used to measure CO_2 emissions, then you must retain records of all analyses and calculations conducted as listed in §§98.166(b), (c), and (d).

§98.168 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart Y—Petroleum Refineries

§98.250 Definition of Source Category.

(a) A petroleum refinery is any facility engaged in producing gasoline, gasoline blending stocks, naphtha, kerosene, distillate fuel oils, residual fuel oils, lubricants, or asphalt (bitumen) through distillation of petroleum or through redistillation, cracking, or reforming of unfinished petroleum derivatives, except as provided in paragraph (b) of this section.

(b) For the purposes of this subpart, facilities that distill only pipeline transmix (off-spec material created when different specification products mix during pipeline transportation) are not petroleum refineries, regardless of the products produced.

(c) This source category consists of the following sources at petroleum refineries: catalytic cracking units; fluid coking units; delayed coking units; catalytic reforming units; coke calcining units; asphalt blowing operations; blowdown systems; storage tanks; process equipment components (compressors, pumps, valves, pressure relief devices, flanges, and connectors) in gas service; marine vessel, barge, tanker truck, and similar loading operations; flares; sulfur recovery plants; and non-merchant hydrogen plants (i.e., hydrogen plants that are owned or under the direct control of the refinery owner and operator).

Subpart Y—Petroleum Refineries

§98.251 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a petroleum refineries process and the facility meets the requirements of either §98.2(a)(1) or (a)(2).

§98.252 GHGs to report.

You must report:

(a) CO_2, CH_4, and N_2O combustion emissions from stationary combustion units and from each flare. Calculate and report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C, except for CO_2 emissions from combustion of refinery fuel gas. For CO_2 emissions from combustion of fuel gas, use either equation C-5 in subpart C of this part or the Tier 4 methodology in subpart C of this part. You may aggregate units, monitor common stacks, or monitor common (fuel) pipes as provided in §98.36(c) when calculating and reporting emissions from stationary combustion units.

(b) CO_2, CH_4, and N_2O coke burn-off emissions from each catalytic cracking unit, fluid coking unit, and catalytic reforming unit under this subpart.

(c) CO_2 emissions from sour gas sent off site for sulfur recovery operations under this subpart. You must follow the calculation methodologies from §98.253(f)and the monitoring and

QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of this subpart.

(d) CO_2 process emissions from each on-site sulfur recovery plant under this subpart.

(e) CO_2, CH_4, and N_2O emissions from each coke calcining unit under this subpart.

(f) CO_2 and CH_4 emissions from asphalt blowing operations under this subpart.

(g) CH_4 emissions from equipment leaks, storage tanks, loading operations, delayed coking units, and uncontrolled blowdown systems under this subpart.

(h) CO_2, CH_4, and N_2O emissions from each process vent not specifically included in paragraphs (a) through (g) of this section under this subpart.

(i) CO_2 and CH_4 emissions from non-merchant hydrogen production under this subpart. You must follow the calculation methodologies, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of subpart P of this part.

§98.253 Calculating GHG emissions.

(a) Calculate GHG emissions required to be reported in §98.252(b) through (i) using the applicable methods in paragraphs (b) through (n) of this section.

(b) For flares, calculate GHG emissions according to the requirements in paragraphs (b)(1) through (b)(3) of this section.

(1) Calculate the CO_2 emissions according to the applicable requirements in paragraphs (b)(1)(i) through (b)(1)(iii) of this section.

(i) Flow measurement. If you have a continuous flow monitor on the flare, you must use the measured flow rates when the monitor is operational and the flow rate is within the calibrated range of the measurement device to calculate the flare gas flow. If you do not have a continuous flow monitor on the flare and for periods when the monitor is not operational or the flow rate is outside the calibrated range of the measurement device, you must use engineering calculations, company records, or similar estimates of volumetric flare gas flow.

(ii) Heat value or carbon content measurement. If you have a continuous higher heating value monitor or gas composition monitor on the flare or if you monitor these parameters at least weekly, you must use the measured heat value or carbon content value in calculating the CO_2 emissions from the flare using the applicable methods in paragraphs (b)(1)(ii)(A) and (b)(1)(ii)(B).

(A) If you monitor gas composition, calculate the CO_2 emissions from the flare using Equation Y-1 of this section. If daily or more frequent measurement data are available, you must use daily values when using Equation Y-1 of this section; otherwise, use weekly values.

$$CO_2 = 0.98 \times 0.001 \times \left(\sum_{p=1}^{n} \left[\frac{44}{12} \times (Flare)_p \times \frac{(MW)_p}{MVC} \times (CC)_p \right] \right) \qquad \text{(Eq.Y-1)}$$

Where:

CO_2	=	Annual CO_2 emissions for a specific fuel type (metric tons/year).
0.98	=	Assumed combustion efficiency of a flare.
0.001	=	Unit conversion factor (metric tons per kilogram, mt/kg).
n	=	Number of measurement periods. The minimum value for n is 52 (for weekly measurements); the maximum value for n is 366 (for daily measurements during a leap year).
p	=	Measurement period index.
44	=	Molecular weight of CO_2 (kg/kg-mole).
12	=	Atomic weight of C (kg/kg-mole).
$(Flare)_p$	=	Volume of flare gas combusted during measurement period (standard cubic feet per period, scf/period). If a mass flow meter is used, measure flare gas flow rate in kg/period and replace the term "$(MW)_p$/MVC" with "1".
$(MW)_p$	=	Average molecular weight of the flare gas combusted during measurement period (kg/kg-mole). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.
MVC	=	Molar volume conversion factor (849.5 scf/kg-mole).
$(CC)_p$	=	Average carbon content of the flare gas combusted during measurement period (kg C per kg flare gas). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.

(B) If you monitor heat content but do not monitor gas composition, calculate the CO_2 emissions from the flare using Equation Y-2 of this section. If daily or more frequent measurement data are available, you must use daily values when using Equation Y-2 of this section; otherwise, use weekly values.

$$CO_2 = 0.98 \times 0.001 \times \sum_{p=1}^{n} \left[(Flare)_p \times (HHV)_p \times EmF \right] \qquad \text{(Eq.Y-2)}$$

Where:

CO_2	=	Annual CO_2 emissions for a specific fuel type (metric tons/year).
0.98	=	Assumed combustion efficiency of a flare.
0.001	=	Unit conversion factor (metric tons per kilogram, mt/kg).
n	=	Number of measurement periods. The minimum value for n is 52 (for weekly measurements); the maximum value for n is 366 (for daily measurements during a leap year).
p	=	Measurement period index.
$(Flare)_p$	=	Volume of flare gas combusted during measurement period (million (MM) scf/period). If a mass flow meter is used, you must also measure molecular weight and convert the mass flow to a volumetric flow as follows: Flare[MMscf] = 0.000001 × Flare[kg] × MVC/$(MW)_p$, where MVC is the molar volume conversion factor (849.5 scf/kg-mole) and $(MW)_p$ is the average molecular weight of the flare gas combusted during measurement period (kg/kg-mole).
$(HHV)_p$	=	Higher heating value for the flare gas combusted during measurement period (British thermal units per scf, Btu/scf = MMBtu/MMscf). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.
EmF	=	Default CO_2 emission factor of 60 kilograms CO_2/MMBtu (HHV basis).

(iii) Alternative Method for Startup, Shutdown, and Malfunctions~~to heat value or carbon content measurements~~. For startup, shutdown, and malfunctions during which you were unable to measure the parameters required by Equations Y-1 and Y-2 of this section, ~~If you do not measure the~~ you must ~~higher heating value or carbon content of the flare gas at least weekly,~~ determine the quantity of gas discharged to the flare separately for each ~~periods of routine flare operation and for periods of~~ start-up, shutdown, or malfunction, and calculate the CO_2 emissions as specified in paragraphs (b)(1)(iii)(A) ~~through~~ and (b)(1)(iii)(C) of this section.

(A) For periods of start-up, shutdown, or malfunction, use engineering calculations and process knowledge to estimate the carbon content of the flared gas for each start-up, shutdown, or malfunction event. ~~exceeding 500,000 scf/day.~~

(B) ~~For periods of normal operation, use the average heating value measured for the fuel gas for the heating value of the flare gas. If heating value is not measured, the heating value may be estimated from historic data or engineering calculations.~~

Reserved.

(C) Calculate the CO_2 emissions using Equation Y-3 of this section.

$$\cancel{CO_2 = 0.98 \times 0.001 \times \left(Flare_{Norm} \times HHV \times EmF + \sum_{p=1}^{n} \left[\frac{44}{12} \times (Flare_{SSM})_p \times \frac{(MW)_p}{MVC} \times (CC)_p \right] \right)}$$ ~~(Eq.Y-3)~~

$$CO_2 = 0.98 \times 0.001 \times \left(\sum_{p=1}^{n} \left[\frac{44}{12} \times (Flare_{SSM})_p \times \frac{(MW)_p}{MVC} \times (CC)_p \right] \right)$$ (Eq.Y-3)[1]

Where:

CO_2	=	Annual CO_2 emissions for a specific fuel type (metric tons/year).
0.98	=	Assumed combustion efficiency of a flare.
0.001	=	Unit conversion factor (metric tons per kilogram, mt/kg).
~~$Flare_{Norm}$~~	~~=~~	~~Annual volume of flare gas combusted during normal operations from company records, (million (MM) standard cubic feet per year, MMscf/year).~~
~~HHV~~	~~=~~	~~Higher heating value for fuel gas or flare gas from company records (British thermal units per scf, Btu/scf = MMBtu/MMscf).~~
~~EmF~~	~~=~~	~~Default CO_2 emission factor for flare gas of 60 kilograms CO_2/MMBtu (HHV basis).~~
n	=	Number of start-up, shutdown, and malfunction events during the reporting year exceeding 500,000 scf/day.
p	=	Start-up, shutdown, and malfunction event index.
44	=	Molecular weight of CO_2 (kg/kg-mole).
12	=	Atomic weight of C (kg/kg-mole).
$(Flare_{SSM})_p$	=	Volume of flare gas combusted during indexed start-up, shutdown, or malfunction event from engineering calculations, (scf/event).
$(MW)_p$	=	Average molecular weight of the flare gas, from the analysis results or engineering calculations for the event (kg/kg-mole).
MVC	=	Molar volume conversion factor (849.5 scf/kg-mole).

[1] Equation Y-3 was revised to delete the factors used to calculate CO_2 emissions during normal operation of the flare. For normal operation of flares, ERMR proposes that CO_2 emissions be calcualted using either Equation Y-1 or Y-2.

$(CC)_p$ = Average carbon content of the flare gas, from analysis results or engineering calculations for the event (kg C per kg flare gas).

(2) Calculate CH_4 using Equation Y-4 of this section.

$$CH_4 = \left(CO_2 \times \frac{EmF_{CH4}}{EmF}\right) + CO_2 \times \frac{0.02}{0.98} \times \frac{16}{44} \times f_{CH4} \qquad \text{(Eq. Y-4)}$$

Where:

CH_4	=	Annual methane emissions from flared gas (metric tons CH_4/year).
CO_2	=	Emission rate of CO_2 from flared gas calculated in paragraph (b)(1) of this section (metric tons/year).
EmF_{CH4}	=	Default CH_4 emission factor for "PetroleumProducts" from Table C-2 of subpart C of this part (General Stationary Fuel Combustion Sources) (kg CH_4/MMBtu).
EmF	=	Default CO_2 emission factor for flare gas of 60 kg CO_2/MMBtu (HHV basis).
0.02/0.98	=	correction factor for flare combustion efficiency.
16/44	=	correction factor ratio of the molecular weight of CH_4 to CO_2
f_{CH4}	=	Weight fraction of carbon in the flare gas prior to combustion that is contributed by methane from measurement values or engineering calculations (kg C in methane in flare gas/kg C in flare gas); default is 0.4.

(3) Calculate N_2O emissions using Equation Y-5 of this section.

$$N_2O = \left(CO_2 \times \frac{EmF_{N2O}}{EmF}\right) \qquad \text{(Eq. Y-5)}$$

Where:

N_2O = Annual nitrous oxide emissions from flared gas (metric tons N_2O/year).

CO_2 = Emission rate of CO_2 from flared gas calculated in paragraph (b)(1) of this section (metric tons/year).

EmF_{N2O} = Default N_2O emission factor for "PetroleumProducts" from Table C-2 of subpart C of this part (General Stationary Fuel Combustion Sources)(kg N_2O/MMBtu).

EmF = Default CO_2 emission factor for flare gas of 60 kg CO_2/MMBtu (HHV basis).

(c) For catalytic cracking units and traditional fluid coking units, calculate the GHG emissions using the applicable methods described in paragraphs (c)(1) through (c)(5) of this section.

(1) If you operate and maintain a CEMS that measures CO_2 emissions according to subpart C of this part (General Stationary Fuel Combustion Sources), you must calculate and report CO_2 emissions as provided in paragraphs (c)(1)(i) and (c)(1)(ii) of this section. Other catalytic cracking units and traditional fluid coking units must either install a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Combustion Souces), or follow the requirements of paragraphs (c)(2) or (3) of this section.

(i) Calculate CO_2 emissions by following the Tier 4 Calculation Methodology specified in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(ii) If a CO boiler or other post-combustion device is used, you must also calculate the CO_2 emissions from the fuel fired to the CO boiler or post-combustion device using the applicable methods for stationary combustion units in subpart C of this part. Calculate the process emissions from the catalytic cracking unit or fluid coking unit as the difference in the CO_2 CEMS emissions and the calculated combustion emissions associated with the CO boiler.

(2) For catalytic cracking units and fluid coking units ~~with rated capacities greater than 10,000 barrels per stream day (bbls/sd)~~ that do not use a continuous CO_2 CEMS for the final exhaust stack, you must continuously or no less frequently than hourly monitor the O_2, CO_2, and (if necessary) CO concentrations in the exhaust stack from the catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels and calculate the CO_2 emissions according to the requirements of paragraphs (c)(2)(i) through (c)(2)(iii) of this section:

(i) Calculate the CO_2 emissions from each catalytic cracking unit and fluid coking unit using Equation Y-6 of this section.

$$CO_2 = \sum_{p=1}^{n}\left[(Q_r)_p \times \frac{(\%CO_2 + \%CO)_p}{100\%} \times \frac{44}{MVC} \times 0.001\right] \qquad \text{(Eq. Y-6)}$$

Where:

CO_2 = Annual CO_2 mass emissions (metric tons/year).

Q_r = Volumetric flow rate of exhaust gas from the fluid catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels (dry standard cubic feet per hour, dscfh).

$\%CO_2$ = Hourly average percent CO_2 concentration in the exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume – dry basis).

$\%CO$ = Hourly average percent CO concentration in the exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume – dry basis). When there is no post-combustion device, assume %CO to be zero.

44 = Molecular weight of CO_2 (kg/kg-mole).

MVC = Molar volume conversion factor (849.5 scf/kg-mole).

0.001 = Conversion factor (metric ton/kg).

n = Number of hours in calendar year.

(ii) Either continuously monitor the volumetric flow rate of exhaust gas from the fluid catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels or calculate the volumetric flow rate of this exhaust gas stream using Equation Y-7 of this section.

$$Q_r = \frac{\left(79 * Q_a + (100 - \%O_{oxy}) * Q_{oxy}\right)}{100 - \%CO_2 - \%CO - \%O_2} \qquad \text{(Eq. Y-7)}$$

Where:

Q_r = Volumetric flow rate of exhaust gas from the fluid catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels (dscfh).

Q_a = Volumetric flow rate of air to the fluid catalytic cracking unit regenerator or fluid coking unit burner, as determined from control room instrumentation (dscfh).

Q_{oxy} = Volumetric flow rate of oxygen enriched air to the fluid catalytic cracking unit regenerator or fluid coking unit burner as determined from control room instrumentation (dscfh).

$\%O_2$	=	Hourly average percent oxygen concentration in exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume – dry basis).
$\%O_{oxy}$	=	O_2 concentration in oxygen enriched gas stream inlet to the fluid catalytic cracking unit regenerator or fluid coking unit burner based on oxygen purity specifications of the oxygen supply used for enrichment (percent by volume – dry basis).
$\%CO_2$	=	Hourly average percent CO_2 concentration in the exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume – dry basis).
$\%CO$	=	Hourly average percent CO concentration in the exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume – dry basis). When no auxiliary fuel is burned and a continuous CO monitor is not required under 40 CFR part 63 subpart UUU, assume %CO to be zero.

(iii) If you have a CO boiler that uses auxiliary fuels or combusts materials other than catalytic cracking unit or fluid coking unit exhaust gas, you must determine the CO_2 emissions resulting from the combustion of these fuels or other materials following the requirements in subpart C and report those emissions by following the requirements of subpart C of this part.

(3) ~~For catalytic cracking units and fluid coking units with rated capacities of 10,000 barrels per stream day (bbls/sd) or less that do not use a continuous CO_2 CEMS for the final exhaust stack, comply with the requirements in paragraphs (c)(3)(i) of this section or paragraphs (c)(3)(ii) and (c)(3)(iii) of this section, as applicable.~~

Reserved.

~~(i) If you continuously or no less frequently than daily monitor the O_2, CO_2, and (if necessary) CO concentrations in the exhaust stack from the catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels, you must calculate the CO_2 emissions according to the requirements of paragraphs (c)(2)(i) through (c)(2)(iii) of this section, except that daily averages are allowed and the summation can be performed on a daily basis.~~

~~(ii) If you do not monitor at least daily the O_2, CO_2, and (if necessary) CO concentrations in the exhaust stack from the catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels, calculate the CO_2 emissions from each catalytic cracking unit and fluid coking unit using Equation Y-8 of this section.~~

$$\cancel{CO_2 = Q_{unit} \times (CBF \times 0.001) \times CC \times \frac{44}{12}} \qquad \text{(Eq. Y-8)}$$

~~Where:~~

~~CO_2 = Annual CO_2 mass emissions (metric tons/year).~~

~~Q_{unit} = Annual throughput of unit from company records (barrels (bbls) per year, bbl/yr).~~

~~CBF = Coke burn-off factor from engineering calculations (kg coke per barrel of feed); default for catalytic cracking units = 7.3; default for fluid coking units = 11.~~

~~0.001 = Conversion factor (metric ton/kg).~~

~~CC = Carbon content of coke based on measurement or engineering estimate (kg C per kg coke); default = 0.94.~~

~~44/12 = Ratio of molecular weight of~~ ~~CO_2~~ ~~to C (kg~~ ~~CO_2~~ ~~per kg C).~~

~~(iii) If you have a CO boiler that uses auxiliary fuels or combusts materials other than catalytic cracking unit or fluid coking unit exhaust gas, you must determine the~~ ~~CO_2~~ ~~emissions resulting from the combustion of these fuels or other materials following the requirements in subpart C of this part (General Stationary Fuel Combustion Sources) and report those emissions by following the requirements of subpart C of this part.~~

(4) Calculate CH_4 emissions using either unit specific measurement data, a unit-specific emission factor based on a source test of the unit, or Equation Y-9 of this section.

$$CH_4 = \left(CO_2 * \frac{EmF_2}{EmF_1} \right) \quad \text{(Eq. Y-9)}$$

Where:

CH_4 = Annual methane emissions from coke burn-off (metric tons CH_4/year).

CO_2 = Emission rate of CO_2 from coke burn-off calculated in paragraphs (c)(1), (c)(2), (e)(1), (e)(2), (g)(1), or (g)(2) of this section, as applicable (metric tons/year).

EmF_1 = Default CO_2 emission factor for petroleum coke from Table C-1 of subpart C of this part (General Stationary Fuel Combustion Sources) (kg CO_2/MMBtu).

EmF_2 = Default CH_4 emission factor for "PetroleumProducts" from Table C-2 of subpart C of this part (General Stationary Fuel Combustion Sources) (kg CH_4/MMBtu).

(5) Calculate N_2O emissions using either unit specific measurement data, a unit-specific emission factor based on a source test of the unit, or Equation Y-10 of this section.

$$N_2O = \left(CO_2 * \frac{EmF_3}{EmF_1} \right) \qquad \text{(Eq. Y-10)}$$

Where:

N_2O = Annual nitrous oxide emissions from coke burn-off (mt N_2O/year).

CO_2 = Emission rate of CO_2 from coke burn-off calculated in paragraphs (c)(1), (c)(2), (e)(1), (e)(2), (g)(1), or (g)(2) of this section, as applicable (metric tons/year).

EmF_1 = Default CO_2 emission factor for petroleum coke from Table C-1 of subpart C of this part (General Stationary Fuel Combustion Sources) (kg CO_2/MMBtu).

EmF_3 = Default N_2O emission factor for ”PetroleumProducts” from Table C-2 of subpart C of this part (kg N_2O/MMBtu).

(d) For fluid coking units that use the flexicoking design, the GHG emissions from the resulting use of the low value fuel gas must be accounted for only once. Typically, these emissions will be accounted for using the methods described in subpart C of this part (General Stationary Fuel Combustion Sources). Alternatively, you may use the methods in paragraph (c) of this section provided that you do not otherwise account for the subsequent combustion of this low value fuel gas.

(e) For catalytic reforming units, calculate the CO_2 emissions using the applicable methods described in paragraphs (e)(1) through (e)(3) of this section and calculate the CH_4 and N_2O emissions using the methods described in paragraphs (c)(4) and (c)(5) of this section, respectively.

(1) If you operate and maintain a CEMS that measures CO_2 emissions according to subpart C of this part (General Stationary Fuel Combustion Sources), you must calculate CO_2 emissions as provided in paragraphs (c)(1)(i) and (c)(1)(ii) of this section. Other catalytic reforming units must either install a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part, or follow the requirements of paragraph (e)(2) or (e)(3) of this section.

(2) If you continuously or no less frequently than daily monitor the O_2, CO_2, and (if necessary) CO concentrations in the exhaust stack from the catalytic reforming unit catalyst regenerator prior to the combustion of other fossil fuels, you must calculate the CO_2 emissions according to the requirements of paragraphs (c)(2)(i) through (c)(2)(iii) of this section.

(3) Calculate CO_2 emissions from the catalytic reforming unit catalyst regenerator using Equation Y-11 of this section.

$$CO_2 = \sum_{1}^{n} \left[\left(CB_Q\right)_n \times CC \times \frac{44}{12} \times 0.001 \right] \qquad \text{(Eq. Y-11)}$$

Where:

CO_2	=	Annual CO_2 emissions (metric tons/year).
CB_Q	=	Coke burn-off quantity per regeneration cycle from engineering estimates (kg coke/cycle).
n	=	Number of regeneration cycles in the calendar year.
CC	=	Carbon content of coke based on measurement or engineering estimate (kg C per kg coke); default = 0.94.
44/12	=	Ratio of molecular weight of CO_2 to C (kg CO_2 per kg C).
0.001	=	Conversion factor (metric ton/kg).

(f) For on-site sulfur recovery plants, calculate and report CO_2 process emissions from sulfur recovery plants according to the requirements in paragraphs (f)(1) through (f)(5) of this section. Combustion emissions from the sulfur recovery plant (e.g., from fuel combustion in the Claus burner or the tail gas treatment incinerator) must be reported under subpart C of this part (General Stationary Fuel Combustion Sources). For the purposes of this subpart, the sour gas stream for which monitoring is required according to paragraphs (f)(2) through (f)(5) of this section is not considered a fuel.

(1) If you operate and maintain a CEMS that measures CO_2 emissions according to subpart C of this part, you must calculate CO_2 emissions under this subpart by following the Tier 4 Calculation Methodology specified in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources). You must monitor fuel use in the Claus burner, tail gas incinerator, or other

combustion sources that discharge via the final exhaust stack from the sulfur recovery plant and calculate the combustion emissions from the fuel use according to subpart C of this part. Calculate the process emissions from the sulfur recovery plant as the difference in the CO_2 CEMS emissions and the calculated combustion emissions associated with the sulfur recovery plant final exhaust stack. Other sulfur recovery plants must either install a CEMS that complies with the Tier 4 Calculation Methodology in subpart C, or follow the requirements of paragraphs (f)(2) through (f)(5) of this section.

(2) Flow measurement. If you have a continuous flow monitor on the sour gas feed to the sulfur recovery plant, you must use the measured flow rates when the monitor is operational to calculate the sour gas flow rate. If you do not have a continuous flow monitor on the sour gas feed to the sulfur recovery plant, you must use engineering calculations, company records, or similar estimates of volumetric sour gas flow.

(3) Carbon content. If you have a continuous gas composition monitor capable of measuring carbon content on the sour gas feed to the sulfur recovery plant or if you monitor gas composition for carbon content on a routine basis, you must use the measured carbon content value. Alternatively, you may develop a site-specific carbon content factor using limited

measurement data or engineering estimates or use the default factor of 0.20.

(4) Calculate the CO_2 emissions from each sulfur recovery plant using Equation Y-12 of this section.

$$CO_2 = F_{SG} * \frac{44}{MVC} * MF_C * 0.001 \quad \text{(Eq. Y-12)}$$

Where:

CO_2 = Annual CO_2 emissions (metric tons/year).

F_{SG} = Volumetric flow rate of sour gas feed (including sour water stripper gas) to the sulfur recovery plant (scf/year).

44 = Molecular weight of CO_2 (kg/kg-mole).

MVC = Molar volume conversion factor (849.5 scf/kg-mole).

MF_C = Mole fraction of carbon in the sour gas to the sulfur recovery plant (kg-mole C/kg-mole gas); default = 0.20.

0.001 = Conversion factor, kg to metric tons

(5) If tail gas is recycled to the front of the sulfur recovery plant and the recycled flow rate and carbon content is included in the measured data under paragraphs (f)(2) and (f)(3) of this section, respectively, then the annual CO_2 emissions calculated in paragraph (f)(4) of this section must be corrected to avoid double counting these emissions. You may use engineering estimates to perform this correction or assume that the corrected CO_2 emissions are 95 percent of the uncorrected value calculated using Equation Y-12 of this section.

(g) For coke calcining units, calculate GHG emissions according to the applicable provisions in paragraphs (g)(1) through (g)(3) of this section.

(1) If you operate and maintain a CEMS that measures CO_2 emissions according to subpart C of this part, you must calculate and report CO_2 emissions under this subpart by following the Tier 4 Calculation Methodology specified in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources). You must monitor fuel use in the coke calcining unit that discharges via the final exhaust stack from the coke calcining unit and calculate the combustion emissions from the fuel use according to subpart C of this part. Calculate the process emissions from the coke calcining unit as the difference in the CO_2 CEMS emissions and the calculated combustion emissions associated with the coke calcining unit final exhaust stack. Other coke calcining units must either install a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part, or follow the requirements of paragraph (g)(2) of this section.

(2) Calculate the CO_2 emissions from the coke calcining unit using Equation Y-13 of this section.

$$CO_2 = \frac{44}{12} * \left(M_{in} * CC_{GC} - \left(M_{out} + M_{dust}\right) * CC_{MPC}\right) \qquad \text{(Eq. Y-13)}$$

Where:

CO_2	=	Annual CO_2 emissions (metric tons/year).
M_{in}	=	Annual mass of green coke fed to the coke calcining unit from facility records (metric tons/year).
CC_{GC}	=	Average mass fraction carbon content of green coke from facility measurement data (metric ton carbon/metric ton green coke).
M_{out}	=	Annual mass of marketable petroleum coke produced by the coke calcining unit from facility records (metric tons petroleum coke/year).
M_{dust}	=	Annual mass of petroleum coke dust collected in the dust collection system of the coke calcining unit from facility records (metric ton petroleum coke dust/year)
CC_{MPC}	=	Average mass fraction carbon content of marketable petroleum coke produced by the coke calcining unit from facility measurement data (metric ton carbon/metric ton petroleum coke).
44	=	Molecular weight of CO_2 (kg/kg-mole).
12	=	Atomic weight of C (kg/kg-mole).

(3) For all coke calcining units, use the CO_2 emissions from the coke calcining unit calculated in paragraphs (g)(1) or (g)(2), as applicable, and calculate CH_4 using the methods described in paragraph (c)(4) of this section and N_2O emissions using the methods described in paragraph (c)(5) of this section.

(h) [Reporting only.] For asphalt blowing operations, calculate GHG emissions according to the requirements in paragraph (j) of this section or according to the applicable provisions in paragraphs (h)(1) and (h)(2) of this section.

(1) For uncontrolled asphalt blowing operations or asphalt blowing operations controlled by vapor scrubbing, calculate CO_2

and CH_4 emissions using Equations Y-14 and Y-15 of this section, respectively.

$$CO_2 = \left(Q_{AB} \times EF_{AB.CO2}\right) \qquad \text{(Eq. Y-14)}$$

Where:

CO_2 = Annual CO_2 emissions from uncontrolled asphalt blowing (metric tons CO_2/year).

Q_{AB} = Quantity of asphalt blown (million barrels per year, MMbbl/year).

$EF_{AB,CO2}$ = Emission factor for CO_2 from uncontrolled asphalt blowing from facility-specific test data (metric tons CO_2/MMbbl asphalt blown); default = 1,100.

$$CH_4 = \left(Q_{AB} \times EF_{AB,CH4}\right) \qquad \text{(Eq. Y-15)}$$

Where:

CH_4 = Annual methane emissions from uncontrolled asphalt blowing (metric tons CH_4/year).

Q_{AB} = Quantity of asphalt blown (million barrels per year, MMbbl/year).

$EF_{AB,CH4}$ = Emission factor for CH_4 from uncontrolled asphalt blowing from facility-specific test data (metric tons CH_4/MMbbl asphalt blown); default = 580.

(2) For asphalt blowing operations controlled by thermal oxidizer or flare, calculate CO_2 and CH_4 emissions using Equations Y-16 and Y-17 of this section, respectively, provided these emissions are not already included in the flare emissions calculated in paragraph (b) of this section or in the stationary combustion unit emissions required under subpart C of this part (General Stationary Fuel Combustion Sources).

$$CO_2 = 0.98 \times \left(Q_{AB} \times CEF_{AB} \times \frac{44}{12}\right) \qquad \text{(Eq. Y-16)}$$

Where:

CO_2	=	Annual CO_2 emissions from controlled asphalt blowing (metric tons CO_2/year).
0.98	=	Assumed combustion efficiency of thermal oxidizer or flare.
Q_{AB}	=	Quantity of asphalt blown (MMbbl/year).
CEF_{AB}	=	Carbon emission factor from asphalt blowing from facility-specific test data (metric tons C/MMbbl asphalt blown); default = 2,750.
44	=	Molecular weight of CO_2 (kg/kg-mole).
12	=	Atomic weight of C (kg/kg-mole).

$$CH_4 = 0.02 \times \left(Q_{AB} \times EF_{AB,CH4}\right) \quad \text{(Eq. Y-17)}$$

Where:

CH_4	=	Annual methane emissions from controlled asphalt blowing (metric tons CH_4/year).
0.02	=	Fraction of methane uncombusted in thermal oxidizer or flare based on assumed 98% combustion efficiency.
Q_{AB}	=	Quantity of asphalt blown (million barrels per year, MMbbl/year).
$EF_{AB,CH4}$	=	Emission factor for CH_4 from uncontrolled asphalt blowing from facility-specific test data (metric tons CH_4/MMbbl asphalt blown); default = 580.

(i) For delayed coking units, calculate the CH_4 emissions from the depressurization of the coking unit vessel (i.e., the "coke drum") to atmosphere using either of the methods provided in paragraphs (i)(1) or (i)(2), provided no water or steam is added to the vessel once it is vented to the atmosphere. You must use the method in paragraph (i)(1) of this section if you add water or steam to the vessel after it is vented to the atmosphere.

(1) Use the process vent method in paragraph (j) of this section and also calculate the CH_4 emissions from the subsequent opening of the vessel for coke cutting operations using Equation Y-18 of this section. If you have coke drums or vessels of different dimensions, use Equation Y-18 for each set of coke drums or vessels of the same size and sum the resultant emissions across each set of coke drums or vessels to calculate the CH_4 emissions for all delayed coking units.

$$CH_4 = \left(N \times H \times \frac{(P_{CV} + 14.7)}{14.7} \times f_{void} \times \frac{\pi \times D^2}{4} \times \frac{16}{MVC} \times MF_{CH4} \times 0.001 \right) \quad \text{(Eq. Y-18)}$$

Where:

CH_4 = Annual methane emissions from the delayed coking unit vessel opening (metric ton/year).

N = Cumulative number of vessel openings for all delayed coking unit vessels of the same dimensions during the year.

H = Height of coking unit vessel (feet).

P_{CV} = Gauge pressure of the coking vessel when opened to the atmosphere prior to coke cutting or, if the alternative method provided in paragraph (i)(2) of this section is used, gauge pressure of the coking vessel when depressurization gases are first routed to the atmosphere (pounds per square inch gauge, psig)

14.7 = Assumed atmospheric pressure (pounds per square inch, psi)

f_{void} = Volumetric void fraction of coking vessel prior to steaming based on engineering calculations (cf gas/cf of vessel)~~; default = 0.6~~.

D = Diameter of coking unit vessel (feet).

16 = Molecular weight of CH_4 (kg/kg-mole).

MVC = Molar volume conversion factor (849.5 scf/ kg-mole).

MF_{CH4} = Average ~~M~~mole fraction of methane in coking vessel gas based on the analysis of at least two samples per year, collected at least four months a part (kg-mole CH_4/kg-mole gas, wet basis)~~; default value is 0.01~~.

0.001 = Conversion factor (metric ton/kg).

(2) Calculate the CH_4 emissions from the depressurization vent and subsequent opening of the vessel for coke cutting operations using Equation Y-18 of this section and the pressure of the coking vessel when the depressurization gases are first routed to the atmosphere. If you have coke drums or vessels of different dimensions, use Equation Y-18 for each set of coke drums or vessels of the same size and sum the resultant emissions across each set of coke drums or vessels to calculate the CH_4 emissions for all delayed coking units.

(j) For each process vent not covered in paragraphs (a) through (i) of this section that can be reasonably expected to contain greater than 2 percent by volume CO_2 or greater than 0.5 percent by volume of CH_4 or greater than 0.01 percent by volume (100 parts per million) of N_2O, calculate GHG emissions using the Equation Y-19 of this section. You must use Equation Y-19 of this section for catalytic reforming unit depressurization and purge vents when methane is used as the purge gas or if you elected this method as an alternative to the methods in paragraphs (h)(1) or (h)(2) of this section.

$$E_x = \sum_{p=1}^{N}\left((VR)_p \times (MF_x)_p \times \frac{MW_x}{MVC} \times (VT)_p \times 0.001\right) \qquad \text{(Eq. Y-19)}$$

Where:

E_x	=	Annual emissions of each GHG from process vent (metric ton/yr).
N	=	Number of venting events per year.
P	=	Index of venting events.
$(VR)_p$	=	Average volumetric flow rate of process gas during the event (scf per hour).
$(MF_x)_p$	=	Mole fraction of GHG x in process vent during the event (kg-mol of GHG x/kg-mol vent gas).
MW_x	=	Molecular weight of GHG x (kg/kg-mole); use 44 for CO_2 or N_2O and 16 for CH_4.
MVC	=	Molar volume conversion factor (849.5 scf/kg-mole).
$(VT)_p$	=	Venting time for the event, (hours).
0.001	=	Conversion factor (metric ton/kg)

(k) For uncontrolled blowdown systems, you must ~~either~~ use the methods for process vents in paragraph (j) of this section. ~~or calculate CH_4 emissions using Equation Y-20 of this section. Blowdown systems where the uncondensed gas stream is routed to a flare or similar control device is considered to be controlled and is not required to estimate emissions under this paragraph (k).~~

$$\cancel{CH_4 = \left(Q_{Ref} \times EF_{BD} \times \frac{16}{MVC} \times 0.001 \right)} \qquad \text{~~(Eq. Y-20)~~}$$

~~Where:~~

~~CH_4~~	~~=~~	~~Methane emission rate from blowdown systems (mt CH_4/year).~~
~~Q_{Ref}~~	~~=~~	~~Quantity of crude oil plus the quantity of intermediate products received from off site that are processed at the facility (MMbbl/year).~~
~~EF_{BD}~~	~~=~~	~~Methane emission factor for uncontrolled blown systems (scf CH_4/MMbbl); default is 137,000.~~
~~16~~	~~=~~	~~Molecular weight of CH_4 (kg/kg-mole).~~

~~MVC = Molar volume conversion factor (849.5 scf/kg-mole).~~
~~0.001 = Conversion factor (metric ton/kg).~~

(l) [Reporting only.] For equipment leaks, calculate CH_4 emissions using the method specified in either paragraph (l)(1) or (l)(2) of this section.

(1) Use process-specific methane composition data (from measurement data or process knowledge) and any of the emission estimation procedures provided in the Protocol for Equipment Leak Emissions Estimates (EPA-453/R-95-017, NTIS PB96-175401).

(2) Use Equation Y-21 of this section.

$$CH_4 = \left(0.4 \times N_{CD} + 0.2 \times N_{PU1} + 0.1 \times N_{PU2} + 4.3 \times N_{H2} + 6 \times N_{FGS}\right) \quad \text{(Eq. Y-21)}$$

Where:

CH_4 = Annual methane emissions from equipment leaks (metric tons/year)

N_{CD} = Number of atmospheric crude oil distillation columns at the facility.

N_{PU1} = Cumulative number of catalytic cracking units, coking units (delayed or fluid), hydrocracking, and full-range distillation columns (including depropanizer and debutanizer distillation columns) at the facility.

N_{PU2} = Cumulative number of hydrotreating/hydrorefining units, catalytic reforming units, and visbreaking units at the facility.

N_{H2} = Total number of hydrogen plants at the facility.

N_{FGS} = Total number of fuel gas systems at the facility.

(m) [Reporting only.] For storage tanks, except as provided in paragraph (m)(3) of this section, calculate CH_4 emissions using the applicable methods in paragraphs (m)(1) and (m)(2) of this section.

(1) For storage tanks other than those processing unstabilized crude oil, you must either calculate CH_4 emissions from storage tanks that have a vapor-phase methane concentration of 0.5 volume percent or more using tank-specific methane composition data (from measurement data or product knowledge) and the AP-42 emission estimation methods provided in Section 7.1 of the AP-42: "Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources", including TANKS Model (Version 4.09D) or similar programs, or estimate CH_4 emissions from storage tanks using Equation Y-22 of this section.

$$CH_4 = \left(0.1 \times Q_{Ref}\right) \quad \text{(Eq. Y-22)}$$

Where:

CH_4 = Annual methane emissions from storage tanks (metric tons/year).

0.1 = Default emission factor for storage tanks (metric ton CH_4/MMbbl).

Q_{Ref} = Quantity of crude oil plus the quantity of intermediate products received from off site that are processed at the facility (MMbbl/year).

(2) For storage tanks that process unstabilized crude oil, calculate CH_4 emissions from the storage of unstabilized crude oil using either tank-specific methane composition data (from measurement data or product knowledge) and direct measurement of the gas generation rate or by using Equation Y-23 of this section.

$$CH_4 = (995{,}000 \times Q_{un} \times \Delta P) \times MF_{CH4} \times \frac{16}{MVC} \times 0.001 \qquad \text{(Eq. Y-23)}$$

Where:

CH_4	=	Annual methane emissions from storage tanks (metric tons/year).
Q_{un}	=	Quantity of unstabilized crude oil received at the facility (MMbbl/year).
ΔP	=	Pressure differential from the previous storage pressure to atmospheric pressure (pounds per square inch, psi).
MF_{CH4}	=	Mole fraction of CH_4 in vent gas from the unstabilized crude oil storage tank from facility measurements (kg-mole CH_4/kg-mole gas); use 0.27 as a default if measurement data are not available.
995,000	=	Correlation Equation factor (scf gas per MMbbl per psi)
16	=	Molecular weight of CH_4 (kg/kg-mole).
MVC	=	Molar volume conversion factor (849.5 scf/kg-mole).
0.001	=	Conversion factor (metric ton/kg).

(3) You do not need to calculate CH_4 emissions from storage tanks that meet any of the following descriptions:

(i) Units permanently attached to conveyances such as trucks, trailers, rail cars, barges, or ships;

(ii) Pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere;

(iii) Bottoms receivers or sumps;

(iv) Vessels storing wastewater; or

(v) Reactor vessels associated with a manufacturing process unit.

(n) [Reporting only.] For crude oil, intermediate, or product loading operations for which the equilibrium vapor-phase concentration of methane is 0.5 volume percent or more, calculate CH_4 emissions from loading operations using product-specific, vapor-phase methane composition data (from measurement data or process knowledge) and the emission estimation procedures provided in Section 5.2 of the AP-42: "Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources." For loading operations in which the equilibrium vapor-phase concentration of methane is less than 0.5 volume percent, you may assume zero methane emissions.

§98.254 Monitoring and QA/QC requirements.

(a) Fuel flow meters, gas composition monitors, and heating value monitors associated with stationary combustion sources must follow the monitoring and QA/QC requirements in §98.34.

(b) All flow meters, gas composition monitors, and heating value monitors that are used to provide data for the GHG emissions calculations in this subpart for sources other than stationary combustion sources shall be calibrated according to the procedures in the applicable methods specified in paragraphs (c) through (e) of this section, the procedures specified by the manufacturer, or §§98.3(i). Recalibrate each flow meter either biennially (every two years) or at the minimum frequency specified by the manufacturer. Recalibrate each gas composition monitor and heating value monitor either annually or at the minimum frequency specified by the manufacturer.

(c) For flare or sour gas flow meters, operate and maintain the flow meter using any of the following methods, a method published by a consensus-based standards organization (e.g., ASTM, API, etc.) or follow the procedures specified by the flow meter manufacturer. Flow meters must have a rated accuracy of ±5 percent or lower.

(1) ASME MFC–3M–2004 Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi (incorporated by reference, see §98.7).

(2) ASME MFC–4M–1986 (Reaffirmed 1997) Measurement of Gas Flow by Turbine Meters (incorporated by reference, see §98.7).

(3) ASME MFC–6M–1998 Measurement of Fluid Flow in Pipes Using Vortex Flowmeters (incorporated by reference, see §98.7).

(4) ASME MFC–7M–1987 (Reaffirmed 1992) Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles (incorporated by reference, see §98.7).

(5) ASME MFC-11M-2006 Measurement of Fluid Flow by Means of Coriolis Mass Flowmeters (incorporated by reference, see §98.7).

(6) ASME MFC-14M-2003 Measurement of Fluid Flow Using Small Bore Precision Orifice Meters (incorporated by reference, see §98.7).

(7) ASME MFC-18M-2001 Measurement of Fluid Flow Using Variable Area Meters (incorporated by reference, see §98.7).

(8) AGA Report No. 11 Measurement of Natural Gas by Coriolis Meter (2003) (incorporated by reference, see §98.7).

(d) Determine flare gas composition using any of the following methods.

(1) Method 18 at 40 CFR part 60, appendix A-6.

(2) ASTM D1945-03 Standard Test Method for Analysis of Natural Gas by Gas Chromatography (incorporated by reference, see §98.7).

(3) ASTM D1946-90 (Reapproved 2006) Standard Practice for Analysis of Reformed Gas by Gas Chromatography (incorporated by reference, see §98.7).

(4) GPA 2261–00 Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography (incorporated by reference, see §98.7).

(5) UOP539-97 Refinery Gas Analysis by Gas Chromatography (incorporated by reference, see §98.7).

(e) Determine flare gas higher heating value using any of the following methods.

(1) ASTM D4809-06 Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method) (incorporated by reference, see §98.7).

(2) ASTM D240-02 (Reapproved 2007) Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (incorporated by reference, see §98.7).

(3) ASTM D1826-94 (Reapproved 2003) Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter (incorporated by reference, see §98.7).

(4) ASTM D3588-98 (Reapproved 2003) Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels (incorporated by reference, see §98.7).

(5) ASTM D4891-89 (Reapproved 2006) Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion (incorporated by reference, see §98.7).

(f) For exhaust gas flow meters used to comply with the requirements in §98.253(c)(2)(ii), install, operate, calibrate, and maintain exhaust gas flow meter according to the requirements in 40 CFR 63.1572(c) or according to the following requirements.

(1) Locate the flow meter(s) and other necessary equipment such as straightening vanes in a position that provides representative flow; reduce swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.

(2) Use a flow rate meter with an accuracy within ±5 percent.

(3) Use a continuous monitoring system capable of correcting for the temperature, pressure, and moisture content to output flow in dry standard cubic feet (standard conditions as defined in §98.6).

(4) Install, operate, and maintain each continuous monitoring system according to the manufacturer's specifications and requirements.

(g) For exhaust gas CO_2/CO/O_2 composition monitors used to comply with the requirements in §98.253(c)(2), install, operate, calibrate, and maintain exhaust gas composition monitors according to the the requirements in 40 CFR 60.105a(b)(2) or 40 CFR 63.1572(a) or according to the manufacturer's specifications and requirements.

(h) Determine the mass of petroleum coke as required by Equation Y-13 of this subpart using mass measurement equipment meeting the requirements for commercial weighing equipment as described in Specifications, Tolerances, and Other Technical Requirements For Weighing and Measuring Devices, NIST Handbook 44 (2009) (incorporated by reference, see §98.7). Calibrate the measurement device according to the procedures specified by the method, the procedures specified by the manufacturer, or

§98.3(i). Recalibrate either biennially or at the minimum frequency specified by the manufacturer.

(i) Determine the carbon content of petroleum coke as required by Equation Y-13 of this subpart using any one of the following methods. Calibrate the measurement device according to procedures specified by the method or procedures specified by the measurement device manufacturer.

(1) ASTM D3176-89 (Reapproved 2002) Standard Practice for Ultimate Analysis of Coal and Coke (incorporated by reference, see §98.7).

(2) ASTM D5291-02 (Reapproved 2007) Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants (incorporated by reference, see §98.7).

(3) ASTM D5373-08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal (incorporated by reference, see §98.7).

(j) Determine the quantity of petroleum process streams using company records. These quantities include the quantity of asphalt blown, quantity of crude oil plus the quantity of intermediate products received from off site, and the quantity of unstabilized crude oil received at the facility.

(k) The owner or operator shall document the procedures used to ensure the accuracy of the estimates of fuel usage, gas composition, and heating value including but not limited to calibration of weighing equipment, fuel flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices shall also be recorded, and the technical basis for these estimates shall be provided.

(l) All CO_2 CEMS and flow rate monitors used for direct measurement of GHG emissions must comply with the QA procedures in §98.34(c).

(m) For purposes of §98.34(b)(3)(ii)(E), the equipment necessary to take daily measurements of carbon content and molecular weight shall be in place for refinery fuel gas, and daily sampling and analysis shall therefore be required, by no later than January 1, 2012.

§98.255 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required (e.g., concentrations, flow rates, fuel heating values, carbon content values). Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a CEMS malfunctions during unit operation or if a required fuel sample is not taken), a substitute data value for the missing parameter shall be used in the calculations.

(a) For stationary combustion sources, use the missing data procedures in subpart C of this part.

(b) For each missing value of the heat content, carbon content, or molecular weight of the fuel, substitute the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If the “after” value is not obtained by the end of the reporting year, you may use the “before” value for the missing data substitution. If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.

(c) For missing CO_2, CO, O_2, CH_4, or N_2O concentrations, gas flow rate, and percent moisture, the substitute data values shall be the best available estimate(s) of the parameter(s), based on all available process data (e.g., processing rates, operating hours, etc.). The owner or operator shall document and keep records of the procedures used for all such estimates.

(d) For hydrogen plants, use the missing data procedures in subpart P of this part.

§98.256 Data reporting requirements.

In addition to the reporting requirements of §98.3(c), you must report the information specified in paragraphs (a) through (q) of this section.

Subpart Y—Petroleum Refineries

(a) For combustion sources, follow the data reporting requirements under subpart C of this part (General Stationary Fuel Combustion Sources).

(b) For hydrogen plants, follow the data reporting requirements under subpart P of this part (Hydrogen Production).

(c) [RESERVED].

(d) [RESERVED].

(e) For flares, owners and operators shall report:

(1) The flare ID number (if applicable).

(2) A description of the type of flare (steam assisted, air-assisted).

(3) A description of the flare service (general facility flare, unit flare, emergency only or back-up flare).

(4) The calculated CO_2, CH_4, and N_2O annual emissions for each flare, expressed in metric tons of each pollutant emitted.

(5) A description of the method used to calculate the CO_2 emissions for each flare (e.g., reference section and equation number).

(6) If you use Equation Y-1 of this subpart, the annual volume of flare gas combusted (in scf/year) and the annual average molecular weight (in kg/kg-mole) and carbon content of the flare gas (in kg carbon per kg flare gas).

(7) If you use Equation Y-2 of this subpart, the annual volume of flare gas combusted (in million (MM) scf/year) and the

annual average higher heating value of the flare gas (in MMBtu per MMscf).

(8) If you use Equation Y-3 of this subpart, ~~the annual volume of flare gas combusted (in MMscf/year) during normal operations, the annual average higher heating value of the flare gas (in MMBtu/MMscf),~~ the number of SSM events, and ~~exceeding 500,000 scf/day, and~~ the volume of gas flared (in scf/event) and the average molecular weight (in kg/kg-mole) and carbon content of the flare gas (in kg carbon per kg flare) for each SSM event ~~over 500,000 scf/day~~.

(9) The fraction of carbon in the flare gas contributed by methane used in Equation Y-4 of this subpart and the basis for its value.

(f) For catalytic cracking units, traditional fluid coking units, and catalytic reforming units, owners and operators shall report:

(1) The unit ID number (if applicable).

(2) A description of the type of unit (fluid catalytic cracking unit, thermal catalytic cracking unit, traditional fluid coking unit, or catalytic reforming unit).

(3) Maximum rated throughput of the unit, in bbl/stream day.

(4) The calculated CO_2, CH_4, and N_2O annual emissions for each unit, expressed in metric tons of each pollutant emitted.

(5) A description of the method used to calculate the CO_2 emissions for each unit (e.g., reference section and equation number).

(6) If you use a CEMS, the relevant information required under §98.36(e)(2)(vi) for the Tier 4 Calculation Methodology, the CO_2 annual emissions as measured by the CEMS (unadjusted to remove CO_2 combustion emissions associated with a CO boiler, if present) and the process CO_2 emissions as calculated according to §98.253(c)(1)(ii). Report the CO_2 annual emissions associated with fuel combustion under subpart C of this part (General Stationary Fuel Combustion Sources).

(7) If you use Equation Y-6 of this subpart, the annual average exhaust gas flow rate, $\%CO_2$, and %CO.

(8) If you use Equation Y-7 of this subpart, the annual average flow rate of inlet air and oxygen-enriched air, $\%O_2$, $\%O_{oxy}$, $\%CO_2$, and %CO.

(9) ~~If you use Equation Y-8 of this subpart, the coke burn-off factor, annual throughput of unit, and the average carbon content of coke and the basis for the value.~~

Reserved.

(10) ~~Indicate whether you use a measured value, a unit-specific emission factor, or a default emission factor for CH_4 emissions. If you use a unit-specific emission factor for CH_4, report the units of measure for the unit-specific factor, the~~

~~activity data for calculating emissions (e.g., if the emission factor is based on coke burn-off rate, the annual quantity of coke burned), and the basis for the factor.~~

Reserved.

(11) Indicate whether you use a measured value, a unit-specific emission factor, or a default emission factor for N_2O emissions. If you use a unit-specific emission factor for N_2O, report the units of measure for the unit-specific factor, the activity data for calculating emissions (e.g., if the emission factor is based on coke burn-off rate, the annual quantity of coke burned), and the basis for the factor.

(12) If you use Equation Y-11 of this subpart, the number of regeneration cycles during the reporting year, the average coke burn-off quantity per cycle, and the average carbon content of the coke.

(g) For fluid coking unit of the flexicoking type, the owner or operator shall report:

(1) The unit ID number (if applicable).

(2) A description of the type of unit.

(3) Maximum rated throughput of the unit, in bbl/stream day.

(4) Indicate whether the GHG emissions from the low heat value gas are accounted for in subpart C of this part or §98.253(c).

(5) If the GHG emissions for the low heat value gas are calculated at the flexicoking unit, also report the calculated annual CO_2, CH_4, and N_2O emissions for each unit, expressed in metric tons of each pollutant emitted, and the applicable equation input parameters specified in paragraphs (f)(7) through (f)(11) of this section.

(h) For sulfur recovery plants and for emissions from sour gas sent off-site for sulfur recovery, the owner and operator shall report:

(1) The plant ID number (if applicable).

(2) Maximum rated throughput of each independent sulfur recovery plant, in metric tons sulfur produced/stream day.

(3) The calculated CO_2 annual emissions for each sulfur recovery plant, expressed in metric tons. The calculated annual CO_2 emissions from sour gas sent off-site for sulfur recovery, expressed in metric tons.

(4) If you use Equation Y-12 of this subpart, the annual volumetric flow to the sulfur recovery plant (in scf/year) and the annual average mole fraction of carbon in the sour gas (in kg-mole C/kg-mole gas).

(5) If you recycle tail gas to the front of the sulfur recovery plant, indicate whether the recycled flow rate and carbon content are included in the measured data under §98.253(f)(2) and (3). Indicate whether a correction for CO_2

emissions in the tail gas was used in Equation Y-12. If so, then report the value of the correction, the annual volume of recycled tail gas (in scf/year) and the annual average mole fraction of carbon in the tail gas (in kg-mole C/kg-mole gas). Indicate whether you used the default (95%) or a unit specific correction, and if used, report the approach used.

(6) If you use a CEMS, the relevant information required under §98.36(e)(2)(vi) for the Tier 4 Calculation Methodology, the CO_2 annual emissions as measured by the CEMS and the annual process CO_2 emissions calculated according to §98.253(f)(1). Report the CO_2 annual emissions associated with fuel combustion subpart C of this part (General Stationary Fuel Combustion Sources).

(i) For coke calcining units, the owner and operator shall report:

(1) The unit ID number (if applicable).

(2) Maximum rated throughput of the unit, in metric tons coke calcined/stream day.

(3) The calculated CO_2, CH_4, and N_2O annual emissions for each unit, expressed in metric tons of each pollutant emitted.

(4) A description of the method used to calculate the CO_2 emissions for each unit (e.g., reference section and equation number).

(5) If you use Equation Y-13 of this subpart, annual mass and carbon content of green coke fed to the unit, the annual mass and carbon content of marketable coke produced, and the annual mass of coke dust collected in dust collection systems.

(6) If you use a CEMS, the relevant information required under §98.36(e)(2)(vi) for the Tier 4 Calculation Methodology, the CO_2 annual emissions as measured by the CEMS and the annual process CO_2 emissions calculated according to §98.253(g)(1). Report the CO_2 annual emissions associated with fuel combustion under subpart C of this part (General Stationary Fuel Combustion Sources).

(7) Indicate whether you use a measured value, a unit-specific emission factor or a default for CH_4 emissions. If you use a unit-specific emission factor for CH_4, the unit-specific emission factor for CH_4, the units of measure for the unit-specific factor, the activity data for calculating emissions (e.g., if the emission factor is based on coke burn-off rate, the annual quantity of coke burned), and the basis for the factor.

(8) If you use a site-specific emission factor in Equation Y-10 of this subpart, the site-specific emission factor and the basis of the factor.

(j) For asphalt blowing operations, the owner or operator shall report:

(1) The unit ID number (if applicable).

(2) The quantity of asphalt blown (in Million bbl) at the facility in the reporting year.

(3) The type of control device used to reduce methane (and other organic) emissions from the unit.

(4) The calculated annual CO_2 and CH_4 emissions for each unit, expressed in metric tons of each pollutant emitted.

(5) If you use Equation Y-14 of this subpart, the CO_2 emission factor used and the basis for the value.

(6) If you use Equation Y-15 of this subpart, the CH_4 emission factor used and the basis for the value.

(7) If you use Equation Y-16 of this subpart, the carbon emission factor used and the basis for the value.

(8) If you use Equation Y-17 of this subpart, the CH_4 emission factor used and the basis for the value.

(k) For delayed coking units, the owner or operator shall report:

(1) The cumulative annual CH_4 emissions (in metric tons of each pollutant emitted) for all delayed coking units at the facility.

(2) A description of the method used to calculate the CH_4 emissions for each unit (e.g., reference section and equation number).

(3) The total number of delayed coking units at the facility, the total number of delayed coking drums at the facility, and for each coke drum or vessel: the dimensions, the typical gauge pressure of the coking drum when first vented to the atmosphere, typical void fraction, the typical drum outage (i.e. the unfilled distance from the top of the drum, in feet), and annual number of coke-cutting cycles.

(4) For each set of coking drums that are the same dimensions: the number of coking drums in the set, the height and diameter of the coke drums (in feet), the cumulative number of vessel openings for all delayed coking drums in the set, the typical venting pressure (in psig), void fraction (in cf gas/cf of vessel), and the mole fraction of methane in coking gas (in kg-mole CF_4/kg-mole gas, wet basis).

(5) The basis for the volumetric void fraction of the coke vessel prior to steaming and the basis for the mole fraction of methane in the coking gas.

(l) For process vents subject to §98.253(j), the owner or operator shall report:

(1) The vent ID number (if applicable).

(2) The unit or operation associated with the emissions.

(3) The type of control device used to reduce methane (and other organic) emissions from the unit, if applicable.

(4) The calculated annual CO_2, CH_4, and N_2O emissions for each vent, expressed in metric tons of each pollutant emitted.

(5) The annual volumetric flow discharged to the atmosphere (in scf), mole fraction of each GHG above the concentration threshold, and for intermittent vents, the number of venting events and the cumulative venting time.

(m) For uncontrolled blowdown systems, the owner or operator shall report:

(1) The cumulative annual CH_4 emissions (in metric tons of each pollutant emitted) for uncontrolled blowdown systems.

(2) ~~The total quantity (in Million bbl) of crude oil plus the quantity of intermediate products received from off-site that are processed at the facility in the reporting year.~~The information required for process vents in paragraph (l) of this section.

(3) ~~The methane emission factor used for uncontrolled blowdown systems and the basis for the value.~~

Reserved.

(n) For equipment leaks, the owner or operator shall report:

(1) The cumulative CH_4 emissions (in metric tons of each pollutant emitted) for all equipment leak sources.

(2) The method used to calculate the reported equipment leak emissions.

(3) The number of each type of emission source listed in Equation Y-21 of this subpart at the facility.

(o) For storage tanks, the owner or operator shall report:

(1) The cumulative annual CH_4 emissions (in metric tons of each pollutant emitted) for all storage tanks, except for those used to process unstabilized crude oil.

(2) The method used to calculate the reported storage tank emissions for storage tanks other than those processing unstabilized crude (AP-42, TANKS 4.09D, Equation Y-22 of this subpart, other).

(3) The total quantity (in MMbbl) of crude oil plus the quantity of intermediate products received from off-site that are processed at the facility in the reporting year.

(4) The cumulative CH_4 emissions (in metric tons of each pollutant emitted) for storage tanks used to process unstabilized crude oil.

(5) The method used to calculate the reported storage tank emissions for storage tanks processing unstabilized crude oil.

(6) The quantity of unstabilized crude oil received during the calendar year (in MMbbl), the average pressure differential (in psi), and the mole fraction of CH_4 in vent gas from the unstabilized crude oil storage tank, and the basis for the mole fraction.

(7) The tank-specific methane composition data and the gas generation rate data, if you did not use Equation Y-23.

(p) For loading operations, the owner or operator shall report:

(1) The cumulative annual CH_4 emissions (in metric tons of each pollutant emitted) for loading operations.

(2) The quantity and types of materials loaded by vessel type (barge, tanker, marine vessel, etc.) that have an equilibrium vapor-phase concentration of methane of 0.5 volume percent or greater, and the type of vessels in which the material is loaded.

(3) The type of control system used to reduce emissions from the loading of material with an equilibrium vapor-phase concentration of methane of 0.5 volume percent or greater, if any (submerged loading, vapor balancing, etc.).

(q) Name of each method listed in §98.254 or a description of manufacturer's recommended method used to determine a measured parameter.

§98.257 Records that must be retained.

(a) In addition to the records required by §98.3(g), you must retain the records of all parameters monitored under §98.255.

(b) For each process vent for which the concentration of CO_2, N_2O and CH_4 are determined to be below the thresholds in

§98.253(j), the owner or operator shall maintain records of the method used to determine the CO_2, N_2O, and CH_4 concentration and all supporting documentation necessary to demonstrate the thresholds in §98.253(j) are not exceeded during the reporting year.

§98.258 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart AA—Pulp and Paper Manufacturing

§98.270 Definition of Source Category.

(a) The pulp and paper manufacturing source category consists of facilities that produce market pulp (i.e., stand-alone pulp facilities), manufacture pulp and paper (i.e., integrated facilities), produce paper products from purchased pulp, produce secondary fiber from recycled paper, convert paper into paperboard products (e.g., containers), or operate coating and laminating processes.

(b) The emission units for which GHG emissions must be reported are listed in paragraphs (b)(1) through (b)(5) of this section:

(1) Chemical recovery furnaces at kraft and soda mills (including recovery furnaces that burn spent pulping liquor produced by both the kraft and semichemical process).

(2) Chemical recovery combustion units at sulfite facilities.

(3) Chemical recovery combustion units at stand-alone semichemical facilities.

(4) Pulp mill lime kilns at kraft and soda facilities.

(5) Systems for adding makeup chemicals ($CaCO_3$, Na_2CO_3) in the chemical recovery areas of chemical pulp mills.

Subpart AA—Pulp and Paper Manufacturing

§98.271 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a pulp and paper manufacturing process and the facility meets the requirements of either §98.2(a)(1) or (a)(2).

§98.272 GHGs to report.

You must report the emissions listed in paragraphs (a) through (f) of this section:[1]

(a) CO_2, biogenic CO_2, CH_4, and N_2O emissions from each kraft or soda chemical recovery furnace.

(b) CO_2, biogenic CO_2, CH_4, and N_2O emissions from each sulfite chemical recovery combustion unit.

(c) CO_2, biogenic CO_2, CH_4, and N_2O emissions from each stand-alone semichemical chemical recovery combustion unit.

(d) CO_2, biogenic CO_2, CH_4, and N_2O emissions from each kraft or soda pulp mill lime kiln.

(e) CO_2 emissions from addition of makeup chemicals ($CaCO_3$, Na_2CO_3) in the chemical recovery areas of chemical pulp mills.

(f) CO_2, CH_4, and N_2O combustion emissions from each stationary combustion unit. You must calculate and report these emissions under subpart C of this part (General

[1] WCI ERs previously included methodologies for calculating CH_4 and N_2O emissions from wastewater treatment plants at this source category. Coverage of these facilities will now be left to the discretion of the jurisdiction.

Stationary Fuel Combustion Sources) by following the requirements of subpart C.

§98.273 Calculating GHG emissions.

(a) For each chemical recovery furnace located at a kraft or soda facility, you must determine CO_2, biogenic CO_2, CH_4, and N_2O emissions using the procedures in paragraphs (a)(1) through (a)(3) of this section. CH_4 and N_2O emissions must be calculated as the sum of emissions from combustion of fossil fuels and combustion of biomass in spent liquor solids.

(1) Calculate fossil fuel-based CO_2 emissions from direct measurement of fossil fuels consumed and the methodology for stationary combustion sources specified by §98.33(a) (as modified by this Article) for the appropriate fuel type ~~default emissions factors according to the Tier 1 methodology for stationary combustion sources in §98.33(a)(1)~~.[2]

(2) Calculate fossil fuel-based CH_4 and N_2O emissions from direct measurement of fossil fuels consumed, default HHV, and default emissions factors and convert to metric tons of CO_2 equivalent according to the methodology for stationary combustion sources in §98.33(c).

[2] Although Subpart C generally allows the use of higher tiers, even when a lower tier is specified for a particular unit or fuel, section 98.273 could be read as *requiring* the use of Tier 1. WCI is seeking clarification of the correct interpretation of section 98.273 in order to assure that the proposed changes are consistent with harmonization.

(3) Calculate biogenic CO_2 emissions and emissions of CH_4 and N_2O from biomass using measured quantities of spent liquor solids fired, site-specific HHV, and default or site-specific emissions factors[3], according to Equation AA-1 of this section:

$$CO_2, CH_4, or\ N_2O\ from\ biomass = (0.907.18) * \text{Solids} * \text{HHV} * \text{EF} \quad \text{(Eq.AA-1)}$$

Where:

CO_2, CH_4, or N_2O, from Biomass	=	Biogenic CO_2 emissions or emissions of CH_4 or N_2O from spent liquor solids combustion (metric tons per year).
Solids	=	Mass of spent liquor solids combusted (short tons per year) determined according to §98.274(b).
HHV	=	Annual high heat value of the spent liquor solids (mmBtu per kilogram) determined according to 98.274(b).
EF	=	Default emission factor for CO_2, CH_4, or N_2O, from Table AA-1 of this subpart (kg CO_2, CH_4, or N_2O per mmBtu).
0.90718	=	Conversion factor from short tons to metric tons.

(b) For each chemical recovery combustion unit located at a sulfite or stand-alone semichemical facility, you must determine CO_2, CH_4, and N_2O emissions using the procedures in paragraphs (b)(1) through (b)(4) of this section:

(1) Calculate fossil CO_2 emissions from fossil fuels from direct measurement of fossil fuels consumed and the

methodology for stationary combustion sources specified by §98.33(a) (as modified by this Article) for the appropriate fuel type ~~default emissions factors according to the Tier 1 Calculation Methodology for stationary combustion sources in §98.33(a)(1)~~.

(2) Calculate CH_4 and N_2O emissions from fossil fuels from direct measurement of fossil fuels consumed, default HHV, and default emissions factors and convert to metric tons of CO_2 equivalent according to the methodology for stationary combustion sources in §98.33(c).

(3) Calculate biogenic CO_2 emissions using measured quantities of spent liquor solids fired and the carbon content of the spent liquor solids, according to Equation AA-2 of this section:

$$Biogenic\ CO_2 = \frac{44}{12} * \mathrm{Solids} * \mathrm{CC} * (0.90718) \qquad \text{(Eq. AA-2)}$$

Where:

Biogenic CO_2	=	Annual CO_2 mass emissions for spent liquor solids combustion (metric tons per year).
Solids	=	Mass of the spent liquor solids combusted (short tons per year) determined according to §98.274(b).
CC	=	Annual carbon content of the spent liquor solids, determined according to §98.274(b) (percent by weight, expressed as a decimal fraction, e.g., 95% = 0.95).
44/12	=	Ratio of molecular weights, CO_2 to carbon.
0.90718	=	Conversion from short tons to metric tons

(4) Calculate CH_4 and N_2O emissions from biomass using Equation AA-1 of this section and the default CH_4 and N_2O emissions factors for kraft facilities in Table AA-1 of this subpart and convert the CH_4 or N_2O emissions to metric tons of CO_2 equivalent by multiplying each annual CH_4 and N_2O emissions total by the appropriate global warming potential (GWP) factor from Table A-1 of subpart A of this part.

(c) For each pulp mill lime kiln located at a kraft or soda facility, you must determine CO_2, CH_4, and N_2O emissions using the procedures in paragraphs (c)(1) through (c)(3) of this section:

(1) Calculate CO_2 emissions from fossil fuels from direct measurement of fossil fuels consumed and the methodology for stationary combustion sources specified by §98.33(a) (as modified by this Article) for the appropriate fuel type. ~~and default HHV and default emissions factors, according to the Tier 1 Calculation Methodology for stationary combustion sources in §98.33(a)(1); use the default HHV listed in Table C-1 of subpart C and~~ Where the applicable method specified by § 98.33(a) allows the use of a default emission factor, use the default CO_2 emissions factors listed in Table AA-2 of this subpart.

(2) Calculate CH_4 and N_2O emissions from fossil fuel from direct measurement of fossil fuels consumed, default HHV, and default emissions factors and convert to metric tons of CO_2 equivalent according to the methodology for stationary combustion sources in §98.33(c); use the default HHV listed in Table C-1 of subpart C and the default CH_4 and N_2O emissions factors listed in Table AA-2 of this subpart.

(3) Biogenic CO_2 emissions from conversion of $CaCO_3$ to CaO are included in the biogenic CO_2 estimates calculated for the chemical recovery furnace in paragraph (a)(3) of this section.

(d) For makeup chemical use, you must calculate CO_2 emissions by using direct or indirect measurement of the quantity of chemicals added and ratios of the molecular weights of CO_2 and the makeup chemicals, according to Equation AA-3 of this section:

$$CO_2 = \left[M_{(CaCO_3)} * \frac{44}{100} + M_{(Na_2CO_3)} \frac{44}{105.99} \right] * 1000\, kg / metric\, ton \quad \text{(Eq. AA-3)}$$

Where:

CO_2	=	CO_2 mass emissions from makeup chemicals (kilograms/yr).
M ($CaCO_3$)	=	Make-up quantity of $CaCO_3$ used for the reporting year (metric tons per year).
M ($NaCO_3$)	=	Make-up quantity of Na_2CO_3 used for the reporting year (metric tons per year).
44	=	Molecular weight of CO_2.
100	=	Molecular weight of $CaCO_3$.
105.99	=	Molecular weight of Na_2CO_3.

§98.274 Monitoring and QA/QC requirements.

(a) Each facility subject to this subpart must quality assure the GHG emissions data according to the applicable requirements in §98.34. All QA/QC data must be available for inspection upon request.

(b) Fuel properties needed to perform the calculations in Equations AA-1 and AA-2 of this subpart must be determined according to paragraphs (b)(1) through (b)(3) of this section.

(1) High heat values of black liquor must be determined no less than annually using T684 om–06 Gross Heating Value of Black Liquor, TAPPI (incorporated by reference, see §98.7). If measurements are performed more frequently than annually, then the high heat value used in Equation AA-1 of this subpart must be based on the average of the representative measurements made during the year.

(2) The annual mass of spent liquor solids must be determined using either of the methods specified in paragraph (b)(2)(i) or (b)(2)(ii).

(i) Measure the mass of spent liquor solids annually (or more frequently) using T-650 om–05 Solids Content of Black Liquor, TAPPI (incorporated by reference in §98.7). If measurements are performed more frequently than annually, then the mass of spent liquor solids used in

Equation AA-1 of this subpart must be based on the average of the representative measurements made during the year.

(ii) Determine the annual mass of spent liquor solids based on records of measurements made with an online measurement system that determines the mass of spent liquor solids fired in a chemical recovery furnace or chemical recovery combustion unit.

(3) Carbon analyses for spent pulping liquor must be determined no less than annually using ASTM D5373-08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal (incorporated by reference, see §98.7). If measurements using ASTM D5373-08 are performed more frequently than annually, then the spent pulping liquor carbon content used in Equation AA-2 of this subpart must be based on the average of the representative measurements made during the year.

(c) Each facility must keep records that include a detailed explanation of how company records of measurements are used to estimate GHG emissions. The owner or operator must also document the procedures used to ensure the accuracy of the measurements of fuel, spent liquor solids, and makeup chemical usage, including, but not limited to calibration of weighing equipment, fuel flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices must be recorded and the technical basis for these estimates must be provided. The procedures used to convert spent pulping liquor flow rates to units of mass (i.e., spent liquor solids firing rates) also must be documented.

(d) Records must be made available upon request for verification of the calculations and measurements.

§98.275 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation or if a required sample is not taken), a substitute data value for the missing parameter shall be used in the calculations, according to the requirements of paragraphs (a) through (c) of this section:

(a) There are no missing data procedures for measurements of heat content and carbon content of spent pulping liquor. A re-test must be performed if the data from any annual measurements are determined to be invalid.

(b) For missing measurements of the mass of spent liquor solids or spent pulping liquor flow rates, use the lesser value of either the maximum mass or fuel flow rate for the combustion unit, or the maximum mass or flow rate that the fuel meter can measure.

(c) For the use of makeup chemicals (carbonates), the substitute data value shall be the best available estimate of makeup chemical consumption, based on available data (e.g., past accounting records, production rates). The owner or operator shall document and keep records of the procedures used for all such estimates.

§98.276 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the information in paragraphs (a) through (K) of this section as applicable:

(a) Annual emissions of CO_2, biogenic CO_2, CH_4, biogenic CH_4 N_2O, and biogenic N_2O (metric tons per year).

(b) Annual quantities fossil fuels by type used in chemical recovery furnaces and chemical recovery combustion units in short tons for solid fuels, gallons for liquid fuels and scf for gaseous fuels.

(c) Annual mass of the spent liquor solids combusted (short tons per year), and basis for determining the annual mass of the spent liquor solids combusted (whether based on T650 om-05 Solids Content of Black Liquor, TAPPI (incorporated by reference, see §98.7) or an online measurement system).

(d) The high heat value (HHV) of the spent liquor solids used in Equation AA-1 of this subpart (mmBtu per kilogram).

(e) The default emission factor for CO_2, CH_4, or N_2O, used in Equation AA-1 of this subpart (kg CO_2, CH_4, or N_2O per mmBtu).

(f) The carbon content (CC) of the spent liquor solids, used in Equation AA-2 of this subpart (percent by weight, expressed as a decimal fraction, e.g., 95% = 0.95).

(g) Annual quantities of fossil fuels by type used in pulp mill lime kilns in short tons for solid fuels, gallons for liquid fuels and scf for gaseous fuels.

(h) Make-up quantity of $CaCO_3$ used for the reporting year (metric tons per year) used in Equation AA-3 of this subpart.

(i) Make-up quantity of Na_2CO_3 used for the reporting year (metric tons per year) used in Equation AA-3 of this subpart.

(j) Annual steam purchases(pounds of steam per year).

(k) Annual production of pulp and/or paper products produced (metric tons).

§98.277 Records that must be retained.

Subpart AA—Pulp and Paper Manufacturing

In addition to the information required by §98.3(g), you must retain the records in paragraphs (a) through (f) of this section.

(a) GHG emission estimates (including separate estimates of biogenic CO_2) for each emissions source listed under §98.270(b).

(b) Annual analyses of spent pulping liquor HHV for each chemical recovery furnace at kraft and soda facilities.

(c) Annual analyses of spent pulping liquor carbon content for each chemical recovery combustion unit at a sulfite or semichemical pulp facility.

(d) Annual quantity of spent liquor solids combusted in each chemical recovery furnace and chemical recovery combustion unit, and the basis for detemining the annual quantity of the spent liquor solids combusted (whether based on T650 om–05 Solids Content of Black Liquor, TAPPI (incorporated by reference, see §98.7) or an online measurement system). If an online measurement system is used, you must retain records of the calaulations used to determine the annual quantity of spent liquor solids combusted from the continuous measurements.

(e) Annual steam purchases.

(f) Annual quantities of makeup chemicals used.

Subpart AA—Pulp and Paper Manufacturing

§98.278 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Table AA-1 of Subpart AA—Kraft Pulping Liquor Emissions Factors for Biomass-Based CO_2, CH_4, and N_2O.

Wood Furnish	Biomass-Based Emissions Factors (kg/mmBtu HHV)		
	CO_2[a]	**CH_4**	**N_2O**
North American Softwood	94.4	0.030	0.005
North American Hardwood	93.7		
Bagasse	95.5		
Bamboo	93.7		
Straw	95.1		

[a] Includes emissions from both the recovery furnace and pulp mill lime kiln.

Table AA-2 of Subpart AA—Kraft Lime Kiln and Calciner Emissions Factors for Fossil Fuel-Based CO_2, CH_4, and N_2O

Fuel	Fossil Fuel-Based Emissions Factors (kg/mmBtu HHV)					
	Kraft Lime Kilns			Kraft Calciners		
	CO_2	**CH_4**	**N_2O**	**CO_2**	**CH_4**	**N_2O**
Residual Oil	76.7	0.0027	0	76.7	0.0027	0.0003
Distillate Oil	73.5			73.5		0.0004
Natural Gas	56.0			56.0		0.0001
Biogas	0			0		0.0001

Subpart CC—Soda Ash Manufacturing

§98.290 Definition of the source category.

A soda ash manufacturing facility is any facility with a manufacturing line that produces soda ash by one of the methods in paragraphs (a) through (c) of this section:

(a) Calcining trona.

(b) Calcining sodium sesquicarbonate.

(c) Using a liquid alkaline feedstock process that directly produces CO_2.

In the context of the soda ash manufacturing sector, "calcining" means the thermal/chemical conversion of the bicarbonate fraction of the feedstock to sodium carbonate.

§98.291 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a soda ash manufacturing process and the facility meets the requirements of either §98.2(a)(1) or (a)(2).

§98.292 GHGs to report.

You must report:

(a) CO_2 process emissions from each soda ash manufacturing line combined.[1]

(b) CO_2 combustion emissions from each soda ash manufacturing line.

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[1]Clarification – if CO_2 generated during calcination is recycled to carbonation towers, these calculated process emissions will be adjusted by the measured quantity of recycled CO_2 determined by the method identified in §98.293(d).

(c) CH_4 and N_2O combustion emissions from each soda ash manufacturing line. You must calculate and report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

(d) CO_2, CH_4, and N_2O emissions from each stationary combustion unit other than soda ash manufacturing lines. You must calculate and report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

§98.293 Calculating GHG emissions.

You must calculate and report the annual process CO_2 emissions from each soda ash manufacturing line using the procedures specified in paragraph (a) or (b) of this section.

(a) For each soda ash manufacturing line that meets the conditions specified in §98.33(b)(4)(ii) or (b)(4)(iii), you must calculate and report under this subpart the combined process and combustion CO_2 emissions by operating and maintaining a CEMS to measure CO_2 emissions according to the Tier 4 Calculation Methodology specified in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(b) For each soda ash manufacturing line that is not subject to the requirements in paragraph (a) of this section, calculate and report the process CO_2 emissions from the soda ash manufacturing line by using the procedure in either paragraphs (b)(1), (b)(2), or (b)(3) of this section; and the combustion CO_2 emissions using the procedure in paragraph (b)(4) of this section.

(1) Calculate and report under this subpart the combined process and combustion CO_2 emissions by operating and maintaining a CEMS to measure CO_2 emissions according to the Tier 4 Calculation Methodology specified in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(2) Use either Equation CC-1 or Equation CC-2 of this section to calculate annual CO_2 process emissions from each manufacturing line that calcines trona to produce soda ash:

$$E_k = \sum_{n=1}^{12} [(IC_T)_n * (T_t)_n] * \frac{2000}{2205} * \frac{0.097}{1} \quad \text{(Eq. CC-1)}$$

$$E_k = \sum_{n=1}^{12} [(IC_{sa})_n * (T_{sa})_n] * \frac{2000}{2205} * \frac{0.138}{1} \quad \text{(Eq. CC-2)}$$

Where:

E_k = Annual CO_2 process emissions from each manufacturing line, k (metric tons).

$(IC_T)_n$ = Inorganic carbon content (percent by weight, expressed as a decimal fraction) in trona input, from the carbon analysis results for

		month n. This represents the ratio of trona to trona ore.
$(IC_{sa})_n$	=	Inorganic carbon content(percent by weight, expressed as a decimal fraction) in soda ash output, from the carbon analysis results for month n. This represents the purity of the soda ash produced.
$(T_t)_n$	=	Mass of trona input in month n (tons).
$(T_{sa})_n$	=	Mass of soda ash output in month n (tons).
2000/2205	=	Conversion factor to convert tons to metric tons.
0.097/1	=	Ratio of ton of CO_2 emitted for each ton of trona.
0.138/1	=	Ratio of ton of CO_2 emitted for each ton of soda ash produced.

(3) Site-specific emission factor method. Use Equations CC-3, CC-4, and CC-5 of this section to determine annual CO_2 process emissions from manufacturing lines that use the liquid alkaline feedstock process to produce soda ash. You must conduct an annual performance test and measure CO_2 emissions and flow rates at all process vents from the mine water stripper/evaporator for each manufacturing line and calculate CO_2 emissions as described in paragraphs (b)(3)(i) through (b)(3)(iv) of this section.

(i) During the performance test, you must measure the process vent flow from each process vent during the test and calculate the average rate for the test period in metric tons per hour.

(ii) Using the test data, you must calculate the hourly CO_2 emission rate using Equation CC-3 of this section:

$$ER_{CO2} = [(C_{co2} * 10000) * 2.59x10^{-9} * 44] * (Q * 60) * 4.53x10^{-4} \quad \text{(Eq. CC-3)}$$

Where:

ER_{CO2}	=	CO_2 mass emission rate (metric tons/hour).
C_{CO2}	=	Hourly CO_2 concentration (percent CO_2) as determined by §98.294(c).
10000	=	Parts per million per percent
2.59×10^{-9}	=	Conversion factor (pounds-mole/dscf/ppm).
44	=	Pounds per pound-mole of carbon dioxide.
Q	=	Stack gas volumetric flow rate per minute (dscfm).
60	=	Minutes per hour
4.53×10^{-4}	=	Conversion factor (metric tons/pound)

(iii) Using the test data, you must calculate a CO_2 emission factor for the process using Equation CC-4 of this section:

$$EF_{CO2} = \frac{ER_{CO2}}{(V_t * 4.53x10^{-4})} \quad \text{(Eq. CC-4)}$$

Where:

EF_{CO2}	=	CO_2 emission factor (metric tons CO_2/metric ton of process vent flow from mine water stripper/evaporator).
ER_{CO2}	=	CO_2 mass emission rate (metric tons/hour).
V_t	=	Process vent flow rate from mine water stripper/evaporator during annual performance test (pounds/hour).
4.53×10^{-4}	=	Conversion factor (metric tons/pound)

(iv) You must calculate annual CO_2 process emissions from each manufacturing line using Equation CC-5 of this section:

$$E_k = EF_{CO2} * (V_a * 0.453) * H \qquad \text{(Eq. CC-5)}$$

Where:

E_k	=	Annual CO_2 process emissions for each manufacturing line, k (metric tons).
EF_{CO2}	=	CO_2 emission factor (metric tons CO_2/metric ton of process vent flow from mine water stripper/evaporator).
V_a	=	Annual process vent flow rate from mine water stripper/evaporator (thousand pounds/hour).
H	=	Annual operating hours for the each manufacturing line.
0.453	=	Conversion factor (metric tons/thousand pounds).

(4) Calculate and report under subpart C of this part (General Stationary Fuel Combustion Sources) the combustion CO_2, CH_4, and N_2O emissions in the soda ash manufacturing line according to the applicable requirements in subpart C.

§98.294 Monitoring and QA/QC requirements.

Section 98.293 provides ~~three~~ four different procedures for emission calculations. The appropriate paragraphs (a) through (~~c~~d) of this section should be used for the procedure chosen.[2]

[2]For plants that recycle CO_2 generated during calcination to carbonation towers, WCI requested that CEMS be installed in the recycle loop to measure the quantity of recycled CO_2. As a result, an additional method was added to §98.293(d). The resulting measurement of the quantity of recycled CO_2 was also added to §98.296(a)(5) and §98.296(b)(12).

Subpart CC—Soda Ash Manufacturing

(a) If you determine your emissions using §98.293(b)(2) (Equation CC-1 of this subpart) you must:

(1) Determine the monthly inorganic carbon content of the trona from a weekly composite analysis for each soda ash manufacturing line, using a modified version of ASTM E359-00(Reapproved 2005)e1, Standard Test Methods for Analysis of Soda Ash (Sodium Carbonate) (incorporated by reference, see §98.7). ASTM E359-00(Reapproved 2005)e1 is designed to measure the total alkalinity in soda ash not in trona. The modified method of ASTM E359-00 adjusts the regular ASTM method to expresse the results in terms of trona. Although ASTM E359-00(Reapproved 2005)e1 uses manual titration, suitable autotitrators may also be used for this determination.

(2) Measure the mass of trona input produced by each soda ash manufacturing line on a monthly basis using belt scales or methods used for accounting purposes.

(3) Document the procedures used to ensure the accuracy of the monthly measurements of trona consumed.

(b) If you calculate CO_2 process emissions based on soda ash production (§98.293(b)(2)Equation CC-2 of this subpart), you must:

(1) Determine the inorganic carbon content of the soda ash (i.e., soda ash purity) using ASTM E359-

00(Reapproved 2005)e1 Standard Test Methods for Analysis of Soda Ash (Sodium Carbonate) (incorporated by reference, see §98.7). Although ASTM E359-00(Reapproved 2005)e1 uses manual titration, suitable autotitrators may also be used for this determination.

(2) Measure the mass of soda ash produced by each soda ash manufacturing line on a monthly basis using belt scales, by weighing the soda ash at the truck or rail loadout points of your facility, or methods used for accounting purposes.

(3) Document the procedures used to ensure the accuracy of the monthly measurements of soda ash produced.

(c) If you calculate CO_2 emissions using the site-specific emission factor method in §98.293(b)(3), you must:

(1) Conduct an annual performance test that is based on representative performance (i.e., performance based on normal operating conditions) of the affected process.

(2) Sample the stack gas and conduct three emissions test runs of 1 hour each.

(3) Conduct the stack test using EPA Method 3A at 40 CFR part 60, appendix A-2 to measure the CO_2 concentration, Method 2, 2A, 2C, 2D, or 2F at 40 CFR part 60, appendix A-1 or Method 26 at 40 CFR part 60, appendix A-2 to determine the stack gas volumetric flow rate. All QA/QC procedures

specified in the reference test methods and any associated performance specifications apply. For each test, the facility must prepare an emission factor determination report that must include the items in paragraphs (c)(3)(i) through (c)(3)(iii) of this section.

(i) Analysis of samples, determination of emissions, and raw data.

(ii) All information and data used to derive the emissions factor(s).

(iii) You must determine the average process vent flow rate from the mine water stripper/evaporater during each test and document how it was determined.

(4) You must also determine the the annual vent flow rate from the mine water stripper/evaporater from monthly information using the same plant instruments or procedures used for accounting purposes (i.e., volumetric flow meter).

(d) If you recycle CO_2 generated during calcination to carbonation towers, then you must install a CEMS in the recycle loop and measure this quantity of CO_2.

§98.295 Procedures for estimating missing data.

For the emission calculation methodologies in §98.293(b)(2)and (b)(3), a complete record of all measured parameters used in the GHG emissions calculations is required (e.g., inorganic carbon content values, etc.).

Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in the paragraphs (a) through (d) of this section. You must document and keep records of the procedures used for all such missing value estimates.

(a) For each missing value of the weekly composite of inorganic carbon content of either soda ash or trona, the substitute data value shall be the arithmetic average of the quality-assured values of inorganic carbon contents from the week immediately preceding and the week immediately following the missing data incident. If no quality-assured data on inorganic carbon contents are available prior to the missing data incident, the substitute data value shall be the first quality-assured value for carbon contents obtained after the missing data period.

(b) For each missing value of either the monthly soda ash production or the trona consumption, the substitute data value shall shall be the best available estimate(s) of the parameter(s), based on all available process data or data used for accounting purposes.

(c) For each missing value collected during the performance test (hourly CO_2 concentration, stack gas volumetric flow rate, or average process vent flow from mine water stripper/evaporator during performance test), you must repeat the annual performance test following the calculation and monitoring and QA/QC requirements under §§98.293(b)(3) and 98.294(c).

(d) For each missing value of the monthly process vent flow rate from mine water stripper/evaporator, the subsititute data value shall be the best available estimate(s) of the parameter(s), based on all available process data or the lesser of the maximum capacity of the system or the maximum rate the meter can measure.

§98.296 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) or (b) of this section, as appropriate for each soda ash manufacturing facility.

(a) If a CEMS is used to measure CO_2 emissions, then you must report under this subpart the relevant information required under §98.36 and the following information in this paragraph (a):

(1) Annual consumption of trona or liquid alkaline feedstock for each manufacturing line (metric tons).

(2) Annual production of soda ash for each manufacturing line (tons).

(3) Annual production capacity of soda ash for each manufacturing line (tons).

(4) Identification number of each manufacturing line.

(5) Annual quantity of generated CO_2 recycled to carbonation towers (tons), if applicable.

(b) If a CEMS is not used to measure CO_2 emissions, then you must report the information listed in this paragraph (b):

(1) Identification number of each manufacturing line.

(2) Annual process CO_2 emissions from each soda ash manufacturing line (metric tons).

(3) Annual production of soda ash (tons).

(4) Annual production capacity of soda ash for each manufacturing line (tons).

(5) Monthly consumption of trona or liquid alkaline feedstock for each manufacturing line (tons).

(6) Monthly production of soda ash for each manufacturing line (metric tons).

(7) Inorganic carbon content factor of trona or soda ash (depending on use of Equations CC-1 or CC-2 of this subpart) as measured by the applicable method in §98.294(b) or (c) for each month (percent by weight expressed as a decimal fraction).

(8) Whether CO_2 emissions for each manufacturing line were calculated using a trona input method as described in Equation CC-1 of this subpart, a soda ash output method as described in Equation CC-2 of this subpart, or a site-specific emission factor method as described in Equations CC-3 through CC-5 of this subpart.

(9) Number of manufacturing lines located used to produce soda ash.

(10) If you produce soda ash using the liquid alkaline feedstock process and use the site-specific emission factor method (§98.293(b)(3)) to estimate emissions then you must report the following relevant information:

(i) Stack gas volumetric flow rate per minute (dscfm)

(ii) Hourly CO_2 concentration (percent CO_2)

(iii) CO_2 emission factor (metric tons CO_2/metric tons of process vent flow from mine water stripper/evaporator).

(iv) CO_2 mass emission rate (metric tons/hour).

(v) Average process vent flow from mine water stripper/evaporater during performance test (pounds/hour).

(vi) Annual process vent flow rate from mine stripper/evaporator (thousand pounds/hour).

(vii) Annual operating hours for each manufacturing line used to produce soda ash using liquid alkaline feedstock (hours).

(11) Number of times missing data procedures were used and for which parameter as specified in this paragraph (b)(11):

(i) Trona or soda ash (number of months).

(ii) Inorganic carbon contents of trona or soda ash (weeks).

(iii) Process vent flow rate from mine water stripper/evaporator (number of months).

(iv) Stack gas volumetric flow rate during performance test(number of times).

(v) Hourly CO_2 concentration (number of times).

(vi) Average vent process vent flow rate from mine stripper/evaporator during performance test (number of times).

(12) Annual quantity of generated CO_2 recycled to carbonation towers (tons), if applicable.

§98.297 Records that must be retained.

In addition to the records required by §98.3(g), you must retain the records specified in paragraphs (a) and (b) of this section for each soda ash manufacturing line.

Subpart CC—Soda Ash Manufacturing

(a) If a CEMS is used to measure CO_2 emissions, then you must retain under this subpart the records required for the Tier 4 Calculation Methodology specified in subpart C of this part and the information listed in this paragraph (a):

(1) Monthly production of soda ash (tons)

(2) Monthly consumption of trona or liquid alkaline feedstock (tons)

(3) Annual operating hours (hours).

(b) If a CEMS is not used to measure emissions, then you must retain records for the information listed in this paragraph (b):

(1) Records of all analyses and calculations conducted for determining all reported data as listed in §98.296(b).

(2) If using Equation CC-1 or CC-2 of this subpart, weekly inorganic carbon content factor of trona or soda ash, depending on method chosen, as measured by the applicable method in §98.294(b)(percent by weight expressed as a decimal fraction).

(3) Annual operating hours for each manufacturing line used to produce soda ash (hours).

(4) You must document the procedures used to ensure the accuracy of the monthly trona consumption or soda ash

prodcution measurements including, but not limited to, calibration of weighing equipment and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.

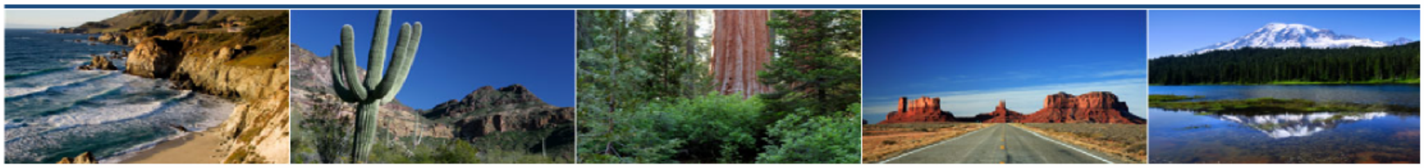
(5) If you produce soda ash using the liquid alkaline feedstock process and use the site-specific emission factor method to estimate emissions (§98.293(b)(3)) then you must also retain the following relevant information:

(i) Records of performance test results.

(ii) You must document the procedures used to ensure the accuracy of the annual average vent flow measurements including, but not limited to, calibration of flow rate meters and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.

§98.298 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.



§WCI.8 REQUIREMENTS FOR VERIFICATION OF GREENHOUSE GAS EMISSIONS DATA REPORTS AND REQUIREMENTS APPLICABLE TO EMISSIONS DATA VERIFIERS (UPDATED FOR USE IN U.S. JURISDICTIONS TO CONFORM TO HARMONIZED ERS)

Note: The verification requirements laid out in this section strive for consistency with ISO 14064-3[1] requirements and set forth a high standard for verification that will ultimately support a WCI cap and trade program. Due to differences in rulemaking procedures between jurisdictions, Supplement 1 provides supplemental text that jurisdictions must incorporate into either the jurisdiction's prescriptive rule language, replacing more general procedural language in Section WCI.8, or into enforceable guidance documents. There are notes in WCI.8 that direct readers to appropriate text in Verification Supplement 1 when applicable.

It would be ideal for all jurisdictions to enforce the same requirements and have the same implementation processes for accreditation and verification to ensure that consistent accurate data exists throughout the WCI regional program. Reporters and verifiers with operations throughout the WCI region will benefit from a consistent approach and such an approach would facilitate administration of the verification requirements by a central body or designee.

(a) Applicability and Scope.

(1) Except as provided in WCI.8(a)(2) through (~~4~~5) owners or operators [Each jurisdiction will select the specific terminology for the regulated persons in accordance with their customary rule-writing practices] are required to obtain annual verification for a facility that emits 25,000 metric tons CO_2e or more per year in combined emissions from one or more of the source categories listed in ~~WCI.1~~section 98.2 in any calendar year starting on or after 2010.

(2) When the operation of a facility, fuel supplier, or electricity importer subject to the requirements of this section is changed such that the operator has reported less than 25,000 metric tons of CO_2e emissions for a calendar year, the operator shall obtain verification of annual emissions reports for the lesser of three subsequent calendar years or for those years remaining in the current compliance period. If CO_2e emissions of a facility, fuel supplier, or electricity importer subject to the requirements of this section

[1] ISO (2006) ISO 14064-3: Greenhouse Gases-Part 3: Specification with guidance for the validation and verification of greenhouse gas assertions, March, 2006, International Organization for Standardization, Switzerland.

again exceed 25,000 metric tons in any calendar year the provisions of WCI.8(a)(1) apply.

(3) Carbon dioxide emissions from the combustion of biomass fuels shall be included in the determination regarding verification applicability, with the following exceptions:

(A) Until such time as [the jurisdiction] has made a determination regarding the carbon neutrality of any biomass fuels, a maximum of 15,000 metric tons of carbon dioxide emissions from the combustion of pure solid biomass fuel may be excluded from calculation of GHG emissions for comparison to the 25,000 metric ton CO_2e per year verification threshold in paragraph (a) of this section.

(B) After such time as [the jurisdiction] has made a determination regarding the carbon neutrality of any biomass fuels, the carbon dioxide emissions from the combustion of those fuels may be excluded from calculation of GHG emissions for determining whether the 25,000 metric tons CO_2e per year verification threshold in paragraph (a)(1) of this section has been met.

[Under Design Recommendation 1.3, carbon neutral biomass will be excluded from the cap-and-trade program. A WCI Partner jurisdiction, however, may, in its discretion, choose to require carbon dioxide emissions from the combustion of biomass fuel to be included in the determination of the verification threshold in order to obtain a complete inventory of the fuels being combusted in the jurisdiction.]

(4) Owners or operators may exclude carbon dioxide emissions from the combustion of biomass fuels that [jurisdiction] has deemed carbon neutral from the scope of verification.

(5) Emissions designated "reporting only" in this article shall be excluded from the determination regarding verification applicability.

[A WCI Partner jurisdiction may, in its discretion, choose to require carbon dioxide emissions from the combustion of biomass fuel to be included in the scope of verification.]

~~(5)~~(6) Notwithstanding WCI.8(a)(2) and (3), any facility, fuel supplier or electricity importer subject to a cap-and-trade program for CO_2e emissions established by [the jurisdiction] shall obtain verification of reported annual emissions.

(b) Requirements for Annual Verification of Emissions Data Reports.

(1) Verification bodies shall conduct verification processes and design verification procedures to determine whether there is a reasonable level of assurance for each separate emissions data report every year of the verification cycle. The verification team shall find that there is a reasonable level of assurance for an emissions data report if the report

(A) contains no material misstatement; and

(B) conforms to the requirements of this article.

(2) The verification body must provide verification services in compliance with WCI.8.

(3) Facility owners or operators, fuel suppliers, and electricity importers required to obtain annual verification shall be subject to full verification requirements in the first year that

verification is required for an emissions data report. Upon completion of a positive verification statement under full verification requirements, the facility owner or operator, fuel supplier, or electricity importer may be eligible for two years of less intensive verification services as ~~described~~ defined in section WCI.8(x)~~9~~. This cycle may be repeated in subsequent three-year cycles; however, full verification requirements shall apply at least once every three years.

(4) Facility owners or operators, fuel suppliers, and electricity importers required to obtain annual verification will be required to obtain full verification services if any of the following apply:

(A) There has been a change in the verification body from the previous year; or

(B) A verification body issued an adverse verification statement for that facility's previous year's emissions data report.

(C) Reporters subject to the verification requirements of this section, must complete their verification process, including submittal of a verification statement to [the jurisdiction], by September 1 of the year following the reporting year.

(c) Accreditation Requirements for Verification Bodies.

(1) The accreditation requirements specified in this subsection shall apply to all verification bodies that wish to provide verification services under this rule.

(2) A verification body is qualified to conduct verification services ~~for the WCI~~ in [the jurisdiction] if

(A) it has demonstrated knowledge of [the ~~WCI~~ jurisdiction] reporting requirements; ~~and~~

(B) it has the characteristics and capabilities deemed necessary by [the jurisdiction] to perform verification services; and

(C) it is accredited to ISO 14065 through

(i) a program developed under ISO 17011 by an accreditation body that is a member of the International Accreditation Forum~~.~~; or

(ii) a program developed or authorized [the jurisdiction] under [the jurisdiction's] required statutory or regulatory process that is at least as stringent as the process defined in ISO 17011.

[Note the details of the WCI's specific accreditation process for verification bodies ~~(which~~ has yet to be developed~~) will be consistent with ISO 14065 through an accreditation program that will developed under ISO 17011 and will include demonstrated knowledge of the WCI reporting requirements~~. The WCI will explore additional accreditation requirements and/or other criteria for individual lead verifiers, general verifiers, and/or sector specialists.]

(3) Prior to January 1, 2013, accreditation by the California Air Resources Board under Title 17, California Code of Regulation, section 95132, may be substituted for the accreditation required under WCI.8(c)(2)(B).

(d) Requirements for Verification Services. The following verification services must be provided for each emissions data report.

(1) As part of the verification services, the verification team shall review documents submitted, assess risks of a material misstatement, develop a verification plan (that includes a sampling plan), evaluate the emissions data report against the verification requirements, and assess the materiality of errors, omissions and misstatements identified.

(2) The verification team shall request any information and documents needed for verification services. Such information shall include, but is not limited to original records and supporting data for the emissions data report.

(e) A verification team must include the following:

(1) a Lead Verifier;

(2) an Independent Peer Reviewer;

(3) any subcontractor elected to provide verification services under WCI.8(f).

(f) Subcontracting. The following requirements shall apply to any verification body that elects to subcontract verification services.

(1) The primary verification body must assume full legal responsibility for verification services performed by subcontracted verifiers or verification bodies.

(2) A verification body or verifier acting as a subcontractor to the primary verification body will not further subcontract that same work to another firm or individual.

(3) A verification body or verifier acting as a subcontractor is subject to all Conflict of Interest requirements in Section WCI.8(g).

(4) A verification body or verifier acting as a subcontractor must be identified by the primary verification body as part of the verification team.

(g) Conflict of Interest Requirements for Verification Bodies. The conflict of interest provisions of this section shall apply to the verification body, entities related to the verification body, and the verification team accredited according to the requirements of the WCI to perform verification services for the WCI program. Member for purposes of this section means any employee or subcontractor of the verification body or entities related to the verification body. Member also includes any individual with a majority equity share in the verification body or entities related to the verification body.

(1) Prior to a jurisdiction accepting a verification statement, and prior to a jurisdiction accepting the associated emissions report for consideration for approval, the AVA must determine that the verification body has a low potential for conflict of interest as described under WCI.8(g)(6). To inform this determination by the AVA, a self-evaluation of the potential for any conflict of interest that the verification body, entities related to the verification body, and members of the verification team, including subcontractors, may have with the owner or operator or their related entities for which verification services will be or have been provided shall be submitted to the AVA. This self-evaluation must include an evaluation of any threats to the verification body's

independence including: [*note: a standardized Conflict of Interest Assessment form will be developed for the WCI*]

[To facilitate timely determinations of conflict-of-interest potential, and to reduce the risk of finding medium or high conflict-of-interest potential after verification services have been initiated, it is recommended that jurisdictions require that the self evaluations be submitted and evaluated by the AVA prior to the initiation of verification services. A jurisdiction may elect to allow verification services to commence prior to the determination of the conflict-of-interest potential by the AVA.]

(A) Threats created by the reporting operation offering inducements to the verification body, subcontractors or verification team members for a positive opinion;

(B) Threats created by members of the verification body, verification team members, subcontractors, or family of subcontractors or team members having a financial interest in the reporting operation or its operator;

(C) Threats created by members of the verification body reviewing work of the verification body, subcontractors, members of the verification team, or related companies, including but not limited to any situation where the body, subcontractors, team members or companies have provided services related to greenhouse gases;

(D) Threats created by members of the verification body, verification team members, or subcontractors having a close relationship with the reporting operation, such that they might become too sympathetic to the interests of the reporting operation; and

(E) Threats created by members of the verification body, verification team members, or subcontractors being deterred from acting objectively or exercising professional skepticism by threats, actual or perceived, from the reporting operation.

(2) The verification body shall deem the potential for conflict of interest to be low if

(A) No threats as listed in WCI.8(g)(1) exist, and

(B) Any non-verification services provided by the verification body to the owner or operator within the last three years are valued at less than five percent of the verification body's annual revenue in each of those years.

(3) The verification body shall deem the potential for conflict of interest to be high if threats as listed in WCI.8(g)(1)(A) or (E) exist.

[A jurisdiction may expand the list of high threats (i.e. un-mitigatable conflicts) with the items included in paragraph 2 of the Conflict of Interest section of Supplement 1 below.]

(4) The verification body shall deem the potential for a conflict of interest to be medium if the potential for a conflict of interest is not deemed to be either low or high as specified in sections WCI.8(g)(2)-(3).

(5) If a verification body deems the potential for conflict of interest to be medium and wishes to provide verification services for the owner or operator, then the verification body shall submit, in addition to the self-evaluation, a plan to avoid, neutralize, or mitigate the potential conflict of interest situation.

(6) Conflict of Interest Determinations. The AVA shall review the self-evaluation submitted by the verification body and determine the verification body's potential conflict of interest in performing verification services for the owner or operator.

[In addition to the AVA determination, a jurisdiction may elect to conduct audits of conflict of interest submissions for compliance verification and enforcement purposes.]

(A) The AVA shall notify the verification body in writing when the conflict of interest evaluation information submitted under section WCI.8(g)(1) is deemed complete. Within 45 days after deeming the evaluation information complete, the AVA shall determine the conflict-of-interest potential and shall notify the verification body or owner or operator if the potential conflict of interest is determined to be medium or high.

(B) If the AVA determines the verification body or any member of the verification team has any threats specified in section WCI.8(g)(1), the AVA shall find a high potential conflict of interest and verification services may not proceed.

(C) If the AVA determines that there is a low potential conflict of interest prior to the verification services being provided, verification services may proceed.

(D) If the AVA determines that the verification body and verification team have a medium potential for a conflict of interest, the AVA shall evaluate the conflict of interest mitigation plan and may request additional information from the applicant to complete the determination. In determining potential conflict of interest, the AVA may consider factors including, but not limited to, the nature of previous work performed, the current and past relationships between the verification body and its subcontractors with the owner or operator, and the cost of the verification services to be performed. The AVA will determine whether these factors when considered in combination with the mitigation plan demonstrate a low level of potential conflict of interest or a high level. If the AVA determines that there is a low potential conflict of interest prior to the verification services being initiated, verification services may proceed. If a high potential is determined prior to verification services being initiated, verification services may not proceed. If a high potential is determined after verification services have been initiated, the verification statement shall not be accepted..

(7) Monitoring Conflict of Interest Situations.

(A) After commencement of verification services, the verification body shall monitor and immediately make full disclosure in writing to the AVA regarding any potential for a conflict of interest situation that arises. This disclosure shall include a description of actions that the verification body has taken or proposes to take to avoid, neutralize, or mitigate the potential for a conflict of interest.

(B) The verification body shall monitor arrangements or relationships that may be present for a period of one year after the completion of verification services. During that period, within 30 calendar days of any change in arrangements or relationships with the owner or operator for which the verification body has provided verification services that may create a medium or high threat of conflict of interest, the verification body shall notify the AVA of the change and provide a description of the nature of the change. The AVA will make a conflict of interest determination under WCI.8(g)(6).

(C) The verification body shall report to the AVA any changes in its organizational structure, including mergers, acquisitions, or divestitures that may have created a medium or high threat of conflict of interest for one year after completion of verification services within 30 days and submit an evaluation of how the change(s) impacts the potential for conflict of interest.

(D) The AVA may invalidate a verification finding if a medium or high threat of a conflict of interest has arisen for the verification body or any member of the verification team and, in the case of a medium threat, the threat has not been adequately mitigated. In such a case, the owner or operator shall be provided 180 calendar days to have their emissions report verified by a different verification body.

(E) If the verification body or its subcontractor(s) are found to have violated the conflict of interest requirements of this section, the AVA may rescind its accreditation for any appropriate period of time . Additionally, the AVA may separately revoke its recognition of an accredited Verification Body under WCI.8(w). *[The WCI intends to develop more detailed accreditation requirements in the future.]*

(h) Notice of Verification Services. Prior to commencing verification services for a facility owner or operator, fuel supplier, and electricity importer, the verification body shall submit a notice of verification services to the AVA. Verification activities shall not proceed for 15 business days or until the verification body receives written approval to proceed from the AVA, whichever is earlier. If the AVA does not respond to the verification body within 15 business days, the verification body may begin to conduct verification activities.

[The NOVS form will be standardized across WCI and developed later.]

(i) Verification Plan.

(1) Accounting for requirements set by WCI.8, the verification plan shall document:

(A) the scope of the verification;

(B) the level of assurance;

(C) the verification standard;

(D) the verification criteria;

(E) the objectives of the verification;

(F) the timing of the verification, including site visits;

(G) the nature of the communications required;

(H) the resources required to conduct the verification, including the role of verification team members; and

(I) the nature, timing and extent of the verification procedures, including the sampling plan.

(2) The verification body shall retain the verification plan in paper, electronic, or other format for a period of not less than seven years following the submission of each verification statement.

(j) Site visits. In years for which full verification services are required under WCI.8(b)(3), at least one member of the verification team shall at a minimum make one onsite site visit to each facility or fuel supply location *[Note that exact location of fuel supplier site visits remains TBD]* for which an emissions data report is submitted. The verification team member(s) shall also conduct an onsite visit of the headquarters or other location of central data management, if different from the facility or fuel supply location, when the owner or operator is an electricity importer.

(k) Owners or operators shall make available to the verification team all information and documentation used to calculate and report emissions, electricity transactions, and other information required under this rule, as applicable.

(l) As applicable for electricity importers, the verification team shall review electricity transaction records, including receipts of power attributed to the Northwest or Southwest region as verifiable via North American Electric Reliability Corporation (NERC) E-Tags, settlements data, or other information as confirmation of the region of origin. [*Note that this procedure is subject to change pending WCI Electricity Committee review.*]

(m) Data Checks. To determine the reliability of the submitted emissions data report, the verification team shall use data checks as defined in WCI.~~9~~8(x). Verifiers will use their professional judgment in determining how many data checks are needed to provide a reasonable level of assurance.

(n) Emissions Data Report Modifications. If as a result of review by the verification team and prior to completion of a verification statement the owner or operator chooses to make improvements or corrections to the submitted emissions data report, a revised emissions data report must be submitted to [the jurisdiction] as specified by section WCI.8(q). The owner or operator shall maintain documentation to support any revisions made to the initial emissions data report. Documentation for all emissions data report submittals shall be retained by the operator for seven years pursuant to section ~~WCI.4~~ 98.3(g).

(o) Materiality and Conformance Assessment Criteria. The verifier shall determine if the annual emissions report is prepared in such a way that it satisfies WCI.8(b)(1).

(1) A verification team shall determine that an emission data report contains a material misstatement, if either of the following is true:

(A) Based on the verification team's own determination of the level of emissions subject to verification based on the sampling plan, the verification team concludes that total reported emissions are less than 95 percent accurate using the following equation:

$$PA = 100 - [(SOU/TRE) \cancel{*} \times 100)]$$

Where:

PA = Percent accuracy

SOU	=	The net result of summing overstatements and understatements resulting from errors, omissions and misreporting
TRE	=	Total reported emissions

(B) The individual or aggregate effect of one or more errors, omissions or misstatements identified in the course of verification make it probable that the judgment of a reasonable person regarding the total reported emissions would have been changed or influenced by the error, omission or misrepresentation.

(2) To assess conformance with this rule the verification team shall review the methods and factors used to develop the emissions data report for adherence to the requirements of this rule.

(3) The verification team shall keep a log of any issues identified in the course of verification activities that may affect determinations of material misstatement and nonconformance, and how those issues were resolved.

(p) Completion of verification services shall include:

(1) Verification Statement. Upon completion of the verification services required by WCI.8, the verification body shall prepare either a positive or adverse verification statement, for each emissions data report, based on its findings during the verification process. The verification body shall provide the verification statement(s) to the reporter and to the AVA [alternatively, this could be the reporter's responsibility to submit the statement to the AVA], according to the schedule specified in section WCI.2(b). Before each statement is completed, the verification body shall have the verification services and findings of the verification team independently reviewed and approved by an Independent Peer Reviewer.

~~Verification Statement. Upon completion of the verification services required by WCI.8, the verification body shall complete a verification statement for each emissions data report, and provide that statement to the owner or operator and [the jurisdiction or other body] according to the schedule specified in section WCI.2(b). Before that statement is completed, the verification body shall have the verification services and findings of the verification team independently reviewed and approved by an Independent Peer Reviewer.~~

~~The verification body shall provide either a positive or adverse verification statement to the reporter and to the AVA *[alternatively, this could be the reporter's responsibility to submit the statement to the AVA]* based on its findings during the verification process.~~

(2) The lead verifier in the verification team shall attest on the verification statement that the verification team has carried out all verification services as required by this rule, and the Independent Peer Reviewer shall attest to his or her independent review on behalf of the verification body and his or her concurrence with the verification findings. If the Independent Peer Reviewer does not determine that the verification team has carried out all verification services as required by the rule or if the Independent Peer Reviewer rejects the verification team's findings, then the verification body cannot issue a positive verification statement.

(3) The verification body shall provide to the owner or operator a detailed verification report. The verification report shall at minimum include the detailed comparison of the

data checks with the submitted emissions data report, errors, omissions and misstatements identified during the course of the verification, any corrections made to the original annual emissions report as a result of the verification, and observations about the data management systems that are connected to the errors, omissions and misstatements identified, as well as any qualifying comments on findings during verification services. The detailed verification report shall be made available to [the jurisdiction] upon request.

(q) Prior to the verification body providing an adverse verification statement pursuant to WCI.8(p)(2), the owner or operator shall be provided at least 14 working days to modify the emissions data report to correct any material misstatement or nonconformance found by the verification team. The modified report and verification statement must be submitted to [the jurisdiction] before the applicable verification deadline, unless the operator makes a request to [the jurisidiction*]* as follows:

(1) If the owner or operator and the verification body cannot reach agreement on modifications to the emissions data report that result in a positive verification statement, the operator may petition the AVA to make a final decision as to the verifiability of the submitted emissions data report.

(2) If the AVA determines that the emissions data report does not meet the standards and requirements specified in this article, the owner or operator shall have the opportunity to submit within 60 calendar days of the date of this decision *[Note that this time frame may need to be changed pending details of cap-and-trade system design and needs.]* any emissions data report revisions that address the AVA's determination, for re-verification of the emissions data report. In re-verifying a revised emissions data report, the verification body and verification team shall be subject to the requirements in section WCI.8(q)-(s).

(3) Upon provision of the verification statement to [the jurisdiction], the emissions data report shall be considered final and no changes shall be made except as provided in section WCI.8(n) or (q). All verification requirements of this rule shall be considered complete upon provision of the verification statement.

(r) In addition to initiating WCI's dispute resolution process, the operator and verification body must inform the applicable accreditation body of the dispute.

(s) The AVA may make void the positive verification statement submitted by the verification body if:

(1) The AVA finds a high level of conflict of interest existed between a verification body and an owner or operator; or,

(2) An emissions data report that received a positive verification statement fails an audit by the AVA.

(t) Upon request by the AVA, the owner or operator shall provide the data used to generate an emissions data report, including all data available to a verification body. The AVA may also review the full verification report given by the verification body to the owner or operator. The full verification report shall be provided to the AVA upon request.

(u) Upon written notification by the AVA, the verification body shall make itself available for a verification services audit.

(v) Duration of verification services by one verification body. Facility owners or operators, fuel suppliers, or electricity importers subject to annual verification shall not use the same verification body for a period of more than six consecutive years. If a facility owner or operator, fuel supplier, or electricity importer is required or elects to contract with another verification body, they may contract verification services from the previous verification body only after not using the previous verification body for at least three years. If a verification body or verification team member has been providing verification services for an owner or operator in a greenhouse gas reporting or reductions program other than [the jurisdiction's] within the previous three years, those years of services will count towards the six consecutive year limit in this section.

(w) Revocation of Recognition. A jurisdiction may review, and for good cause, work to revoke or modify the accreditation status of a recognized verification body. If a recognized verification body is suspended in any other mandatory or voluntary GHG reporting or trading program, that verification body will not be allowed to provide any verification services until that suspension ends. If a recognized verification body has its accreditation revoked under any other mandatory or voluntary GHG reporting or trading program, that verification body will no longer be allowed to provide verification services under WCI.8 until it is reaccredited.

(x) Definitions. The following definitions shall apply to terms used in this section:

"Accreditation and Verification Authority" or "AVA" means [the jurisdiction] or any entity or entities to which [the jurisdiction] assigns any of the responsibilities for oversight and execution of the accreditation and verification program established in WCI.8.

"Adverse verification statement" means a verification statement rendered by a verification body stating that the verification body cannot conclude that there is a reasonable level of assurance for an emissions data report.

"Conflict of interest" means a situation in which, because of financial or other activities or relationships with other persons or organizations, a person or body is unable or potentially unable to render an impartial verification opinion of a potential client's greenhouse gas emissions, or the person or body's objectivity in performing verification services is or might be otherwise compromised.

"Data check" means an independent calculation or checking of data conducted by a verifier to recreate the emissions for a discreet source included in an emissions data report.

"Full verification" means all verification services as provided in section WCI.8(b).

"Less Intensive Verification" means the verification services provided in interim years between full verifications; less intensive verification only requires risk assessment and data checks on an owner or operator's emissions data report based on the most current sampling plan developed as part of the most current full verification services. This level of verification may only be used if the verifier can provide findings with a reasonable level of assurance.

"Material misstatement" means an error or omission, or a collection of errors or omissions, that results in a determination that a verification statement contains a material misstatement under WCI.8(o)(1)(A) or (B).

“Positive verification statement” means a verification statement rendered by a verification body stating that the verification body can say with reasonable assurance that the submitted emissions data report is free of material misstatement and that the emissions data report conforms to the requirements of this article.

“Verification” means a systematic, independent and documented process for the evaluation of an operator’s emissions data report against the WCI’s reporting procedures and methods for calculating and reporting GHG emissions.

“Verification body” means a firm accredited by the [Accreditation Body TBD] and recognized by the jurisdiction or its designee, that is able to render a verification statement and provide verification services for operators subject to reporting under this article.

“Verification cycle” means three years of verification activities. Each verification cycle must include at least one year of full verification, and may include two years of less intensive verification, if eligible.

“Verification statement” means the final written declaration rendered by a verification body attesting whether an operator’s emissions data report is free of material misstatement and whether the emissions data report conforms to the requirements of this article.

“Verification services” means services provided during verification as specified in WCI.8, including but not limited to reviewing an operator’s emissions data report, verifying its accuracy according to the standards specified in this article, assessing the operator’s compliance with this rule, and submitting a verification opinion to the *[jurisdiction or its agent]*.

“Verification team” means all of those working for a verification body, including all subcontractors, to provide verification services for an operator.

“Verifier” means an individual employed or contracted by an accredited verification body who has been deemed competent by the verification body to carry out verification services as specified in section WCI.8.

Verification Supplement 1

Note: the additional content in this Supplement must either be included in regulatory text in the appropriate subsections of WCI.8 or enforceable guidance documents by jurisdictions. The language in this section provides further explanation of items required in WCI.8 or alternative, more prescriptive language of those requirements.

Preliminary Activities and Verification Plan

The verification team shall discuss with the owner or operator the scope and objective of the verification services and obtain information from the owner or operator necessary to develop a verification plan. Such information shall include but is not limited to:

- Information to allow the verification team to develop a general understanding of facility or entity boundaries, operations, emissions sources, electricity transactions, as applicable;
- Information about the data management system used to track GHG emissions, electricity transactions, and other required measurement data as applicable;
- Information regarding the training or qualifications of personnel involved in developing the GHG emissions data report;
- Description of the specific methodologies used to quantify and report GHG emissions, electricity transactions, and other required data as applicable;
- Records of measured data related to emissions and operations for the prior and current period;
- Inventory of sources and their associated emissions for the reporting period, and
- Any prior verification reports, if applicable.

In developing the verification plan, the verifier shall:

- Gain an understanding of the organization and the process that emit greenhouse gases;
- Conduct a risk assessment to evaluate inherent, control and detection risk;
- Conduct preliminary analytical testing to identify anomalies in the data;
- Conduct a sensitivity analysis to assess the relative contribution of each source in the inventory to the reported annual emissions, and
- Consider any other relevant developments at the facility, in the regulations, or legal environment.

Sampling Plan

As part of the verification procedures, the verification team shall develop a sampling plan that, when combined with the other verification procedures, provides sufficient and appropriate evidence to allow the verifier to arrive at a conclusion. The sampling plan shall be designed to achieve the specified verification objective. The sample plan shall consider:

- Statistical versus non-statistical approaches
- Design of the sample, including the population characteristics
- Stratification (categorization of population into subgroups)
- Emission weighted selection
- Sample size

- Sample selection

As relevant information becomes available during the course of verification activities, the verification team must modify the sampling plan as necessary to address potential issues emerge of material misstatement or nonconformance with the requirements of this rule.

Data Checks

The verification team conducts data checks throughout the verification process and shall focus first on the largest and most uncertain estimates of emissions and electricity transactions.

- In establishing the verification plan, the verification team shall use professional judgment to determine the number of data checks required for the team to conclude with reasonable assurance whether the reported emissions and transactions are free of material misstatement and the emissions data report otherwise conforms to the requirements of this rule.
- The verification team shall choose emissions sources, and electricity transactions data as applicable, for data checks based on their relative sizes and risks of material misstatement as indicated in the verification plan;
- The verification team, through the conformance assessment, shall ensure that the appropriate methodologies and emission factors have been applied for the emissions sources and electricity transactions for sampled data covered under sections WCI.20 through WCI.XX;

Site Visits

During the site visit, the verification team member(s) shall conduct the following:

- Observe whether all sources at the site are represented in the emissions report as specified in sections WCI.20 to WCI.XX as applicable to the owner or operator.
- Assess whether the source inventory is identified, categorized, and reported appropriately. Collect evidence as to explanations for data anomalies identified in the verification plan.
- Understand the data trail used by the owner or operator to measure, quantify, and report greenhouse gas emissions and, when applicable, electricity transactions.
- Understand and evaluate the associated data controls used by the owner to ensure the completeness and accuracy of the data

Materiality Assessment

In assessing whether misstatements are material, the verification team shall determine whether the total reported emissions are at least 95 percent accurate using the following equation:

Percent accuracy = 100 – (sum of (errors, omissions, misreporting) * 100 / (total reported emissions))

To assess conformance with this rule the verification team shall review the methods and factors used to develop the emissions data report for adherence to the requirement of this rule. The verification team shall keep a record of any errors, omissions or misstatements identified in the course of verification activities that may affect determinations of material misstatement and nonconformance, and how those issues were resolved.

Conflict of Interest (*could replace more general procedural language in Section WCI.8*)

(1) Conflict of Interest Submittal Requirements for Accredited Verification Bodies.

(A) Before the start of any work related to providing verification services to an owner or operator, a verification body must first be authorized in writing by *the AVA* to provide verification services. To obtain authorization the verification body shall submit to *the AVA* a self-evaluation of the potential for any conflict of interest that the verification body, entities related to the verification body, and members of the verification team including, subcontractors may have with the owner or operator or their related entities for which it will perform verification services. For the purposes of this section, the term member refers to staff on the verification team, in the verification body and any subcontractors. The submittal shall include the following:

(i) Identification of whether the potential for conflict of interest is high, low, or medium based on factors specified in this section;

(ii) An organizational chart of the business structure of the verification body, including its related entities and brief description of the primary work done by the verification body and related entities;

(iii) iii. Identification of whether any member of the verification body, entities related to the verification body, or the verification team including subcontractors has previously provided verification services for the owner or operator or its related entities and, if so, the years in which such verification services were provided;

(iv) Identification of whether any member of the verification body, entities related to the verification body, or the verification team or including subcontractors has engaged in any non-verification services of any nature with the owner or operator or related entities either within or outside the WCI region during the previous three years. The verification body must also disclose any services listed under section (high COI list) it has provided to the owner or operator, regardless of when these services occurred. If non-verification services have previously been provided, the following information shall also be submitted:

(v) Identification of the nature and location of the work performed for the owner or operator and whether the work is similar to the type of work to be performed during verification, such as emissions inventory auditing, energy efficiency, renewable energy, or other work with implications for the operator's greenhouse gas emissions or the accounting of greenhouse gas emissions or electricity transactions;

(vi) The nature of past, present or future relationships the verification body, entities related to the verification body, and members of the verification team including subcontractors have with the owner or operator or related entity including:

- Instances when any member has performed or intends to perform work for the owner or operator;
- Identification of whether work is currently being performed for the owner or operator and, if so, the nature of the work;

- Whether any member has any contracts or other arrangements to perform work for the owner or operator or a related entity;
- Identify how much work was performed in each of the last three years, as a percentage of the verification body's total gross income for each of the last three years;
- Identify how much work related to greenhouse gases or electricity transactions was has performed for the owner or operator or related entities in each of the last three years, as a percentage of the verification body's income for each of the last three years;
- Identify how much work was performed by each subcontractor for the operator in each of the last three years, as a percentage of each subcontractor's total gross income for each of the last three years.

(vii) Explanation of how the amount and nature of work previously performed is such that any member of the verification team's credibility and lack of bias should not be under question.

(viii) A list of names of the verification team members that will perform verification services for the owner or operator and a description of any instances of personal or family relationships with management or employees of the owner or operator that potentially represent a conflict of interest; and,

(ix) Identification of any other circumstances or relevant information known to the verification body or owner or operator that could result in a conflict of interest, or any situation where the appearance of impartiality could undermine confidence in the verification body's ability to assess the reported emissions.

(2) The potential for a conflict of interest shall be deemed to be high where:

(A) The verification body and owner or operator share any management staff or board of directors membership, or any of the management staff of the owner or operator have been employed by the verification body, or vice versa, within the previous three years; or

(B) Within the previous three years, any member of the verification body, any entity related to the verification body, and the verification team has provided to the owner or operator any of the following non-verification services:

(i) Designing, developing, implementing, or maintaining an inventory or information or data management system for facility greenhouse gases, or, where applicable, electricity transactions;

(ii) Developing greenhouse gas emission factors or other greenhouse gas-related engineering analysis;

(iii) Designing energy efficiency, renewable power, or other projects which explicitly identify greenhouse gas reductions as a benefit;

(iv) Preparing or producing greenhouse gas-related manuals, handbooks, or procedures specifically for the reporting facility;

(v) Appraisal services of carbon or greenhouse gas liabilities or assets;

(vi) Brokering in, advising on, or assisting in any way in carbon or greenhouse gas-related markets;

(vii) Managing any health, environment or safety functions which explicitly identify greenhouse gas reductions as a benefit;

(viii) Bookkeeping or other services related to the accounting records or financial statements, unless those services limited to financial auditing;

(ix) Any service related to information systems, unless those systems will not be part of the verification process and excluding third-party auditor or registration services;

(x) Appraisal and valuation services, both tangible and intangible related to GHG emissions or reductions inventories;

(xi) Fairness opinions and contribution-in-kind reports in which the verification body has provided its opinion on the adequacy of consideration in a transaction, unless the resulting services shall not be part of the verification process;

(xii) Any actuarially oriented advisory service involving the determination of amounts recorded in financial statements and related accounts;

(xiii) Any internal audit service as provided under section (GHG plan) that has been outsourced by the operator that relates to the owner's or operator's internal accounting controls, financial systems or financial statements, unless no consulting or advice was provided as part of the audit;

(xiv) Acting as a broker-dealer (registered or unregistered), promoter or underwriter on behalf of the owner or operator;

(xv) Any legal services related to GHG emissions;

(xvi) Expert services to the owner or operator or his or her legal representative for the purpose of advocating his or her's interests in litigation or in a regulatory or administrative proceeding or investigation involving GHG emissions, unless providing factual testimony.

(C) The potential for a conflict of interest shall also be deemed to be high where any staff member of the verification body, entity related to the verification body, or the verification team has provided verification services for the owner or operator for six consecutive years or within three years of the termination of a previous GHG verification contract with the owner or operator. If a verification body or verification team member has been providing verification services for a [operator/owner] in a greenhouse gas reporting or reductions program other than WCI within the past three years, those years of services will count towards the six consecutive year limit in the WCI.

(D) The potential for a conflict of interest shall be deemed high where the Independent Peer Reviewer for the verification team has provided verification or non-verification services for the operator during the current reporting year.

(3) The potential for a conflict of interest shall be deemed to be low where no potential for a conflict of interest is found under section WCI.8(g) *[may need to be updated, depending upon final version of WCI.8)* and any non-verification services provided by all members of the verification body and the verification team to the owner or operator within the last three years are valued at less than five percent of the verification body's revenue.

****

WCI.8 OPTIONAL GUIDANCE

Note: This text is supporting material and not intended as part of the essential requirements.

Collection of Evidence

The verification body shall obtain sufficient and appropriate evidence to be able to draw reasonable conclusions on which to base the verification statement. The verification body obtains evidence by performing verification procedures. Verification procedures are classified as:

- **Computation (or Recalculation)** is the checking of mathematical accuracy of documents or records
- **Observation** of a process or procedure
- **Confirmation** is obtaining representations from a third party
- **Enquiry** is seeking information from a knowledgeable person
- **Inspection** of Records or Documents/Assets
- **Re-performance** is the verifiers independent execution of procedures or controls
- **Analysis** is the evaluation of information made by studying the plausible relationships among different types of data

Some or all of these techniques can be used to obtain sufficient and appropriate evidence. Site visits are used to obtain evidence that is readily available at that location.

Western Climate Initiative

Final Essential Requirements of Mandatory Reporting

Amended for Harmonization of Reporting in Canadian Jurisdictions

December 17, 2010

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1 Introduction

This document and the attachments provide an overview of the amendments made to WCI Final Essential Requirements of Mandatory Reporting for harmonization of reporting for Canadian jurisdictions.

On July 15, 2009, the WCI partners published the Final Essential Requirements for Mandatory Reporting (the “ERs”) to be implemented by the WCI Partner jurisdictions. On September 22, 2009, U.S. EPA adopted its final Mandatory Greenhouse Gas Reporting Rule (the “EPA rule”), implementing its Greenhouse Gas (GHG) Reporting Program. Many U.S. facilities in the WCI region will be subject to both reporting programs.

The WCI partners were concerned that the existence of two different reporting systems in a WCI state could result in the imposition of duplicative or conflicting reporting obligations on facilities subject to both programs. The Partners therefore directed the WCI Reporting Committee to develop amended ERs that are harmonized with the EPA rule.

On November 12, 2010, the WCI published the “Harmonization of Essential Requirements for Mandatory Reporting in U.S. Jurisdictions with EPA Mandatory Reporting Rule” (U.S. ER’s), WCI’s approach for harmonizing the ERs and the EPA rule in U.S. jurisdictions. It takes the form of a markup of the EPA rule showing the changes to the EPA program that are needed to support a cap-and-trade program. WCI jurisdictions in the U.S., particularly those implementing a cap-and-trade program, may implement the harmonized U.S. ERs by adopting a rule that incorporates the EPA rule by reference with the changes shown in the markup.

To ensure that the amended ERs are provided that are methodologically consistent with the harmonized U.S. ERs but appropriate for use in the Canadian partner jurisdictions, the WCI released two packages to stakeholders. The first draft for stakeholder comment “Harmonization of Essential Requirements for Mandatory Reporting in Canadian Jurisdictions with the WCI Essential Requirements for Mandatory Reporting and the EPA Greenhouse Gas Reporting Program“ covering most reporting sectors was released on September 8, 2010 and the second draft covering the remainder was released on October 29, 2010.

This “Final Essential Requirements for Mandatory Reporting – Canadian Harmonization Version” (Canadian ERs) represents WCI’s adoption of the amended quantification methods for use in Canadian Partner jurisdictions for all source categories as modified in WCI.1(a)(1). These methods replace the original ERs in use for 2010 reporting and are designed to be adopted for use by Canadian jurisdictions for 2011 calendar year emissions, reported in 2012.

To ensure that a complete package of quantification methods can be referenced, the ER for imported electricity is re-published within the amended ERs. Several modifications to the general provisions in the ERs made in the November 12, 2010 U.S. harmonization document are also incorporated into the Canadian version. The format of the harmonized Canadian ERs follows the original WCI format, a format that had already been used in guidance documents and regulations in several Canadian WCI jurisdictions.

Since the U.S. EPA only finalized quantification methods for Petroleum and Natural Gas Systems (Subpart W) on November 8, 2010 it has been possible to incorporate only a subset of elements, some addressing stakeholder comments, into the WCI Canadian ERs. In 2011, the WCI will develop cap and trade quality requirements for sources covered by Subpart W for use in both Canadian and U.S. jurisdictions.

Further evaluation with respect to "reporting only" sources within the scope of the methods in ERs, particularly for specific oil and gas sources will be occurring as will analysis and incorporation of further reporting implementation and compliance requirements for cap and trade system.

This document and the attachments provide an overview of the amendments made to WCI Final Essential Requirements of Mandatory Reporting for harmonization of reporting for Canadian jurisdictions. A summary of the comments received and WCI's response is set forth in section 5. Changes made to the general provisions of the harmonized ERs are listed in section 6 below.

2 Harmonization Principles

2.1 For U.S. Jurisdictions

The harmonization principles for U.S. jurisdictions are outlined in the "Harmonization of Essential Requirements for Mandatory Reporting in U.S. Jurisdictions with EPA Mandatory Reporting Rule[1].

2.2 For Canadian Jurisdictions

In developing harmonized ERs for use in Canadian Partner jurisdictions that modify the existing ERs, the WCI Reporting Committee adhered to the following principles:

1. A Canadian facility should apply the same functions, equations, sampling protocols and measurement criteria as U.S. facilities subject to the U.S. version of the harmonized ERs. This means that the harmonized ERs will achieve the same level of reporting accuracy for Canadian and U.S. facilities, but the U.S. version may require more data elements to be reported to harmonize with the EPA rule.

[1] http://www.westernclimateinitiative.org/news-and-updates/125-harmonization-of-essential-requirements-for-mandatory-reporting-in-us-jurisdictions-with-epa-mandatory-reporting-rule

2. The quantification methods included in the harmonized ERs must remain sufficiently reliable and accurate to be employed in a GHG cap-and-trade program.

3. The WCI reporting system must remain suitable for use in Canadian Partner jurisdictions. For example, it must allow reporting in metric as well as English units and must where necessary include Canada-specific emission factors.

4. The harmonized ERs should facilitate harmonization with Canadian federal reporting. Some Canadian Partner jurisdictions are working with Environment Canada to develop a one-window reporting tool for provincial and national GHG reporting requirements.

WCI intends to follow the same principles with regard to future additions or amendments to the EPA rule, such as the recently finalized Subpart W for the oil and gas industry, and the recently proposed revisions to Subpart A (general provisions) and several source category subparts.[2] WCI will review each proposed revision to assess its suitability for cap-and-trade before incorporating it into the harmonized ERs.

3 Harmonization Approach

3.1 For U.S. Jurisdictions

The harmonization approach for U.S. jurisdictions is outlined in the "Harmonization of Essential Requirements for Mandatory Reporting in U.S. Jurisdictions with EPA Mandatory Reporting Rule"[3].

3.2 For Canadian Jurisdictions

For the Canadian jurisdictions, the key requirement is that the WCI reporting system as a whole require the use of comparable methodologies and produce comparable results for facilities of the same type, so that a "tonne is a tonne" in both the U.S. and Canada. For Canadian jurisdictions it is not nearly as important to avoid small differences between the ERs and the EPA rule as it is for the U.S. jurisdictions, where such differences could create a risk of inadvertent non-compliance.

Canadian Partners have invested substantial resources in developing regulations to implement the existing WCI ERs. In addition, the provinces face technical and legal issues with the

[2] Pre-publication version posted on July 20, 2010 at: http://www.epa.gov/climatechange/emissions/technical-corrections.html#revisions
[3] http://www.westernclimateinitiative.org/news-and-updates/125-harmonization-of-essential-requirements-for-mandatory-reporting-in-us-jurisdictions-with-epa-mandatory-reporting-rule

incorporation by reference of the EPA rule that do not apply to the states. Therefore, in this document, the WCI finalizes amendments to the existing WCI ERs to assure that they conform in substance with the U.S. version of the harmonized ERs, as well as facilitating harmonization with Environment Canada and the use of Canada-specific reporting metrics and factors.

3.3 Verification

Consistent with the Design Recommendations for the WCI Regional Cap-and-Trade Program, the harmonized U.S. and Canadian ERs require third party verification of emission reports by entities and facilities included in the cap. Minor revisions to the verification rule, WCI.8, are included in Section 6 of this document as an amendment to the Canadian ERs.

The amount of data to be reported for Canadian jurisdictions has been reduced to reflect third party verification requirements for emissions reports at a certain threshold of emissions as compared to that which is required to be reported to the EPA for their internal verification.

3.4 Missing Data Procedures

The EPA rule includes procedures in each subpart for replacing missing data resulting from monitoring failures. With the exception of methodologies for facilities subject to 40 CFR Part 75 (the acid rain program), these missing data procedures do not appear to be sufficiently rigorous to support a cap-and-trade system. There is no limitation on the amount of data that may be missing, and replacement methods appear to be both inadequate (for example, many use only one or two available data points) and inequitable (for example, Part 75 power plants have to apply punitive methods, while other facilities do not).

In order to move forward with a harmonization proposal in time to allow implementation for the 2011 reporting year, the Canadian harmonized ERs incorporate the EPA missing data procedures. Before implementation of the cap-and-trade program, however, the WCI intends to revisit this issue. The WCI is investigating how the EPA missing data procedures can be modified to be more consistent with the needs of a cap-and-trade program while adhering to the harmonization principles and intends to propose and implement the necessary modifications in time for the 2012 reporting year.

As a partial measure to address the possibility of gaming, the harmonized ERs include a provision making it clear that the use of a missing data procedure does not excuse a facility's failure to follow the monitoring requirements of the rule.

4 Summary of Changes to the Original WCI ERs

The following table summarizes the changes to the ER's general provisions that the WCI is finalizing for implementation in Canadian jurisdictions. The specific language for the amendments to the general provisions is made in Section 6 of this document. The specific language for the changes to the quantification methods is set forth in the republished Final Essential Requirements of Mandatory Reporting – Amended for Canadian Harmonization.

Section	Change to WCI Rule	Rationale
WCI.1(a)(1)	Revised and updated source category list	Reflects current state of WCI quantification methods.
WCI.1(g)	Creates preliminary list of "reporting only" sources for identification of data that will be reported for informational purposes only	Provides indication of which source categories and/or specific emission sources are considered reporting only by the WCI.
WCI.2(b)(2)(B)	Post-2011 verification date established as September 1.	Clarifies verification date for WCI jurisdictions.
WCI.2(h)	Added a method for calculating weighted averages.	This subsection provides clarity on how to determine averages from samples, and produces more accurate emissions estimates.
WCI.4(b)	Modifies requirement to submit records to within 20 days of a request from a WCI jurisdiction.	Modified from 10-day response time in existing WCI.4(b) in response to stakeholder comments.
WCI.5(c)	Added section make it clear the missing data procedures included in the harmonized ERs do not excuse facilities from possible enforcement action for failure to conduct the monitoring required by the rule.	See section 3.4.

Section	Change to WCI Rule	Rationale
WCI.8(a)(4.1)	Added new section to ensure that "reporting only" sources will not be counted towards the threshold for verification. Consequential change required to section WCI.8(a)(1)	Not all quantification methods specified by the harmonized ERs are suitable for a cap-and-trade system. The "reporting only" label provides notice to stakeholders on WCI's current view on which emissions should not be subject to the cap-and-trade program.
WCI.8(b)(4)(C)	Modification of language for oversight and accreditation of verification bodies	Clarifies language on verification body oversight and accreditation
WCI.8(p)(1) and (2)	Modification of requirements for a verification statement	Clarifies verification statement requirements

5 Stakeholder Comments and Response

5.1 General Comments

Twenty separate stakeholder responses were received on the Canadian harmonization proposals. The majority of these comments were from companies active in the oil and gas industry and addressed specific items in the general stationary combustion, petroleum and natural gas systems, and natural gas transmission and distribution quantification methods. Several comments were also received from the forest products industry.

Each comment was reviewed and modifications made to the quantification methods where appropriate. Comments addressing policy items were noted and will be discussed by the Reporting Committee. Several commenters indicated the need to declare further sources as "reporting only" (as discussed in the table in Section 4, above).

Since the amended package was built off of the "Harmonization of Essential Requirements for Mandatory Reporting in U.S. Jurisdictions with EPA Mandatory Reporting Rule"[4], the response to stakeholder comments in that document can be referenced as a preliminary way of understanding the modifications that were made.

6 Modifications to the General Provisions

The following is a list of the modifications to the general provisions (WCI.1 to WCI.9) as published by the WCI on July 15, 2009 that are being made in the "Final Essential Requirements of Mandatory Reporting – Canadian Harmonization version", published on December 17, 2010.

WCI.1(a)(1) is replaced by the following:
(1) Any facility that emits 10,000 metric tons CO2e or more per year in combined emissions from one or more of the source categories listed in this paragraph in any calendar year starting in 2010.

Adipic acid manufacturing [WCI.050]
Aluminum manufacturing [WCI.070]
Ammonia manufacturing [WCI.080]
Carbon dioxide transfer recipients [still being assessed]
Cement manufacturing [WCI.090]
Coal storage [WCI.100]
Copper and nickel [WCI.260]
Electricity generation [WCI.040]
Electricity transmission [WCI.230]
Electronics manufacturing [WCI.110]
Ferroalloy production [WCI.270]
General stationary fuel combustion [WCI.020]
Glass Production [WCI.140] HCFC-22 production [WCI.120]
Hydrogen production [WCI.130]
Industrial wastewater [WCI.203(g)]
Iron and steel manufacturing [WCI.150]
Lead production [WCI.160]
Lime manufacturing [WCI.170]
Magnesium production [WCI.290]
Miscellaneous uses of carbonates [WCI.180]
Natural gas transmission and distribution systems [WCI.350]
Nitric acid manufacturing [WCI.310]
Mobile equipment [WCI.280]

[4] http://www.westernclimateinitiative.org/news-and-updates/125-harmonization-of-essential-requirements-for-mandatory-reporting-in-us-jurisdictions-with-epa-mandatory-reporting-rule

Petroleum and natural gas systems [WCI.360]
Petrochemical production [WCI.300]
Petroleum refineries [WCI.200]
Phosphoric acid production [WCI.340]
Pulp and paper manufacturing [WCI.210]
Refinery fuel gas [WCI.030]
Soda ash manufacturing [WCI.220]
Underground coal mines [WCI.250]
Zinc production [WCI.240]

WCI.1(g) is added:

1(g): The following emissions data shall be submitted for information only and may not be subject to cap-and-trade requirements[5]:

(1) Data submitted by a source category designated as "reporting only." This provision does not apply to emissions from general stationary combustion at a source in a "reporting only" category.
(2) Emissions data calculated with a methodology identified as "reporting only."
(3) Reporting only sources are identified as the following:
Carbon dioxide from biomass determined to be carbon neutral by the jurisdiction
Fugitive HFC emissions in electrical generation
Coal storage
Asphalt blowing at refineries
Equipment leaks at refineries
Storage tanks at refineries
Industrial wastewater treatment
Product loading at refineries
Mobile equipment

WCI.2(b)(2)(B) is modified to read:

"For reporting years 2012 and later*, ~~[date to be determined]~~* by September 1 of the year following the reporting year.'

WCI.2(h) is added:

(j) The following shall apply unless in conflict with any other provision in the quantification methods
(1) Samples must be spaced apart as evenly as possible over time, taking into account the operating schedule of the relevant unit or facility.
(2) A weighted average of the values derived from the samples must be calculated and reported by using the following formula:

[5] The identification of data as "reporting only" may be subject to review before the adoption of a cap-and-trade program. On adoption the jurisdiction will likely substitute a citation to the rules implementing the program for the words "cap-and-trade requirements." Further analysis of reporting only sources is occurring, particularly for specific emission sources within the Petroleum and Natural Gas Systems and Natural Gas Transmission and Distribution quantification methods.

$$V_E = \frac{\sum_{j=1}^{n}(V_j \times M_j)}{\sum_{j=1}^{n} M_j}$$

Where:

VE = The value of the parameter to be reported under the quantification method for period E.

j = Each period during period E for which a sample is required by [jurisdiction] under the applicable quantification method

n = The number of periods j in period E.

Vj = The value of the sample for period j.

Mj = The mass of the sampled material processed or otherwise used by the relevant unit or facility in period j.

(3) You must keep records of the date and result for each sample and mass measurement used in the equation in subsection (2) and of the calculation of each weighted average included in your report must be kept.

WCI.4(b) is modified to read:

(b) Upon request by *[jurisdiction],* the operator shall provide within ~~10~~ 20 ~~working~~ days all documents and data used to develop an emissions data report.

WCI.5(c) is added

(c) Notwithstanding the missing data procedures in the quantification methods the failure to conduct monitoring in accordance with these methods shall constitute a violation.

WCI.8(a)(1) is modified to read:

(1) Except as provided in WCI.8(a)(2) through (~~4~~4.1) owners or operators [Each jurisdiction will select the specific terminology for the regulated persons in accordance with their customary rule-writing practices] are required to obtain annual verification for a facility that emits 25,000 metric tons CO2e or more per year in combined emissions from one or more of the source categories listed in WCI.1 in any calendar year starting on or after 2010.

WCI.8(a)(4.1) is added:

"Emissions designated "reporting only" in this article shall be excluded from the determination regarding verification applicability.

WCI.8(b)(4)(C) Accreditation Requirements for Verification Bodies is revised to read:

(1) The accreditation requirements specified in this subsection shall apply to all verification bodies that wish to provide verification services under this rule.

(2) A verification body is qualified to conduct verification services for the WCI in [the jurisdiction] if

(A) it has demonstrated knowledge of [the WCI jurisdiction] reporting requirements; and

(B) it has the characteristics and capabilities deemed necessary by [the jurisdiction] to perform verification services; and

(C) it is accredited to ISO 14065 through

(i) a program developed under ISO 17011 by an accreditation body that is a member of the International Accreditation Forum.; or

(ii) a program developed or authorized [the jurisdiction] under [the jurisdiction's] required statutory or regulatory process that is at least as stringent as the process defined in ISO 17011.

[Note the details of the WCI's specific accreditation process for verification bodies ~~(which~~ has yet to be developed~~) will be consistent with ISO 14065 through an accreditation program that will developed under ISO 17011 and will include demonstrated knowledge of the WCI reporting requirements.~~ The WCI will explore additional accreditation requirements and/or other criteria for individual lead verifiers, general verifiers, and/or sector specialists.]

WCI.8(p)(1) and (2) are revised as follows:

(p) Completion of verification services shall include:

(1) Verification Statement. Upon completion of the verification services required by WCI.8, the verification body shall prepare either a positive or adverse verification statement, for each emissions data report, based on its findings during the verification process. The verification body shall provide the verification statement(s) to the reporter and to the AVA [alternatively, this could be the reporter's responsibility to submit the statement to the AVA], according to the schedule specified in section WCI.2(b). Before each statement is completed, the verification body shall have the verification services and findings of the verification team independently reviewed and approved by an Independent Peer Reviewer.

~~(1) Verification Statement. Upon completion of the verification services required by WCI.8, the verification body shall complete a verification statement for each emissions data report, and provide that statement to the owner or operator and [the jurisdiction or other body] according to the schedule specified in section WCI.2(b). Before that statement is completed, the verification body shall have the verification services and findings of the verification team independently reviewed and approved by an Independent Peer Reviewer.~~

~~(2) The verification body shall provide either a positive or adverse verification statement to the reporter and to the AVA *[alternatively, this could be the reporter's responsibility to submit the statement to the AVA]* based on its findings during the verification process.~~

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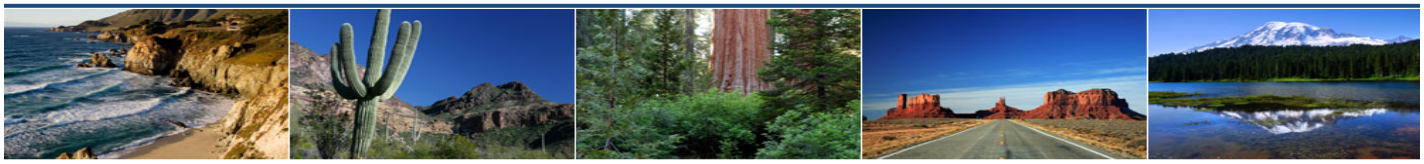

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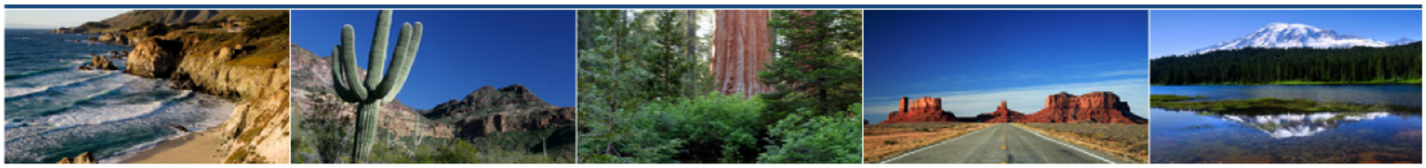

GENERAL PROVISIONS

§ WCI.0 through § WCI.10

EMISSIONS QUANTIFICATION, AND SAMPLING, ANALYSIS AND MEASUREMENT

§ WCI.20 General Stationary Combustion
§ WCI.30 Refinery Fuel Gas Combustion
§ WCI.40 Electricity Generation
§ WCI.50 Adipic Acid Manufacturing
§ WCI.60 Imported Electricity
§ WCI.70 Primary Aluminum Production
§ WCI.80 Ammonia Manufacturing
§ WCI.90 Cement Manufacturing
§ WCI.100 Coal Storage
§ WCI.110 Electronics Manufacturing
§ WCI.120 HCFC-22 Production and HFC-23 Destruction
§ WCI.130 Hydrogen Production
§ WCI.140 Glass Production
§ WCI.150 Iron and Steel Manufacturing
§ WCI.160 Lead Production
§ WCI.170 Lime Manufacturing
§ WCI.180 Carbonates Use
§ WCI.200 Petroleum Refineries
§ WCI.210 Pulp and Paper Manufacturing
§ WCI.220 Soda Ash Manufacturing
§ WCI.230 Electricity Transmission (and Emissions from Electrical Equipment in Electricity Generation)
§ WCI.240 Zinc Production

§ WCI.250 Underground Coal Mines
§ WCI.260 Nickel and Copper Metal Production
§ WCI.270 Ferroalloy Production
§ WCI.280 Mobile Equipment at Facilities
§ WCI.290 Magnesium Production
§ WCI.300 Petrochemical Manufacturing
§ WCI.310 Nitric Acid Manufacturing
§ WCI.340 Phosphoric Acid Production
§ WCI.350 Natural Gas Transmission and Distribution
§ WCI.360 Petroleum and Natural Gas Production and Natural Gas Processing

§ WCI.0 through § WCI.10

Refer to the Essential Requirements for Reporting published July 15, 2009, with the following changes:

WCI.1(a)(1) is replaced by the following:
(1) Any facility that emits 10,000 metric tons CO2e or more per year in combined emissions from one or more of the source categories listed in this paragraph in any calendar year starting in 2010.

Adipic acid manufacturing [WCI.050]
Aluminum manufacturing [WCI.070]
Ammonia manufacturing [WCI.080]
Carbon dioxide transfer recipients [still being assessed]
Cement manufacturing [WCI.090]
Coal storage [WCI.100]
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Electricity generation [WCI.040]
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Ferroalloy production [WCI.270]
General stationary fuel combustion [WCI.020]
Glass Production [WCI.140] HCFC-22 production [WCI.120]
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Iron and steel manufacturing [WCI.150]
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Soda ash manufacturing [WCI.220]

Underground coal mines [WCI.250]
Zinc production [WCI.240]

WCI.1(g) is added:

1(g): The following emissions data shall be submitted for information only and may not be subject to cap-and-trade requirements[1]:

(1) Data submitted by a source category designated as "reporting only." This provision does not apply to emissions from general stationary combustion at a source in a "reporting only" category.

(2) Emissions data calculated with a methodology identified as "reporting only."

(3) Reporting only sources are identified as the following:

Carbon dioxide from biomass determined to be carbon neutral by the jurisdiction
Fugitive HFC emissions in electrical generation
Coal storage
Asphalt blowing at refineries
Equipment leaks at refineries
Storage tanks at refineries
Industrial wastewater treatment
Product loading at refineries
Mobile equipment

WCI.2(b)(2)(B) is modified to read:
"For reporting years 2012 and later, ~~*[date to be determined]*~~ by September 1 of the year following the reporting year.'

WCI.2(h) is added:

(j) The following shall apply unless in conflict with any other provision in the quantification methods

(1) Samples must be spaced apart as evenly as possible over time, taking into account the operating schedule of the relevant unit or facility.

(2) A weighted average of the values derived from the samples must be calculated and reported by using the following formula:

$$V_E = \frac{\sum_{j=1}^{n}(V_j \times M_j)}{\sum_{j=1}^{n} M_j}$$

Where:

[1] The identification of data as "reporting only" may be subject to possible revision before the adoption of a cap-and-trade program. On adoption the jurisdiction will likely substitute a citation to the rules implementing the program for the words "cap-and-trade requirements." Further analysis of reporting only sources is occurring, particularly for specific emission sources within the Petroleum and Natural Gas Systems and Natural Gas Transmission and Distribution quantification methods.

VE = The value of the parameter to be reported under the quantification method for period E.
j = Each period during period E for which a sample is required by [jurisdiction] under the applicable quantification method
n = The number of periods j in period E.
Vj = The value of the sample for period j.
Mj = The mass of the sampled material processed or otherwise used by the relevant unit or facility in period j.

(3) You must keep records of the date and result for each sample and mass measurement used in the equation in subsection (2) and of the calculation of each weighted average included in your report must be kept.

WCI.4(b) is modified to read:

(b) Upon request by *[jurisdiction],* the operator shall provide within ~~10~~ 20 ~~working~~ days all documents and data used to develop an emissions data report.

WCI.5(c) is added

(c) Notwithstanding the missing data procedures in the quantification methods the failure to conduct monitoring in accordance with these methods shall constitute a violation.

WCI.8(a)(1) is modified to read:

(1) Except as provided in WCI.8(a)(2) through (44.1) owners or operators [Each jurisdiction will select the specific terminology for the regulated persons in accordance with their customary rule-writing practices] are required to obtain annual verification for a facility that emits 25,000 metric tons CO2e or more per year in combined emissions from one or more of the source categories listed in WCI.1 in any calendar year starting on or after 2010.

WCI.8(a)(4.1) is added:

"Emissions designated "reporting only" in this article shall be excluded from the determination regarding verification applicability.

WCI.8(b)(4)(C) Accreditation Requirements for Verification Bodies is revised to read:

(1) The accreditation requirements specified in this subsection shall apply to all verification bodies that wish to provide verification services under this rule.

(2) A verification body is qualified to conduct verification services for the WCI in [the jurisdiction] if

(A) it has demonstrated knowledge of [the WCI jurisdiction] reporting requirements; and
(B) it has the characteristics and capabilities deemed necessary by [the jurisdiction] to perform verification services; and
(C) it is accredited to ISO 14065 through
  (i) a program developed under ISO 17011 by an accreditation body that is a member of the International Accreditation Forum.; or
  (ii) a program developed or authorized [the jurisdiction] under [the jurisdiction's] required statutory or regulatory process that is at least as stringent as the process defined in ISO 17011.

[Note the details of the WCI's specific accreditation process for verification bodies ~~(which~~ has yet to be developed~~) will be consistent with ISO 14065 through an accreditation program that will developed under ISO 17011 and will include demonstrated knowledge of the WCI reporting requirements.~~ The WCI will explore additional accreditation requirements and/or other criteria for individual lead verifiers, general verifiers, and/or sector specialists.]

WCI.8(p)(1) and (2) are revised as follows:

(p) Completion of verification services shall include:

(1) Verification Statement. Upon completion of the verification services required by WCI.8, the verification body shall prepare either a positive or adverse verification statement, for each emissions data report, based on its findings during the verification process. The verification body shall provide the verification statement(s) to the reporter and to the AVA [alternatively, this could be the reporter's responsibility to submit the statement to the AVA], according to the schedule specified in section WCI.2(b). Before each statement is completed, the verification body shall have the verification services and findings of the verification team independently reviewed and approved by an Independent Peer Reviewer.

~~(1) Verification Statement. Upon completion of the verification services required by WCI.8, the verification body shall complete a verification statement for each emissions data report, and provide that statement to the owner or operator and [the jurisdiction or other body] according to the schedule specified in section WCI.2(b). Before that statement is completed, the verification body shall have the verification services and findings of the verification team independently reviewed and approved by an Independent Peer Reviewer.~~

~~(2) The verification body shall provide either a positive or adverse verification statement to the reporter and to the AVA *[alternatively, this could be the reporter's responsibility to submit the statement to the AVA]* based on its findings during the verification process.~~

§ WCI.20 GENERAL STATIONARY COMBUSTION

§ WCI.21 Source Category Definition

Stationary fuel combustion sources are devices that combust solid, liquid, or gaseous fuel generally for the purpose of producing electricity, generating steam or providing useful heat or energy for industrial, commercial, or institutional use; or reducing the volume of waste by removing combustible matter. Stationary fuel combustion sources are boilers, simple and combined cycle combustion turbines, engines, incinerators (including units that combust hazardous waste), process heaters, and any other stationary combustion device that is not specifically addressed under the methods for another source category. This source category does not include portable equipment, emergency generators, and emergency equipment (including emergency flares).

§ WCI.22 Greenhouse Gas Reporting Requirements

The emissions data report shall include the following information at the facility level:

(a) Annual greenhouse gas emissions in tonnes, reported as follows:

- (1) Total CO_2 emissions for fossil fuels, reported by fuel type.
- (2) Total CO_2 emissions for biomass, reported by fuel type.
- (3) Total CH_4 emissions, reported by fuel type.
- (4) Total N_2O emissions, reported by fuel type.

(b) Annual fuel consumption:

- (1) For gases, report in units of standard cubic meters.
- (2) For liquids, report in units of kilolitres.
- (3) For non-biomass solids, report in units of tonnes.
- (4) For biomass solid fuels, report in units of bone dry tonnes.

(c) Annual weighted average carbon content of each fuel, if used to compute CO_2 emissions.

(d) Annual weighted average high heat value of each fuel, if used to compute CO_2 emissions.

(e) Annual steam generation in kilograms, for units that burn biomass fuels or municipal solid waste and generate steam.

§ WCI.23 Calculation of CO_2 Emissions

For each fuel, calculate CO_2 mass emissions using one of the four calculation methodologies specified in this section, subject to the restrictions in WCI.23(e). If a fuel or fuels is not listed in all of Tables 20-1 through 20-7; or in Table C-1 or C-2 of U.S. EPA 40 CFR Part 98, Subpart C, then emissions from such fuels do not need to be reported so long as total emissions of these fuels do not exceed 0.5% of total facility emissions. If emissions from the sum of these fuels exceeds 0.5% of total facility emissions, then the requirements of WCI.023 stand so long as only a maximum of 0.5% of total facility emissions from unlisted fuels is not reported.

(a) Calculation Methodology 1. Calculate the annual CO_2 mass emissions for each type of fuel by substituting a fuel-specific default CO_2 emission factor, a default high heat value, and the annual fuel consumption into Equation 20-1:

$$CO_2 = Fuel \times HHV \times EF \times 0.001$$ **Equation 20-1**

Where:

CO_2 = Annual CO_2 mass emissions for the specific fuel type (tonnes).

Fuel = Mass or volume of fuel combusted per year (express mass in tonnes for solid fuel, volume in standard cubic meters for gaseous fuel, or volume in kilolitres for liquid fuel).

HHV = Default high heat value of the fuel, from Table 20-1 and 20-1a (GJ per tonne for solid fuel, GJ per kilolitre for liquid fuel, or GJ per cubic meter for gaseous fuel).

EF = Fuel-specific default CO_2 emission factor, from Tables 20-1a, 20-2, 20-3, 20-5, or 20-7, as applicable (kg CO_2/GJ).

(HHV x EF) instead of using separate HHV and EF values, you can replace the two values by using default emission factors from Tables 20-2, 20-3, or 20-5, as applicable (in units of kg CO_2 per tonne for solid fuel, kg CO_2 per kilolitre for liquid fuel, or kg CO_2 per cubic meter for gaseous fuel)

0.001 = Conversion factor from kilograms to tonnes.

(b) Calculation Methodology 2. Calculate the annual CO_2 mass emissions using a default fuel-specific CO_2 emission factor, a high heat value provided by the supplier or measured by the operator, using Equation 20-2, except for emissions from the combustion of biomass fuels, for which the operator may instead elect to use the method shown in Equation 20-3. For use of Calculation Methodology 2 for municipal solid waste, Equation 20-3 must be used.

(1) For any type of fuel for which an emission factor is provided in Tables 20-1a, 20-2, 20-3, 20-5, or 20-7, as applicable, except biomass fuels when the operator elects to use the method in WCI.23(b)(2), use Equation 20-2:

$$CO_2 = \sum_{p=1}^{n} Fuel_p \times HHV_p \times EF \times 0.001$$ **Equation 20-2**

Where:

CO_2 = Annual CO_2 mass emissions for a specific fuel type (tonnes).

n = Number of required heat content measurements for the year as specified in WCI.25.

$Fuel_p$ = Mass or volume of the fuel combusted during the measurement period *p* (express mass in tonnes for solid fuel, volume in standard cubic meters for gaseous fuel, or volume in kilolitres for liquid fuel).

HHV_p	=	High heat value of the fuel for the measurement period *p* (GJ per tonne for solid fuel, GJ per kilolitre for liquid fuel, or GJ per cubic meter for gaseous fuel).
EF	=	Fuel-specific default CO_2 emission factor, from Tables 20-1a, 20-2, 20-3, 20-5, or 20-7, as applicable (kg CO_2/GJ).
0.001	=	Conversion factor from kilograms to tonnes.

(2) For units that combust municipal solid waste and that produce steam, use Equation 20-3. Equation 20-3 of this section may also be used for any solid biomass fuel listed in Table 20-2 of this subpart provided that steam is generated by the unit.

$$CO_2 = Steam \times B \times EF \times 0.001$$ **Equation 20-3**

Where:

CO_2	=	Annual CO_2 mass emissions from biomass solid fuel or municipal solid waste combustion (tonnes).
Steam	=	Total mass of steam generated by biomass solid fuel or municipal solid waste combustion during the reporting year (tonnes steam).
B	=	Ratio of the boiler's design rated heat input capacity to its design rated steam output capacity (GJ/tonne steam).
EF	=	Default emission factor for biomass solid fuel or municipal solid waste, from Table 20-2 or Table 20-7, as applicable (kg CO_2/GJ).[1]
0.001	=	Conversion factor from kilograms to tonnes.

(c) Calculation Methodology 3. Calculate the annual CO_2 mass emissions for each fuel by using measurements of fuel carbon content or molar fraction (for gaseous fuels only), conducted by the operator or provided by the fuel supplier, and the quantity of fuel combusted.

(1) For a solid fuel, except for the combustion of municipal solid waste, use Equation 20-4 of this section:

$$CO_2 = \sum_{i=1}^{n} Fuel_i \times CC_i \times 3.664$$ **Equation 20-4**

Where:

CO_2	=	Annual CO_2 mass emissions from the combustion of the specific solid fuel (tonnes).
n	=	Number of carbon content determinations for the year.
$Fuel_i$	=	Mass of the solid fuel combusted in measurement period *i* (tonnes).
CC_i	=	Carbon content of the solid fuel, from the fuel analysis results for measurement period *i* (percent by weight, expressed as a decimal fraction, e.g., 95% = 0.95).
3.664	=	Ratio of molecular weights, CO_2 to carbon.

(2) For biomass fuels, in units that produce steam, use either Equation 20-4 above or Equation 20-5; for municipal solid waste combustion in units that produce steam, use Equation 20-5:

[1] The ER required development of a site-specific emission factor for MSW. For harmonization with Part 98, Subpart C, this requirement was deleted. However, jurisdictions may allow or require testing to develop a site-specific emission factor as an alternative to the default emission factors in Subpart C, Table C-1.

$$CO_2 = Steam \times B \times EF \times 0.001$$ **Equation 20-5**

Where:

CO_2	=	Annual CO_2 mass emissions from biomass solid fuel or municipal solid waste combustion (tonnes).
Steam	=	Total mass of steam generated by biomass solid fuel or municipal solid waste combustion during the reporting year (tonnes steam).
B	=	Ratio of the boiler's design rated heat input capacity to its design rated steam output capacity (GJ/tonne steam).
EF	=	Default emission factor for biomass solid fuel or municipal solid waste, from Table 20-2 or 20-7, as applicable (kg CO_2/GJ), adjusted no less often than every third year as provided in WCI.25(a)(7)(B).
0.001	=	Conversion factor from kilograms to tonnes.

(3) For a liquid fuel, use Equation 20-6 of this section:

$$CO_2 = \sum_{i=1}^{n} 3.664 \times Fuel_i \times CC_i$$ **Equation 20-6**

Where:

CO_2	=	Annual CO_2 mass emissions from the combustion of the specific liquid fuel (tonnes).
n	=	Number of required carbon content determinations for the year, as specified in WCI.25.
$Fuel_i$	=	Volume of the liquid fuel combusted in measurement period *i* (kilolitres).
CC_i	=	Carbon content of the liquid fuel, from the fuel analysis results for measurement period *i* (tonne C per kilolitre of fuel).
3.664	=	Ratio of molecular weights, CO_2 to carbon.

(4) For a gaseous fuel, use Equation 20-7 of this section:

$$CO_2 = \sum_{i=1}^{n} 3.664 \times Fuel_i \times CC_i \times \frac{MW}{MVC} \times 0.001$$ **Equation 20-7**

Where:

CO_2	=	Annual CO_2 mass emissions from combustion of the specific gaseous fuel (tonnes).
n	=	Number of required carbon content and molecular weight determinations for the year, as specified in WCI.25.
$Fuel_i$	=	Volume of the gaseous fuel combusted in period *i* (a day or month, as applicable) (m^3) at the reference temperature and pressure conditions used by the facility. If a mass flow meter is used, measure the fuel combusted in period *i* in kg and replace the term "MW/MVC" with "1".
CC_i	=	Average carbon content of the gaseous fuel, from the fuel analysis results for the period *i* (day or month, as applicable) (kg C per kg of fuel).

MW	=	Molecular weight of the gaseous fuel, from fuel analysis (kg/kg-mole).
MVC	=	Molar volume conversion at the reference conditions $Fuel_i$ (m^3/kg-mole).
	=	8.3145 * [273.16 + reference temperature in °C]/[reference pressure in kilopascals] (which is 23.64 m^3 per kg-mole for STP of 15 °C and 1 atmosphere).
3.664	=	Ratio of molecular weights, CO_2 to carbon.
0.001	=	Conversion factor from kg to tonnes.

(d) Calculation Methodology 4. Calculate the annual CO_2 mass emissions from all fuels combusted in a unit, by using data from continuous emission monitoring systems (CEMS) as specified in (d)(1) through (d)(7). This methodology requires a CO_2 concentration monitor and a stack gas volumetric flow monitor, except as otherwise provided in paragraph (d)(2) of this section.

(1) For a facility that operates CEMS in response to federal, state, provincial, or local regulation, use CO_2 or O_2 concentrations and flue gas flow measurements to determine hourly CO_2 mass emissions using methodologies provided in *Protocols And Performance Specifications For Continuous Monitoring Of Gaseous Emissions From Thermal Power Generation* (Report EPS 1/PG/7 (Revised) December 2005) (or by other relevant document, if superseded).

(2) The operator shall report CO_2 emissions for the reporting year in tonnes based on the sum of hourly CO_2 mass emissions over the year, converted to tonnes.

(3) An oxygen (O_2) concentration monitor may be used in lieu of a CO_2 concentration monitor in a CEMS installed before January 1, 2012, to determine the hourly CO_2 concentrations, if the effluent gas stream monitored by the CEMS consists solely of combustion products (i.e., no process CO_2 emissions or CO_2 emissions from acid gas control are mixed with the combustion products) and if only the following fuels are combusted in the unit: coal, petroleum coke, oil, natural gas, propane, butane, wood bark, or wood residue.

(A) If the unit combusts waste-derived fuels (as defined in the General Provisions and including municipal solid waste), emissions calculations shall not be based on O_2 concentrations.

(B) If the operator of a facility that combusts biomass fuels uses O_2 concentrations to calculate CO_2 concentrations, annual source testing must demonstrate that calculated CO_2 concentrations, when compared to measured CO_2 concentrations, meet the Relative Accuracy Test Audit (RATA) requirements in *Protocols And Performance Specifications For Continuous Monitoring Of Gaseous Emissions From Thermal Power Generation* (Report EPS 1/PG/7 (Revised) December 2005) (or by other relevant document, if superseded).

(4) If both biomass fuel (including fuels that are partially biomass) and fossil fuel are combusted during the year, determine and report the biogenic CO_2 mass emissions separately, as described in paragraph (f) of this section.

(5) For any units for which CO_2 emissions are reported using CEMS data, the operator is relieved of the requirement to separately report process emissions from combustion emissions for that unit or to report emissions separately for different fossil fuels for that

unit when only fossil fuels are co-fired. In this circumstance, operators shall still report fuel use by fuel type as otherwise required.

(6) If a facility is subject to requirements for continuous monitoring of gaseous emissions, and the operator chooses to add devices to an existing CEMS for the purpose of measuring CO_2 concentrations or flue gas flow, the operator shall select and operate the added devices pursuant to the appropriate requirements for the facility as applicable in Canada.

(7) If a facility does not have a CEMS and the operator chooses to add one in order to measure CO_2 concentrations, the operator shall select and operate the CEMS pursuant to the appropriate requirements or equivalent requirements as applicable in Canada. Operators who add CEMS under this paragraph are subject to the specifications in paragraphs (d)(1) through (d)(5), if applicable.

(e) Use of the Four CO_2 Calculation Methodologies. Use of the four CO_2 emissions calculation methodologies described in paragraphs (a) through (d) of this section is subject to the following requirements and restrictions:

(1) Calculation Methodology 1 (Equation 20-1).

(A) May be used by a facility that is not subject to the verification requirements by regulation for any type of fuel for which a default high heat value (Table 20-1 and 20-1a) and a default CO_2 emission factor (Tables 20-1a, 20-2, 20-3, or 20-5, as applicable) is specified.

(B) May be used for a facility emitting at any level for the combustion of natural gas with a high heat value between 36.3 and 40.98 MJ per cubic meter, and for the combustion of any of the fuels listed in Table 20-1a.

(C) May be used for a facility emitting at any level for the combustion of municipal solid waste in a unit that does not generate steam.

(D) May be used for the combustion of biomass listed in Table 20-2 that is exempted from verification requirements by the jurisdiction, unless it is specifically addressed under the provisions for another source category (e.g., spent pulping liquor from pulp and paper facilities).

(E) May not be used at a facility emitting at any level for a fuel for which you routinely perform fuel sampling and analysis for the fuel high heat value or can obtain the results of fuel sampling and analysis for the fuel high heat value from the fuel supplier at the minimum frequency specified in WCI.25(a), or at a greater frequency. In such cases, Calculation Method 2, 3 or 4 shall be used for those fuels.

(2) Calculation Methodology 2 (Equations 20-2 and 20-3).

(A) May not be used by a facility that is subject to the verification requirements by regulation, except as specified in paragraphs (e)(2)(B) through (E) of this section. Otherwise, Calculation Methodology 2 may be used for any type of fuel combusted for which a default CO_2 emission factor for the fuel is specified in Tables 20-1a, 20-2, 20-3, 20-5, or 20-7, as applicable.

(B) Calculation Methodology 2 may be used for the combustion of natural gas with a high heat value between 36.3 and 40.98 MJ per cubic meter at a facility emitting at any level. Notwithstanding the provisions in paragraph (e)(1) of this section, Calculation Methodology 2, 3, or 4 shall be used for combustion in any unit with a rated heat input capacity greater than 264 GJ/hr (250mmBtu/hr) and that has operated for more than 1,000 hours in any of the past three years, when the fuel is natural gas with a high heat value between 36.3 and 40.98 MJ per cubic meter.

(C) Calculation Methodology 2 may be used at a facility emitting at any level for the combustion of any of the fuels listed in Table 20-1a, and for biomass that has been determined by [the jurisdiction] not to be subject to a compliance obligation under the cap-and-trade program.

(D) Equation 20-3 may be used for the combustion of municipal solid waste only at facilities that are not subject to verification by regulation.

(E) Equation 20-2 may not be used for the combustion of municipal solid waste.

(3) Calculation Methodology 3 (Equations 20-4 through 20-7) may be used for the combustion of any type of fuel, except as specified in paragraph (e)(3)(A) through (E) of this section.

(A) Notwithstanding the provisions in paragraph (e)(1) and (e)(2) of this section, Calculation Methodology 3 or 4 must be used at a facility subject to verification for all combustion in any unit with a rated heat input capacity greater than 264 GJ/hr (250mmBtu/hr) and that has operated for more than 1,000 hours in any of the past three years, except when the fuel is natural gas with a high heat value between 36.3 and 40.98 MJ per cubic meter, the fuel is listed in Table 20-1a, or the fuel is biomass that has been determined by [the jurisdiction] not to be subject to a compliance obligation under the cap-and-trade program.

(B) Must be used for all other combustion at a facility subject to verification, except for combustion of fuels for which Calculation Methodology 1 or 2 is permitted, as described in paragraphs (e)(1) and (e)(2) of this section.

(C) May not be used when the use of Calculation Methodology 4 is required.

(D) Equation 20-4 may not be used for the calculation of emissions from combustion of municipal solid waste.

(E) Equation 20-5 may be used for the combustion of municipal solid waste at a facility emitting at any level; however, it must be used for the combustion of municipal solid waste if the facility is subject to verification by regulation, unless Calculation Methodology 4 is required.

(4) Calculation Methodology 4 may be used for a unit combusting any type of fuel. Notwithstanding the provisions in paragraphs (e)(1) through (3) of this section, Calculation Methodology 4 must be used for a combustion unit with a CEMS that is required by any federal, provincial, or local regulation and that includes both a stack gas volumetric flow rate monitor and a CO_2 concentration monitor.

(5) You may elect to use any applicable higher calculation methodology for one or more of the fuels combusted in a unit. For example, if a unit combusts natural gas and distillate

fuel oil, you may elect to use Calculation Methodology 1 for natural gas and Calculation Methodology 2 for the fuel oil, even though Calculation Methodology 1 could have been used for both fuels. However, for units that use Calculation Methodology 4, CO_2 emissions from the combustion of all fuels shall be based solely on CEMS measurements.

(f) CO_2 emissions from combustion of mixtures of biomass or biomass fuel and fossil fuel. Use the procedures of this paragraph (f) to estimate biogenic CO_2 emissions from units that combust a combination of biomass and fossil fuels, including combustion of waste-derived fuels (e.g., municipal solid waste, tires, etc,) that are partially biomass.

(1) If CEMS are not used to measure CO_2 and the facility combusts biomass fuels that do not include waste-derived fuels (e.g., municipal solid waste and tires), use Calculation Methodology 1, 2, or 3, as applicable, to calculate the annual biogenic CO_2 mass emissions from the combustion of biomass fuels. Determine the mass of biomass combusted using either company records, or, for premixed fuels that contain biomass and fossil fuels (e.g., mixtures containing biodiesel), use best available information to determine the mass of biomass fuels and document the procedure.

(2) If a CEMS is used to measure CO_2 (or O_2 as a surrogate) and the facility combusts biomass fuels that do not include waste-derived fuels (as defined in the General Provisions), use Calculation Methodology 1, 2, or 3 to calculate the annual CO_2 mass emissions from the combustion of fossil fuels. Calculate biomass fuel emissions by subtracting the fossil fuel-related emissions from the total CO_2 emissions determined from the CEMS-based methodology.

(3) If the owner or operator that combusts fuels or fuel mixtures for which the biomass fraction is unknown or cannot be documented (e.g., municipal solid waste, tire-derived fuel, etc.), or if the owner or operator combusts a biomass fuel for which a CO_2 emission factor is not provided in Table 20-2, use the following to estimate biogenic CO_2 emissions:

(A) Use Calculation Methodology 1, 2, 3, or 4 to calculate the total annual CO_2 mass emissions, as applicable.

(B) Determine the biogenic portion of the CO_2 emissions using ASTM D6866-08 "Standard Test Methods for Determining the Biobased Content of Solid, Liquid, and Gaseous Samples Using Radiocarbon Analysis", as specified in this paragraph. This procedure is not required for fuels that contain less than 5 percent biomass by weight or for waste-derived fuels that are less than 30 percent by weight of total fuels combusted in the year for which emissions are being reported, except where the operator wishes to report a biomass fuel fraction of CO_2 emissions.

(C) The operator shall conduct ASTM D6866-08 analysis on a representative fuel or exhaust gas sample at least every three months. The exhaust gas samples shall be collected over at least 24 consecutive hours following the standard practice specified by ASTM D7459-08 "Standard Practice for Collection of Integrated Samples for the Speciation of Biomass (Biogenic) and Fossil-Derived Carbon Dioxide Emitted from Stationary Emissions Sources." If municipal solid waste is combusted, the ASTM D6866-08 analysis must be performed on the exhaust gas stream.

(D) The operator shall divide total CO_2 emissions between biomass fuel emissions and non-biomass fuel emissions using the average proportions of the samples analyzed for the year for which emissions are being reported.

(E) If there is a common fuel source to multiple units at the facility, the operator may elect to conduct ASTM D6866-06a testing for only one of the units sharing the common fuel source.

(4) If Equation 20-1 of this section is selected to calculate the annual biogenic mass emissions for wood, wood waste, or other solid biomass-derived fuel, Equation 20-8 of this section may be used to quantify biogenic fuel consumption, provided that all of the required input parameters are accurately quantified. Similar equations and calculation methodologies based on steam generation and boiler efficiency may be used, provided that they are documented.

$$(Fuel)_p = \frac{[H \times S] - (HI)_{nb}}{(HHV)_{bio} \times (Eff)_{bio}} \qquad \textbf{Equation 20-8}$$

Where:

$(Fuel)_p$	=	Quantity of biomass consumed during the measurement period *p* (tonnes/year or tonnes/month, as applicable).
H	=	Average enthalpy of the boiler steam for the measurement period (GJ/tonne).
S	=	Total boiler steam production for the measurement period (tonne/month or tonne/year, as applicable).
$(HI)_{nb}$	=	Heat input from co-fired fossil fuels and non-biomass-derived fuels for the measurement period, based on company records of fuel usage and default or measured HHV values (GJ/month or GJ/year, as applicable).
$(HHV)_{bio}$	=	Default or measured high heat value of the biomass fuel (GJ/tonne).
$(Eff)_{bio}$	=	Percent efficiency of biomass-to-energy conversion, expressed as a decimal fraction.

(g) Calculation of CO_2 from sorbent.

(1) When a unit is a fluidized bed boiler, is equipped with a wet flue gas desulfurization system, or uses other acid gas emission controls with sorbent injection, use Equation 20-9 of this section to calculate the CO_2 emissions from the sorbent, if those CO_2 emissions are not monitored by CEMS:

$$CO_2 = S \times R \times \left(\frac{MW_{CO2}}{MW_S}\right) \qquad \textbf{Equation 20-9}$$

Where:

CO_2	=	CO_2 emitted from sorbent for the reporting year (tonnes).
S	=	Limestone or other sorbent used in the reporting year, from company records (tonnes).
R	=	1.00, the calcium-to-sulphur stoichiometric ratio.

MW_{CO2} = Molecular weight of carbon dioxide.
MW_S = Molecular weight of sorbent.

(2) The annual CO_2 mass emissions for the unit shall be the sum of the CO_2 emissions from the combustion process and the CO_2 emissions from the sorbent.

§ WCI.24 Calculation of CH_4 and N_2O Emissions

Calculate the annual CH_4 and N_2O mass emissions from stationary fuel combustion sources using the procedures in paragraph (a), (b), or (c), as appropriate. You are not required to calculate the annual CH_4 and N_2O emissions for fuels that are not listed in Tables 20-2, 20-3, 20-4 and 20-6. However, you may use engineering estimates to calculate the annual CH_4 and N_2O emissions for fuels that are not listed in Tables 20-2, 20-3, 20-4 and 20-6.

(a) If the high heat value of the fuel is not measured for CO_2 estimation, calculate CH_4 and N_2O emissions using Equation 20-10 for all fuels except coal. For coal, use Equation 20-11:

$$CH_4 \text{ or } N_2O = Fuel \times HHV_D \times EF \times 0.000001 \qquad \textbf{Equation 20-10}$$

$$CH_4 \text{ or } N_2O = Fuel \times EF_c \times 0.001 \qquad \textbf{Equation 20-11}$$

Where:
CH_4 or N_2O = Combustion emissions from specific fuel type (tonnes CH_4 or N_2O per year).
Fuel = Mass or volume of fuel combusted per year (express mass in tonnes for solid fuel, volume in standard cubic meters for gaseous fuel, or volume in kilolitres for liquid fuel).
HHV_D = Default high heat value specified by fuel type provided in Table 20-1, (GJ per tonne for solid fuel, GJ per kilolitre for liquid fuel, or GJ per cubic meter for gaseous fuel).
EF = Default CH_4 or N_2O emission factor provided in Tables 20-2 or 20-4, as applicable, grams CH_4 or N_2O per GJ. The facility may also use equipment-specific factors from U.S. EPA AP-42 for the specific equipment as appropriate.
EF_c = Default CH_4 or N_2O emission factor for coal provided in Table 20-6 (grams CH_4 or N_2O per kg of coal). The facility may also use equipment specific factors from U.S. EPA AP-42 for the specific equipment as appropriate.
0.000001 = Factor to convert grams to tonnes in Equation 20-10.
0.001 = Factor to convert g/kg to tonne/tonne in Equation 20-11.

(b) If the high heat value of the fuel is measured or provided by the fuel supplier for CO_2 estimation, calculate CH_4 and N_2O emissions using Equation 20-12 for all fuels except coal. For coal, use Equation 20-13:

$$CH_4 \text{ or } N_2O = \sum_{p=1}^{n} Fuel_p \times HHV_p \times EF \times 0.000001 \qquad \textbf{Equation 20-12}$$

$$CH_4 \text{ or } N_2O = \sum_{p=1}^{n} Fuel_p \times EF_c \times 0.000001 \qquad \textbf{Equation 20-13}$$

Where:

CH_4 or N_2O = CH_4 or N_2O emissions from a specific fuel type (tonnes CH_4 or N_2O per year).

$Fuel_p$ = Mass or volume of the fuel combusted during the measurement period *p* (express mass in tonnes for solid fuel, volume in standard cubic meters for gaseous fuel, or volume in kilolitres for liquid fuel).

HHV_p = High heat value measured directly or provided by the fuel supplier for the measurement period *p* specified by fuel type (GJ per tonne for solid fuel, GJ per kilolitre for liquid fuel, or GJ per cubic meter for gaseous fuel).

EF = Default CH_4 or N_2O emission factor provided in Tables 20-2 or 20-4, as applicable (grams CH_4 or N_2O per GJ). The facility may also use equipment-specific factors from U.S. EPA AP-42 for the specific equipment as appropriate.

EF_c = CH_4 or N_2O emission factor for coal, either measured directly or provided by the fuel supplier (grams CH_4 or N_2O per tonne of coal).

0.000001 = Factor to convert grams to tonnes.

(c) For biomass and municipal solid waste combustion where Equation 20-3 or 20-5 are used to calculate CO_2 emissions, use Equation 20-14 of this section to estimate CH_4 and N_2O emissions:

$$CH_4 \ or \ N_2O = Steam \times B \times EF \times 0.000001$$ **Equation 20-14**

Where:

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a municipal solid waste (tonnes).

Steam = Total mass of steam generated by municipal solid waste combustion during the reporting year (tonnes steam).

B = Ratio of the boiler's design rated heat input capacity to its design rated steam output (GJ/tonne steam).

EF = Fuel-specific emission factor for CH_4 or N_2O, from Tables 20-2, 20-4, or 20-6, as applicable (grams CH_4 or N_2O per GJ).

0.000001 = Conversion factor from grams to tonnes.

(d) Use Equation 20-15 of this section for units that use Calculation Methodology 4 and for which heat input is monitored on a year round basis.

$$CH_4 \ or \ N_2O = (HI)_A \times EF \times 0.000001$$ **Equation 20-15**

Where:

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (tonnes).

$(HI)_A$ = Cumulative annual heat input from the fuel (GJ), derived from the electronic data reports or estimated from the best available information (e.g., fuel feed rate measurements, fuel heating values, engineering analysis, etc.).

EF = Fuel-specific emission factor for CH_4 or N_2O, from Tables 20-2, 20-4, or 20-6, as applicable (grams CH_4 or N_2O per GJ).

0.000001 = Conversion factor from grams to tonnes.

(1) If only one type of fuel is combusted during normal operation, substitute the cumulative annual heat input from combustion of the fuel into Equation 20-15 of this section to calculate the annual CH_4 or N_2O emissions.

(2) If more than one type of fuel listed is combusted during normal operation, use Equation 20-15 of this section separately for each type of fuel.

(e) When multiple fuels are combusted during the reporting year, sum the fuel-specific results from Equations 20-8, 20-9, 20-10, or 20-11 of this section (as applicable) to obtain the total annual CH_4 and N_2O emissions, in tonnes.

(f) The operator may elect to calculate CH_4 or N_2O emissions using source-specific emission factors derived from source tests conducted at least annually under the supervision of the regulator. Upon approval of a source test plan, the source test procedures in that plan shall be repeated in each future year to update the source specific emission factors annually.

(g) Use of the four CH_4 and N_2O Calculation Methodologies. Use of the four CH_4 and N_2O emissions calculation methodologies described in paragraphs (a) through (d) of this section is subject to the following requirements and restrictions:

(1) WCI.24(a) may not be used by a facility that is subject to the verification requirements of WCI.8, except for stationary combustion units that combust natural gas with a higher heating value between 36.3 and 40.98 MJ per cubic meter. Otherwise, WCI.24(a) may be used for any type of fuel for which a default CH_4 or N_2O emission factor (Tables 20-2, 20-4, 20-6, and 20-7) and a default higher heat value (Table 20-1 and 20-1a) is specified.

(2) WCI.24(b) may be used for a unit of any size combusting any type of fuel.

(3) WCI.24(c) may only be used for biomass or municipal solid waste combustion. WCI.24(c) must be used instead of WCI.24(a) for any unit combusting municipal solid waste that generates steam.

(4) WCI.24(d) may be used for a unit of any size combusting any type of fuel, and must be used for any units for which Calculation Methodology 4 is used to estimate CO_2 emissions and heat input is monitored on a year round basis.

§ WCI.25 Sampling, Analysis, and Measurement Requirements

(a) Fuel Sampling Requirements. Fuel sampling must be conducted or fuel sampling results must be received from the fuel supplier at minimum at the frequency specified in paragraphs (a)(1) through (a)(7) of this section, subject to the requirements of WCI.23(e) and WCI.24(g). All fuel samples shall be taken at a location in the fuel handling system that provides a representative of the fuel combusted.

(1) Once for each new fuel shipment or delivery for coal.

(2) Once for each new fuel shipment or delivery of fuels, or quarterly for each of the fuels listed in Table 20-1a (when required).

(3) Semiannually for natural gas (when required).

(4) Quarterly for liquid fuels and fossil fuel-derived gaseous fuels other than fuels listed in Table 20-1a (when Table 20-1a is used).

(5) Quarterly for gases derived from biomass including landfill gas and biogas from wastewater treatment or agricultural processes.

(6) For gaseous fuels other than natural gas, gases derived from biomass, and biogas, daily sampling and analysis to determine the carbon content and molecular weight of the fuel is required if the necessary equipment is in place to make these measurements. For 2011 calendar year emissions only, if the necessary equipment is not in place to make the measurements, weekly sampling and analysis shall be performed. If on-line instrumentation is to be used, the equipment necessary to perform daily sampling and analysis of carbon content and molecular weight must determine fuel carbon content accurate to ±5 percent.

(7) Monthly for solid fuels other than coal and waste-derived fuels (including municipal solid waste), as specified below:

(A) The monthly solid fuel sample shall be a composite sample of weekly samples.

(B) The solid fuel shall be sampled at a location after all fuel treatment operations but before fuel mixing, and the samples shall be representative of the fuel chemical and physical characteristics immediately prior to combustion.

(C) Each weekly sub-sample shall be collected at a time (day and hour) of the week when the fuel consumption rate is representative and unbiased.

(D) Four weekly samples (or a sample collected during each week of operation during the month) of equal mass shall be combined to form the monthly composite sample.

(E) The monthly composite sample shall be homogenized and well mixed prior to withdrawal of a sample for analysis.

(F) One in twelve composite samples shall be randomly selected for additional analysis of its discrete constituent samples. This information will be used to monitor the homogeneity of the composite.

(8) For biomass fuels and waste-derived fuels (including municipal solid waste), the following may apply in lieu of WCI.25(a)(5):

(A) If CO_2 emissions are calculated using Equation 20-2 in WCI.23(b)(1) or Equation 20-4 in WCI.23(c)(1), the source-specific high heat value or carbon content is determined annually. If CO_2 emissions are calculated using Equation 20-5 in WCI.23(c)(2) (biomass fuels and municipal solid waste only), the operator shall adjust the emission factor, in kg CO_2/GJ not less frequently than every third year, through a stack test measurement of CO_2 and use of the applicable ASME Performance Test Code to determine heat input from all heat outputs, including the steam, flue gases, ash and losses.

(b) Fuel Consumption Monitoring Requirements.

(1) Facilities may determine fuel consumption on the basis of direct measurement or recorded fuel purchase or sales invoices measuring any stock change (measured in MJ, litres, million standard cubic meters, tonnes or bone dry tonnes) using Equation 20-16. For facilities that are covered by WCI.360 (Petroleum and Natural Gas Production and

Gas Processing) but are less than 10,000 tonnes in individual size, an operator may calculate fuel consumption for propane and diesel without correcting for the difference in inventory at the beginning and end of the year.

Equation 20-16

Fuel Consumption in the Report Year = Total Fuel Purchases – Total Fuel Sales + Amount Stored at Beginning of Year – Amount Stored at Year End

(2) Fuel consumption measured in MJ values shall be converted to the required metrics of mass or volume using heat content values that are either provided by the supplier, measured by the facility, or provided in Table 20-1.

(3) All oil and gas flow meters (except for gas billing meters) shall be calibrated prior to the first year for which GHG emissions are reported under this rule, using an applicable flow meter test method listed in by regulation or the calibration procedures specified by the flow meter manufacturer. Fuel flow meters shall be recalibrated either annually or at the minimum frequency specified by the manufacturer.

(4) For fuel oil, tank drop measurements may also be used.

(5) Fuel flow meters that measure mass flow rates may be used for liquid fuels, provided that the fuel density is used to convert the readings to volumetric flow rates. The density shall be measured at the same frequency as the carbon content, using ASTM D1298-99 (Reapproved 2005) "Standard Test Method for Density, Relative Density (Specific Gravity), or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method."

(6) Facilities using Calculation Methods 1 or 2 for CO_2 emissions may use the following default density values for fuel oil, in lieu of using the ASTM method in paragraph (b)(5) of this section: 0.81 kg/litre for No. 1 oil; 0.86 kg/litre for No. 2 oil; 0.97 kg/litre for No. 6 oil. These default densities may not be used for facilities using Calculation Method 3.

(c) Fuel Heat Content Monitoring Requirements. High heat values shall be based on the results of fuel sampling and analysis received from the fuel supplier or determined by the operator, in either case using an applicable analytical method listed by regulation.

(1) For gases, use ASTM D1826-94 (Reapproved 2003) "Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter", ASTM D3588-98 (Reapproved 2003) "Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels", or ASTM D4891-89 (Reapproved 2006), GPA Standard 2261-00 "Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography." The operator may alternatively elect to use on-line instrumentation that determines heating value accurate to within ±5.0 percent. Where existing on-line instrumentation provides only low heat value, the operator shall convert the value to high heat value as follows:

$$HHV = LHV \times CF$$ **Equation 20-17**

Where:

HHV = fuel or fuel mixture high heat value (MJ/scm).

LHV = fuel or fuel mixture low heat value (MJ/scm).
CF = conversion factor.

For natural gas, a CF of 1.11 shall be used. For refinery fuel gas and mixtures of refinery fuel gas, a weekly average fuel system-specific CF shall be derived as follows:

(A) By concurrent LHV instrumentation measurements and HHV determined by on-line instrumentation or laboratory analysis as part of the daily carbon content determination; or,

(B) By the HHV/LHV ratio obtained from the laboratory analysis of the daily samples.

(2) For middle distillates and oil, or liquid waste-derived fuels, use ASTM D240-02 (Reapproved 2007) "Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter" or ASTM D4809-06 (Reapproved 2005) "Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method)."

(3) For solid biomass-derived fuels, use ASTM D5865-07a "Standard Test Method for Gross Calorific Value of Coal and Coke."

(4) For waste-derived fuels, use ASTM D5865-07a or ASTM D5468-02 (Reapproved 2007) "Standard Test Method for Gross Calorific and Ash Value of Waste Materials." Operators who combust waste-derived fuels that are not pure biomass fuels shall determine the biomass fuel portion of CO_2 emissions using the method specified in WCI.23(f), if applicable

(5) Use Equation 20-18 to calculate the weighted annual average heat content of the fuel, if the measured heat content is used to calculate CO_2 emissions.

$$(HHV)_{annual} = \frac{\sum_{p=1}^{n} (HHV)_p \times (Fuel)_p}{\sum_{p=1}^{n} (Fuel)_p}$$ **Equation 20-18**

Where:

$(HHV)_{annual}$ = Weighted annual average high heat value of the fuel (GJ per tonne for solid fuel, GJ per kilolitre for liquid fuel, or GJ per cubic meter for gaseous fuel).

$(HHV)_p$ = High heat value of the fuel, for measurement period *p* (GJ per tonne for solid fuel, GJ per kilolitre for liquid fuel, or GJ per cubic meter for gaseous fuel).

$(Fuel)_p$ = Mass or volume of the fuel combusted during measurement period *p* (express mass in tonnes for solid fuel, volume in standard cubic meters for gaseous fuel, or volume in kilolitres for liquid fuel).

n = Number of measurement periods in the year that fuel is burned in the unit.

(d) Fuel Carbon Content Monitoring Requirements. Fuel carbon content and either molecular weight or molar fraction for gaseous fuels shall be based on the results of fuel sampling and analysis received from the fuel supplier or determined by the operator, in either case using an applicable analytical method listed by regulation.

(1) For coal and coke, solid biomass fuels, and waste-derived fuels; use ASTM 5373-08 "Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal".

(2) For liquid fuels, use the following ASTM methods: For petroleum-based liquid fuels and liquid waste-derived fuels, use ASTM D5291-02 (Reapproved 2007) "Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants," ultimate analysis of oil or computations based on ASTM D3238-95 (Reapproved 2005), and either ASTM D2502-04 "Standard Test Method for Estimation of Mean Relative Molecular Mass of Petroleum Oils From Viscosity Measurements" or ASTM D2503-92 (Reapproved 2007) "Standard Test Method for Relative Molecular Mass (Molecular Weight) of Hydrocarbons by Thermoelectric Measurement of Vapor Pressure."

(3) For gaseous fuels, use ASTM D1945-03 (Reapproved 2006) "Standard Test Method for Analysis of Natural Gas by Gas Chromatography" or ASTM D1946-90 (Reapproved 2006) "Standard Practice for Analysis of Reformed Gas by Gas Chromatography."

(4) Use Equation 20-19 to calculate the weighted annual average carbon content of the fuel, if the measured carbon content is used to calculate CO_2 emissions.

$$(CC)_{annual} = \frac{\sum_{p=1}^{n}(CC)_p \times (Fuel)_p}{\sum_{p=1}^{n}(Fuel)_p}$$ **Equation 20-19**

Where:

$(CC)_{annual}$ = Weighted annual average carbon content of the fuel (percent C by weight for solid fuel, tonne C per kilolitre for liquid fuel, or kg C per kg fuel for gaseous fuel).

$(CC)_p$ = Carbon content of the fuel, for measurement period *p* (percent C by weight for solid fuel, tonne C per kilolitre for liquid fuel, or kg C per kg fuel for gaseous fuel).

$(Fuel)_p$ = Mass or volume of the fuel combusted during measurement period *p* (express mass in tonnes for solid fuel, volume in standard cubic meters for gaseous fuel, or volume in kilolitres for liquid fuel).

n = Number of measurement periods in the years that fuel is burned in the unit.

(e) Fuel Analytical Data Capture. When the applicable emissions estimation methodologies in WCI.23 and WCI.24 require periodic collection of fuel analytical data for an emissions source, the operator shall demonstrate every reasonable effort to obtain a fuel analytical data capture rate of 100 percent for each report year.

(1) If the operator is unable to obtain fuel analytical data such that more than 20 percent of emissions from a source cannot be directly accounted for, the emissions from that source shall be considered unverifiable for the report year.

(2) If the fuel analytical data capture rate is at least 80 percent but less than 100 percent for any emissions source identified in WCI.23 and WCI.24, the operator shall use the methods in WCI.26(b) to substitute for the missing values for the period of missing data.

(f) Specific Requirements for Petroleum and Natural Gas Production and Gas Processing. For field or process gas combustion or general stationary combustion of natural gas within facilities covered by WCI.360, legislative or regulatory requirements, such as those required by the Petroleum and Natural Gas Act of British Columbia are sufficient for the points of measurement that are metered. For British Columbia, combustion sources specifically covered by the Petroleum and Natural Gas Act are to be calculated in the manner prescribed by the Act and its regulations, guidelines, and policies. Combustion sources not covered by the Act must be metered according to the following sampling and measurement requirements:

(1) For combustion emission sources where meters are not required by legislation or regulation, a calculated shrinkage value is sufficient but must be assigned using engineering estimation techniques to the various sources, if required for reporting.

(2) For field, pipeline quality natural gas or process gas combustion emission sources where metering is not required by law or regulation and shrinkage is not calculated, engineering estimation techniques that consolidate to common meter points such as that at the input to a processing plant used for financial purposes are sufficient. As required, fuel use must be allocated (using equipment specifications, operating hours, and flow rates) to specific emission sources.

(3) For upstream sources, a meter is required at each installation or at a point where fuel use can allocated to multiple combustion sources such that the aggregated of all combustion sources are metered.

All combustion estimates must be calculated in such a manner that ensures that fugitive, flaring, and venting emissions as calculated under WCI.360 are uniquely reported and that no double-counting of emissions in one or more categories occurs.

Carbon content and molecular weight of the field or process gas determined annually by a company or operator for a specific field for operational and regulatory purposes must be used as inputs to Equation 20-7. When this is data is not available, the generic emission factors provided in Table 360-3 (or as provided by the jurisdiction) must be used by a company or operator for the specific gas field in question.

(g) Specific Requirements for Natural Gas Transmission and Distribution. Measurement and Metering Act of Canada standards (or other appropriate standards if the Measurement and Metering Act is not applicable) are deemed to be sufficiently rigorous for the sampling, analysis and measurement for the combustion of pipeline quality natural gas (including for derivation of standard gas composition) for facilities covered by WCI.350 – Natural Gas Transmission and Distribution. If a required meter is not covered by the Measurement and Metering Act, it must exist and meet the requirements of the applicable greenhouse gas reporting regulation for the jurisdiction.

§ WCI.26 Procedures for Estimating Missing Data.

Whenever a quality-assured value of a required parameter is unavailable (e.g., if a CEMS malfunctions during unit operation or if a required fuel sample is not taken), a substitute data value for the missing parameter shall be used in the calculations.

(a) For all units subject to the requirements of WCI.20 that monitor and report emissions using a CEMS, the missing data backfilling procedures in *Protocols And Performance Specifications For Continuous Monitoring Of Gaseous Emissions From Thermal Power Generation* (Report EPS 1/PG/7 (Revised) December 2005) (or by other relevant document, if superseded) shall be followed for CO_2 concentration, stack gas flow rate, fuel flow rate, high heating value, and fuel carbon content.

(b) For units that use Calculation Methodologies 1, 2, 3, or 4, perform missing data substitution as follows for each parameter:

(1) For each missing value of the high heating value, carbon content, or molecular weight of the fuel, substitute the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If the “after” value has not been obtained by the time that the GHG emissions must be calculated, you may use the “before” value for missing data substitution or the best available estimate of the parameter, based on all available process data (e.g., electrical load, steam production, operating hours). If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.

(2) For missing records of CO_2 concentration, stack gas flow rate, percent moisture, fuel usage, and sorbent usage, the substitute data value shall be the best available estimate of the parameter, based on all available process data (e.g., electrical load, steam production, operating hours, etc.). You must document and retain records of the procedures used for all such estimates.

§ WCI.27 Definitions

Except as specified in this section, all terms used in this subpart have the same meaning given in the General Provisions.

Emergency generator means a stationary combustion device, such as a reciprocating internal combustion engine or turbine that serves solely as a secondary source of mechanical or electrical power whenever the primary energy supply is disrupted or discontinued during power outages or natural disasters that are beyond the control of the owner or operator of a facility. An emergency generator operates only during emergency situations, for training of personnel under simulated emergency conditions, as part of emergency demand response procedures, or for standard performance testing procedures as required by law or by the generator manufacturer. A generator that serves as a back-up power source under conditions of load shedding, peak shaving, power interruptions pursuant to an interruptible power service agreement, or scheduled facility maintenance shall not be considered an emergency generator.

Emergency equipment means any auxiliary fossil fuel-powered equipment, such as a fire pump, that is used only in emergency situations.

Pipeline quality natural gas means natural gas having a high heat value equal to or greater than 36.1 MJ/m^3 or less than 40.98 MJ/m^3, and which is at least 90 percent methane by volume, and which is less than 5 percent carbon dioxide by volume.

Portable means designed and capable of being carried or moved from one location to another. Indications of portability include but are not limited to wheels, skids, carrying handles, dolly, trailer, or platform. Equipment is not portable if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The equipment or a replacement resides at the same location for more than 12 consecutive months.

(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least two years, and operates at that facility for at least three months each year.

(4) The equipment is moved from one location to another in an attempt to circumvent the portable residence time requirements of this definition.

U.S. AP-42 means the Fifth Edition, Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources, U.S. EPA., as amended from time to time

Table 20-1: Default High Heat Value by Fuel Type

Liquid Fuels	**High Heat Value (GJ/kl)**
Asphalt & Road Oil	44.46
Aviation Gasoline	33.52
Diesel	38.3
Aviation Turbo Fuel	37.4
Kerosene	37.68
Propane	25.31
Ethane	17.22
Butane	28.44
Lubricants	39.16
Motor Gasoline – Off-Road	35
Light Fuel Oil	38.8
Residual Fuel Oil (No. 5 & No. 6)	42.5
Crude Oil	38.32
Naphtha	35.17
Petrochemical Feedstocks	35.17
Petroleum Coke – Refinery Use	46.35
Petroleum Coke – Upgrader Use	40.57
Ethanol (100%)	21.04
Biodiesel (100%)	32.06

Rendered Animal Fat	31.05
Vegetable Oil	30.05
Solid Fuels	**High Heat Value (GJ/tonne)**
Anthracite Coal	27.7
Bituminous Coal	26.33
Foreign Bituminous Coal	29.82
Sub-Bituminous Coal	19.15
Lignite	15
Coal Coke	28.83
Solid Wood Waste	18
Spent Pulping Liquor	14
Municipal Solid Waste	11.57
Tires	31.18
Agricultural By-products	8.6
Solid By-products	26.93
Gaseous Fuels	**High Heat Value (GJ/m^3)**
Natural Gas	0.03832
Coke Oven Gas	0.01914
Still Gas – Refineries	0.03608
Still Gas – Upgraders	0.04324
Landfill Gas (captured methane)	0.0359
Biogas (captured methane)	0.0281

[1] The default high heat value for "propane" is only for the pure gas species. For the product commercially sold as propane, the value for liquefied petroleum gas in Table 20-1a should be used instead.

Table 20-1a—Fuels for which Calculation Methodologies 1 or 2 may be used at a facility emitting at any level.

Fuel Type	Default High Heat Value	Default CO_2 Emission Factor
Petroleum Products	**GJ/kilolitre**	**kg CO_2/GJ**
Distillate Fuel Oil No. 1	38.78	69.37
Distillate Fuel Oil No. 2	38.50	70.05
Distillate Fuel Oil No. 4	40.73	71.07
Kerosene	37.68	67.25
Liquefied Petroleum Gases (LPG)	25.66	59.65
Propane (pure, not mixtures of LPGs)[1]	25.31	59.66
Propylene	25.39	62.46
Ethane	17.22	56.68
Ethylene	27.90	63.86
Isobutane	27.06	61.48
Isobutylene	28.73	64.16
Butane	28.44	60.83
Butylene	28.73	64.15
Natural Gasoline	30.69	63.29
Motor Gasoline	34.87	65.40

Table 20-1a—Fuels for which Calculation Methodologies 1 or 2 may be used at a facility emitting at any level.

Fuel Type	Default High Heat Value	Default CO_2 Emission Factor
Aviation Gasoline	33.52	69.87
Kerosene-type Jet Fuel	37.66	68.40

[1] The default factors for "propane" are only for the pure gas species. For the product commercially sold as propane, the values for LPG should be used instead.

Table 20-2: Default Emission Factors by Fuel Type

Liquid Fuels	CO_2 Emission Factor (kg/l)	CO_2 Emission Factor (kg/GJ)	CH_4 Emission Factor (g/l)	CH_4 Emission Factor (g/GJ)	N_2O Emission Factor (g/l)	N_2O Emission Factor (g/GJ)
Aviation Gasoline	2.342	69.87	2.2	65.63	0.23	6.862
Diesel	2.663	69.53	0.133	3.473	0.4	10.44
Aviation Turbo Fuel	2.534	67.75	0.08	2.139	0.23	6.150
Kerosene						
- Electric Utilities	2.534	67.25	0.006	0.159	0.031	0.823
- Industrial	2.534	67.25	0.006	0.159	0.031	0.823
- Producer Consumption	2.534	67.25	0.006	0.159	0.031	0.823
- Forestry, Construction, and Commercial/Institutional	2.534	67.25	0.026	0.69	0.031	0.823
Propane						
- Residential	1.51	59.66	0.027	1.067	0.108	4.267
- All other uses	1.51	59.66	0.024	0.948	0.108	4.267
Ethane	0.976	56.68	N/A	N/A	N/A	N/A
Butane	1.73	60.83	0.024	0.844	0.108	3.797
Lubricants	1.41	36.01	N/A	N/A	N/A	N/A
Motor Gasoline – Off-Road	2.289	65.40	2.7	77.14	0.05	1.429
Light Fuel Oil						
- Electric Utilities	2.725	70.23	0.18	4.639	0.031	0.799
- Industrial	2.725	70.23	0.006	0.155	0.031	0.799
- Producer Consumption	2.643	68.12	0.006	0.155	0.031	0.799
- Forestry, Construction, and Commercial/Institutional	2.725	70.23	0.026	0.67	0.031	0.799
Residual Fuel Oil (No. 5 & No. 6)						
- Electric Utilities	3.124	73.51	0.034	0.800	0.064	1.506
- Industrial	3.124	73.51	0.12	2.824	0.064	1.506
- Producer Consumption	3.158	74.31	0.12	2.824	0.064	1.506
- Forestry, Construction, and Commercial/Institutional	3.124	73.51	0.057	1.341	0.064	1.820
Naphtha	0.625	17.77	N/A	N/A	N/A	N/A
Petrochemical Feedstocks	0.5	14.22	N/A	N/A	N/A	N/A
Petroleum Coke - Refinery Use	3.826	82.55	0.12	2.589	0.0265	0.572
Petroleum Coke - Upgrader Use	3.494	86.12	0.12	2.958	0.0231	0.569

Biomass	CO_2 Emission Factor (kg/kg)	CO_2 Emission Factor (kg/GJ)	CH_4 Emission Factor (g/kg)	CH_4 Emission Factor (g/GJ)	N_2O Emission Factor (g/kg)	N_2O Emission Factor (g/GJ)
Landfill Gas	2.989	83.3	0.6	16.7	0.06	1.671
Wood Waste (Env. Canada)[1]	0.95	52.8	0.05	2.778	0.02	1.111
Wood Waste (U.S. EPA)[2]	1.590	88.9	0.51	28.4	0.068	3.79
Spent Pulping Liquor (Env. Canada)	1.428	102.0	0.05	3.571	0.02	1.429
Spent Pulping Liquor (U.S. EPA)	1.394	99.60	0.44	31.65	0.073	5.275
Agricultural By-products	NA	112	NA	NA	NA	NA
Solid By-products	NA	100	NA	NA	NA	NA
Biogas (captured methane)	NA	49.4	NA	NA	NA	NA
Ethanol (100%)	NA	64.9	NA	NA	NA	NA
Biodiesel (100%)	NA	70	NA	NA	NA	NA
Rendered Animal Fat	NA	67.4	NA	NA	NA	NA
Vegetable Oil	NA	77.3	NA	NA	NA	NA
Other Solid Fuels	**CO_2 Emission Factor (kg/kg)**	**CO_2 Emission Factor (kg/GJ)**	**CH_4 Emission Factor (g/kg)**	**CH_4 Emission Factor (g/GJ)**	**N_2O Emission Factor (g/kg)**	**N_2O Emission Factor (g/GJ)**
Coal Coke	2.48	86.02	0.03	1.041	0.02	0.694
Tires	N/A	85	N/A	N/A	N/A	N/A
Gaseous Fuels	**CO_2 Emission Factor (kg/m^3)**	**CO_2 Emission Factor (kg/GJ)**	**CH_4 Emission Factor (g/m^3)**	**CH_4 Emission Factor (g/GJ)**	**N_2O Emission Factor (g/m^3)**	**N_2O Emission Factor (g/GJ)**
Coke Oven Gas	1.6	83.60	0.037	1.933	0.035	1.829
Still Gas – Refineries	1.75	48.50	N/A	N/A	0.0222	0.615
Still Gas – Upgraders	2.14	49.49	N/A	N/A	0.0222	0.513

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007, unless otherwise stated

[1] Assumes 50% moisture content of wood waste

[2] Assumes 12% moisture content of wood waste

Table 20-3: Default Carbon Dioxide Emission Factors for Natural Gas by Province

	Marketable Gas (kg/m^3)	Marketable Gas (kg/GJ)	Non-Marketable Gas (kg/m^3)	Non-Marketable Gas (kg/GJ)
Quebec	1.878	49.01	Not occurring	Not occurring
Ontario	1.879	49.03	Not occurring	Not occurring
Manitoba	1.877	48.98	Not occurring	Not occurring
British Columbia	1.916	50.00	2.151	56.13

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007

Table 20-4: Default Methane and Nitrous Oxide Emission Factors for Natural Gas

	CH_4 (g/m^3)	CH_4 (g/GJ)	N_2O (g/m^3)	N_2O (g/GJ)
Electric Utilities	0.49	12.79	0.049	1.279

Industrial	0.037	0.966	0.033	0.861
Producer Consumption (Non-marketable)	6.5	169.6	0.06	1.566
Pipelines	1.9	49.58	0.05	1.305
Cement	0.037	0.966	0.034	0.887
Manufacturing Industries	0.037	0.966	0.033	0.861
Residential, Construction, Commercial/Institutional, Agriculture	0.037	0.966	0.035	0.913

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007

Table 20-5: Default Carbon Dioxide Emission Factors for Coal

	Emission Factor (kg CO_2/kg coal)	Emission Factor (kg CO_2/GJ)
Quebec		
- Canadian Bituminous	2.25	85.5
- U.S. Bituminous	2.34	88.9
- Anthracite	2.39	86.3
Ontario		
- Canadian Bituminous	2.25	85.5
- U.S. Bituminous	2.43	81.5
- Sub-bituminous	1.73	90.3
- Lignite	1.48	98.7
- Anthracite	2.39	86.3
Manitoba		
- Canadian Bituminous	2.25	85.5
- U.S. Bituminous	2.43	81.5
- Sub-bituminous	1.73	90.3
- Lignite	1.42	94.7
- Anthracite	2.39	86.3
British Columbia		
- Canadian Bituminous	2.07	78.6
- U.S. Bituminous	2.43	81.5
- Sub-bituminous	1.77	92.4

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007

Table 20-6: Default Methane and Nitrous Oxide Emission Factors for Coal

	CH_4 Emission Factor (g/kg)	N_2O Emission Factor (g/kg)
Electric Utilities	0.022	0.032
Industry and Heat and Steam Plants	0.03	0.02
Residential, Public Administration	4	0.02

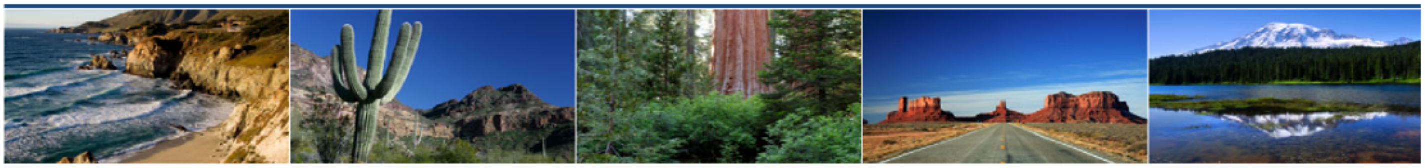
Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007

Table 20-7: Other Emission Factors

	CO_2 Emission Factor (kg/GJ)	CH_4 Emission Factor (g/GJ)	N_2O Emission Factor (g/GJ)
Municipal Solid Waste	85.6	30	4
Peat	103	1	1.5

Source: 2006 IPCC Guidelines for National Greenhouse Gas Inventories, except the CO_2 emission factor for municipal solid waste is from the U.S. EPA from table C-1 of 40 CFR 98 subpart C.

The WCI notes the significant difference in both the black liquor and solid biomass emission factors published by the EPA and Environment Canada (as well as those submitted by industry associations). In lieu of recommending a single emission factor at this time (as there is no certainty as to which is most accurate) the WCI is presenting both. The WCI will be working with experts in the two federal agencies and other organizations to ascertain the most accurate emission factor to use for both Metric and English unit versions of the Essential Requirements of Mandatory Reporting.



§ WCI.30 REFINERY FUEL GAS COMBUSTION

§ WCI.31 Source Category Definition

This source category consists of any combustion device that is located at a petroleum refinery and that combusts refinery fuel gas, still gas, flexigas, or associated gas.

§ WCI.32 Greenhouse Gas Reporting Requirements

In addition to the information required by the regulation, the emissions data report shall include the following information at the facility level:

(a) Annual CO_2, CH_4, and N_2O emissions from refinery fuel gas combustion in tonnes.

(b) Annual fuel consumption in units of standard cubic metres.

(c) Average carbon content of each fuel used to compute CO_2 emissions.

§ WCI.33 Calculation of Greenhouse Gas Emissions

(a) Calculation of CO_2 Emissions: Owners and operators shall calculate daily CO_2 emissions for each fuel gas system using any of the methods specified in paragraphs (a)(1) through (a)(4) of this section. Calculate the total annual CO_2 emissions from combustion of all fuel gas by summing the CO_2 emissions from each fuel gas system.

(1) Use a CEMS that complies with the provisions in section WCI.23(d).

(2) Calculate CO_2 emissions from each refinery fuel gas system and flexigas system using measured carbon content and molecular weight of the gas and Equation 30-1.

$$CO_2 = \sum_{i=1}^{n} Fuel_i \times CC_i \times \frac{MW}{MVC} \times 3.664 \times 0.001$$

Equation 30-1

Where:

CO_2 = Carbon dioxide emissions (tonnes/year).
$Fuel_i$ = Daily refinery fuel or flexigas combusted (Rm^3) at reference temperature and pressure conditions as used by the facility. If a mass flow meter is used, measure the daily fuel combusted in kg and replace the term "MW/MVC" with "1".
CC_i = Daily sample of carbon content of the fuel (kg C/kg fuel).
MW = Daily sample of molecular weight of fuel (kg/kg-mole).
MVC = Molar volume conversion factor at the same reference conditions as the variable $Fuel_i$ (Rm^3/kg-mole).
= 8.3145 * [273.16 + reference temperature in °C]/[reference pressure in kilopascal].
3.664 = Conversion factor for carbon to carbon dioxide.
0.001 = Conversion factor for kg to tonnes.
n = Number of days in a year.

(3) For associated gas, low heat content gas, or other fossil fuels; follow the requirements for general stationary source combustion sources in WCI .23(b) or (c), as appropriate for each fuel.

(4) Where individual fuels are mixed prior to combustion, the operator may choose to calculate CO_2 emissions for each fuel prior to mixing instead of using the methods in paragraphs (a)(1) or (a)(2) of this section. In this case, the operator must determine the fuel flow rate and appropriate fuel specific parameters (e.g. carbon content, HHV) of each fuel stream prior to mixing, calculate CO_2 emissions for each fuel stream, and sum the emissions of the individual fuel streams to determine total CO_2 emissions from the mixture. CO_2 emissions for each fuel stream must be estimated using the following methods:

(A) For natural gas and associated gas, use the appropriate methodology specified in section WCI.23(b) or (c).

(B) For refinery fuel gas, flexigas, and low heat content gas, use the methodology in paragraph (a)(2) of this section.

(b) Calculation of CH_4 and N_2O Emissions. Owners and operators shall use the methods specified in section WCI.24 to calculate the annual CH_4 and N_2O emissions.

§ WCI.34 Sampling, Analysis, and Measurement Requirements

(a) Measure the fuel consumption rate daily using methods specified in WCI.25(b).

(b) Daily sampling and analysis to determine the carbon content and molecular weight of the fuel is required if there is sampling at a frequency of daily or more currently or if there is online instruments in place to monitor carbon content. Otherwise, weekly sampling and analysis of carbon content and molecular weight shall be performed. The equipment necessary to perform daily sampling and analysis of carbon content and molecular weight for refinery fuel gas must be installed no later than January 1, 2012.

(c) Measure the carbon content for fuel gas and flexigas using either ASTM D1945-03 (Reapproved 2006) or ASTM D1946-90 (Reapproved 2006). Where these methods do not adequately quantify all major hydrocarbons, then an owner or operator may request use of an alternative ASTM or other method to be approved by the regulator. Alternatively, the results of chromatographic analysis of the fuel gas may be used, provided that the gas chromatograph is operated, maintained, and calibrated according to the manufacturer's instructions; and the methods used for operation, maintenance, and calibration of the gas chromatograph are documented in a plan.

§ WCI.35 Procedures for estimating missing data.

Whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations by following the requirements of WCI.26.

§ WCI.40 ELECTRICITY GENERATION

§ WCI.41 Source Category Definition

An electricity generating unit is any combustion device that combusts solid, liquid, or gaseous fuel for the purpose of producing electricity either for sale or for use onsite. This source category includes cogeneration (combined heat and power) units. This source category does not include portable or emergency generators less than 10 MW in nameplate generating capacity as defined in WCI.27.

§ WCI.42 Greenhouse Gas Reporting Requirements

For each electricity generating unit, the emissions data report shall include the following information:

(a) Annual greenhouse gas emissions in tonnes, reported as follows:

(1) Total CO_2 emissions for fossil fuels, reported by fuel type.

(2) Total CO_2 emissions for all biomass fuels combined.

(3) Total CH_4 emissions for all fuels combined.

(4) Total N_2O emissions for all fuels combined.

(b) Annual fuel consumption:

(1) For gases, report in units of standard cubic meters.

(2) For liquids, report in units of kilolitres.

(3) For non-biomass solids, report in units of tonnes.

(4) For biomass-derived solid fuels, report in units of bone dry tonnes.

(c) Annual weighted average carbon content of each fuel, if used to compute CO_2 emissions as specified in WCI.43.

(d) Annual weighted average high heating value of each fuel, if used to compute CO_2 emissions as specified WCI.43.

(e) The nameplate generating capacity in megawatts (MW) and net power generated in the reporting year in megawatt hours (MWh).

(f) For each cogeneration unit, indicate whether topping or bottoming cycle and provide useful thermal output as applicable, in MJ. Where steam or heat is acquired from another facility for the generation of electricity, report the provider and amount of acquired steam or heat in MJ. Where supplemental firing has been applied to support electricity generation, report this purpose and fuel consumption by fuel type using the units in WCI.42(b).

(g) Process CO_2 emissions from acid gas scrubbers and acid gas reagent.

(h) Fugitive emissions of each of the HFCs from cooling units that support power generation.

(i) Fugitive CO_2 emissions from geothermal facilities.

(j) Fugitive CH_4 emissions from coal storage at coal-fired electricity generating facilities shall be reported as specified in section WCI.100.

§ WCI.43 Calculation of Greenhouse Gas Emissions

If a facility combusts natural gas or diesel in more than one electrical generating unit, and each unit is not individually metered (or, in the case of diesel, does not have a dedicated tank) and no CEMS is in place, the facility may calculate CO_2, CH_4, and N_2O emissions for each unit by using a common meter or tank that meets the requirement of this method, of WCI.020, and/or regulation, as appropriate.

To disaggregate emissions from the common meter for each unit, an engineering estimation approach that takes into account total emissions, relative operating hours of each unit, and combustion efficiency of each unit must be used. For diesel generating facilities in non-integrated remote areas, the disaggregation may be performed by calculation of MWh energy delivered by the facility and each diesel generating unit in combination with the amount of fuel used.

(a) Calculation of CO_2 Emissions.

Operators shall use CEMS to measure CO_2 emissions if required to operate a CEMS by any other federal, provincial, or local regulation and that includes both a stack gas volumetric flow rate monitor and a CO_2 concentration monitor. Operators not required to operate a CEMS by another regulation may use either CEMS or the calculation methods specified in paragraphs (a)(1) through (a)(7). Operators may use such a CEMS for calculation of CO_2 emissions from electrical generating units for any fuel covered in WCI.43, if applicable to the situation at the facility. Operators using CEMS to determine CO_2 emissions shall comply with the provisions in section WCI.23(d).

(1) Fuels Listed in Table 20-1a and Natural Gas. For electric generating units combusting natural gas (with a high heat value greater than or equal to 36.3 MJ/scm and less than or equal to 40.98 MJ/scm) or fuels in Table 20-1a, use methods in accordance with WCI.23.

(A) Calculation Methodology 1 may not be used at a facility for a fuel for which you routinely perform fuel sampling and analysis for the fuel high heat value or can obtain the results of fuel sampling and analysis for the fuel heat value from the fuel supplier at the frequency specified in WCI.25(a), or at a greater frequency. In such cases, Calculation Methodologies 2, 3, or 4 shall be used for those fuels.

(B) Natural Gas. For electric generating units combusting natural gas with a high heat value less than 36.3 MJ/scm or greater than 40.98 MJ/scm use the measured carbon content of the fuel and the Calculation Methodology 3 in WCI.23(c) or Calculation Methodology 4 in WCI.23(d).

(2) Coal or Petroleum Coke. For electric generating units combusting coal or petroleum coke, use the measured carbon content of the fuel and Calculation Methodology 3 in WCI.23(c).

(3) Middle Distillates, Gasoline, Residual Oil, or Liquid Petroleum Gases that are not listed in Table 20-1a. For electric generating units combusting middle distillates, gasoline, residual oil, or LPG, that are not listed in Table 20-1a, use one of the following methods:

(A) The measured carbon content of the fuel and Calculation Methodology 3 in WCI.23(c); or

(B) The measured heat content of the fuel and Calculation Methodology 2 in WCI.23(b), provided the facility is not subject to verification requirements by regulation.

(4) Refinery Fuel Gas, Flexigas, or Associated Gas. For electric generating units combusting refinery fuel gas, flexigas, or associated gas, use the methods specified in WCI.30.

(5) Landfill Gas, Biogas, or Biomass. For electric generating units combusting landfill gas, biogas, or biomass, use methods in accordance with WCI.23.

(6) Municipal Solid Waste. Electric generating units combusting municipal solid waste, may use the measured steam generated, the default emission factor in WCI.20 Table 20-7, and the calculation methodology in WCI.23(b)(2), provided the facility is not subject to verification requirements by regulation. If the facility is subject to verification requirements by regulation, the operator shall use CEMS to measure CO_2 emissions in accordance with WCI.23(d), or calculate emissions using steam flow and a CO_2 emission factor according to the provisions of WCI.23(c)(2).

(7) Start-up Fuels. The operators of generating facilities that primarily combust biomass-derived fuels but combust fossil fuels during start-up, shut-down, or malfunction operating periods only, shall calculate CO_2 emissions from fossil fuel combustion using one of the following methods. Malfunction means the unplanned outage of equipment; breakdown of equipment; or failure of equipment to operate normally, associated with the operation of a combustion device for an electricity generation unit(s). It does not include normal changes in operation conditions such as variations in combustion temperature, oxygen levels or moisture content of the fuel.

(A) The default emission factors from Tables 20-1a, 20-2, 20-3, 20-5 or 20-7, and default HHV from Tables 20-1 or 20-1a, as applicable, and calculation methodology 1 provided in WCI.23(a);

(B) The measured heat content of the fuel and Calculation Methodology 2 provided in WCI.23(b);

(C) The measured carbon content of the fuel and Calculation Methodology 3 provided in WCI.23(c); or

(D) For combustion of refinery fuel gas, the measured heat content and carbon content of the fuel, and the calculation methodology provided in WCI.30.

(8) Co-fired Electricity Generating Units. For electricity generating units that combust more than one type of fuel, the operator shall calculate CO_2 emissions as follows.

(A) For co-fired electricity generators that burn only fossil fuels, CO_2 emissions shall be determined using one of the following methods:

(i) A continuous emission monitoring system in accordance with Calculation Methodology 4 in WCI.23(d). Operators using this method need not report emissions separately for each fossil fuel.

(ii) For units not equipped with a continuous emission system, calculate the CO_2 emissions separately for each fuel type using the methods specified in paragraphs (a)(1) through (a)(4) of this section.

(B) For co-fired electricity generators that burn biomass-derived fuel with a fossil fuel, CO_2 emissions shall be determined using one of the following methods:

(i) A continuous emission monitoring system in accordance with Calculation Methodology 4 in WCI.23(d). Operators using this method shall determine the portion of the total CO_2 emissions attributable to the biomass-derived fuel and portion of the total CO_2 emissions attributable to the fossil fuel using the methods specified in WCI.23(d)(4).

(ii) For units not equipped with a continuous emission system, calculate the CO_2 emissions separately for each fuel type using the methods specified in paragraphs (a)(1) through (a)(7) of this section.

(b) Calculation of CH_4 and N_2O Emissions. Operators of electricity generating units shall use the methods specified in WCI.24 to calculate the annual CH_4 and N_2O emissions. For coal combustion, use the default CH_4 emission factor(s) in Table 20-6.

(c) Calculation of CO_2 Emissions from Acid Gas Scrubbing. Operators of electricity generating units that use acid gas scrubbers or add an acid gas reagent to the combustion unit shall calculate the annual CO_2 emissions from these processes using Equation 40-1 if these emissions are not already captured in CO_2 emissions determined using a continuous emissions monitoring system.

$$CO_2 = S \times R \times \left(CO_{2MW} / Sorbent_{MW}\right) \qquad \textbf{Equation 40-1}$$

Where:

CO_2	=	CO_2 emitted from sorbent for the report year (tonnes).
S	=	Limestone or other sorbent used in the report year (tonnes).
R	=	Ratio of moles of CO_2 released upon capture of one mole of acid gas.
$CO_{2\ MW}$	=	Molecular weight of carbon dioxide (44).
$Sorbent_{MW}$	=	Molecular weight of sorbent (if calcium carbonate, 100).

(d) Calculating Fugitive HFC Emissions from Cooling Units. Operators of electricity generating facilities shall calculate fugitive HFC emissions for each HFC compound used in cooling units that support power generation or are used in heat transfers to cool stack gases using either the methodology in paragraph (d)(1) or (d)(2). The Operator is not required to report GHG emissions from air or water cooling systems or condensers that do not contain HFCs or from heating ventilation and air conditioning systems used for cooling of control rooms, offices and buildings at the facility.

(1) Use Equation 40-2 to calculate annual HFC emissions:

$$HFC = HFC_{inventory} + HFC_{purchases/acquisitions} - HFC_{sales/disbursements} + HFC_{\Delta capacity}$$ **Equation 40-2**

Where:

HFC	=	Annual fugitive HFC emission (tonnes).
$HFC_{inventory}$	=	The difference between the quantity of HFC in storage at the beginning of the year and the quantity in storage at the end of the year. Stored HFC includes HFC contained in cylinders (such as 115-pound storage cylinders), gas carts, and other storage containers. It does not include HFC gas held in operating equipment. The change in inventory will be negative if the quantity of HFC in storage increases over the course of the year.
$HFC_{purchases/acquisitions}$	=	The sum of all HFC acquired from other entities during the year either in storage containers or in equipment.
$HFC_{sales/disbursements}$	=	The sum of all the HFC sold or otherwise transferred offsite to other entities during the year either in storage containers or in equipment.
$HFC_{\Delta capacity}$	=	The net change in the total nameplate capacity (i.e. the full and proper charge) of the cooling equipment. The net change in capacity will be negative if the total nameplate capacity at the end of the year is less than the total nameplate capacity at the beginning of the year.

(2) Use service logs to document HFC usage and emissions from each cooling unit. Service logs should document all maintenance and service performed on the unit during the report year, including the quantity of HFCs added to or removed from the unit, and include a record at the beginning and end of each report year. The operator may use service log information along with the following simplified material balance equations to quantify fugitive HFCs from unit installation, servicing, and retirement, as applicable. The operator shall include the sum of HFC emissions from the applicable equations in the greenhouse gas emissions data report.

$$HFC_{Install} = R_{new} - C_{new}$$ **Equation 40-2a**

$$HFC_{Service} = R_{recharge} - R_{Recover}$$ **Equation 40-2b**

$$HFC_{Retire} = C_{retire} - R_{retire}$$ **Equation 40-2c**

Where:

$HFC_{Install}$	=	HFC emitted during initial charging/installation of the unit (kilograms).
$HFC_{Service}$	=	HFC emitted during use and servicing of the unit for the report year (kilograms).

HFC_{Retire} = HFC emitted during the removal from service/retirement of the unit (kilograms).
R_{new} = HFC used to fill new unit (omit if unit was pre-charged by the manufacturer), (kilograms).
C_{new} = Nameplate capacity of new unit (omit if unit was pre-charged by the manufacturer) (kilograms).
$R_{recharge}$ = HFC used to recharge the unit during maintenance and service (kilograms).
$R_{recover}$ = HFC recovered from the unit during maintenance and service (kilograms).
C_{retire} = Nameplate capacity of the retired unit (kilograms).
R_{retire} = HFC recovered from the retired unit (kilograms).

(e) Fugitive CO_2 Emissions from Geothermal Facilities. Operators of geothermal electricity generating facilities shall calculate the fugitive CO_2 emissions using one of the following methods:

(1) Calculate the fugitive CO_2 emissions using Equation 40-3:

$$CO_2 = 7.14 \times Heat \times 0.001$$ **Equation 40-3**

Where:

CO_2 = CO_2 emissions (tonnes per year).
7.14 = Default fugitive CO_2 emission factor for geothermal facilities (kg per GJ).
Heat = Heat taken from geothermal steam and/or fluid (GJ/yr).
0.001 = Conversion factor from kg to tonnes.

(2) Calculate CO_2 emissions using source specific emission factor approved by the regulator for this rule..

§ WCI.44 Sampling, Analysis, and Measurement Requirements

(a) CO_2, CH_4 and N_2O Emissions from Fuel Combustion. Operators using CEMS to estimate CO_2 emissions from fuel combustion shall comply with the requirements in WCI.23(d). Operators using methods other than CEMS shall comply with the applicable fuel sampling, fuel consumption monitoring, heat content monitoring, carbon content monitoring, and calculation methods specified in WCI.25.

(b) CO_2 Emissions from Acid Gas Scrubbing. Operators of electricity generating units that use acid gas scrubbers or add an acid gas reagent to the combustion unit shall measure the amount of limestone or other sorbent used during the reporting year.

(c) CO_2 Emissions from Geothermal Facilities. Operators of geothermal facilities shall measure the heat recovered from geothermal steam. If using source specific emission factor instead of the default factor, the operator shall conduct an annual test of the CO_2 emission rate using a method approved by the regulator. The operator shall submit a test plan to the regulator for approval. Once approved, the annual tests shall be conducted in accordance with the approved test plan under the supervision of the regulator .

§ WCI.45 Procedures for estimating missing data.

Whenever a quality-assured value of a required parameter is unavailable (e.g., if a CEMS malfunctions during unit operation or if a required fuel sample is not taken), a substitute data value for the missing parameter shall be used in the calculations.

(a) For all units using CEMS to measure CO_2 emissions, follow the missing data procedures in WCI.26(a)

(b) For all other missing parameters used to calculate GHG emissions, follow the missing data procedures in WCI.26(b).

§ WCI.46 Definitions

Except as specified in this section, all terms used in this subpart have the same meaning given in the General Provisions.

<u>Bottoming cycle plant</u> means a cogeneration plant in which the energy input to the system is first applied to a useful thermal energy application or process, and at least some of the rejected heat emerging from the application or process is then used for electricity production.

<u>Cogeneration unit</u> means a stationary fuel combustion device which simultaneously generates electrical and thermal energy that is (a) used by the operator of the facility where the cogeneration unit is located; or (b) transferred to another facility for use by that facility.

<u>Cogeneration system</u> means individual cogeneration components, including the prime mover (heat engine), generator, heat recovery, and electrical interconnection, configured into an integrated system that provides sequential generation of multiple forms of useful energy (usually electrical and thermal), at least one form of which the facility consumes on-site or makes available to other users for an end-use other than electricity generation.

<u>Topping cycle plant</u> means a cogeneration plant in which the energy input to the plant is first used to produce electricity, and at least some of the reject heat from the electricity production process is then used to provide useful thermal output.

§ WCI.50 ADIPIC ACID MANUFACTURING

§ WCI.51 Source Category Definition

The adipic acid production source category consists of all adipic acid production facilities that use oxidation to produce adipic acid.

§ WCI.52 Greenhouse Gas Reporting Requirements

For the purpose of the Regulation, the annual emissions data report for adipic acid manufacturing shall include the following information at the facility level calculated in accordance this method:

(a) Annual process N_2O emissions from adipic acid production (tonnes).

(b) Annual adipic acid production (tonnes).

(c) Emissions of CO_2, CH_4, and N_2O from stationary combustion must report under WCI.20 (General Stationary Fuel Combustion Sources) following the requirements of WCI.20.

§ WCI.53 Calculation of N_2O Emissions

(a) You must determine annual N_2O emissions from adipic acid production according to paragraphs (a)(1) or (a)(2) of this section.

(1) Use a site-specific emission factor and production data according to paragraphs (b) through (g) of this section.

(2) Request approval by the Director for an alternative method of determining N_2O emissions.

(b) You must conduct an annual performance test or use continuous monitors according to paragraphs (b)(1) through (b)(3) of this section.

(1) You must conduct the test on the waste gas stream from the nitric acid oxidation step of the process using the methods specified in WCI.54 (b) through (d) or use a continuous monitoring system.

(2) You must conduct the performance test under normal process operating conditions and without using N_2O abatement technology or use a continuous monitoring system.

(3) You must measure the adipic acid production rate during the test and calculate the production rate for the test period or the continuous monitoring period in tonnes per hour.

(c) You must determine an N_2O emissions factor to use in Equation 50-2 of this section according to paragraphs (c)(1) or (c)(2) of this section.

(1) You may request Director approval for an alternative method of determining N_2O concentrations according to the procedures in paragraphs (a)(2) of this section.

(2) Using the results of the test or continuous monitors in paragraph (b) of this section, you must calculate a facility-specific emissions factor according to Equation 50-1 for performance testing and 50-1a for continuous monitors of this section:

$$EF_{N2O} = \frac{\sum_{1}^{n} \frac{C_{N2O} * 1.826\times10^{-6} * Q}{P}}{n}$$ **Equation 50-1**

$$EF_{N2O} = \frac{C_{N2O} * 1.826\times10^{-6} * Q}{P}$$ **Equation 50-1a**

Where:

EF_{N2O}	=	Average facility-specific N_2O emissions factor (kg N_2O generated/tonne adipic acid produced).
C_{N2O}	=	N_2O concentration per test run during the performance test or average hourly concentrations for continuous monitors (ppm N_2O).
$1.828x10^{-6}$	=	Conversion factor (kg/dsm^3-ppm N_2O).
Q	=	Volumetric flow rate of effluent gas per test run during the performance test or hourly readings for continuous monitor (dsm^3/hr).
P	=	Production rate per test run during the performance test or the average hourly production rate for continuous monitors (tonnes adipic acid produced/hr).
n	=	Number of test runs.

(d) If applicable, you must determine the destruction efficiency for each N_2O abatement technology used at your facility according to paragraphs (d)(1), (d)(2), (d)(3) or (d)(4) of this section.

(1) Use the manufacturer's specified destruction efficiency.

(2) Estimate the destruction efficiency through process knowledge. Examples of information that could constitute process knowledge include calculations based on material balances, process stoichiometry, or previous test results provided the results are still relevant to the current vent stream conditions. You must document how process knowledge was used to determine the destruction efficiency.

(3) Calculate the destruction efficiency by conducting an additional performance test on the emissions stream following the N_2O abatement technology.

(4) Calculate the destruction efficiency by the use of continuous monitors on the controlled and uncontrolled emissions.

(e) If applicable, you must determine the abatement factor for each N_2O abatement technology used at your facility. The abatement factor is calculated for each adipic acid facility according to Equation 50-2 of this section.

$$AF = \frac{P_{a\ Abate}}{P_a}$$ **Equation 50-2**

Where:

AF	=	Abatement factor of N_2O abatement technology (fraction of annual production that abatement technology is operating).
$P_{a\ Abate}$	=	Annual adipic acid production during which N_2O abatement was used (tonne acid produced).
P_a	=	Total annual adipic acid production (tonne acid produced).

(f) You must determine the annual amount of adipic acid produced and the annual adipic acid production during which N_2O abatement is operating.

(g) You must calculate annual adipic acid production process emissions of N_2O by multiplying the emissions factor (determined using Equation 50-1 of this section) by the adipic acid production for each period and accounting for N_2O abatement, according to Equation 50-3 of this section:

$$N_2O = \sum_{i=1}^{N} \frac{EF_{N20i} * P_{ai} * (1-(DF_i * AF_i))}{1000}$$ **Equation 50-3**

Where:

N_2O	=	Annual N_2O mass emissions from adipic acid production (tonnes).
EF_{N2Oi}	=	Facility-specific N_2O emissions factor for the period *i* (kg N_2O generated/tonne adipic acid produced).
P_{ai}	=	Adipic acid produced in the period *i* (tonnes).
DF_i	=	Destruction efficiency of N_2O abatement technology for the period *i* (abatement device destruction efficiency, percent of N_2O removed from air stream).
AF_i	=	Abatement factor of N_2O abatement technology for the period *i* (fraction of annual production abatement technology is operating).
1000	=	Conversion factor (kg/tonne).
N	=	Number of different periods in the year. For performance test, the period would be the time between each test (e.g., N is 1 year if performance test conducted annually). For continuous monitors, N would be the number of months in the year (or more) with P_{ai}, EF_{N2Oi}, DF_i and AF_i to be calculated for each month.

§ WCI.54 Monitoring Requirements

(a) You must conduct a new performance test and calculate a new facility-specific emissions factor according to the frequency specified in paragraphs (a)(1) of this section, or use continuous monitors to calculate a facility-specific emissions factor and destruction efficiency according to paragraphs (a)(2) of this section.

(1) Performance Test

(i) Conduct the performance test annually.

(ii) Conduct the performance test when your adipic acid production process is changed either by altering the ratio of cyclohexanone to cyclohexanol or by installing abatement equipment.

(2) Continuous Monitors

(i) Use continuous monitors to determine the uncontrolled emissions and the controlled N_2O emissions to derive an N_2O emission factor and abatement system destruction factor.

(ii) The continuous monitors shall be operated in accordance with quality assurance and quality control program approved by the Director.

(b) You must measure the N_2O concentration during the performance test using one of the methods in paragraphs (b)(1) through (b)(3) of this section.

(1) EPA Method 320, Measurement of Vapor Phase Organic and Inorganic Emissions by Extractive Fourier Transform Infrared (FTIR) Spectroscopy in 40 CFR part 63 (U.S.), Appendix A;

(2) ASTM D6348-03 Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy; or

(3) An equivalent method or continuous monitors, with Director approval.

(c) You must determine the production rate(s) during the performance test according to paragraph (c)(1) or (c)(2) of this section.

(1) Direct measurement (such as using flow meters or weigh scales).

(2) Existing plant procedures used for accounting purposes.

(d) You must conduct all required performance tests according to the methods in WCI.54(b). For each test, the facility must prepare an emissions factor determination report that must include the items in paragraphs (d)(1) through (d)(3) of this section:

(1) Analysis of samples, determination of emissions, and raw data.

(2) All information and data used to derive the emissions factor.

(3) The production rate(s) during the performance test and how each production rate was determined.

(e) You must determine the monthly adipic acid production quantity and the monthly adipic acid production during which N_2O abatement technology is operating according to the methods in paragraphs (c)(1) or (c)(2) of this section.

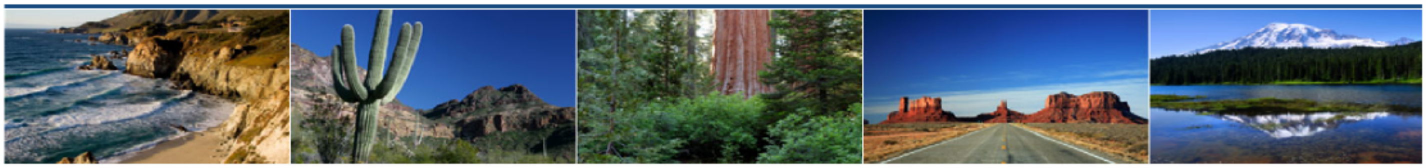
(f) You must determine the annual adipic acid production quantity and the annual adipic production quantity during which N_2O abatement technology is operating by summing the respective monthly adipic acid production quantities.

§ WCI.55 Procedures for Estimating Missing Data

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraphs (a) and (b) of this section.

(a) For each missing value of monthly adipic acid production, the substitute data shall be the best available estimate based on all available process data or data used for accounting purposes (such as sales records).

(b) For missing values related to the performance test, including emission factors, production rate, and N_2O concentration, you must conduct a new performance test according to the procedures in §98.54 (a) through (d).



§ WCI.60 IMPORTED ELECTRICITY

[*The requirements in this attachment do not include the default emissions factors necessary for reporting imported electricity from asset-controlling suppliers or imports from unspecified sources. Default factors for unspecified sources are under development by the Electricity Committee and asset-controlling suppliers will need to approach each jurisdiction for approval of a differentiated default factor.*]

§ WCI.61 Definitions

"Asset-controlling supplier" means any entity that owns or operates electricity generating facilities or serves as an exclusive marketer for certain generating facilities even though it does not own them, and is assigned a supplier-specific identification number for its fleet of generating facilities by [*the jurisdiction*].

"Balancing authority" means a responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports interconnection frequency in real time.

"Balancing authority area" means the collection of generation, transmission, and loads within the metered boundaries of a balancing authority. A balancing authority maintains load-resource balance within this area.

"Busbar" means a power conduit of an electricity generating facility that serves as the starting point for the electricity transmission system.

"Electricity generating facility" means a facility that generates electricity and includes one or more electricity generating units at the same location.

"Electricity importer" means [common boundary FJD] an owner of imported electricity [*or electricity wheeled through the WCI Region*] as it is delivered to the first point of delivery in the WCI Region or; [individual boundary FJD] an owner of imported electricity [*or electricity wheeled through the WCI Region*] as it is delivered to the first point of delivery in the WCI Partner jurisdiction of the final point of delivery. [The definition used may vary by jurisdiction.]

"Electricity transaction" means the purchase, sale, import, export or exchange of electric power.

"Electricity wheeled through the WCI Region" means electricity that is imported into the WCI Region but is simultaneously exported out of the WCI Region and has a final point of delivery in a location outside of the WCI Region.

"Entity" means a person, firm, association, organization, partnership, business trust, corporation, limited liability company, company, or government agency.

"Exchange agreement" means a commitment between electricity market participants to swap energy for energy. Exchange transactions do not involve transfers of payment or receipts of money for the full market value of the energy being exchanged, but may include payment for net differences due to market price differences between the two parts of the transaction or to settle minor imbalances.

“Final point of delivery” means the last point of delivery for a given electricity transaction.

“First Jurisdictional Deliverer” means the owner or operator of an electricity generating facility in a WCI Partner jurisdiction or an electricity importer that is jurisdictional to the regulatory authority of a WCI Partner jurisdiction or the immediate downstream purchaser or recipient of electricity from a non-jurisdictional electricity importer.

“Gross generation” means the total electrical output of the generating unit, expressed in megawatt hours (MWh) per year.

“Imported electricity” means electric power generated outside the WCI Region, delivered into the WCI Region and having a final point of delivery in the WCI Region.

“Megawatt hour” or “MWh” means the electrical energy unit of measure equal to one million watts of power supplied to, or taken from, an electric circuit steadily for one hour.

“Multi-jurisdictional retail provider” means a retail provider that provides electricity to consumers in [*the jurisdiction*] and in one or more other non-WCI jurisdictions in a contiguous service territory.

“Nameplate generating capacity” means the maximum rated output of a generator under specific conditions designated by the manufacturer, expressed in megawatts (MW) or kilowatts (kW).

“Net power generated” means the gross generation minus station service or unit service power requirements, expressed in megawatt hours (MWh) per year. In the case of cogeneration, this value is intended to include internal consumption of electricity for the purposes of a production process, as well as power put on the grid.

“NERC E-tag” means North American Electric Reliability Corporation (NERC) energy tag representing transactions on the North American bulk electricity market scheduled to flow between or across balancing authority areas.

“Point of delivery” means a point on an electricity transmission or distribution system where a power supplier delivers electricity to the receiver of that energy. This point can be an interconnection with another system or a substation where the transmission provider’s transmission and distribution systems are connected to another system, or a distribution substation where electricity is imported into the WCI region over a multi-jurisdictional retail provider’s distribution system.

“Power contract” means an arrangement for the purchase of electricity. Power contracts may be, but are not limited to, power purchase agreements and tariff provisions.

“Purchasing/selling entity” means an entity that purchases or sells energy or capacity and reserves transmission services between or among balancing authority areas.

“Renewable energy” means energy from sources that constantly renew themselves or that are regarded as practically inexhaustible. Renewable energy includes, but is not limited to, energy derived from solar, wind, geothermal, hydroelectric, wood, biomass, tidal power, sea currents, and ocean thermal gradients.

“Renewable energy certificate” or “renewable energy credit” means a certificate of proof issued by an approved generation information system or third-party verifier that one MWh of electricity was generated by a renewable energy source.

“Retail provider” means an entity that provides electricity to retail end users in [*the jurisdiction*].

“Specified source” means a specific electricity generating unit or electricity generating facility which can be matched to a reported electricity transaction due to full or partial ownership by the first jurisdictional deliverer or due to its identification in a power contract with the first jurisdictional deliverer.

“Unspecified source” means electricity generation that cannot be matched to a specific electricity generating facility or electricity generating unit. Unspecified sources of electricity may include electricity purchased from entities that own fleets of generating facilities such as independent power producers, retail providers, and federal power agencies and power purchased from electricity marketers, brokers, and markets.

“Western Climate Initiative” or “WCI” means a collaborative effort of the U.S. states and Canadian provinces that comprise the WCI Region to reduce greenhouse gas emissions in their respective jurisdictions.

“WCI Region” means the Canadian provinces of British Columbia, Manitoba, Ontario, and Quebec plus the U.S. states of Arizona, California, Montana, New Mexico, Oregon, Utah, and Washington, excluding lands that are not subject to state or provincial jurisdiction.

§ WCI.62 Greenhouse Gas Emissions Data Report: First Jurisdictional Deliverers of Imported Electricity

(a) General Requirements. First jurisdictional deliverers shall meet the following general requirements in preparing their greenhouse gas emissions data report for each report year. When reporting emissions and electricity transactions, first jurisdictional deliverers, excluding imported electricity that is imported at the distribution level by multi-jurisdictional retail providers, shall:

(1) Specify the amount of greenhouse gas emissions in metric tons CO_2e;

(2) Specify the amount of electricity in MWh;

(3) Aggregate imported electricity and emissions from specified sources by electricity generating facility or electricity generating unit, as applicable;

(4) For electricity from specified sources, specify the facility name, the facility ID, and, if applicable, the electricity generating unit ID for the unit generating the electricity;

(5) Report the amount of imported electricity from specified sources as measured at the busbar;

(6) For imported electricity transactions from specified sources where measurements at the busbar are not known, report the amount of imported electricity from the applicable specified sources as measured at the first point of delivery in [*the jurisdiction]* and report estimated transmission losses for each specified source;

(7) Report the amount of electricity from unspecified sources as measured at the first point of delivery in [*the jurisdiction*];

(8) For electricity from unspecified sources, disaggregate imported electricity by the balancing authority area or other geographic area as defined by [*the jurisdiction*] from which the electricity originated;

(9) Report the amount of electricity from asset-controlling suppliers as measured at the first point of delivery in [*the jurisdiction*];

(10) For electricity from asset-controlling suppliers, disaggregate imported electricity by the asset-controlling or asset-owning supplier from which the electricity was purchased;

(11) Report the number of renewable energy certificates from sources not in the WCI region that are retired, or whose greenhouse gas source specification fields are retired, as applicable, associated with imported electricity from an unspecified source or imported electricity from a specified source having an emission rate equal to or less than the default rate for the balancing authority where the specified generating facility is located;

(12) Specify electricity imported under exchange agreements as you would other import transactions;

(13) Report quantities of electricity wheeled through the WCI Region as measured at the first point of delivery inside [*the jurisdiction*];

(14) Retain for purposes of verification NERC E-tags, power contracts, settlements data, and all other information needed to confirm the transactions.

(b) Report Content. First Jurisdictional Deliverers shall include the following information in the greenhouse gas emissions data report for each report year.

(1) Specified Imported Electricity Transactions. Imported electricity and emissions from specified sources for which the First Jurisdictional Deliverer is the electricity importer or that the First Jurisdictional Deliverer purchased or received immediately downstream from a non-jurisdictional electricity importer.

(A) Electricity imported into the WCI Region from a specified hydroelectric generating facility with nameplate capacity of greater than 30 MW that was operational prior to January 1, 2008 or from a specified nuclear facility that was operational prior to January 1, 2008 shall be listed as one of the following:

(i) Electricity purchased with a contract in effect prior to January 1, 2008 that remains in effect or has been renegotiated for the same facility for the same share or quantity of net generation within one year of contract expiration;

(ii) Electricity purchased not meeting WCI.62(b)(1)(A)(i) and that is not associated with an increase in the facility's generating capacity;

(iii) Electricity purchased not meeting WCI.62(b)(1)(A)(i) that is associated with an increase in the facility's generating capacity due to increased efficiencies or other capacity increasing actions;

(iv) Electricity purchased from hydroelectric generating facilities during a "spill or sell" situation where power not purchased is lost;

(v) Electricity purchased that does not meet WCI.62(b)(1)(A)(i) due to federal power redistribution polices for federally owned resources and not related to price bidding.

(2) Unspecified Imported Electricity Transactions. Imported electricity and emissions from unspecified sources for which the First Jurisdictional Deliverer is the electricity importer or that the First Jurisdictional Deliverer purchased or received immediately downstream from a non-jurisdictional electricity importer.

(3) Imported Electricity from Asset-Controlling Suppliers. Imported electricity and emissions from asset-controlling suppliers for which the First Jurisdictional Deliverer is the electricity importer or that the First Jurisdictional Deliverer purchased or received immediately downstream from a non-jurisdictional electricity importer.

(4) Electricity Wheeled Through the WCI Region. Electricity wheeled through the WCI Region for which the First Jurisdictional Deliverer is the electricity importer or that the First Jurisdictional Deliverer purchased or received immediately downstream from a non-jurisdictional electricity importer.

§ WCI.63 Calculation of Emissions from Specified Sources

For each specified source, calculate CO_2 mass emissions using one of the two calculation methodologies specified in this section.

(a) Calculation Methodology 1: If the specified source reports emissions to [*the jurisdiction*], The Climate Registry, the U.S.EPA under 40 CFR Part 75 or to Environment Canada under Section 71 of the Canadian Environmental Protection Act calculate emissions using Equation 60-1:

$$CO_2 = CO_{2t} \times \frac{MWh_{imp}}{MWh_t} \qquad \textbf{Equation 60-1}$$

Where:

CO_2 = Annual CO_2 mass emissions for imported electricity from the specified source (metric tons).

CO_{2t} = Total annual CO_2 mass emissions from the specified source (metric tons) reported, in order of preference, to [*the jurisdiction*], The Climate Registry, or to the U.S.EPA or Environment Canada.

MWh_{imp} = Megawatt-hours of electricity imported from the specified source, including estimated losses for transactions not measured at the busbar.

MWh_t = Total megawatt-hours of net power generated by the specified source.

(b) Calculation Methodology 2: If the specified source does not report emissions to [*the jurisdiction*], The Climate Registry, the U.S.EPA under 40 CFR Part 75 or to Environment Canada under Section 71 of the Canadian Environmental Protection Act, calculate emissions using Equation 60-2:

$$CO_2 = \sum HHV_f \times EF_f \times 0.001 \times \frac{MWh_{imp}}{MWh_t} \qquad \textbf{Equation 60-2}$$

Where:

CO_2	=	Annual CO_2 mass emissions for a specific fuel type (metric tons).
HHV_f	=	Higher heating value of the fuel *f* consumed for electricity production as reported in U.S. EIA Form 923, or its successor (mmBtu).
EF_f	=	Fuel-specific default CO_2 emission factor, from column 5 of Table 20-1 or from Table 20-2 (kg CO_2/mmBtu).
0.001	=	Conversion factor from kilograms to metric tons.
MWh_{imp}	=	Megawatt-hours of electricity imported from the specified source.
MWh_t	=	Total megawatt-hours of net power generated by the specified source as reported in U.S. EIA Form 923, or its successor.

§ WCI.64 Calculation of Emissions from Asset-Controlling Suppliers and Unspecified Sources

For imported electricity from asset-controlling suppliers or unspecified sources, calculate emissions using the methodology specified in this section.

(a) Calculation Methodology: Calculate the annual CO_2 mass emissions by multiplying the reported quantities of imported electricity from each asset-controlling supplier, balancing authority area, or other geographic region defined by [*the jurisdiction*] by the appropriate default emission factor according to Equation 60-3:

$$CO_2 = MWh \times DEF$$ **Equation 60-3**

Where:

CO_2	=	Annual CO_2 mass emissions for imported electricity from the specified source (metric tons).
MWh	=	Megawatt-hours of electricity imported from the asset-controlling supplier, balancing authority area, or other geographic region defined by [*the jurisdiction*].
DEF	=	The default emission factor corresponding to the asset-controlling supplier, balancing authority area, or other geographic region defined by [*the jurisdiction*].

§ WCI.65 Greenhouse Gas Emissions Data Report: Additional Requirements for Retail Providers Only

[*This section is optional. It is intended for any WCI jurisdiction that wishes to collect information about high-GHG generating facilities in other jurisdictions owned by retail providers serving its own jurisdiction.*]

Retail providers shall include the following information in the greenhouse gas emissions data report for each report year, in addition to the information identified in the sections above.

(a) If the retail provider holds a contract that entitles the retail provider to a specified percentage of the generation in the report year from an electricity generating facility not located in the WCI Region, the retail provider shall include electricity purchased or sold from that facility as being from a partially owned facility.

(b) For electricity generating facilities not located in the WCI Region that are fully or partially owned by the retail provider that have CO2 emissions greater than 500 kg of CO2 per MWh based on the most recent greenhouse gas emissions data report that received a positive verification opinion or on CO2 emissions reported to U.S.EPA under 40 CFR Part 75 or reported to Environment Canada under Section 71 of the Canadian Environmental Protection Act, the retail provider shall include:

(1) Facility name, state/province designated facility ID, state/province designated generating unit ID as applicable, percent ownership share at the facility level, ownership share at the generating unit level as applicable, and both net and gross power generated in the report year;

(2) Quantity of electricity sold by the retail provider or on behalf of the retail provider from the electricity generating facility or electricity generating unit having a final point of delivery outside the WCI Region, as measured at the busbar.

§ WCI.66 Greenhouse Gas Emissions Data Report: Additional Requirements for Multi-Jurisdictional Retail Providers Only.

[*This section applies only to jurisdictions with Multi-Jurisdictional Retail Providers, as defined.*]

Multi-jurisdictional retail providers that import electricity into the WCI Region at the distribution level shall include the following information in the greenhouse gas emissions data report for each report year in addition to the information identified in the sections above. Multi-jurisdictional retail providers meeting this condition shall provide:

(a) A report of the greenhouse gas emissions associated with serving the load of the service territory that includes consumers in [*the jurisdiction*] following [*the jurisdiction's*] reporting protocol for retail providers or The Climate Registry's Electric Power Sector Protocol;

(b) The total retail load served by the multi-jurisdictional retail provider in the service territory that includes consumers in [*the jurisdiction*];

(c) The retail load of customers served in [*the jurisdiction's*] portion of the service territory;

(d) The greenhouse gas emissions associated with the imported electricity as the quantity of emissions reported in WCI.64(a) multiplied by the ratio of the quantity of electricity reported in WCI.64(b) to the quantity of electricity reported in WCI.64(c); and

(e) If the average emission rates differ among the various state or provincial portions of the service territory due to mandatory factors such as different Renewable Portfolio Standard requirements in [*the jurisdiction*] and the other jurisdictions, the multi-jurisdictional retail provider may report an adjusted quantity of greenhouse emissions and file a report that describes how the quantity reported in WCI.64(d) was adjusted.

§ WCI.70 PRIMARY ALUMINUM PRODUCTION

§ WCI.71 Source Category Definition

A primary aluminum production process converts alumina mineral to aluminum metal using the Hall-Héroult manufacturing process, which includes electrolysis in prebake and Søderberg cells and anode baking for prebake cells.

§ WCI.72 Greenhouse Gas Reporting Requirements

For each facility that includes a primary aluminum production process, the emissions data report must contain the following information:

(a) CO_2 emissions from anode consumption from prebaked and Søderberg electrolysis cells.

(b) CO_2 emissions from anode and cathode baking.

(c) CF_4 and C_2F_6 emissions for anode effects.

(d) CO_2 emissions from green coke calcination.

(e) SF_6 emissions from cover gas consumption.

(f) CO_2, N_2O, and CH_4 emissions from stationary combustion units as specified in WCI.20.

(g) Annual aluminum production.

(h) Type of smelter technology used.

(i) CF_4 and C_2F_6 emissions from anode effects in all prebake and all Søderberg electrolysis cells combined.

(j) Anode effect minutes per cell-day (AE-mins/cell-day), anode effect frequency (AE/cell-day), and anode effect duration (minutes); alternatively, anode effect overvoltage factor (kg CF_4/metric ton Al) , potline overvoltage (mV/cell day), and current efficiency (%).

(k) Smelter-specific slope coefficients (or overvoltage emission factors) and the last date when the smelter-specific slope coefficients (or overvoltage emission factors) were measured.

(l) Method used to measure the frequency and duration of anode effects (or overvoltage).

(m) Annual anode consumption for prebake cells.

(n) Annual CO_2 emissions from the smelter for prebake cells.

(o) Annual paste consumption for Søderberg cells.

(p) Annual CO_2 emissions from the smelter for Søderberg cells.

(q) Smelter-specific inputs to the CO_2 process equations (e.g., levels of sulphur and ash) that were used in the calculation, on an annual basis.

§ WCI.73 Calculation of GHG Emissions

(a) Calculate CO_2 emissions from anode consumption using either Equation 70-1 or 70-2, as applicable.

(1) For Prebaked Anodes:

$$E_{CO_2} = \sum_{i=1}^{12} [NCC \times MP \times \frac{(100 - S_a - Ash_a)}{100} \times 3.664]_i \qquad \textbf{Equation 70-1}$$

Where:

E_{CO2}	=	Annual CO_2 emissions (tonnes).
NCC	=	Net anode consumption per metric ton of aluminum for month *i* (tonne/tonne aluminum).
MP	=	Aluminum production for month *i* (tonne).
S_a	=	Sulphur content in baked anodes for month *i* (wt %).
Ash_a	=	Ash content in baked anodes for month *i* (wt %).
3.664	=	Conversion factor from carbon to CO_2.

(2) For Søderberg Anodes:

$$E_{CO_2} = \sum_{i=1}^{12} \begin{bmatrix} (PC \times MP) - \left(BSM \times \frac{MP}{1000}\right) - \left(\frac{BC}{100} \times PC \times MP \times \left(\frac{S_p + Ash_p + H_p}{100}\right)\right) \\ -\left(\frac{100 - BC}{100} \times PC \times MP \times \frac{S_c + Ash_c}{100}\right) - (CD \times MP) \end{bmatrix}_i \times 3.664 \qquad \textbf{Equation 70-2}$$

Where:

E_{CO2}	=	Annual CO_2 emissions (tonnes).
PC	=	Paste consumption for month *i* (tonnes paste/tonne aluminum).
MP	=	Aluminum production for month *i* (tonnes).
BSM	=	Emissions of benzene-soluble matter (kilograms benzene-soluble matter/tonne aluminum).
BC	=	Average binder (pitch) content in paste for month *i* (wt %).
S_p	=	Sulphur content in pitch for month *i* (wt %).
Ash_p	=	Ash content in pitch (wt %).
H_p	=	Hydrogen content in pitch (wt %).
S_c	=	Sulphur content in calcinated coke (wt %).
Ash_c	=	Ash content in calcinated coke (wt %).
CD	=	Carbon in skimmed dust from Søderberg cells (tonne C/tonne aluminum).
3.664	=	Conversion factor from carbon to CO_2.

(b) If anode or cathode baking is performed onsite, calculate CO_2 emissions as specified in paragraphs (b)(1) or (2) as applicable. Total emissions as specified in paragraph (b)(3) if both (b)(1) and (2) are applicable.

(1) Calculate CO_2 emissions from packing coke using Equation 70-3.

$$EC_{CO_2} = \sum_{i=1}^{12} \left(PCC \times BAP \times \frac{100 - Ash_{pc} - S_{pc}}{100} \right)_i \times 3.664$$ **Equation 70-3**

Where:

EC_{CO2} = Annual CO_2 emissions (tonnes pre year).
PCC = Packing coke consumption per tonne of baked anode for month *i* (tonnes coke/tonne anodes).
BAP = Baked anode production for month *i* (tonnes).
Ash_{pc} = Ash content in packing coke for month *i* (wt %).
S_{pc} = Sulphur content in packing coke for month *i* (wt %).
3.664 = Conversion factor from carbon to CO_2.

(2) Calculate CO_2 emissions from pitch coking using Equation 70-4.

$$EP_{CO_2} = \sum_{i=1}^{12} \left(GAW - BAP - \left(\frac{H_p}{100} \times \frac{PC}{100} \times GAW \right) - RT \right)_i \times 3.664$$ **Equation 70-4**

Where:

EP_{CO2} = CO_2 emissions (tonnes pre year).
GAW = Green anode consumption for month *i* (tonnes).
BAP = Baked anode production for month *i* (tonnes).
H_p = Hydrogen content in pitch for month *i* (wt %).
PC = Pitch content in green anode for month *i* (wt %).
RT = Recovered tar for month *i* (tonnes).
3.664 = Conversion factor from carbon to CO_2.

(3) Calculate total CO_2 emissions for anode baking using Equation 70-5.

$$E_{anodebaking} = EC_{CO2} + EP_{CO2}$$ **Equation 70-5**

Where:

$E_{anodebaking}$ = Total annual CO_2 emissions from anode baking (tonnes).
EC_{CO2} = Annual CO_2 emissions from packing coke (tonnes).
EP_{CO2} = Annual CO_2 emissions from pitch coking (tonnes).

(c) Calculate CF_4 emissions using either paragraph (c)(1) or (c)(2) and calculate C_2F_6 emissions using paragraph (c)(3).

(1) Calculate CF_4 emissions from anode effect duration using Equation 70-6.

$$E_{CF_4} = \sum_{i=1}^{12} [S_{CF4} \times AEM \times MP]_i$$ **Equation 70-6**

Where:

E_{CF4} = Annual emissions of CF_4 (tonnes/yr).
S_{CF4} = Slope coefficient ([tonnes of CF_4/tonne aluminum]/[AE minutes/cell-days]).

AEM = Anode effect frequency (AE-minutes/cell-day), calculated monthly.
MP = Monthly aluminum production (tonnes).

(2) Calculate CF_4 emissions from overvoltage using Equation 70-7.

$$E_{CF_4} = \sum_{i=1}^{12} [EF_{CF_4} \times MP]_i$$ **Equation 70-7**

Where:
E_{CF4} = Annual emissions of CF_4 (tonnes/yr).
EF_{CF4} = Overvoltage emission factor (tonnes of CF_4/tonne aluminum).
MP = Monthly aluminum production (tonnes).

(3) Calculate C_2F_6 emissions from anode effects using Equation 70-8.

$$E_{C_2F_6} = \sum_{i=1}^{12} [E_{CF_4} \times F_{C_2F_6/CF_4}]_i$$ **Equation 70-8**

Where:
E_{C2F6} = Annual emissions of C_2F_6 (tonnes/yr).
E_{CF4} = Monthly emissions of CF_4 (tonnes/yr).
$F_{C2F6/CF4}$ = Weight fraction of C_2F_6/CF_4 (kg C_2F_6/kg CF_4).

(d) Calculate CO_2 emissions from onsite green coke calcination furnaces using Equation 70-9.

$$E_{CO_2} = \sum_{n=1}^{12} \left[\left[GC \times \frac{(100 - H_2O_{gc} - V_{gc} - S_{gc})}{100} - (CC + UCC + DE) \times \frac{(100 - S_{cc})}{100}\right] \times 3.664\right]_i + \left[GC \times 0.035 \times \frac{44}{16}\right]_i$$ **Equation 70-9**

Where:
E_{CO2} = CO_2 emissions (tonnes pre year).
GC = Green coke feed for month *i* (tonnes).
H_2O_{gc} = Humidity in green coke feed for month *i* (wt %).
V_{gc} = Volatiles in green coke feed for month *i* (wt %).
S_{gc} = Sulphur content in green coke feed in month *i* (wt %).
S_{cc} = Sulphur content in calcinated coke in month *i* (wt %).
CC = Calcinated coke produced in month *i* (tonnes).
UCC = Under-calcinated coke produced in month *i* (tonnes).
DE = Coke dust emissions for month *i* (tonnes).
3.664 = Conversion factor from carbon to CO_2.
0.035 = Assumed CH_4 and tar content in coke volatiles, contributing to CO_2 emissions.
44/16 = Conversion factor from methane to CO_2.

(e) Calculate SF_6 emissions from cover gas consumption using one of the following methods:

(1) Calculate the annual SF_6 emissions using inventory records and Equation 70-10:

$$E_{SF6} = S_{Inv-Begin} - S_{Inv-End} + S_{Purchased} - S_{Shipped} \qquad \textbf{Equation 70-10}$$

Where:

E_{SF6} = SF_6 emissions from cover gas (tonnes).
$S_{Purchased}$ = Quantity of SF_6 purchased (tonnes).
$S_{Shipped}$ = Quantity of SF_6 shipped offsite (tonnes).
$S_{Inv\text{-}Begin}$ = Quantity of SF_6 in storage at the beginning of the year, (tonnes).
$S_{Inv\text{-}End}$ = Quantity of SF_6 in storage at the end of the year (tonnes).

(2) Calculate the annual SF_6 emissions using Equation 70-11 and direct measurement of the SF_6 input to electrolysis cells and the SF_6 waste gases collected and transferred off-site:

$$E_{SF6} = \sum_{i=1}^{12} [(Q_{Input} \times C_{Input}) - (Q_{Output} \times C_{Output})]_i \qquad \textbf{Equation 70-11}$$

Where:

E_{SF6} = SF_6 emissions from cover gas (tonnes).
$Q_{in;put}$ = Quantity of SF_6 input to the electrolysis cell for month *i* (tonnes).
C_{Input} = Concentration of SF_6 input to the electrolysis cell for month *i* (tonnes).
Q_{Output} = Quantity of SF_6 gas collected during month *i* (if applicable) (tonnes).
C_{Output} = Concentration of SF_6 gas collected and sent off-site during month *i* (tonnes).

§ WCI.74 Monitoring Requirements

(a) Except as specified in paragraphs (b) through (c) of this section, all parameters must be measured monthly.

(b) Conduct performance tests once every 36 months to determine the slope or Pechiney coefficients for each pot line using the *Protocol for Measurement of Tetrafluoromethane and Hexafluoroethane Emissions from Primary Aluminum Production,* U.S. Environmental Protection Agency and International Aluminum Institute. April 2008. The test must be repeated whenever:

(1) Thirty-six months have passed since the last measurements;

(2) A change occurs in the control algorithm that affects the mix of types of anode effects or the nature of the anode effect termination routine; or

(3) Changes occur in the distribution or duration of anode effects (e.g. when the percentage of manual kills changes or if, over time, the number of anode effects decreases and results in a fewer number of longer anode effects) or, for Rio Tinto Alcan control technology, when the algorithm for bridge movements and anode effect overvoltage accounting changes.

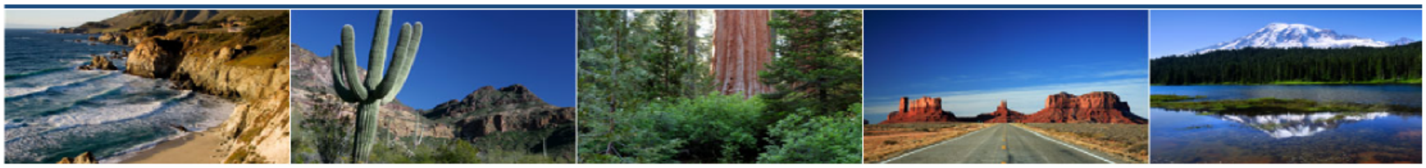
(c) If using the direct measurement approach in WCI.73(e)(2) to calculate SF_6 emissions from cover gas consumption, the quantity of SF_6 gas input to the electrolysis cell month and the quantity and SF_6 concentration of any waste gas collected and sent off-site must be measured.

§ WCI.75 Missing Data Procedures

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraphs (a) or (b) of this section. You must document and keep records of the procedures used for all such estimates.

(a) For each missing value of the carbon content and molecular weight, the substitute data value shall be the arithmetic average of the quality assured values of the parameter immediately preceding and immediately following the missing data incident. If no quality assured data are available prior to the missing data incident, the substitute data value shall be the first quality assured data value obtained after the missing data period.

(b) For missing feedstock and production values, the substitute data value shall be the best available estimate of the parameter, based on all available process data. You must document and retain records of the procedures used for all such estimates.



§ WCI.80 AMMONIA MANUFACTURING

§ WCI.81 Source Category Definition

The ammonia manufacturing source category comprises the process units listed in paragraphs (a) and (b) of this section.

(a) Ammonia manufacturing processes in which ammonia is manufactured from a fossil-based feedstock produced via steam reforming of a hydrocarbon.

(b) Ammonia manufacturing processes in which ammonia is manufactured through the gasification of solid and liquid raw material.

§ WCI.82 Greenhouse Gas Reporting Requirements

For the purpose of the Regulation, the annual emissions data report for ammonia acid manufacturing shall include the following information at the facility level calculated in accordance this method:

(a) CO_2 process emissions from steam reforming of a hydrocarbon or the gasification of solid and liquid raw material following the requirements in this subpart.

(b) CO_2, CH_4, and N_2O emissions from each stationary fuel combustion unit. You must report these emissions under WCI.20 (General Stationary Fuel Combustion Sources), by following the requirements of WCI.20.

(c) If a CEMS is used to measure CO_2 emissions, then you must report the relevant information required under WCI.23 for Calculation Methodology 4 and the following information:

Annual quantity of each type of feedstock consumed for ammonia manufacturing (sm^3 of feedstock or kilolitres of feedstock or tonnes of feedstock).

(d) If a CEMS is not used to measure emissions, then you must report the following information:

(1) Whether carbon content for each feedstock is based on reports from the supplier or analysis of carbon content.

(2) If a facility uses gaseous feedstock, the carbon content of the gaseous feedstock, for month *n*, (kg C per sm^3 of feedstock).

(3) If a facility uses liquid feedstock, the carbon content of the liquid feedstock, for month *n*, (kg C per kilolitre of feedstock).

(4) If a facility uses solid feedstock, the carbon content of the solid feedstock, for month *n*, (kg C per kg of feedstock).

(5) Annual CO_2 emissions associated with the waste recycle stream (tonnes).

(6) Carbon content of the waste recycle stream (kg C per kg of waste recycle stream).

(7) Volume of the waste recycle stream (sm^3).

(e) Annual urea production (tonnes).

§ WCI.83 Calculating GHG emissions

You must calculate and report the annual process CO_2 emissions from each ammonia manufacturing process unit using the procedures in either paragraph (a) or (b) of this section.

(a) Calculate and report under this subpart the process CO_2 emissions by operating and maintaining CEMS according to the Tier 4 Calculation Methodology specified in WCI.23 and all associated requirements for Tier 4 in WCI.20 (General Stationary Fuel Combustion Sources).

(b) Calculate and report under this subpart process CO_2 emissions using the procedures in paragraphs (b)(1) through (b)(6) of this section for gaseous feedstock, liquid feedstock, or solid feedstock, as applicable.

(1) Gaseous feedstock. You must calculate the CO_2 process emissions from gaseous feedstock according to Equation 80-1 of this section:

$$CO_{2,G,k} = \left(\sum_{n=1}^{12} 3.664 * Fdstk_{n,k} * CC_n * \frac{MW}{MVC}\right) * 0.001 \quad \textbf{Equation 80-1}$$

Where:

$CO_{2,G,k}$	=	Annual CO_2 emissions arising from gaseous feedstock consumption (tonnes).
$Fdstk_{n,k}$	=	Volume of the gaseous feedstock used in month *n* (Rm^3 of feedstock) at reference temperature and pressure conditions as used by the facility. If a mass flow meter is used, measure the feedstock used in the month *n* as kg feedstock and replace the term “MW/MVC” with “1”..
CC_n	=	Carbon content of the gaseous feedstock, for month *n*, (kg C per kg of feedstock), determined according to WCI.84(c).
MW	=	Molecular weight of the gaseous feedstock (kg/kg-mole).
MVC	=	Molar volume conversion factor at the same reference conditions as the above $Fdstk_{n,k}$ (Rm^3/kg-mole).
	=	8.3145 * [273.16 + reference temperature in °C] / [reference pressure in kilopascal]
3.664	=	Ratio of molecular weights, CO_2 to carbon.
0.001	=	Conversion factor from kg to tonnes.
k	=	Processing unit.
n	=	Number of months.

(2) Liquid feedstock. You must calculate, from each ammonia manufacturing unit, the CO_2 process emissions from liquid feedstock according to Equation 80-2 of this section:

$$CO_{2,L,k} = \left(\sum_{n=1}^{12} 3.664 * Fdstk_{n,k} * CC_n\right) * 0.001 \quad \textbf{Equation 80-2}$$

Where:

$CO_{2,L,k}$ = Annual CO_2 emissions arising from liquid feedstock consumption (tonnes).

$Fdstk_{n,k}$ = Volume of the liquid feedstock used in month *n* (kilolitres of feedstock). If a mass flow meter is used, measure the feedstock used in month *n* as kg of feedstock and measure the carbon content of feedstock in kg C per kg of feedstock.

CC_n = Carbon content of the liquid feedstock, for month *n* as determined according to WCI.84(c) (kg of C per kilolitre of feedstock when feedstock consumption is measured in kilolitres or kg of C per kg of feedstock when feedstock consumption is measured in kg).

3.664 = Ratio of molecular weights, CO_2 to carbon.

0.001 = Conversion factor from kg to tonnes.

k = Processing unit.

n = Number of months.

(3) Solid feedstock. You must calculate, from each ammonia manufacturing unit, the CO_2 process emissions from solid feedstock according to Equation 80-3 of this section:

$$CO_{2,S,k} = (\sum_{n=1}^{12} 3.664 * Fdstk_{n,k} * CC_n) * 0.001 \qquad \textbf{Equation 80-3}$$

Where:

$CO_{2,S,k}$ = Annual CO_2 emissions arising from solid feedstock consumption (tonnes).

$Fdstk_{n,k}$ = Mass of the solid feedstock used in month *n* (kg of feedstock).

CC_n = Carbon content of the solid feedstock, for month *n*, (kg C per kg of feedstock), determined according to WCI.84(c).

3.664 = Ratio of molecular weights, CO_2 to carbon.

0.001 = Conversion factor from kg to tonnes.

k = Processing unit.

n = Number of months.

(4) You must calculate the annual process CO_2 emissions from each ammonia processing unit *k* at your facility summing emissions, as applicable from Equation 80-1, 80-2, and 80-3 of this section using Equation 80-4.

$$E_{CO2_k} = CO_{2,G} + CO_{2,S} + CO_{2,L} \qquad \textbf{Equation 80-4}$$

Where:

E_{CO2k} = Annual CO_2 emissions from each ammonia processing unit *k* (tonnes).

k = Processing unit.

(5) You must determine the combined CO_2 emissions from all ammonia processing units at your facility using Equation 80-5 of this section.

$$CO_2 = \sum_{k=1}^{n} E_{CO2_k}$$

Equation 80-5

Where:

CO_2 = Annual combined CO_2 emissions from all ammonia processing units (tonnes).

E_{CO2k} = Annual CO_2 emissions from each ammonia processing unit *k* (tonnes).

k = Processing unit.

n = Total number of ammonia processing units.

(6) If applicable, ammonia manufacturing facilities that utilize the waste recycle stream as a fuel must calculate emissions associated with the waste stream for each ammonia process unit according to Equation 80-6 of this section:

$$CO_2 = \left(\sum_{n=1}^{12} 3.664 * RecycleStream_n * CC_n * \frac{MW}{MVC}\right) * 0.001$$

Equation 80-6

Where:

CO2 = Annual CO_2 contained in waste recycle stream (tonnes).

$RecycleStream_n$ = Volume of the waste recycle stream in month *n* (Rm^3) at reference temperature and pressure conditions as used by the facility. If a mass flow meter is used, measure the waste recycle stream in month *n* as kg and replace the term "MW/MVC" with "1".

CC_n = Carbon content of the waste recycle stream, for month *n*, (kg C per kg of waste recycle stream) determined according to WCI.84(f).

MW = Molecular weight of the waste recycle stream (kg/kg-mole).

MVC = Molar volume conversion factor at the same reference conditions as the above $RecycleStream_n$ (Rm^3/kg-mole).

= 8.3145 * [273.16 + reference temperature in °C] / [reference pressure in kilopascal].

3.664 = Ratio of molecular weights, CO_2 to carbon.

0.001 = Conversion factor from kg to tonnes.

n = Number of month

(c) If GHG emissions from an ammonia manufacturing unit are vented through the same stack as any combustion unit or process equipment that reports CO_2 emissions using a CEMS that complies with the Tier 4 Calculation Methodology in WCI.23 (General Stationary Fuel Combustion Sources), then the calculation methodology in paragraph (b) of this section shall not be used to calculate process emissions. The owner or operator shall report under this subpart the combined stack emissions according to the Tier 4 Calculation Methodology in WCI.23 and all associated requirements for Methods 4 in WCI.23.

§ WCI.84 Monitoring and QA/QC Requirements

(a) You must continuously measure the quantity of gaseous or liquid feedstock consumed using a flow meter. The quantity of solid feedstock consumed can be obtained from company records and aggregated on a monthly basis.

(b) You must document the procedures used to ensure the accuracy of the estimates of feedstock consumption.

(c) You must determine monthly carbon contents and the average molecular weight of each feedstock consumed from reports from your supplier. As an alternative to using supplier information on carbon contents, you can also collect a sample of each feedstock on a monthly basis and analyze the carbon content and molecular weight of the fuel using any of the following methods listed in paragraphs (c)(1) through (c)(8) of this section, as applicable.

(1) ASTM D1945-03 Standard Test Method for Analysis of Natural Gas by Gas Chromatography (incorporated by reference, see regulation).

(2) ASTM D1946-90 (Reapproved 2006) Standard Practice for Analysis of Reformed Gas by Gas Chromatography (incorporated by reference, see regulation).

(3) ASTM D2502-04 (Reapproved 2002) Standard Test Method for Estimation of Mean Relative Molecular Mass of Petroleum Oils from Viscosity Measurements (incorporated by reference, see regulation).

(4) ASTM D2503-92 (Reapproved 2007) Standard Test Method for Relative Molecular Mass (Molecular Weight) of Hydrocarbons by Thermoelectric Measurement of Vapor Pressure (incorporated by reference, see regulation).

(5) ASTM D3238-95 (Reapproved 2005) Standard Test Method for Calculation of Carbon Distribution and Structural Group Analysis of Petroleum Oils by the n-d-M Method (incorporated by reference, see regulation).

(6) ASTM D5291-02 (Reapproved 2007) Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants (incorporated by reference, regulation).

(7) ASTM D3176-89 (Reapproved 2002) Standard Practice for Ultimate Analysis of Coal and Coke (incorporated by reference, see regulation).

(8) ASTM D5373-08 Standard Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal (incorporated by reference, see regulation).

(d) Calibrate all oil and gas flow meters (except for gas billing meters) and perform oil tank measurements according to the monitoring and QA/QC requirements for Method 3 in WCI.25.

(e) For quality assurance and quality control of the supplier data, on an annual basis, you must measure the carbon contents of a representative sample of the feedstocks consumed using the appropriate ASTM Method as listed in paragraphs (c)(1) through (c)(8) of this section.

(f) Facilities must continuously measure the quantity of waste gas recycled using a flow meter, as applicable. You must determine the carbon content and the molecular weight of the waste recycle stream by collecting a sample of each waste recycle stream on a monthly basis and analyzing the carbon content using the appropriate ASTM Method as listed in paragraphs (c)(1) through (c)(8) of this section.

(g) If CO_2 from ammonia production is used to produce urea at the same facility, you must determine the quantity of urea produced using methods or plant instruments used for accounting purposes (such as sales records). You must document the procedures used to ensure the accuracy of the estimates of urea produced.

§ WCI.85 Procedures for Estimating Missing Data

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever the monitoring and quality assurance procedures in WCI.84 cannot be followed (e.g., if a meter malfunctions during unit operation), a substitute data value for the missing parameter shall be used in the calculations following paragraphs (a) and (b) of this section. You must document and keep records of the procedures used for all such estimates.

(a) For missing data on monthly carbon contents of feedstock or the waste recycle stream, the substitute data value shall be the arithmetic average of the quality-assured values of that carbon content in the month preceding and the month immediately following the missing data incident. If no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value for carbon content obtained in the month after the missing data period.

(b) For missing feedstock supply rates or waste recycle stream used to determine monthly feedstock consumption or monthly waste recycle stream quantity, you must determine the best available estimate(s) of the parameter(s), based on all available process data.

§ WCI.90 CEMENT MANUFACTURING

§ WCI.91 Source Category Definition

Cement manufacturing is comprised of all processes that are used to manufacture Portland, natural, masonry, pozzolanic, or other hydraulic cements.

§ WCI.92 Greenhouse Gas Reporting Requirements

In addition to the information required by regulation, the annual emissions data report shall contain the following information:

(a) Total emissions of CO_2, CH_4, and N_2O in tonnes.

(b) Annual CO_2 process emissions from calcination (tonnes) and the following information:

(1) Monthly plant specific clinker emission factors (tonnes CO_2/tonnes clinker).

(A) Monthly quantities of clinker produced (tonnes).

(B) Monthly total calcium content of clinker, expressed as calcium oxide (CaO) (weight fraction, tonne CaO/tonne clinker).

(C) Monthly total magnesium content of clinker, expressed as magnesium oxide (MgO) (weight fraction, tonne MgO/tonne clinker).

(D) Monthly non-calcined calcium oxide content of clinker, expressed as CaO (weight fraction, tonne CaO/tonne clinker).

(E) Monthly non-calcined magnesium oxide content of clinker, expressed as MgO (weight fraction, tonne MgO/tonne clinker).

(F) Monthly quantity of non-carbonate raw materials entering the kiln (tonnes).

(2) Quarterly cement kiln dust (CKD) emission factor (tonne CO_2/tonne CKD not recycled back to the kiln).

(A) Quarterly quantity of CKD not recycled back to the kiln (tonnes).

(c) Annual CO_2 process emissions from organic carbon oxidation (tonnes) and the following information:

(1) Amount of raw material consumed in the report year (tonnes).

(2) Annual organic carbon content of raw material (weight fraction).

(d) Annual CO_2, CH_4, and N_2O emissions from fuel combustion in all kilns combined, following the calculation methods and reporting requirements specified in WCI.93(c) (tonnes).

(e) Annual CO_2, CH_4, and N_2O emissions from all other fuel combustion units combined (kilns excluded), following the calculation methods and reporting requirements specified in WCI.20 (tonne).

(f) If a continuous emissions monitor is used to measure CO_2 emissions from kilns, then the requirements of paragraphs (b) and (c) of this section do not apply for CO_2. Cement plants that measure CO_2 emissions using CEMS shall report fuel usage by fuel type for kilns.

(g) Operators of cement plants shall also comply with the reporting requirements for any other applicable source category listed by regulation, including but not limited to the following:

(1) Coal fuel storage as specified in WCI.100.

(2) Electricity generating as specified in WCI.40.

(3) Cogeneration systems as specified in WCI.42(f).

(h) Number of times missing data procedures were used to determine clinker production, non-calcined calcium oxide, magnesium oxide content of clinker, CKD not recycled, non-calcined calcium oxide, magnesium oxide content of CKD, organic carbon content, and raw material consumption.

§ WCI.93 Calculation of Greenhouse Gas Emissions From Kilns

(a) Determine CO_2 emissions as specified under either paragraph (a)(1) or (a)(2) of this section.

(1) Calculate the total process and combustion CO_2 emissions from all the kilns using a continuous emissions monitoring system (CEMS) as specified in WCI.23(d) and combustion CO_2 emissions from all the kilns using the calculation methodologies specified in paragraph (c) of this section.

(2) Calculate the sum of CO_2 process emissions from kilns and CO_2 fuel combustion emissions from kilns using the calculation methodologies specified in paragraph (b) and (c) of this section.

(b) Process CO_2 Emissions Calculation Methodology. Calculate total CO_2 process emissions as the sum of emissions from calcination, using the method specified in paragraph (b)(1) of this section; and from organic carbon oxidation, using the method specified in paragraph (b)(2) of this section (Equation 90-1).

$$E_{CO2\text{-}P} = E_{CO2\text{-}C} + E_{CO2\text{-}F} \qquad \textbf{Equation 90-1}$$

Where:

$E_{CO2\text{-}P}$ = Annual process CO_2 emissions (tonne/year).
$E_{CO2\text{-}C}$ = Annual process CO_2 emissions from calcination (tonne/year).
$E_{CO2\text{-}F}$ = Annual process CO_2 emissions from feed oxidation (tonne/year).

(1) Calcination Emissions. Calculate CO_2 process emissions from calcination using Equation 90-2 and a plant-specific clinker emission factor and a plant-specific cement kiln dust (CKD) emission factor as specified in this section.

$$E_{CO2-C} = \sum_{m=1}^{12}\left[Q_{cli,m} \times EF_{cli,m}\right] + \sum_{q}^{4}\left[Q_{CKD,q} \times EF_{CKD,q}\right] \qquad \textbf{Equation 90-2}$$

Where:

$E_{CO2\text{-}C}$ = Annual process CO_2 emissions from calcination (tonnes).
$Q_{Cli,m}$ = Quantity of clinker produced in month *m* (tonnes).
$EF_{Cli,m}$ = CO_2 emission factor for clinker produced in month *m*, computed as specified in paragraph (b)(1)(A) of this section (tonnes CO_2/tonne clinker).
$Q_{CKD,q}$ = Quantity CKD not recycled to the kiln in quarter *q* (tonnes).
$EF_{CKD,q}$ = CO_2 emission factor for CKD not recycled to the kiln in quarter *q*, computed as specified in paragraph (b)(1)(B) of this section (tonne CO_2/tonne CKD).

(A) Clinker Emission Factor. Calculate a plant-specific clinker emission factor (EF_{Cli}) for each month based on monthly measurements of the weight fractions of calcium (as CaO) and magnesium (as MgO) content in the clinker and in the non-carbonate raw materials entering the kiln, using Equation 90-3.

$$EF_{Cli} = (CaO_{Cli} - CaO_{f}) \times 0.785 + (MgO_{Cli} - MgO_{f}) \times 1.092$$

Equation 90-3

Where:
EF_{Cli} = Monthly CO_2 emission factor for clinker (tonne CO_2/tonne clinker).
CaO_{Cli} = Monthly total calcium content of clinker expressed as calcium oxide (tonne CaO/tonne clinker).
CaO_f = Monthly non-calcined calcium oxide content of clinker (tonne CaO/tonne clinker).
MgO_{Cli} = Monthly total magnesium content of clinker expressed as magnesium oxide (tonne MgO/tonne clinker).
MgO_f = Monthly non-calcined magnesium oxide content of clinker (tonne MgO/tonne clinker).
0.785 = Ratio of molecular weights of CO_2 to CaO.
1.092 = Ratio of molecular weights of CO_2 to MgO.

(B) CKD Emission Factor. If CKD is generated and not recycled back to the kiln, then calculate a plant-specific CKD emission factor based on quarterly sampling. The CKD emission factor shall be calculated using Equation 90-4.

$$EF_{CKD} = (CaO_{CKD} - CaO_{f}) \times 0.785 + (MgO_{ckd} - MgO_{f}) \times 1.092$$

Equation 90-4

Where:
EF_{CKD} = Quarterly CO_2 emission factor for CKD not recycled to the kiln (tonne CO_2/tonne CKD).
CaO_{CKD} = Quarterly total calcium oxide content of CKD (tonne CaO/tonne CKD).
CaO_f = Quarterly non-calcined calcium oxide content of CKD (tonne CaO/tonne CKD).
MgO_{CKD} = Quarterly total magnesium oxide content of CKD (tonne MgO/tonne CKD).
MgO_f = Quarterly non-calcined magnesium oxide content of CKD (tonne MgO/tonne CKD).
0.785 = Ratio of molecular weights of CO_2 to CaO.
1.092 = Ratio of molecular weights of CO_2 to MgO.

(2) Organic Carbon Oxidation Emissions. Calculate CO_2 process emissions from the total organic content in raw materials by using Equation 90-5.

$$E_{CO_2-F} = TOC_{RM} \times RM \times 3.664 \qquad \textbf{Equation 90-5}$$

Where:

E_{CO2-F}	=	Annual process CO_2 emissions from raw material oxidation (tonnes).
TOC_{RM}	=	Total organic carbon content in raw material (wt. fraction), measured using the method in WCI.94(g) or using a default of 0.002 (0.2%).
RM	=	Amount of raw material consumed (tonnes/year).
3.664	=	CO_2 to carbon molar ratio.

(c) Fuel Combustion Emissions in Kilns. Calculate CO_2, CH_4, and N_2O emissions from stationary fuel combustion following the calculation methods specified in WCI.20. Cement plants that combust pure biomass-derived fuels and combust fossil fuels only during periods of start-up, shut-down, or malfunction may report CO_2 emissions from fossil fuels using the emission factor methodology in WCI.23(a). “Pure” means that the biomass-derived fuels account for at least 97 percent of the total amount of carbon in the fuels burned.

§ WCI.94 Sampling, Analysis, and Measurement Requirements

(a) Determine monthly, the plant-specific weight fractions of total calcium (as CaO) and total magnesium (as MgO) in clinker using ASTM C114, an equivalent industry method, or a method approved by the Director. The monitoring must be conducted either daily from clinker drawn from the exit of the kiln or monthly from clinker drawn from bulk storage.

(b) Determine quarterly, the plant-specific weight fractions of total calcium (as CaO) and total magnesium (as MgO) in CKD using ASTM C114, an equivalent industry method, or a method approved by the Director. The monitoring must be conducted daily from CKD samples drawn from the exit of the kiln or quarterly from CKD samples drawn from bulk storage.

(c) Determine monthly, the plant-specific weight fractions of calcium oxide (CaO) and magnesium oxide (MgO) that enters the kiln as a non-carbonate species to clinker by chemical analysis of feed material using documented analytical method, the appropriate industrial standard practice, or a value of 0.0.

(d) Determine quarterly, the plant-specific weight fractions of calcium oxide (CaO) and magnesium oxide (MgO) that enters the kiln as a non-carbonate species to CKD by chemical analysis of feed material using documented analytical method, the appropriate industrial standard practice, or a value of 0.0.

(e) Determine monthly, the plant-specific weight fractions of calcium oxide (CaO) and magnesium oxide (MgO) that remains in clinker by chemical analysis of feed material using documented analytical method, the appropriate industrial standard practice, or a value of 0.0.

(f) Determine quarterly, the plant-specific weight fractions of calcium oxide (CaO) and magnesium oxide (MgO) that remains in CKD by chemical analysis of feed material using documented analytical method, the appropriate industrial standard practice, or a value of 0.0.

(g) Determine annually, the total organic carbon contents of raw materials using ASTM C114, an equivalent industry method, method approved for total organic carbon determination in raw mineral material, or use a default value of 0.002 (0.2%). The analysis must be conducted on sample material drawn from bulk raw material storage for each category of raw material.

(h) The quantity of clinker produced must be determined monthly by either:

(1) Direct weight measurement using the same plant techniques used for accounting purposes, such as reconciling weigh hoppers or belt weigh feeders measurements against inventory measurements, or

(2) Direct measurement of raw kiln feed and application of a kiln-specific feed-to-clinker factor. Facilities that opt to use a feed to clinker factor must verify the accuracy of this factor on a monthly basis.

(i) The quantity of CKD not recycled back to the kiln must be determined quarterly by either using the same plant techniques used for accounting purposes, such as direct weight measurement using weigh hoppers or belt weigh feeders, and/or material balances.

(j) The quantity of raw materials consumed (i.e. limestone, sand, shale, iron oxide, alumina, and non-carbonate raw material) must be determined monthly by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.

§ WCI.95 Procedures for Estimating Missing Data

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations. The owner or operator must document and keep records of the procedures used for all such estimates.

(a) If the CEMS approach is used to determine combined process and combustion CO_2 emissions, the missing data procedures in WCI.20 apply.

(b) For CO_2 process emissions from cement manufacturing facilities calculated according to WCI.93(b), if data on the carbonate content (of clinker or CKD), noncalcined content (of clinker or CKD) or the annual organic carbon content of raw materials are missing, facilities must undertake a new analysis.

(c) For each missing value of monthly clinker production, the substitute data value must be the best available estimate of the monthly clinker production based on information used for accounting purposes, or use the maximum tons per day capacity of the system and the number of days per month.

(d) For each missing value of monthly raw material consumption, the substitute data value must be the best available estimate of the monthly raw material consumption based on information used for accounting purposes (such as purchase records), or use the maximum tons per day raw material throughput of the kiln and the number of days per month.

§ WCI.100 COAL STORAGE

§ WCI.101 Source Category Definition

Coal storage piles are located at any facilities that combust coal. Coal storage piles release fugitive CH_4 emissions. Within natural coal deposits, CH_4 is either trapped under pressure within porous void spaces or adsorbed to the coal. Coal mining, post-mining activities, and coal-handling activities release pressurized CH_4 to the atmosphere; adsorbed CH_4 is also released until the CH_4 in the coal reaches equilibrium with the surrounding atmospheric conditions.

§ WCI.102 Greenhouse Gas Reporting Requirements

The emissions data report shall include the following information at the facility level:

(a) Annual greenhouse gas emissions in tonnes, reported as follows:

  (1) Total CH_4 emissions.

(b) Annual coal purchases (tons for U.S.; tonnes for Canada).

(c) Source of coal purchases:

  (1) Coal basin.

  (2) State/province.

  (3) Coal mine type (surface or underground).

§ WCI.103 Calculation of CH_4 Emissions

Note that this methodology for calculation of methane emissions uses emission factors for post-mining operations including all processes occurring after mining at the coal deposit and prior to combustion (e.g., preparation, handling, processing, transportation, storage, etc.) even though coal storage piles are only a subset of the overall post-mining operations. This follows the approach in the Climate Action Reserve reporting protocol, attributing all post-mining fugitive methane emissions to the facility combusting the coal, which is ultimately responsible for the coal having been processed and delivered to the facility.

Calculate fugitive CH_4 emissions from coal storage piles as specified under paragraph (a), (b), or (c) of this section.

(a) For coal purchased from U.S. sources, calculate fugitive CH_4 emissions using Equation 100-1 and Table 100-1.

(b) For coal purchased from Canadian sources, calculate fugitive CH_4 emissions using Equation 100-1 and Table 100-2.

(c) For coal purchased from non-U.S. and non-Canadian sources, owners or operators should use either WCI.103(a) or WCI.103(b), whichever is the most applicable. This chosen approach is subject to approval by the regulator.

$$CH_4 = \sum_i (PC_i \times EF_i) \times 0.6772 / 1{,}000$$ **Equation 100-1**

Where:

CH_4 = Fugitive emissions from coal storage piles for each coal category *i*, (tonnes CH_4 per year);
PC_i = Purchased coal for each coal category *i* (tonnes per year);
EF_i = Default CH_4 emission factor for each coal category *i* specified by location and mine type that coal originated from, provided in Table 100-1 or Table 100-2 (m^3 CH_4 per tonne of coal);
0.6772 = Methane conversion factor to convert m^3 to kg;
1,000 = Factor to convert kg to tonnes.

§ WCI.104 Sampling, Analysis, and Measurement Requirements

(a) Coal Purchase Monitoring Requirements.

Facilities may determine the quantity of coal purchased either using records provided by the coal supplier(s) or monitoring coal purchase quantities using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.

§ WCI.105 Procedures for Estimating Missing Data

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraph (a) of this section. You must document and keep records of the procedures used for all such estimates.

(a) For missing feedstock and production values, the substitute data value shall be the best available estimate of the parameter, based on all available process data. You must document and retain records of the procedures used for all such estimates.

Table 100-1. U.S. Default Fugitive Methane Emission Factors from Post-Mining Coal Storage and Handling (CH_4 m^3 per Tonne)

Coal Origin		Coal Mine Type	
Coal Basin	**States**	**Surface Post-Mining Factors**	**Underground Post-Mining Factors**
Northern Appalachia	Maryland, Ohio, Pennsylvania, West Virginia North	0.6025	1.4048
Central Appalachia (WV)	Tennessee, West Virginia South	0.2529	1.3892
Central Appalachia (VA)	Virginia	0.2529	4.0490
Central Appalachia (E KY)	East Kentucky	0.2529	0.6244
Warrior	Alabama, Mississippi	0.3122	2.7066
Illinois	Illinois, Indiana, Kentucky West	0.3465	0.6525
Rockies (Piceance Basin)	Arizona, California, Colorado, New Mexico, Utah	0.3372	1.9917
Rockies (Uinta Basin)		0.1623	1.0083

Rockies (San Juan Basin)		0.0749	1.0645
Rockies (Green River Basin)		0.3372	2.5068
Rockies (Raton Basin)		0.3372	1.2987
N. Great Plains	Montana, North Dakota, Wyoming	0.0562	0.1592
West Interior (Forest City, Cherokee Basins)	Arkansas, Iowa, Kansas, Louisiana, Missouri, Oklahoma, Texas	0.3465	0.6525
West Interior (Arkoma Basin)		0.7555	3.3591
West Interior (Gulf Coast Basin)		0.3372	1.2987
Northwest (AK)	Alaska	0.0562	1.6233
Northwest (WA)	Washington	0.0562	0.5900

Source: *Inventory of U.S. Greenhouse Gas Emissions and Sinks:1990 – 2005* April 15, 2007, U.S. Environmental Protection Agency. Annex 3, Methodological Descriptions for Additional Source or Sink Categories, Section 3.3, Table A-115, Coal Surface and Post-Mining CH_4 Emission Factors (ft^3 per Short Ton; converted to m^3 per metric ton). (Only Post-Mining EFs used from Table). State assignments shown from Table 113 of Annex 3.

Table 100-2. Canada Default Fugitive Methane Emission Factors from Post-Mining Coal Storage and Handling (CH_4 m^3 per Tonne)

Coal Origin		Coal Mine Type	
Province	**Coalfield**	**Surface Post-Mining Factors**	**Underground Post-Mining Factors**
British Columbia	Comox	0.500	n/a
	Crowness	0.169	n/a
	Elk Valley	0.900	n/a
	Peace River	0.361	n/a
	Province Average	0.521	n/a
Alberta	Battle River	0.067	n/a
	Cadomin-Luscar	0.709	n/a
	Coalspur	0.314	n/a
	Obed Mountain	0.238	n/a
	Sheerness	0.048	n/a
	Smokey River	0.125	0.067
	Wabamun	0.176	n/a
	Province Average	0.263	0.067
Saskatchewan	Estavan	0.055	n/a
	Willow Bunch	0.053	n/a
	Province Average	0.054	n/a
New Brunswick	Province Average	0.060	n/a
Nova Scotia	Province Average	n/a	2.923

Source: *Management of Methane Emissions from Coal Mines: Environmental, Engineering, Economic and Institutional Implications of Options*. Prepared by Brian G. King, Neill and Gunter (Nova Scotia) Limited, Darmouth, Nova Scotia for Environment Canada. Contract Number K2031-3-7062. March 1994. This document is cited by Environment Canada in the NIR 1990-2007 (Final Submission, April 2009), , but post-mining emission factors are not provided, so they were developed for WCI purposes by Province. Surface emission factors were derived from Table 3.1 (Coal production statistics [Column A] and post-mining emissions [Column F]). Underground emission factors were derived from Table 3.2 (Coal production statistics and post-mining emissions).

§ WCI.110 ELECTRONICS MANUFACTURING

§ WCI.111 Source Category Definition

Electronics manufacturing facilities include, but are not limited to, facilities that manufacture semiconductors, liquid crystal displays (LCDs), micro-electro-mechanical systems (MEMS), and photovoltaic cells (PV). The electronics source category consists of any of the processes listed in paragraphs (a) through (f) of this section that are located at electronics manufacturing facilities.

(a) Processes in which the etching process uses plasma-generated fluorine atoms and other reactive fluorine-containing fragments, which chemically react with exposed thin-films (e.g., dielectric, metals) and silicon to selectively remove portions of material.

(b) Processes in which chambers used for depositing thin films are cleaned periodically using plasma-generated fluorine atoms and other reactive fluorine-containing fragments from fluorinated and other gases.

(c) Processes in which wafers are cleaned using plasma-generated fluorine atoms or other reactive fluorine-containing fragments to remove residual material from wafer surfaces.

(d) Processes in which some fluorinated compounds can be transformed in the plasma processes into different fluorinated compounds which are then exhausted, unless abated, into the atmosphere.

(e) Processes in which the chemical vapor deposition process or other manufacturing processes use N_2O.

(f) Processes in which fluorinated GHGs are used as heat transfer fluids to cool process equipment, control temperature during device testing, and solder semiconductor devices to circuit boards.

§ WCI.112 Greenhouse Gas Reporting Requirements

In addition to the information required by regulation, the annual emissions data report shall contain the following information:

(a) Annual emissions of N_2O and fluorinated GHGs. The fluorinated GHGs that are emitted from electronics production processes include, but are not limited to, those listed in Table 110-1 of this subpart. The process that must be reported include: fluorinated GHGs from plasma etching, fluorinated GHGs from chamber cleaning, fluorinated GHGs from wafer cleaning, N_2O from chemical vapor deposition and other manufacturing processes, and fluorinated GHGs from heat transfer fluid use.

(b) CO_2, N_2O, and CH_4 emissions from stationary combustion units as specified in WCI.20.

(c) The method of emissions calculation used in WCI.113.

(d) Production in terms of substrate surface area (e.g., silicon, PV-cell, LCD).

(e) Emission factors used for process utilization and by-product formation rates and the source for each factor for each fluorinated GHG and N_2O.

(f) Where process categories for semiconductor facilities as defined in WCI.113(a)(1)(i) through (a)(1)(iii) are not used, descriptions of individual processes or process categories used to estimate emissions.

(g) For each fluorinated GHG and N_2O, annual gas consumed during the reporting year and facility-wide gas-specific heel-factors used.

(h) The apportioning factors for each process category (i.e., fractions of each gas fed into each individual process or process category used to calculate fluorinated GHG and N_2O emissions) and a description of the engineering model used for apportioning gas usage per WCI.114(b). If the method used to develop the apportioning factors permits the development of facility-wide consumption estimates that are independent of the estimates calculated in Equation 110-6 of this subpart (e.g., that are based on wafer passes for each individual process or process category), report the independent facility-wide consumption estimate for each fluorinated GHG and N_2O.

(i) Fraction of each gas fed into each process type that is fed into tools with abatement systems.

(j) Description of all abatement systems through which fluorinated GHGs or N_2O flow at the facility, including the number of devices of each manufacturer, model numbers, manufacturers guaranteed destruction or removal efficiencies, if any, and record of destruction or removal efficiency measurements over its in-use life. The inventory of abatement systems shall also include a description of the associated tools and/or processes for which these systems treat exhaust.

(k) For each abatement system through which fluorinated GHGs or N_2O flow at the facility, for which controlled emissions are reported, the following:

(1) Certification that each abatement system used at the facility is installed, maintained, and operated in accordance with manufacturers' specifications.

(2) The uptime and the calculations to determine uptime for that reporting year.

(3) The default destruction or removal efficiency value or properly measured destruction or removal efficiencies for each abatement system used in that reporting year to reflect controlled emissions.

(4) Where the default destruction or removal efficiency value is used to report controlled emissions, certification that the abatement systems for which controlled emissions are being reported are specifically designed for fluorinated GHG and N_2O abatement.

(5) Where properly measured destruction or removal efficiencies or class averages of destruction or removal efficiencies are used to report controlled emissions, the following:

(i) A description of the class including the abatement system manufacturer and model number, and the fluorinated GHG and N_2O in the process effluent stream;
(ii) The total number of systems in that class for the reporting year.
(iii) The total number of systems for which destruction or removal efficiency was measured in that class for the reporting year.

(iv) A description of the calculation used to determine the class average, including all inputs of the calculation.

(v) A description of method of randomly selecting class members for testing.

(l) For heat transfer fluid emissions, inputs to the mass-balance equation, Equation 110-8 of this subpart for each fluorinated GHG.

(m) Example calculations for fluorinated GHG, N_2O, and heat transfer fluid emissions.

§ WCI.113 Calculation of GHG Emissions

(a) For each fluorinated GHG and each process type used at the facility (i.e., plasma etching, chamber cleaning, or wafer cleaning) as appropriate, calculate annual facility-level emissions using Equations 110-1 and 110-2 of this section and according to the procedures in paragraph (a)(1), (a)(2), or (a)(3) of this section.

$$processtypeE_i = \sum_{j=1}^{N} E_{ij}$$ **Equation 110-1**

Where:

$processtypeE_i$	=	Annual emissions of input gas *i* from the processes type (tonnes);
E_{ij}	=	Annual emissions of input gas *i* from individual process *j* or process category *j* (tonnes); and
N	=	Total number of individual processes *j* or process categories *j*, which depend on the electronics manufacturing facility and emission calculation methodology.

$$processtypeBE_k = \sum_{j=1}^{N} \sum_{i} BE_{kij}$$ **Equation 110-2**

Where:

$processtypeBE_k$	=	Annual emissions of by-product gas *k* from the processes type (tonnes);
BE_{kij}	=	Annual emissions of by-product *k* formed from input gas *i* during individual process *j* or process category *j* (tonnes); and
N	=	Total number of individual processes *j* or process categories *j*, which depend on the electronics manufacturing facility and emission calculation methodology.

(1) Semiconductor facilities that fabricate devices on wafers measuring 300 mm or less in diameter shall calculate annual facility-level emissions of each fluorinated GHG used at a facility for each fluorinated GHG-using process type, either from all individual processes at that facility in accordance with WCI.114(c), or from process categories as defined in this paragraph (a)(1).

(i) All etching process categories for which annual fluorinated GHG emissions shall be calculated are defined in this paragraph (a)(1)(i).

(A) Oxide etch means any process using fluorinated GHG reagents to selectively remove SiO_2, SiO_x-based, or fully organic-based thin-film material that has been deposited on a wafer during semiconductor device manufacturing.

(B) Nitride etch means any process using fluorinated GHG reagents to selectively remove SiN, SiON, Si_3N_4, SiC, SiCO, SiCN, etc. (represented by the general chemical formula, $Si_wO_xN_yX_z$ where *w*, *x*, *y* and *z* are zero or integers and *X* can be some other element such as carbon) that has been deposited on a wafer during semiconductor manufacturing.

(C) Silicon etch also often called polysilicon etch, means any process using fluorinated GHG reagents to selectively remove silicon during semiconductor manufacturing.

(D) Metal etch means any process using fluorinated GHG reagents associated with removing metal films (such as aluminum or tungsten) that have been deposited on a wafer during semiconductor manufacturing.

(ii) All chamber cleaning process categories for which annual fluorinated GHG emissions shall be calculated are defined in this paragraph (a)(1)(ii).

(A) In situ plasma means cleaning thin-film production chambers, after processing one or more wafers, with a fluorinated GHG cleaning reagent that is dissociated into its cleaning constituents by a plasma generated inside the chamber where the film was produced.

(B) Remote plasma system means cleaning thin-film production chambers, after processing one or more wafers, with a fluorinated GHG cleaning reagent dissociated by a remotely located (e.g., upstream) plasma source.

(C) In situ thermal means cleaning thin-film production chambers, after processing one or more wafers, with a fluorinated GHG cleaning reagent that is thermally dissociated into its cleaning constituents inside the chamber where the thin-film (or thin films) was (were) produced.

(iii) All wafer cleaning process categories for which annual fluorinated GHG emissions shall be calculated are defined in this paragraph (a)(1)(iii) .

(A) Bevel cleaning means any process using fluorinated GHG reagents with plasma to clean the edges of wafers during semiconductor manufacture.

(B) Ashing means any process using fluorinated GHG reagents with plasma to remove photoresist materials during wafer manufacture.

(2) Semiconductor facilities that fabricate devices on wafers measuring greater than 300 mm in diameter shall calculate annual facility-level emissions of each fluorinated GHG used at a facility for all individual processes at that facility in accordance with WCI.114(c).

(3) All other electronics facilities shall calculate annual facility-level emissions of each fluorinated GHG used at a facility for each process type, including etching and chemical vapor deposition chamber cleaning.

(b) For each fluorinated GHG and each individual process, process category, or process type used at the facility as appropriate, calculate annual facility-level emissions using Equations 110-3 and 110-4 of this section, and according to the procedures in either paragraph (b)(1), (b)(2), or (b)(3) of this section.

$$E_{ij} = C_{ij}\left(1 - U_{ij}\right)\left(1 - a_{ij} \times d_{kj}\right) \times 0.001$$

Equation 110-3

Where:

E_{ij}	=	Annual emissions of input gas *i* from individual process, process category, or process type *j* (tonnes);
C_{ij}	=	Amount of input gas *i* consumed in individual process, process category, or process type *j*, as calculated in Equation 110-6 (kg) of this section and apportioned pursuant to WCI.114(b);
U_{ij}	=	Process utilization for input gas *i* during individual process, process category, or process type *j*;
a_{ij}	=	Fraction of input gas *i* used in individual process, process category, or process type *j* with abatement systems;
d_{ij}	=	Fraction of input gas *i* destroyed in abatement systems connected to individual process, process category, or process type *j*, accounting for uptime as specified in WCI.114(e)(2). This is zero unless the facility adheres to requirements in WCI.114(e); and
0.001	=	Conversion factor from kg to tonnes.

$$BE_{ijk} = B_{ijk} \times C_{ij} \times \left(1 - a_{ij} \times d_{kj}\right) \times 0.001$$

Equation 110-4

Where:

BE_{ijk}	=	Annual emissions of by-product *k* formed from input gas *i* during individual process, process category, or process type *j* (tonnes);
B_{ijk}	=	Amount of gas *k* created as a by-product per amount of input gas *i* (kg) consumed in individual process, process category, or process type *j* (kg);
C_{ij}	=	Amount of input gas *i* consumed in individual process, process category, or process type *j*, as calculated in Equation 110-6 (kg) of this section and apportioned pursuant to WCI.114(b);
a_{ij}	=	Fraction of input gas *i* used in individual process, process category, or process type *j* with abatement systems;
d_{kj}	=	Fraction of by-product gas k destroyed in abatement systems connected to individual process, process category, or process type j, accounting for uptime as specified in WCI.114(e)(2). This is zero unless the facility adheres to requirements in WCI.114(e); and
0.001	=	Conversion factor from kg to tonnes.

(1) Semiconductor facilities that fabricate devices on wafers measuring 300 mm or less in diameter shall use the procedures in either paragraph (b)(1)(i) or (b)(1)(ii) of this section.

(i) Except as provided in paragraph (b)(1)(ii), use default process category emission factors for process utilization and by-product formation rates shown in Tables 110-2, 110-3, and 110-4 of this subpart as appropriate.

(ii) Recipe-specific measurements may be used instead of the process category default factors provided that the methods in WCI.114(c) are followed.

(2) Semiconductor facilities that fabricate devices on wafers measuring greater than 300 mm in diameter shall use recipe-specific measurements and follow methods in WCI.114(c) to calculate emissions from each fluorinated GHG-using process type. Equations 110-1 through 110-4 shall be used to calculate fluorinated GHG emissions from all fluorinated GHG-using process recipes.

(3) All other electronics facilities shall use the default process type-specific emission factors for process utilization and by-product formation rates shown in Tables 110-5, 110-6, and 110-7 of this subpart for MEMS, LCD, and PV manufacturing, respectively.

(c) Calculate annual facility-level N_2O emissions from electronics manufacturing processes, using Equation 110-5 of this section and the methods in this paragraph (c).

(1) Use a factor for N_2O utilization for chemical vapor deposition processes pursuant to either paragraph (c)(1)(i) or (c)(1)(ii) of this section.

(i) Develop a facility-specific N_2O utilization factor averaged over all N_2O-using recipes used for chemical vapor deposition processes in accordance with WCI.114(d).

(ii) If a facility-specific N_2O utilization factor for chemical vapor deposition processes is not available, a value of 20 percent must be used as the default utilization factor for N_2O from chemical vapor deposition processes.

(2) Use a factor for N_2O utilization for other manufacturing processes pursuant to either paragraph (c)(2)(i) or (c)(2)(ii) of this section.

(i) Develop a facility-specific N_2O utilization factor averaged over all N_2O-using recipes used for manufacturing processes other than chemical vapor deposition processes in accordance with WCI.114(d).

(ii) If a facility-specific N_2O utilization factor for manufacturing processes other than chemical vapor deposition is not available, a value of 0 percent must be used as a default utilization factor for N_2O from manufacturing processes other than chemical vapor deposition.

(3) If a facility employs abatement systems and wishes to quantify and document N_2O emission reductions due to these systems, it must adhere to the requirements in WCI.114(e).

(4) Calculate annual facility-level N_2O emissions for all processes at the facility using Equation 110-5 of this section.

$$E(N_2O) = \sum_j C_{N_2O,j}\left(1 - U_{N_2O,j}\right)\left(1 - a_{N_2O,j} \times d_{N_2O,j}\right) \times 0.001$$

Equation 110-5

Where:

$E(N_2O)$	=	Annual emissions of N_2O (tonnes/year);
$C_{N2O,j}$	=	Amount of N_2O consumed for N_2O-using process *j*, as calculated in Equation 110-6 of this section and apportioned to N_2O-using process *j* (kg);
$U_{N2O,j}$	=	Process utilization for N_2O-using process *j*;
$a_{N2O,j}$	=	Fraction of N_2O used in N_2O-using process *j* with abatement systems;
$d_{N2O,j}$	=	Fraction of N_2O for N_2O-using process *j* destroyed by abatement systems connected to process *j*, accounting for uptime as specified in WCI.114(e)(2). This is zero unless the facility adheres to requirements in WCI.114(e); and
0.001	=	Conversion factor from kg to tonnes.

(d) Calculate gas consumption for each fluorinated GHG and N_2O used at the facility using facility-wide gas-specific heel factors, as determined in WCI.114(a), and using Equation 110-6 of this section.

$$C_i = \left(I_{Bi} - I_{Ei} + A_i - D_i\right) \times 0.001$$

Equation 110-6

Where:

C_i	=	Annual consumption of input gas *i* (tonnes /year);
I_{Bi}	=	Inventory of input gas *i* stored in cylinders or other containers at the beginning of the year, including heels (kg);
I_{Ej}	=	Inventory of input gas *i* stored in cylinders or other containers at the end of the year, including heels (kg);
A_i	=	Acquisitions of gas *i* during the year through purchases or other transactions, including heels in cylinders or other containers returned to the electronics manufacturing facility (kg);
D_i	=	Disbursements under exceptional circumstances of gas *i* through sales or other transactions during the year, including heels in cylinders or other containers returned by the electronics manufacturing facility to the chemical supplier, calculated using Equation 110-7 of this section (kg); and
0.001	=	Conversion factor from kg to tonnes.

(e) Calculate disbursements of gas *i* using Equation 110-7 of this section.

$$D_i = h_i \times N_i \times F_i + X_i$$

Equation 110-7

Where:

D_i = Disbursements of gas *i* through sales or other transactions during the year, including heels in cylinders or other containers returned by the electronics manufacturing facility to the gas distributor (kg);
h_i = Facility-wide gas-specific heel factor for input gas *i* (%), as determined in WCI.114 of this subpart;
N_i = Number of cylinders or other containers returned to the gas distributor containing the standard heel of gas *i*;
F_i = Full capacity of cylinders or other containers containing gas *i* (kg); and
X_i = Disbursements under exceptional circumstances of gas *i* through sales or other transactions during the year. These include returns of containers whose contents have been weighed due to an exceptional circumstance as specified in WCI.114(a)(5) of this subpart (kg).

(f) For facilities that use fluorinated heat transfer fluids, you shall report the annual emissions of fluorinated GHG heat transfer fluids using the mass balance approach described in Equation 110-8 of this section.

$$E_i = \rho_i\left(I_{ib} + P_i - N_i + R_i - I_{ie} - D_i\right) \times 0.001 \qquad \textbf{Equation 110-8}$$

Where:

E_i = Emissions of fluorinated GHG heat transfer fluid *i*, (tonnes/year);
ρ_i = Density of fluorinated heat transfer fluid *i* (kg/litre);
I_{ib} = Inventory of fluorinated heat transfer fluid *i* (in containers, not equipment) at the beginning of the reporting year (litres). The inventory at the beginning of the reporting year must be the same as the inventory at the end of the previous reporting year;
P_i = Acquisitions of fluorinated heat transfer fluid *i* during the current reporting year (litres). Includes amounts purchased from chemical suppliers, amounts purchased from equipment suppliers with or inside of equipment, and amounts returned to the facility after off-site recycling;
N_i = Total nameplate capacity (full and proper charge) of equipment that uses fluorinated heat transfer fluid *i* and that is newly installed during the reporting year (litres);
R_i = Total nameplate capacity (full and proper charge) of equipment that uses fluorinated heat transfer fluid *i* and that is removed from service during the current reporting year (litres);
I_{ie} = Inventory of fluorinated heat transfer fluid *i* (in containers, not equipment) at the end of current reporting year (litres);
D_i = Disbursements of fluorinated heat transfer fluid *i* during the current reporting year (litres). Includes amounts returned to chemical suppliers, sold with or inside of equipment, and sent off site for verifiable recycling or destruction. Disbursements should include only amounts that are properly stored and transported so as to prevent emissions in transit; and
0.001 = Conversion factor from kg to tonnes.

§ WCI.114 Sampling, Analysis, and Measurement Requirements

(a) For purposes of Equation 110-6 of this section, you must estimate facility-wide gas-specific heel factors for each cylinder/container type for each gas used according to the procedures in paragraphs (a)(1) through (a)(6) of this section.

(1) Base the facility-wide gas-specific heel factors on the residual weight or pressure of a gas cylinder/container that the facility uses to change out that cylinder/container for each cylinder/container type for each gas used.

(2) The residual weight or pressure used for WCI.114(a)(1) shall be determined by monitoring the mass or the pressure of your cylinders/containers. If monitoring the pressure, convert the pressure to mass using the ideal gas law, as displayed in Equation 110-9 of this section, with an appropriately selected *Z* value.

$$pV = ZnRT \qquad \textbf{Equation 110-9}$$

Where:

p	=	Absolute pressure of the gas (Pa);
V	=	Volume of the gas (m^3);
Z	=	Compressibility factor;
n	=	Amount of substance of the gas (moles);
R	=	Gas constant (8.314 Joule/Kelvin mole); and
T	=	Absolute temperature (K).

(3) Use the facility-wide gas-specific cylinder/container residual mass, determined from WCI.114(a)(1) and (a)(2), to calculate the unused gas for each container, which when expressed as fraction of the initial mass in the cylinder/container is the heel factor.

(4) The initial mass used to calculate the facility-wide gas-specific heel factor may be based on the weight of the gas provided in the gas supplier documents; however, the facilities remain responsible for the accuracy of these masses and weights under this subpart.

(5) In the exceptional circumstance that a cylinder/container is changed at a residual mass or pressure that differs by more than 20 percent from the facility-wide gas-specific determined values, that cylinder shall be weighed, or the pressure of that cylinder shall be measured with a pressure gauge, in place of using a heel factor.

(6) Recalculate facility-wide gas-specific heel factors applied at the facility in the event that the residual weight or pressure of the gas cylinder/container that the facility uses to change out that cylinder/container differs by more than 1 percentage point from that used to calculate the previous gas-specific heel factor.

(b) Semiconductor facilities shall apportion fluorinated GHG consumption by process category, as defined in WCI.113(a)(1)(i) through (a)(1)(iii), or by individual process using a facility-specific engineering model based on wafer passes.

(c) If factors for fluorinated GHG process utilization and by-product formation rates are used other than the defaults provided in Tables 110-2 through 110-4 of this subpart, the factors must have been measured using the "International SEMATECH Manufacturing Initiative's Guideline for Environmental Characterization of Semiconductor Process Equipment" (December 2006). Factors for fluorinated GHG process utilization and by-product formation rates measured by manufacturing equipment suppliers may be used if the conditions in paragraphs (c)(1) and (c)(2) of this section are met.

(1) The manufacturing equipment supplier has measured the GHG emission factors for process utilization and by-product formation rates using the "International SEMATECH Manufacturing Initiative's Guideline for Environmental Characterization of Semiconductor Process Equipment" (December 2006).

(2) The conditions under which the measurements were made are representative of the facility's fluorinated GHG emitting processes.

(d) If N_2O utilization factors other than those defaults provided in WCI.113(c)(1)(ii) or (c)(2)(ii) are used, factors that have been measured using the "International SEMATECH Manufacturing Initiative's Guideline for Environmental Characterization of Semiconductor Process Equipment" (December 2006) must be used. Utilization factors measured by manufacturing equipment suppliers may be used if the conditions in paragraphs (d)(1) and (d)(2) of this section are met.

(1) The manufacturing equipment supplier has measured the N_2O utilization factors using the "International SEMATECH Manufacturing Initiative's Guideline for Environmental Characterization of Semiconductor Process Equipment" (December 2006).

(2) The conditions under which the measurements were made are representative of the facility's N_2O emitting processes.

(e) If the facility employs abatement systems and wishes to reflect emission reductions due to these systems in appropriate calculations in WCI.113, the facility must adhere to the procedures in paragraphs (e)(1) and (e)(2) of this section. If the facility uses the default destruction or removal efficiency of 60 percent, the facility must adhere to procedures in paragraph (e)(3) of this section. If the facility uses either a properly measured destruction or removal efficiency, or a class average of properly measured destruction or removal efficiencies during a reporting year, the facility must adhere to procedures in paragraph (e)(4) of this section.

(1) The facility must certify and document that the systems are properly installed, operated, and maintained according to manufacturers' specifications by adhering to the procedures in paragraphs (e)(1)(i) and (e)(1)(ii) of this section.

(i) Proper installation must be verified by certifying the systems are installed in accordance with the manufacturers' specifications.
(ii) Proper operation and maintenance must be verified by certifying the systems are operated and maintained in accordance with the manufacturers' specifications.

(2) The facility must take into account and report the uptime of abatement systems when using destruction or removal efficiencies to reflect emission reductions. Abatement system uptime is expressed as the sum of an abatement system's operational productive, standby, and engineering times divided by the total operations time of its associated

manufacturing tool(s) as referenced in SEMI Standard E-10-0340 "Specification for Definition and Measurement of Equipment Reliability, Availability, and Maintainability" (2004).

(3) To report controlled emissions using the default destruction or removal efficiency, the facility must certify and document that the abatement systems at the facility for which it is reporting controlled emissions are specifically designed for fluorinated GHG and N_2O abatement and you shall use a default destruction or removal efficiency of 60 percent for those abatement systems.

(4) If the facility does not use the default destruction or removal efficiency value to report controlled emissions, the facility must use either a properly measured destruction or removal efficiency, or a class average of properly measured destruction or removal efficiencies during a reporting year, determined in accordance with procedures in paragraphs (e)(4)(i) through (e)(4)(v) of this section.

(i) Destruction or removal efficiencies must be properly measured in accordance with EPA's "Protocol for Measuring Destruction or Removal Efficiency of Fluorinated Greenhouse Gas Abatement Equipment in Electronics Manufacturing" (March 2010).

(ii) A facility must annually select and properly measure the destruction or removal efficiency for a random sample of abatement systems to include in a Random Sampling Abatement System Testing Program (RSASTP) in accordance with procedures in paragraphs (e)(4)(ii)(A) and (e)(4)(ii)(B) of this section.

(A) Each reporting year a random sample of three or 20 percent of installed abatement systems, whichever is greater, for each abatement system class shall be tested. In instances where 20 percent of the total number of abatement systems in each class does not equate to a whole number, the number of systems to be tested shall be determined by rounding up to the nearest integer.

(B) The facility must select the random sample each reporting year for the RSASTP without repetition of systems in the sample, until all systems in each class are properly measured in a 5-year period.

(iii) If a facility has measured the destruction or removal efficiency of a particular abatement system during the previous two-year period, the facility shall calculate emissions from that system using the destruction or removal efficiency most recently measured for that particular system.

(iv) If an individual abatement system has not yet undergone proper destruction or removal efficiency testing during the previous two-year period, the facility may apply a simple average of the properly measured destruction or removal efficiencies for all systems of that class, in accordance with the RSASTP. The facility shall maintain or exceed the RSASTP schedule and regime if it wishes to apply class average destruction or removal efficiency factors to abatement systems that have not been properly measured as per the RSASTP.

(v) In instances where redundant abatement systems are used, the facility may account for the total abatement system uptime calculated for a specific exhaust stream during the reporting year.

(f) Facilities must adhere to the QA/QC procedures of this paragraph when estimating fluorinated GHG and N_2O emissions from all electronics manufacturing processes:

(1) Facilities must follow the QA/QC procedures in the "International SEMATECH Manufacturing Initiative's Guideline for Environmental Characterization of Semiconductor Process Equipment" (December 2006) when estimating facility-specific, recipe-specific fluorinated GHG and N_2O utilization and by-product formation rates.

(2) Facilities must follow the QA/QC procedures in EPA's "Protocol for Measuring Destruction or Removal Efficiency of Fluorinated Greenhouse Gas Abatement Equipment in Electronics Manufacturing" (March 2010) when estimating abatement systems destruction or removal efficiency.

(3) Facilities must certify that gas consumption is tracked to a high degree of precision as part of normal facility operations ensuring that the inventory at the beginning of the reporting is the same as the inventory at the end of the previous year.

(g) Facilities must adhere to the QA/QC procedures of this paragraph when estimating fluorinated GHG emissions from heat transfer fluid use and annual gas consumption for each fluorinated GHG and N_2O used at the facility:

(1) Facilities must review all inputs to Equations 110-6 and 110-8 of this section to ensure that all inputs and outputs to the facility's system are accounted for.

(2) Facilities must not enter negative inputs into the mass balance Equations 110-6 and 110-8 of this section and shall ensure that no negative emissions are calculated.

(3) Facilities must ensure that the beginning of year inventory matches the end of year inventory from the previous year.

(h) All instruments (e.g., mass spectrometers and fourier transform infrared measuring systems) used to determine the concentration of fluorinated GHG and N_2O in process streams shall be calibrated just prior to destruction or removal efficiency, gas utilization, or by-product formation measurement through analysis of certified standards with known concentrations of the same chemicals in the same ranges (fractions by mass) as the process samples. Calibration gases prepared from a high-concentration certified standard using a gas dilution system that meets the requirements specified in Method 205, 40 CFR part 51, Appendix M may also be used.

(i) All flowmeters, weigh scales, pressure gauges, and thermometers used to measure quantities that are monitored under this section or used in calculations under §WCI.113 shall have an accuracy and precision of one percent of full scale or better.

§ WCI.115 Missing Data Procedures

(a) Except as provided in paragraph WCI.115(b), a complete record of all measured parameters used in the fluorinated GHG and N_2O emissions calculations in WCI.113 andWCI.114 is required.

(b) If a facility uses heat transfer fluids and is missing data for one or more of the parameters in Equation 110-8 of this subpart, the facility must estimate heat transfer fluid emissions using the arithmetic average of the emission rates for the year immediately preceding the period of missing data and the months immediately following the period of missing data. Alternatively, you may estimate missing information using records from the heat transfer fluid supplier. The facility must document the method used and values estimated for all missing data values.

Table 110-1. Examples of Fluorinated GHGs Used by the Electronics Industry

Product Type	Fluorinated GHGs used during manufacturing
Electronics	CF_4, C_2F_6, C_3F_8, c-C_4F_8, c-C_4F_8O, C_4F_6, C_5F_8, CHF_3, CH_2F_2, NF_3, SF6,and HTFs [CF_3-(O-CF(CF_3)-CF_2)$_n$-(O-CF_2)$_m$-O-CF_3, C_nF_{2n+2}, $C_nF_{2n+1}(O)C_mF_{2m+1}$, $C_nF_{2n}O$, $(C_nF2_{n+1})_3N$].

Table 110-2. Default Emission Factors for Refined Process Categories for Semiconductor Manufacturing for 150 mm Wafer Size

Refined Process Category	Process Gas *i*										
	CF_4	C_2F_6	CHF_3	CH_2F_2	C_3F_8	c-C_4F_8	NF_3	SF_6	C_4F_6	C_5F_8	C_4F_8O
PATTERNING/ETCHING											
Oxide etch											
$1\text{-}U_i$	0.2-0.8	0.2-0.7	0.2-0.7	0.02-0.3	NA	0.1-0.3	0.1-0.4	0.1-0.4	0.05-0.2	0.05-0.3	NA
BCF_4	NA	0.05-0.5	0.01-0.8	0.05-0.1	NA	0.01-0.3	NA	NA	0.02-0.4	0.02-0.4	NA
BC_2F_6	NA	NA	NA	NA	NA	0.01-0.3	NA	NA	0.02-0.3	0.02-0.3	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Nitride etch											
$1\text{-}U_i$	0.2-0.8	0.2-0.7	0.2-0.7	0.02-0.3	NA	0.1-0.3	0.1-0.4	0.1-0.4	0.05-0.2	0.05-0.3	NA
BCF_4	NA	0.05-0.5	0.01-0.8	0.05-0.1	NA	0.01-0.3	NA	NA	0.02-0.4	0.02-0.4	NA
BC_2F_6	NA	NA	NA	NA	NA	0.01-0.3	NA	NA	0.02-0.3	0.02-0.3	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Silicon etch											
$1\text{-}U_i$	0.2-0.8	0.2-0.7	0.2-0.7	0.02-0.3	NA	0.1-0.3	0.1-0.4	0.1-0.4	0.05-0.2	0.05-0.3	NA
BCF_4	NA	0.05-0.5	0.01-0.8	0.05-0.1	NA	0.01-0.3	NA	NA	0.02-0.4	0.02-0.4	NA
BC_2F_6	NA	NA	NA	NA	NA	0.01-0.3	NA	NA	0.02-0.3	0.02-0.3	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Metal etch											
$1\text{-}U_i$	0.2-0.8	0.2-0.7	0.2-0.7	0.02-0.3	NA	0.1-0.3	0.1-0.4	0.1-0.4	0.05-0.2	0.05-0.3	NA
BCF_4	NA	0.05-0.5	0.01-0.8	0.05-0.1	NA	0.01-0.3	NA	NA	0.02-0.4	0.02-0.4	NA
BC_2F_6	NA	NA	NA	NA	NA	0.01-0.3	NA	NA	0.02-0.3	0.02-0.3	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
CHAMBER CLEANING											
In situ plasma cleaning											
$1\text{-}U_i$	0.8-0.95	0.4-0.8	NA	NA	0.2-0.6	0.05-0.3	0.05-0.3	NA	NA	0.05-0.2	0.05-0.2
BCF_4	NA	0.05-0.2	NA	NA	0.05-0.2	0.05-0.2	0.05-0.2	NA	NA	0.05-0.2	0.05-0.2

Refined Process Category	Process Gas *i*										
	CF_4	C_2F_6	CHF_3	CH_2F_2	C_3F_8	c-C_4F_8	NF_3	SF_6	C_4F_6	C_5F_8	C_4F_8O
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.02-0.08
Remote plasma cleaning											
$1-U_i$	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BCF_4	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
In situ thermal cleaning											
$1-U_i$	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BCF_4	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
WAFER CLEANING											
Bevel cleaning											
$1-U_i$	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BCF_4	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Ashing											
$1-U_i$	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BCF_4	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Notes: NA denotes not applicable based on currently available information.

Table 110-3. Default Emission Factors for Refined Process Categories for Semiconductor Manufacturing for 200 mm Wafer Size

Refined Process Category	Process Gas i										
	CF_4	C_2F_6	CHF_3	CH_2F_2	C_3F_8	c-C_4F_8	NF_3	SF_6	C_4F_6	C_5F_8	C_4F_8O
PATTERNING/ETCHING											
Oxide etch											
$1-U_i$	0.2-0.8	0.2-0.7	0.2-0.7	0.02-0.3	NA	0.1-0.3	0.1-0.4	0.1-0.4	0.05-0.5	0.05-0.3	NA
BCF_4	NA	0.05-0.5	0.01-0.8	0.05-0.1	NA	0.01-0.3	NA	NA	0.02-0.4	0.02-0.4	NA
BC_2F_6	NA	NA	NA	NA	NA	0.01-0.3	NA	NA	0.02-0.3	0.02-0.3	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Nitride etch											
$1-U_i$	0.2-0.8	0.2-0.7	0.1-0.7	0.02-0.3	NA	0.05-0.3	0.1-0.4	0.1-0.4	0.05-0.2	0.05-0.3	NA
BCF_4	NA	0.05-0.5	0.01-0.8	0.05-0.1	NA	0.02-0.3	NA	NA	0.02-0.4	0.02-0.4	NA
BC_2F_6	NA	NA	NA	NA	NA	0.005-0.3	NA	NA	0.02-0.3	0.02-0.3	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Silicon etch											
$1-U_i$	0.2-0.8	0.2-0.7	0.2-0.7	0.02-0.3	NA	0.1-0.3	0.1-0.4	0.1-0.4	0.05-0.2	0.05-0.3	NA
BCF_4	NA	0.05-0.5	0.01-0.8	0.05-0.1	NA	0.01-0.3	NA	NA	0.02-0.4	0.02-0.4	NA
BC_2F_6	NA	NA	NA	NA	NA	0.01-0.3	NA	NA	0.02-0.3	0.02-0.3	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Metal etch											
$1-U_i$	0.2-0.8	0.2-0.7	0.2-0.7	0.02-0.3	NA	0.1-0.3	0.1-0.4	0.1-0.4	0.05-0.2	0.05-0.3	NA
BCF_4	NA	0.05-0.5	0.01-0.8	0.05-0.1	NA	0.01-0.3	NA	NA	0.02-0.4	0.02-0.4	NA
BC_2F_6	NA	NA	NA	NA	NA	0.01-0.3	NA	NA	0.02-0.3	0.02-0.3	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
CHAMBER CLEANING											
In situ plasma cleaning											
$1-U_i$	0.8-0.95	0.4-0.8	NA	NA	0.2-0.6	005-0.3	0.05-0.2	NA	NA	0.05-0.2	0.05-0.2

Refined Process Category	Process Gas *i*										
	CF_4	C_2F_6	CHF_3	CH_2F_2	C_3F_8	$c\text{-}C_4F_8$	NF_3	SF_6	C_4F_6	C_5F_8	C_4F_8O
BCF_4	NA	0.05-0.2	NA	NA	0.05-0.2	0.05-0.2	0.05-0.1	NA	NA	0.05-0.2	0.05-0.2
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.02-0.08
Remote plasma cleaning											
$1\text{-}U_i$	NA	NA	NA	NA	NA	NA	0.005-0.03	NA	NA	NA	NA
BCF_4	NA	NA	NA	NA	NA	NA	0.0001-0.2	NA	NA	NA	NA
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
In situ thermal cleaning											
$1\text{-}U_i$	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BCF_4	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
WAFER CLEANING											
Bevel cleaning											
$1\text{-}U_i$	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BCF_4	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Ashing											
$1\text{-}U_i$	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BCF_4	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Notes: NA denotes not applicable based on currently available information.

Table 110-4. Default Emission Factors for Refined Process Categories for Semiconductor Manufacturing for 300 mm Wafer Size

Refined Process Category	Process Gas *i*										
	CF_4	C_2F_6	CHF_3	CH_2F_2	C_3F_8	$c\text{-}C_4F_8$	NF_3	SF_6	C_4F_6	C_5F_8	C_4F_8O
PATTERNING/ETCHING											
Oxide etch											
$1\text{-}U_i$	0.2-0.8	0.2-0.7	0.2-0.4	0.1-0.8	NA	0.05-0.3	0.1-0.4	0.1-0.4	0.05-0.3	0.05-0.3	NA
BCF_4	NA	0.05-0.5	0.005-0.03	0.001-0.01	NA	0.005-0.1	NA	NA	0.02-0.4	0.02-0.4	NA
BC_2F_6	NA	NA	NA	NA	NA	0.005-0.1	NA	NA	0.02-0.3	0.02-0.3	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Nitride etch											
$1\text{-}U_i$	0.2-0.8	0.2-0.7	0.2-0.4	0.1-0.8	NA	0.08-0.3	0.1-0.4	0.1-0.4	0.05-0.2	0.05-0.3	NA
BCF_4	NA	0.05-0.5	0.003-0.1	0.01-0.1	NA	0.02-0.3	NA	NA	0.05-0.4	0.05-0.4	NA
BC_2F_6	NA	NA	NA	NA	NA	0.02-0.3	NA	NA	0.05-0.4	0.05-0.4	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Silicon etch											
$1\text{-}U_i$	0.2-0.8	0.2-0.7	0.2-0.7	0.02-0.3	NA	0.1-0.3	0.1-0.4	0.1-0.4	0.05-0.2	0.05-0.3	NA
BCF_4	NA	0.05-0.5	0.01-0.8	0.05-0.1	NA	0.01-0.3	NA	NA	0.02-0.4	0.02-0.4	NA
BC_2F_6	NA	NA	NA	NA	NA	0.01-0.3	NA	NA	0.02-0.3	0.02-0.3	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Metal etch											
$1\text{-}U_i$	0.2-0.8	0.2-0.7	0.2-0.7	0.02-0.3	NA	0.1-0.3	0.1-0.4	0.1-0.4	0.05-0.2	0.05-0.3	NA
BCF_4	NA	0.05-0.5	0.01-0.8	0.05-0.1	NA	0.01-0.3	NA	NA	0.02-0.4	0.02-0.4	NA
BC_2F_6	NA	NA	NA	NA	NA	0.01-0.3	NA	NA	0.02-0.3	0.02-0.3	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
CHAMBER CLEANING											
In situ plasma cleaning											
$1\text{-}U_i$	NA	NA	NA	NA	NA	NA	0.1-0.4	NA	NA	NA	NA

Refined Process Category	Process Gas *i*										
	CF_4	C_2F_6	CHF_3	CH_2F_2	C_3F_8	c-C_4F_8	NF_3	SF_6	C_4F_6	C_5F_8	C_4F_8O
BCF_4	NA	NA	NA	NA	NA	NA	0.001-0.6	NA	NA	NA	NA
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Remote plasma cleaning											
$1-U_i$	NA	NA	NA	NA	NA	NA	0.002-0.03	NA	NA	NA	NA
BCF_4	NA	NA	NA	NA	NA	NA	0.001-0.05	NA	NA	NA	NA
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
In situ thermal cleaning											
$1-U_i$	NA	NA	NA	NA	NA	NA	0.1-0.4	NA	NA	NA	NA
BCF_4	NA	NA	NA	NA	NA	NA	0.005-.05	NA	NA	NA	NA
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
WAFER CLEANING											
Bevel cleaning											
$1-U_i$	0.3-0.8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BCF_4	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Ashing											
$1-U_i$	0.3-0.8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BCF_4	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Notes: NA denotes not applicable based on currently available information.

Table 110-5. Default Emission Factors for MEMS Manufacturing

Process Type Factors	Process Gas *i*											
	CF_4	C_2F_6	CHF_3	CH_2F_2	C_3F_8	$c\text{-}C_4F_8$	NF_3 Remote	NF_3	SF_6	C_4F_6[a]	C_5F_8[a]	C_4F_8O[a]
Etch $1\text{-}U_i$	0.7	0.4[1]	0.4[1]	0.06[1]	NA	0.2[1]	NA	0.2	0.2	0.1	0.2	NA
Etch BCF_4	NA	0.4[1]	0.07[1]	0.08[1]	NA	0.2	NA	NA	NA	0.3[1]	0.2	NA
Etch BC_2F_6	NA	NA	NA	NA	NA	0.2	NA	NA	NA	0.2[1]	0.2	NA
CVD $1\text{-}U_i$	0.9	0.6	NA	NA	0.4	0.1	0.02	0.2	NA	NA	0.1	0.1
CVD BCF_4	NA	0.1	NA	NA	0.1	0.1	0.02[2]	0.1[2]	NA	NA	0.1	0.1
CVD BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.4

Notes: NA denotes not applicable based on currently available information.
[1] Estimate includes multi-gas etch processes.
[2] Estimate reflects presence of low-k, carbide and multi-gas etch processes that may contain a C-containing fluorinated GHG additive.

Table 110-6. Default Emission Factors for LCD Manufacturing

Process Type Factors	Process Gas *i*								
	CF_4	C_2F_6	CHF_3	CH_2F_2	C_3F_8	$c\text{-}C_4F_8$	NF_3 Remote	NF_3	SF_6
Etch $1\text{-}U_i$	0.6	NA	0.2	NA	NA	0.1	NA	NA	0.3
Etch BCF_4	NA	NA	0.07	NA	NA	0.009	NA	NA	NA
Etch $BCHF_3$	NA	NA	NA	NA	NA	0.02	NA	NA	NA
Etch BC_2F_6	NA	NA	0.05	NA	NA	NA	NA	NA	NA
CVD $1\text{-}U_i$	NA	NA	NA	NA	NA	NA	0.03	0.3	0.9

Notes: NA denotes not applicable based on currently available information.

Table 110-7. Default Emission Factors for PV Manufacturing

Process Type Factors	Process Gas *i*								
	CF_4	C_2F_6	CHF_3	CH_2F_2	C_3F_8	c-C_4F_8	NF_3 Remote	NF_3	SF_6
Etch 1-U_i	0.7	0.4	0.4	NA	NA	0.2	NA	NA	0.4
Etch BCF_4	NA	0.2	NA	NA	NA	0.1	NA	NA	NA
Etch BC_2F_6	NA	NA	NA	NA	NA	0.1	NA	NA	NA
CVD 1-U_i	NA	0.6	NA	NA	0.1	0.1	NA	0.3	0.4
CVD BCF_4	NA	0.2	NA	NA	0.2	0.1	NA	NA	NA

Notes: NA denotes "not applicable" based on currently available information.

§ WCI.120 HCFC-22 PRODUCTION AND HFC-23 DESTRUCTION

§ WCI.121 Source Category Definition

The HCFC-22 production and HFC-23 destruction source category consists of HCFC-22 production processes and HFC-23 destruction processes. An HCFC-22 production process produces HCFC-22 ($CHClF_2$ or chlorodifluoromethane) from chloroform ($CHCl_3$) and hydrogen fluoride (HF). An HFC-23 destruction process is any process in which HFC-23 (CHF_3 or trifluoromethane) undergoes destruction. An HFC-23 destruction process may or may not be co-located at the same facility with an HCFC-22 production process.

§ WCI.122 Greenhouse Gas Reporting Requirements

In addition to the information required by regulation, the annual emissions data report shall contain the following information:

(a) HFC-23 emissions from HCFC-22 production processes and HFC-23 destruction processes (tonnes).

(b) HCFC-22 production facilities shall report the following information at the facility level:

(1) Annual mass of HCFC-22 produced (tonnes).

(2) Loss Factor used to account for the loss of HCFC-22 upstream of the measurement.

(3) Annual mass of reactants fed into the process (tonnes).

(4) Mass of materials other than HCFC-22 and HFC-23 (i.e., unreacted reactants, HCl and other by-products) that occur in more than trace concentrations and that are permanently removed from the process (tonnes).

(5) Method for tracking startups, shutdowns, and malfunctions and HFC-23 generation/emissions during these events.

(6) Names and addresses of facilities to which any HFC-23 was sent for destruction, and the quantities of HFC-23 (tonnes) sent to each.

(7) Annual mass of the HFC-23 generated (tonnes).

(8) Annual mass of any HFC-23 sent off site for sale (tonnes).

(9) Annual mass of any HFC-23 sent off site for destruction (tonnes).

(10) Mass of HFC-23 in storage at the beginning and end of the year (tonnes).

(11) Annual mass of HFC-23 emitted (tonnes).

(12) Annual mass of HFC-23 emitted from equipment leaks (tonnes).

(13) Annual mass of HFC-23 emitted from process vents (tonnes).

(c) Each HFC-23 destruction facility shall report the concentration (mass fraction) of HFC-23 measured at the outlet of the destruction device during the facility's annual HFC-23 concentration measurements at the outlet of the device..

(d) By the date of the first report or within 60 days of commencing HFC-23 destruction, HFC-23 destruction facilities shall submit a one-time report including the following information for each destruction process:

(1) Destruction efficiency (DE).

(2) Methods used to determine destruction efficiency.

(3) Methods used to record the mass of HFC-23 destroyed.

(4) Name of other relevant federal or provincial regulations that may apply to the destruction process.

(5) If any changes are made that affect HFC-23 destruction efficiency or the methods used to record volume destroyed, then these changes must be reflected in a revision to this report. The revised report must be submitted to regulators within 60 days of the change.

§ WCI.123 Calculation of GHG Emissions

(a) The mass of HFC-23 generated from each HCFC-22 production process shall be estimated using either paragraph (1) or (2) of this section.

(1) Where the mass flow of the combined stream of HFC-23 and another reaction product (e.g., HCl, etc.) is measured, multiply the weekly (or more frequent) HFC-23 concentration measurement (which may be the average of more frequent concentration measurements) by the weekly (or more frequent) mass flow of the combined stream of HFC-23 and the other product. To estimate annual HFC-23 production, sum the weekly (or more frequent) estimates of the quantities of HFC-23 produced over the year. This calculation is shown in Equation 120-1.

$$G_{23} = \sum_{p=1}^{n} c_{23} \times F_p \times 10^{-3}$$

Equation 120-1

Where:

G_{23}	=	Mass of HFC-23 generated annually (tonnes).
c_{23}	=	Fraction HFC-23 by weight in HFC-23/other product stream.
F_p	=	Mass flow of HFC-23/other product stream during the period *p* (kg).
p	=	Period over which mass flows and concentrations are measured.
n	=	Number of concentration and flow measurement periods for the year.
10^{-3}	=	Conversion factor from kilograms to tonnes.

(2) Where the mass of only a reaction product other than HFC-23 (either HCFC-22 or HCl) is measured, multiply the ratio of the weekly (or more frequent) measurement of the HFC-23 concentration and the weekly (or more frequent) measurement of the other product concentration by the weekly (or more frequent) mass produced of the other product. To estimate annual HFC-23 production, sum the weekly (or more frequent) estimates of the quantities of HFC-23 produced over the year. If the other product is HCFC-22, then used Equation 120-2. If the other product is HCl, then use Equations 120-2 and 120-3 substituting HCl for HCFC-22.

$$G_{23} = \sum_{p=1}^{n} \left(\frac{c_{23}}{c_{22}} \right) \times P_{22} \times 10^{-3}$$

Equation 120-2

Where:

G_{23}	=	Mass of HFC-23 generated annually (tonnes).
c_{23}	=	Fraction HFC-23 by weight in HCFC-22/HFC-23 stream.
c_{22}	=	Fraction HCFC-22 by weight in HCFC-22/HFC-23 stream.
P_{22}	=	Mass of HCFC-22 produced over the period *p* (kg) (calculated using Equation 120-3).
p	=	Period over which mass flows and concentrations are measured.
n	=	Number of concentration and flow measurement periods for the year.
10^{-3}	=	Conversion factor from kilograms to tonnes.

(b) The mass of HCFC-22 produced over the period *p* shall be estimated using Equation 120-3.

$$P_{22} = LF \times (O_{22} - U_{22})$$

Equation 120-3

Where:

P_{22}	=	Mass of HCFC-22 produced over the period *p* (kg).
O_{22}	=	Mass of HCFC-22 that is measured coming out of the production process over the period *p* (kg).
U_{22}	=	Mass of used HCFC-22 that is added to the production process upstream of the output measurement over the period *p* (kg).
LF	=	Factor to account for the loss of HCFC-22 upstream of the measurement. The loss factor shall either have the value of 1.015 or another value that can be demonstrated to account for losses of HCFC-22 between the reactor and the point of measurement at the facility where production is being estimated.

(c) For HCFC-22 production facilities that do not use a thermal oxidizer or that have a thermal oxidizer that is not directly connected to the HCFC-22 production equipment, HFC-23 emissions shall be estimated using Equation 120-4.

$$E_{23} = G_{23} - \left(S_{23} + OD_{23} + D_{23} + I_{23}\right)$$

Equation 120-4

Where:

E_{23}	=	Mass of HFC-23 emitted annually (tonnes).
G_{23}	=	Mass of HFC-23 generated annually (tonnes).
S_{23}	=	Mass of HFC-23 sent off site for sale annually (tonnes).
OD_{23}	=	Mass of HFC-23 sent off site for destruction (tonnes).
D_{23}	=	Mass of HFC-23 destroyed on site (tonnes).
I_{23}	=	Increase in HFC-23 inventory (HFC-23 in storage at end of year – HFC-23 in storage at beginning of year (tonnes).

(d) For HCFC-22 production facilities that use a thermal oxidizer connected to the HCFC-22 production equipment, HFC-23 emissions shall be estimated using Equation 120-5.

$$E_{23} = E_L + E_{PV} + E_D$$

Equation 120-5

Where:

E_{23}	=	Mass of HFC-23 emitted annually (tonnes).
E_L	=	Mass of HFC-23 emitted annually from equipment leaks (tonnes) (calculated using Equation 120-6).
E_{PV}	=	Mass of HFC-23 emitted annually from process vents (tonnes) (calculated using Equation 120-7).
E_D	=	Mass of HFC-23 emitted annually from thermal oxidizer (tonnes) (calculated using Equation 120-8).

(1) The mass of HFC-23 emitted annually from equipment leaks (for use in Equation 120-5) shall be estimated by using Equation 120-6.

$$E_L = \sum_{p=1}^{n} \sum_{t} c_{23} \times \left(F_{Gt} \times N_{Gt} + F_{Lt} \times N_{Lt}\right) \times 10^{-3}$$

Equation 120-6

Where:

E_L	=	Mass of HFC-23 emitted annually from equipment leaks (tonnes).
c_{23}	=	Fraction HFC-23 by weight in the streams in the equipment.
F_{Gt}	=	Applicable leak rate specified in Table 120-1 for each source of equipment type and service *t* with a screening value greater than or equal to 10,000 ppmv (kg/hr/source).
N_{Gt}	=	Number of sources of equipment type and service *t* with screening values greater than or equal to 10,000 ppmv (kg/hr/source).
F_{Lt}	=	Applicable leak rate specified in Table 120-1 for each source of equipment type and service *t* with a screening value less than 10,000 ppmv (kg/hr/source).
N_{Lt}	=	Number of sources of equipment type and service *t* with screening values less than 10,000 ppmv (kg/hr/source).
p	=	One hour.
n	=	Number of hours during the year during which equipment contained HFC-23.
t	=	Equipment type and service as specified in Table 120-1.
10^{-3}	=	Conversion factor from kilograms to tonnes.

(2) The mass of HFC-23 emitted annually from process vents (for use in Equation 120-5) shall be estimated by using Equation 120-7.

$$E_{PV} = \sum_{p=1}^{n} ER_T \times \left(\frac{PR_p}{PR_T}\right) \times l_p \times 10^{-3}$$

Equation 120-7

Where:

E_{PV}	=	Mass of HFC-23 emitted annually from process vents (tonnes).
ER_T	=	HFC-23 emission rate from the process vents during the period of the most recent test (kg/hr).
PR_p	=	HCFC-22 production rate during the period *p* (kg/hr).
PR_T	=	HCFC-22 production rate during the most recent test period (kg/hr).
l_p	=	Length of period *p* (hours).
10^{-3}	=	Conversion factor from kilograms to tonnes.

(3) The mass of HFC-23 emitted from destruction devices (for use in Equation 120-5) shall be estimated by using Equation 120-8.

$$E_D = F_D - D_{23}$$

Equation 120-8

Where:

E_D = Mass of HFC-23 emitted annually from destruction device (tonnes).
F_D = Mass of HFC-23 annual fed into the destruction device (tonnes).
D_{23} = Mass of HFC-23 destroyed annually (tonnes).

(4) For facilities that destroy HFC-23, the total mass of HFC-23 destroyed (for use in Equations 120-4 and 120-8) shall be estimated by using Equation 120-9.

$$D_{23} = F_D \times DE$$

Equation 120-9

Where:

D_{23} = Mass of HFC-23 destroyed annually (tonnes).
F_D = Mass of HFC-23 annual fed into the destruction device (tonnes).
DE = Destruction efficiency of the destruction device (fraction).

§ WCI.124 Sampling, Analysis, and Measurement Requirements

The measurements that are reported for this category or used to estimate quantities used in the WCI.123 calculation methodologies shall be determined as specified in paragraphs (a) through (q).

(a) The concentrations (fractions by weight) of HFC23 (c_{23} in Equations 120-1 and 120-2) and HCFC-22 (c_{22} in Equation 120-2) in the product stream shall be measured at least weekly using equipment and methods (e.g., gas chromatography) with an accuracy and precision of 5 percent or better at the concentrations of the process samples.

(b) The mass flow of the product stream containing the HFC-23 (F_p in Equation 120-1) shall be measured at least weekly using weigh scales, flowmeters, or a combination of volumetric and density measurements with an accuracy and precision of 1.0 percent of full scale or better.

(c) The mass of HCFC-22 (O_{22} in Equation 120-3) or HCl (substituted value for O_{22} in Equation 120-3) coming out of the production process shall be measured at least weekly using weigh scales, flowmeters, or a combination of volumetric and density measurements with an accuracy and precision of 1.0 percent of full scale or better.

(d) The mass of any used HCFC-22 added back into the production process upstream of the output measurement in paragraph (c) of this section (U_{22} in Equation 120-3) shall be measured (when being added) using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 1.0 percent of full scale or better. If the mass in paragraph (c) of this section is measured by weighing containers that include returned heels as well as newly produced fluorinated GHGs, the returned heels shall be considered used fluorinated HCFC-22 for purposes of this paragraph (d) of this section and WCI.123(b).

(e) The loss factor LF of this subpart for the mass of HCFC-22 produced (*LF* in Equation 120-3) shall have the value 1.015 or another value that can be demonstrated, to the satisfaction of the jurisdiction, to account for losses of HCFC-22 between the reactor and the point of measurement at the facility where production is being estimated.

(f) The mass of HFC-23 sent off site for sale (S_{23} in Equation 120-4) shall be measured at least weekly (when being packaged) using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 1.0 percent of full scale or better.

(g) The mass of HFC-23 sent off site for destruction (OD_{23} in Equation 120-4) shall be measured at least weekly (when being packaged) using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 1.0 percent of full scale or better. If the measured mass includes more than trace concentrations of materials other than HFC-23, the concentration of the fluorinated GHG shall be measured at least weekly using equipment and methods (e.g., gas chromatography) with an accuracy and precision of 5 percent or better at the concentrations of the process samples. This concentration (mass fraction) shall be multiplied by the mass measurement to obtain the mass of the HFC-23 sent to another facility for destruction.

(h) The masses of HFC-23 in storage at the beginning and end of the year (I_{23} in Equation 120-4) shall be measured using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 1.0 percent of full scale or better.

(i) The number of sources of equipment type t with screening values greater than or equal to 10,000 ppmv (N_{Gt} in Equation 120-6) shall be determined using EPA Method 21 at 40 CFR part 60, appendix A-7, and defining a leak as follows:

(1) A leak source that could emit HFC-23, and

(2) A leak source at whose surface a concentration of fluorocarbons equal to or greater than 10,000 ppm is measured.

(j) The number of sources of equipment type t with screening values less than 10,000 ppmv (N_{Lt} in Equation 120-6) shall be the difference between the number of leak sources of equipment type t that could emit HFC-23 and the number of sources of equipment type t with screening values greater than or equal to 10,000 ppmv as determined under paragraph (i) of this section.

(k) The mass of HFC-23 emitted from process vents (E_{PV} in Equation 120-5) shall be estimated at least monthly by incorporating the results of the most recent emissions test into Equation 120-7 of this subpart. HCFC-22 production facilities that use a destruction device connected to the HCFC-22 production equipment shall conduct emissions tests at process vents at least once every five years or after significant changes to the process. Emissions tests shall be conducted in accordance with EPA Method 18 at 40 CFR part 60, appendixA-6, under conditions that are typical for the production process at the facility. The sensitivity of the tests shall be sufficient to detect an emission rate that would result in annual emissions of 200 kg of HFC-23 if sustained over one year.

(l) For purposes of Equation 120-9 of this subpart, the destruction efficiency must be equated to the destruction efficiency (*DE*) determined during a new or previous performance test of the destruction device. HFC-23 destruction facilities shall conduct annual measurements of HFC-23 concentrations at the outlet of the destruction device in accordance with EPA Method 18 at 40 CFR part 60, appendix A-6. Three samples shall be taken under conditions that are typical for the production process and destruction device at the facility, and the average concentration of HFC-23 shall be determined. The sensitivity of the concentration measurement shall be sufficient to detect an outlet concentration equal to or less than the outlet concentration determined in the destruction efficiency performance test. If the concentration measurement indicates that the HFC-23 concentration is less than or equal to that measured during the performance test that is the basis for the destruction efficiency, continue to use the previously determined destruction efficiency. If the concentration measurement indicates that the HFC-23 concentration is greater than that measured during the performance test that is the basis for the destruction efficiency, facilities shall either:

(1) Substitute the higher HFC-23 concentration for that measured during the destruction efficiency performance test and calculate a new destruction efficiency, or

(2) Estimate the mass emissions of HFC-23 from the destruction device based on the measured HFC-23 concentration and volumetric flow rate determined by measurement of volumetric flow rate using EPA Method 2, 2A, 2C,2D, or 2F at 40 CFR part 60, appendix A-1, or Method 26 at 40 CFR part 60, appendix A-2. Determine the mass rate of HFC-23 into the destruction device by measuring the HFC23 concentration and volumetric flow rate at the inlet or by a metering device for HFC-23 sent to the device. Determine a new destruction efficiency based on the mass flow rate of HFC-23 into and out of the destruction device.

(m) HCFC-22 production facilities shall account for HFC-23 generation and emissions that occur as a result of startups, shutdowns, and malfunctions, either recording HFC-23 generation and emissions during these events, or documenting that these events do not result in significant HFC-23 generation and/or emissions.

(n) The mass of HFC-23 fed into the destruction device (F_D in Equations 120-8 and 120-9) shall be measured at least weekly using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 1.0 percent of full scale or better. If the measured mass includes more than trace concentrations of materials other than HFC23, the concentrations of the HFC-23 shall be measured at least weekly using equipment and methods (e.g., gas chromatography) with an accuracy and precision of 5 percent or better at the concentrations of the process samples. This concentration (mass fraction) shall be multiplied by the mass measurement to obtain the mass of the HFC-23 destroyed.

(o) In their estimates of the mass of HFC-23 destroyed, HFC-23 destruction facilities shall account for any temporary reductions in the destruction efficiency that result from any startups, shutdowns, or malfunctions of the destruction device, including departures from the operating conditions defined in state or local permitting requirements and/or destruction device manufacturer specifications.

(p) Calibrate all flow meters, weigh scales, and combinations of volumetric and density measures using NIST-traceable standards and suitable methods published by a consensus standards organization (e.g., ASTM, ASME, ISO, or others). Recalibrate all flow meters, weigh scales, and combinations of volumetric and density measures at the minimum frequency specified by the manufacturer.

(q) All gas chromatographs used to determine the concentration of HFC-23 in process streams (c_{23} in Equations 120-1 and 120-2) shall be calibrated at least monthly through analysis of certified standards (or of calibration gases prepared from a high-concentration certified standard using a gas dilution system that meets the requirements specified in Method 205 at 40 CFR part 51, appendix M) with known HFC-23 concentrations that are in the same range (fractions by mass) as the process samples.

§ WCI.125 Missing Data Procedures

(a) A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation or if a required process sample is not taken), a substitute data value for the missing parameter shall be used in the calculations, according to the following requirements:

(1) For each missing value of the HFC-23 or HCFC-22 concentration, the substitute data value shall be the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.

(2) For each missing value of the product stream mass flow or product mass, the substitute value of that parameter shall be a secondary product measurement where such a measurement is available. If that measurement is taken significantly downstream of the usual mass flow or mass measurement (e.g., at the shipping dock rather than near the reactor), the measurement shall be multiplied by 1.015 to compensate for losses. Where a secondary mass measurement is not available, the substitute value of the parameter shall be an estimate based on a related parameter. For example, if a flowmeter measuring the mass fed into a destruction device is rendered inoperable, then the mass fed into the destruction device may be estimated using the production rate and the previously observed relationship between the production rate and the mass flow rate into the destruction device.

Table 120-1 – Emission Factors for Equipment Leaks

Equipment Type	Service	Emission Factor (kg/hr/source)	
		≥10,000 ppmv	<10,000 ppmv
Valves	Gas	0.0782	0.000131
Valves	Light liquid	0.0892	0.000165
Pump seals	Light liquid	0.243	0.00187
Compressor seals	Gas	1.608	0.0894
Pressure relief valves	Gas	1.691	0.0447
Connectors	All	0.113	0.0000810
Open-ended lines	All	0.01195	0.00150

§ WCI.130 HYDROGEN PRODUCTION

§ WCI.131 Source Category Definition

A hydrogen production process produces hydrogen gas by steam hydrocarbon reforming, partial oxidation of hydrocarbons, or other transformation of hydrocarbon feedstock. The hydrogen produced may be either transferred offsite or used onsite at petrochemical, ammonia production, refineries, and other plants.

§ WCI.132 Greenhouse Gas Reporting Requirements

For each facility, the annual emissions report must contain the following information:

(a) Process CO_2 Emissions. The CO_2 process emissions from the hydrogen production process.

(b) Feedstock Consumption (if estimating emissions using mass balance approach in WCI.133(b)). Annual feedstock consumption by feedstock type (including petroleum coke) reported in units of million standard metres for gases, litres for liquids, tonnes for non-biomass solids, and bone dry tonnes for biomass-derived solid fuels.

(c) Production. Annual hydrogen produced (tonnes).

(d) Stationary Combustion Units. Report CO_2, N_2O, and CH_4 emissions as specified in WCI.20.

§ WCI.133 Calculation of Greenhouse Gas Emissions

The owner or operator shall calculate and report CO_2 process emissions using the methods in paragraphs (a) or (b) of this section.

(a) Continuous Emission Monitoring Systems. The owner or operator may calculate CO_2 process emissions using CEMS. The owner or operator must comply with the requirements in section WCI.23.

(b) Feedstock Material Balance. The owner or operator may calculate CO_2 process emissions using the following method.

(1) <u>Gaseous fuel and feedstock.</u> You must calculate the annual CO_2 process emissions from gaseous fuel and feedstock according to Equation 130-1 of this section:

$$CO_2 = \left(\sum_{n=1}^{k} \frac{44}{12} * Fdstk_n * CC_n * \frac{MW}{MVC}\right) * 0.001 \qquad \textbf{Equation 130-1}$$

Where:

CO_2 = Annual CO_2 process emissions arising from fuel and feedstock consumption (tonnes/yr).

$Fdstk_n$	=	Volume of the gaseous fuel and feedstock used in month *n* (m^3 at standard conditions of 20°C and 1 atmosphere) of fuel and feedstock).
CC_n	=	Weighted average carbon content of the gaseous fuel and feedstock, from the results of one or more analyses for month *n* (Rm^3 at reference temperature and pressure conditions as used by the facility). If a mass flow meter is used, measure the feedstock used in month *n* in kg and replace the term "MW/MVC" with "1".
MW	=	Molecular weight of the gaseous fuel and feedstock (kg/kg-mole).
MVC	=	Molar volume conversion factor at the same reference conditions as the above $Fdstk_n$ (Rm^3/kg-mole). MVC can be 8.3145 * [273.16 + reference temperature in °C] / [reference pressure in kilopascal].
k	=	Months in the year.
44/12	=	Ratio of molecular weights, CO_2 to carbon.
0.001	=	Conversion factor from kg to tonnes.

(2) Liquid fuel and feedstock. You must calculate the annual CO_2 process emissions from liquid fuel and feedstock according to Equation 130-2 of this section:

$$CO_2 = \left(\sum_{n=1}^{k} \frac{44}{12} * Fdstk_n * CC_n\right) * 0.001 \qquad \textbf{Equation 130-2}$$

Where:

CO_2	=	Annual CO_2 emissions arising from fuel and feedstock consumption (tonnes/yr).
$Fdstk_n$	=	Volume of the liquid fuel and feedstock used in month *n* (m^3 of fuel and feedstock). If a mass flow meter is used, measure the fuel and feedstock used in month *n* in kg and measure the carbon content of feedstock in kg of C per kg of feedstock.
CC_n	=	Weighted average carbon content of the liquid fuel and feedstock, from the results of daily analyses for month *n* (kg of C per m^3 of fuel and feedstock when the usage is measured in m^3, or kg of C per kg of feedstock and fuel when the usage is measured in kg).
k	=	Months in the year.
44/12	=	Ratio of molecular weights, CO_2 to carbon.
0.001	=	Conversion factor from kg to tonnes.

(3) Solid fuel and feedstock. You must calculate the annual CO_2 process emissions from solid fuel and feedstock according to Equation 130-3 of this section:

$$CO_2 = \sum_{n=1}^{k} \frac{44}{12} * (Fdstk_n * CC_n) * 0.001 \qquad \textbf{Equation 130-3}$$

Where:

CO_2	=	Annual CO_2 emissions from fuel and feedstock consumption in tonnes per year (tonnes/yr).
$Fdstk_n$	=	Mass of solid fuel and feedstock used in month *n* (kg of fuel and feedstock).
CC_n	=	Weighted average carbon content of the solid fuel and feedstock, from the results of daily analyses for month *n* (kg carbon per kg of fuel and feedstock).
k	=	Months in the year.

44/12	=	Ratio of molecular weights, CO_2 to carbon.
0.001	=	Conversion factor from kg to tonnes.

(c) If GHG emissions from a hydrogen production process unit are vented through the same stack as any combustion unit or process equipment that reports CO_2 emissions using a CEMS that complies with WCI.23, then the calculation methodology in paragraph (b) of this section shall not be used to calculate process emissions. The owner or operator shall report the combined stack emissions according to the CEMS methodology in WCI.23.

§ WCI.134 Sampling, Analysis, and Measurement Requirements

(a) Owners or operators using CEMS to estimate CO_2 emissions shall comply with the monitoring requirements in section WCI.23.

(b) Owners or operators using the methods in section WCI.133 (b) or paragraph (c) of this section shall perform the following monitoring:

(1) The owner or operator shall measure the feedstock consumption rate daily.
(2) The owner or operator shall collect samples of each feedstock consumed and analyze each sample for carbon content using the methods specified in WCI.25(c). For natural gas feedstock not mixed with another feedstock prior to consumption, samples shall be collected and analyzed once per month. For all other feedstocks, samples shall be collected and analyzed daily and a weighted average established for month *n*. Daily samples may be combined to generate a monthly composite sample for carbon analysis. The samples shall be collected from a location in the feedstock handling system that provides samples representative of the feedstock consumed in the hydrogen production process.
(3) Owners or operators shall quantify the hydrogen produced daily.
(4) Owners or operators shall quantify the CO_2 and CO collected and transferred off-site quarterly.

(c) You must use the following methods, as applicable, to determine the carbon content of the feedstocks:

(1) ASTM D2013–07 Standard Practice of Preparing Coal Samples for Analysis.

(2) ASTM D2234/D2234M–07 Standard Practice for Collection of a Gross Sample of Coal.

(3) ASTM D2597–94 (Reapproved 2004) Standard Test Method for Analysis of Demethanized Hydrocarbon Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography.

(4) ASTM D3176–89 (Reapproved 2002), Standard Practice for Ultimate Analysis of Coal and Coke.

(5) ASTM D4057–06 Standard Practice for Manual Sampling of Petroleum and Petroleum Products.

(6) ASTM D4177–95 (Reapproved 2005) Standard Practice for Automatic Sampling of Petroleum and Petroleum Products.

(7) ASTM D6609–08 Standard Guide for Part-Stream Sampling of Coal.

(8) ASTM D6883–04 Standard Practice for Manual Sampling of Stationary Coal from Railroad Cars, Barges, Trucks, or Stockpiles.

(9) ASTM D7430–08ae1 Standard Practice for Mechanical Sampling of Coal.

(10) ASTM UOP539–97 Refinery Gas Analysis by Gas Chromatography.

(11) GPA 2261–00 Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography.

(12) ISO 3170: Petroleum Liquids— Manual sampling—Third Edition.

(13) ISO 3171: Petroleum Liquids— Automatic pipeline sampling—Second Edition.

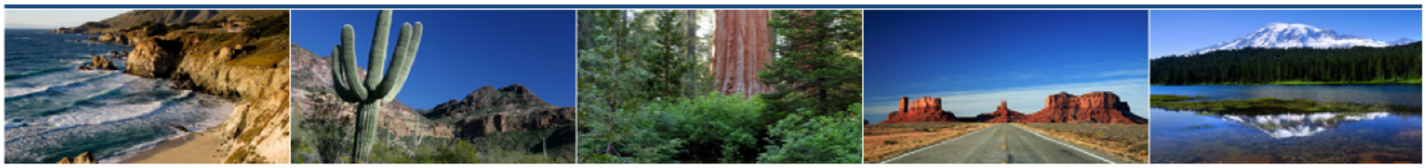
§ WCI.135 Procedures for Estimating Missing Data

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation, etc.), a substitute data value for the missing parameter must be used in the calculations as specified in paragraphs (a), (b), and (c) of this section:

(a) For each missing value of the monthly fuel and feedstock consumption, the substitute data value must be the best available estimate of the fuel and feedstock consumption, based on all available process data (e.g., hydrogen production, electrical load, and operating hours). You must document and keep records of the procedures used for all such estimates.

(b) For each missing value of the carbon content or molecular weight of the fuel and feedstock, the substitute data value must be the arithmetic average of the quality-assured values of carbon contents or molecular weight of the fuel and feedstock immediately preceding and immediately following the missing data incident. If no quality-assured data on carbon contents or molecular weight of the fuel and feedstock are available prior to the missing data incident, the substitute data value must be the first quality-assured value for carbon contents or molecular weight of the fuel and feedstock obtained after the missing data period. You must document and keep records of the procedures used for all such estimates.

(c) For missing CEMS data, you must use the missing data procedures in WCI.20.



§ WCI.140 GLASS PRODUCTION

§ WCI.141 Source Category Definition

A glass manufacturing facility manufactures flat glass, container glass, pressed and blown glass, or wool fiberglass by melting a mixture of raw materials to produce molten glass and form the molten glass into sheets, containers, fibers, or other shapes. A glass manufacturing facility uses one or more glass melting furnaces to produce glass. A glass melting furnace that is an experimental furnace or a research and development process unit is not subject to this subpart.

§ WCI.142 Greenhouse Gas Reporting Requirements

For the purpose of the Regulation the annual emissions data report shall include the following information:

(a) Total CO_2 process emissions from all glass melting furnaces.

(b) Total CO_2, CH_4 and N_2O combustion emissions from all glass melting furnaces. You must calculate and report these emissions under WCI.20 (General Stationary Fuel Combustion Sources) by following the requirements of WCI.20.

(c) Total CO_2, CH_4, and N_2O emissions from all stationary fuel combustion units other than glass melting furnaces. You must report these emissions under WCI.20 (General Stationary Fuel Combustion Sources) by following the requirements of WCI.20.

(d) If a CEMS is used to measure CO_2 emissions, then you must report under this method the relevant information required under WCI.23(d) for the Calculation Methodology 4 and the following information:

Annual quantity of glass produced (tonnes).

(e) If a CEMS is not used to determine CO_2 emissions from glass melting furnaces, and process CO_2 emissions are calculated according to the procedures specified in WCI.143(b), then you must report the following information:

(1) Annual quantity of each carbonate-based raw material charged (tonnes)for all furnaces combined.

(2) Annual quantity of glass produced (tonnes) from all furnaces combined.

(3) Total number of glass melting furnaces.

(f) The number of times in the reporting year that missing data procedures were followed to measure monthly quantities of carbonate-based raw materials or mass fraction of the carbonate-based minerals for each glass melting furnace

§ WCI.143 Calculation of GHG Emissions

You must calculate the annual process CO_2 emissions from each glass melting furnace using the procedure in paragraphs (a) and (b) of this section.

(a) For each glass melting furnace that meets the conditions specified in WCI.23(e)(4), you must calculate under this source the combined process and combustion CO_2 emissions by operating and maintaining a CEMS to measure CO_2 emissions according to the Calculation Methodology 4 specified in WCI.23(d) and all associated requirements in WCI.20 (General Stationary Fuel Combustion Sources).

(b) For each glass melting furnace that is not subject to the requirements in paragraph (a) of this section, use either the procedure in paragraph (b)(1) or (b)(2) of this section.

(1) Calculate the combined process and combustion CO_2 emissions by operating and maintaining a CEMS to measure CO_2 emissions according to the Calculation Methodology 4 specified in WCI.23(d) (General Stationary Fuel Combustion Sources).

(2) Calculate the process and combustion CO_2 emissions separately using the procedures specified in paragraphs (b)(2)(i) through (b)(2)(vi) of this section.

(i) For each carbonate-based raw material charged to the furnace, obtain from the supplier of the raw material the carbonate-based mineral mass fraction.

(ii) Determine the quantity of each carbonate-based raw material charged to the furnace.

(iii) Apply the appropriate emission factor for each carbonate-based raw material charged to the furnace, as shown in Table 140-1 to this subpart.

(iv) Use Equation 140-1 of this section to calculate process mass emissions of CO_2 for each furnace:

$$E_{CO2} = \sum_{i=1}^{n} \left(M_i \times MF_i \times EF_i \times F_i \right) \qquad \textbf{Equation 140-1}$$

Where:

E_{CO2} = Process emissions of CO_2 from the furnace (tonnes).

n = Number of carbonate-based raw materials charged to furnace.

MF_i = Annual average mass fraction of carbonate-based mineral *i* in carbonate-based raw material *i* (weight fraction).

M_i = Annual amount of carbonate-based raw material *i* charged to furnace (tonnes).

EF_i = Emission factor for carbonate-based mineral *i* (tonnes CO_2 per tonne carbonate-based mineral as shown in Table 140-1).

F_i = Fraction of calcination achieved for carbonate-based mineral *i*, 1.0 for completed calcination (weight fraction).

(v) You must calculate and report the total process CO_2 emissions from glass melting furnaces at the facility using Equation 140-2 of this section:

$$CO_2 = \sum_{i=1}^{k} E_{CO_2 i}$$

Equation 140-2

Where:

CO_2 = Annual process CO_2 emissions from glass manufacturing facility (tonnes).

E_{CO2i} = Annual CO_2 emissions from glass melting furnace i (tonnes).

k = Number of glass melting furnaces.

(vi) Calculate and report under WCI.20 (General Stationary Fuel Combustion Sources) the combustion CO_2 emissions in the glass furnace according to the applicable requirements in WCI.20.

§ WCI.144 Sampling, Analysis, and Measurement Requirements

(a) You must measure annual amounts of carbonate-based raw materials charged to each glass melting furnace from monthly measurements using plant instruments used for accounting purposes, such as calibrated scales or weigh hoppers. Total annual mass charged to glass melting furnaces at the facility shall be compared to records of raw material purchases for the year.

(b) You must measure carbonate-based mineral mass fractions at least annually to verify the mass fraction data provided by the supplier of the raw material; such measurements shall be based on sampling and chemical analysis conducted by a certified laboratory using ASTM D3682-01 (Reapproved 2006) Standard Test Method for Major and Minor Elements in Combustion Residues from Coal Utilization Processes (incorporated by reference, see regulation).

(c) You must determine the annual average mass fraction for the carbonate-based mineral in each carbonate-based raw material by calculating an arithmetic average of the monthly data obtained from raw material suppliers or sampling and chemical analysis.

(d) As an alternative to data provided by the raw material supplier, a value of 1.0 can be used for the monthly mass fraction (MF_i) of carbonate-based mineral i in Equation 140-1 of this section.

(e) You must determine on an annual basis the calcination fraction for each carbonate consumed based on sampling and chemical analysis using an industry consensus standard. This chemical analysis must be conducted using an x-ray fluorescence test or other enhanced testing method published by an industry consensus standards organization (e.g., ASTM, ASME, API, etc.).

§ WCI.145 Procedures for Estimating Missing Data

A complete record of all measured parameters used in the GHG emissions calculations is required (e.g., carbonate raw materials consumed, etc.). If the monitoring and quality assurance procedures in WCI.144 cannot be followed and data is missing, you must use the most appropriate of the missing data procedures in paragraphs (a) and (b) of this section. You must document and keep records of the procedures used for all such missing value estimates.

(a) For missing data on the monthly amounts of carbonate-based raw materials charged to any glass melting furnace use the best available estimate(s) of the parameter(s), based on all available process data or data used for accounting purposes, such as purchase records.

(b) For missing data on the mass fractions of carbonate-based minerals in the carbonate-based raw materials assume that the mass fraction of each carbonate based mineral is 1.0.

Table 140-1 —CO_2 Emission Factors for Carbonate-Based Minerals

Carbonate-Based Raw Material – Mineral	CO_2 Emission Factor[a]
Limestone – $CaCO_3$	0.43971
Dolomite – $CaMg(CO_3)_2$	0.47732
Sodium carbonate/soda ash – Na_2CO_3	0.41492

[a] Emission factors in units of tonnes of CO_2 emitted per tonne of carbonate-based mineral charged to the furnace.

§ WCI.150 IRON AND STEEL MANUFACTURING

§ WCI.151 Source Category Definition

Iron and steel manufacturing comprises five categories: taconite iron ore processing, primary facilities that produce both iron and steel, secondary steelmaking facilities, iron production facilities, and offsite production of metallurgical coke. These processes may occur together in an "integrated" facility or they may occur in separate offsite facilities.

§ WCI.152 Greenhouse Gas Reporting Requirements

In addition to the information required by regulation, the annual emissions data report shall contain the following information:

(a) Annual process CO_2 emissions (tonnes) for the following processes:

(1) Taconite indurating furnace

(2) Basic oxygen furnace (BOF)

(3) Coke making operation

(4) Sinter process

(5) Electric arc furnace (EAF)

(6) Argon-oxygen decarburization vessel

(7) Direct reduction furnace

(8) Blast furnace

(b) Annual production/usage quantities (tonnes) for the following processes:

(1) Taconite indurating furnace – fired pellets produced on-site

(2) BOF – steel produced on-site

(3) Coke making operation – coke produced and coal charged

(4) Sinter process – sinter produced

(5) EAF – steel produced on-site

(6) Argon-oxygen decarburization vessel – molten steel charged

(7) Direct reduction furnace – iron produced

(8) Blast furnace – iron produced

(c) CO_2, N_2O, and CH_4 emissions, not accounted for elsewhere in WCI.150, from stationary combustion units as specified in WCI.20. Report these emissions from stationary combustion for each of the following devices:

(1) Taconite indurating furnace

(2) BOF

(3) Coke making operation (coke oven batteries)

(4) Sinter process (sintering furnace)

(5) EAF

(6) Argon-oxygen decarburization vessel

(7) Direct reduction furnace

(8) Blast furnace

(9) Any other stoves, boiler, process heaters, reheat furnaces and other combustion sources.

§ WCI.153 Calculation of CO_2 Emissions

(a) Process CO_2 emissions. Determine process CO_2 emissions as specified under either paragraph (1) or (2) of this section.

(1) Continuous emissions monitoring systems (CEMS) as specified in WCI.23(d).

(2) Calculation methodologies specified in paragraph (b) of this section.

[CEMS and mass balance approach are based on IPCC Tier 3 methods.)

(b) Process CO_2 Emissions Calculation Methodology. Calculate CO_2 process emissions for each taconite indurating furnace, basic oxygen furnace, non-recovery coke oven battery, sinter process, EAF, argon-oxygen decarburization vessel, blast furnace, and direct reduction furnace using the following mass balance approaches specified in paragraphs (b)(1) through (b)(8). Specific process inputs or outputs that contribute less than 1 percent of the total mass of carbon into or out of the process do not have to be included in the paragraphs (b)(1) through (b)(8) mass balances.

(1) Calculate taconite indurating furnace CO_2 emissions using Equation 150-1:

$$E_T = \left[\left(T \times C_T \right) - \left(P \times C_P \right) - \left(R \times C_R \right) \right] \times 3.664 \qquad \textbf{Equation 150-1}$$

Where:

E_T	=	Annual CO_2 emissions from taconite indurating furnace (tonnes);
T	=	Annual mass of greenball (taconite) pellets fed to furnace (tonnes);
C_T	=	Carbon content of greenball (taconite) pellets (tonnes C/tonnes taconite pellets);
P	=	Annual mass of fired pellets producted by the furnace (tonnes);
C_P	=	Carbon content of fired pellets (tonnes C/tonnes fired pellets);
R	=	Annual mass of air pollution control residue collected (tonnes);

C_R	=	Carbon content of air pollution control residue (tonnes C/tonnes residue);
3.664	=	Conversion factor from tonnes of C to tonnes of CO_2.

(2) Calculate basic oxygen process furnace CO_2 emissions using Equation 150-2:

$$E_{BOF} = [(I \times C_I) + (SC \times C_{SC}) + (FL \times C_{FL}) + (CAR \times C_{CAR}) - (ST \times C_{ST}) - (SL \times C_{SL}) - (BOG \times C_{BOG}) - (R \times C_R)] \times 3.664$$

Equation 150-2

Where:

E_{BOF}	=	Annual CO_2 emissions from basic oxygen furnaces (tonnes);
I	=	Annual mass of molten iron charged to furnace (tonnes);
C_I	=	Carbon content of molten iron (tonnes C/tonnes molten iron);
SC	=	Annual mass of ferrous scrap charged to furnace (tonnes);
C_{SC}	=	Carbon content of ferrous scrap (tonnes C/tonnes ferrous scrap);
FL	=	Annual mass for flux materials (e.g., limestone, dolomite, etc.) charged to furnace (tonnes);
C_{FL}	=	Carbon content of flux materials (tonnes C/tonnes flux material);
CAR	=	Annual mass of carbonaceous material (e.g., coal, coke, etc.) charged to furnace (tonnes);
C_{CAR}	=	Carbon content of carbonaceous material (tonnes C/tonnes carbonaceous material);
ST	=	Annual mass of molten raw steel produced by furnace (tonnes);
C_{ST}	=	Carbon content of steel (tonnes C/tonnes steel);
SL	=	Annual mass of slag produced by furnace (tonnes);
C_{SL}	=	Carbon content of slag (tonnes C/tonnes slag);
BOG	=	Annual mass of basic oxygen furnace gas transferred off site (tonnes);
C_{BOG}	=	Carbon content of basic oxygen furnace gas transferred off site (tonnes C/tonnes basic oxygen furnace gas);
R	=	Annual mass of air pollution control residue collected (tonnes);
C_R	=	Carbon content of air pollution control residue (tonnes C/tonnes residue);
3.664	=	Conversion factor from tonnes of C to tonnes of CO_2.

(3) Calculate coke oven battery CO_2 emissions using Equation 150-3:

$$E_{coke} = [(CC \times C_{CC}) - (CO \times C_{CO}) - (BY \times C_{BY}) - (R \times C_R) - (COG \times C_{COG})] \times 3.664$$

Equation 150-3

Where:

E_{coke}	=	Annual CO_2 emissions from coke production (tonnes);

CC	=	Annual mass of coking coal charged to battery (tonnes);
C_{CC}	=	Carbon content of coking coal (tonnes C/tonnes coking coal);
CO	=	Annual mass of coke produced (tonnes);
C_{CO}	=	Carbon content of coke (tonnes C/tonnes coke);
BY	=	Annual mass of by-product from by-product coke oven battery (tonnes);
C_{BY}	=	Carbon content of by-product (tonnes C/tonnes by-product);
R	=	Quantity of air pollution control residue collected (tonnes);
C_R	=	Carbon content of air pollution control residue (tonnes C/tonnes residue);
COG	=	Annual mass of coke oven gas transferred off site (tonnes);
C_{COG}	=	Carbon content of coke oven gas transferred off site (tonnes C/tonnes coke oven gas);
3.664	=	Conversion factor from tonnes of C to tonnes of CO_2.

(4) Calculate sinter process CO_2 emissions using Equation 150-4:

$$E_{sinter} = [(CAR \times C_{CAR}) + (FE \times C_{FE}) - (S \times C_S) - (R \times C_R)] \times 3.664$$

Equation 150-4

Where:

E_{sinter}	=	Annual CO_2 emissions from sinter process (tonnes);
CAR	=	Annual mass of carbonaceous material (e.g., coal, coke, etc.) charged to furnace (tonnes);
C_{CAR}	=	Carbon content of carbonaceous material (tonnes C/ tonnes carbonaceous material);
FE	=	Annual mass of sinter feed material (tonnes);
C_{FE}	=	Carbon content of sinter feed material (tonnes C/tonnes sinter feed material);
S	=	Annual mass of sinter produced (tonnes);
C_S	=	Carbon content of sinter produced (tonnes C/tonnes sinter);
R	=	Quantity of air pollution control residue collected (tonnes);
C_R	=	Carbon content of air pollution control residue (tonnes C/ tonnes residue);
3.664	=	Conversion factor from tonnes of C to tonnes of CO_2.

(5) Calculate electric arc furnace (EAF) CO_2 emissions using Equation 150-5:

$$E_{EAF} = [(I \times C_I) + (SC \times C_{SC}) + (FL \times C_{FL}) + (EL \times C_{EL}) + (CAR \times C_{CAR}) - (ST \times C_{ST}) - (SL \times C_{SL}) - (R \times C_R)] \times 3.664$$

Equation 150-5

Where:

E_{EAF}	=	Annual CO_2 emissions from EAF (tonnes);
I	=	Annual mass of direct reduced iron (if any) charged to furnace (tonnes);
C_I	=	Carbon content of direct reduced iron (tonnes C/ tonnes direct reduced iron);
SC	=	Annual mass of ferrous scrap charged to furnace (tonnes);
C_{SC}	=	Carbon content of ferrous scrap (tonnes C/ tonnes ferrous scrap);

FL	=	Annual mass for flux materials (e.g., limestone, dolomite, etc.) charged to furnace (tonnes);
C_{FL}	=	Carbon content of flux materials (tonnes C/ tonnes flux material);
EL	=	Annual mass for carbon electrodes consumed (tonnes);
C_{EL}	=	Carbon content of carbon electrodes (tonnes C/ tonnes carbon electrode);
CAR	=	Annual mass of carbonaceous material (e.g., coal, coke, etc.) charged to furnace (tonnes);
C_{CAR}	=	Carbon content of carbonaceous material (tonnes C/ tonnes carbonaceous material);
ST	=	Annual mass of molten raw steel produced by furnace (tonnes);
C_{ST}	=	Carbon content of steel (tonnes C/ tonnes steel);
SL	=	Annual mass of slag produced by furnace (tonnes);
C_{SL}	=	Carbon content of slag (tonnes C/ tonnes slag);
R	=	Annual mass of air pollution control residue collected (tonnes);
C_R	=	Carbon content of air pollution control residue (tonnes C/ tonnes residue);
3.664	=	Conversion factor from tonnes of C to tonnes of CO_2.

(6) Calculate argon-oxygen decarburization vessel CO_2 emissions using Equation 150-6:

$$E_{AOD} = \left[Steel \times \left(C_{in} - C_{out}\right) - \left(R \times C_R\right)\right] \times 3.664$$ **Equation 150-6**

Where:

E_{AOD}	=	Annual CO_2 emissions from argon-oxygen decarburization vessels (tonnes);
Steel	=	Annual mass of molten steel charged to vessel (tonnes);
C_{in}	=	Carbon content of molten steel before decarburization (tonnes C/ tonnes molten steel);
C_{out}	=	Carbon content of molten steel after decarburization (tonnes C/ tonnes molten steel);
R	=	Annual mass of air pollution control residue collected (tonnes);
C_R	=	Carbon content of air pollution control residue (tonnes C/ tonnes residue);
3.664	=	Conversion factor from tonnes of C to tonnes of CO_2.

(7) Calculate direct reduction furnace CO_2 emissions using Equation 150-7:

$$E_{DR} = \left[\left(Ore \times C_{Ore}\right) + \sum\left(CAR \times C_{CAR}\right) + \sum\left(OT \times C_{OT}\right) - \left(I \times C_I\right) - \left(NM \times C_{NM}\right) - \left(R \times C_R\right)\right] \times 3.664$$

Equation 150-7

Where:

E_{DR}	=	Annual CO_2 emissions from direct reduction furnace (tonnes);
Ore	=	Annual mass of iron ore or iron ore pellets fed to the furnace (tonnes);
C_{Ore}	=	Carbon content of iron ore or iron ore pellets (tonnes C/ tonnes iron ore or iron ore pellets);
CAR	=	Annual mass of non-fuel carbonaceous materials (e.g., coal, coke, by-products, etc.) charged to furnace (tonnes);

C_{CAR} = Carbon content of non-fuel carbonaceous materials (tonnes C/ tonnes non-fuel carbonaceous material);
OT = Annual mass of other materials charged to furnace (tonnes);
C_{OT} = Carbon content of other materials (tonnes C/ tonnes other materials);
I = Annual mass of iron produced (tonnes);
C_I = Carbon content of iron (tonnes C/ tonnes iron);
NM = Annual mass for non-metallic materials produced (tonnes);
C_{NM} = Carbon content of non-metallic materials (tonnes C/ tonnes non-metallic minerals);
R = Annual mass of air pollution control residue collected (tonnes);
C_R = Carbon content of air pollution control residue (tonnes C/ tonnes residue);
3.664 = Conversion factor from tonnes of C to tonnes of CO_2.

(8) Calculate blast furnace CO_2 emissions using Equation 150-8:

$$E_{BF} = \left[(Ore \times C_{Ore}) + \sum(CAR \times C_{CAR}) + \sum(F \times C_F) + \sum(OT \times C_{OT}) - (I \times C_I) - (NM \times C_{NM}) - (BG \times C_{BG}) - (R \times C_R)\right] \times 3.664$$

Equation 150-8

Where:

E_{BF} = Annual CO_2 emissions from blast furnace (tonnes);
Ore = Annual mass of iron ore or iron ore pellets fed to the furnace (tonnes);
C_{Ore} = Carbon content of iron ore or iron ore pellets (tonnes C/ tonnes iron ore or iron ore pellets);
CAR = Annual mass of non-fuel carbonaceous materials (e.g., coal, coke, by-products, etc.) charged to furnace (tonnes);
C_{CAR} = Carbon content of non-fuel carbonaceous materials (tonnes C/ tonnes non-fuel carbonaceous material);
F = Annual mass for flux materials (e.g., limestone, dolomite, etc.) charged to furnace (tonnes);
C_F = Carbon content of flux materials (tonnes C/ tonnes flux material);
OT = Annual mass of other materials charged to furnace (tonnes);
C_{OT} = Carbon content of other materials (tonnes C/ tonnes other materials);
I = Annual mass of iron produced (tonnes);
C_I = Carbon content of iron (tonnes C/ tonnes iron);
NM = Annual mass for non-metallic materials produced (tonnes);
C_{NM} = Carbon content of non-metallic materials (tonnes C/ tonnes non-metallic minerals);
BG = Annual mass for blast furnace gas transferred off-site (tonnes);
C_{BG} = Carbon content of blast furnace gas (tonnes C/ tonnes blast furnace gas);
R = Annual mass of air pollution control residue collected (tonnes);
C_R = Carbon content of air pollution control residue (tonnes C/ tonnes residue);
3.664 = Conversion factor from tonnes of C to tonnes of CO_2.

(9) Calculate total CO_2 emissions using Equation 150-9:

$$E_{CO2} = E_T + E_{BOF} + E_{coke} + E_{\sin ter} + E_{EAF} + E_{AOD} + E_{DR} + E_{BF} \quad \textbf{Equation 150-9}$$

Where:

E_{CO2} = Total CO_2 emissions (tonnes);
E_T = Emissions from taconite indurating furnace (tonnes);
E_{BOF} = Emissions from basic oxygen furnace (BOF) (tonnes);
E_{coke} = Emissions from coke production (tonnes);
E_{sinter} = Emissions from sinter production (tonnes);
E_{EAF} = Emissions from electric arc furnace (EAF) (tonnes);
E_{AOD} = Emissions from argon-oxygen decarburization vessels (tonnes);
E_{DR} = Emissions from direct reduction furnace (tonnes);
E_{BF} = Emissions from blast furnace (tonnes);

§ WCI.154 Calculation of CH_4 Emissions

(a) Process CH_4 emissions. Determine process CH_4 emissions as specified under either paragraph (1) or paragraph (2) of this section.

(1) Continuous emissions monitoring systems (CEMS) as specified in WCI.23(d).

(2) Site-specific emission factors.

§ WCI.155 Sampling, Analysis, and Measurement Requirements

The annual mass of each material used in the WCI.153 mass balance methodologies shall be determined using plant instruments used for accounting purposes, including either direct measurement of the quantity of material used in the process or by calculations using process operating information.

The average carbon content of each material used shall be determined as specified under paragraph (a) or (b) of this section.

(a) Obtain carbon content by collecting and analyzing at least three representative samples of the material each year using one of the following methods:

(1) For iron ore, taconite pellets, and other iron-bearing materials, use ASTM E1915-07a “Standard Test Methods for Analysis of Metal Bearing Ores and Related Materials by Combustion Infrared-Absorption Spectrometry”.

(2) For iron and ferrous scrap, use ASTM E1019-08 “Standard Test Methods for Determination of Carbon, Sulphur, Nitrogen, and Oxygen in Steel, Iron, Nickel, and Cobalt Alloys by Various Combustion and Fusion Techniques”.

(3) For coal, coke, and other carbonaceous materials (e.g., electrodes, etc.), use ASTM D5373-08 “Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal” or ASTM D5142-09 “Standard Test Methods for Proximate Analysis of the Analysis Sample of Coal and

Coke by Instrumental Procedures", for petroleum liquid based fuels and liquid waste-derived fuels.

(4) For steel, use one of the methods described in subparagraph (i) through (iv):

(i) ASM CS-104 UNS No. G10460 "Carbon Steel of Medium Carbon Content".

(ii) ISO/TR 15349-1: 1998 "Unalloyed steel – Determination of low carbon content, Part 1: Infrared absorption method after combustion in an electric resistance furnace (by peak separation) (1998-10-15) – First Edition".

(iii) ISO/TR 15349-3: 1998 "Unalloyed steel – Determination of low carbon content, Part 3: Infrared absorption method after combustion in an electric resistance furnace (with preheating) (1998-10-15) – First Edition".

(iv) ASTM E415-08 "Standard Test Method for Atomic Emission Vacuum Spectrometric Analysis of Carbon and Low-Alloy Steel".

(5) For flux (i.e., limestone or dolomite) and slag, use ASTM C25-06 "Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime".

(6) For fuels, determine carbon content and molecular weight (if applicable) using the applicable methods listed in §WCI.20.

(7) For steel production by-products (e.g., blast furnace gas, coke oven gas, coal tar, light oil, sinter off gas, slag dust, etc.), use an online instrument that determines carbon content to ±5%, or use sampling and analysis as contained in WCI.25(a) and WCI.25(d).

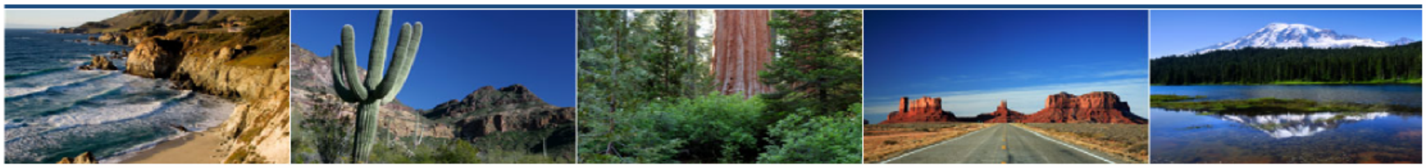
(b) Obtain carbon content from material vendor or supplier.

§ WCI.156 Procedures for Estimating Missing Data

A complete record of all measured parameters used in the GHG emissions calculations is required. Whenever the sampling procedures in WCI.155 cannot be followed (e.g., if a meter malfunctions during unit operation), a substitute data value for the missing parameter shall be used in accordance with paragraphs (a) and (b) of this section. You must document and keep records of the procedures used for all such estimates.

(a) For missing data on monthly carbon contents of feedstock or the waste recycle stream, the substitute data value shall be the arithmetic average of the quality-assured values of that carbon content in the month preceding and the month immediately following the missing data incident. If no quality-assured data is available prior to the missing data incident, the substitute data value shall be the first quality-assured value for carbon content obtained in the month after the missing data period.

(b) For missing feedstock supply rates or waste recycle stream used to determine monthly feedstock consumption or monthly waste recycle stream quantity, you must determine the best available estimate(s) of the parameter(s), based on all available process data.



§ WCI.160 LEAD PRODUCTION

§ WCI.161 Source Category Definition

The lead production category includes two primary production processes used to produce lead from lead concentrates (i.e., the sintering/smelting process and the direct smelting process). In addition, secondary production or recycling of lead (primarily from scrapped lead acid batteries) is included in the category.

§ WCI.162 Greenhouse Gas Reporting Requirements

In addition to the information required by regulation the annual emissions data report shall contain the following information:

(a) Annual emissions of CO_2 at the facility level (tonnes).

(b) Annual quantities of each material used (tonnes).

(c) Carbon content of each material used (tonnes C/ tonne reducing agent).

(d) Inferred waste-based carbon-containing material emission factor (if waste-based reducing agent quantification method used).

(e) If you use the missing data procedures in WCI.165(b), you must report how the monthly mass of carbon-containing materials with missing data was determined and the number of months the missing data procedures were used.

(f) CO_2, CH_4, and N_2O emissions from each stationary fuel combustion unit. You must report these emissions under WCI.20 (General Stationary Fuel Combustion Sources), by following the requirements of WCI.20.

§ WCI.163 Calculation of CO_2 Emissions

Calculate total CO_2 emissions as specified under paragraph (a) or (b) of this section.

(a) Determine facility CO_2 emissions using continuous emissions monitoring systems (CEMS) as specified in WCI.23(d).

(b) Calculate total CO_2 emissions using Equation 160-1. Specific materials that in aggregate contribute less than 0.5% of the total carbon into the process may be excluded from the calculation performed using Equation 160-1.

$$E_{Pb} = \sum_{x} (RA_x \times C_x) \times 3.664 \qquad \textbf{Equation 160-1}$$

Where:

E_{Pb} = Annual CO_2 emissions from lead production (tonnes);
RA_x = Annual quantity of material x used (tonnes);
C_x = Carbon content of material x (tonnes C/ tonnes of x);
3.664 = Conversion factor from tonnes of C to tonnes of CO_2.

§ WCI.164 Sampling, Analysis, and Measurement Requirements

The annual mass of each material introduced into the smelting furnace shall be determined by summing the monthly mass for the material determined for each month of the calendar year. The monthly mass may be determined using plant instruments used for accounting purposes, including either direct measurement of the quantity of the material placed in the unit or by calculations using process operating information.

The average carbon content of each material introduced into the smelting furnace shall be determined as specified under paragraph (a) or (b) of this section.

(a) Obtain carbon content by collecting and analyzing at least three representative samples of the material each year using one of the following methods:

(1) For solid carbonaceous reducing agents and carbon electrodes, use ASTM D5373-08 "Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal".

(2) For liquid reducing agents, use one of the methods described in subparagraph (i) through (iv):

i. ASTM D2502-04 (Reapproved 2002) "Standard Test Method for Estimation of Molecular Weight (Relative Molecular Mass) of Petroleum Oils from Viscosity Measurements".

ii. ASTM D2503-92 (Reapproved 2002) "Standard Test Method for Relative Molecular Mass (Relative Molecular Weight) of Hydrocarbons by Thermoelectric Measurement of Vapor Pressure".

iii. ASTM D3238-95 (Reapproved 2005) "Standard Test Method for Calculation of Carbon Distribution and Structural Group Analysis of Petroleum Oils by the n-d-M Method".

iv. ASTM D5291-02 (Reapproved 2007) "Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants".

(3) For gaseous reducing agents, use one of the methods described in subparagraph (i) or (ii):

i. ASTM D1945-03 "Standard Test Method for Analysis of Natural Gas by Gas Chromatography".

ii. ASTM D1946-90 "Standard Practice for Analysis of Reformed Gas by Gas Chromatography".

(4) For waste-based carbon-containing material, determine carbon content by operating the smelting furnace both with and without the waste-reducing agents while keeping the composition of other material introduced constant.

i. To ensure representativeness of waste-based carbon-containing material variability, the specific testing plan (e.g. number of test runs, other process variables to keep constant, timing of runs) for these trials must be approved by the jurisdiction.

(b) Obtain carbon content from material vendor or supplier.

§ WCI.165 Procedures for Estimating Missing Data

A complete record of all measured parameters used in the GHG emissions calculations in WCI.163 is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in the paragraphs (a) and (b) of this section. You must document and keep records of the procedures used for all such estimates.

(a) For each missing data for the carbon content for the smelting furnaces at your facility that estimate annual process CO_2 emissions using the carbon mass balance procedure in WCI.163, 100 percent data availability is required. You must repeat the test for average carbon contents of inputs according to the procedures in WCI.164 if data are missing.

(b) For missing records of the monthly mass of carbon-containing materials, the substitute data value must be based on the best available estimate of the mass of the material from all available process data or data used for accounting purposes (such as purchase records).

§ WCI.170 LIME MANUFACTURING

§ WCI.171 Source Category Definition

Lime manufacturing is comprised of all processes that are used to manufacture a lime product (e.g., calcium oxide, high calcium quicklime, calcium hydroxide, hydrated lime, dolomitic quick lime, dolomitic hydrate, or other products) by calcination of limestone or other highly calcareous materials such as dolomite, aragonite, chalk, coral, marble, and shell.

This source category includes all lime manufacturing plants unless the plant is located at a kraft pulp mill, soda pulp mill, sulfite pulp mill, or only processes sludge containing calcium carbonate from water softening processes. The lime manufacturing source category consists of marketed and non-marketed lime manufacturing facilities.

Lime kilns at pulp and paper manufacturing facilities must report emissions under WCI.210 (Pulp and Paper Manufacturing).

§ WCI.172 Greenhouse Gas Reporting Requirements

In addition to the information required by regulation, the annual emissions data report shall contain the following information:

(a) Total emissions of CO_2, CH_4, and N_2O in tonnes.

(b) CO_2 process emissions from lime production (tonnes) for all kilns combined and the following information:

(1) For lime production:

(A) The emission factor (kg CO_2/ tonne) for each lime type for each month.

(B) The quantity of each type of lime produced (tonnes) each month.

(C) The calcium oxide (CaO) content (weight fraction) of each lime type for each month.

(D) The magnesium oxide (MgO) content (weight fraction) of each lime type for each month.

(2) For the production of calcined byproducts and wastes:

(A) The emission factor (kg CO_2/ tonne) for each calcined byproduct/waste type for each quarter.

(B) The quantity of each type of calcined byproduct/waste type produced each quarter.

(C) The calcium oxide (CaO) content (weight fraction) of each calcined byproduct/waste type for each quarter.

(D) The magnesium oxide (MgO) content (weight fraction) of each calcined byproduct/waste type for each quarter.

(3) Number of times during the reporting year that missing data procedures were followed to measure lime production.

(c) CO_2, CH_4, and N_2O emissions from fuel combustion in all kilns combined, following the calculation methods and reporting requirements specified in WCI.173(c) (tonnes).

(d) CO_2, CH_4, and N_2O emissions from all other fuel combustion units combined (kilns excluded), following the calculation methods and reporting requirements specified in WCI.20 (tonnes).

(e) If a continuous emissions monitor is used to measure CO_2 emissions from kilns, then the requirements of paragraph (b) of this section do not apply for CO_2.

(f) Operators of lime plants shall also comply with the reporting requirements for any other applicable source category listed by regulation, including but not limited to the following:

(1) Coal fuel storage as specified in WCI.100.

(2) Electricity generating as specified in WCI.40.

(3) Cogeneration systems as specified in WCI.42(f).

§ WCI.173 Calculation of greenhouse Gas Emissions from Kilns

(a) Determine process CO_2 emissions as specified under either paragraph (a)(1) or (a)(2) of this section.

(1) Continuous emissions monitoring systems (CEMS) as specified in WCI.23(d).

(2) Calculate the sum of CO_2 process emissions from kilns and CO_2 fuel combustion emissions from kilns using the calculation methodologies specified in paragraph (b) and (c) of this section**.**

(b) Process CO_2 Emissions Calculation Methodology. Calculate total CO_2 process emissions as the sum of emissions from lime production, using the method specified in paragraph (b)(1) of this section.

(1) CO_2 Process Emissions. Calculate CO_2 emissions from the production of each type of lime using Equation 170-1 and a plant-specific lime emission factor and a plant-specific calcined byproduct/waste emission factor as specified in this section.

$$CO_2 = \sum_{m}^{12}\sum_{i}\left[QL_{mi} \times EF_{QL_{mi}}\right] + \sum_{q}^{4}\sum_{j}\left[CBW_{qj} \times EF_{CBW_{qj}}\right] \qquad \textbf{Equation 170-1}$$

Where:

CO_2 = CO_2 emissions in tonnes/yr.

QL_{mi} = Quantity of lime type *i* produced in month *m*, tonnes.

EF_{QLmi} = Emission factor of lime type *i* produced in month *m*, tonnes CO_2/tonne lime computed as specified in paragraph (b)(2) of this section.

CBW_{qj} = Quantity of calcined byproduct/waste type *j*, including LKD, scrubber sludge and other calcined wastes produced in quarter *q*, tonnes.

EF_{CBWqj}= Emission factor of calcined byproduct/waste type *j* produced in quarter *q*, computed as specified in paragraph (b)(3) of this section.

(2) Monthly Lime Emission Factor. Calculate a plant-specific lime emission factor (EF_{QL}) for each type of lime and month based on the measured CaO and MgO contents in lime and using Equation 170-2.

$$EF_{QL} = (f_{CaO} \times 0.785) + (f_{MgO} \times 1.092)$$ **Equation 170-2**

Where:

EF_{QL} = Process CO_2 emission factor for lime produced, tonnes CO_2/ tonnes lime.

f_{CaO} = CaO content of lime, calculated by subtracting CaO content of lime in uncalcined $CaCO_3$ remaining in lime from total CaO content of lime, tonnes CaO/ tonne lime

0.785 = Ratio of molecular weights of CO_2 to CaO.

f_{MgO} = MgO content of lime, calculated by subtracting MgO content of lime in uncalcined $MgCO_3$ remaining in lime from total MgO content of lime, tonnes MgO/ tonne lime.

1.092 = Ratio of molecular weights of CO_2 to MgO

(3) Quarterly Calcined Byproduct/Waste Emission Factor. The calcined byproduct/waste emission factor shall be calculated using Equation 170-3.

$$EF_{CBW} = (f_{CaO} \times 0.785) + (f_{MgO} \times 1.092)$$ **Equation 170-3**

Where:

EF_{CBW} = Calcined byproduct/waste emission factor.

f_{CaO} = CaO content of byproduct and waste, calculated by subtracting CaO content of byproduct and waste in uncalcined $CaCO_3$ remaining in calcined byproduct and waste from total CaO content of byproduct and waste, tonnes CaO/ tonne byproduct and waste.

0.785 = Ratio of molecular weights of CO_2 to CaO .

f_{MgO} = MgO content of byproduct and waste, calculated by subtracting MgO content of byproduct and waste in uncalcined $MgCO_3$ remaining in byproduct and waste from total MgO content of byproduct and waste, tonnes MgO/ tonnes byproduct and waste .

1.092 = Ratio of molecular weights of CO_2 to MgO

(c) Fuel Combustion Emissions in Kilns. Calculate CO_2, CH_4, and N_2O emissions from stationary fuel combustion emissions following the calculation methods specified in WCI.20. Operators of lime manufacturing plants that primarily combust biomass-derived fuels and combust fossil fuels only during periods of start-up, shut-down, or malfunction may report CO_2 emissions from fossil fuels using the emission factor methodology in WCI.23(a).

"Pure" means that the biomass-derived fuels account for 97 percent of the total amount of carbon in the fuels burned.

§ WCI.174 Sampling, Analysis, and Measurement Requirements

(a) You must determine the chemical composition (CaO and MgO contents) of each type of lime and each type of calcined byproduct/waste according to paragraph (a)(1) and (a)(2) of this section. Samples for analysis of the calcium oxide and magnesium oxide content of each lime type and each calcined byproduct/waste type should be collected during the same month or quarter as the production data. At least one sample must be collected monthly for each lime type produced during the month and quarterly for each calcined byproduct/waste type produced.

(1) ASTM C25-06 Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime.

(2) The National Lime Association's CO_2 Emissions Calculation Protocol for the Lime Industry English Units Version, February 5, 2008 Revision – National Lime Association.

(b) The quantity of lime produced and sold is to be estimated monthly using direct measurements (such as rail and truck scales) of lime sales for each lime type, and adjusted to take into account the difference in beginning- and end-of-period inventories of each lime type. The inventory period shall be annual at a minimum.

(c) The quantity of calcined byproduct/waste sold is to be estimated monthly using direct measurements (such as rail and truck scales) of calcined byproduct/waste sales for each calcined byproduct/waste type, and adjusted to take into account the difference in beginning- and end-of-period inventories of each calcined byproduct/waste type. The inventory period shall be annual at a minimum. The quantity of calcined byproduct/waste not sold is to be determined no less often than annually for each calcined/byproduct waste type using direct measurements (such as rail and truck scales), or a calcined byproduct/waste generation rate (i.e. calcined byproduct produced as a factor of lime production).

(d) Follow the quality assurance/quality control procedures (including documentation) in National Lime Association's CO_2 Emissions Calculation Protocol for the Lime Industry English Units Version, February 5, 2008 Revision – National Lime Association.

§ WCI.175 Procedures for Estimating Missing Data

A complete record of all measured parameters used in the GHG emissions calculations is required (e.g., oxide content, quantity of lime products, etc.). Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraphs (a) or (b) of this section. You must document and keep records of the procedures used for all such estimates.

(a) For each missing value of the quantity of lime produced (by lime type), and quantity of byproduct/waste produced and sold, the substitute data value shall be the best available estimate based on all available process data or data used for accounting purposes.

(b) For missing values related to the CaO and MgO content, you must conduct a new composition test.

§ WCI.180 CARBONATES USE

§ WCI.181 Source Category Definition

This source category includes any equipment that uses carbonates listed in Table 180-1 in manufacturing processes that emit carbon dioxide. Table 180-1 includes the following carbonates: limestone, dolomite, ankerite, magnesite, siderite, rhodochrosite, or sodium carbonate. Facilities are considered to emit CO_2 if they consume at least 1,800 tonnes per year of carbonates heated to a temperature sufficient to allow the calcination reaction to occur.

This source category does not include equipment that uses carbonates or carbonate-containing minerals that are consumed in the production of cement, copper and nickel, electricity generation, ferroalloys, glass, iron and steel, lead, lime, phosphoric acid, pulp and paper, soda ash, sodium bicarbonate, sodium hydroxide, or zinc.

This source category does not include carbonates used in sorbent technology used to control emissions from stationary fuel combustion equipment. Emissions from carbonates used in sorbent technology are reported under WCI.20 (Stationary Fuel Combustion Sources).

§ WCI.182 Greenhouse Gas Reporting Requirements

For the purpose of the Regulation, the annual emissions data report for carbonate use shall include the following information at the facility level calculated in accordance with this method:

(a) Annual CO_2 emissions from miscellaneous carbonate use (tonnes).

(b) Annual mass of each carbonate type consumed (tonnes).

(c) If you followed the calculation method of WCI.183(a), you must report the following information:

(1) Annual carbonate consumption by carbonate type (tonnes).

(2) Annual calcination fractions used in calculations.

(d) If you followed the calculation method of WCI.183(b), you must report the following information:

(1) Annual carbonate input by carbonate type (tonnes).

(2) Annual carbonate output by carbonate type (tonnes).

(e) Number of times in the reporting year that missing data procedures were followed to measure carbonate consumption, carbonate input or carbonate output (months).

§ WCI.183 Calculating GHG emissions.

You must determine CO_2 process emissions from carbonate use in accordance with the procedures specified in either paragraphs (a) or (b) of this section.

(a) Calculate the process emissions of CO_2 using calcination fractions with Equation 180-1 of this section.

$$E_{CO2} = \sum_{i=1}^{n} \left(M_i \times EF_i \times F_i \right)$$

Equation 180-1

Where:

ECO_2	=	Annual CO_2 mass emissions from consumption of carbonates (tonnes).
M_i	=	Annual mass of carbonate type *i* consumed (tonnes).
EF_i	=	Emission factor for the carbonate type *i*, as specified in Table 180-1 to this Subpart, tonnes CO_2/tonne carbonate consumed.
F_i	=	Fraction calcination achieved for each particular carbonate type *i* (weight fraction). As an alternative to measuring the calcination fraction, a value of 1.0 can be used.
n	=	Number of carbonate types.

(b) Calculate the process emissions of CO_2 using actual mass of output carbonates with Equation 180-2 of this section.

$$E_{CO2} = \left[\sum_{k=1}^{m} \left(M_k \times EF_k \right) - \sum_{j=1}^{n} \left(M_j \times EF_j \right) \right]$$

Equation 180-2

Where:

ECO_2	=	Annual CO_2 mass emissions from consumption of carbonates (tonnes).
M_k	=	Annual mass of input carbonate type *k* (tonnes).
EF_k	=	Emission factor for the input carbonate type *k*, as specified in Table 180-1 of this method (tonnes CO_2/tonne carbonate input).
M_j	=	Annual mass of output carbonate type *j* (tonnes).
EF_j	=	Emission factor for the output carbonate type *j*, as specified in Table 180-1 of this method (tonnes CO_2/tonne carbonate input).
m	=	Number of input carbonate types.
n	=	Number of output carbonate types.

§ WCI.184 Monitoring and QA/QC requirements.

(a) The annual mass of carbonate consumed (for Equation 180-1 of this subpart) or carbonate inputs (for Equation 180-2 of this subpart) must be determined annually from monthly measurements using the same plant instruments used for accounting purposes including purchase records or direct measurement, such as weigh hoppers or weigh belt feeders.

(b) The annual mass of carbonate outputs (for Equation 180-2 of this subpart) must be determined annually from monthly measurements using the same plant instruments used for accounting purposes including purchase records or direct measurement, such as weigh hoppers or belt weigh feeders.

(c) If you follow the procedures of WCI.183(a), as an alternative to assuming a calcination fraction of 1.0, you can determine on an annual basis the calcination fraction for each carbonate consumed based on sampling and chemical analysis using a suitable method such as using an x-ray fluorescence standard method or other enhanced industry consensus standard method published by an industry consensus standard organization (e.g., ASTM, ASME, etc.).

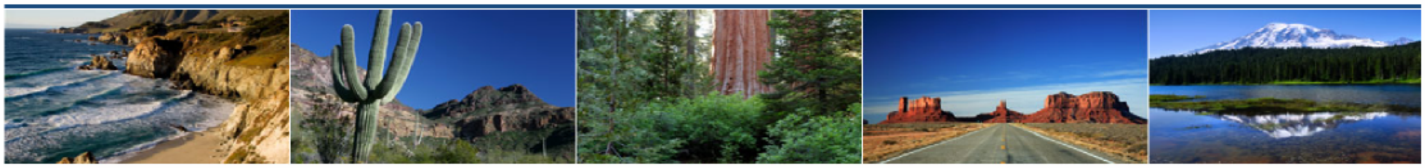
§ WCI.185 Procedures for estimating missing data.

(a) A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraph (b) of this section. You must document and keep records of the procedures used for all such estimates.

(b) For each missing value of monthly carbonate consumed, monthly carbonate output, or monthly carbonate input, the substitute data value must be the best available estimate based on the all available process data or data used for accounting purposes.

Table 180-1 — CO_2 Emission Factors for Common Carbonates

Mineral Name - Carbonate	CO_2 Emission Factor (tonnes CO_2/tonne carbonate)
Limestone - $CaCO_3$	0.43971
Magnesite - $MgCO_3$	0.52197
Dolomite - $CaMg(CO_3)_2$	0.47732
Siderite - $FeCO_3$	0.37987
Ankerite - $Ca(Fe,Mg,Mn)(CO_3)_2$	0.47572
Rhodochrosite - $MnCO_3$	0.38286
Sodium Carbonate/Soda Ash – Na_2CO_3	0.41492
Others	Facility specific factor to be determined through analysis or supplier information



§ WCI.200 PETROLEUM REFINERIES

§ WCI.201 Source Category Definition

(a) A petroleum refinery consists of all processes used to produce gasoline, aromatics, kerosene, distillate fuel oils, residual fuel oils, lubricants, asphalt, or other products through distillation of petroleum or through redistillation, cracking, rearrangement or reforming of unfinished petroleum derivatives.

(b) For the purposes of this subpart, facilities that distill only pipeline transmix (off-spec material created when different specification products mix during pipeline transportation) are not petroleum refineries, regardless of the products produced.

(c) This source category consists of the following sources at petroleum refineries: catalytic cracking units; fluid coking units; delayed coking units; catalytic reforming units; coke calcining units; asphalt blowing operations; blowdown systems; storage tanks; process equipment components (compressors, pumps, valves, pressure relief devices, flanges, and connectors) in gas service; marine vessel, barge, tanker truck, and similar loading operations; flares; sulphur recovery plants; and non-merchant hydrogen plants (i.e., hydrogen plants that are owned or under the direct control of the refinery owner and operator).

§ WCI.202 Greenhouse Gas Reporting Requirements

In addition to the information required by regulation, the annual emissions report must contain the following information reported at the facility level:

(a) Catalyst Regeneration. Report CO_2, CH_4, and N_2O emissions.

(b) Process Vents. Report CO_2, CH_4, and N_2O emissions.

(c) Asphalt Production. Report CO_2 and CH_4 emissions.

(d) Sulphur Recovery. Report CO_2 emissions.

(e) Flares and Other Control Devices. Report CO_2, CH_4, and N_2O emissions.

(f) Above-Ground Storage Tanks. Report CH_4 emissions.

(g) Wastewater Treatment. Report CH_4 and N_2O emissions from anaerobic treatment.

(h) Oil-water separators. Report CH_4 emissions from oil-water separators.

(i) Equipment Leaks. Report CH_4 emissions.

(j) Coke calcining units. Report CO_2, CH_4, and N_2O emissions.

(k) Uncontrolled blowdown systems. Report CH_4 emissions.

(l) Loading Operations. Report CH_4 emissions.

(m) Delayed Coking Units. Report CH_4 emissions.

(n) Stationary Combustion Units Other than Flares and Control Devices. CO_2, CH_4, and N_2O emissions as specified in WCI.30 for combustion of refinery fuel gas, still gas, flexigas, or associated gas and WCI.20 for combustion of all other fuels.

(o) Feedstock Consumption: Report feedstock consumption, by type, for all feedstocks which result in GHG emissions in the reporting year (including petroleum coke) in units of cubic meters for gases, kilolitres for liquids, tonnes for non-biomass solids, and bone dry tonnes for biomass-derived solid fuels.

(p) Fuel Consumption: Report fuel consumption by fuel type consumed in the reporting year in units of cubic meters for gases, kilolitres for liquids, tonnes for non-biomass solids, and bone dry tonnes for biomass-derived solid fuels.

§ WCI.203 Calculation of Greenhouse Gas Emissions

The operator shall calculate GHG emissions using the methods in paragraphs (a) through (m) of this section. If a continuous emissions monitor is used to measure CO_2 emissions from process vents, asphalt production, sulphur recovery, or other control devices then the operator shall calculate the CO_2 emissions from these processes using a continuous emissions monitoring system (CEMS) as specified in WCI.23(d). When the flue gas from two or more processes or stationary combustion sources are discharged through a common stack or duct before exiting to the atmosphere and if CEMS as specified in WCI.23(d) are used to continuously monitor the CO2 emissions, you may report the combined emissions from the processes or stationary combustion sources sharing the common stack or duct in lieu of separately reporting the GHG emission from individual processes or stationary combustion sources.

(a) Catalyst Regeneration. Operators shall calculate the CO_2, CH_4, and N_2O process emissions resulting from catalyst regeneration using the methods in paragraph (a)(1), (a)(2) and (a)(3), respectively.

(1) For units equipped with CEMS, operators shall calculate CO_2 process emissions resulting from catalyst regeneration using CEMS in accordance with WCI.20. In the absence of CEMS data, the operator shall use the methods in paragraphs (a)(1)(A) through (a)(1)(C).

(A) (i) The person shall calculate process CO_2 emissions from the continuous regeneration of catalyst material in fluid catalytic cracking units (FCCU) and fluid cokers using Equations 200-1, 200-1b, 200-2, and 200-3

$$CO_2 = \sum_{i=1}^{n} CR_i \times CF \times 3.664 \times 0.001$$ **Equation 200-1**

Where:

CO_2	=	CO_2 emissions (tonnes/yr).
n	=	Number of hours of operation in the report.
CR_i	=	Hourly coke burn rate in kg/week.
CF	=	Carbon fraction in coke burned.

3.664 = Ratio of molecular weights, CO_2 to carbon.
0.001 = Conversion factor from kg to tonnes.

(ii) Alternatively, the person may calculate process CO_2 emissions from the continuous regeneration of catalyst material in fluid catalytic cracking units (FCCU) and fluid cokers using Equations 200-1b and 200-2.

$$CO_2 = \sum_{p=1}^{n} \left[(Q_r)_p \times \frac{(\%CO_2 + \%CO)_p}{100\%} \times \frac{44}{MVC} \times 0.001 \right]$$ **Equation 200-1b**

Where:
CO_2 = CO_2 emissions (tonnes/yr).
Q_r = Volumetric flow rate of exhaust gas before entering the emission control system using Equation 200-2 and at reference temperature and pressure conditions as used by the facility (dRm^3/hr).
$\%CO_2$ = Average hourly CO_2 concentration in regenerator exhaust, per cent by volume – dry basis.
%CO = Average hourly CO concentration in regenerator exhaust, per cent by volume – dry basis. When there is no post-combustion device, assume %CO to be zero.
44 = Molecular weight of CO_2 (kg/kg-mole).
MVC = Molar volume conversion factor at the same reference conditions as the above Q_r (Rm^3/kg-mole).
= 8.3145 * [273.16 + reference temperature in °C]/[reference pressure in kilopascal].
0.001 = Conversion factor from kg to tonnes.
n = Number of hours of operation in the report year.

(iii) Either continuously monitor the volumetric flow rate of exhaust gas from the fluid catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels or calculate the volumetric flow rate of this exhaust gas stream using Equation 200-2 of this section.

$$Q_r = \frac{(79 * Q_a + (100 - \%O_{oxy}) * Q_{oxy})}{100 - \%CO_2 - \%CO - \%O_2}$$ **Equation 200-2**

Where:
Q_r = Volumetric flow rate of exhaust gas from regenerator before entering the emission control system at reference temperature and pressure conditions as used by the facility (dRm^3/min).
Q_a = Volumetric flow rate of air to regenerator, as determined from control room instrumentation at reference temperature and pressure conditions as used for variable Q_r (dRm^3/min).

O_{oxy}	=	Oxygen concentration in oxygen enriched air stream, percent by volume – dry basis.
Q_{oxy}	=	Volumetric flow rate of O_2 enriched air to regenerator as determined from catalytic cracking unit control room instrumentation at reference temperature and pressure conditions used for variable Q_r (dRm^3/min).
$\%CO_2$	=	Carbon dioxide concentration in regenerator exhaust, percent by volume – dry basis.
$\%CO$	=	CO concentration in regenerator exhaust, percent by volume – dry basis. When no auxiliary fuel is burned and a continuous CO monitor is not required, assume %CO to be zero.
$\%O_2$	=	O_2 concentration in regenerator exhaust, percent by volume – dry basis.

(iv) Calculate the hourly coke burn rate using Equation 200-3 or from facility measurement or engineering estimate:

$$CR_i = K_1 Q_r \times (\%CO_2 + \%CO) + K_2 Q_a - K_3 Q_r \times \left[\%CO/2 + \%CO_2 + \%O_2\right] + K_3 Q_{oxy} \times (\%O_{oxy})$$

Equation 200-3

Where:

CR_i	=	Hourly coke burn rate in kg/hour.
K_1, K_2, K_3	=	Material balance and conversion factors (K_1, K_2, and K_3 from Table 200-1 or from facility measurement or engineering estimate).
Q_r	=	Volumetric flow rate of exhaust gas before entering the emission control system from Equation 200-2 (dRm^3/min)
Q_a	=	Volumetric flow rate of air to regenerator as determined from control room instrumentation at reference temperature and pressure conditions used in variable Q_r (dRm^3/min)
$\%CO_2$	=	CO_2 concentration in regenerator exhaust, percent by volume – dry basis
$\%CO$	=	CO concentration in regenerator exhaust, percent by volume – dry basis
$\%O_2$	=	O_2 concentration in regenerator exhaust, percent by volume – dry basis
Q_{oxy}	=	Volumetric flow rate of O_2 enriched air to regenerator as determined from control room instrumentation at reference temperature and pressure conditions used in variable Q_r (dRm^3/min)
$\%O_{oxy}$	=	O_2 concentration in O_2 enriched air stream inlet to regenerator, percent by volume – dry basis

(B) The operator shall calculate process CO_2 emissions resulting from continuous catalyst regeneration in operations other than FCCUs and fluid cokers (e.g. catalytic reforming) using Equation 200-4.

$$CO_2 = CC_{irc} \times (CF_{spent} - CF_{regen}) \times H \times 3.664$$

Equation 200-4

Where:

CO_2	=	CO_2 emissions (tonnes/yr)
CC_{irc}	=	Average catalyst regeneration rate (tonnes/hr)
CF_{spent}	=	Weight carbon fraction of spent catalyst
CF_{regen}	=	Weight carbon fraction of regenerated catalyst (default = 0)
H	=	Hours regenerator was operational (hr/yr)
3.664	=	Ratio of molecular weights, CO_2 to carbon

(C) The operator shall calculate process CO_2 emissions resulting from periodic catalyst regeneration using Equations 200-5

$$CO_2 = \sum_{1}^{n} \left[\left(CB_Q \right)_n \times CC \times 3.664 \times 0.001 \right]$$ **Equation 200-5**

Where:

O_2	=	Annual CO_2 emissions (tonnes/year).
CB_Q	=	Coke burn-off quantity per regeneration cycle from engineering estimates (kg coke/cycle).
n	=	Number of regeneration cycles in the calendar year.
CC	=	Carbon content of coke based on measurement or engineering estimate (kg C per kg coke); default = 0.94.
3.664	=	Ratio of molecular weights, CO_2 to carbon
0.001	=	Conversion factor (tonne/kg).

(2) Calculate CH_4 emissions using either unit specific measurement data, a unit-specific emission factor based on a source test of the unit, or Equation 200-6 of this section.

$$CH_4 = \left(CO_2 \times \frac{EmF_2}{EmF_1} \right)$$ **Equation 200-6**

Where:

CH_4	=	Annual methane emissions from coke burn-off (tonnes CH_4/year).
CO_2	=	Emission rate of CO_2 from coke burn-off calculated in paragraph (a)(1) of this section, as applicable (metric tons/year).
EmF_1	=	Default CO_2 emission factor for petroleum coke of 97 kg CO_2/GJ.
EmF_2	=	Default CH_4 emission factor of 2.8×10^{-3} kg CH_4/GJ.

(3) Calculate N_2O emissions using either unit specific measurement data, a unit-specific emission factor based on a source test of the unit, or Equation 200-7 of this section.

$$N_2O = \left(CO_2 \times \frac{EmF_3}{EmF_1} \right)$$ **Equation 200-7**

Where:

N_2O	=	Annual nitrous oxide emissions from coke burn-off (tonnes N_2O/year).
CO_2	=	Emission rate of CO_2 from coke burn-off calculated in paragraphs (a)(1) of this section, as applicable (tonnes/year).
EmF_1	=	Default CO_2 emission factor for petroleum coke of 97 kg CO_2/GJ.
EmF_3	=	Default N_2O emission factor of 5.7 x 10^{-4} kg N_2O/GJ.

(b) **Process Vents.** Except for process emissions reported under other requirements of this regulation, the operator shall calculate process emissions of CO_2, CH_4, and N_2O from process vents using Equation 200-8 for each process vent that can be reasonably expected to contain greater than 2 percent by volume CO_2 or greater than 0.5 percent by volume of CH_4 or greater than 0.01 percent by volume (100 parts per million) of N_2O.

$$E_x = \sum_{i=1}^{n} VR_i \times F_{xi} \times (MW_x / MVC) \times VT_i \times 0.001$$ **Equation 200-8**

Where:

E_x	=	Annual emissions of *x* (tonnes/yr), where *x* = CO_2, N_2O, or CH_4.
VR_i	=	Average volumetric flow rate for venting event *i* from measurement data, process knowledge or engineering estimates at reference temperature and pressure conditions as used by the facility (Rm^3/unit time). If a mass flow meter is used, measure the flow rate in kg/unit time and replace the term "MW_x/MVC" with "1".
F_{xi}	=	Molar fraction of *x* in vent gas stream during event *i* from measurement data, process knowledge or engineering estimates.
MW_x	=	Molecular weight of *x* (kg/kg-mole).
MVC	=	Molar volume conversion factor at the same reference conditions as the above VR_i (Rm^3/kg-mole).
	=	8.3145 * [273.16 + reference temperature in °C]/[reference pressure in kilopascal]
VT_i	=	Time duration of venting event *i*, in same units of time as VR_i.
n	=	Number of venting events in report year.
0.001	=	Conversion factor from kg to tonnes.

(c) **Asphalt Production**. The operator shall calculate CO_2 and CH_4 process emissions from asphalt blowing activities using either process vent method specified in paragraph (b) or according to the applicable provisions in paragraphs (c)(1) and (c)(2) of this section.

(1) For uncontrolled asphalt blowing operations or asphalt blowing operations controlled by vapor scrubbing, calculate CO_2 and CH_4 emissions using Equations 200-9 and 200-10 of this section, respectively.

$$CO_2 = (Q_{AB} \times EF_{AB.CO2})$$ **Equation 200-9**

Where:

CO_2	=	Annual CO_2 emissions from uncontrolled asphalt blowing (tonnes CO_2/year).
Q_{AB}	=	Quantity of asphalt blown (million barrels per year, MMbbl/year).

$EF_{AB,CO2}$ = Emission factor for CO_2 from uncontrolled asphalt blowing from facility-specific test data (tonnes CO_2/MMbbl asphalt blown); default = 1,100.

$$CH_4 = (Q_{AB} \times EF_{AB,CH4}) \quad \textbf{Equation 200-10}$$

Where:

CH_4 = Annual methane emissions from uncontrolled asphalt blowing (tonnes CH_4/year).
Q_{AB} = Quantity of asphalt blown (million barrels per year, MMbbl/year).
$EF_{AB,CH4}$ = Emission factor for CH_4 from uncontrolled asphalt blowing from facility-specific test data (tonnes CH_4/MMbbl asphalt blown); default = 580.

(2) For asphalt blowing operations controlled by thermal oxidizer or flare, calculate CO_2 and CH_4 emissions using Equations 200-11 and 200-12 of this section, respectively, provided these emissions are not already included in the flare emissions calculated in paragraph (e) of this section or in the stationary combustion unit emissions required under WCI.20.

$$CO_2 = 0.98 \times (Q_{AB} \times CEF_{AB} \times 3.664) \quad \textbf{Equation 200-11}$$

Where:

CO_2 = Annual CO_2 emissions from controlled asphalt blowing (tonnes CO_2/year).
0.98 = Assumed combustion efficiency of thermal oxidizer or flare.
Q_{AB} = Quantity of asphalt blown (MMbbl/year).
CEF_{AB} = Carbon emission factor from asphalt blowing from facility-specific test data (tonnes C/MMbbl asphalt blown); default = 2,750.
3.664 = ratio of molecular weights, carbon dioxide to carbon

$$CH_4 = 0.02 \times (Q_{AB} \times EF_{AB,CH4}) \quad \textbf{Equation 200-12}$$

Where:

CH_4 = Annual methane emissions from controlled asphalt blowing (tonnes CH_4/year).
0.02 = Fraction of methane uncombusted in thermal oxidizer or flare based on assumed 98% combustion efficiency.
Q_{AB} = Quantity of asphalt blown (million barrels per year, MMbbl/year).
$EF_{AB,CH4}$ = Emission factor for CH_4 from uncontrolled asphalt blowing from facility-specific test data (tonnes CH_4/MMbbl asphalt blown); default = 580.

(d) **Sulphur Recovery**. The operator shall calculate CO_2 process emissions from sulphur recovery units (SRUs) using Equation 200-13. For the molar fraction (MF) of CO_2 in the sour gas, use either a default factor of 0.20 or a source specific molar fraction value approved by the regulator and derived from source tests conducted at least once per calendar year under the supervision of the regulator.

$$CO_2 = FR \times MW_{CO2} / MVC \times MF \times 0.001 \quad \textbf{Equation 200-13}$$

Where:

CO_2 = Emissions of CO_2 (tonnes/yr).
FR = Volumetric flow rate of acid gas to SRU at reference temperature and pressure conditions as used by the facility (Rm^3/year). If a mass flow meter is used, measure the acid gas flow in kg per year and replace the term "MW_{CO2}/MVC" with "1".
MW_{CO2} = Molecular weight of CO_2 (44 kg/kg-mole).
MVC = Molar volume conversion factor at the same reference conditions as the FR variable (Rm^3/kg-mole).
= 8.3145 * [273.16 + reference temperature in °C]/[reference pressure in kilopascal].
MF = Molar fraction (%) of CO_2 in sour gas based on measurement or engineering estimate (default MF = 20% expressed as 0.20).
0.001 = Conversion factor from kg to tonnes.

(e) **Flares and Other Control Devices**.

(1) The operator shall calculate and report CO_2, CH_4 and N_2O emissions resulting from the combustion of flare pilot and purge gas using the appropriate method(s) specified in section WCI.20.

(2) The operator shall calculate and report CO_2 emissions resulting from the combustion of hydrocarbons routed to flares for destruction as follows:

(A) Heat value or carbon content measurement. If you have a continuous higher heating value monitor or gas composition monitor on the flare or if you monitor these parameters at least weekly, you must use the measured heat value or carbon content value in calculating the CO_2 emissions from the flare using the applicable methods in paragraphs (e)(2)(A)(i) and (e)(2)(A)(ii).

(i) If you monitor gas composition, calculate the CO_2 emissions from the flare using Equation 200-14 of this section. If daily or more frequent measurement data are available, you must use daily values when using Equation 200-14 of this section; otherwise, use weekly values.

$$CO_2 = 0.98 \times 0.001 \times \left(\sum_{p=1}^{n} \left[3.664 \times (Flare)_p \times \frac{(MW)_p}{MVC} \times (CC)_p \right] \right) \quad \textbf{Equation 200-14}$$

Where:
CO_2 = Annual CO_2 emissions for a specific fuel type (tonnes/year).
0.98 = Assumed combustion efficiency of a flare.
0.001 = Unit conversion factor (tonnes per kilogram).
n = Number of measurement periods. The minimum value for *n* is 52 (for weekly measurements); the maximum value for *n* is 366 (for daily measurements during a leap year).
p = Measurement period index.
3.664 = Ratio of molecular weights, carbon dioxide to carbon

$(Flare)_p$ = Volume of flare gas combusted during measurement period at reference temperature and pressure conditions as used by the facility (Rm^3/period) . If a mass flow meter is used, measure flare gas flow rate in kg/period and replace the term "$(MW)_p/MVC$" with "1".

$(MW)_p$ = Average molecular weight of the flare gas combusted during measurement period *p* (kg/kg-mole). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.

MVC = Molar volume conversion factor at the same reference conditions as the above $(Flare)_p$ (Rm^3/kg-mole).

= 8.3145 * [273.16 + reference temperature in °C]/[reference pressure in kilopascal].

$(CC)_p$ = Average carbon content of the flare gas combusted during measurement period *p* (kg C per kg flare gas). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.

(ii) If you monitor heat content but do not monitor gas composition, calculate the CO_2 emissions from the flare using Equation 200-15 of this section. If daily or more frequent measurement data are available, you must use daily values when using Equation 200-15 of this section; otherwise, use weekly values.

$$CO_2 = 0.98 \times 0.001 \times \sum_{p=1}^{n} \left[(Flare)_p \times (HHV)_p \times EmF \right] \qquad \textbf{Equation 200-15}$$

Where:

CO_2 = Annual CO_2 emissions for a specific fuel type (tonnes/year).

0.98 = Assumed combustion efficiency of a flare.

0.001 = Unit conversion factor (tonnes per kilogram).

n = Number of measurement periods. The minimum value for *n* is 52 (for weekly measurements); the maximum value for *n* is 366 (for daily measurements during a leap year).

p = Measurement period index.

$(Flare)_p$ = Volume of flare gas combusted during measurement period *p* at reference temperature and pressure conditions as used by the facility (Rm^3/period). If a mass flow meter is used, the person must also measure molecular weight and convert the mass flow to a volumetric flow as follows: Flare[m3] = Flare[kg] × $MVC/(MW)_p$, where MVC is the molar volume conversion factor at the same reference conditions as $(Flare)_p$ (Rm^3/kg-mole) and $(MW)_p$ is the average molecular weight of the flare gas combusted during measurement period *p* (kg/kg-mole).

$(HHV)_p$ = Higher heating value for the flare gas combusted during measurement period *p* (GJ per m^3). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.

EmF = Default CO_2 emission factor of 57 kilograms CO_2/GJ (HHV basis).

(B) Alternative Method. For startup, shutdown, and malfunctions during which you were unable to measure the parameters required by Equations 200-14 and 200-15 of this section, you must determine the quantity of gas discharged to the flare separately for each start-up, shutdown, or malfunction, and calculate the CO_2 emissions as specified in paragraphs (e)(2)(B)(i) and (e)(2)(B)(ii) of this section.

(i) For periods of start-up, shutdown, or malfunction, use engineering calculations and process knowledge to estimate the carbon content of the flared gas for each start-up, shutdown, or malfunction event.

(ii) For the reporting of emissions from normal operation flares in the year 2011, you may use the average heating value measured for the fuel gas for the heating value of the flare gas. If heating value is not measured, the heating value may be estimated from historic data or engineering calculation. If you are unable to use the methods in WCI.203(e)(2) in 2012 due to health or safety reasons, you may use the alternate method in the subsection in 2012 if it is consented to in writing by the Director.

(iii) Calculate the CO_2 emissions using Equation 200-16 of this section.

$$CO_2 = 0.98 \times 0.001 \times \left(\sum_{p=1}^{n} \left[3.664 \times (Flare_{SSM})_p \times \frac{(MW)_p}{MVC} \times (CC)_p \right] \right) \quad \textbf{Equation 200-16}$$

Where:

CO_2 = Annual CO_2 emissions for a specific fuel type (tonnes/year).

0.98 = Assumed combustion efficiency of a flare.

0.001 = Unit conversion factor (tonnes per kilogram, mt/kg).

n = Number of start-up, shutdown, and malfunction events during the reporting year.

p = Start-up, shutdown, and malfunction event index.

$(Flare_{SSM})_p$ = Volume of flare gas combusted during indexed start-up, shutdown, or malfunction event *p* from engineering calculations, at reference temperature and pressure conditions as used by the facility (Rm^3/event). If a mass flow meter is used, measure the flare gas combusted in kg per event and replace the term "(MW)p/MVC" with "1".

$(MW)_p$ = Average molecular weight of the flare gas, from the analysis results or engineering calculations for the event *p* (kg/kg-mole).

MVC = Molar volume conversion factor at the same reference conditions as the above $(Flare_{SSM})_p$ (Rm^3/kg-mole).

= 8.3145 * [273.16 + reference temperature in °C]/[reference pressure in kilopascal].

$(CC)_p$ = Average carbon content of the flare gas, from analysis results or engineering calculations for the event *p* (kg C per kg flare gas).

3.664 = Ratio of molecular weights, carbon dioxide to carbon.

(3) The operator shall calculate and report CH_4 and N_2O emissions resulting from the combustion of hydrocarbons routed to flares for destruction using the methods specified in paragraphs (e)(3)(A) and (e)(3)(B):

(A) Calculate CH_4 using Equation 200-17 of this section.

$$CH_4 = \left(CO_2 \times \frac{\mathrm{EmF}_{CH4}}{\mathrm{EmF}} \right) + CO_2 \times \frac{0.02}{0.98} \times \frac{16}{44} \times f_{CH4}$$ **Equation 200-17**

Where:

CH_4 = Annual methane emissions from flared gas (tonnes CH_4/year).

CO_2 = Emission rate of CO_2 from flared gas calculated in paragraph (e)(1) and (e)(2) of this section (tonnes/year).

EmF_{CH4} = Default CH_4 emission factor for petroleum products of 2.8 x 10^{-3} kg/GJ.

EmF = Default CO_2 emission factor for flare gas of 57 kilograms CO_2/GJ (HHV basis).

0.02/0.98 = Correction factor for flare combustion efficiency.

16/44 = Correction factor ratio of the molecular weight of CH_4 to CO_2

f_{CH4} = Weight fraction of carbon in the flare gas prior to combustion that is contributed by methane from measurement values or engineering calculations (kg C in methane in flare gas/kg C in flare gas); default is 0.4.

(B) Calculate N_2O emissions using Equation 200-18 of this section.

$$N_2O = \left(CO_2 \times \frac{\mathrm{EmF}_{N2O}}{\mathrm{EmF}} \right)$$ **Equation 200-18**

Where:

N_2O = Annual nitrous oxide emissions from flared gas (tonnes N_2O/year).

CO_2 = Emission rate of CO_2 from flared gas calculated in paragraph (e)(1) and (e)(2) of this section (tonnes/year).

EmF_{N2O} = Default N_2O emission factor for petroleum products of 5.7 x 10^{-4} kg/GJ.

EmF = Default CO_2 emission factor for flare gas of 57 kilograms CO_2/GJ (HHV basis).

(4) The operator who uses methods other than flares (e.g. incineration, combustion as a supplemental fuel in heaters or boilers) to destroy low Btu gases (e.g. coker flue gas, gases from vapor recovery systems, casing vents and product storage tanks) shall calculate CO_2 emissions using Equation 200-19. The operator shall determine CC_A and MW_A quarterly using methods specified in WCI.20 and use the annual average values of CC_A and MW_A to calculate CO_2 emissions.

$$CO_2 = GV_A \times CC_A \times MW_A / MVC \times 3.664 \times 0.001$$ **Equation 200-19**

Where:

CO_2	=	CO_2 emissions (tonnes/year).
GV_A	=	Volume of gas *A* destroyed annually at reference temperature and pressure conditions as used by the facility (Rm^3/year). If a mass flow meter is used, measure the gas destroyed in kg and replace the term "MW_A/MVC" with "1".
CC_A	=	Carbon content of gas *A* (kg C/kg fuel).
MW_A	=	Molecular weight of gas *A*.
MVC	=	Molar volume factor at the same reference conditions as the GV_A variable (Rm^3/kg-mole).
	=	8.3145 * [273.16 + reference temperature in °C]/[reference pressure in kilopascal].
3.664	=	Ratio of molecular weights, CO_2 to carbon.
0.001	=	Conversion factor – kg to tonnes.

(f) **Storage Tanks.** For storage tanks other than those processing unstabilized crude oil except as provided in paragraph (f)(3) of this section, calculate CH_4 emissions using the applicable methods in paragraphs (f)(1) and (f)(2) of this section.

(1) For storage tanks other than those processing unstabilized crude oil, you must either calculate CH_4 emissions from storage tanks that have a vapor-phase methane concentration of 0.5 volume percent or more using tank-specific methane composition data (from measurement data or product knowledge) and the AP-42 emission estimation methods provided in Section 7.1 of the AP-42: "Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources", including TANKS Model (Version 4.09D) or similar programs, or estimate CH_4 emissions from storage tanks using Equation 200-20 of this section.

$$CH_4 = \left(0.1 \times Q_{\mathrm{Re}f}\right) \qquad \textbf{Equation 200-20}$$

Where:

CH_4	=	Annual methane emissions from storage tanks (tonnes/year).
0.1	=	Default emission factor for storage tanks (tonne CH_4/MMbbl).
Q_{Ref}	=	Quantity of crude oil plus the quantity of intermediate products received from off site that are processed at the facility (MMbbl/year).

(2) For storage tanks that process unstabilized crude oil, calculate CH_4 emissions from the storage of unstabilized crude oil using either tank-specific methane composition data (from measurement data or product knowledge) and direct measurement of the gas generation rate or by using Equation 200-21 of this section.

$$CH_4 = (995{,}000 \times Q_{un} \times \Delta P) \times MF_{CH4} \times \frac{16}{MVC} \times 0.001 \qquad \textbf{Equation 200-21}$$

Where:

CH_4	=	Annual methane emissions from storage tanks (tonnes/year).
Q_{un}	=	Quantity of unstabilized crude oil received at the facility (MMbbl/year).

ΔP = Pressure differential from the previous storage pressure to atmospheric pressure (pounds per square inch, psi).
MF_{CH4} = Mole fraction of CH_4 in vent gas from the unstabilized crude oil storage tank from facility measurements (kg-mole CH_4/kg-mole gas); use 0.27 as a default if measurement data are not available.
995,000 = Correlation Equation factor (scf gas per MMbbl per psi).
16 = Molecular weight of CH_4 (kg/kg-mole).
MVC = Molar volume conversion (849.5 scf/kg-mole).
0.001 = Conversion factor (tonne/kg).

(3) You do not need to calculate CH_4 emissions from storage tanks that meet any of the following descriptions:
(A) Units permanently attached to conveyances such as trucks, trailers, rail cars, barges, or ships;
(B) Pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere;
(C) Bottoms receivers or sumps;
(D) Vessels storing wastewater; or
(E) Reactor vessels associated with a manufacturing process unit.

(g) **Industrial Wastewater Processing**.

(1) The operator shall calculate CH_4 emissions from anaerobic wastewater treatment (such as anaerobic reactor, digester, or lagoon) using Equation 200-22 or Equation 200-23.

$$CH_4 = Q \times COD_{qave} \times B \times MCF \times 0.001$$ **Equation 200-22**

$$CH_4 = Q \times BOD_{5qave} \times B \times MCF \times 0.001$$ **Equation 200-23**

Where:
CH_4 = Emission of methane (tonnes/yr).
Q = Volume of wastewater treated (m^3/yr).
COD_{qave} = Average of quarterly determinations of chemical oxygen demand of the wastewater (kg/m^3).
BOD_{5qave} = Average of quarterly determinations of five-day biochemical oxygen demand of the wastewater (kg/m^3).
B = Methane generation capacity (B = 0.25 kg CH_4/kg COD and 0.06 kg CH_4/kg BOD_5).
MCF = Methane correction factor for anaerobic decay (0-1.0) from Table 200-2.
0.001 = Conversion factor – kg to tonnes.

(2) For anaerobic processes from which biogas is recovered and not emitted, you must adjust the CH_4 emissions calculated in paragraph (g)(1) by the amount of CH_4 collected.

(3) The operator shall calculate N_2O emissions from wastewater treatment using Equation 200-24.

$$N_2O = Q \times N_{qave} \times EF_{N2O} \times 1.571 \times 0.001 \quad \textbf{Equation 200-24}$$

Where:

N_2O	=	Emissions of N_2O (tonnes/yr).
Q	=	Volume of wastewater treated (m^3/yr).
N_{qave}	=	Average of quarterly determinations of N in effluent (kg N/m^3).
EF_{N2O}	=	Emission factor for N_2O from discharged wastewater (0.005 kg N_2O-N/kg N).
1.571	=	Conversion factor – kg N_2O-N to kg N_2O.
0.001	=	Conversion factor – kg to tonnes.

(h) **Oil-Water Separators.** The operator shall calculate CH_4 emissions from oil-water separators using Equation 200-25. For the CF_{NMHC} conversion factor, operators shall use either a default factor of 0.6 or species specific conversion factors determined by analysis using a sampling and analysis methodology approved by regulator.

$$CH_4 = EF_{sep} \times V_{water} \times CF_{NMHC} \times 0.001 \quad \textbf{Equation 200-25}$$

Where:

CH_4	=	Emission of methane (tonnes/yr).
EF_{sep}	=	NMHC (non methane hydrocarbon) emission factor (kg/m^3) from Table 200-3.
V_{water}	=	Volume of waste water treated by the separator (m^3/yr).
CF_{NMHC}	=	NMHC to CH_4 conversion factor.
0.001	=	Conversion factor from kg to tonnes.

(i) **Equipment leaks**. Calculate CH_4 emissions using the method specified in either paragraph (i)(1) or (i)(2) of this section.

(1) Use process-specific methane composition data (from measurement data or process knowledge) and any of the emission estimation procedures provided in the Protocol for Equipment Leak Emissions Estimates (EPA-453/R-95-017, NTIS PB96-175401).

(2) Use Equation 200-26 of this section.

$$CH_4 = (0.4 \times N_{CD} + 0.2 \times N_{PU1} + 0.1 \times N_{PU2} + 4.3 \times N_{H2} + 6 \times N_{FGS}) \quad \textbf{Equation 200-26}$$

Where:

CH_4	=	Annual methane emissions from equipment leaks (tonnes/year)
N_{CD}	=	Number of atmospheric crude oil distillation columns at the facility.

N_{PU1} = Cumulative number of catalytic cracking units, coking units (delayed or fluid), hydrocracking, and full-range distillation columns (including depropanizer and debutanizer distillation columns) at the facility.
N_{PU2} = Cumulative number of hydrotreating/hydrorefining units, catalytic reforming units, and visbreaking units at the facility.
N_{H2} = Total number of hydrogen plants at the facility.
N_{FGS} = Total number of fuel gas systems at the facility.

(j) **Coke Calcining.** The operator shall calculate GHG emissions according to the applicable provisions in paragraphs (j)(1) through (j)(3) of this section.

(1) If you operate and maintain a CEMS that measures CO_2 emissions according to WCI.20, you must calculate and report CO_2 emissions for coke calcining by following the CEMS Calculation Methodology specified in WCI.20. If the coke calcining unit is not equipped with CEMS must either install a CEMS that complies with the CEMS requirements in WCI.23, or follow the requirements of paragraph (j)(2) of this section.

(2) Calculate the CO_2 emissions from the coke calcining unit using Equation 200-27 of this section.

$$CO_2 = 3.664 \times \left(M_{in} \times CC_{GC} - (M_{out} + M_{dust}) \times CC_{MPC}\right)$$ **Equation 200-27**

Where:
CO_2 = Annual CO_2 emissions (tonnes/year).
M_{in} = Annual mass of green coke fed to the coke calcining unit from facility records (tonnes/year).
CC_{GC} = Average mass fraction carbon content of green coke from facility measurement data (tonne carbon/tonne green coke).
M_{out} = Annual mass of marketable petroleum coke produced by the coke calcining unit from facility records (tonnes petroleum coke/year).
M_{dust} = Annual mass of petroleum coke dust collected in the dust collection system of the coke calcining unit from facility records (tonne petroleum coke dust/year)
CC_{MPC} = Average mass fraction carbon content of marketable petroleum coke produced by the coke calcining unit from facility measurement data (tonne carbon/tonne petroleum coke).
3.664 = Ratio of molecular weights, carbon dioxide to carbon

(3) For all coke calcining units, use the CO_2 emissions from the coke calcining unit calculated in paragraphs (j)(1) or (j)(2), as applicable, and calculate CH_4 and N_2O using the following methods:

(A) Calculate CH_4 emissions using either unit specific measurement data, a unit-specific emission factor based on a source test of the unit, or Equation 200-28 of this section.

$$CH_4 = \left(CO_2 \times \frac{EmF_2}{EmF_1} \right)$$ **Equation 200-28**

Where:

CH_4 = Annual methane emissions (tonnes CH_4/year).

CO_2 = Emission rate of CO_2 calculated in paragraphs (j)(1) and (j)(2) of this section, as applicable (tonnes/year).

EmF_1 = Default CO_2 emission factor for petroleum coke (97 kg CO_2/GJ).

EmF_2 = Default CH_4 emission factor of 2.8 x 10^{-3} kg CH_4/GJ).

(B) Calculate N_2O emissions using either unit specific measurement data, a unit-specific emission factor based on a source test of the unit, or Equation 200-29 of this section.

$$N_2O = \left(CO_2 \times \frac{EmF_3}{EmF_1} \right)$$ **Equation 200-29**

Where:

N_2O = Annual nitrous oxide emissions (tonnes N_2O/year).

CO_2 = Emission rate of CO_2 from paragraphs (j)(1) and (j)(2) of this section, as applicable (tonnes/year).

EmF_1 = Default CO_2 emission factor for petroleum coke (97 kg CO_2/GJ)

EmF_3 = Default N_2O emission factor of 5.7 x 10^{-4} kg N_2O/GJ.

(k) **Uncontrolled Blowdown Systems**. For uncontrolled blowdown systems, you must use the methods for process vents in paragraph (b) of this section.

(l) **Loading Operations**. For crude oil, intermediate, or product loading operations for which the equilibrium vapor-phase concentration of methane is 0.5 volume percent or more, calculate CH_4 emissions from loading operations using product-specific, vapor-phase methane composition data (from measurement data or process knowledge) and the emission estimation procedures provided in Section 5.2 of the AP-42: "Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources." For loading operations in which the equilibrium vapor-phase concentration of methane is less than 0.5 volume percent, you may assume zero methane emissions.

(m) **Delayed coking units.** Calculate the CH_4 emissions from the depressurization of the coking unit vessel (i.e., the "coke drum") to the atmosphere using either of the methods provided in paragraphs (m)(1) or (m)(2), provided no water or steam is added to the vessel once it is vented to the atmosphere. You must use the method in paragraph (m)(1) of this section if you add water or steam to the vessel after it is vented to the atmosphere.

(1) Use the process vent method in paragraph (b) of this section and also calculate the CH_4 emissions from the subsequent opening of the vessel for coke cutting operations using Equation 200-30 of this section. If you have coke drums or vessels of different dimensions, use Equation 200-30 for each set of coke drums

or vessels of the same size and sum the resultant emissions across each set of coke drums or vessels to calculate the CH_4 emissions for all delayed coking units.

$$CH_4 = \left(N \times H \times \frac{(P_{CV} + 101.325)}{101.325} \times f_{void} \times \frac{\pi \times D^2}{4} \times \frac{16}{MVC} \times MF_{CH4} \times 0.001 \right) \quad \textbf{Equation 200-30}$$

Where:

CH_4	=	Annual methane emissions from the delayed coking unit vessel opening (tonnes/year).
N	=	Cumulative number of vessel openings for all delayed coking unit vessels of the same dimensions during the year.
H	=	Height of coking unit vessel (metres).
P_{CV}	=	Gauge pressure of the coking vessel when opened to the atmosphere prior to coke cutting or, if the alternative method provided in paragraph (m)(2) of this section is used, gauge pressure of the coking vessel when depressurization gases are first routed to the atmosphere (kilopascals).
101.325	=	Assumed atmospheric pressure (kilopascals).
f_{void}	=	Volumetric void fraction of coking vessel prior to steaming based on engineering judgement at reference temperature and pressure conditions as used by the facility (Rm^3 gas/m^3 of vessel).
D	=	Diameter of coking unit vessel (metres).
16	=	Molecular weight of CH_4 (kg/kg-mole).
MVC	=	Molar volume factor at the same reference conditions as the cooking vessel (Rm^3/kg-mole).
	=	8.3145 * [273.16 + reference temperature in °C]/[reference pressure in kilopascal].
MF_{CH4}	=	Average mole fraction of methane in coking vessel gas based on the analysis of at least two samples per year, collected at least four months apart (kg-mole CH_4/kg-mole gas, wet basis).
0.001	=	Conversion factor (tonne/kg).

(2) Calculate the CH_4 emissions from the depressurization vent and subsequent opening of the vessel for coke cutting operations using Equation 200-30 of this section and the pressure of the coking vessel when the depressurization gases are first routed to the atmosphere. If you have coke drums or vessels of different dimensions, use Equation 200-30 for each set of coke drums or vessels of the same size and sum the resultant emissions across each set of coke drums or vessels to calculate the CH_4 emissions for all delayed coking units.

§ WCI.204 Sampling, Analysis, and Measurement Requirements

Where the ASTM or other consensus based organization analysis or other measurement methods specified in this subsection are not offered by any supplier in the Jurisdiction, you may request approval by the Director in writing for another equivalent method.

(a) Catalyst Regeneration.

(1) For FCCUs and fluid coking units, the operators shall measure the following parameters:

(A) The daily oxygen concentration in the oxygen enriched air stream inlet to the regenerator.

(B) Continuous measurements of the volumetric flow rate of air and oxygen enriched air entering the regenerator.

(C) Weekly periodic measurements of the CO_2, CO and O_2 concentrations in the regenerator exhaust gas (or continuous measurements if the equipment necessary to make continuous measurements is already in place).

(D) Daily determinations of the carbon content of the coke burned.

(E) The number of hours of operation.

(F) The measured daily or weekly values can be used to derive the minute or hourly parameters as required by the corresponding equations.

(2) For periodic catalyst regeneration, the operators shall measure the following parameters.

(A) The mass of catalyst regenerated in each regeneration cycle.

(B) The weight fraction of carbon on the catalyst prior to and after catalyst regeneration.

(3) For continuous catalyst regeneration in operations other than FCCUs and fluid cokers, the operators shall measure the following parameters.

(A) The hourly catalyst regeneration rate.

(B) The weight fraction of carbon on the catalyst prior to and after catalyst regeneration.

(C) The number of hours of operation.

(b) Process vents. Operators shall measure the following parameters for each process vent.

(1) The vent flow rate for each venting event from measurement data, process knowledge or engineering estimates.

(2) The molar fraction of CO_2, N_2O, and CH_4 in the vent gas stream during each venting event from measurement data, process knowledge or engineering estimates.

(3) The duration of each venting event.

(c) Asphalt Production. Operators shall measure the mass of asphalt blown.

(d) Sulphur Recovery. The operator shall measure the volumetric flow rate of acid gas to the SRU. If using source specific molar fraction value that is based on measurements value instead of the default factor or engineering estimates, the person shall conduct an annual test of the molar fraction value.

(e) Flares and Other Control Devices. The operator shall measure the following:

(1) If you have a continuous flow monitor on the flare, you must use the measured flow rates when the monitor is operational and the flow rate is within the calibrated range of the

measurement device to calculate the flare gas flow. If you do not have a continuous flow monitor on the flare and for periods when the monitor is not operational or the flow rate is outside the calibrated range of the measurement device, you must use engineering calculations, company records, or similar estimates of volumetric flare gas flow.

(2) If using the method specified in WCI.203(e)(2)(A)(i), monitor the carbon content of the flare gas daily if the flare is already equipped with the necessary measurement devices (at least weekly if not).

(3) If using the method specified in WCI.203(e)(2)(A)(ii), monitor the high heat value of the flare gas daily if the flare is already equipped with the necessary measurement devices (at least weekly if not).

(f) Storage Tanks. The operator shall determine the annual throughput of crude oil, naphtha, distillate oil, asphalt, and gas oil for each storage tank using company record or applicable plant instruments.

(g) Wastewater Treatment. Operators shall measure the following parameters.

(1) You must collect samples representing wastewater influent to the anaerobic wastewater treatment process, following all preliminary and primary treatment steps (e.g., after grit removal, primary clarification, oil-water separation, dissolved air flotation, or similar solids and oil separation processes). You must collect and analyze samples for COD or BOD_5 concentration once each calendar week.

(2) You must measure the flowrate of wastewater entering anaerobic wastewater treatment process once each calendar week. The flow measurement location must correspond to the location used to collect samples analyzed for COD or BOD_5 concentration.

(3) The quarterly nitrogen content of the wastewater.

(h) Oil-Water Separators. Operators shall measure the daily volume of waste water treated by the oil-water separators .

(i) Coke Calcining. Determine the mass of petroleum coke as required using measurement equipment used for accounting purposes. Determine the carbon content of petroleum coke as using any one of the following methods:

(1) ASTM D3176-89 (Reapproved 2002) Standard Practice for Ultimate Analysis of Coal and Coke.

(2) ASTM D5291-02 (Reapproved 2007) Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants.

(3) ASTM D5373-08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal

§ WCI.205 Procedures for Estimating Missing Data.

A complete record of all measured parameters used in the GHG emissions calculations is required (e.g., concentrations, flow rates, fuel heating values, carbon content values). Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a CEMS malfunctions during unit operation or if a required fuel sample is not taken), a substitute data value for the missing parameter shall be used in the calculations.

(a) For stationary combustion sources, use the missing data procedures in WCI.20.
(b) For each missing value of the heat content, carbon content, or molecular weight of the fuel, substitute the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If the "after" value is not obtained by the end of the reporting year, you may use the "before" value for the missing data substitution. If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.
(c) For missing CO_2, CO, O_2, CH_4, or N_2O concentrations, gas flow rate, and percent moisture, the substitute data values shall be the best available estimate(s) of the parameter(s), based on all available process data (e.g., processing rates, operating hours, etc.). The owner or operator shall document and keep records of the procedures used for all such estimates.

§ WCI.206 Definitions

Except as specified in this section, all terms used in this subpart have the same meaning given in the General Provisions.

Unstabilized crude oil means crude oil that is pumped from the well to a pipeline or pressurized storage vessel for transport to the refinery without intermediate storage in a storage tank at atmospheric pressures. Unstabilized crude oil is characterized by having a true vapor pressure of 5 pounds per square inch absolute (psia) or greater.

Table 200-1. Coke burn rate material balance and conversion factors

	(kg min)/(hr dRm³%)	(lb min)/(hr dscf %)
K_1	0.2982	0.0186
K_2	2.0880	0.1303
K_3	0.0994	0.0062

Table 200-2. Default MCF Values for Industrial Wastewater

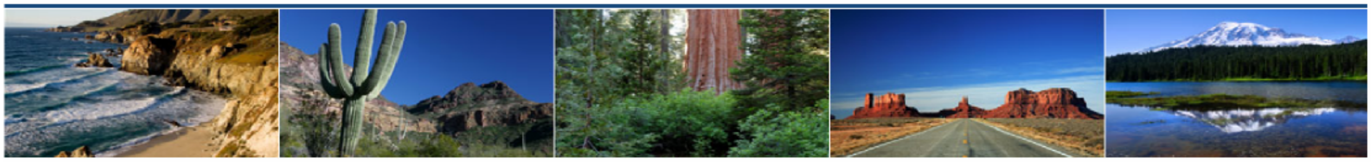
Type of Treatment and Discharge Pathway or System	Comments	MCF	Range
Untreated			
Sea, river and lake discharge	Rivers with high organic loading may turn anaerobic, however this is not considered here	0.1	0 - 0.2
Treated			
Aerobic treatment plant	Well maintained, some CH_4 may be emitted from settling basins	0	0 – 0.1
Aerobic treatment plant	Not well maintained, overloaded	0.3	0.2 – 0.4
Anaerobic digester for sludge	CH_4 recovery not considered here	0.8	0.8 – 1.0
Anaerobic reactor	CH_4 recovery not considered here	0.8	0.8 – 1.0
Anaerobic shallow lagoon	Depth less than 2 Meters	0.2	0 – 0.3
Anaerobic deep lagoon	Depth more than 2 Meters	0.8	0.8 – 1.0
For CH_4 generation capacity (B) in kg CH_4/kg COD, use default factor of 0.25 kg CH_4/kg COD.			

The emission factor for N_2O from discharged wastewater (EF_{N2O}) is 0.005 kg N_2O-N/kg-N. MCF = methane conversion factor (the fraction of waste treated anaerobically). COD = chemical oxygen demand (kg COD/m^3).

Table 200-3. Emission Factors for Oil/Water Separators

Separator Type	Emission factor (EF_{sep})[a] kg NMHC/m^3 wastewater treated
Gravity type - uncovered	1.11×10^{-1}
Gravity type - covered	3.30×10^{-3}
Gravity type – covered and connected to destruction device	0
DAF[b] or IAF[c] - uncovered	4.00×10^{-3}[d]
DAF or IAF - covered	1.20×10^{-04}[d]
DAF or IAF – covered and connected to a destruction device	0

[a] EFs do not include ethane
[b] DAF = dissolved air flotation type
[c] IAF = induced air flotation device
[d] EFs for these types of separators apply where they are installed as secondary treatment systems



§ WCI.210 PULP AND PAPER MANUFACTURING

§ WCI.211 Source Category Definition

The pulp and paper manufacturing source category consists of facilities that produce market pulp (i.e., stand-alone pulp facilities), manufacture pulp and paper (i.e., integrated facilities), produce paper products from purchased pulp, produce secondary fibre from recycled paper, convert paper into paperboard products (e.g., containers), or operate coating and laminating processes.

§ WCI.212 Greenhouse Gas Reporting Requirements

In addition to the information required by regulation, the annual emissions report must contain the following information:

(a) Annual CO_2, biogenic CO_2, CH_4, and N_2O process emissions from all recovery units and kilns combined in tonnes, as specified in WCI.213.

(b) Annual CO_2 emissions from addition of makeup chemicals ($CaCO_3$ and Na_2CO_3) in the chemical recovery areas of chemical pulp mills.

(c) CO_2, N_2O and CH_4 emissions from electricity generation units in tonnes, as specified in WCI.43. CO_2, N_2O, and CH_4 emissions from stationary combustion units in tonnes, as specified in WCI.23.

(d) Annual consumption of carbonate in tonnes.

(e) Annual black liquor production in tonnes.

(f) Annual CH_4 and N_2O emissions from onsite wastewater treatment plants in tonnes, as specified in WCI.200 (if required by regulation)

§ WCI.213 Calculation of GHG Emissions

Calculate emissions from each unit (i.e., kraft or soda chemical recovery furnace, sulfite chemical recovery combustion unit, stand-alone semichemical recovery combustion unit, or kraft or soda pulp mill lime kiln) as specified under paragraphs (a) through (d) of this section. CH_4 and N_2O emissions must be calculated as the sum of emissions from combustion of fossil fuels and combustion of biomass in spent liquor solids.

(a) Calculate fossil-fuel based CO_2 emissions from direct measurement of fossil fuels consumed and the methodology for stationary combustion sources specified by WCI.20, or the methodology for electricity generation specified by WCI.43, for the appropriate fuel type. For kraft or soda pulp mill lime kilns, if WCI.20 allows the use of default emission factors, use the default CO_2 emission factors listed in Table 210-1.

(b) Calculate fossil-fuel based CH_4 and N_2O emissions from direct measurement of fossil fuels consumed, default HHV, and default emission factors according to the methodology specified by WCI.20 or WCI.43. For kraft or soda pulp mill lime kilns, use the default CH_4 and N_2O emission factors listed in Table 210-1.

(c) Calculate biogenic CO_2 emissions and emissions of CH_4 and N_2O from biomass as specified under subparagraphs (1) through (3).

(1) For kraft or soda chemical recovery furnaces, calculate emissions using Equation 210-1:

$$Emissions = Solids \times HHV \times EF \qquad \textbf{Equation 210-1}$$

Where:

Emissions	=	Biogenic CO_2 emissions and emissions of CH_4 and N_2O from biomass (spent liquor solids) combustion (tonnes/year).
Solids	=	Mass of spent liquor solids combusted (tonnes/year).
HHV	=	Annual high heat value of spent liquor solids (GJ/kg).
EF	=	Default emission factor for CO_2, CH_4, and N_2O from Table 210-2 (kg/GJ)

(2) For sulfite or stand-alone semichemical chemical recovery combustion units, calculate CO_2 emissions using Equation 210-2:

$$E_{CO2} = 3.664 \times Solids \times CC \qquad \textbf{Equation 210-2}$$

Where:

E_{CO2}	=	Biogenic CO_2 emissions from spent liquor solids combustion (tonnes/year).
3.664	=	Ratio of molecular weights, CO_2 to carbon.
Solids	=	Mass of spent liquor solids combusted (tonnes/year).
CC	=	Annual carbon content of spent liquor solids (percent by weight, expressed as a decimal fraction).

(3) For sulfite or stand-alone semichemical chemical recovery combustion units, calculate emissions of CH_4 and N_2O from biomass using Equation 210-1.

(d) For make-up chemical use, calculate CO_2 emissions by using direct or indirect measurement of the quantity of chemicals added and ratios of the molecular weights of CO_2 and make-up chemicals using Equation 210-3:

$$CO_2 = \left(\left[M_{CaCO3} \times \frac{44}{100} \right] + \left[M_{Na2CO3} \times \frac{44}{105.99} \right] \right) \qquad \textbf{Equation 210-3}$$

Where:

CO_2	=	CO_2 emissions from make-up chemicals (tonnes/year).
M_{CaCO3}	=	Make-up quantity of $CaCO_3$ used for reporting year (tonnes/year).
M_{Na2CO3}	=	Make-up quantity of Na_2CO_3 used for reporting year (tonnes/year).
44	=	Molecular weight of CO_2.
100	=	Molecular weight of $CaCO_3$.
105.99	=	Molecular weight of Na_2CO_3.

§ WCI.214 Sampling, Analysis, and Measurement Requirements

At least annually, determine the following fuel properties. If measurements are performed more frequently than annually, then fuel properties must be based on the average of the representative measurements made during the year.

(a) Determine high heat values of black liquor using Technical Association of the Pulp and Paper Industry (TAPPI) T684 om-06 “Gross High Heating Value of Black Liquor”.

(b) Determine annual mass of spent liquor solids using one of the methods specified in subparagraph (1) or (2)

(1) Measure mass of annual spent liquor solids using TAPPI T650 om-05 “Solids Content of Black Liquor”.

(2) Determine mass of annual spent liquor solids based on records of measurements made with an online measurement system that determines the mass of spent liquor solids fired in a chemical recovery furnace or chemical recovery combustion unit. Measure the quantity of black liquor produced each month.

(c) Determine carbon content using ASTM D5373-08 “Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal”, or ASTM 5291 - Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants.

§ WCI.215 Procedures for Estimating Missing Data

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation or if a required sample is not taken), a substitute data value for the missing parameter shall be used in the calculations, according to the requirements of paragraphs (a) through (c) of this section:

a) There are no missing data procedures for measurements of heat content and carbon content of spent pulping liquor. A re-test must be performed if the data from any annual measurements are determined to be invalid.
b) For missing measurements of the mass of spent liquor solids or spent pulping liquor flow rates, use the lesser value of either the maximum mass or fuel flow rate for the combustion unit, or the maximum mass or flow rate that the fuel meter can measure.
c) For the use of makeup chemicals ($CaCO_3$ and Na_2CO_3), the substitute data value shall be the best available estimate of makeup chemical consumption, based on available data (e.g., past accounting records, production rates). The owner or operator shall document and keep records of the procedures used for all such estimates.

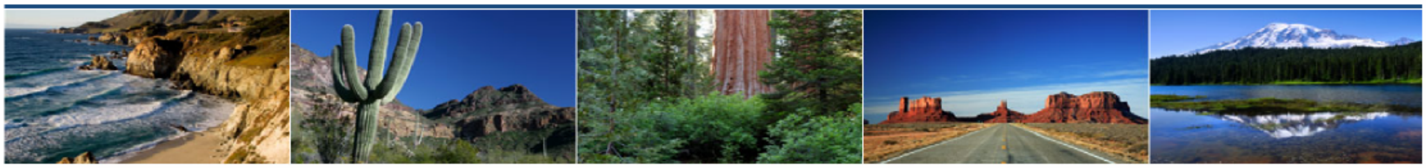
Table 210-1 . Kraft Lime Kiln and Calciner Emissions Factors for Fossil Fuel-Based CO_2, CH_4, and N_2O

Fuel	Fossil Fuel-Based Emissions Factors (kg/GJ HHV)					
	Kraft Lime Kilns			Kraft Calciners		
	CO_2	CH_4	N_2O	CO_2	CH_4	N_2O
Residual Oil	72.7	0.0026	0	72.7	0.0026	0.00028
Distillate Oil	69.7			69.7		0.00038
Natural Gas	53.1			53.1		0.00009
Biogas	0			0		0.00009

Table 210-2. Kraft Pulping Liquor Emissions Factors for Biomass-Based CO_2, CH_4, and N_2O

Wood Furnish	Biomass-Based Emissions Factors (kg/GJ HHV)		
	CO_2[a]	CH_4	N_2O
North American Softwood	89.5	0.028	0.0047
North American Hardwood	88.8		
Bagasse	90.5		
Bamboo	88.8		
Straw	90.2		

[a] Includes emissions from both the recovery furnace and pulp mill lime kiln.



§ WCI.220 SODA ASH MANUFACTURING

§ WCI.221 Source Category Definition

A soda ash manufacturing facility is any facility with a manufacturing line that produces soda ash by one of the methods in paragraphs (a) through (c) of this section:

(a) Calcining trona.

(b) Calcining sodium sesquicarbonate.

(c) Using a liquid alkaline feedstock process that directly produces CO_2.

In the context of the soda ash manufacturing sector, "calcining" means the thermal/chemical conversion of the bicarbonate fraction of the feedstock to sodium carbonate.

§ WCI.222 Greenhouse Gas Reporting Requirements

In addition to the information required by regulation, each annual report must contain the following information

(a) CO_2 process emissions from the soda ash manufacturing facility.

(b) CO_2, CH_4 and N_2O combustion emissions must be calculated and reported under WCI.20 (General Stationary Combustion) by following the requirements of WCI.20.

(c) If a CEMS is used to measure CO_2 emissions, then you must report under this method the relevant information required under WCI.23.

(d) Annual consumption of trona or liquid alkaline feedstock for each manufacturing line (tonnes).

(e) Annual production of soda ash (tonnes).

(f) Annual quantity of generated CO_2 recycled to carbonation towers (tonnes), if applicable.

(g) Number of times missing data procedures were used.

§ WCI.223 Calculation of Greenhouse Gas Emissions

Calculate and report the annual process CO_2 emissions from each soda ash manufacturing line using the procedures specified in paragraph (a) or (b) of this section.

(a) For each soda ash manufacturing line that meets the conditions specified in WCI.23(e), calculate and report under this method the combined process and combustion CO_2 emissions by operating and maintaining a CEMS to measure CO_2 emissions according to Calculation Methodology 4 specified in WCI.23(d) and all associated requirements.

(b) For each soda ash manufacturing line that is not subject to the requirements in paragraph (a) of this section, calculate and report the process CO_2 emissions from the soda ash manufacturing line by using the procedure in either paragraphs (b)(1), (b)(2), or (b)(3) of this section; and the combustion CO_2 emissions using the procedure in paragraph (b)(4) of this section.

(1) Calculate and report under this method the combined process and combustion CO_2 emissions by operating and maintaining a CEMS to measure CO_2 emissions according to Calculation Methodology 4 specified in WCI.23(d) and all associated requirements for Calculation Method 4 in WCI.23(d) (General Stationary Combustion).

(2) Use either Equation 220-1 or Equation 220-2 of this section to calculate annual CO_2 process emissions from each manufacturing line that calcines trona to produce soda ash:

$$E_k = \sum_{n=1}^{12} [(IC_T)_n * (T_t)_n] * \frac{0.097}{1} \qquad \textbf{Equation 220-1}$$

$$E_k = \sum_{n=1}^{12} [(IC_{sa})_n * (T_{sa})_n] * \frac{0.138}{1} \qquad \textbf{Equation 220-2}$$

Where:

E_k = Annual CO_2 process emissions from each manufacturing line, *k* (tonnes).

$(IC_T)_n$ = Inorganic carbon content (percent by weight, expressed as a decimal fraction) in trona input, from the carbon analysis results for month *n*. This represents the ratio of trona to trona ore.

$(IC_{sa})_n$ = Inorganic carbon content(percent by weight, expressed as a decimal fraction) in soda ash output, from the carbon analysis results for month *n*. This represents the purity of the soda ash produced.

$(T_t)_n$ = Mass of trona input in month *n* (tonnes).

$(T_{sa})_n$ = Mass of soda ash output in month *n* (tonnes).

0.097/1 = Ratio of tonne of CO_2 emitted for each tonne of trona.

0.138/1 = Ratio of tonne of CO_2 emitted for each tonne of soda ash produced.

(3) Site-specific emission factor method. Use Equations 220-3, 220-4, and 220-5 of this section to determine annual CO_2 process emissions from manufacturing lines that use the liquid alkaline feedstock process to produce soda ash. You must conduct an annual performance test and measure CO_2 emissions and flow rates at all process vents from the mine water stripper/evaporator for each manufacturing line and calculate CO_2 emissions as described in paragraphs (b)(3)(i) through (b)(3)(iv) of this section.

(i) During the performance test, you must measure the process vent flow from each process vent during the test and calculate the average rate for the test period in tonnes per hour.

(ii) Using the test data, you must calculate the hourly CO_2 emission rate using Equation 220-3 of this section:

$$ER_{CO2} = [(C_{co2} * 10000) * 4.16 \times 10^{-8} * 44] * (Q * 60) * 0.001 \quad \textbf{Equation 220-3}$$

Where:

ER_{CO2}	=	CO_2 mass emission rate (tonnes/hour).
C_{CO2}	=	Hourly CO_2 concentration (per cent CO_2) as determined by WCI.224(c).
10000	=	Conversion factor from per cent to parts per million
4.16×10^{-8}	=	Conversion factor from ppm to kg-mole/dsm^3 (kg-mole/dsm^3/ppm).
44	=	kg per kg-mole of carbon dioxide.
Q	=	Stack gas volumetric flow rate per minute (dsm^3 per minute).
60	=	Minutes per hour
0.001	=	Conversion factor from kg to tonnes (tonnes/kg)

(iii) Using the test data, you must calculate a CO_2 emission factor for the process using Equation 220-4 of this section:

$$EF_{CO2} = \frac{ER_{CO2}}{V_t} \quad \textbf{Equation 220-4}$$

Where:

EF_{CO2}	=	CO_2 emission factor (tonnes CO_2/tonne of process vent flow from mine water stripper/evaporator).
ER_{CO2}	=	CO_2 mass emission rate (tonnes/hour).
V_t	=	Process vent mass flow rate from mine water stripper/evaporator during annual performance test (tonnes/hour).

(iv) Calculate annual CO_2 process emissions from each manufacturing line using Equation 220-5 of this section:

$$E_k = EF_{CO2} * V_a * H \quad \textbf{Equation 220-5}$$

Where:

E_k	=	Annual CO_2 process emissions for each manufacturing line, *k* (tonnes).
EF_{CO2}	=	CO_2 emission factor (tonnes CO_2/tonne of process vent flow from mine water stripper/evaporator).

V_a = Annual process vent mass flow rate from mine water stripper/evaporator (tonnes/hour).

H = Annual operating hours for the each manufacturing line.

(4) Calculate and report under WCI.20 (General Stationary Fuel Combustion Sources) the combustion CO_2, CH_4, and N_2O emissions in the soda ash manufacturing line according to the applicable requirements of WCI.20.

§ WCI.224 Sampling, Analysis, and Measurement Requirements

Section WCI.223 provides four different procedures for emission calculations. The appropriate paragraphs (a) through (d) of this section should be used for the procedure chosen.

(a) If you determine your emissions using WCI.223 (b)(2), Equation 220-1 of this subpart you must:

(1) Determine the monthly inorganic carbon content of the trona from a weekly composite analysis for each soda ash manufacturing line, using a modified version of ASTM E359-00(Reapproved 2005)e1, Standard Test Methods for Analysis of Soda Ash (Sodium Carbonate). ASTM E359-00(Reapproved 2005)e1 is designed to measure the total alkalinity in soda ash, not in trona. The modified method of ASTM E359-00 adjusts the regular ASTM method to express the results in terms of trona. Although ASTM E359-00(Reapproved 2005)e1 uses manual titration, suitable autotitrators may also be used for this determination.

(2) Measure the mass of trona input produced by each soda ash manufacturing line on a monthly basis using belt scales or methods used for accounting purposes.

(3) Document the procedures used to ensure the accuracy of the monthly measurements of trona consumed.

(b) If you calculate CO_2 process emissions based on soda ash production using WCI.223(b)(2), Equation 220-2 of this subpart, you must:

(1) Determine the inorganic carbon content of the soda ash (i.e., soda ash purity) using ASTM E359-00(Reapproved 2005)e1 Standard Test Methods for Analysis of Soda Ash (Sodium Carbonate). Although ASTM E359-00(Reapproved 2005) uses manual titration, suitable autotitrators may also be used for this determination.

(2) Measure the mass of soda ash produced by each soda ash manufacturing line on a monthly basis using belt scales, by weighing the soda ash at the truck or rail load out points of your facility, or methods used for accounting purposes.

(3) Document the procedures used to ensure the accuracy of the monthly measurements of soda ash produced.

(c) If you calculate CO_2 emissions using the site-specific emission factor method in WCI.223(b)(3), you must:

(1) Conduct an annual performance test that is based on representative performance (i.e., performance based on normal operating conditions) of the affected process.

(2) Sample the stack gas and conduct three emissions test runs of 1 hour each.

(3) Conduct the stack test using EPA Method 3A at 40 CFR part 60, appendix A-2 to measure the CO2 concentration; and Method 2, 2A, 2C, 2D, or 2F at 40 CFR part 60, appendix A-1 or Method 26 at 40 CFR part 60, appendix A-2 to determine the stack gas volumetric flow rate. All QA/QC procedures specified in the reference test methods and any associated performance specifications apply. For each test, the facility must prepare an emission factor determination report that must include the items in paragraphs (c)(3)(i) through (c)(3)(iii) of this section.

(i) Analysis of samples, determination of emissions, and raw data.

(ii) All information and data used to derive the emissions factor(s).

(iii) You must determine the average process vent flow rate from the mine water stripper/evaporator during each test and document how it was determined.

(4) You must also determine the annual vent flow rate from the mine water stripper/evaporator from monthly information using the same plant instruments or procedures used for accounting purposes (i.e., volumetric flow meter).

WCI.225 Procedures for Estimating Missing Data

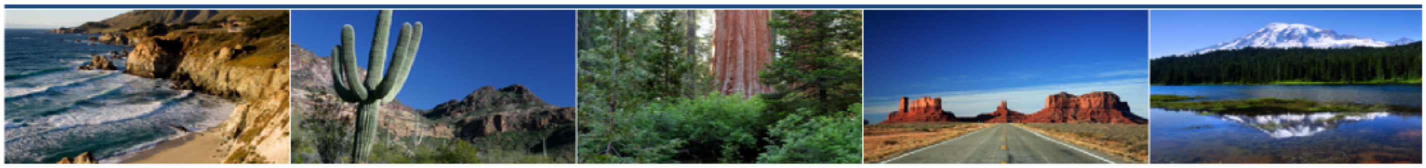
For the emission calculation methodologies in WCI.223(b)(2)and (b)(3), a complete record of all measured parameters used in the GHG emissions calculations is required (e.g., inorganic carbon content values, etc.). Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in the paragraphs (a) through (d) of this section. You must document and keep records of the procedures used for all such missing value estimates.

(a) For each missing value of the weekly composite of inorganic carbon content of either soda ash or trona, the substitute data value shall be the arithmetic average of the quality-assured values of inorganic carbon contents from the week immediately preceding and the week immediately following the missing data incident. If no quality-assured data on inorganic carbon contents are available prior to the missing data incident, the substitute data value shall be the first quality-assured value for carbon contents obtained after the missing data period.

(b) For each missing value of either the monthly soda ash production or the trona consumption, the substitute data value shall be the best available estimate(s) of the parameter(s), based on all available process data or data used for accounting purposes.

(c) For each missing value collected during the performance test (hourly CO_2 concentration, stack gas volumetric flow rate, or average process vent flow from mine water stripper/evaporator during performance test), you must repeat the annual performance test following the calculation and monitoring and QA/QC requirements under WCI.223(b)(3) and WCI.224(c).

(d) For each missing value of the monthly process vent flow rate from mine water stripper/evaporator, the substitute data value shall be the best available estimate(s) of the parameter(s), based on all available process data or the lesser of the maximum capacity of the system or the maximum rate the meter can measure.



§ WCI.230 ELECTRICITY TRANSMISSION (AND EMISSIONS FROM ELECTRICAL EQUIPMENT IN ELECTRICITY GENERATION)

§ WCI.231 Source Category Definition

Sulfur hexafluoride (SF_6) and perfluorocarbons (PFCs) are used as gaseous dielectric mediums for electric power distribution equipment, including transmission and distribution systems, substations, high-voltage circuit breakers, switches, and other electrical equipment. This category includes fugitive emissions from equipment that is located at a facility that the operator is responsible for maintaining in proper working order.

§ WCI.232 Greenhouse Gas Reporting Requirements

For each facility, the emissions data report shall include the following information:

(a) Annual greenhouse gas emissions in tonnes, reported as follows:

(1) Fugitive SF_6 emitted from equipment.

(2) Fugitive PFCs emitted from equipment

§ WCI.233 Calculation of SF_6 Emissions

SF_6 emissions must be calculated using either a mass-balance or direct measurement approach. Section (a) describes the mass balance approach; section (b) describes the direct measurement approach.

(a) Mass Balance Approach.

(1) Calculate the annual SF_6 emissions using a mass balance approach that tracks and systematically accounts for all operator uses of SF_6, as follows. Any quantity of SF_6 that cannot be accounted for is then assumed to have been emitted into the atmosphere.

(2) Calculate the change in inventory of SF_6 in storage using Equation 230-1.

$$\Delta S_{Inv} = S_{Inv-Begin} - S_{Inv-End} \qquad \textbf{Equation 230-1}$$

Where:

ΔS_{Inv} = Change in inventory of SF_6 in storage, kilograms ("Storage" includes cylinders, gas carts, and other storage containers, but excludes equipment. Value will be negative if quantity of SF_6 increases during the year);

$S_{Inv-Begin}$ = Quantity of SF_6 in storage at the beginning of the year, kilograms;

$S_{Inv-End}$ = Quantity of SF_6 in storage at the end of the year, kilograms.

(3) Calculate the sum of all SF_6 acquired from other entities during the year either in storage containers or in equipment using Equation 230-2.

Equation 230-2

$$S_{PA} = S_{Cyl} + S_{Equip} + S_{\mathrm{Re}cyc-ret}$$

Where:

S_{PA} = Sum of all SF_6 acquired from other entities during the year either in storage containers or in equipment, kilograms;

S_{Cyl} = Quantity of SF_6 purchased from producers or distributors in cylinders, kilograms;

S_{Equip} = Quantity of SF_6 provided by equipment manufacturers with/inside equipment, kilograms;

$S_{Recyc-ret}$ = Quantity of SF_6 returned to site after off-site recycling, kilograms.

(4) Calculate the sum of all SF_6 sold or otherwise disbursed during the year either in storage containers or in equipment using Equation 230-3.

$$S_{SD} = S_{Sales} + S_{\mathrm{Re}turns} + S_{Destruct} + S_{\mathrm{Re}cyc-off}$$ **Equation 230-3**

Where:

S_{SD} = Sum of all SF_6 sold or otherwise disbursed during the year either in storage containers or in equipment, kilograms;

S_{Sales} = Quantity of SF_6 sold to other entities (including gas left in equipment that is sold), kilograms;

$S_{Returns}$ = Quantity of SF_6 returned to suppliers, kilograms;

$S_{Destruct}$ = Quantity of SF_6 sent to destruction facilities, kilograms;

$S_{Recyc-off}$ = Quantity of SF_6 sent off-site for recycling, kilograms.

(5) Calculate the net increase in nameplate capacity of equipment using Equation 230-4.

$$\Delta S_{Cap} = S_{Cap-new} - S_{Cap-retire}$$

Equation 230-4

Where:

ΔS_{Cap} = Net increase in total nameplate capacity of equipment using SF_6 in storage, kilograms ("Total nameplate capacity" refers to the full and proper charge of the equipment rather than to the actual charge, which may reflect leakage.);

$S_{Cap-new}$ = Total nameplate capacity (proper full charge) of new equipment, kilograms;

$S_{Cap-retire}$ = Total nameplate capacity (proper full charge) of retired or sold equipment, kilograms.

(6) Calculate total annual emissions using Equation 230-5.

$$S = \left(\Delta S_{Inv} + S_{PA} - S_{SD} - \Delta S_{Cap} \right) / 1{,}000 \qquad \textbf{Equation 230-5}$$

Where:

S	=	Annual SF_6 emissions, tonnes;
ΔS_{Inv}	=	Change in inventory of SF_6 in storage, kilograms ("Storage" includes cylinders, gas carts, and other storage containers, but excludes equipment. Value will be negative if quantity of SF_6 increases during the year);
S_{PA}	=	Sum of all SF_6 acquired during the year either in storage containers or in equipment, kilograms;
S_{SD}	=	Sum of all SF_6 sold or otherwise disbursed during the year either in storage containers or in equipment, kilograms;
ΔS_{Cap}	=	Net increase in total nameplate capacity of equipment using SF_6 in storage, kilograms ("Total nameplate capacity" refers to the full and proper charge of the equipment rather than to the actual charge, which may reflect leakage.);
1,000	=	Factor to convert kilograms to tonnes.

(b) Direct Measurement Approach.

SF_6 emissions are estimated by directly measuring the mass of SF_6 added to electrical equipment during operation (operation phase) and the amount of SF_6 collected from any decommissioned equipment (decommissioning phase).

In the operation phase, SF_6 added to equipment can be measured using one of two methods: automated mass-flow measurement or weigh-scale measurement. In automated mass-flow measurement, mass-flow meters attached to electrical equipment directly measure the amount of SF_6 added to equipment. In weigh-scale measurement, an SF_6 cylinder is measured before and after its contents are added to electrical equipment with the difference being equal to the SF_6 added to the equipment. Annual SF_6 emissions for both methods are calculated according to Equation 230-6.

$$S_O = \sum_{i}^{N} s_i \qquad \textbf{Equation 230-6}$$

Where:

S_O	=	Annual SF_6 emissions during operation phase, kilograms;
N	=	Number of SF_6 additions in a given year;
s_i	=	SF_6 added to equipment during addition *i*, kilograms.

Annual SF_6 emissions during the decommissioning phase are calculated according to Equation 230-7.

$$S_D = \sum_{i}^{N}(NC_i - S_i)$$

Equation 230-7

Where:

S_D = Annual SF_6 emissions during decommissioning phase, kilograms;

N = Number of equipment decommissioned in a given year;

NC_i = Nameplate capacity of decommissioned equipment *i*, kilograms;

S_i = SF_6 collected from decommissioned equipment *i*, kilograms.

Total annual SF_6 emissions are calculated as the sum of SF_6 emissions from equipment operation and decommissioning, according to Equation 230-8.

$$S = \frac{S_O + S_D}{1,000}$$

Equation 230-8

Where:

S = Annual SF_6 emissions, tonnes;
S_O = Annual SF_6 emissions during operation phase, kilograms;
S_D = Annual SF_6 emissions during decommissioning phase, kilograms.

(c) The methods in either paragraph (a) or (b) of this section shall be used to estimate emissions of PFCs from power transformers, substituting the relevant PFC(s) for SF_6 in Equations 230-1 through 230-8.

§ WCI.234 Sampling, Analysis, and Measurement Requirements

Calibration of equipment used to measure the mass of SF_6 or PFCs used for top-ups to electrical equipment must be conducted as specified in paragraphs (a) and (b) of this section.

a) For automated mass-flow measurement, equipment must be calibrated according to regulation.

b) For weigh-scale measurement, equipment must be calibrated every 6 months by weighing objects of pre-determined mass and zeroing the weigh scale accordingly.

§ WCI.235 Procedures for Estimating Missing Data

A complete record of all measured parameters used in the GHG emissions calculations is required. Replace missing data, if needed, based on data from equipment with a similar nameplate capacity for SF_6 and PFCs, and from similar equipment repair, replacement, and maintenance operations.

§ WCI.240 ZINC PRODUCTION

§ WCI.241 Source Category Definition

The zinc production category includes three primary production processes used to produce zinc (i.e., electro-thermic distillation, pyrometallurgical, and electrolytic). In addition, secondary zinc production is also included in this category.

§ WCI.242 Greenhouse Gas Reporting Requirements

In addition to the information required by regulation, the annual emissions data report shall contain the following information:

(a) Annual emissions of CO_2 at the facility level (tonnes).

(b) Annual quantities of each carbon-containing input material used (tonnes).

(c) Carbon content of each carbon-containing input material used (tonnes C/ tonne reducing agent).

(d) Inferred waste-based carbon-containing material emission factor (if waste-based reducing agent quantification method used).

(e) If you use the missing data procedures in WCI.245(b), you must report how the monthly mass of carbon-containing materials with missing data was determined and the number of months the missing data procedures were used.

(f) CO_2, CH_4, and N_2O emissions from each stationary fuel combustion unit. You must report these emissions under WCI.20 (General Stationary Fuel Combustion Sources), by following the requirements of WCI.20.

§ WCI.243 Calculation of CO_2 Emissions

Calculate total CO_2 emissions as specified under paragraph (a) or (b) of this section.

(a) Determine facility CO_2 emissions using continuous emissions monitoring systems (CEMS) as specified in WCI.23(d).

(b) Calculate total CO_2 emissions using Equation 240-1. Specific materials that in aggregate contribute less than 0.5% of the total carbon into the process may be excluded from the calculation performed using Equation 240-1.

$$E_{CO_2} = \sum_i (Q_i \times C_i) \times 3.664 \qquad \textbf{Equation 240-1}$$

Where:

E_{CO2} = Annual CO_2 emissions from carbon-containing materials (tonnes);

Q_i = Annual quantity of carbon-containing material *i* (tonnes);

C_i = Carbon content of carbon-containing material *i* (tonnes C/ tonne process input);

3.664 = Stoichiometric conversion factor from C to CO_2.

§ WCI.244 Sampling, Analysis, and Measurement Requirements

The annual mass of each solid carbon-containing input material consumed shall be determined by summing the monthly mass for the material determined for each month of the calendar year. The monthly mass may be determined using facility instruments, procedures, or records used for accounting purposes, including either direct measurement of the quantity of the material consumed or by calculations using process operating information.

The average carbon content of each material consumed shall be determined as specified under paragraph (a) or (b) of this section.

(a) Obtain carbon content by collecting and analyzing at least three representative samples of the material each year using one of the following methods:

(1) For zinc-bearing materials, use ASTM E1941-04 "Standard Test Method for Determination of Carbon in Refractory and Reactive Metals and Their Alloys".
(2) For carbonaceous reducing agents and carbon electrodes, use ASTM D5373-08 "Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal".
(3) For flux materials (i.e., limestone or dolomite), use ASTM C25-06 "Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime".
(4) For waste-based carbon-containing material, determine carbon content by operating the smelting furnace both with and without the waste-reducing agents while keeping the composition of other material introduced constant.
    i. To ensure representativeness of waste-based reducing agent variability, the specific testing plan (e.g. number of test runs, other process variables to keep constant, timing of runs) for these trials must be approved by the jurisdiction.

(b) Obtain carbon content from material vendor or supplier.

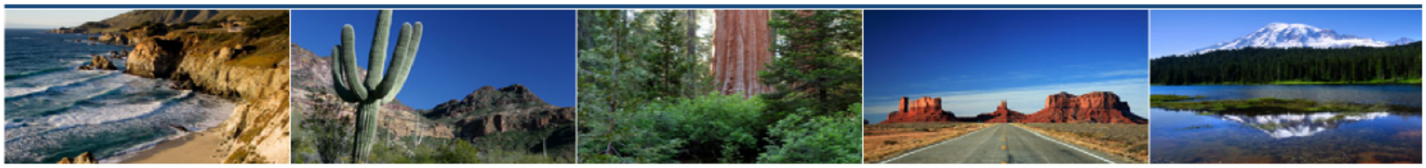
§ WCI.245 Procedures for Estimating Missing Data

For the carbon input procedure in WCI.243, a complete record of all measured parameters used in the GHG emissions calculations is required (e.g., raw materials carbon content values, etc.). Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraphs (a) and (b) of this section. You must document and keep records of the procedures used for all such estimates.

(a) For missing records of the carbon content of inputs for facilities that estimate emissions using the carbon input procedure in WCI.243; 100 percent data availability is required.

You must repeat the test for average carbon contents of inputs according to the procedures in WCI.245(b) if data are missing.

(b) For missing records of the annual mass of carbon-containing inputs using the carbon input procedure in WCI.243, the substitute data value must be based on the best available estimate of the mass of the input material from all available process data or information used for accounting purposes, such as purchase records.



§ WCI.250 UNDERGROUND COAL MINES

§ WCI.251 Source Category Definition

The underground coal mine source category consists of active underground coal mines, and any underground mines under development that have operational pre-mining degasification systems. An underground coal mine is a mine at which coal is produced by tunneling into the earth to the coalbed, which is then mined with underground mining equipment such as cutting machines and continuous, longwall, and shortwall mining machines, and transported to the surface.

(a) Underground coal mines are categorized as active if any one of the following five conditions apply:

   (1) Mine development is underway.

   (2) Coal has been produced within the last 90 days.

   (3) Mine personnel are present in the mine workings.

   (4) Mine ventilation fans are operative.

   (5) The mine operates on an intermittent basis.

(b) The underground coal mine source category includes the following:

   (1) Each ventilation well or shaft, including both those wells and shafts where gas is emitted and those where gas is sold, used onsite, or otherwise destroyed (including by flaring).

   (2) Each degasification system well or shaft, including degasification systems deployed before, during, or after mining operations are conducted in a mine area. This includes both those wells and shafts where gas is emitted, and those where gas is sold, used onsite, or otherwise destroyed (including by flaring).

(c) The underground coal mine source category does not include abandoned or closed mines, surface coal mines, or post-coal mining activities (i.e., storage or transportation of coal).

§ WCI.252 Greenhouse Gas Reporting Requirements

In addition to the information required by regulation, the annual emissions data report shall contain the following information:

(a) Quarterly CH_4 destruction at all ventilation and degasification system destruction devices or point of offsite transport (tonnes CH_4).

(b) Quarterly CH_4 emissions (net) from all ventilation and degasification systems (tonnes CH_4).

(c) Quarterly CO_2 emissions from onsite destruction of coal mine gas CH_4, where the gas is not a fuel input for energy generation or use (e.g., flaring) (tonnes CO_2).

§ WCI.253 Calculation of GHG Emissions

(a) For each ventilation shaft, vent hole, or centralized point into which CH_4 from multiple shafts and/or vent holes are collected, calculate the quarterly CH_4 liberated from the ventilation system using Equation 250-1 of this section. Measure CH_4 content, flow rate, temperature, pressure, and moisture content of the gas using the procedures outlined in WCI.254.

$$CH_{4V} = n \times \left(V \times MCF \times \frac{C}{100\%} \times 0.6775 \times \frac{288.71K}{T} \times \frac{P}{1\ atm} \times 1{,}440 \right)$$

Equation 250-1

Where:

CH_{4V}	=	Quarterly CH_4 liberated from a ventilation monitoring point (tonnes CH_4);
V	=	Daily volumetric flow rate for the quarter (cubic meters) based on sampling or a flow rate meter. If a flow rate meter is used and the meter automatically corrects for temperature and pressure, replace "288.71K/T × P/1 atm" with "1";
MCF	=	Moisture correction factor for the measurement period, volumetric basis;
	=	1 when V and C are measured on a dry basis or if both are measured on a wet basis.
	=	1 - $(f_{H2O})_n$ when V is measured on a wet basis and C is measured on a dry basis.
	=	$1/[1-(f_{H2O})]$ when V is measured on a dry basis and C is measured on a wet basis.
(f_{H2O})	=	Moisture content of the CH_4 emitted during the measurement period, volumetric basis (cubic meter water per cubic meter emitted gas);
C	=	Daily CH_4 concentration of ventilation gas for the quarter (%, wet basis);
n	=	Number of days in the quarter where active ventilation of mining operations is taking place at the monitoring point;
0.6775	=	Density of CH_4 at 288.71 K (15.56 °C) and 1 atm (kg/m^3);
288.71K	=	288.71 Kelvin;
T	=	Temperature at which flow is measured (K) for the quarter;
P	=	Pressure at which flow is measured (atm); and
1,440	=	Conversion factor (min/day).

(1) Unless required to be modified to meet existing regulatory inspection schedules, the quarterly periods are:

(i) January 1 – March 31.

(ii) April 1 – June 30.

(iii) July 1 – September 30.

(iv) October 1 – December 31.

(2) Daily values of V, MCF, C, T, and P must be based on measurements taken at least once each quarter with no fewer than 6 weeks between measurements. If measurements are taken more frequently than once per quarter, then use the average value for all

measurements taken. If continuous measurements are taken, then use the average value over the time period of continuous monitoring.

(3) If a facility has more than one monitoring point, the facility must calculate total CH4 liberated from ventilation systems ($CH_{4VTotal}$) as the sum of the CH_4 from all ventilation monitoring points in the mine, as follows in Equation 250-2:

$$CH_{4VTotal} = \sum_{i=1}^{m} (CH_{4V})_i$$

Equation 250-2

Where:

$CH_{4VTotal}$	=	Total quarterly CH_4 liberated from ventilation systems (tonnes CH_4);
CH_{4V}	=	Quarterly CH_4 liberated from each ventilation monitoring point (tonnes CH_4); and
m	=	Number of ventilation monitoring points.

(b) For each monitoring point in the degasification system (this could be at each degasification well and/or vent hole, or at more centralized points into which CH_4 from multiple wells and/or vent holes are collected), calculate the weekly CH_4 liberated from the mine using CH_4 measured weekly or more frequently (including by CEMS) according to WCI.254(c), CH_4 content, flow rate, temperature, pressure, and moisture content, and Equation 250-3 of this section.

$$CH_{4D} = \sum_{i=1}^{n} \left(V_i \times MCF_i \times \frac{C_i}{100\%} \times 0.6775 \times \frac{288.71K}{T_i} \times \frac{P_i}{1\,atm} \times 1{,}440 \right)$$

Equation 250-3

Where:

CH_{4D}	=	Weekly CH_4 liberated from a monitoring point (tonnes CH_4);
V_i	=	Daily measured total volumetric flow rate for the days in the week when the degasification system is in operation at that monitoring point, based on sampling or a flow rate meter (cubic meters). If a flow rate meter is used and the meter automatically corrects for temperature and pressure, replace“288.71K/T × P/1 atm” with “1”;
MCF_i	=	Moisture correction factor for the measurement period, volumetric basis;
	=	1 when V_i and C_i are measured on a dry basis or if both are measured on a wet basis.
	=	$1-(f_{H2O})_i$ when V_i is measured on a wet basis and C_i is measured on a dry basis.
	=	$1/[1-(f_{H2O})_i]$ when V_i is measured on a dry basis and C_i is measured on a wet basis.
$(f_{H2O})_i$	=	Moisture content of the CH_4 emitted during the measurement period, volumetric basis (cubic meter water per cubic meter emitted gas);

C_i	=	Daily CH_4 concentration of gas for the days in the week when the degasification system is in operation at that monitoring point (%, wet basis);
n	=	Number of days in the week that the system is operational at that measurement point.
0.6775	=	Density of CH_4 at 288.71 K (15.56 °C) and 1 atm (kg/m^3);
288.71K	=	288.71 Kelvin;
T_i	=	Daily temperature at which flow is measured (K);
P_i	=	Daily pressure at which flow is measured (atm); and
1,440	=	Conversion factor (min/day).

(1) Daily values for V, MCF, C, T, and P must be based on measurements taken at least once each calendar week with at least 3 days between measurements. If measurements are taken more frequently than once per week, then use the average value for all measurements taken that week. If continuous measurements are taken, then use the average values over the time period of continuous monitoring when the continuous monitoring equipment is properly functioning.

(2) Quarterly total CH_4 liberated from degasification systems for the mine should be determined as the sum of CH_4 liberated determined at each of the monitoring points in the mine, summed over the number of weeks in the quarter, as follows in Equation 250-4:

$$CH_{4DTotal} = \sum_{i=1}^{m} \sum_{j=1}^{w} \left(CH_{4D}\right)_{i,j}$$

Equation 250-4

Where: :

$CH_{4DTotal}$	=	Quarterly CH_4 liberated from all degasification monitoring points (tonnes CH_4);
CH_{4D}	=	Weekly CH_4 liberated from a degasification monitoring point (tonnes CH_4);
m	=	Number of monitoring points; and
w	=	Number of weeks in the quarter during which the degasification system is operated.

(c) If gas from degasification system wells or ventilation shafts is sold, used onsite, or otherwise destroyed (including by flaring), calculate the quarterly CH_4 destroyed for each destruction device and each point of offsite transport to a destruction device, using Equation 250-5 of this section. You must measure CH_4 content and flow rate according to the provisions in WCI.254.

$$CH_{4Destroyed} = CH_4 \times DE$$

Equation 250-5

Where:

$CH_{4Destroyed}$	=	Quarterly CH_4 destroyed (tonnes);
CH_4	=	Quarterly CH_4 routed to the destruction device or offsite transfer point (tonnes); and

DE	=	Destruction efficiency (lesser of manufacturer's specified destruction efficiency and 0.99). If the gas is transported off-site for destruction, use DE = 1.

(d) Calculate total CH_4 destroyed as the sum of the methane destroyed at all destruction devices (onsite and offsite), using Equation 250-6 of this section.

$$CH_{4DestroyedTotal} = \sum_{i=1}^{d} \left(CH_{4Destroyed} \right)_d$$

Equation 250-6

Where:

$CH_{4DestroyedTotal}$	=	Quarterly total CH_4 destroyed at the mine (tonnes CH_4);
$CH_{4Destroyed}$	=	Quarterly CH_4 destroyed from each destruction device or offsite transfer point; and
d	=	Number of onsite destruction devices and points of offsite transport.

(e) Calculate the quarterly measured net CH4 emissions to the atmosphere using Equation 250-7 of this section.

$$CH_{emitted\,(net)} = CH_{4VTotal} + CH_{4DTotal} - CH_{4DestroyedTotal}$$

Equation 250-7

Where:

$CH_{4emitted\,(net)}$	=	Quarterly CH_4 emissions from the mine (tonnes).
$CH_{4VTotal}$	=	Quarterly sum of the CH_4 liberated from all mine ventilation monitoring points (CH_{4V}), calculated using Equation 250-2 of this section (tonnes).
$CH_{4DTotal}$	=	Quarterly sum of the CH_4 liberated from all mine degasification monitoring points (CH_{4D}), calculated using Equation 250-4 of this section (tonnes).
$CH_{4DestroyedTotal}$	=	Quarterly sum of the measured CH_4 destroyed from all mine ventilation and degasification systems, calculated using Equation 250-6 of this section (tonnes).

(f) For the methane collected from degasification and/or ventilation systems that is destroyed on site and is not a fuel input for energy generation or use (those emissions are monitored and reported under WCI.20), estimate the CO_2 emissions using Equation 250-8 of this section.

$$CO_2 = CH_{4Destroyed\ on\ site} \times \left(\frac{44}{16} \right)$$

Equation 250-8

Where:

CO_2	=	Total quarterly CO_2 emissions from CH_4 destruction (tonnes);
$CH_{4Destroyedonsite}$	=	Quarterly sum of the CH_4 destroyed, calculated as the sum of CH_4 destroyed for each onsite, non-energy use, as calculated individually in Equation 250-5 of this section (tonnes); and
44/16	=	Ratio of molecular weights of CO_2 to CH_4.

§ WCI.254 Sampling, Analysis, and Measurement Requirements

Emissions may be estimated by monitoring as specified under paragraphs (a) through (g).

(a) For CH_4 liberated from ventilation systems, CH_4 must be monitored from each ventilation well and shaft, from a centralized monitoring point, or from a combination of the two options. Operators are allowed flexibility for aggregating emissions from more than one ventilation well or shaft, as long as emissions from all are addressed, and the methodology for calculating total emissions documented. Monitor using one of the following options:

(1) Collect quarterly or more frequent grab samples (with no fewer than 6 weeks between measurements) and make quarterly measurements of flow rate, temperature, and pressure. The sampling and measurements must be made at the same locations as MSHA inspection samples are taken (or appropriate equivalent in Canada), and should be taken when the mine is operating under normal conditions. Follow MSHA sampling procedures as set forth in the MSHA Handbook "General Coal Mine Inspection Procedures and Inspection Tracking System Handbook Number PH–08–V–1", January 1, 2008 or appropriate equivalent in Canada. Record the date of sampling, airflow, temperature, and pressure measured, the hand-held methane and oxygen readings (percent), the bottle number of samples collected, and the location of the measurement or collection.

(2) Obtain results of the quarterly (or more frequent) testing performed by appropriate equivalent to MSHA in Canada (if any).

(3) Monitor emissions through the use of one or more continuous emission monitoring systems (CEMS). If operators use CEMS as the basis for emissions reporting, they must provide documentation on the process for using data obtained from their CEMS to estimate emissions from their mine ventilation systems.

(b) For CH_4 liberated at degasification systems, CH_4 must be monitored from each well and gob gas vent hole, from a centralized monitoring point, or from a combination of the two options. Operators are allowed flexibility for aggregating emissions from more than one well or gob gas vent hole, as long as emissions from all are addressed, and the methodology for calculating total emissions documented. Monitor both gas volume and methane concentration by one of the following two options:

(1) Monitor emissions through the use of one or more continuous emissions monitoring systems (CEMS).

(2) Collect weekly (once each calendar week, with at least three days between measurements) or more frequent samples, for all degasification wells and gob gas vent

holes. Determine weekly or more frequent flow rates and methane composition from these degasification wells and gob gas vent holes. Methane composition should be determined either by submitting samples to a lab for analysis, or from the use of methanometers at the degasification well site. Follow the sampling protocols for sampling of methane emissions from ventilation shafts, as described in WCI.254(a)(1).

(c) Monitoring must adhere to one of the following standards:

(1) ASTM D1945–03 "Standard Test Method for Analysis of Natural Gas by Gas Chromatography"

(2) ASTM D1946–90 (Reapproved 2006) "Standard Practice for Analysis of Reformed Gas by Gas Chromatography"

(3) ASTM D4891–89 (Reapproved 2006) "Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion"

(4) ASTM UOP539–97 "Refinery Gas Analysis by Gas Chromatography"

(d) All fuel flow meters, gas composition monitors, and heating value monitors that are used to provide data for the GHG emissions calculations shall be calibrated prior to the first reporting year, using the applicable methods specified in paragraphs (d)(1) through (7) of this section. Alternatively, calibration procedures specified by the flow meter manufacturer may be used. Fuel flow meters, gas composition monitors, and heating value monitors shall be recalibrated either annually or at the minimum frequency specified by the manufacturer, whichever is more frequent. For fuel, flare, or sour gas flow meters, the operator shall operate, maintain, and calibrate the flow meter using any of the following test methods or follow the procedures specified by the flow meter manufacturer. Flow meters must meet the accuracy requirements specified by regulation in the jurisdiction.

(1) ASME MFC–3M–2004 "Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi"

(2) ASME MFC–4M–1986 (Reaffirmed 1997) "Measurement of Gas Flow by Turbine Meters"

(3) ASME MFC–6M–1998 "Measurement of Fluid Flow in Pipes Using Vortex Flowmeters"

(4) ASME MFC–7M–1987 (Reaffirmed 1992) "Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles"

(5) ASME MFC–11M–2006 "Measurement of Fluid Flow by Means of Coriolis Mass Flowmeters"

(6) ASME MFC–14M–2003 "Measurement of Fluid Flow Using Small Bore Precision Orifice Meters"

(7) ASME MFC–18M–2001 "Measurement of Fluid Flow using Variable Area Meters"

(e) For CH_4 destruction, CH_4 must be monitored at each onsite destruction device and each point of offsite transport for combustion using continuous monitors of gas routed to the device or point of offsite transport.

(f) All temperature and pressure monitors must be calibrated using the procedures and frequencies specified by the manufacturer.

(g) If applicable, the owner or operator shall document the procedures used to ensure the accuracy of gas flow rate, gas composition, temperature, and pressure measurements. These procedures include, but are not limited to, calibration of fuel flow meters, and other measurement devices. The estimated accuracy of measurements, and the technical basis for the estimated accuracy shall be recorded.

§ WCI.255 Missing Data Procedures

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation or if a required fuel sample is not taken), a substitute data value for the missing parameter shall be used in the calculations, in accordance with the following.

(a) For each missing value of CH_4 concentration, flow rate, temperature, and pressure for ventilation and degasification systems, the substitute data value shall be the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.

§ WCI.260 NICKEL AND COPPER METAL PRODUCTION

§ WCI.261 Source Category Definition

The nickel and copper metal production category includes process-related sources at nickel and copper metal smelting and refining facilities. Metals addressed in other categories (i.e., iron and steel, ferroalloys, aluminum, magnesium, lead, and zinc) are not included in this category.

The nickel and copper metal production category includes three main processes that produce CO_2 emissions: removal of impurities from nickel or copper ore concentrate using carbonate flux reagents (i.e., limestone [$CaCO_3$] or dolomite [$CaCO_3 \cdot MgCO_3$]), the use of other reducing agents to extract metals from their oxides (e.g., metallurgical coke, coal, natural gas, etc.), and the use of material (e.g., coke) for slag cleaning and the consumption of graphite or carbon electrodes in electric arc furnaces. It is important to distinguish between fuels used for combustion and fuels used as reducing agents; only fuels used as reducing agents should be included in the base metal production category. Fuels used for combustion are reported in WCI.020.

§ WCI.262 Greenhouse Gas Reporting Requirements

In addition to the information required by the Reporting Regulation, the annual emissions data report shall contain the following information:

(a) Annual emissions of CO_2 at the facility level (tonnes).

(b) Annual quantities of each carbonate flux reagent used (tonnes).

(c) Fractional purity of each carbonate flux reagent used (tonnes carbonate/tonnes raw material).

(d) Annual quantities of other reducing agents used (tonnes).

(e) Carbon content of other reducing agent used or material used for slag cleaning (tonnes C/tonne reducing agent or material for slag cleaning).

(f) Annual quantity of ore processed (tonnes).

(g) Carbon content of ore processed (tonnes C/tonne ore).

§ WCI.263 Calculation of CO_2 Emissions

Calculate total CO_2 emissions as specified under paragraph (a) through (d) of this section.

(a) Calculate CO_2 emissions from carbonate flux reagents using Equation 260-1.

$$E_{cf} = Q_{ls} \times f_{ls} \times \left(\frac{44}{100}\right) + Q_d \times f_d \times \left(\frac{88}{184}\right) \qquad \textbf{Equation 260-1}$$

Where:

E_{cf} = Annual CO_2 emissions from carbonate flux reagents (tonnes);

Q_{ls} = Annual quantity of limestone consumed (tonnes);

f_{ls} = Fractional purity of limestone (tonnes $CaCO_3$/tonnes of raw material);

44/100 = Stoichiometric conversion factor from $CaCO_3$ to CO_2;

Q_d = Annual quantity of dolomite consumed (tonnes);

f_d = Fractional purity of dolomite (tonnes $CaCO_3 \cdot MgCO_3$/tonnes of raw material);

88/184 = Stoichiometric conversion factor from $CaCO_3 \cdot MgCO_3$ to CO_2.

(b) Calculate CO_2 emissions from other reducing agents or material used in slag cleaning using Equation 260-2.

$$E_{ra} = Q_a \times C_a \times 3.664$$

Equation 260-2

Where:

E_{ra} = Annual CO_2 emissions from other reducing agents or material used for slag cleaning (tonnes);

Q_a = Annual quantity of other reducing agents or material used for slag cleaning (tonnes);

C_a = Carbon content of other reducing agents or material used for slag cleaning (tonnes C/tonne of reducing agent or material used for slag cleaning);

3.664 = Stoichiometric conversion factor from C to CO_2.

(c) Calculate CO_2 emissions from release of carbon from metal ores using Equation 260-3.

$$E_{ore} = Q_{ore} \times C_{ore} \times 3.664$$

Equation 260-3

Where:

E_{ore} = Annual process CO_2 emissions from metal ore, tonnes

Q_{ore} = Annual quantity of nickel or copper metal ore consumed (tonnes);

C_{ore} = Carbon content of nickel or copper metal ore (tonnes C/tonne of nickel or copper ore);

3.664 = Stoichiometric conversion factor from C to CO_2.

(d) Calculate CO_2 emissions from carbon electrode consumption in electric arc furnaces (EAFs) using Equation 260-4.

$$E_{ce} = Q_{ce} \times C_{ce} \times 3.664$$

Equation 260-4

Where:

E_{ce} = Annual CO_2 emissions from carbon electrode consumption in EAFs (tonnes);

Q_{ce} = Quantity of carbon electrodes consumed (tonnes);

C_{ce} = Carbon content of carbon electrodes (tonnes C/tonne carbon electrodes);

3.664 = Stoichiometric conversion factor from C to CO_2.

§ WCI.264 Sampling, Analysis, and Measurement Requirements

The annual mass of each solid carbon-containing input material consumed shall be determined using facility instruments, procedures, or records used for accounting purposes, including either direct measurement of the quantity of the material consumed or by calculations using process operating information.

The average carbon content of each material consumed shall be determined as specified under paragraph (a) or (b) of this section.

(a) Obtain carbon content by collecting and analyzing at least three representative samples of the material each year using one of the following methods:

(1) For coal and coke, use ASTM D5373-08 "Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal and Coke".

(2) For petroleum-based liquid fuels and liquid waste-derived fuels, use ASTM D5291-02 (Reapproved 2007) "Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants", ultimate analysis of oil or computations based on ASTM D3238-95 (Reapproved 2005) and either ASTM D2502-04 or ASTM D2503-92 (Reapproved 2007).

(3) For gaseous fuels, use ASTM D1945-03 or ASTM D1946-90 (Reapproved 2006).

(4) For carbonate flux reagents (i.e., limestone and dolomite), use ASTM C25-06 "Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime".

(b) Obtain carbon contents of the material, including carbon electrodes, from the vendor or supplier.

§ WCI.265 Procedures for Estimating Missing Data

For the carbon input procedure in WCI.263, a complete record of all measured parameters used in the GHG emissions calculations is required (e.g., raw materials carbon content values, etc.). Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraphs (a) and (b) of this section. You must document and keep records of the procedures used for all such estimates.

(a) For missing records of the carbon content of inputs for facilities that estimate emissions using the carbon input procedure in WCI.263; 100 percent data availability is required. You must repeat the test for average carbon contents of inputs according to the procedures in WCI.264 if data are missing.

(b) For missing records of the annual mass of carbon-containing inputs using the carbon input procedure in WCI.263, the substitute data value must be based on the best available estimate of the mass of the input material from all available process data or information used for accounting purposes, such as purchase records.

§ WCI.270 FERROALLOY PRODUCTION

§ WCI.271 Source Category Definition

Ferroalloy production consists of any facility that uses pyrometallurgical techniques to produce any of the following metals: ferrochromium, ferromanganese, ferromolybdenum, ferronickel, ferrosilicon, ferrotitanium, ferrotungsten, ferrovanadium, silicomanganese, or silicon metal.

§ WCI.272 Greenhouse Gas Reporting Requirements

In addition to the information required by regulation, the annual emissions data report shall contain the following information:

(a) Annual process CO_2 emissions (tonnes) from each electric arc furnace (EAF) used in the production of any ferroalloy listed in WCI.271.

(b) Annual process CH_4 emissions (tonnes) from each electric arc furnace (EAF) used in the production of any ferroalloy listed in Table 270-1 (i.e., ferrosilicon [65%, 75%, or 90%] or silicon metal).

(c) CO_2, N_2O, and CH_4 emissions from stationary combustion units as specified in WCI.20.

(d) Annual facility ferroalloy product production capacity (tonnes).

(e) Annual production for each ferroalloy product from each EAF (tonnes).

(f) Total number of EAFs at facility used for production of ferroalloy products.

(g) Identification number of each EAF

(h) Annual material quantity for each material included for the calculation of annual process CO_2 emissions for each EAF.

(i) Annual average of the carbon content determinations for each material included for the calculation of annual process CO_2 emissions for each EAF.

(j) Method used for determination of carbon content for each material reported (e.g., supplier provided information, representative samples analyses, etc.)

(k) If missing data procedures used (WCI.275), how monthly mass of carbon-containing inputs and output with missing data was determined and the number of months the missing data procedures were used.

§ WCI.273 Calculation of GHG Emissions

(a) Process CO_2 emissions. Determine process CO_2 emissions as specified under either paragraph (1) or (2) of this section.

(1) Continuous emissions monitoring systems (CEMS) as specified in WCI.23(d).

(2) Calculation methodologies specified in paragraph (b) of this section.

(b) Process CO_2 Emissions Calculation Methodology. Calculate electric arc furnace (EAF) CO_2 emissions using the mass balance approach specified in paragraphs (b)(1) and (b)(2). Specific process inputs or outputs that contribute less than 1 percent of the total carbon into or out of the process do not have to be included in the paragraph (b)(1) and (b)(2) mass balances

(1) Calculate EAF CO_2 emissions using Equation 270-1:

$$E_{EAF} = \left[(RA \times C_{RA}) + (EL \times C_{EL}) + (Ore \times C_{Ore}) + (FL \times C_{FL}) - (PR \times C_{PR}) - (NP \times C_{NP})\right] \times 3.664$$

Equation 270-1

Where:

E_{EAF}	=	Annual CO_2 emissions from EAF (tonnes);
RA	=	Annual mass of reducing agent charged or introduced to EAF (tonnes);
C_{RA}	=	Carbon content of reducing agent (tonnes C/ tonnes reducing agent);
EL	=	Annual mass of carbon electrodes consumed (tonnes);
C_{EL}	=	Carbon content of carbon electrodes (tonnes C/ tonnes carbon electrode);
Ore	=	Annual mass of ore charged to EAF (tonnes);
C_{Ore}	=	Carbon content of ore (tonnes C/ tonnes carbon electrode);
FL	=	Annual mass of flux materials charged or introduced to EAF (tonnes);
C_{FL}	=	Carbon content of flux materials (tonnes C/ tonnes flux material);
PR	=	Annual mass of alloy product tapped from EAF (tonnes);
C_{PR}	=	Carbon content of alloy product (tonnes C/ tonnes alloy product);
NP	=	Annual mass of outgoing non-product material removed from EAF (tonnes);
C_{NP}	=	Carbon content of outgoing non-product material (tonnes C/tonnes non-product);
3.664	=	Conversion factor from tonnes of C to tonnes of CO_2.

(2) Determine combined annual CO_2 emissions from all EAFs at the facility using Equation 270-2:

$$E_{CO2-Fac} = \sum_{1}^{k} E_{EAF-k}$$

Equation 270-2

Where:

$E_{CO2\text{-}Fac}$	=	Annual process CO_2 emissions from EAFs at facility used for the production of any ferroalloy listed in listed in WCI.271 (tonnes).
$E_{EAF\text{-}k}$	=	Annual process CO_2 emissions calculated from EAF *k* using Equation 270-1 (tonnes).
k	=	Total number of EAFs at facility used for the production of any ferroalloy listed in WCI.271 (tonnes).

(c) Process CH_4 Emissions Calculation Methodology. For any ferroalloy listed in Table 270-1, calculate emissions using procedure specified in paragraphs (c)(1) and (c)(2).

(1) For each EAF, calculate annual CH_4 emissions using Equation 270-3:

$$E_{CH4} = \sum_{1}^{i} \left(M_i \times EF_i \right)$$ **Equation 270-3**

Where:

E_{CH4} = Annual process CH_4 emissions from an individual EAF (tonnes).
M_i = Annual mass of alloy product *i* produced in the EAF (tonnes).
EF_i = CH_4 emission factor for alloy product *i* from Table 270-1 (tonne CH_4/ tonne of alloy product *i*).

(2) Determine combined annual CH_4 emissions from all EAFs at the facility using Equation 270-4:

$$E_{CH4-Fac} = \sum_{1}^{j} E_{CH4-j}$$ **Equation 270-4**

Where:

$E_{CH4\text{-}Fac}$ = Annual process CH_4 emissions from EAFs at facility used for the production of ferroalloys listed in Table 270-1 (tonnes).
$E_{CH4\text{-}j}$ = Annual process CH_4 emissions calculated from EAF *j* using Equation 270-3 (tonnes).
j = Total number of EAFs at facility used for the production of ferroalloys listed in Table 270-1.

§ WCI.274 Sampling, Analysis, and Measurement Requirements

The annual mass of each material used in the WCI.273 mass balance methodologies shall be determined using plant instruments used for accounting purposes, including either direct measurement of the quantity of material used in the process or by calculations using process operating information.

The average carbon content of each material used shall be determined as specified under paragraph (a) or (b) of this section.

(a) Obtain carbon content by collecting and analyzing at least three representative samples of the material each year using one of the following methods:

(1) For metal ore and alloy product, use ASTM E1941-04 “Standard Test Method for Determination of Carbon in Refractory and Reactive Metals and Their Alloys”.

(2) For carbonaceous reducing agents and carbon electrodes, use ASTM D5373-08 “Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal”.

(3) For flux materials (e.g., limestone, dolomite, etc.), use ASTM C25-06 "Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime".

(b) Obtain carbon content from material vendor or supplier.

§ WCI.275 Missing Data Procedures

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraphs (a) or (b) of this section. Records must be documented and kept of the procedures used for all such estimates.

(a) If CO_2 emissions for EAFs are estimated using the carbon mass balance in WCI.273(b)(1), 100 percent data availability is required for the carbon content of the input and output materials. The test for average carbon contents according to WCI.274 must be repeated if data are missing.

(b) For each missing value of monthly mass of carbon-containing inputs and outputs, the substitute data value must be based on the best available estimate of the mass of inputs and outputs from all available process data or data used for accounting purposes.

(c) If CH_4 emissions for EAFs are required to be calculated, the estimate is based on an annual quantity of certain alloy products, so 100 percent data availability is required.

Table 270-1 —Electric Arc Furnace (EAF) CH_4 Emission Factors.

	CH_4 Emission Factor (metric ton CH_4 per metric ton product)		
	EAF Operation		
Alloy product produced in EAF	**Batch-Charging**	**Sprinkle-Charging[a]**	**Sprinkle-Charging and >750°C[b]**
Silicon metal	0.0015	0.0012	0.0007
Ferrosilicon 90%	0.0014	0.0011	0.0006
Ferrosilicon 75%	0.0013	0.0010	0.0005
Ferrosilicon 65%	0.0013	0.0010	0.0005

[a] Sprinkle-charging is charging intermittently every minute.

[b] Temperature measured in off-gas channel downstream of the furnace hood.

§ WCI.280 MOBILE EQUIPMENT AT FACILITIES

§ WCI.281 Source Category Definition

The mobile equipment at facilities category includes:

(a) Mobile equipment used for the on-site transportation or movement of substances, materials or products, and

(b) Other mobile equipment such as tractors, mobile cranes, log transfer equipment, mining machinery, graders, backhoes and bulldozers, and other industrial equipment,

but *does not include* on-road vehicles, aircraft, or marine vessels.

For clarity, an on-road vehicle means a motor vehicle that:

(a) Can exceed a speed of 40 kilometers per hour on a level paved surface, and

(b) Has features customarily associated with safe and practical highway use such as a reverse gear (unless the vehicle is a motorcycle), a differential, and safety features required by federal or provincial laws,

but *does not include* vehicles that exhibit features that render use on a highway unsafe, impractical, or highly unlikely, such as tracked road contact or inordinate size.

Mobile equipment that is part of normal facility operations that are operated by contractors is also included, as it is managed or controlled by the facility.

§ WCI.282 Greenhouse Gas Reporting Requirements

In addition to the information required by the British Columbia Reporting Regulation, the annual emissions data report shall contain the following information:

(a) Total emissions of CO_2, CO_2 from biomass, CH_4, and N_2O at the facility level by fuel type (including differentiation of biodiesel and ethanol from conventional fuel types) (tonnes).

(b) Annual and quarterly quantities of fuel used by fuel type (including differentiation of biodiesel and ethanol from conventional fuel types) (litres) from the sum of mobile equipment at the facility.

§ WCI.283 Calculation of CO_2 Emissions

Calculate the annual CO_2 mass emissions from mobile equipment using the procedures in paragraph (a) or (b). If neither (a) or (b) is appropriate for a source(s), method (c) may be used. Use method (d) as required.

(a) If fossil fuel quantities are measured, calculate total CO_2 emissions using Equation 280-1.

$$E_{i,CO2} = Q_i \times EF_i$$

Equation 280-1

Where:

$E_{i,CO2}$ = Quarterly CO_2 emissions from mobile equipment for fuel *i* (metric tons);

Q_i = Quarterly quantity of fuel *i* used in mobile equipment (litres);

EF_i = Emission factor for the fuel (metric tons CO_2e/litre, required emission factors provided in WCI.020).

(b) If fossil fuel quantities are not measured, use hours of operation for each mobile equipment to calculate total CO_2 emissions using Equations 280-2 and 280-3.

$$E_{i,k,CO2} = \left(h_{i,k} \times hp_{i,k} \times LF_{i,k} \times BSFC_{i,k}\right) \times EF_{i,CO2}$$ **Equation 280-2**

$$E_{Total,i,CO2} = \sum_k E_{i,k,CO2}$$ **Equation 280-3**

Where:

$E_{i,k,CO2}$ = Quarterly CO_2 emissions from mobile equipment *k* for fuel *i* (metric tons);

$h_{i,k}$ = Quarterly hours of operation for mobile equipment *k* for fuel *i* (hours);

$hp_{i,k}$ = Rated equipment horsepower for mobile equipment *k* for fuel *i* (horsepower);

$LF_{i,k}$ = Load factor for mobile equipment *k* for fuel *i* (unitless; ranges between 0 and 1);

$BSFC_{i,k}$ = Brake-specific fuel consumption for mobile equipment *k* for fuel *i* (litres/horsepower-hour);

$EF_{i,CO2}$ = Emission factor for fuel *i* (metric tons CO_2e/litre, required emission factors provided in WCI.020);

$E_{Total,i,CO2}$ = Total quarterly CO_2 emissions for fuel *i* (metric tons).

(c) If neither methods (a) or (b) is appropriate for a source(s), determine emissions using the site-specific emission factor method. Conduct analysis of hourly fuel use from mobile sources at the facility during a range of typical operations.

(i) A range of typical operating conditions for the mobile source(s) at the facility must be documented and analyzed (e.g., including the type of mobile equipment in operation).

(ii) The average hourly fuel use rate for each of the typical operations must be calculated.

(iii) The number of hours of each type of operation at the facility in the year must be determined.

(iv) The annual total mobile emissions must be calculated by multiplying the hours of operation with the average fuel use rate and the fuel-specific emission factor for each of the typical operations.

(d) CO_2 Emissions Calculation Methodology for Mixtures of Biomass Fuel and Fossil Fuel. Calculate biomass and non-biomass CO_2 emissions as specified in paragraph (1) of this section.

(1) The owner or operator that combusts fuels or fuel mixtures where there is a mixture of biofuel (i.e. biodiesel and ethanol) and other fuels shall determine the portion of the biofuel used by broad fuel category (i.e. gasoline and diesel) and use the appropriate emission factors for each of the biofuel and the conventional fuel. When reporting emissions, CO_2 from the biomass component of biofuels shall be reported separately from CO_2 from fossil fuels.

§ WCI.284 Calculation of CH_4 and N_2O Emissions

Calculate the annual CH_4 and N_2O mass emissions from mobile equipment using the procedures in paragraph (a) or (b), as appropriate. If neither (a) or (b) is appropriate, method (c) may be used. Annual emissions for each fuel type and GHG are calculated as the sum of the quarterly emissions. Annual emissions are reported by fuel and by GHG.

(a) If fossil fuel quantities are measured, calculate total CH_4 and N_2O emissions using Equation 280-4 and the emission factors provided in WCI.020.

$$E_{i,g} = Q_i \times EF_{i,g} \times \left(\frac{1}{10^6}\right) \qquad \textbf{Equation 280-4}$$

Where:

$E_{i,g}$ = Quarterly emissions of greenhouse gas *g* (CH_4 or N_2O) from mobile equipment for fuel *i* (metric tons);

Q_i = Quarterly quantity of fuel *i* (litres);

$EF_{i,g}$ = Greenhouse gas *g* (CH_4 or N_2O) mobile equipment emission factor for fuel *i* (grams/litre) (required emission factors provided in WCI.020);

$(1/10^6)$ = Conversion factor from grams to metric tons.

(b) If fossil fuel quantities are not measured, use hours of operation for each mobile equipment to calculate total CH_4 or N_2O emissions using Equations 280-5 and 280-6.

$$E_{i,k,g} = \left(h_{i,k} \times hp_{i,k} \times LF_{i,k} \times BSFC_{i,k}\right) \times EF_{i,g} \times \left(\frac{1}{10^6}\right) \qquad \textbf{Equation 280-5}$$

$$E_{Total,i,g} = \sum_{k} E_{i,k,g} \qquad \textbf{Equation 280-6}$$

Where:

$E_{i,k,g}$ = Quarterly greenhouse gas *g* (CH_4 or N_2O) emissions from mobile equipment *k* for fuel *i* (metric tons);

$h_{i,k}$ = Quarterly hours of operation for mobile equipment *k* for fuel *i* (hours);

$hp_{i,k}$ = Rated equipment horsepower for mobile equipment *k* for fuel *i* (horsepower);

$LF_{i,k}$ = Load factor for mobile equipment *k* for fuel *i* (unitless; ranges between 0 and 1);

$BSFC_{i,k}$ = Brake-specific fuel consumption for mobile equipment *k* for fuel *i* (litres/horsepower-hour);

$EF_{i,g}$ = Emission factor for greenhouse gas *g* (CH_4 or N_2O) for fuel *i* (grams/litre, required emission factors provided in WCI.020);

$(1/10^6)$ = Conversion factor from grams to metric tons;

$E_{Total,i,g}$ = Total quarterly emissions greenhouse gas *g* (CH_4 or N_2O) for fuel *i* (metric tons).

(c) If neither methods (a) or (b) is appropriate, determine emissions using the *site-specific emission factor method.* Conduct analysis of hourly fuel use from mobile sources at the facility during a range of typical operations.

(i) A range of typical operating conditions for the mobile source(s) at the facility must be documented and analyzed (e.g., include the type of mobile equipment in operation).
(ii) The average hourly fuel use rate for each of the typical operations must be calculated.
(iii) The number of hours of each type of operation at the facility in the year must be determined.
(iv) The annual total mobile emissions must be calculated by multiplying the hours of operation with the average fuel use rate and the fuel-specific emission factor for each of the typical operations.

§ WCI.285 Sampling, Analysis, and Measurement Requirements

Fuel use and emission factors shall be determined as specified under paragraphs (a), (b) and (c) of this section.

(a) For biofuels, the portion(s) of ethanol or biodiesel from vendor specifications.

(b) For conventional fuels and biofuels, required emission factors listed in WCI.020.

(c) Fuel volumes used shall be determined by vendor receipts, dipstick measurement, or other appropriate means on a quarterly basis, starting on January 1 of the calendar year.

§ WCI.290 MAGNESIUM PRODUCTION

§ WCI.291 Source Category Definition

Magnesium production and processing source category consists of any process in which magnesium metal is produced through smelting (including electrolytic smelting), refining, or remelting operations or in which molten magnesium is used in alloying, casting, drawing, extruding, forming, or rolling operations.

Two important sector-specific definitions are the following:

(a) *Cover gas* means SF_6, HFC–134a, fluorinated ketone (FK 5–1–12) or other gas used to protect the surface of molten magnesium from rapid oxidation and burning in the presence of air. The molten magnesium may be the surface of a casting or ingot production operation or the surface of a crucible of molten magnesium that feeds a casting operation.

(b) *Carrier gas* means the gas with which cover gas is mixed to transport and dilute the cover gas thus maximizing its efficient use. Carrier gases typically include CO_2, N_2, and/or dry air.

§ WCI.292 Greenhouse Gas Reporting Requirements

In addition to the information required by regulation, the annual emissions data report shall contain the following information:

(a) Annual emissions of the following gases in tonnes per year resulting from their use as cover gases or carrier gases in magnesium production or processing:

(1) Sulfur hexafluoride (SF_6).

(2) HFC–134a.

(3) FK 5–1–12 (a fluorinated ketone).

(4) Carbon dioxide (CO_2).

(5) Any other GHGs (as defined by regulation).

(b) CO_2, N_2O, and CH_4 emissions from stationary combustion units as specified in WCI.20.

(c) Types of production processes at the facility (e.g., primary, secondary, die casting, etc.).

(d) Amount of magnesium produced or processed in metric tons for each process type, including the output of primary and secondary magnesium production processes and the input to magnesium casting processes.

(e) For any missing data, the length of time the data were missing for each cover gas or carrier gas, the method used to estimate emissions in their absence, and the quantity of emissions thereby estimated.

(f) If applicable, an explanation of any change greater than 30 percent in the facility's cover gas usage rate (e.g., installation of new melt protection technology, leak discovered in the cover gas delivery system that resulted in increased emissions, etc.).

(g) Description of any new melt protection technologies adopted to account for reduced or increased GHG emissions in any given year.

§ WCI.293 Calculation of GHG Emissions

(a) Calculate the mass of each GHG emitted from magnesium production or processing over the calendar year using either Equation 290-1 or Equation 290-2 of this section, as appropriate. Both of these equations equate emissions of cover gases or carrier gases to consumption of cover gases or carrier gases.

(1) To estimate emissions of cover gases or carrier gases by monitoring changes in container masses and inventories, emissions of each cover gas or carrier gas shall be estimated using Equation 290-1 of this section:

$$E_x = \left(I_{B,x} - I_{E,x} + A_x - D_x\right) \times 0.001$$

Equation 290-1

Where:

E_x	=	Emissions of each cover gas or carrier gas *x* over the reporting year (tonnes);
$I_{B,x}$	=	Inventory of each cover gas or carrier gas *x* stored in cylinders or other containers at the beginning of the year, including heels (kg);
$I_{E,x}$	=	Inventory of each cover gas or carrier gas *x* stored in cylinders or other containers at the end of the year, including heels (kg);
A_x	=	Acquisitions of each cover gas or carrier gas *x* during the year through purchases or other transactions, including heels in cylinders or other containers returned to the magnesium production or processing facility (kg);.
D_x	=	Disbursements of each cover gas or carrier gas *x* to sources and locations outside the facility through sales or other transactions during the year, including heels in cylinders or other containers returned by the magnesium production or processing facility to the gas supplier (kg);
0.001	=	Conversion factor from kg to tonnes; and
x	=	Each cover gas or carrier gas that is a GHG.

(2) To estimate emissions of cover gases or carrier gases by monitoring changes in the masses of individual containers as their contents are used, emissions of each cover gas or carrier gas shall be estimated using Equation 290-2 of this section:

$$E_x = \sum_{p=1}^{n} Q_p \times 0.001$$

Equation 290-2

Where:

E_x = Emissions of each cover gas or carrier gas *x* over the reporting year (tonnes);
Q_p = Mass of the cover or carrier gas consumed (kg) over the container-use period *p* as estimated using Equation 290-3;
n = Number of container-use periods in the year;
= Inventory of each cover gas or carrier gas *x* stored in cylinders or other containers at the beginning of the year, including heels (kg);
0.001 = Conversion factor from kg to tonnes; and
x = Each cover gas or carrier gas that is a GHG.

(b) For purposes of Equation 290-2 of this section, the mass of the cover gas used over the period *p* for an individual container shall be estimated by using Equation 290-3 of this section:

$$Q_p = M_B - M_E$$

Equation 290-3

Where:

Q_p = Mass of the cover or carrier gas consumed (kg) over the container-use period *p* (e.g., one month, etc.);
M_B = Mass of the container's contents (kg) at the beginning of period *p*; and
M_E = Mass of the container's contents (kg) at the end of period *p*.

(c) If a facility has mass flow controllers (MFC) and the capacity to track and record MFC measurements to estimate total gas usage, the mass of each cover or carrier gas monitored may be used as the mass of cover or carrier gas consumed (Q_p), in kg for period *p* in Equation 290-2 of this section.

§ WCI.294 Sampling, Analysis, and Measurement Requirements

Emissions (consumption) of cover gases and carrier gases may be estimated by monitoring as specified under paragraphs (a) through (c). Emissions must be estimated at least annually.

(a) Monitor the changes in container weights and inventories using Equation 290-1 of this subpart as follows:

(1) All quantities required by Equation 290-1 of this subpart must be measured using scales or load cells with an accuracy of 1 percent of full scale or better, accounting for the tare weights of the containers.

(2) Gas masses or weights provided by the gas supplier (e.g., for the contents of containers containing new gas or for the heels remaining in containers returned to the gas supplier) if the supplier provides documentation verifying that accuracy standards are met. However, the facility remains responsible for the accuracy of these masses or weights under this subpart.

(b) Monitor the changes in individual container weights as the contents of each container are used using Equations 290-2 and 290-3 of this subpart. The container identities and masses must be monitored and recorded as follows:

(1) Track the identities and masses of containers leaving and entering storage with check-out and check-in sheets and procedures. The masses of cylinders returning to storage shall be measured immediately before the cylinders are put back into storage.

(2) All the quantities required by Equations 290-2 and 290-3 of this subpart must be measured using scales or load cells with an accuracy of 1 percent of full scale or better, accounting for the tare weights of the containers.

(3) Gas masses or weights provided by the gas supplier (e.g., for the contents of cylinders containing new gas or for the heels remaining in cylinders returned to the gas supplier) if the supplier provides documentation verifying that accuracy standards are met. However, the facility remains responsible for the accuracy of these masses or weights under this subpart.

(c) Monitoring the mass flow of the pure cover gas or carrier gas into the gas distribution system. When estimating emissions by monitoring the mass flow of the pure cover gas or carrier gas into the gas distribution system, gas flow meters, or mass flow controllers, with an accuracy of 1 percent of full scale or better must be used.

All flow meters, scales, and load cells used to measure quantities that are to be reported under this subpart shall be calibrated using calibration procedures specified by the flow meter, scale, or load cell manufacturer. Calibration shall be performed prior to the first reporting year. After the initial calibration, recalibration shall be performed at the minimum frequency specified by the manufacturer.

§ WCI.295 Missing Data Procedures

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraphs (a) or (b) of this section. Records must be documented and kept of the procedures used for all such estimates.

(a) A complete record of all measured parameters used in the GHG emission calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter will be used in the calculations as specified in paragraph (b) of this section.

(b) Replace missing data on the emissions of cover or carrier gases by multiplying magnesium production during the missing data period by the average cover or carrier gas usage rate from the most recent period when operating conditions were similar to those for the period for which the data are missing. Calculate the usage rate for each cover or carrier gas using Equation 290-4 of this section:

$$R_x = \left(\frac{C_x}{Mg}\right) \times 0.001$$

Equation 290-4

Where:

R_x	=	Usage rate of a particular cover gas or carrier gas *x* over the period of comparable operation (tonnes gas/tonne Mg);
C_x	=	Consumption of a particular cover gas or carrier gas *x* over the period of comparable operation (kg);
Mg	=	Magnesium produced or fed into the process over the period of comparable operation (tonnes);
0.001	=	Conversion factor from kg to tonnes; and
x	=	Each cover gas or carrier gas that is a GHG.

(c) If the precise before and after weights are not available, it should be assumed that the container was emptied in the process (i.e., quantity purchased should be used, less heel).

§ WCI.300 PETROCHEMICAL MANUFACTURING

§ WCI.301 Source Category Definition

(a) The petrochemical manufacturing source category consists of any facility that manufacturers petrochemicals, including acrylonitrile, carbon black, propylene, ethylene, ethylene dichloride, ethylene oxide, or methanol, from feedstocks derived from petroleum, or petroleum and natural gas liquids.

(b) A process that produces a petrochemical as a byproduct is not part of the petrochemical production source category.

(c) A facility that makes methanol, hydrogen, and/or ammonia from synthesis gas should report under this section if the annual mass of methanol produced exceeds the individual annual mass production levels of both hydrogen recovered as product and ammonia. The facility should report under WCI.130 (Hydrogen Production) if the annual mass of hydrogen recovered as product exceeds the individual annual mass production levels of both methanol and ammonia. The facility should report under WCI.80 (Ammonia Manufacturing) if the annual mass of ammonia produced exceeds the individual annual mass production levels of both hydrogen recovered as product and methanol.

(d) A direct chlorination process that is operated independently of an oxychlorination process to produce ethylene dichloride is not part of the petrochemical production source category.

(e) A process that produces a petrochemical from bio-based feedstock is not part of the petrochemical production source category.

§ WCI.302 Greenhouse Gas Reporting Requirements

In addition to the information required by the regulation, the annual emissions report must contain the following information:

(a) CO_2, N_2O, and CH_4 emissions from combustion of fuels in the stationary combustion units in tonnes, as specified in WCI.20.

(b) CO_2, N_2O, and CH_4 emissions from flares or other combustion devices in tonnes using methods WCI.303(a)(1), WCI.303(a)(2) or WCI.303(c).

(c) CO_2, N_2O, and CH_4 process emissions from vents in tonnes using method WCI.303(a)(3).

(d) CO_2, N_2O, and CH_4 process emissions from equipment leaks in tonnes using method WCI.303(a)(4).

(e) CO_2 process emissions in tonnes using method WCI.303(b).

(f) CO_2, N_2O, and CH_4 process emissions from ethylene production facilities in tonnes using WCI.303(c).

(g) Annual consumption of feedstock by type for all feedstocks that result in GHG emissions in standard cubic meters for gases, kilolitres for liquids, and tonnes for solid fuels.

§ WCI.303 Calculation of GHG Emissions

Calculate GHG emissions using one of the methods in paragraphs (a), (b), or (c):

(a) **Method 1:** Calculate the GHG emissions from petrochemical production processes using the methods specific in paragraphs (a)(1) through (a)(3) of this section.

(1) For flares, calculate CO_2, CH_4 and N_2O emissions using the methods specified in WCI.203(e).

(2) For combustion devices other than flares, calculate CO_2, CH_4 and N_2O emissions resulting from the combustion of fuels and process off-gas as specified in paragraphs (a)(2)(i) through (a)(2)(iii):

(i) Calculate CO_2 emissions from fuels and process off-gas in accordance with the methods in specified in WCI.20.

(ii) Calculate CH_4 and N_2O emissions from combustion of fuels using the applicable methods in WCI.24. Use the appropriate default emission factors for CH_4 and N_2O from Tables 20-2, 20-4, 20-6, and 20-7.

(iii) Calculate CH_4 and N_2O emissions from process off-gas using the applicable equation 20-12 in WCI.24, and the default emission factors of 2.8×10^{-3} kg/GJ for CH_4 and 5.7×10^{-4} kg/GJ for N_2O.

(3) Calculate the emissions from process vents using the method specified in WCI.203(b) for each process vent that can be reasonably expected to contain greater than 2 percent by volume CO_2 or greater than 0.5 percent by volume of CH_4 or greater than 0.01 percent by volume (100 parts per million) of N_2O.

(4) Calculate the emissions from equipment leaks using the method specified in WCI.203(i)(1).

(b) **Method 2:** Calculate the emissions of CO_2 from each process unit, for each calendar month as described in paragraphs (b)(1) through (b)(5) of this section.

(1) For each gaseous and liquid feedstock and product, measure the volume or mass used or produced each calendar month with a flow meter. Alternatively, for liquids, you may calculate the volume used or collected in each month based on measurements of the liquid level in a storage tank at least once per month (and just prior to each change in direction of the level of the liquid). Fuels used for combustion purposes are not considered to be feedstocks. The emissions from the combustion of fuels (other than process off-gas) in stationary combustion units must be calculated in accordance with the methods specified in WCI.23 for CO_2 and the methods specified in WCI.24 for CH_4 and N_2O.

(2) For each solid feedstock and product, measure the mass used or produced each calendar month.

(3) Collect a sample of each feedstock and product at least once per month and determine the carbon content of each sample. Alternatively, you may use the results of analyses conducted by a fuel or feedstock supplier, provided the sampling and analysis is

conducted at least once per month. If multiple valid carbon content measurements are made during the monthly measurement period, average them arithmetically.

(4) If you determine that the monthly average concentration of a specific compound in a feedstock or product is greater than 99.5 percent by volume (or mass for liquids and solids), then as an alternative to the sampling and analysis specified in paragraph (b)(3) of this section, you may calculate the carbon content assuming 100 percent of that feedstock or product is the specific compound during periods of normal operation. You must maintain records of any determination made in accordance with this paragraph (b)(4) along with all supporting data, calculations, and other information. This alternative may not be used for products during periods of operation when off-specification product is produced. You must reevaluate determinations made under this paragraph (b)(4) after any process change that affects the feedstock or product composition. You must keep records of the process change and the corresponding composition determinations. If the feedstock or product composition changes so that the average monthly concentration falls below 99.5 percent, you are no longer permitted to use this alternative method.

(5) Calculate the CO_2 mass emissions for each petrochemical process unit using Equations 300-1 through 300-4 of this section.

(i) <u>Gaseous feedstocks and products</u>. Use Equation 300-1 of this section to calculate the net annual carbon input or output from gaseous feedstocks and products. Note that the result will be a negative value if there are no gaseous feedstocks in the process but there are gaseous products.

$$C_g = \sum_{n=1}^{12} [\sum_{i=1}^{j\ or\ k} [(F_{gf})_{i,n} * (CC_{gf})_{i,n} * \frac{(MW_f)_i}{MVC} - (P_{gp})_{i,n} * (CC_{gp})_{i,n} * \frac{(MW_p)_i}{MVC}]]$$

Equation 300-1

Where:

C_g = Annual net contribution to calculated emissions from carbon (C) in gaseous materials (kg/yr).

$(F_{gf})_{i,n}$ = Volume of gaseous feedstock i introduced in month n (Rm^3) at reference temperature and pressure conditions as used by the facility. If a mass flow meter is used, measure the feedstock introduced in month n in kg and replace the term "$(MW_f)_i/MVC$" with "1".

$(CC_{gf})_{i,n}$ = Average carbon content of the gaseous feedstock i for month n (kg C per kg of feedstock).

$(MW_f)_i$ = Molecular weight of gaseous feedstock i (kg/kg-mole).

MVC = Molar volume conversion factor at the same reference conditions as the above $(F_{gf})_{i,n}$ (Rm^3/kg-mole).

= 8.3145 * [273.16 + reference temperature in °C] / [reference pressure in kilopascal]

$(P_{gp})_{i,n}$ = Volume of gaseous product i produced in month n (Rm^3) at the same reference conditions as the above $(F_{gf})_{i,n}$. If a mass flow meter is used, measure the gaseous product produced in month *n* in kg and replace the term "(MWp)i/MVC" with "1".

$(CC_{gp})_{i,n}$ = Average carbon content of gaseous product *i*, including streams containing CO_2 recovered for sale or use in another process, for month *n* (kg of C per m^3 of product when liquid product is measured in m^3, or kg of C per kg of product when product is measured in kg)

$(MW_p)_i$ = Molecular weight of gaseous product *i* (kg/kg-mole).

j = Number of feedstocks.

k = Number of products.

(ii) Liquid feedstocks and products. Use Equation 300-2 of this section to calculate the net carbon input or output from liquid feedstocks and products. Note that the result will be a negative value if there are no liquid feedstocks in the process but there are liquid products.

$$C_l = \sum_{n=1}^{12} [\sum_{i=1}^{j\ or\ k} [(F_{lf})_{i,n} * (CC_{lf})_{i,n} - (P_{lp})_{i,n} * (CC_{lp})_{i,n}]] \qquad \textbf{Equation 300-2}$$

Where:

C_l = Annual net contribution to calculated emissions from carbon in liquid materials, including liquid organic wastes (kg/yr).

$(F_{lf})_{i,n}$ = Volume or mass of liquid feedstock *i* introduced in month *n* (m^3 of feedstock). If a mass flow meter is used, measure the liquid feedstock in month *n* introduced in kg and measure the carbon content of feedstock in kg of C per kg of feedstock.

$(CC_{lf})_{i,n}$ = Average carbon content of liquid feedstock *i* for month *n* (kg C of C per m^3 of feedstock when feedstock usage is measured in m^3, or kg of C per kg of feedstock when feedstock usage is measured in kg).

$(P_{lp})_{i,n}$ = Volume or mass of liquid product i produced in month *n* (m^3). If a mass flow meter is used, measure the liquid product produced in kg and measure the carbon content of liquid product in kg of C per kg of product.

$(CC_{lp})_{i,n}$ = Average carbon content of liquid product *i*, including organic liquid wastes, for month *n* (kg C of C per m^3 of product when liquid product is measured in m^3, or kg of C per kg of product when product is measured in kg)

j = Number of feedstocks.

k = Number of products.

(iii) Solid feedstocks and products. Use Equation 300-3 of this section to calculate the net annual carbon input or output from solid feedstocks and products. Note that the result will be a negative value if there are no solid feedstocks in the process but there are solid products.

$$C_s = \sum_{n=1}^{12} \left\{ \sum_{i=1}^{j\ or\ k} \left[(F_{sf})_{i,n} * (CC_{sf})_{i,n} - (P_{sp})_{i,n} * (CC_{sp})_{i,n} \right] \right\} \qquad \textbf{Equation 300-3}$$

Where:

C_s = Annual net contribution to calculated emissions from carbon in solid materials (kg/yr).
$(F_{sf})_{i,n}$ = Mass of solid feedstock *i* introduced in month *n* (kg).
$(CC_{sf})_{i,n}$ = Average carbon content of solid feedstock *i* for month *n* (kg C per kg of feedstock).
$(P_{sp})_{i,n}$ = Mass of solid product *i* produced in month *n* (kg).
$(CC_{sp})_{i,n}$ = Average carbon content of solid product *i* in month *n* (kg C per kg of product).
j = Number of feedstocks.
k = Number of products.

(iv) Annual emissions. Use the results from Equations 300-1 through 300-3 of this section, as applicable, in Equation 300-4 of this section to calculate annual CO_2 emissions.

$$CO_2 = 0.001 * 3.664 * \left(C_g + C_l + C_s\right) \qquad \textbf{Equation 300-4}$$

Where:

CO_2 = Annual CO_2 mass emissions from process operations and process off-gas combustion (tonnes/year).
0.001 = Conversion factor from kg to tonnes.
3.664 = Ratio of molecular weight, carbon dioxide to carbon.

(c) **Method 3:** (Optional combustion methodology for ethylene production processes) For ethylene production processes, calculate CO_2, CH_4, and N_2O emissions as specified in paragraphs (c)(1) and (c)(2):

(1) For each flare, calculate CO_2, CH_4, and N_2O emissions using the methodology for flares specified in WCI.203(e).

(2) For all other combustion units, calculate the CO_2 emissions from combustion of fuel that contains ethylene process off-gas using either Calculation Methodology 3 or Calculation Methodogy 4 in WCI.23(c) and (d), respectively. Calculate CH_4 and N_2O emissions using the applicable method in WCI.24 and the emission factors of 2.8 x 10^{-3} kg/GJ for CH_4 and 5.7 x 10^{-4} kg/GJ for N_2O. You are not required to use the same calculation method for each stationary combustion unit that burns ethylene process off-gas.

§ WCI.304 Monitoring Requirements

(a) If you calculate emissions using the method specified in WCI.303(a):

(1) **Flares.** You must comply with the monitoring requirements for flares specified in WCI.204(e). The person may monitor the carbon content or the high heat value of the flares gas of flares in a petrochemical production facility on a quarterly basis.

(2) **Process Vents.** You must comply with the monitoring requirements for process vents specified in WCI.204(b).

(b) If you calculate emissions using the method specified in WCI.303(b):

(1) **Feedstock Consumption.** You must measure the feedstock consumption using the same plant instruments used for accounting purposes, such as weigh hoppers, belt weigh feeders, or flow meters.

(2) **Product Production.** You must measure the amount of product produced using the same plant instruments used for accounting purposes, such as weigh hoppers, belt weigh feeders, or flow meters.

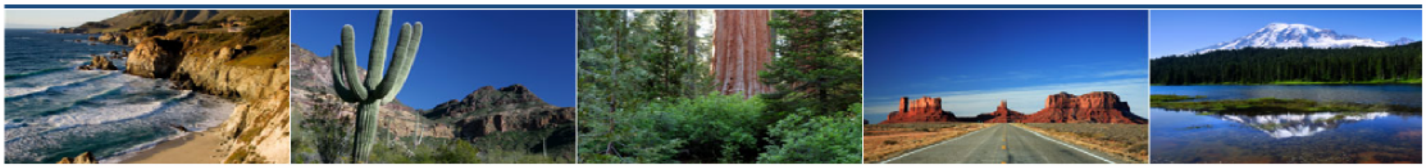
(3) **Carbon Content.** Except as allowed by WCI.303(b)(4), the carbon content of each feedstock and product must be measured at least once per month.

§ WCI.305 Procedures for Estimating Missing Data

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraphs (a) or (b) of this section. You must document and keep records of the procedures used for all such estimates.

(a) For each missing value of the carbon content and molecular weight, the substitute data value shall be the arithmetic average of the quality assured values of the parameter immediately preceding and immediately following the missing data incident. If no quality assured data are available prior to the missing data incident, the substitute data value shall be the first quality assured data value obtained after the missing data period.

(b) For missing feedstock and production values, the substitute data value shall be the best available estimate of the parameter, based on all available process data. You must document and retain records of the procedures used for all such estimates.



§ WCI.310 NITRIC ACID MANUFACTURING

§ WCI.311 Source Category Definition

A nitric acid production facility uses one or more trains to produce weak nitric acid (30 to 70 percent in strength). A nitric acid train produces weak nitric acid through the catalytic oxidation of ammonia.

§ WCI.312 Greenhouse Gas Reporting Requirements

For the purpose of the Regulation the annual emissions data report shall include the following information at the facility level calculated in accordance this method

(a) You must report facility wide N_2O process emissions as required by this method.

(b) Annual nitric acid production from the nitric acid facility (tonnes, 100 percent acid basis).

(c) You must report under WCI.20 (General Stationary Fuel Combustion Sources) the emissions of CO_2, CH_4, and N_2O from each stationary combustion unit by following the requirements of WCI.20.

§ WCI.313 Calculation of GHG emissions

(a) You must determine annual N_2O process emissions from each nitric acid train according to paragraphs (a)(1) or (a)(2) of this section.

(1) Use a site-specific emission factor and production data according to paragraphs (b) through (h) of this section.

(2) Request Director approval for an alternative method of determining N_2O emissions according to paragraphs.

(b) You must conduct an annual performance test according to paragraphs (b)(1) through (b)(3) of this section.

(1) You must measure N_2O emissions from the absorber tail gas vent for each nitric acid train using the methods specified in WCI.314(b) through (d).

(2) You must conduct the performance test under normal process operating conditions and without using N_2O abatement technology (if applicable).

(3) You must measure the production rate during the performance test and calculate the production rate for the test period in metric tons (100 percent acid basis) per hour.

(c) You must determine an N_2O emissions factor to use in Equation 310-3 of this section according to paragraphs (c)(1) or (c)(2) of this section.

(1) You may request Director approval for an alternative method of determining N_2O concentration according to the procedures in paragraphs (a)(2) of this section. Alternative methods include the use of N_2O CEMs.

(2) Using the results of the performance test in paragraph (b) of this section, you must calculate an average site-specific emission factor for each nitric acid train “t” according to Equation 310-1 of this section:

$$EF_{N2Ot} = \frac{\sum_{1}^{n} \frac{C_{N2O} * 1.828\times10^{-6} * Q}{P}}{n} \qquad \textbf{Equation 310-1}$$

Where:

EF_{N2Ot} = Average site-specific N_2O emissions factor for nitric acid train *t* (kg N_2O generated/tonne nitric acid produced, 100 percent acid basis).

C_{N2O} = N_2O concentration for each test run during the performance test (ppm N_2O).

1.828×10^{-6} = Conversion factor (kg/dsm^3-ppm N_2O).

Q = Volumetric flow rate of effluent gas for each test run during the performance test (dsm^3/hr).

P = Production rate for each test run during the performance test (tonnes nitric acid produced per hour, 100 percent acid basis).

n = Number of test runs.

(d) If applicable, you must determine the destruction efficiency for each N_2O abatement technology according to paragraphs (d)(1), (d)(2), or (d)(3) of this section.

(1) Use the manufacturer’s specified destruction efficiency.

(2) Estimate the destruction efficiency through process knowledge. Examples of information that could constitute process knowledge include calculations based on material balance, process stoichiometry, or previous test results provided the results are still relevant to the current vent stream conditions. You must document how process knowledge (if applicable) was used to determine the destruction efficiency.

(3) Calculate the destruction efficiency by conducting an additional performance test on the emissions stream following the N_2O abatement technology.

(e) If applicable, you must determine the abatement factor for each N_2O abatement technology. The abatement factor is calculated for each nitric acid train according to Equation 310-2 of this section.

$$AF_{N\,t} = \frac{P_{a\,t\,Abate}}{P_{a\,t}} \qquad \textbf{Equation 310-2}$$

Where:

$AF_{N\,t}$ = Abatement factor of N_2O abatement technology at nitric acid train *t* (fraction of annual production that abatement technology is operating).

$P_{a\,t}$ = Total annual nitric acid production from nitric acid train *t* (tonne acid produced, 100 percent acid basis).

$P_{a\,t\,Abate}$ = Annual nitric acid production from nitric acid train *t* during which N_2O abatement was used (tonne acid produced, 100 percent acid basis).

(f) You must determine the annual amount of nitric acid produced and the annual amount of nitric acid produced while each N_2O abatement technology is operating from each nitric acid train (100 percent basis).

(g) You must calculate N_2O emissions for each nitric acid train by multiplying the emissions factor (determined in Equation 310-1 of this section) by the annual nitric acid production and accounting for N_2O abatement, according to Equation 310-3 of this section:

$$E_{N_2Ot} = \sum_{N=1}^{z} \frac{EF_{N20t} * P_{a\,t} * (1 - (DF_{N\,t} * AF_{N\,t}))}{1000} \qquad \textbf{Equation 310-3}$$

Where:

E_{N2Ot} = N_2O mass emissions per year for nitric acid train *t* (tonnes).

EF_{N2Ot} = Average site-specific N_2O emissions factor for nitric acid train *t* (kg N_2O generated/tonne acid produced, 100 percent acid basis).

$P_{a\,t}$ = Annual nitric acid production from the train *t* (tonne acid produced, 100 percent acid basis).

$DF_{N\,t}$ = Destruction efficiency of N_2O abatement technology N that is used on nitric acid train *t* (percent of N_2O removed from air stream).

$AF_{N\,t}$ = Abatement factor of N_2O abatement technology for nitric acid train *t* (fraction of annual production that abatement technology is operating).

1000 = Conversion factor (kg/tonne).

z = Number of different N_2O abatement technologies.

(h) You must determine the annual nitric acid production emissions combined from all nitric acid trains at your facility using Equation 310-4 of this section:

$$N_2O = \sum_{t=1}^{m} E_{N2Ot} \qquad \textbf{Equation 310-4}$$

Where:

N_2O = Annual process N_2O emissions from nitric acid production facility (tonnes)

E_{N2Ot} = N_2O mass emissions per year for nitric acid train *t* (tonnes).

m = Number of nitric acid trains.

§ WCI.314 Sampling, Analysis, and Measurement Requirements

(a) You must conduct a new performance test and calculate a new site-specific emissions factor according to a test plan as specified in paragraphs (a)(1) through (a)(3) of this section.

(1) Conduct the performance test annually.

(2) Conduct the performance test when your nitric acid production process is changed, specifically when abatement equipment is installed.

(3) If you requested Director approval for an alternative method of determining N_2O concentration under WCI.313(a)(2), you must conduct the performance test if your request has not been approved by the Director within 150 days of the end of the reporting year in which it was submitted.

(b) You must measure the N_2O concentration during the performance test using one of the methods in paragraphs (b)(1) through (b)(3) of this section.

(1) EPA Method 320 at 40 CFR part 63, appendix A, Measurement of Vapor Phase Organic and Inorganic Emissions by Extractive Fourier Transform Infrared (FTIR) Spectroscopy.

(2) ASTM D6348-03 Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy.

(3) An equivalent method, with Director approval.

(c) You must determine the production rate(s) (100 percent basis) from each nitric acid train during the performance test according to paragraphs (c)(1) or (c)(2) of this section.

(1) Direct measurement of production and concentration (such as using flow meters or weigh scales, for production and concentration measurements).

(2) Existing plant procedures used for accounting purposes (i.e. dedicated tank-level and acid concentration measurements).

(d) You must conduct all performance tests in conjunction with the applicable methods approved by the Director. For each test, the facility must prepare an emission factor determination report that must include the items in paragraphs (d)(1) through (d)(3) of this section.

(1) Analysis of samples, determination of emissions, and raw data.

(2) All information and data used to derive the emissions factor(s).

(3) The production rate during each test and how it was determined.

(e) You must determine the monthly nitric acid production and the monthly nitric acid production during which N_2O abatement technology is operating from each nitric acid train according to the methods in paragraphs (c)(1) or (c)(2) of this section.

(f) You must determine the annual nitric acid production and the annual nitric acid production during which N_2O abatement technology is operating for each train by summing the respective monthly nitric acid production quantities.

§ WCI.315 Procedures for Estimating Missing Data

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraphs (a) and (b) of this section.

(a) For each missing value of nitric acid production, the substitute data shall be the best available estimate based on all available process data or data used for accounting purposes (such as sales records).

(b) For missing values related to the performance test, including emission factors, production rate, and N_2O concentration, you must conduct a new performance test according to the procedures in WCI.314 (a) through (d).

§ WCI.340 PHOSPHORIC ACID PRODUCTION

§ WCI.341 Source Category Definition

The phosphoric acid production source category consists of facilities that use a wet-process phosphoric acid process line to produce phosphoric acid by reacting phosphate rock with acid.

§ WCI.342 Greenhouse Gas Reporting Requirements

In addition to the information required by regulation, the annual emissions data report shall contain the following information:

(a) Annual CO_2 process emissions from all wet-process phosphoric acid production lines, as specified in WCI.343 (tonnes).

(b) CO_2, N_2O, and CH_4 emissions from stationary combustion units, as specified in WCI.20 (tonnes).

(c) Annual phosphoric acid production (tonnes).

(d) Annual phosphoric acid permitted production capacity (tonnes).

(e) Annual arithmetic average percent inorganic carbon in phosphate rock from monthly records (%).

(f) Annual phosphate rock consumption from monthly records (tonnes).

(g) Number of times missing data procedures were used to estimate phosphate rock consumption (months) and inorganic carbon contents of the phosphate rock (month).

§ WCI.343 Calculation of CO_2 Emissions

(a) Calculate CO_2 process emissions using Equation 340-1 and the measured inorganic carbon content and feedstock input of the phosphate rock.

$$CO_2 = \sum_{i=1}^{12} \frac{FS_i * CF_i * 3.664}{c} \qquad \textbf{Equation 340-1}$$

Where:

CO_2 = Annual carbon dioxide emitted (tonnes/year).
FS_i = Feedstock consumption in month *i* (tonnes/month).
CF_i = Carbonate content of feedstock (kg C/tonne feedstock) for month *i*.
3.664 = Ratio of molecular weights, CO_2 to carbon.
c = Conversion factor (1,000 kg/tonne).

§ WCI.344 Sampling, Analysis, and Measurement Requirements

The monthly mass of phosphate rock consumed shall be determined using either existing plant procedures that are used for accounting purposes (such as sales records) or data from existing monitoring equipment that is used to measure total mass flow of phosphorus-bearing feed.

The monthly inorganic carbon content shall be obtained as specified under paragraphs (a) and (b) of this section.

(a) Obtain a monthly grab sample of phosphate rock directly from the rock being fed to the process line according to the following requirements:

(1) Follow the applicable standard method in "Phosphate Mining States Methods Used and Adopted by the Association of Fertilizer and Phosphate Chemists AFPC Manual 10th Edition 2009 – Version 1.9".

(2) If phosphate rock is obtained from more than one origin in a month, a sample must be obtained from each origin of rock or a composite representative sample must be obtained.

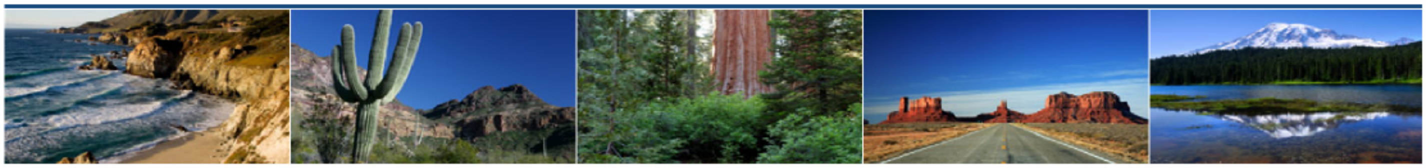
(b) Determine the inorganic carbon content of each monthly grab sample of phosphate rock (consumed in the production of phosphoric acid) using the applicable standard method in "Phosphate Mining States Methods Used and Adopted by the Association of Fertilizer and Phosphate Chemists AFPC Manual 10th Edition 2009 – Version 1.9".

§ WCI.345 Missing Data Procedures

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraphs (a) or (b) of this section. Records must be documented and kept of the procedures used for all such estimates.

(a) A substitute data value must be determined by calculated the arithmetic average of the quality-assured values of inorganic carbon contents of phosphate rock of origin *i* from samples immediately preceding and immediately following the missing data incident. If no quality-assured data on inorganic carbon contents of phosphate rock of origin *i* are available prior to the missing data incident, then the substitute data value shall be the first quality-assured value of inorganic carbon contents for phosphate rock of origin *i* obtained after the missing data period.

(b) For each missing value of monthly mass consumption of phosphate rock (by origin), the substitute data value shall be the best available estimate based on all available process data or data used for accounting purposes.



Due to the U.S. EPA finalizing publication of Part 98, Subpart W in November, 2010, the WCI has not yet performed detailed analyses on it for harmonization with cap and trade reporting. These analyses will be occurring in 2011. As such, for some specific emission sources identified in this quantification method option is given to facilities to report – for 2011 calendar year emissions only - using EPA equations and/or methods where these methods will give as or more accurate estimates of emissions than the otherwise prescribed methods.

§ WCI.350 NATURAL GAS TRANSMISSION AND DISTRIBUTION

§ WCI.351 Source Category Definition

This source category consists of the following:

(a) *Onshore natural gas transmission compression.* Onshore natural gas transmission compression means any stationary combination of compressors that move natural gas at elevated pressure from production fields or natural gas processing facilities in transmission pipelines to natural gas distribution pipelines or into storage. In addition, transmission compressor station may include equipment for liquids separation, natural gas dehydration, and tanks for the storage of water and hydrocarbon liquids. Residue (sales) gas compression operated by natural gas processing facilities are included in the onshore natural gas processing segment and are excluded from this segment.

(b) *Underground natural gas storage.* Underground natural gas storage means subsurface storage, including depleted gas or oil reservoirs and salt dome caverns that store natural gas that has been transferred from its original location for the primary purpose of load balancing (the process of equalizing the receipt and delivery of natural gas); natural gas underground storage processes and operations (including compression, dehydration and flow measurement, and excluding transmission pipelines); and all the wellheads connected to the compression units located at the facility that inject and recover natural gas into and from the underground reservoirs.

(c) *Liquefied natural gas (LNG) storage.* LNG storage means onshore LNG storage vessels located above ground, equipment for liquefying natural gas, compressors to capture and re-liquefy boil-off-gas, re-condensers, and vapourization units for re-gasification of the liquefied natural gas.

(d) *LNG import and export equipment.* LNG import equipment means all onshore or offshore equipment that receives imported LNG via ocean transport, stores LNG, re-gasifies LNG, and delivers re-gasified natural gas to a natural gas transmission or distribution system. LNG export equipment means all onshore or offshore equipment that receives natural gas, liquefies natural gas, stores LNG, and transfers the LNG via ocean transportation to any location, including locations in Canada.

(e) *Natural gas distribution.* Natural gas distribution consists of all natural gas equipment downstream of the station yard inlet shut-off valves of natural gas transmission pipelines at stations where pressure reduction and/or measuring first occurs for eventual delivery of natural gas to consumers.

(f) *Natural gas transmission pipelines.* Natural gas transmission pipelines means a high pressure pipeline (and associated equipment) transporting sellable quality natural gas from production or natural gas processing to natural gas distribution pressure let-down, metering and/or regulating stations before delivery to customers.

§ WCI.352 Greenhouse Gas Reporting Requirements

Where greenhouse gases are not emitted from a specific emission source identified in paragraphs (a) to (h) below, then the reported emissions for the specific source shall be reported as zero or "not applicable".

In addition to the information required by regulation, the annual emissions data report for both each individual facility over 10,000 tonnes, and the aggregate of facilities less than 10,000 tonnes (or as otherwise specified by regulation), must contain the following information:

(a) CO_2 and CH_4 (and N_2O, if applicable) emissions (in tonnes) from each industry segment specified in paragraph (b) through (f) of this section and from stationary and portable combustion equipment identified in paragraphs (g) and (h) of the section.

(b) For onshore natural gas transmission compression and natural gas transmission pipelines, report CO_2 and CH_4 (and N_2O, if applicable) emissions from the following sources:

(1) Compressor venting (from the following sources):

(i) Reciprocating compressors. *[WCI.353(f)]*

(ii) Centrifugal compressors. *[WCI.353(e)]*

(iii) Blowdown vent stacks. *[WCI.353(c)]*

(iv) Natural gas pneumatic continuous high bleed devices and pumps. *[WCI.353(a)]*

(v) Natural gas pneumatic continuous low bleed and intermittent (low and high) bleed device venting. *[WCI.353(b)]*

(vi) Other venting emission sources.* *[WCI.353(l)]*

(2) Compressor fugitive equipment leaks from valves, connectors, open ended lines, pressure relief valves and meters. *[WCI.353(g)]*

(3) Compressor station flaring. *[WCI.353(d)]*

(4) Compressor other fugitive emission sources.**[WCI.353(l)]*

(5) Pipeline above ground meters and regulators at custody transfer city gate stations, including fugitive equipment leaks from connectors, block valves, control valves, pressure relief valves, orifice meters, regulators, and open ended lines. *[WCI.353(g)]*

(6) Above ground meters and regulators at non-custody transfer city gate stations, including station equipment leaks. Customer meters are excluded and instead are reported under WCI.352(f)(9). *[WCI.353(h)]*

(7) Pipeline flaring. *[WCI.353(d)]*

(8) Pipeline below ground meters and regulators and valve fugitives. *[WCI.353(h)]*

(9) Pipeline other fugitive emission sources not covered in (b)(5), (b)(6), (b)(7), or (b)(8) above (including, but not limited to, third party hits, farm taps, tubing systems less than one half inch diameter, pipe leaks, and customer meter sets).* *[WCI.353(l)]*

(10) Pipeline other venting emission sources.**[WCI.353(l)]*

(11) Transmission storage tanks [Reserved].

(c) For underground natural gas storage, report CO_2 and CH_4 (and N_2O, if applicable) emissions from the following sources:

(1) Venting (from the following sources):

(i) Reciprocating compressors. *[WCI.353(f)]*

(ii) Centrifugal compressors. *[WCI.353(e)]*

(iii) Natural gas pneumatic continuous high bleed devices and pumps. *[WCI.353(a)]*

(iv) Natural gas pneumatic continuous low bleed and intermittent (low and high) bleed devices. *[WCI.353(b)]*

(v) Other venting emission sources.* *[WCI.353(l)]*

(2) Fugitive equipment leaks from valves, connectors, open ended lines, pressure relief valves and meters. *[WCI.353(g)], [WCI.353(h)]*

(3) Flares. *[WCI.353(d)]*

(4) Other fugitive emission sources.* *[WCI.353(l)]*

(d) For LNG storage, report CO_2 and CH_4 (and N_2O, if applicable) emissions from the following sources:

(1) Venting (from the following sources):

(i) Reciprocating compressors. *[WCI.353(f)]*

(ii) Centrifugal compressors. *[WCI.353(e)]*

(iii) Other venting emission sources.* *[WCI.353(l)]*

(2) Fugitive equipment leaks from valves, pump seals, connectors, vapour recovery compressors, and other equipment leak sources. *[WCI.353(g)], [WCI.353(h)]*

(3) Flares. *[WCI.353(d)]*

(4) Other fugitive emission sources.* *[WCI.353(l)]*

(e) LNG import and export equipment, report CO_2 and CH_4 (and N_2O, if applicable) emissions from the following sources:

(1) Venting (from the following sources):

(i) Reciprocating compressors. *[WCI.353(f)]*

(ii) Centrifugal compressors. *[WCI.353(e)]*

(iii) Blowdown vent stacks. *[WCI.353(c)]*

(iv) Other venting emission sources.* *[WCI.353(l)]*

(2) Fugitive equipment leaks from valves, pump seals, connectors, vapour recovery compressors, and other equipment leak sources. *[WCI.353(g)], [WCI.353(h)]*

(3) Flares. *[WCI.353(d)]*

(4) Other fugitive emission sources.**[WCI.353(l)]*

(f) For natural gas distribution, report CO_2 and CH_4 (and N_2O, if applicable) emissions from the following sources:

(1) Above ground meters and regulators, at custody transfer city gate stations, including fugitive equipment leaks from connectors, block valves, control valves, pressure relief valves, orifice meters, regulators, and open ended lines. Customer meters are excluded and instead are reported under WCI.352(f)(9). *[WCI.353(g)]*

(2) Above ground meters and regulators at non-custody transfer city gate stations, including station equipment leaks. Customer meters are excluded and instead are reported under WCI.352(f)(9). *[WCI.353(h)]*

(3) Below ground meters and regulators and vault fugitives. *[WCI.353(h)]*

(4) Pipeline main fugitive equipment leaks. *[WCI.353(h)]*

(5) Service line fugitive equipment leaks. *[WCI.353(h)]*

(6) Pipeline flaring. *[WCI.353(d)]*

(7) Flares. *[WCI.353(d)]*

(8) Other venting emission sources.* *[WCI.353(l)]*

(9) Other fugitive emission sources (including but not limited to third party hits, farm taps, tubing systems less than one half inch diameter, and customer meter sets).* *[WCI.353(l)]*

(g) Report CO_2, CH_4, and N_2O emissions from each stationary fuel combustion source type combusting field gas or process vent gas *[WCI.363(w)]* and fuels other than field gas or process vent gas. Report stationary combustion sources that combust fuels other than field gas or process vent gas using WCI.20 (General Stationary Combustion Sources) quantification methods.

(h) Report CO_2, CH_4, and N_2O emissions from each portable equipment combustion source type combusting field gas or process vent gas *[WCI.363(w)]* and fuels other than field gas or process vent gas. Report portable equipment combustion sources that combust fuels other than field gas or process vent gas using WCI.20 (General Stationary Combustion Sources) quantification methods.

(i) Report data for each aggregated source type within paragraph (b) through (f) of this section as follows (for each individual facility or aggregate of facilities reported, as required by regulation):

(1) Where there is a choice of quantification method used for a source, the specific method(s) used and under what circumstances.

(2) Facility- and company-specific emission factors used in place of Tables 350-1 to 350-5.

(3) Count of natural gas pneumatic continuous high bleed devices.

(4) Count of natural gas pneumatic continuous low bleed devices.

(5) Count of natural gas pneumatic intermittent (low and high) bleed devices.

(6) Count of natural gas driven pneumatic pumps.

(7) Total pipeline length.

(8) For each dehydrator unit report the following:

(i) Glycol dehydrators:

(A) The number of glycol dehydrators less than and greater than or equal to 11,328 Sm^3/day operated

(ii) Desiccant dehydrators:

(A) The number of desiccant dehydrators operated.

(9) For each compressor report the following:

(i) Type of compressor whether reciprocating, centrifugal dry seal, or centrifugal wet seal.
(ii) Compressor capacity in horsepower.
(iii)Number of blowdowns per year.
(iv) Operating mode(s) during the year

(10) For fugitive equipment leaks and population count/emission factor sources using emission factors are used for estimating emissions in WCI.353(g) and (h), report the following:

(i) Component count for each source for which an emission factor is provided in this document. Approximate counts may be provided for the 2011 calendar year (reported in 2012) in preparation for full counts in the 2012 calendar year.

(ii) Total counts of leaks found in leak detection surveys by type of leak source for which an emission factor is provided.

(11) For natural gas distribution, report the following in addition to other requirements:
(i) Number of custody transfer gate stations.

(12) Number of non-custody transfer gate stations.

(13) Identification (including geographic coordinates) of any facility that was above 1,000 tonnes of greenhouse gas emissions in the previous year that was:
(i) Acquired during the reporting year;
(ii) Sold, decommissioned, or shut-in during the reporting year; and,
(iii) Greenhouse gas emissions for the facility in the previous year.

** other venting emission or other fugitive sources not specificially listed are not required to be reported if a specific other venting or other fugitive source type is reasonably estimated to be below 0.5% of total operation emissions and total emissions not reported under this clause do not exceed 1% of total operation emissions (if an individual facility is part of a larger reporting operation, the 0.5% or 1% should be interpreted as 0.5% or 1% of the reporting operation emissions, otherwise interpret as 0.5% or 1% of the facility emissions). The applicable regulator may, upon request and provision of sufficient information, provide a list of sources believed to be below these thresholds for all operations for which reporting and verification would not be required.*

§ WCI.353 Calculation of Greenhouse Gas Emissions

If greenhouse gases are not emitted from one or more of the following emission sources, the reporter will not need to calculate emissions from the emission source(s) in question and reported emissions for the emission source(s) will be zero or "not applicable". Where a quantification method is not provided for a specific source (such as for other venting and other fugitive sources), industry inventory practices must be used to estimate emissions. For ambient conditions, reporters must use average atmospheric conditions or typical operating conditions as applicable to the respective monitoring methods in this section.

(a) Natural gas pneumatic continuous high bleed device venting and natural gas driven pneumatic pump venting.

(1) Calculate emissions from a natural gas pneumatic continuous high bleed flow control device venting as follows:

(i) Estimate gas consumption for all continuous high bleed natural gas powered devices using statistically defensible emission factors that are reviewed every three to five years*. Factors should be developed using separate representative samples of the populations of high-bleed devices. Samples do not necessarily need to be repeated over time at a given location. Prior to 2013, Calculation Methodology 2 may be used.

(ii) Calculate CH_4 and CO_2 emissions from continuous high bleed pneumatic devices using Equation 350-1 of this section.

$$E_{GHGi} = V_{NG} \times M_i \times \left(\frac{MW_i}{MVC}\right) \times 0.001 \qquad \textbf{Equation 350-1}$$

Where:

E_{GHGi}	=	Emissions of GHG *i* (CH_4 or CO_2) (tonnes).
V_{NG}	=	Volume of natural gas consumed by continuous high bleed pneumatic devices (m^3/year).
M_i	=	Mole fraction of CH_4 or CO_2 in natural gas supply.
MW_i	=	Molecular weight of GHG_i.
MVC	=	Molar volume conversion factor.
0.001	=	Conversion factor from kg to tonnes

(2) For pneumatic pumps and if in 2011 or 2012 the statistically defensible emission factor is not available for continuous high bleed pneumatic devices, use the following method to estimate emissions from continuous high bleed devices and natural gas driven pneumatic pumps.

(i) For continuous high bleed devices, calculate vented emissions using manufacturer data.

(A) Obtain from the manufacturer specific pneumatic device model natural gas bleed rate during normal operation.

(B) Calculate the natural gas emissions for each continuous bleed device using Equation 350-2 of this section.

$$E_{s,n} = B_s \times t \qquad \textbf{Equation 350-2}$$

Where:

$E_{s,n}$	=	Annual natural gas emissions at standard conditions (m^3).
B_s	=	Natural gas driven pneumatic device bleed rate volume at standard conditions, as provided by the manufacturer (m^3/minute).
T	=	Amount of time that the pneumatic device has been operational through the reporting period (minutes).

(C) If manufacturer data for a specific device is not available, then use data for a similar device model, size and operational characteristics (or published default values) to estimate emissions.

(ii) Calculate emissions from natural gas driven pneumatic pump venting as follows:

(A) Obtain from the manufacturer specific pump model natural gas emission (or manufacturer "gas consumption") per unit volume of liquid circulation rate at pump speeds and operating pressures.

(B) Maintain a log of the amount of liquid pumped annually from individual pumps.

(C) Calculate the natural gas emissions for each pump using Equation 350-3 of this section.

$$E_{s,n} = F_s \times V \qquad \textbf{Equation 350-3}$$

Where:

$E_{s,n}$ = Annual natural gas emissions at standard conditions (m^3/year).
F_s = Natural gas driven pneumatic pump gas emission in "emission per volume of liquid pumped at operating pressure" at standard conditions, as provided by the manufacturer (m^3/liter).
V = Volume of liquid pumped annually (liters/year).
.

(D) If manufacturer data for a specific pump in Equation 350-3 is not available, then use data for a similar pump model, size and operational characteristics (or published default values) to estimate emissions.

(iii) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (j) and (k) of this section.

(3) Provide the total number of continuous high bleed natural gas pneumatic devices and pneumatic pumps of each type as follows:
(i) In the first calendar year, all continuous high bleed natural gas pneumatic devices and pneumatic pumps must be counted.
(ii) For the calendar year immediately following first calendar year, and for calendar years thereafter, facilities must update the total count of continuous high bleed pneumatic devices and pneumatic pumps and adjust accordingly to reflect any modifications due to changes in equipment.

* *[a phased in metering approach per that in WCI.364(a) is being considered for potential application for continuous high bleed devices covered by WCI.350 in place of the statistically defensible emission factor approach.]*

(b) <u>Natural gas pneumatic continuous low bleed and intermittent (low and high) bleed device venting</u>. Calculate emissions from natural gas pneumatic low continuous bleed, and intermittent (low and high) bleed device venting (separately) using Equation 350-4 of this section.

$$Mass_{s,i} = Count \times EF \times GHG_i \times t \times \rho_i \times 0.001 \qquad \textbf{Equation 350-4}$$

Where:

$Mass_{s,i}$	=	Annual total mass GHG emissions at standard conditions from all natural gas pneumatic continuous low bleed, and intermittent (low and high) bleed device venting, for GHG *i* (tonnes/year).
Count	=	Total number of natural gas pneumatic continuous low bleed, or intermittent (low and high) bleed devices.
EF	=	Population volumetric emission factors for natural gas pneumatic continuous low bleed, or intermittent (low and high) bleed device venting listed in Tables 350-1 and 350-2 of this section for onshore natural gas transmission and underground natural gas storage facilities, respectively.
GHG_i	=	For sources covered by WCI.350 (natural gas transmission), the value for GHG_i is 1.
t	=	Total time the continuous low bleed, or intermittent (low and high) bleed device was operating during the year (hours).
ρ_i	=	Density of GHG *i*, (1.861 kg/m^3 for CO_2 and 0.678 kg/m^3 for CH_4 at STP of 15 ºC and 1 atmosphere).
0.001	=	Conversion factor from kilograms to tonnes.

(1) Provide the total number of continuous low bleed and intermittent (low and high) bleed natural gas pneumatic devices of each type as follows:
   (i) In the first calendar year, for the total number of each type, you may count the total of each type, or count any percentage number of each type plus an engineering estimate based on best available data of the number not counted.
   (ii) In the second calendar year, complete the count of all pneumatic devices, including any changes to equipment counted in prior years.
   (iii) For the calendar year immediately following the third consecutive calendar year, and for calendar years thereafter, facilities must update the total count of pneumatic devices and adjust accordingly to reflect any modifications due to changes in equipment.

(c) <u>Blowdown vent stacks</u>. Calculate blowdown vent stack emissions from depressurizing equipment to the atmosphere (excluding depressurizing to a flare, over-pressure relief, operating pressure control venting and blowdown of non-GHG gases) as follows:

(1) Calculate the total volume (including, but not limited to, pipelines, compressor case or cylinders, manifolds, suction and discharge bottles and vessels) between isolation valves determined by engineering estimates based on best available data.

(2) If the total volume between isolation valves is greater than or equal to 1.42 $Sm^{3,}$ retain logs of the number of blowdowns for each equipment type (including, but not limited to compressors, vessels, pipelines, headers, fractionators, and tanks). Blowdown volumes smaller than 1.42 $Sm^3$are exempt from reporting under paragraph (g) of this section

(3) Calculate the total annual venting emissions for each equipment type using Equation 350-5 of this section:

$$E_{s,n} = N \times \left(V_v \left[\frac{(273.15 + T_s)P_a}{(273.15 + T_a)P_s} \right] - V_v \times C \right)$$

Equation 350-5

Where:

$E_{s,n}$	=	Annual natural gas venting emissions at standard conditions from blowdowns (m^3).
N	=	Number of repetitive blowdowns for each equipment type of a unique volume in calendar year.
V_v	=	Total volume of blowdown equipment chambers (including, but not limited to, pipelines, compressors and vessels) between isolation valves (m^3).
C	=	Purge factor that is 1 if the equipment is not purged or zero if the equipment is purged using non-GHG gases.
T_s	=	Temperature at standard conditions (ºC).
T_a	=	Temperature at actual conditions in the blowdown equipment chamber (^oC).
P_s	=	Absolute pressure at standard conditions (kPa).
P_a	=	Absolute pressure at actual conditions in the blowdown equipment chamber (kPa).

(4) Calculate both CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (j) and (k) of this section.

(5) Blowdowns that are directed to flares use the WCI.353(d) flare stacks calculation method rather than WCI.353(c) blowdown vent stacks calculation method.

(d) Flare stacks. Calculate CO_2, CH_4, and N_2O emissions from a flare stack as follows:

(1) If there is a continuous flow measurement device on the flare, measured flow volumes can be used to calculate the flare gas emissions. If all of the flare gas is not measured by the existing flow measurement device, then the flow not measured can be estimated using engineering calculations based on best available data or company records. If there is not a continuous flow measurement device on the flare, a flow measuring device can be installed on the flare or use engineering calculations based on process knowledge, company records, and best available data can be used.

(2) If there is a continuous gas composition analyzer on gas to the flare, these compositions must be used in calculating emissions. If there is not a continuous gas composition analyzer on gas to the flare, the appropriate gas compositions for each stream of hydrocarbons going to the flare must be used as follows:

(i) When the stream going to flare is natural gas, use the GHG mole percent in feed natural gas for all streams upstream of the de-methanizer or dew point control and GHG mole percent in facility specific residue gas to transmission pipeline systems for all emissions sources downstream of the de-methanizer overhead or dew point control for onshore natural gas processing facilities.

(ii) When the stream going to the flare is a hydrocarbon product stream, such as ethane, butane, pentane-plus and mixed hydrocarbons, then use a representative composition from the source for the stream determined by engineering calculation based on process knowledge and best available data.

(3) Determine flare combustion efficiency from manufacturer. If not available, assume that flare combustion efficiency is 98 percent.

(4) Calculate GHG volumetric emissions at actual conditions using Equations 350-6, 350-7, 350-8, and 350-9 of this section.

$$E_{a,CH4} = V_a \times (1-\eta) \times X_{CH4}$$ **Equation 350-6**

$$E_{a,CO2}(noncombusted) = V_a \times X_{CO2}$$ **Equation 350-7**

$$E_{a,CO2}(combusted) = \sum_j \eta \times V_a \times Y_j \times R_j$$ **Equation 350-8**

$$E_{a,CO2}(total) = E_{a,CO2}(combusted) + E_{a,CO2}(noncombusted)$$ **Equation 350-9**

Where:

$E_{a,CH4}$	=	Contribution of annual noncombusted CH_4 emissions from flare stack under ambient conditions (m^3).
$E_{a,CO2}$ (noncombusted)	=	Contribution of annual CO_2 emissions from CO_2 in the inlet gas passing through the flare noncombusted under ambient conditions (m^3).
$E_{a,CO2}$ (combusted)	=	Contribution of annual emissions from combustion from flare stack under ambient conditions (m^3).
V_a	=	Volume of natural gas sent to flare during the year (m^3).
η	=	Percent of natural gas combusted by flare (default is 98 percent). For gas sent to an unlit flare, η is zero.
X_i	=	Mole fraction of GHG *i* in gas to the flare.
Y_j	=	Mole fraction of natural gas hydrocarbon constituents *j* (i.e., methane, ethane, propane, butane, and pentanes plus).
R_j	=	Number of carbon atoms in the natural gas hydrocarbon constituent *j*; 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes plus).

(5) Calculate GHG volumetric emissions at standard conditions using calculations in paragraph (i) of this section.

(6) Calculate both CH_4 and CO_2 mass emissions from volumetric CH_4 and CO_2 emissions using calculation in paragraph (k) of this section.

(7) Calculate N_2O emissions using the Equation 350-10.

$$E_{N2O} = Fuel \times HHV \times EF \times 0.001$$

Equation 350-10

Where:

E_{N2O}	=	Annual N_2O emissions from the combustion of a particular type of fuel (tonnes).
Fuel	=	Mass or volume of the fuel combusted (mass or volume per year, choose appropriately to be consistent with the units of HHV).
HHV	=	High heat value of the fuel from paragraphs (d)(7)(i), (d)(7)(ii) or (d)(7)(iii) of this section (units must be consistent with Fuel).
EF	=	Use 9.52×10^{-5} kg N_2O/GJ.
0.001	=	Conversion factor from kilograms to tonnes.

(i) For fuels listed in Table 20-1, use the provided default HHV in the table.
(ii) For field gas or process vent gas, use 4.579×10^{-2} GJ/m^3 for HHV.
(iii) For fuels not listed in Table 20-1 and not field gas or process vent gas, you must use the methodology set forth in the Tier 2 methodology described in WCI.20 to determine HHV.

(8) To avoid double-counting, this emissions source excludes any emissions calculated under other emissions sources in this section. Where gas to be flared is manifolded from multiple sources in WCI.353 to a common flare, report all flaring emissions under WCI.353(d).

(e) Centrifugal compressor venting. Calculate emissions from centrifugal compressor vents as follows:*

(1) For each centrifugal compressor determine the volume of vapours from wet seal oil degassing tank sent to an atmospheric vent or flare using a temporary or permanent flow measurement meter such as, but not limited to, a vane anemometer according to methods set forth in WCI.354(b).

(2) Estimate annual emissions using meter flow measurement using Equation 350-11 of this section.

$$E_{a,i} = MT \times t \times M_i \times (1 - B)$$

Equation 350-11

Where:

$E_{a,i}$ = Annual GHG *i* (either CH_4 or CO_2) volumetric emissions at ambient conditions.
MT = Meter reading of gas emissions per unit time.
t = Total time the compressor associated with the wet seal(s) is operational in the reporting year.
M_i = Mole percent of GHG *i* in the degassing vent gas; use the appropriate gas compositions in paragraph (j)(2) of this section.
B = Percentage of centrifugal compressor vent gas sent to vapour recovery or fuel gas or other beneficial use as determined by keeping logs of the number of operating hours for the vapour recovery system and the amount of vent gas that is directed to the fuel gas system.

(3) An engineering estimate approach based on similar equipment specifications and operating conditions may be used to determine the MT variable in place of actual metered values for centrifugal compressors that are isolated for extended periods of time and used for peaking purposes in place of metered gas emissions if an applicable meter is not present on the compressor.

(4) Calculate CH_4 and CO_2 volumetric emissions at standard conditions using paragraph (i) of this section.

(5) Calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (k) of this section.

(6) Calculate emissions from degassing vent vapours to flares as follows:

(i) Use the degassing vent vapour volume and gas composition as determined in paragraphs (e)(1) through (3) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (d) of this section to determine degassing vent vapour emissions from the flare.

(7) Emissions from dry seal centrifugal compressor vents, blow down valve leakage and unit isolation valve leakage to open ended vented are covered under WCI.353(l).

* For 2011 calendar year emissions only, an operator may use other equations and methods as presented by the EPA in 40 CFR Part 98.233(o) so long as the method is as accurate or more accurate as that presented here for the specific emission source in question and the appropriate regulator is notified of the choice.

(f) Reciprocating compressor venting. Calculate annual CH_4 and CO_2 emissions from all reciprocating compressor vents as follows.* Where venting emissions are sent to a common flare, calculate emissions using WCI.352(d).

(1) Estimate annual emissions using the flow measurement in (f)(2) or (f)(3) below and Equation 350-12.

$$E_{a,i,m} = MT \times t \times M_i$$

Equation 350-12

Where:

$E_{a,i,m}$ = Annual volumetric emissions of GHG *i* (either CH_4 or CO_2) at ambient conditions.

MT = Measured volumetric gas emissions (m^3/hour) under ambient conditions.

t = Total time the compressor is in the mode for which $E_{a,i,m}$ is being calculated, in the calendar year (hours).

M_i = Mole fraction of GHG *i* in the vent gas; use the appropriate gas compositions in paragraph (j)(2) of this section.

(2) If the reciprocating rod packing and blowdown vent is connected to an open ended vent line then use one of the following two methods to calculate emissions**.**

(i) Measure emissions from all vents (including emissions manifolded to common vents) including rod packing, unit isolation valves, and blowdown vents using either calibrated bagging or high volume sampler according to methods set forth in WCI.354(c) and (d).

(ii) Use a temporary meter such as a vane anemometer or a permanent meter such as an orifice meter to measure emissions from all vents (including emissions manifolded to a common vent) including rod packing vents, unit isolation valves, and blowdown valves according to methods set forth in WCI.354(b). If you do not have a permanent flow meter, you may install a port for insertion of a temporary meter or a permanent flow meter on the vents. For through-valve leakage to open ended vents, such as unit isolation valves on not operating, depressurized compressors and blowdown valves on pressurized compressors, you may use an acoustic detection device according to methods set forth in WCI.354(a).

(3) If the rod packing case is not equipped with a vent line use the following method to estimate emissions:

(i) Use the methods described in WCI.354(a) to conduct a progressive sample leak detection of fugitive equipment leaks from the packing case into an open distance piece, or from the compressor crank case breather cap or vent with a closed distance piece.

(ii) Measure emissions using a high flow sampler, or calibrated bag, or appropriate meter according to methods set forth in WCI.354(b), (c), or (d).

(4) Conduct an annual measurement for each compressor in the mode in which it is found during the annual measurement. Measure emissions from (including emissions manifolded to common vents) reciprocating rod packing vents, unit isolation valve vents, and blowdown valve vents.

(i) Operating or standby pressurized mode, blowdown vent leakage through the blowdown vent stack.

(ii) Operating mode, reciprocating rod packing emissions.

(iii) Not operating, depressurized mode, unit isolation valve leakage through the blowdown vent stack, without blind flanges.

(A) For the not operating, depressurized mode, each compressor must be measured at least once in any three consecutive calendar years if this mode is not found in the annual measurement. If a compressor is not operated and has blind flanges in place throughout the 3 year period, measurement is not required in this mode. If the compressor is in standby depressurized mode without blind flanges in place and is not operated throughout the 3 year period, it must be measured in the standby depressurized mode

(5) Calculate CH_4 and CO_2 volumetric emissions at standard conditions using calculations in paragraph (i) of this section.

(6) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in paragraphs (j) and (k) of this section.

(7) Determine if the reciprocating compressor vent vapors are sent to a vapor recovery system.
   (i) Adjust the emissions estimated in paragraphs (f)(1) of this section downward by the magnitude of emissions recovered using a vapor recovery system as determined by engineering estimate based on best available data.

* For 2011 calendar year emissions only, an operator may use other equations and methods as presented by the EPA in 40 CFR Part 98.233(p) so long as the method is as accurate or more accurate as that presented here for the specific emission source in question and the appropriate regulator is notified of the choice.

(g) Leak detection and leaker emission factors. Existing legislative or regulatory requirements or progressive sampling methods described in WCI.354(a) must be used to conduct a leak detection of fugitive equipment leaks from all sources listed in WCI.352(b)(2), b(6), (c)(2), (d)(2), (e)(2), and (f)(1). This paragraph (g) applies to emissions sources in streams with gas content greater than 10 percent CH_4 plus CO_2 by weight. Emissions sources in streams with gas content less than 10 percent CH_4 plus CO_2 by weight need to be reported instead under WCI.354(l). Tubing systems equal to or less than one half inch diameter are exempt from the requirements of this paragraph (g) need to be reported under WCI.354(l).

If fugitive equipment leaks are detected for sources listed in this paragraph, calculate emissions using Equation 350-13 (for volumetric emission factor [m^3/hour/component]) or Equation 350-14 (for mass emission factors [tonnes/hour/component]) of this section, as appropriate, for each source with fugitive equipment leaks.

$$E_{s,i} = Count \times EF_s \times GHG_i \times t_x \times \rho_i \times 0.001$$

Equation 350-13

$$E_{s,i} = Count \times EF_s \times GHG_i \times t_x$$

Equation 350-14

Where:

$E_{s,i}$	=	Annual total mass emissions of GHG *i* (CH_4 or CO_2) at standard conditions from each fugitive equipment leak source (tonnes/year).
Count	=	Total number of this type of emission source found to be leaking during t_x.
EF_s	=	Leaker emission factor for specific sources listed in Table 350-1 through Table 350-5 of this section or facility/company-specific emission factors used in place of Tables 350-1 to 350-5 (m^3/component/year for Equation 350-13 and tonnes/component/year for Equation 350-14).
GHG_i	=	For volumetric emissions in Equation 350-13, use 1 for CH_4 and 1.1×10^{-2} for CO_2. For mass emissions in Equation 350-14, use mass fractions of CH_4 and CO_2 from operation/facility specific data or the 2007 Canadian Energy Partnership for Environmental Innovation Methodology Manual.[1]
t_x	=	Total time the component was found leaking and operational, in hours. If one leak detection survey is conducted, assume the component was leaking from the start of the year until the leak was repaired and then zero for the remainder of the year. If the leak was not repaired, assume the component was leaking for the entire year. If multiple leak detection surveys are conducted, assume that the component found to be leaking has been leaking since the previous survey, or the beginning of the calendar year. For the last leak detection survey in the calendar year, assume that all leaking components continue to leak until the end of the calendar year or until the component was repaired and then zero until the end of the year.
ρ_i	=	Density of GHG *i* (1.861 kg/m^3 for CO_2 and 0.678 kg/m^3 for CH_4 at STP of 15 ºC and 1 atmosphere*).
0.001	=	Conversion factor from kilograms to tonnes.

(1) Onshore natural gas transmission compression facilities shall use the appropriate default leaker emission factors listed in Table 350-1 of this section for fugitive equipment leaks detected from connectors, valves, pressure relief valves, meters, and open ended lines.

(2) Underground natural gas storage facilities for storage stations shall use the appropriate default leaker emission factors listed in Table 350-2 of this section for fugitive equipment leaks detected from connectors, valves, pressure relief valves, meters, and open ended lines.

(3) LNG storage facilities shall use the appropriate default leaker emission factors listed in Table 350-3 of this section for fugitive equipment leaks detected from valves, pump seals, connectors, and other equipment.

(4) LNG import and export facilities shall use the appropriate default leaker emission factors listed in Table 350-4 of this section for fugitive equipment leaks detected from valves; pump seals; connectors; and other.

[1] Clearstone Engineering Ltd. *Methodology Manual: Estimation of Air Emissions from the Canadian Natural Gas Transmission, Storage and Distribution System.* Prepared for Canadian Energy Partnership for Environmental Innovation (CEPEI). 2007

(5) Natural gas distribution facilities for above ground meters and regulators at city gate stations at custody transfer shall use the appropriate default leaker emission factors listed in Table 350-5 of this section for fugitive equipment leaks detected from connectors, block valves, control valves, pressure relief valves, orifice meters, regulators, and open ended lines.

(h) <u>Population count and emission factors</u>. This paragraph applies to emissions sources listed in WCI.352 b(7), b(9), (c)(2), (d)(2), (e)(2), (f)(2), (f)(3), (f)(4) and (f)(5) on streams with gas content greater than 10 percent CH_4 plus CO_2 by weight. Emissions sources in streams with gas content less than 10 percent CH_4 plus CO_2 by weight do not need to be reported. Tubing systems equal or less than one half inch diameter are exempt from the requirements of paragraph (h) of this section and instead are to be reported under WCI.353(l).

Calculate emissions from all sources listed in this paragraph using Equation 350-15 (for volumetric emission factor [m^3/hour/component]) or Equation 350-16 (for mass emission factors [tonnes/hour/component]) of this section, as appropriate.

$$E_{s,i} = Count \times EF_s \times GHG_i \times t \times \rho_i \times 0.001$$

Equation 350-15

$$E_{s,i} = Count \times EF_s \times GHG_i \times t$$

Equation 350-16

Where:

$E_{s,i}$ = Annual total mass GHG emissions of GHG *i* (CH_4 or CO_2) at standard conditions from each fugitive source (tonnes/year).

Count = Total number of this type of emission source at the facility. Average component counts by major equipment pieces from the 2007 Canadian Energy Partnership for Environmental Innovation Methodology Manual (or other relevant Canadian Gas Association and/or Canadian Association of Petroleum Producers documentation) may be used as appropriate for operations and required by (h)(1) through (h)(5), below. If facility or company specific major equipment count data that meet or exceed the quality of the relevant CGA default count data are available, they must be used in its place.

EF_s = Population emission factor for specific sources listed in Table 350-1 through Table 350-5 of this section (m3/component/year for Equation 350-15 and tonnes/component/year for Equation 350-16). EF for non-custody transfer city gate stations is determined in Equation 350-17. The direction on the use of Tables 350-1 through 350-5 provided prior to the tables must be followed.

GHG_i = For volumetric emissions in Equation 350-15, use 1 for CH_4 and 1.1×10^{-2} for CO_2. For mass emissions in Equation 350-16, use mass fractions of CH_4 and CO_2 from operation/facility specific data or the 2007 Canadian Energy Partnership for Environmental Innovation Methodology Manual.

t	=	Total time the specific source associated with the fugitive equipment leak was operational in the reporting year (hours).
ρ_i	=	Density of GHG *i* (1.861 kg/m^3 for CO_2 and 0.678 kg/m^3 for CH_4 at STP of 15 ºC and 1 atmosphere*).
0.001	=	Conversion factor from kilograms to tonnes.

(1) Underground natural gas storage facilities for storage wellheads shall use the appropriate default population emission factors listed in Table 350-2 of this section for fugitive equipment leaks from connectors, valves, pressure relief valves, and open ended lines.

(2) LNG storage facilities shall use the appropriate default population emission factors listed in Table 350-3 of this section for fugitive equipment leaks from vapour recovery compressors.

(3) LNG import and export facilities shall use the appropriate default population emission factor listed in Table 350-4 of this section for fugitive equipment leaks from vapour recovery compressors.

(4) Natural gas distribution facilities shall use the appropriate emission factors as described in paragraph (h)(5) of this section.

(i) Below grade meters and regulators; mains; and services, shall use the appropriate default population emission factors listed in Table 350-5 of this section.

(ii) Above grade meters and regulators at city gate stations not at custody transfer as listed WCI.352(f)(5), must use the total volumetric GHG emissions at standard conditions for all equipment leak sources calculated in paragraph (i)(6) of this section to develop facility emission factors using Equation 350-17 of this section. The calculated facility emission factor from Equation 350-17 of this section shall be used in Equations 350-15 and 350-16 of this section.

$$EF = \sum \frac{E_{s,i}}{Count}$$

Equation 350-17

Where:

EF	=	Facility emission factor for a meter at above grade M&R at city gate stations not at custody transfer in meters cubed per meter per year.
$E_{s,i}$	=	Annual volumetric GHG emissions at standard condition from all equipment leak sources at all above grade M&R city gate stations at custody transfer, from paragraph (i) of this section.
Count	=	Total number of meter runs at all above grade M&R city gate stations at custody transfer

(iii) To ensure proper calculation of emissions from pipeline main equipment leaks, Equations 350-15 and 350-16 and their inputs may be modified as necessary to meet 2007 Canadian Energy Partnership for Environmental Innovation Methodology Manual standards. For example, the length of the installed underground pipeline should be used in place of count and company specific leak data is permitted.

(i) Volumetric emissions. Calculate volumetric emissions at standard conditions as specified in paragraphs (i)(1) or (2) of this section determined by engineering estimate based on best available data unless otherwise specified.

(1) Calculate natural gas volumetric emissions at standard conditions by converting ambient temperature and pressure of natural gas emissions to standard temperature and pressure (15 ºC and 1 atmosphere in Canada) natural gas using Equation 350-18 of this section.

$$E_{s,n} = \frac{E_{a,n} \times (273.15 + T_s) \times P_a}{(273.15 + T_a) \times P_s}$$

Equation 350-18

Where:

$E_{s,n}$	=	Natural gas volumetric emissions at standard temperature and pressure (STP) conditions (m^3).
$E_{a,n}$	=	Natural gas volumetric emissions at ambient conditions (m^3).
T_s	=	Temperature at standard conditions (^oC).
T_a	=	Temperature at actual emission conditions (^oC).
P_s	=	Absolute pressure at standard conditions (kPa).
P_a	=	Absolute pressure at ambient conditions (kPa).

(2) Calculate GHG volumetric emissions at standard conditions by converting ambient temperature and pressure of GHG emissions to standard temperature and pressure using Equation 350-19 this section.

$$E_{s,i} = \frac{E_{a,i} \times (273.15 + T_s) \times P_a}{(273.15 + T_a) \times P_s}$$

Equation 350-19

Where:

$E_{s,i}$	=	GHG *i* volumetric emissions at standard temperature and pressure (STP) conditions (m^3).
$E_{a,i}$	=	GHG *i* volumetric emissions at actual conditions (m^3).
T_s	=	Temperature at standard conditions. (^oC).
T_a	=	Temperature at actual emission conditions. (^oC).
P_s	=	Absolute pressure at standard conditions (kPa).
P_a	=	Absolute pressure at ambient conditions (kPa).

(j) GHG volumetric emissions. Calculate GHG volumetric emissions at standard conditions as specified in paragraphs (j)(1) and (2) of this section determined by engineering estimate based on best available data unless otherwise specified.

(1) Estimate CH_4 and CO_2 emissions from natural gas emissions using Equation 350-20 of this section.

$$E_{s,i} = E_{s,n} \times M_i$$

Equation 350-20

Where:

$E_{s,i}$	=	GHG *i* (either CH_4 or CO_2) volumetric emissions at standard conditions.
$E_{s,n}$	=	Natural gas volumetric emissions at standard conditions.
M_i	=	Mole fraction of GHG *i* in the natural gas.

(2) For Equation 350-20 of this section, the mole fraction, M_i, shall be the annual average mole fraction for each facility, as specified in paragraphs (j)(2)(i) through (v) of this section.

(i) GHG mole fraction in transmission pipeline natural gas that passes through the facility for onshore natural gas transmission compression facilities.

(ii) GHG mole fraction in natural gas stored in underground natural gas storage facilities.

(iii) GHG mole fraction in natural gas stored in LNG storage facilities.

(iv) GHG mole fraction in natural gas stored in LNG import and export facilities.

(v) GHG mole fraction in local distribution pipeline natural gas that passes through the facility for natural gas distribution facilities.

(k) GHG mass emissions. Calculate GHG mass emissions in carbon dioxide equivalent at standard conditions by converting the GHG volumetric emissions into mass emissions using Equation 350-21 of this section.

$$Mass_{s,i} = E_{s,i} \times \rho_i \times GWP \times 0.001$$

Equation 350-21

Where:

$Mass_{s,i}$	=	GHG *i* (either CH_4 or CO_2) mass emissions at standard conditions (tonnes CO_2e).
$E_{s,i}$	=	GHG *i* (either CH_4 or CO_2) volumetric emissions at standard conditions (m^3).
ρ_i	=	Density of GHG *i* (1.861 kg/m^3 for CO_2 and 0.678 kg/m^3 for CH_4 at STP of 15 degrees celsius and 1 atmosphere*).
GWP	=	Global warming potential of GHG *i*, (1 for CO_2 and 21 for CH_4, and 310 for N_2O).

0.001 = Conversion factor from kilograms to tonnes.

* gas densities calculated using the 12th edition of the Gas Processors Suppliers Association Engineering Data Book.

(l) Other venting or fugitive emissions. All venting or fugitive emissions not covered by quantification methods in WCI.353 must be calculated by methodologies consistent with those presented here, in the 2007 Canadian Energy Partnership for Environmental Innovation Methodology Manual[2] (as amended from time to time), or in other relevant Canadian Gas Association documentation.

§ WCI.354 Sampling, Analysis, and Measurement Requirements

Instruments used for sampling, analysis and measurement must be operated and calibrated according to legislative, manufacturer's, or other written specifications or requirements. All sampling, analysis and measurement must be conducted only by, or under the direct supervision of individuals with demonstrated understanding and experience in the application (and principles related) of the specific sampling, analysis and measurement technique in use.

(a) (i) If a documented leak detection or integrity management standard or requirement that is required by legislation or regulation such as CSA Z662-07 Oil & Gas Pipeline Systems or similar standard Canadian Gas Association methodologies (as amended from time to time) is used, the documented standard or requirement must be followed – including service schedules for different components and/or facilities - with reporting as required for input to the calculation methods herein.

(ii) If there is no such legal requirement, then progressive sampling is required using one of the methods outlined below in combination with best industry practices for use of the method– including service schedules for different components - to determine the count of leaks (and time leaking) required in WCI.353(f), (g), and (h) as applicable. Progressive sampling means establishing a statistically valid baseline sample of leaks under normal operating conditions for the 2011 and 2012 calendar years, with subsequent sampling determined based random or spot sampling, modeling or measurement of leaks under normal operating conditions. A minimum of 18 months and a maximum of 36 months is allowed between surveys. This interval is determined based on whether there are indications of leaks. If a leak found and immediately repaired, the existing schedule may be maintained.

Leak detection for fugitive equipment leaks must be performed for all identified equipment in operation or on standby mode during a reporting period.

(1) Optical gas imaging instrument. Use an optical gas imaging instrument for fugitive equipment leaks detection in accordance with 40 CFR part 60, subpart A, §60.18(i)(1) and (2) *Alternative work practice for monitoring equipment leaks* (or per relevant

[2] Clearstone Engineering Ltd. *Methodology Manual: Estimation of Air Emissions from the Canadian Natural Gas Transmission, Storage and Distribution System.* Prepared for Canadian Energy Partnership for Environmental Innovation (CEPEI). 2007.

standard in Canada). In addition, the optical gas imaging instrument must be operated to image the source types required by this proposed reporting rule in accordance with the instrument manufacturer's operating parameters. The optical gas imaging instrument must comply with the following requirements:

(i) Provide the operator with an image of the potential leak points for each piece of equipment at both the detection sensitivity level and within the distance used in the daily instrument check described in the relevant best practices. The detection sensitivity level depends upon the frequency at which leak monitoring is to be performed.
(ii) Provide a date and time stamp for video records of every monitoring event.

(2) Bubble tests.

(3) Portable organic vapour analyzer. Use a portable organic vapour analyzer in accordance with US EPA Method 21 or as outlined in standard Canadian Gas Association methodologies or the CAPP Best Management Practices for Fugitive Emissions

(4) Other methods as outlined in standard Canadian Gas Association methodologies or the CAPP Best Management Practices for Fugitive Emissions may be used as necessary for operational circumstances. Other methods that are deemed to be technically sound based on an engineering assessment may also be used as necessary for operational circumstances provided that sufficient documentation as to the method used, results on tests, its reliability and accuracy is maintained and updated at regular intervals.

(b) All flow meters, composition analyzers and pressure gauges that are used to provide data for the GHG emissions calculations shall use measurement methods, maintenance practices, and calibration methods, prior to the first reporting year and in each subsequent reporting year using an appropriate standard method published by a consensus standards organization such as Canadian Standards Association (CSA), Canadian Gas Association, Canadian Energy Pipeline Association (CEPA), ASTM International, American National Standards Institute (ANSI), the relevant provincial or national oil and gas regulator, Measurement Canada, Canadian Association of Petroleum Producers (CAPP), American Petroleum Institute (API), American Society of Mechanical Engineers (ASME), and North American Energy Standards Board (NAESB). If a consensus based standard is not available, industry standard practices such as manufacturer instructions must be used.

(c) Use calibrated bags (also known as vent bags) only where the emissions are at near-atmospheric pressures and hydrogen sulphide levels are such that it is safe to handle and can capture all the emissions, below the maximum temperature specified by the vent bag manufacturer, and the entire emissions volume can be encompassed for measurement.

(1) Hold the bag in place enclosing the emissions source to capture the entire emissions and record the time required for completely filling the bag. If the bag inflates in less than one second, assume one second inflation time.

(2) Perform three measurements of the time required to fill the bag, report the emissions as the average of the three readings.

(3) Estimate natural gas volumetric emissions at standard conditions using calculations in WCI.353(i).

(4) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in WCI.353(j) and (k).

(d) Use a high volume sampler to measure emissions within the capacity of the instrument.

(1) A technician following (and competent to follow) manufacturer instructions shall conduct measurements, including equipment manufacturer operating procedures and measurement methodologies relevant to using a high volume sampler, positioning the instrument for complete capture of the fugitive equipment leaks without creating backpressure on the source.

(2) If the high volume sampler, along with all attachments available from the manufacturer, is not able to capture all the emissions from the source then you shall use anti-static wraps or other aids to capture all emissions without violating operating requirements as provided in the instrument manufacturer's manual.

(3) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in WCI.353(j) and (k).

(4) Calibrate the instrument at 2.5 percent methane with 97.5 percent air and 100 percent CH_4 by using calibrated gas samples and by following manufacturer's instructions for calibration.

§ WCI.355 Procedures for Estimating Missing Data

A complete record of all estimated and/or measured parameters used in the GHG emissions calculations is required. If data are lost or an error occurs during annual emissions estimation or measurements, the estimation or measurement activity for those sources must be repeated as soon as possible, including in the subsequent reporting year if missing data are not discovered until after December 31 of the reporting year, until valid data for reporting is obtained. Data developed and/or collected in a subsequent reporting year to substitute for missing data cannot be used for that subsequent year's emissions estimation. Where missing data procedures are used for the previous year, at least 30 days must separate emissions estimation or measurements for the previous year and emissions estimation or meausrements for the current year of data collection. For missing data that are continuously monitored or measured (for example flow meters), or for missing temperature and pressure data, the reporter may use best available data for use in emissions determinations. The reporter must record and report the basis for the best available data in these cases.

§ WCI.356 Definitions

Blowdown vent stack emissions mean natural gas and/or CO_2 released due to maintenance and/or blowdown operations including compressor blowdown and emergency shut-down (ESD) system testing.

Calibrated bag means a flexible, non-elastic, anti-static bag of a calibrated volume that can be affixed to a emitting source such that the emissions inflate the bag to its calibrated volume.

Centrifugal compressor means any equipment that increases the pressure of a process natural gas or CO_2 by centrifugal action, employing rotating movement of the driven shaft.

Centrifugal compressor dry seals mean a series of rings around the compressor shaft where it exits the compressor case that operates mechanically under the opposing forces to prevent natural gas or CO_2 from escaping to the atmosphere.

Centrifugal compressor dry seals emissions mean natural gas or CO_2 released from a dry seal vent pipe and/or the seal face around the rotating shaft where it exits one or both ends of the compressor case.

Centrifugal compressor wet seal degassing venting emissions means emissions that occur when the high-pressure oil barriers for centrifugal compressors are depressurized to release absorbed natural gas or CO_2. High-pressure oil is used as a barrier against escaping gas in centrifugal compressor shafts. Very little gas escapes through the oil barrier, but under high pressure, considerably more gas is absorbed by the oil. The seal oil is purged of the absorbed gas (using heaters, flash tanks, and degassing techniques) and recirculated. The separated gas is commonly vented to the atmosphere.

Component means each metal to metal joint or seal of non-welded connection separated by a compression gasket, screwed thread (with or without thread sealing compound), metal to metal compression, or fluid barrier through which natural gas or liquid can escape to the atmosphere.

Compressor means any machine for raising the pressure of a natural gas by drawing in low pressure natural gas and discharging significantly higher pressure natural gas.

Continuous bleed means a continuous flow of pneumatic supply gas to the process measurement device (e.g. level control, temperature control, pressure control) where the supply gas pressure is modulated by the process condition, and then flows to the valve controller where the signal is compared with the process set-point to adjust gas pressure in the valve actuator.

De-methanizer means the natural gas processing unit that separates methane rich residue gas from the heavier hydrocarbons (e.g., ethane, propane, butane, pentane-plus) in feed natural gas stream.

Equipment leak detection means the process of identifying emissions from equipment, components, and other point sources.

Engineering estimation, for the purposes of WCI.350 and WCI.360 means an estimate of emissions based on engineering principles applied to measured and/or approximated physical parameters such as dimensions of containment, actual pressures, actual temperatures, and compositions.

External combustion means fired combustion in which the flame and products of combustion are separated from contact with the process fluid to which the energy is delivered. Process fluids may be air, hot water, or hydrocarbons. External combustion equipment may include fired heaters, industrial boilers, and commercial and domestic combustion units.

Farm taps are pressure regulation stations that deliver gas directly from transmission pipelines to generally rural customers. The gas may or may not be metered, but always does not pass through a city gate station

Field gas means natural gas extracted from a production well prior to its entering the first stage of processing, such as dehydration.

Flare combustion efficiency means the fraction of natural gas, on a volume or mole basis, that is combusted at the flare burner tip.

Fugitive emissions means the unintended or incidental emissions of greenhouse gases from the transmission, processing, storage, use or transportation of fossil fuels, greenhouse gases, or other.

Fugitive equipment leak means the those fugitive emissions which could not reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening.

Gas conditions mean the actual temperature, volume, and pressure of a gas sample.

High-bleed pneumatic devices are automated continuous bleed control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream which is regulated by the process condition flows to a valve actuator controller where it vents (bleeds) to the atmosphere at a rate in excess of six standard cubic feet per hour.

Intermittent bleed pneumatic devices mean automated flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. These are snap-acting or throttling devices that discharge the full volume of the actuator intermittently when control action is necessary, but does not bleed continuously.

Internal combustion means the combustion of a fuel that occurs with an oxidizer (usually air) in a combustion chamber. In an internal combustion engine the expansion of the high-temperature and –pressure gases produced by combustion applies direct force to a component of the engine, such as pistons, turbine blades, or a nozzle. This force moves the component over a distance, generating useful mechanical energy. Internal combustion equipment may include gasoline and diesel industrial engines, natural gas-fired reciprocating engines, and gas turbines.

Liquefied natural gas (LNG) means natural gas (primarily methane) that has been liquefied by reducing its temperature to -162 degrees Celsius at atmospheric pressure.

LNG boiloff gas means natural gas in the gaseous phase that vents from LNG storage tanks due to ambient heat leakage through the tank insulation and heat energy dissipated in the LNG by internal pumps.

Low-bleed pneumatic devices mean automated control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream which is regulated by the process condition flows to a valve actuator controller where it vents (bleeds) to the atmosphere at a rate equal to or less than 0.17 standard cubic meters per hour.

Natural gas driven pneumatic pump means a pump that uses pressurized natural gas to move a piston or diaphragm, which pumps liquids on the opposite side of the piston or diaphragm.

Operating pressure means the containment pressure that characterizes the normal state of gas or liquid inside a particular process, pipeline, vessel or tank.

Pipeline quality natural gas means natural gas having a high heat value equal to or greater than 36.3 MJ/m3 or less than 40.98 MJ/m3, and which is at least ninety percent methane by volume, and which is less than five percent carbon dioxide by volume.

Portable means the same as defined in WCI.27 and WCI.361(a)(2)

Pump means a device used to raise pressure, drive, or increase flow of liquid streams in closed or open conduits.

Pump seals means any seal on a pump drive shaft used to keep methane and/or carbon dioxide containing light liquids from escaping the inside of a pump case to the atmosphere.

Pump seal emissions means hydrocarbon gas released from the seal face between the pump internal chamber and the atmosphere.

Reciprocating compressor means a piece of equipment that increases the pressure of a gas stream by positive displacement, employing linear movement of a shaft driving a piston in a cylinder.

Reciprocating compressor rod packing means a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of the compressed gas stream that escapes to the atmosphere.

Re-condenser means heat exchangers that cool compressed boil-off gas to a temperature that will condense natural gas to a liquid.

Reservoir means a porous and permeable underground natural formation containing significant quantities of hydrocarbon liquids and/or gases.

Transmission pipeline means high pressure cross country pipeline transporting saleable quality natural gas from production or natural gas processing to natural gas distribution pressure let-down, metering, regulating stations where the natural gas is typically odorized before delivery to customers.

Vapour recovery system means any equipment located at the source of potential gas emissions to the atmosphere or to a flare, that is composed of piping, connections, and, if necessary, flow-inducing devices, and that is used for routing the gas back into the process as a product and/or fuel.

Vapourization unit means a process unit that performs controlled heat input to vapourize LNG to supply transmission and distribution pipelines or consumers with natural gas.

Vented emissions means the same as defined in the relevant greenhouse gas reporting regulation, including process designed flow to the atmosphere through seals or vent pipes, equipment blowdown for maintenance, and direct venting of gas used to power equipment (such as pneumatic devices), but not including stationary combustion flue gas.

Directions for the use of Tables 350-1 to 350-5

(a) Starting with 2013 calendar year emissions, for each component listed in the Tables 350-1 to 350-5, or otherwise required by the quantification method referencing Tables 350-1 and 350-2:

(i) If statistically valid facility specific emission factors for a component type are available or can be safely or reasonably developed they must be used

(ii) If facility specific emissions factors for a component type are not available, an operator must use statistically valid company specific emission factors if they can be safely or reasonably developed.

(iii) If statistically valid facility or company specific emission factors for a specific component type cannot be safely and reasonably developed, estimates in the default Tables 350-1 to 350-5 may be used. Equipment or facilities that have low temporal utilization (e.g. equipment such as some booster stations used only sporadically during a year) may continue to use the default tables.

(b) For 2011 and 2012 calendar year emissions,

(i) An operator may use the default factors specified below, company or facility-specific emissions factors (if such emission factors are available). If the default factors in Tables 350-1 to 350-5 are used, an explanation as to why company or facility specific emission factors are cannot be used must be provided to the jurisdiction.

(c) If a facility-specific emission factor has been used in a previous reporting year, it must continue to be used until updated. If a company-specific emission factor has been used in a previous reporting year, it must continue to be used until updated or a facility-specific emission factor is used in its place

(d) Any changes from facility-specific factors to company-specific or table factors, or from company specific factors to the defaults in Tables 350-1 to 350-5 must be approved by the jurisdiction and substantiated by proof that the new approach is more accurate for the facility or facilities in question

(e) If an emission factor required by the quantification method referencing Tables 350-1 through 350-5 is not provided in the tables, emission factors from either the U.S. EPA 40 CFR Part 98.230 Tables W-3 through W-7 or the 2007 Canadian Gas Association Methodology Manual may be used (as converted for use in the relevant equation).

(f) Documentation on the method used to update the emission factors, input data, sampling methodology and other relevant information must be kept by the operator and provided to the jurisdiction or verifier upon request

(g) All emission factors or data collection for emission factors must be developed using Canadian Gas Association (CGA) standard methods, or other methods if CGA methods are not available or applicable. Facility and company-specific emission factors must be updated at a minimum on a three year cycle, with the first update to the original facility and company-specific emission factors for the 2016 reporting period, at the latest.

(h) Updated emission factors can only be incorporated for reporting purposes at the start of a reporting period and not during a calendar year.

(i) The default emission factors provided in Tables 350-1 to 350-5 below are industry average emission factors for Canada as of the 2010 calendar year. The factors will be updated every 3-5 years based on new data, methods and statistically valid samples of the entire industry and developed in collaboration with industry groups.

TABLE 350-1 –DEFAULT EMISSION FACTORS FOR TRANSMISSION

Transmission	Emission Factor (tonnes/hour/component) Direct conversion of EF's in CGA Manual[3] Table 6 (kg to tonnes)
Leaker Emission Factors - All Components, Gas Service	
Connector	4.471 E-7
Block valve	4.131 E-6
Control valve	1.650 E-2
Compressor blowdown valve	3.405 E-3
Pressure relief valve	1.620 E-4
Orifice meter	4.863 E-5
Other meter	9.942 E -6
Regulator	7.945 E-6
Open-ended line	9.183 E-5
Population Emission Factors - Other Components, Gas Service	**Emission Factor (Sm^3/hour/component) Direct conversion of EF's in EPA Subpart W Table W-3 (scf to Sm^3)**
Low-bleed pneumatic device vents	3.99 E-2
High continuous bleed pneumatic device vents	5.32 E-1
Intermittent (low and high) bleed pneumatic device vents	5.32 E-1

* The distribution emission factors in Table 350-5 should be used for equipment in odourized service and the transmission factors in Table 350-1 should be used for equipment in unodourized service, regardless of the actual classification or functionality of the facility

[3] Clearstone Engineering Ltd. *Methodology Manual: Estimation of Air Emissions from the Canadian Natural Gas Transmission, Storage and Distribution System*. Prepared for Canadian Energy Partnership for Environmental Innovation (CEPEI). 2007. As these emission factors are updated from time to time, the intention is to incorporate such updates here.

TABLE 350-2 –DEFAULT METHANE EMISSION FACTORS FOR UNDERGROUND STORAGE*

Underground Storage	Emission Factor (Sm^3/hour/component) Direct conversion of EF's in EPA Subpart W Table W-4 (scf to Sm^3)
Leaker Emission Factors - Storage Station, Gas Service	
Valve[1]	4.268 E-1
Connector	1.60 E-1
Open-ended line	4.967 E-1
Pressure relief valve	1.140
Meter	5.560 E-1
Population Emission Factors - Storage Wellheads, Gas Service	
Connector	2.8 E-4
Valve	2.8 E-3
Pressure relief valve	4.8 E-3
Open-ended line	8.5 E-4
Population Emission Factors - Other Components, Gas Service	
Low-bleed pneumatic device vents	3.99 E-2
High continuous bleed pneumatic device vents	5.32 E-1
Intermittent (low and high) bleed pneumatic device vents	5.32 E-1

*Emission factors are conversions of those contained in the U.S. EPA Subpart W Table W-4.

[1] Valves include control valves, block valves and regulator valves

TABLE 350-3 –DEFAULT METHANE EMISSION FACTORS FOR LIQUEFIED NATURAL GAS (LNG) STORAGE*

LNG Storage	Emission Factor (Sm^3/hour/component) Direct conversion of EF's in EPA Subpart W Table W-5 (scf to Sm^3)
Leaker Emission Factors - LNG Storage Components, LNG Service	
Valve	3.43 E-2
Pump seal	1.15 E-1
Connector	9.9 E-3
Other[1]	5.10 E-2
Population Emission Factors - LNG Storage Compressor, Gas Service	
Vapour Recovery Compressor	1.20 E-1

[1] The "other" equipment type should be applied for any equipment type other than connectors, pumps, or valves.

* Emission factors are conversions of those contained in the U.S. EPA Subpart W Table W-5.

TABLE 350-4–DEFAULT METHANE EMISSION FACTORS FOR LNG TERMINALS*

LNG Terminals	**Emission Factor (Sm^3/hour/component) Direct conversion of EF's in EPA Subpart W Table W-6 (scf to Sm^3)**
Leaker Emission Factors - LNG Terminals Components, LNG Service	
Valve	3.43 E -2
Pump seal	1.15 E-1
Connector	9.9 E-3
Other	5.10 E-2
Population Emission Factors - LNG Terminals Compressor, Gas Service	
Vapour recovery compressor	1.20 E-1

*Emission factors are conversions of those contained in the U.S. EPA Subpart W Table W-6.

TABLE 350-5 –DEFAULT EMISSION FACTORS FOR DISTRIBUTION

Distribution	**Emission Factor** (tonnes/hour/component) Direct conversion of EF's in CGA Manual[4] Table 6 (kg to tonnes)**
Leaker Emission Factors - Above Grade M&R Stations Components, Gas Service	
Connector	8.227 E-8
Block valve	5.607 E-7
Control valve	1.949 E-5
Pressure relief valve	3.944 E-6
Orifice meter	3.011 E-6
Regulator	6.549 E-7
Open-ended line	6.077 E-5
Population Emission Factors - Below Grade M&R Stations Components, Gas Service[1]	**Emission Factor (Sm^3/hour/component) Direct conversion of EF's in EPA Subpart W Table W-7 (scf to Sm^3)**
Below grade M&R station, inlet pressure > 300 psig	3.74 E-2
Below grade M&R station, inlet pressure 100 to 300 psig	5.7 E-3
Below grade M&R station, inlet pressure < 100 psig	2.8 E-3

[4] Clearstone Engineering Ltd. *Methodology Manual: Estimation of Air Emissions from the Canadian Natural Gas Transmission, Storage and Distribution System.* Prepared for Canadian Energy Partnership for Environmental Innovation (CEPEI). 2007. As these emission factors are updated from time to time, the intention is to incorporate such updates here.

Population Emission Factors - Distribution Mains, Gas Service[2]*	Emission Factor (Sm^3/hour/component) Direct conversion of Leak Rates in CGA Forms 4.2.1-3 to 6 (scf to Sm^3) except where noted
Unprotected steel	1.83 E-1
Protected steel	7.22 E-2
Plastic	7.76 E-2
Cast iron*	7.836 E-1
Population Emission Factors - Distribution Services, Gas Service*	**Emission Factor (Sm^3/hour/component) Direct conversion of Leak Rates in CGA Forms 4.2.1-7 to 10 (scf to Sm^3) except where noted**
Unprotected steel	7.08 E-2
Protected steel	3.23 E-2
Plastic	1.04 E-2
Copper	2.7 E-2

[1] Emission Factor is in units of "sm^3/hour/station"
[2] Emission Factor is in units of "sm^3/hour/service"

*Emission factors are conversions of those contained in the U.S. EPA Subpart W Table W-7.

** the distribution emission factors in Table 350-5 should be used for equipment in odourized service and the transmission factors in Table 350-1 should be used for equipment in unodourized service, regardless of the actual classification or functionality of the facility

Due to the U.S. EPA finalizing publication of Part 98, Subpart W in November, 2010, the WCI has not yet performed detailed analyses on it for harmonization with cap and trade reporting. These analyses will be occurring in 2011. As such, for some specific emission sources identified in this quantification method option is given to facilities to report – for 2011 calendar year emissions only - using EPA equations and/or methods where these methods will give as or more accurate estimates of emissions than the otherwise prescribed methods.

§WCI.360 PETROLEUM AND NATURAL GAS PRODUCTION AND GAS PROCESSING

§ WCI.361 Source Category Definition

(a) This source category consists of the following:

(1) *Offshore petroleum and natural gas production.* Offshore petroleum and natural gas production is any platform structure, affixed temporarily or permanently to offshore submerged lands, that houses equipment to extract hydrocarbons from the ocean or lake floor and that processes and/or transfers such hydrocarbons to storage, transport vessels, or onshore. In addition, offshore production includes secondary platform structures connected to the platform structure via walkways, storage tanks associated with the platform structure and floating production and storage offloading equipment (FPSO). This source category does not include reporting of emissions from offshore drilling and exploration that is not conducted on production platforms.

(2) *Onshore petroleum and natural gas production.* Onshore petroleum and natural gas production equipment means all structures associated with wells (including but not limited to compressors, generators, or storage facilities), piping (including but not limited to flowlines or intra-facility gathering lines), and portable non-self-propelled equipment (including but not limited to well drilling and completion equipment, workover equipment, gravity separation equipment, auxiliary non-transportation-related equipment, and leased, rented or contracted equipment) used in the production, extraction, recovery, lifting, stabilization, separation or treating of petroleum and/or natural gas (including condensate). This also includes associated storage or measurement and all systems engaged in gathering produced gas from multiple wells, all EOR operations using $CO_{2,}$ and all petroleum and natural gas production located on islands, artificial islands or structures connected by a causeway to land, an island, or artificial island.

(3) *Onshore natural gas processing.* Natural gas processing plants separates and/or recovers natural gas liquids (NGLs) and/or other non-methane gases and liquids from a stream of produced natural gas to meet onshore natural gas transmission pipeline quality specifications through equipment performing one or more of the following processes: oil and condensate removal, water removal, separation of natural gas liquids, sulphur and carbon dioxide removal, fractionation of NGLs, or other processes, and also the

capture of CO_2 separated from natural gas streams for delivery outside the facility. In addition, field gathering and/or boosting stations that gather and process natural gas from multiple wellheads, and compress and transport natural gas (including but not limited to flowlines or intra-facility gathering lines or compressors) as feed to the natural gas processing plants may be considered a part of the processing plant if emissions are not calculated under onshore petroleum and natural gas production. Gathering and boosting stations that send the natural gas to an onshore natural gas transmission compression facility, or natural gas distribution facility, or to an end user are also considered within onshore natural gas processing for the purposes of emissions calculation. All residue gas compression equipment operated by a processing plant, whether inside or outside the processing plant fence, are considered part of the natural gas processing plant.

(b) This source category does not include natural gas transmission and distribution (i.e., onshore natural gas transmission compression, underground natural gas storage, liquefied natural gas (LNG) storage, LNG import and export equipment, and natural gas distribution). These are included in WCI.350 (Natural Gas Transmission and Distribution).

§ WCI.362 Greenhouse Gas Reporting Requirements

Where greenhouse gases are not emitted from a specific emission source identified in paragraphs (a) to (f), below then the reported emissions for the specific source shall be reported as zero or "not applicable".

In addition to the information required by regulation, the annual emissions data report, for both each individual facility over 10,000 tonnes and the aggregate of facilities less than 10,000 tonnes (or as otherwise specified by regulation), must contain the following information:

(a) CO_2 and CH_4 (and N_2O, if applicable) emissions (in tonnes) from each industry segment specified in paragraph (b) through (d) of this section and from stationary and portable combustion equipment identified in paragraphs (e) and (f) of the section.

(b) For offshore petroleum and natural gas production, report CO_2, CH_4, and N_2O emissions from equipment leaks, vented emission, and flare emission source types as identified in the data collection and emissions estimation study conducted by BOEMRE in compliance with 30 CFR 250.302 through 304. Offshore platforms do not need to report portable emissions *[WCI.363(p), reserved]*

(c) For onshore petroleum and natural gas production, report CO_2 and CH_4 (and N_2O, if applicable) emissions from the following source types:

(1) Natural gas pneumatic continuous high bleed device venting. *[WCI.363(a)]*

(2) Natural gas driven pneumatic pump venting. *[WCI.363(a)]*

(3) Natural gas pneumatic continuous low bleed and intermittent (low and high) bleed device venting. *[WCI.363(b)]*

(4) Acid gas removal venting and incineration process. *[WCI.363(c)]*

(5) Dehydrator vents. *[WCI.363(d)]*

(6) Well venting for liquids unloading. *[WCI.363(e)]*

(7) Gas well venting during well completions or workovers with hydraulic fracturing, except where vent gas is sent to a flare. *[WCI.363(f)]*

(8) Gas well venting during well completions or workovers without hydraulic fracturing, except where vent gas is sent to a flare. *[WCI.363(f)]*

(9) Blowdown vent stacks. *[WCI.363(g)]*

(10) Storage tanks. *[WCI.363(h)]*

(11) Well testing venting and flaring. *[WCI.363(i)]*

(12) Associated gas venting and flaring. *[WCI.363(j)]*

(13) Flare stacks. *[WCI.363(k)]*

(14) Centrifugal compressor venting. *[WCI.363(l)]*

(15) Reciprocating compressor venting. *[WCI.363(m)]*

(16) Gathering pipeline fugitive equipment leaks. *[WCI.363(o) or WCI.363(x) for emission sources not covered by WCI.363(o)]*

(17) Fugitive equipment leaks from valves, connectors, open ended lines, pressure relief valves, pumps, flanges, and other fugitive equipment leak sources (such as instruments, loading arms, stuffing boxes, compressor seals, dump lever arms, and breather caps). *[WCI.363(o]*

(18) EOR injection pump blowdown. *[WCI.363(t)]*

(19) Hydrocarbon liquids dissolved CO_2 from flashing [Reserved]. *[WCI.363(u)]*

(20) Produced water dissolved CO_2 [Reserved]. *[WCI.363(v)]*

(21) Coal bed methane produced water emissions [Reserved]. *[WCI.363(v)]*

(22) Other venting emission sources.* *[WCI.363(x)]*

(23) Other fugitive emission sources.**[WCI.363(x)]*

(d) For onshore natural gas processing, report CO_2 and CH_4 (and N_2O, if applicable) emissions from the following sources:

(1) Acid gas removal venting or incineration. *[WCI.363(c)]*

(2) Dehydrator vents. *[WCI.363(d)]*

(3) Blowdown vent stacks. *[WCI.363(g)]*

(4) Storage tanks. *[WCI.363(h)]*

(5) Flare stacks. *[WCI.363(k)]*

(6) Centrifugal compressor venting. *[WCI.363(l)]*

(7) Reciprocating compressor venting. *[WCI.363(m)]*

(8) Gathering pipeline fugitive equipment leaks. *[WCI.363(o) or WCI.363(x) for emission sources not covered by WCI.363(o)]*

(9) Fugitive equipment leaks from: valves, connectors, open ended lines, pressure relief valves and meters. *[WCI.363(n)]*

(10) Other fugitive emission sources (including reciprocating compressor rod packing fugitives, centrifugal compressor dry and wet seals, etc).**[WCI.363(x)]*

(11) Other venting emission sources.**[WCI.363(x)]*

(e) Report CO_2, CH_4, and N_2O emissions from each stationary fuel combustion source type combusting field gas or process vent gas *[WCI.363(w)]* and fuels other than field gas or process vent gas. Report stationary combustion sources that combust fuels other than field gas or process vent gas using WCI.20 (General Stationary Combustion Sources) quantification methods.**

(f) Report CO_2, CH_4, and N_2O emissions from each portable equipment combustion source type combusting field gas or process vent gas *[WCI.363(w)]* and fuels other than field gas or process vent gas. Report portable equipment combustion sources that combust fuels other than field gas or process vent gas using WCI.20 (General Stationary Combustion Sources) quantification methods.**

(g) Report data for each aggregated source type within paragraph (b) through (d) of this section as follows (for each individual facility or aggregate of facilities reported, as required by regulation):

(1) Where there is a choice of quantification method used for a source, the specific method(s) used and under what circumstances.

(2) Facility and company-specific emission factors used in place of Tables 360-1 and 360-2.

(3) Count of natural gas pneumatic continuous high bleed devices.

(4) Count of natural gas pneumatic continuous low bleed devices.

(5) Count of natural gas intermittent (low and high) bleed devices.

(6) Count of natural gas driven pneumatic pumps.

(7) Total throughput of acid gas removal units.

(8) For each dehydrator unit report the following:
    (i) Glycol dehydrators:

        The number of glycol dehydrators less than and greater than or equal to 11,328 Sm^3/day operated.
    (ii) Desiccant dehydrators:
        (A) The number of desiccant dehydrators operated.

(9) Count of wells vented to the atmosphere for liquids unloading.

(10) Count of wells venting during well completions:
    (i) Number of conventional completions.
    (ii) Number of completions employing hydraulic fracturing.

(11) Count of wells venting during well workovers:
    (i) number well workovers involving well venting to the atmosphere.

(12) For each compressor report the following:
    (i) Type of compressor whether reciprocating, centrifugal dry seal, or centrifugal wet seal.
    (ii) Compressor capacity in horse powers (except for well site natural gas production compressors).
    (iii) Number of blowdowns per year (except for well site natural gas production compressors).
    (iv) Operating mode(s) during the year (except for well site natural gas production compressors).

(13) Number of EOR injection pump blowdowns per year.

(14) Count of wells tested in the reporting period.

(15) Count of wells venting or flaring associated natural gas in the reporting period.

(16) Count of wells being unloaded for liquids in the reporting year.

(17) Count of wells completed (worked over) in the reporting year.

(18) For fugitive equipment leaks and population count/emission factor sources where emission factors are used for estimating emissions in WCI.363(n) and (o), report the following:

(i) Component count for each source for which an emission factor is provided in this document. Approximate counts may be provided for the 2011 calendar year (reported in 2012) in preparation for full counts in the 2012 calendar year.
(ii) Total counts of fugitive equipment leaks found in leak detection surveys by type of leak source for which an emission factor is provided.

(19) Barrels of oil equivalent throughput/processed as determined by engineering estimate based on best available data.

(20) Identification (including geographic coordinates) of any facility that was above 1,000 tonnes of greenhouse gas emissions in the previous year that was:
(i) Acquired during the reporting year;
(ii) Sold, decommissioned or shut-in during the reporting year; and,
(iii) Greenhouse gas emissions for the facility in the previous year .

** Other venting emission or other fugitive sources not specifically listed are not required to be reported if a specific other venting or other fugitive source type is reasonably estimated to be below 0.5% of total operation emissions and total emissions not reported under this clause do not exceed 1% of total operation emissions (if an individual facility is part of a larger reporting operation, the 0.5% or 1% should be interpreted as 0.5% or 1% of the reporting operation emissions, otherwise interpret as 0.5% or 1% of the facility emissions). The applicable regulator may, upon request and provision of sufficient information, provide a list of sources believed to be below these thresholds for all operations for which reporting and verification would not be required.*

*** Portable equipment is portable fuel combustion equipment that cannot move on roadways under its own power and drive train, and that are located at an onshore production facility. Stationary or portable equipment include the following equipment which are integral to the extraction, processing or movement of oil or natural gas: well drilling and completion equipment, workover equipment, natural gas dehydrators, natural gas compressors, electrical generators, steam boilers, and process heaters*

§ WCI.363 Calculating GHG Emissions

If greenhouse gases are not emitted from one or more of the following emission sources, the reporter will not need to calculate emissions from the emission source(s) in question and reported emissions for the emission source(s) will be zero or "not applicable". Where a quantification method is not provided for a specific source (such as for other venting and other fugitive sources), industry inventory practices must be used to estimate emissions. For ambient conditions, reporters must use average atmospheric conditions or typical operating conditions as applicable to the respective monitoring methods in this section.

(a) <u>Natural gas pneumatic continuous high bleed device venting and natural gas driven pneumatic pump venting.</u> Calculate emissions from a natural gas pneumatic continuous high bleed flow control device venting and natural gas drived pneumatic pump venting as follows.

Natural gas driven pneumatic pumps covered in paragraph (d) of this section do not have to report emissions under paragraph (a) of this section:

(1) Calculation Methodology 1. Calculate vented emissions from a natural gas pneumatic continuous high bleed control devices or pneumatic pumps as follows:

(i) Measure gas consumption for all continuous high bleed natural gas powered devices (except pneumatic pumps not equipped with a meter) using a meter or meters that meet accuracy requirements specified by relevant oil and gas metering requirements in the jurisdiction (even if a meter is not prescribed for this circumstance in the relevant requirements). In 2013, reporters are required to meter gas consumption for at least 50% of all continuous high bleed devices. Metering of gas consumption for all continuous high bleed devices is required in 2014. Prior to 2013 and for up to 50% of continuous high bleed devices in 2013, Calculation Methodology 2 may be used. Common meters may be used where possible.

(ii) Calculate CH_4 and CO_2 emissions from continuous high bleed pneumatic devices and pumps using Equation 360-1.

$$E_{GHGi} = V_{NG} \times M_i \times \left(\frac{MW_i}{MVC}\right) \times 0.001$$ **Equation 360-1**

Where:

E_{GHGi}	=	Emissions of GHG *i* (CH_4 or CO_2) (tonnes)
V_{NG}	=	Volume of natural gas consumed by metered continuous high bleed pneumatic devices and pumps (m^3/year).
M_i	=	Mole fraction of CH_4 or CO_2 in natural gas supply.
MW_i	=	Molecular weight of GHG *i* .
MVC	=	Molar volume conversion factor.
0.001	=	Conversion factor from kg to tonnes.

(2) Calculation Methodology 2. Emissions from continuous high bleed devices and natural gas driven pneumatic pumps that are not equipped with meters must be calculated using the following methods.

(i) For continuous high bleed devices, calculate vented emissions using manufacturer data.

(A) Obtain from the manufacturer specific pneumatic device model natural gas bleed rates during normal operation.

(B) Calculate the natural gas emissions for each continuous bleed device using Equation 360-2.

$$E_{s,n} = B_s \times t$$ **Equation 360-2**

Where:

$E_{s,n}$ = Annual natural gas emissions at standard conditions (m^3).
B_s = Natural gas driven pneumatic device bleed rate volume at standard conditions, as provided by the manufacturer (m^3/minute).
t = Amount of time that the pneumatic device has been operational through the reporting period (minutes).

If manufacturer data for a specific device is not available, then use data for a similar device model, size and operational characteristics to estimate emissions.

(ii) Calculate emissions from natural gas driven pneumatic pump venting as follows:

(A) Obtain from the manufacturer specific pump model natural gas emission (or manufacturer "gas consumption") per unit volume of liquid circulation rate at pump speeds and operating pressures.

(B) Maintain a log of the amount of liquid pumped annually from individual pumps.

(C) Calculate the natural gas emissions for each pump using Equation 360-3.

$$E_{s,n} = F_s \times V \qquad \textbf{Equation 360-3}$$

Where:

$E_{s,n}$ = Annual natural gas emissions at standard conditions (m^3/year).
F_s = Natural gas driven pneumatic pump gas emission in "emission per volume of liquid pumped at operating pressure" at standard conditions, as provided by the manufacturer (m^3/liter).
V = Volume of liquid pumped annually (liters/year).

If manufacturer data for a specific pump is not available, then use data for a similar pump model, size and operational characteristics to estimate emissions.

(iii) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (r) and (s) of this section.

(3) Provide the total number of continuous high bleed natural gas pneumatic devices and pneumatic pumps of each type as follows:
(i) In the first calendar year, all continuous high bleed natural gas pneumatic devices and pneumatic pumps must be counted.
(ii) For the calendar year immediately following first calendar year, and for calendar years thereafter, facilities must update the total count of continuous high bleed

pneumatic devices and pneumatic pumps and adjust accordingly to reflect any modifications due to changes in equipment.

(b) Natural gas pneumatic continuous low bleed and intermittent (low and high) bleed device venting. Calculate emissions from natural gas pneumatic continuous low bleed and intermittent (low and high) bleed device venting (separately) using Equation 360-4 of this section.

$$Mass_{s,i} = Count \times EF \times GHG_i \times t$$

Equation 360-4

Where:

$Mass_{s,i}$	=	Annual total mass GHG emissions at standard conditions from all natural gas pneumatic continuous low bleed, and intermittent (low and high) bleed device venting, for GHG *i* (tonnes/year).
Count	=	Total number of natural gas pneumatic continuous low bleed, or intermittent (low and high) bleed devices.
EF	=	Population emission factors for natural gas pneumatic continuous low bleed, or intermittent (low and high) bleed device venting listed in Table 360-1 (tonnes of natural gas/component-hour).
GHG_i	=	Mass fraction of GHG *i* (CH_4 or CO_2), in produced natural gas (tonnes of GHG *i*/tonnes of natural gas).
t	=	Total time the continuous low bleed device, or intermittent (low and high) bleed device was operating during the year (hours).

(1) Provide the total number of continuous low bleed and intermittent (low and high) bleed natural gas pneumatic devices of each type as follows:
   (i) In the first calendar year, for the total number of each type, you may count the total of each type, or count any percentage number of each type plus an engineering estimate based on best available data of the number not counted.
   (ii) In the second calendar year, complete the count of all pneumatic devices, including any changes to equipment counted in prior years.
   (iii) For the calendar year immediately following the third consecutive calendar year, and for calendar years thereafter, facilities must update the total count of pneumatic devices and adjust accordingly to reflect any modifications due to changes in equipment.

(c) Acid gas removal (AGR) venting or incineration process. Except for AGRs where the acid gases are re-injected into the oil/gas field, calculate CO_2 emissions only (not CH_4) for AGR (including but not limited to processes such as amine, membrane, molecular sieve or other absorbents and adsorbents) using Equation 360-5.*

$$E_{a,CO2} = \left(V + \alpha \times \left(V \times \left(Vol_I - Vol_O\right)\right)\right) \times \left(Vol_I - Vol_O\right)$$ **Equation 360-5**

Where:

$E_{a,CO2}$	=	Annual volumetric CO_2 emissions at actual condition (m^3/year).
V	=	Metered total annual volume of natural gas flow into or out of AGR unit (m^3/year) as determined in paragraph (c)(1) of this section.
α	=	Factor is 1 if outlet stream flow is measured. Factor is 0 if inlet stream flow is measured.
Vol_I	=	Volume fraction of CO_2 in natural gas into the AGR unit as determined in paragraph (c)(2) of this section.
Vol_O	=	Volume fraction of CO_2 in natural gas out of the AGR unit as determined in paragraph (c)(3) of this section.

(1) Record the gas flow rate of the inlet and outlet natural gas stream of an AGR unit using a meter according to methods set forth in WCI.364(b).

(2) If a continuous gas analyzer is installed on the inlet gas stream, then the continuous gas analyzer results must be used. If a continuous gas analyzer is not available, either install a continuous gas analyzer or take monthly gas samples from the inlet gas stream to determine Vol_I according to methods set forth in WCI.364(b).

(3) Determine volume fraction of CO_2 content in natural gas out of the AGR units using one of the methods specified in paragraph (c)(3) of this section.

(i) If a continuous gas analyzer is installed on the outlet gas stream, then the continuous gas analyzer results must be used. If a continuous gas analyzer is not available, you may install a continuous gas analyzer.

(ii) If a continuous gas analyzer is not available or installed, monthly gas samples may be taken from the outlet gas stream to determine Vol_O according to methods set forth in WCI.364(b).

(4) Calculate CO_2 volumetric emissions at standard conditions using calculations in paragraph (q) of this section.

(5) Mass CO_2 emissions shall be calculated from volumetric CO_2 emissions using calculations in paragraphs (r) and (s) of this section.

* For 2011 calendar year emissions only, an operator may use other equations and methods as presented by the EPA in 40 CFR Part 98.233(d) so long as the method is as accurate or more accurate as that presented here for the specific emission source in question and the appropriate regulator is notified of the choice.

(d) Dehydrator vents. For dehydrator vents, calculate annual mass CH_4, CO_2 and N_2O (when flared) emissions at standard temperature and pressure (STP) conditions as follows*:

(1) Calculate annual mass emissions from dehydrator vents using a simulation software package of similar accuracy to GRI-GLYCalc Version 4.0 or AspenTech HYSYS®, that uses the Peng-Robinson equation of state to calculate the equilibrium coefficient, speciates CH_4 and CO_2 emissions from dehydrators, and has provisions to include regenerator control devises, a separator flash tank, stripping gas and a gas injection pump or gas assist pump. A minimum of the following parameters must be used for characterizing emissions from dehydrators:

(i) Feed natural gas flow rate.
(ii) Feed natural gas water content.
(iii) Outlet natural gas water content.
(iv) Absorbent circulation pump type (natural gas pneumatic/air pneumatic/electric).
(v) Absorbent circulation rate.
(vi) Absorbent type: including, but not limited to, triethylene glycol (TEG), diethylene glycol (DEG) or ethylene glycol (EG).
(vii) Use of stripping natural gas.
(viii) Use of flash tank separator (and disposition of recovered gas).
(ix) Hours operated.
(x) Wet natural gas temperature, pressure, and composition. Determine this parameter by selecting one of the methods described under paragraph (d)(1)(x) of this section.

(A) Use the wet natural gas composition as defined in paragraph (r)(2)(i) of this section.
(B) If wet natural gas composition cannot be determined using paragraph (r)(2)(i) of this section, select a representative analysis.
(C) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice as specified in WCI.364(b) to sample and analyze wet natural gas composition.
(D) If only composition data for dry natural gas is available, assume the wet natural gas is saturated.

(2) Determine if dehydrator unit has vapor recovery. Adjust the emissions estimated in paragraphs (d)(1) or (d)(2) of this section downward by the magnitude of emissions captured.

(3) Calculate annual emissions from dehydrator vents to flares or regenerator fire-box/fire tubes as follows:

(i) Use the dehydrator vent stack volume and gas composition as determined in paragraph (d)(1) of this section.
(ii) Use the calculation methodology of flare stacks in paragraph (k) of this section to determine dehydrator vent emissions from the flare or regenerator combustion gas vent.

(4) Dehydrators that use desiccant shall calculate emissions from the amount of gas vented from the vessel every time it is depressurized for the desiccant refilling process using Equation 360-6.

$$E_{s,n} = \left(\frac{H \times D^2 \times \pi \times P_2 \times \%G \times 365}{4 \times P_1 \times t} \right) \Big/ 100$$

Equation 360-6

Where:

$E_{s,n}$ = Annual natural gas emissions at standard conditions (m^3).
H = Height of the dehydrator vessel (m).
D = Inside diameter of the vessel (m).
P_1 = Atmospheric pressure (kPa).
P_2 = Pressure of the gas (kPa).
π = pi (3.14).
%G = Percent of packed vessel volume that is gas.
365 = Conversion from days to years.
t = Time between refilling (days).
100 = Conversion of %G to fraction.

(5) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (r) and (s) of this section.

* For 2011 calendar year emissions only, an operator may use other equations and methods as presented by the EPA in 40 CFR Part 98.233(e) so long as the method is as accurate or more accurate as that presented here for the specific emission source in question and the appropriate regulator is notified of the choice.

(e) Well venting for liquids unloading. The CO_2 and CH_4 emissions for well venting for liquids unloading shall be determined using one of the following calculation methodologies:

(1) Calculation Methodology 1. For one well* of each well tubing diameter and producing horizon/formation combination in each gas producing field where gas wells are vented to the atmosphere to expel liquids accumulated in the tubing, a recording flow meter shall be installed on the vent line used to vent gas from the well (e.g. on the vent line off the wellhead separator or atmospheric storage tank) according to the methods set forth in the WCI.364(b). Calculate emission from well venting for liquids unloading using Equation 360-7.

$$E_{a,n} = \sum_h \sum_t t_{h,t} \times FR_{h,t}$$

Equation 360-7

Where:

$E_{a,n}$ = Annual natural gas emissions at actual conditions (m^3).
$t_{h,t}$ = Cumulative amount of time in hours of venting from all wells of the same tubing diameter (t) and producing horizon (h)/formation combination during the year.
$FR_{h,t}$ = Average flow rate (m^3) of the measured well venting for the duration of the liquids unloading, under actual conditions as determined in paragraph (e)(1)(i) of this section.

(i) Determine the well vent average flow rate as specified under paragraph (e)(1)(i) of this section.

(A) The average flow rate per hour of venting is calculated for each unique tubing diameter and producing horizon/formation combination in each producing field by averaging the recorded flow rates for the recorded for one well venting to the atmosphere.

(B) This average flow rate is applied to all wells in the field that have the same tubing diameter and producing horizon/formation combination, for the number of hours of venting these wells.

(C) A new average flow rate is calculated every other calendar year (if necessary) for each reporting field and horizon starting the first calendar year of data collection.

(ii) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (q) of this section.

(2) Calculation Methodology 2. Calculate emissions from each well venting for liquids unloading using Equation 360-8.

$$E_{a,n} = \left(\left[7.854 \times 10^{-5} \right] \times CD^2 \times WD \times \left[\frac{SP}{101.325} \right] \times N_V \right) + \left(SFR \times \left[HR - 1.0 \right] \times Z \right)$$

Equation 360-8

Where:

$E_{a,n}$ = Annual natural gas emissions at actual conditions (m^3/year).
7.854×10^{-5} = $(\pi/4)/(10000)$
CD = Casing diameter (cm).
WD = Well depth (m).
SP = Shut-in pressure (kPa-gage).
N_V = Number of vents per year.
SFR = Average sales flow rate of gas well (m^3/hr).
HR = Hours that the well was left open to the atmosphere during unloading.
1.0 = Hours for average well to blowdown casing volume at shut-in pressure.
Z = If HR is less than 1.0, then Z is equal to 0. If HR is greater than or equal to 1.0, then Z is equal to 1.

(i) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (q) of this section.

(3) Calculation Methodology 3. Calculate emissions from each well venting to the atmosphere for liquids unloading with plunger lift assist using Equation 360-9.

$$E_{a,n} = \left(\left[7.854 \times 10^{-5}\right] \times TD^2 \times WD \times \left[\frac{SP}{101.325}\right] \times N_V\right) + \left(SFR \times \left[HR - 0.5\right] \times Z\right)$$ **Equation 360-9**

Where:

$E_{a,n}$	=	Annual natural gas emissions at actual conditions (m^3/year).
7.854×10^{-5}	=	(π/4)/(10000)
TD	=	Tubing diameter (cm).
WD	=	Tubing depth to plunger bumper (meters).
SP	=	Sales line pressure (kPa-gage).
N_V	=	Number of vents per year.
SFR	=	Average sales flow rate of gas well (m^3/hr).
HR	=	Hours that the well was left open to the atmosphere during unloading.
0.5	=	Hours for average well to blowdown tubing volume at sales line pressure.
Z	=	If HR is less than 0.5 then Z is equal to 0. If HR is greater than or equal to 0.5 then Z is equal to 1.

(i) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (q) of this section.

(4) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (r) and (s) of this section.

* the number of wells required to create an unbiased sample is being considered for future amendment

(f) Gas well venting during well completions and workovers with or without hydraulic fracturing. Calculate emissions from gas conventional or unconventional (from hydraulic fracturing) well venting during well completions and workovers using Equation 360-10. Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (r) of this section. Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (r) and (s) of this section.*

$$E_{a,n} = (t \times FR) - EnF - SG$$

Equation 360-10

Where:

$E_{a,n}$ = Annual natural gas vented emissions at ambient conditions (m^3).
t = Cumulative amount of time in hours of well venting during the year.
FR = Flow rate under ambient conditions, as required in paragraph (f)(1) of this section (m^3/hr).
EnF = Volume of CO_2 or N_2 injected gas (Sm^3) that was injected into the reservoir during an energized fracture job. If the fracture process did not inject gas into the reservoir, then EnF is 0. If injected gas is CO_2 then EnF is 0.
SG = Volume of natural gas (Sm^3) that was recovered into a sales pipeline. If no gas was recovered for sales, SG is 0.

(1) The flow rate for gas well venting during well completions and workovers from hydraulic fracturing shall be determined using either of the calculation methodologies described in this paragraph (f)(1). The same calculation methodology must be used for the entire volume for the reporting year.
   (i) Calculation Methodology 1. For a statistically valid sample of well completions and well workovers, a recording flow meter shall be installed on the vent line during each well unloading event according to methods set forth in WCI.364(b). The average flow rate for each well in the field (m^3/minute of venting) is calculated based on the statistically valid sample of well completions and well workovers.
   (ii) Calculation Methodology 2. For a statistically valid sample of well completions and well workovers, record the pressures measured before and after the well choke according to methods set forth in WCI.364(b). The average flow rate across the choke (m^3/minute of venting) is calculated for each well completion and each well workover.
   (iii) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (q) of this section.
   (iv) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (r) and (s) of this section.

(2) Calculate annual emissions from gas well venting during well completions and workovers to flares as follows:
   (i) Use the gas well venting volume during well completions and workovers as determined in paragraph (f)(1) of this section.
   (ii) Use the calculation methodology of flare stacks in paragraph (k) of this section to determine gas well venting during well completions and workovers emissions from the flare.

* For 2011 calendar year emissions only, an operator may use other equations and methods as presented by the EPA in 40 CFR Part 98.233(g) so long as the method is as accurate or more accurate as that presented here for the specific emission source in question and the appropriate regulator is notified of the choice.

(f.1) Gas well venting during well completions and workovers without hydraulic fracturing. Reserved *[paragraph (f) indicated to be appropriate for use in Canada for gas wells without hydraulic fracturing]*

(g) Blowdown vent stacks. Calculate blowdown vent stack emissions from depressurizing equipment to the atmosphere (excluding depressurizing to a flare, over-pressure relief, operating pressure control venting and blowdown of non-GHG gases; desiccant dehydrator blowdown venting before reloading is covered in paragraph (d)(4) of this section) as follows:

(1) Calculate the total volume (including, but not limited to, pipelines, compressor case or cylinders, manifolds, suction and discharge bottles and vessels) between isolation valves determined by engineering estimates based on best available data.

(2) If the total volume between isolation valves is greater than or equal to 1.42 Sm^3, retain logs of the number of blowdowns for each equipment type (including, but not limited to compressors, vessels, pipelines, headers, fractionators, and tanks). Blowdown volumes smaller than 1.42 Sm^3 are exempt from reporting under paragraph (g) of this section.

(3) Calculate the total annual venting emissions for each equipment type using Equation 360-11:

$$E_{s,n} = N \times \left(V_v \left[\frac{(273.15 + T_s) P_a}{(273.15 + T_a) P_s} \right] - V_v \times C \right)$$

Equation 360-11

Where:

$E_{s,n}$	=	Annual natural gas venting emissions at standard conditions from blowdowns (m^3).
N	=	Number of repetitive blowdowns for each equipment type of a unique volume in calendar year.
V_v	=	Total volume of blowdown equipment chambers (including, but not limited to, pipelines, compressors and vessels) between isolation valves (m^3).
C	=	Purge factor that is 1 if the equipment is not purged or zero if the equipment is purged using non-GHG gases.
T_s	=	Temperature at standard conditions (ºC).
T_a	=	Temperature at actual conditions in the blowdown equipment chamber (ºC).
P_s	=	Absolute pressure at standard conditions (kPa).
P_a	=	Absolute pressure at actual conditions in the blowdown equipment chamber (kPa).

(4) Calculate both CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (r) and (s) of this section.

(5) Blowdowns that are directed to flares use the WCI.363(k) Flare stacks calculation method rather than WCI.363(g) Blowdown vent stacks calculation method.

(h) <u>Onshore production and processing storage tanks</u>. For emissions from atmospheric pressure fixed roof storage tanks receiving hydrocarbon produced liquids from onshore petroleum and natural gas production facilities and onshore natural gas processing facilities, calculate annual CH_4 and CO_2 emissions as specified in paragraphs (h)(1) or (h)(2). For atmospheric storage tanks vented to flares, use the calculation methodology for flare stacks in paragraph (k) of this section. Storage tanks equipped with vapour recovery units (VRU) are exempt from the requirements of this paragraph.

(1) CH_4 and CO_2 emissions at storage tank batteries where the oil production rate is 10 barrels per day or greater shall be calculated using Equation 360-12.

$$E_{GHGi} = GOR \times PR \times \left(\frac{1}{MVC}\right) \times MW_g \times MF_i \times 0.001$$

Equation 360-12

Where:

E_{GHGi}	=	Annual emissions of greenhouse gas *i* (CO_2 or CH_4) (tonnes/year).
GOR	=	Gas Oil Ratio (m^3 gas/m^3 oil).
PR	=	Oil production rate (m^3/measurement period).
MVC	=	Molar volume conversion.
MW_g	=	Molecular weight of the gas (kg/kg-mole).
MF_i	=	Mass fraction of greenhouse gas *i* (CO_2 or CH_4) in gas (kg *i* /kg gas).
0.01	=	Conversion factor (tonnes/kg).

(2) Methane and carbon dioxide emissions at storage tank batteries where the oil production rate is less than 10 barrels per day shall calculate methane emissions using the latest software package for E&P Tank. A minimum of the following parameters must be used to characterize emissions from liquid transfer to atmospheric pressure storage tanks.
(i) Separator oil composition.
(ii) Separator temperature.
(iii) Separator pressure.
(iv) Sales oil API gravity.
(v) Sales oil production rate.
(vi) Sales oil Reid vapour pressure.
(vii) Ambient air temperature.
(viii) Ambient air pressure.

* For 2011 calendar year emissions only, an operator may use other equations and methods as presented by the EPA in 40 CFR Part 98.233(j) so long as the method is as accurate or

more accurate as that presented here for the specific emission source in question and the appropriate regulator is notified of the choice.

(i) Well testing venting and flaring. Calculate CH_4, CO_2, and N_2O (when flared) well testing venting and flaring emissions as follows:

(1) Determine the gas to oil ratio (GOR) of the hydrocarbon production from each well tested.

(2) If GOR cannot be determined from your available data, then use one of the two procedures in paragraph (i)(2) of this section to determine GOR:
(i) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists.
(ii) Or you may use an industry standard practice as described in WCI.364(b).

(3) Estimate venting emissions using Equation 360-13.

$$E_{a,n} = GOR \times FR \times D$$

Equation 360-13

Where:

$E_{a,n}$	=	Annual volumetric natural gas emissions from well testing ambient conditions (m^3).
GOR	=	Gas to oil ratio (m^3 gas/m^3 oil); oil here refers to hydrocarbon liquids produced of all API gravities.
FR	=	Flow rate (m^3 oil/day) for the well being tested.
D	=	Number of days during the year the well is tested.

(4) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (q) of this section.

(5) Calculate both CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (r) and (s) of this section.

(6) Calculate emissions from well testing to flares as follows:
(i) Use the well testing emissions volume and gas composition as determined in paragraphs (i)(1) through (3) of this section.
(ii) Use the calculation methodology of flare stacks in paragraph (k) of this section to determine well testing emissions from the flare.

(j) Associated gas venting and flaring. Calculate associated gas venting and flaring emissions not in conjunction with well testing (refer to section (i): Well testing venting and flaring) as follows:

(1) Determine the GOR ratio of the hydrocarbon production from each well whose associated natural gas is vented or flared. If GOR from each well is not available, the GOR from a cluster of wells in the same field shall be used.

(2) If GOR cannot be determined from your available data, then use one of the two procedures in paragraph (j)(2) of this section to determine GOR:
   (i) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists.
   (ii) Or you may use an industry standard practice as described in WCI.364(b).

(3) Estimate venting emissions using the Equation 360-14.

$$E_{a,n} = GOR \times V$$

Equation 360-14

Where:

$E_{a,n}$	=	Annual volumetric natural gas emissions from associated gas venting under ambient conditions (m^3).
GOR	=	Gas to oil ratio (m^3 gas/m^3 oil); oil here refers to hydrocarbon liquids produced of all API gravities.
V	=	Total volume of oil produced for the calendar year during which associated gas was flared or vented (m^3 oil/year)..

(4) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (q) of this section.

(5) Calculate both CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (r) and (s) of this section.

(6) Calculate emissions from associated natural gas to flares as follows:
   (i) Use the associated natural gas volume and gas composition as determined in paragraph (j)(1) through (4) of this section.
   (ii) Use the calculation methodology of flare stacks in paragraph (k) of this section to determine associated gas emissions from the flare.

(k) Flare stacks. Calculate CO_2, CH_4, and N_2O emissions from a flare stack as follows:

(1) If there is a continuous flow measurement device on the flare, measured flow volumes must be used to calculate the flare gas emissions. If all of the flare gas is not measured by the existing flow measurement device, then the flow not measured can be estimated using engineering calculations based on best available data or company records. If there is not a continuous flow measurement device on the flare, a flow measuring device can be installed on the flare or engineering calculations based on process knowledge, company records, and best available data can be used.

(2) If there is a continuous gas composition analyzer on the gas to the flare, these compositions must be used in calculating emissions. If there is not a continuous gas

composition analyzer on the gas to the flare, the appropriate gas compositions for each stream of hydrocarbons going to the flare must be used as follows:

(i) For onshore natural gas production, determine natural gas composition using (r)(2)(i) of this section.

(ii) For onshore natural gas processing, when the stream going to flare is natural gas, use the GHG mole percent in feed natural gas for all streams upstream of the de-methanizer or dew point control and GHG mole percent in facility specific residue gas to transmission pipeline systems for all emissions sources downstream of the de-methanizer overhead or dew point control for onshore natural gas processing facilities.

(iii) When the stream going to the flare is a hydrocarbon product stream, such as ethane, butane, pentane-plus, and mixed light hydrocarbons then use a representative composition from the source for the stream determined by engineering calculation based on process knowledge and best available data.

(3) Determine flare combustion efficiency from manufacturer. If not available, assume that flare combustion efficiency is 98 percent.

(4) Calculate GHG volumetric emissions at actual conditions using Equations 360-15, 360-16, 360-17, and 360-18.

$$E_{a,CH4} = V_a \times (1-\eta) \times X_{CH4}$$ **Equation 360-15**

$$E_{a,CO2}(noncombusted) = V_a \times X_{CO2}$$ **Equation 360-16**

$$E_{a,CO2}(combusted) = \sum_j \eta \times V_a \times Y_j \times R_j$$ **Equation 360-17**

$$E_{a,CO2}(total) = E_{a,CO2}(combusted) + E_{a,CO2}(noncombusted)$$ **Equation 360-18**

Where:

$E_{a,CH4}$	=	Contribution of annual noncombusted CH_4 emissions from flare stack under ambient conditions (m^3).
$E_{a,CO2}$ (noncombusted)	=	Contribution of annual CO_2 emissions from CO_2 in the inlet gas passing through the flare noncombusted under ambient conditions (m^3).
$E_{a,CO2}$ (combusted)	=	Contribution of annual CO_2 emissions from combustion from flare stack under ambient conditions (m^3).
V_a	=	Volume of natural gas sent to flare during the year (m^3).
η	=	Percent of natural gas combusted by flare (default is 98 percent). For gas sent to an unlit flare, η is zero.
X_i	=	Mole fraction of GHG *i* in gas to the flare.

Y_j = Mole fraction of natural gas hydrocarbon constituents *j* (i.e., methane, ethane, propane, butane, and pentanes plus).

R_j = Number of carbon atoms in the natural gas hydrocarbon constituent *j* (i.e., 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes plus).

(5) Calculate GHG volumetric emissions at standard conditions using calculations in paragraph (q) of this section.

(6) Calculate both CH_4 and CO_2 mass emissions from volumetric CH_4 and CO_2 emissions using calculation in paragraph (s) of this section.

(7) Calculate N_2O emissions using Equation 360-19.

$$E_{N2O} = Fuel \times HHV \times EF \times 0.001$$

Equation 360-19

Where:

E_{N2O} = Annual N_2O emissions from the combustion of a particular type of fuel (tonnes).

Fuel = Mass or volume of the fuel combusted (mass or volume per year, choose appropriately to be consistent with the units of HHV).

HHV = High heat value of the fuel from paragraphs (k)(7)(i), (k)(7)(ii) or (k)(7)(iii) of this section (units must be consistent with Fuel).

EF = Use 9.52×10^{-5} kg N_2O/GJ.

0.001 = Conversion factor from kilograms to tonnes.

(i) For fuels listed in Table 20-1, use the provided default HHV in the table.

(ii) For field gas or process vent gas, use 4.579×10^{-2} GJ/m^3 for HHV.

(iii) For fuels not listed in Table 20-1 and not field gas or process vent gas, you must use the methodology set forth in the Tier 2 methodology described in WCI.20 to determine HHV.

(8) To avoid double-counting, this emissions source excludes any emissions calculated under other emissions sources in WCI.363. Where gas to be flared is manifolded from multiple sources in WCI.363 to a common flare, report all flaring emissions under WCI.363(k).

(l) Centrifugal compressor venting. Calculate emissions from centrifugal compressor venting as follows:*

(1) For each centrifugal compressor determine the volume of vapours from wet seal oil degassing tank sent to an atmospheric vent or flare using a temporary or permanent flow measurement meter such as, but not limited to, a vane anemometer according to methods set forth in WCI.364(b).

(2) Estimate annual emissions using meter flow measurement using Equation 360-20.

$$E_{a,i} = MT \times t \times M_i \times (1 - B)$$

.

Equation 360-20

Where:

$E_{a,i}$	=	Annual volumetric emissions of GHG *i* (either CH_4 or CO_2) at ambient conditions.
MT	=	Meter reading of gas emissions per unit time.
t	=	Total time the compressor associated with the wet seal(s) is operational in the reporting year.
M_i	=	Mole percent of GHG *i* in the degassing vent gas; use the appropriate gas compositions in paragraph (r)(2) of this section.
B	=	Percentage of centrifugal compressor vent gas sent to vapour recovery or fuel gas or other beneficial use as determined by keeping logs of the number of operating hours for the vapour recovery system and the amount of vent gas that is directed to the fuel gas system.

(3) An engineering estimate approach based on similar equipment specifications and operating conditions may be used to determine the MT variable in place of actual metered values for centrifugal compressors that are isolated for extended periods of time and used for peaking purposes in place of metered gas emissions if an applicable meter is not present on the compressor.

(4) Calculate CH_4 and CO_2 volumetric emissions at standard conditions using paragraph (q) of this section.

(5) Calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (s) of this section.

(6) Calculate emissions from degassing vent vapours to flares as follows:
(i) Use the degassing vent vapour volume and gas composition as determined in paragraphs (l)(1) through (3) of this section.
(ii) Use the calculation methodology of flare stacks in paragraph (k) of this section to determine degassing vent vapour emissions from the flare.

(7) Emissions from dry seal centrifugal compressor vents, blow down valve leakage and unit isolation valve leakage to open ended vented are covered under WCI.353(x).

* For 2011 calendar year emissions only, an operator may use other equations and methods as presented by the EPA in 40 CFR Part 98.233(o) so long as the method is as accurate or more accurate as that presented here for the specific emission source in question and the appropriate regulator is notified of the choice.

(m) Reciprocating compressor venting. Calculate annual CH_4 and CO_2 emissions from all reciprocating compressor vents as follows, except as specified in paragraph (m)(8), following*. Where venting emissions are sent to a common flare, calculate emissions using WCI.362(k).

(1) Estimate annual emissions using the flow measurement in (m)(2) or (m)(3) below and Equation 360-21.

$$E_{a,i,m} = MT \times t \times M_i$$

Equation 360-21

Where:

$E_{a,i,m}$	=	Annual volumetric emissions of GHG *i* (either CH_4 or CO_2) at ambient conditions.
MT	=	Measured volumetric gas emissions (m^3/hour) under ambient conditions.
t	=	Total time the compressor is in the mode for which $E_{a,i,m}$ is being calculated, in the calendar year (hours).
M_i	=	Mole fraction of GHG *i* in the vent gas; use the appropriate gas compositions in paragraph (r)(2) of this section.

(2) If the reciprocating rod packing and blowdown vent is connected to an open ended vent line then use one of the following two methods to calculate emissions.

(i) Measure emissions from all vents (including emissions manifolded to common vents) including rod packing, unit isolation valves, and blowdown vents using either calibrated bagging or high volume sampler according to methods set forth in WCI.364(c) and (d).

(ii) Use a temporary meter such as a vane anemometer or a permanent meter such as an orifice meter to measure emissions from all vents (including emissions manifolded to a common vent) including rod packing vents, unit isolation valves, and blowdown valves according to methods set forth in WCI.364(b). If you do not have a permanent flow meter, you may install a port for insertion of a temporary meter or a permanent flow meter on the vents. For through-valve leakage to open ended vents, such as unit isolation valves on not operating, depressurized compressors and blowdown valves on pressurized compressors, you may use an acoustic detection device according to methods set forth in WCI.364(a).

(3) If the rod packing case is not equipped with a vent line use the following method to estimate emissions:

(i) Use the methods described in WCI.364(a) to conduct a progressive sample leak detection of fugitive equipment leaks from the packing case into an open distance piece, or from the compressor crank case breather cap or vent with a closed distance piece.

(ii) Measure emissions using a high flow sampler, or calibrated bag, or appropriate meter according to methods set forth in WCI.364(b), (c), or (d).

(4) Conduct an annual measurement for each compressor in the mode in which it is found during the annual measurement, except as specified in paragraph (m)(8) of this section. Measure emissions from (including emissions manifolded to common vents) reciprocating rod packing vents, unit isolation valve vents, and blowdown valve vents.

(i) Operating or standby pressurized mode, blowdown vent leakage through the blowdown vent stack.

(ii) Operating mode, reciprocating rod packing emissions.

(iii) Not operating, depressurized mode, unit isolation valve leakage through the blowdown vent stack, without blind flanges.

(A) For the not operating, depressurized mode, each compressor must be measured at least once in any three consecutive calendar years if this mode is not found in the annual measurement. If a compressor is not operated and has blind flanges in place throughout the 3 year period, measurement is not required in this mode. If the compressor is in standby depressurized mode without blind flanges in place and is not operated throughout the 3 year period, it must be measured in the standby depressurized mode

(5) Calculate CH_4 and CO_2 volumetric emissions at standard conditions using calculations in paragraph (q) of this section.

(6) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in paragraphs (r) and (s) of this section.

(7) Determine if the reciprocating compressor vent vapors are sent to a vapor recovery system.

(i) Adjust the emissions estimated in paragraphs (f)(1) of this section downward by the magnitude of emissions recovered using a vapor recovery system as determined by engineering estimate based on best available data.

(8) Onshore petroleum and natural gas production shall calculate emissions from well-site reciprocating compressors as follows using Equation 360-22:

$$E_{s,i} = Count \times EF_i$$

Equation 360-22

Where:

$E_{s,i}$	=	Annual total volumetric GHG emissions at standard conditions from reciprocating compressors (m^3/year).
Count	=	Total number of well-site reciprocating compressors for the reporter.

EF_i	=	Emission factor for GHG *i* (either CH_4 or O_2). Use 272.7 Sm^3/year per compressor for CH_4 and 15.2 Sm^3/year per compressor for CO_2 at 20 °C and 1 atmosphere or 268.5 Sm^3/year per compressor for CH_4 and 14.9 Sm^3/year per compressor for CO_2. at 15.6 °C and 1 atmosphere, or as adjusted for different temperatures.

* For 2011 calendar year emissions only, an operator may use other equations and methods as presented by the EPA in 40 CFR Part 98.233(p) so long as the method is as accurate or more accurate as that presented here for the specific emission source in question and the appropriate regulator is notified of the choice.

(n) Leak detection and leaker emission factors. Existing legislative or regulatory requirements or progressive sampling methods described in WCI.364(a) must be used to conduct a leak detection of fugitive equipment leaks from all sources listed in §WCI.362(d)(9). This paragraph (n) applies to emissions sources in streams with gas content greater than 10 percent CH_4 plus CO_2 by weight. Emissions sources in streams with gas content less than 10 percent CH_4 plus CO_2 by weight need to be reported instead under WCI.364(x). Tubing systems equal to or less than one half inch diameter are exempt from the requirements of this paragraph (n) and need to be reported under WCI.364(x).

If fugitive equipment leaks are detected for sources listed in this paragraph, calculate emissions using Equation 360-23 for each source with fugitive equipment leaks.

$$E_{s,i} = Count \times EF_s \times GHG_i \times t_x$$

Equation 360-23

Where:

$E_{s,i}$	=	Annual total volumetric emissions of GHG *i* (either CH_4 or CO_2),at standard conditions from each fugitive equipment leak source (m^3).
Count	=	Total number of this type of emission source found to be leaking during time t_x.
EF_s	=	Leaker volumetric emission factor for specific sources listed in 40 CFR Part 98 Table W-2, relevant Canadian Association of Petroleum Producers (CAPP) methodology manuals, if available or facility/company-specific emission factors used (as converted for use in Equation 360-23).
GHG_i	=	For onshore natural gas processing facilities, concentration of GHG *i* (either CH_4 or CO_2) in the total hydrocarbon of the feed natural gas.
t_x	=	Total time the component was found leaking and operational (hours). If one leak detection survey is conducted, assume the component was leaking from the start of the year until the leak was repaired and then zero for the remainder of the year. If the leak was not repaired, assume the component was leaking for the entire year. If multiple leak detection surveys are conducted, assume that the component found to be leaking has been leaking since the previous survey, or the beginning of the calendar year. For the last leak detection

survey in the calendar year, assume that all leaking components continue to leak until the end of the calendar year or until the component was repaired and then zero until the end of the year.

(1) Calculate GHG mass emissions in carbon dioxide equivalent at standard conditions using calculations in paragraph (s) of this section.

(2) Onshore natural gas processing facilities shall use the appropriate default volumetric leaker emission factors listed in 40 CFR Part 98 Table W-2 (as converted to metric) or relevant Canadian Association of Petroleum Producer methodology manuals, if available for fugitive equipment leaks detected from valves; connectors; open ended lines; pressure relief valves; and meters.

(o) Population count and emission factors. This paragraph applies to emissions sources listed in §WCI.362(c)(3), (c)(16), (c)(17), (c)(21), and (d)(8) on streams with gas content greater than 10 percent CH_4 plus CO_2 by weight. Emissions sources in streams with gas content less than 10 percent CH_4 plus CO_2 by weight do not need to be reported. Tubing systems equal or less than one half inch diameter are exempt from the requirements of paragraph (o) of this section and instead need to be reported under WCI.363(x). Calculate emissions from all sources listed in this paragraph using Equation 360-24.

$$E_{s,i} = Count \times EF_s \times GHG_i \times t$$

Equation 360-24

Where:

$E_{s,i}$	=	Annual total mass emissions of GHG *i* (CH_4 or CO_2) at standard conditions from each fugitive source (tonnes/year).
Count	=	Total number of this type of emission source at the facility. Average component counts by major equipment pieces for Canada from Table 360-3 may be used as appropriate. If facility or company specific major equipment count data that meet or exceed the quality of the relevant default count data are available, they must be used instead. To ensure proper use of kg/km units in emission factors for underground gathering pipelines, the length of the installed underground pipeline should be used in place of count.
EF_s	=	Population mass emission factor for specific major equipment sources listed in Table 360-1 or Table 360-2. The direction on the use of Tables 360-1 and 360-2 provided prior to these tables must be followed.
GHG_i	=	Mass fraction of GHG *i* (CH_4 or CO_2) in produced natural gas or feed natural gas.
t	=	Total time the specific source associated with the fugitive equipment leak was operational in the reporting year (hours).

(1) Onshore petroleum and natural gas production facilities shall use the appropriate default population emission factors listed in Table 360-1 or 360-2 for fugitive equipment leaks from valves, connectors, open ended lines, pressure relief valves, pump, flanges, and other equipment. Where facilities conduct EOR operations the emissions factors listed in Table 360-1 or Table 360-2 shall be used to estimate all streams of gases, including the recycle CO_2 stream. The component count can be determined using either of the methodologies described in this paragraph (o)(1). The same methodology must be used for the entire calendar year..

(i) *Component Count Methodology 1*. For all onshore petroleum and natural gas production operations in the facility perform the following activities:

(A) Count all major equipment listed in Table 360-3 of this section.

(B) Multiply major equipment counts by the average component counts listed in Table 360-3 of this section for onshore natural gas production and onshore oil production, respectively. Use the appropriate factor in Table 360-1 or Table 360-2 of this section or from CAPP methodology manuals, if the appropriate factor is not provided in Tables 360-1 or 360-2.

(ii) *Component Count Methodology 2*. Count each component individually for the facility. Use the appropriate factor Table 360-1 or Table 360-2 of this section or from CAPP methodology manuals, if the appropriate factor is not provided in Tables 360-1 or 360-2.

(2) Onshore natural gas processing facilities shall use the appropriate default population emission factor listed in Table 360-1, Table 360-2 or from CAPP methodology manuals for fugitive equipment leaks from gathering pipelines.

(p) <u>Offshore petroleum and natural gas production facilities in both provincial and federal waters.</u>
[reserved]

(q) <u>Volumetric emissions</u>. Calculate volumetric emissions at standard conditions as specified in paragraphs (q)(1) or (2) determined by engineering estimate based on best available data unless otherwise specified.

(1) Calculate natural gas volumetric emissions at standard conditions by converting ambient temperature and pressure of natural gas emissions to standard temperature and pressure (15 ºC and 1 atmosphere in Canada) natural gas using Equation 360-25 of this section.

$$E_{s,n} = \frac{E_{a,n} \times (273.15 + T_s) \times P_a}{(273.15 + T_a) \times P_s}$$

Equation 360-25

Where:

$E_{s,n}$ = Natural gas volumetric emissions at standard temperature and pressure (STP) conditions (m^3).
$E_{a,n}$ = Natural gas volumetric emissions at ambient conditions (m^3).
T_s = Temperature at standard conditions (^oC).
T_a = Temperature at actual emission conditions (^oC).
P_s = Absolute pressure at standard conditions (kPa).
P_a = Absolute pressure at ambient conditions (kPa).

(2) Calculate GHG volumetric emissions at standard conditions by converting ambient temperature and pressure of GHG emissions to standard temperature and pressure using Equation 360-26.

$$E_{s,i} = \frac{E_{a,i} \times (273.15 + T_s) \times P_a}{(273.15 + T_a) \times P_s}$$

Equation 360-26

Where:

$E_{s,i}$ = GHG *i* volumetric emissions at standard temperature and pressure (STP) conditions (m^3).
$E_{a,i}$ = GHG *i* volumetric emissions at actual conditions (m^3).
T_s = Temperature at standard conditions (^oC).
T_a = Temperature at actual emission conditions (^oC).
P_s = Absolute pressure at standard conditions (kPa).
P_a = Absolute pressure at ambient conditions (kPa).

(r) GHG volumetric emissions. Calculate GHG volumetric emissions at standard conditions as specified in paragraphs (r)(1) and (2) of this section determined by engineering estimate based on best available data unless otherwise specified.

(1) Estimate CH_4 and CO_2 emissions from natural gas emissions using Equation 360-27.

$$E_{s,i} = E_{s,n} \times M_i$$

Equation 360-27

Where:

$E_{s,i}$ = GHG *i* (CH_4 or CO_2) volumetric emissions at standard conditions.
$E_{s,n}$ = Natural gas volumetric emissions at standard conditions.

M_i = Mole fraction of GHG *i* in the natural gas.

(2) For Equation 360-27 of this section, the mole fraction, M_i, shall be the annual average mole fraction for each facility, as specified in paragraphs (r)(2)(i) and (ii) of this section.

(i) GHG mole fraction in produced natural gas for onshore petroleum and natural gas production facilities. If you have a continuous gas composition analyzer for produced natural gas, you must use these values in calculating emissions. If you do not have a continuous gas composition analyzer, then either the known composition for the company or operator for the specific field from Table 360-4 (or as referenced in Table 360-4 (as Table 360-4 is under development)), or the methods set forth in WCI.364(b) must be used.

(ii) GHG mole fraction in feed natural gas for all emissions sources upstream of the de-methanizer or dew point control and GHG mole fraction in facility specific residue gas to transmission pipeline systems for all emissions sources downstream of the de-methanizer overhead or dew point control for onshore natural gas processing facilities. If you have a continuous gas composition analyzer on feed natural gas, you must use these values in calculating emissions. If you have a continuous gas composition analyzer on feed natural gas, you must use these values for determining the mole percent. If you do not have a continuous gas composition analyzer, then the known composition for the company or operator for the specific field must be used as taken according to methods set forth in WCI.364(b).

(s) <u>GHG mass emissions</u>. Calculate GHG mass emissions in carbon dioxide equivalent at standard conditions by converting the GHG volumetric emissions into mass emissions using Equation 360-28.

$$Mass_{s,i} = E_{s,i} \times \rho_i \times GWP_i \times 0.001$$

Equation 360-28

Where:

$Mass_{s,i}$ = GHG *i* (either CH_4 or CO_2) mass emissions at standard conditions (tonnes CO_2e).

$E_{s,i}$ = GHG *i* (either CH_4 or CO_2) volumetric emissions at standard conditions (m^3).

ρ_i = Density of GHG *i*, (1.861 kg/m^3 for CO_2 and 0.678 kg/m^3 for CH_4)*.

GWP_i = Global warming potential of GHG *i* (1 for CO_2 and 21 for CH_4, and 310 for N_2O).0.001 = Conversion factor from kilograms to tonnes.

* gas densities calculated using the 12th edition of the Gas Processors Suppliers Association Engineering Data Book.

(t) <u>EOR injection pump blowdown</u>. Calculate pump blowdown emissions as follows:

(1) Calculate the total volume in cubic meters (including, but not limited to, pipelines, manifolds and vessels) between isolation valves.

(2) Retain logs of the number of blowdowns per reporting period.

(3) Calculate the total annual venting emissions using Equation 360-29.

$$Mass_{c,i} = N \times V_v \times R_c \times GHG_i \times 0.001$$

Equation 360-29

Where:

$Mass_{c,i}$	=	Annual EOR injection gas venting emissions at critical conditions *c* from blowdowns (tonnes).
N	=	Number of blowdowns for the equipment in reporting year.
V_v	=	Total volume of blowdown equipment chambers (including, but not limited to, pipelines, manifolds and vessels) between isolation valves (m^3).
R_c	=	Density of critical phase EOR injection gas (kg/m^3). Use an appropriate standard method published by a consensus-based standards organization if such a method exists or otherwise an industry standard to determine density of super critical EOR injection gas.
GHG_i	=	Mass fraction of GHG_i in critical phase injection gas.
0.001	=	Conversion factor from kilograms to tonnes.

(u) [Reserved]

(v) [Reserved]

(w) Field gas or process vent gas combustion. For combustion units that combust field gas or process vent gas or any blend of field gas and process vent gas, you must comply with following requirements:

(1) Measure the higher heating value of the field gas or process vent gas annually.

(2) If the measured higher heating value is equal to or greater than 36.3 MJ/m^3 and less than 40.98 MJ/m^3, then calculate the CO_2, CH_4, and N_2O emissions using the methods in WCI.20 (General Stationary Combustion Sources) following the methods required for pipeline quality natural gas.

(3) If the measured higher heating value is less than 36.3 MJ/m^3 or greater than 40.98 MJ/m^3, then calculate the CO_2 and CH_4 emissions using either the Tier 3 or Tier 4 methodology in WCI.20 (General Stationary Combustion Sources). Sampling, analysis

and measurement requirements (including for gas composition) required for WCI.360 in WCI.025(f) apply in place of those indicated for Equation 20-7. For N_2O, use 4.579×10^{-2} GJ/m^3 for HHV.

(x) Other venting or fugitive emissions. All venting or fugitive emissions not covered by quantification methods in WCI.363 must be calculated by methodologies consistent with those presented here, the 2009 API Compendium[1], or other similar resource documents.

§ WCI.364 Sampling, Analysis, and Measurement Requirements

Instruments used for sampling, analysis and measurement must be operated and calibrated according to legislative, manufacturer's, or other written specifications or requirements. All sampling, analysis and measurement must be conducted only by, or under the direct supervision of individuals with demonstrated understanding and experience in the application (and principles related) of the specific sampling, analysis and measurement technique in use.

(a) (i) If a documented leak detection or integrity management standard or requirement that is required by legislation or regulation such as CSA Z662-07 Oil & Gas Pipeline Systems or the CAPP Best Management Practices for Fugitive Emissions or similar standard CAPP Methodologies (as amended from time to time) is used, the documented standard or requirement must be followed – including service schedules for different components and/or facilities - with reporting as required for input to the calculation methods herein.

(ii) If there is no such legal requirement, then progressive sampling is required using one of the methods outlined below in combination with best industry practices for use of the method– including service schedules for different components - to determine the count of leaks (and time leaking) required in WCI.363(m), (n), and (o), as applicable. Progressive sampling means establishing a statistically valid baseline sample of leaks under normal operating conditions for the 2011 and 2012 calendar years, with subsequent sampling determined based random or spot sampling modelling or measurement of leaks under normal operating conditions. A minimum of 18 months and a maximum of 36 months is allowed between surveys. This interval is determined based on whether there are indications of leaks. If a leak found and immediately repaired, the existing schedule may be maintained.

Leak detection for fugitive equipment leaks must be performed for all identified equipment in operation or on standby mode during a reporting period.

(1) Optical gas imaging instrument. Use an optical gas imaging instrument for fugitive equipment leaks detection in accordance with 40 CFR part 60, subpart A, §60.18(i)(1) and (2) *Alternative work practice for monitoring equipment leaks* (or per relevant standard in Canada). In addition, the optical gas imaging instrument must be operated to image the source types required by this proposed reporting rule in accordance with

[1] American Petroleum Institute. *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industr*y. August 2009. Table 6-22 (from Clearstone Engineering Ltd.. *A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry*, Volume 5, September 2004.)

the instrument manufacturer's operating parameters. The optical gas imaging instrument must comply with the following requirements:

(i) Provide the operator with an image of the potential leak points for each piece of equipment at both the detection sensitivity level and within the distance used in the daily instrument check described in the relevant best practices. The detection sensitivity level depends upon the frequency at which leak monitoring is to be performed.

(ii) Provide a date and time stamp for video records of every monitoring event.

(2) Bubble tests

(3) Portable organic vapour analyzer. Use a portable organic vapour analyzer in accordance with US EPA Method 21 or as outlined in the CAPP Best Management Practices for Fugitive Emisisons

(4) Other methods as outlined in the CAPP Best Management Practices for Fugitive Emissions or similar standard CAPP Methodologies (as amended from time to time) may be used as necessary for operational circumstances. Other methods that are deemed to be technically sound based on an engineering assessment may also be used as necessary provided that sufficient documentation as to the method used, test results, its reliability, and accuracy is maintained and updated at regular intervals.

(b) All flow meters, composition analyzers and pressure gauges that are used to provide data for the GHG emissions calculations shall use measurement methods, maintenance practices, and calibration methods, prior to the first reporting year and in each subsequent reporting year using an appropriate standard method published by a consensus standards organization such as ASTM International, Canadian Standards Assocation (CSA), American National Standards Institute (ANSI), the relevant provincial or national oil and gas regulator, Measurement Canada, Canadian Association of Petroleum Producers (CAPP), Canadian Gas Association (CGA), American Petroleum Institute (API), American Society of Mechanical Engineers (ASME), and North American Energy Standards Board (NAESB). If a consensus based standard is not available, industry standard practices such as manufacturer instructions must be used.

(c) Use calibrated bags (also known as vent bags) only where the emissions are at near-atmospheric pressures and hydrogen sulphide levels are such that it is safe to handle and can capture all the emissions, below the maximum temperature specified by the vent bag manufacturer, and the entire emissions volume can be encompassed for measurement.

(1) Hold the bag in place enclosing the emissions source to capture the entire emissions and record the time required for completely filling the bag. If the bag inflates in less than one second, assume one second inflation time.

(2) Perform three measurements of the time required to fill the bag, report the emissions as the average of the three readings.

(3) Estimate natural gas volumetric emissions at standard conditions using calculations in WCI.363(q).

(4) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in WCI.363(r) and (s).

(d) Use a high volume sampler to measure emissions within the capacity of the instrument.

(1) A technician following manufacturer instructions shall conduct measurements, including equipment manufacturer operating procedures and measurement methodologies relevant to using a high volume sampler, including, positioning the instrument for complete capture of the fugitive equipment leaks without creating backpressure on the source.

(2) If the high volume sampler, along with all attachments available from the manufacturer, is not able to capture all the emissions from the source, then anti-static wraps or other aids must be used to capture all emissions without violating operating requirements as provided in the instrument manufacturer's manual.

(3) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in WCI.363(r) and (s).

(4) Calibrate the instrument at 2.5 percent methane with 97.5 percent air and 100 percent CH_4 by using calibrated gas samples and by following manufacturer's instructions for calibration.

(e) Peng Robinson Equation of State means the equation of state defined by Equation 360-30 of this section.

$$p = \frac{RT}{V_m - b} - \frac{a\alpha}{V_m^2 + 2bV_m - b^2} \qquad \textbf{Equation 360-30}$$

Where:

p = Absolute pressure.
R = Universal gas constant.
T = Absolute temperature.
V_m = Molar volume.

$$a = \frac{0.45724 R^2 T_c^2}{p_c}$$

$$b = \frac{0.7780 RT_c}{p_c}$$

$$\alpha = \left(1 + \left(0.37464 + 1.54226\omega - 0.26992\omega^2\right)\left(1 - \sqrt{\frac{T}{T_c}}\right)\right)^2$$

Where:

ω	=	Acentric factor of the species.
T_c	=	Critical temperature.
P_c	=	Critical pressure.

(f) Onshore Production and Processing Storage Tanks.

(1) A pressurized sample of produced liquids shall be collected from the separator at a location upstream of the storage tank. This point would typically be at the final separation device before produced oil transitions from separator outlet pressure to atmospheric pressure and enters a production storage tank. This may require the installation of a sampling valve at the appropriate location. Sampling protocol specific to the collection of separator liquid can be found in the following publications:

(i) Appendix C Sampling Protocol section (page 33) of the *E&P TANK Version 2.0 User's Manual*.

(ii) Wyoming Department of Environmental Quality Air Quality Division guidance document *Oil and Gas Production Facilities, Chapter 6, Section 2 Permitting Guidance (revised August 2001), Appendix D Sampling and Analysis of Hydrocarbon Liquids and Natural Gas.*

(iii) Gas Processors Association (GPA) Standard 2174-93, *Obtaining Liquid Hydrocarbon Samples for Analysis by Gas Chromatography*.

(2) The sample collection pressure shall be determined at the time of collection and again prior to processing in the laboratory to insure that sample integrity has been maintained. Liquid temperature should also be determined and recorded at the time of collection.

(3) Sampling and laboratory based determination of the gas to oil ratio GOR shall be conducted at prescribed intervals and at a time when operational parameters of the storage tank battery are representative and consistent with normal operating conditions. Sampling shall be annual for oil production rates between 1.75 and 15.9 m^3/day, semi-annual for oil production rates between15.9 and 79.5 m^3/day, and quarterly for oil production rates greater than 79.5 m^3/day.

(4) An additional sample shall be collected and analyzed if:

(i) The oil production rate at the storage tank battery changes more than 20 percent for time periods in excess of one week (e.g., in cases where a well or wells feeding the storage tank battery stop or start production).

(ii) The separator operating pressures change by more than 10 percent.

(5) The volume (barrels) of liquid produced during the sampling interval shall be determined using a calibrated liquid meter or industry standard method to an accuracy of ±5%.

§ WCI.365 *Procedures for Estimating Missing Data*

A complete record of all estimated and/or measured parameters used in the GHG emissions calculations is required. If data are lost or an error occurs during annual emissions estimation or measurements, the estimation or measurement activity for those sources must be repeated as soon as possible, including in the subsequent reporting year if missing data are not discovered until after December 31 of the reporting year, until valid data for reporting is obtained. Data developed and/or collected in a subsequent reporting year to substitute for missing data cannot be used for that subsequent year's emissions estimation. Where missing data procedures are used for the previous year, at least 30 days must separate emissions estimation or measurements for the previous year and emissions estimation or meausrements for the current year of data collection. For missing data that are continuously monitored or measured (for example flow meters), or for missing temperature and pressure data, the reporter may use best available data for use in emissions determinations. The reporter must record and report the basis for the best available data in these cases.

§ WCI.366 Definitions

Absorbent circulation pump means a pump commonly powered by natural gas pressure that circulates the absorbent liquid between the absorbent regenerator and natural gas contactor.

Acid gas means hydrogen sulphide (H_2S) and carbon dioxide (CO_2) contaminants that are separated from sour natural gas by an acid gas removal unit.

Acid gas removal (AGR) unit means a process unit that separates hydrogen sulphide and/or carbon dioxide from sour natural gas using liquid or solid absorbents or membrane separators.

Acid gas removal vent stack emissions mean the acid gas separated from the acid gas absorbing medium (e.g., an amine solution) and released with methane and other light hydrocarbons to the atmosphere or a flare.

Blowdown vent stack emissions mean natural gas and/or CO_2 released due to maintenance and/or blowdown operations including compressor blowdown and emergency shut-down (ESD) system testing.

Calibrated bag means a flexible, non-elastic, anti-static bag of a calibrated volume that can be affixed to a emitting source such that the emissions inflate the bag to its calibrated volume.

Centrifugal compressor means any equipment that increases the pressure of a process natural gas or CO_2 by centrifugal action, employing rotating movement of the driven shaft.

Centrifugal compressor dry seals mean a series of rings around the compressor shaft where it exits the compressor case that operates mechanically under the opposing forces to prevent natural gas or CO_2 from escaping to the atmosphere.

Centrifugal compressor dry seals emissions mean natural gas or CO_2 released from a dry seal vent pipe and/or the seal face around the rotating shaft where it exits one or both ends of the compressor case.

Centrifugal compressor venting emissions means emissions that occur when the high-pressure oil barriers for centrifugal compressors are depressurized to release absorbed natural gas or CO_2. High-pressure oil is used as a barrier against escaping gas in centrifugal compressor shafts. Very little gas escapes through the oil barrier, but under high pressure, considerably more gas is absorbed by the oil. The seal oil is purged of the absorbed gas (using heaters, flash tanks, and degassing techniques) and recirculated. The separated gas is commonly vented to the atmosphere.

Coal bed methane (CBM) means natural gas which is extracted from underground coal deposits or "beds."

Component means each metal to metal joint or seal of non-welded connection separated by a compression gasket, screwed thread (with or without thread sealing compound), metal to metal compression, or fluid barrier through which natural gas or liquid can escape to the atmosphere.

Compressor means any machine for raising the pressure of a natural gas or CO_2 by drawing in low pressure natural gas or CO_2 and discharging significantly higher pressure natural gas or CO_2.

Condensate means hydrocarbon and other liquid separated from natural gas that condenses due to changes in the temperature, pressure, or both, and remains liquid at storage conditions..

Continuous bleed means a continuous flow of pneumatic supply gas to the process measurement device (e.g. level control, temperature control, pressure control) where the supply gas pressure is modulated by the process condition, and then flows to the valve controller where the signal is compared with the process set-point to adjust gas pressure in the valve actuator

Dehydrator means a device in which a liquid absorbent (including desiccant, ethylene glycol, diethylene glycol, or triethylene glycol) directly contacts a natural gas stream to absorb water vapor.

Dehydrator vent emissions means natural gas and CO_2 released from a natural gas dehydrator system absorbent (typically glycol) reboiler or regenerator, including stripping natural gas and motive natural gas used in absorbent circulation pumps.

De-methanizer means the natural gas processing unit that separates methane rich residue gas from the heavier hydrocarbons (e.g., ethane, propane, butane, pentane-plus) in feed natural gas stream.

Desiccant means a material used in solid-bed dehydrators to remove water from raw natural gas by adsorption. Desiccants include activated alumina, pelletized calcium chloride, lithium chloride and granular silica gel material. Wet natural gas is passed through a bed of the granular or pelletized solid adsorbent in these dehydrators. As the wet gas contacts the surface of the particles of desiccant material, water is adsorbed on the surface of these desiccant particles. Passing through the entire desiccant bed, almost all of the water is adsorbed onto the desiccant material, leaving the dry gas to exit the contactor.

E&P Tank means the most current version of an exploration and production field tank emissions equilibrium program that estimates flashing, working and standing losses of hydrocarbons, including methane, from produced crude oil and gas condensate. Equal or successors to E&P Tank Version 2.0 for Windows Software. Copyright (C) 1996-1999 by The American Petroleum Institute and The Gas Research Institute.

Engineering estimation, for the purposes of WCI.350 and WCI.360 means an estimate of emissions based on engineering principles applied to measured and/or approximated physical parameters such as dimensions of containment, actual pressures, actual temperatures, and compositions.

Enhanced oil recovery (EOR) means the use of certain methods such as water flooding or gas injection into existing wells to increase the recovery of crude oil from a reservoir. In the context of this rule, EOR applies to injection of critical phase carbon dioxide into a crude oil reservoir to enhance the recovery of oil.

Equipment leak detection means the process of identifying emissions from equipment, components, and other point sources.

External combustion means fired combustion in which the flame and products of combustion are separated from contact with the process fluid to which the energy is delivered. Process fluids may be air, hot water, or hydrocarbons. External combustion equipment may include fired heaters, industrial boilers, and commercial and domestic combustion units.

Field means the surface area underlaid or appearing to be underlaid by one or more pools, and the subsurface regions vertically beneath that surface area;

Field gas means natural gas extracted from a production well prior to its entering the first stage of processing, such as dehydration.

Flare combustion efficiency means the fraction of natural gas, on a volume or mole basis, that is combusted at the flare burner tip.

Fugitive emissions means the unintended or incidental emissions of greenhouse gases from the transmission, processing, storage, use or transportation of fossil fuels, greenhouse gases, or other.

Fugitive equipment leak means the those fugitive emissions which could not reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening.

Gas conditions mean the actual temperature, volume, and pressure of a gas sample.

Gas gathering/booster stations mean centralized stations where produced natural gas from individual wells is co-mingled, compressed for transport to processing plants, transmission and distribution systems, and other gathering/booster stations which co-mingle gas from multiple production gathering/booster stations. Such stations may include gas dehydration, gravity separation of liquids (both hydrocarbon and water), pipeline pig launchers and receivers, and gas powered pneumatic devices.

Gas to oil ratio (GOR) means the ratio of the volume of gas at standard temperature and pressure that is produced from a volume of oil when depressurized to standard temperature and pressure.

Gas well means a well completed for production of natural gas from one or more gas zones or reservoirs. Such wells contain no completions for the production of crude oil.

High-bleed pneumatic devices are automated control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream which is regulated by the process condition flows to a valve actuator controller where it vents (bleeds) to the atmosphere at a rate in excess of six standard cubic feet per hour.

Intermittent bleed pneumatic devices mean automated flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. These are snap-acting or throttling devices that discharge the full volume of the actuator intermittently when control action is necessary, but does not bleed continuously.

Internal combustion means the combustion of a fuel that occurs with an oxidizer (usually air) in a combustion chamber. In an internal combustion engine the expansion of the high-temperature and –pressure gases produced by combustion applies direct force to a component of the engine, such as pistons, turbine blades, or a nozzle. This force moves the component over a distance, generating useful mechanical energy. Internal combustion equipment may include gasoline and diesel industrial engines, natural gas-fired reciprocating engines, and gas turbines.

Liquefied natural gas (LNG) means natural gas (primarily methane) that has been liquefied by reducing its temperature to -162 degrees Celsius at atmospheric pressure.

LNG boiloff gas means natural gas in the gaseous phase that vents from LNG storage tanks due to ambient heat leakage through the tank insulation and heat energy dissipated in the LNG by internal pumps.

Low-bleed pneumatic devices mean automated control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream which is regulated by the process condition flows to a valve actuator controller where it vents (bleeds) to the atmosphere at a rate equal to or less than 0.17 standard cubic meters per hour.

Natural gas driven pneumatic pump means a pump that uses pressurized natural gas to move a piston or diaphragm, which pumps liquids on the opposite side of the piston or diaphragm.

Offshore means seaward of the terrestrial borders of the Canada, including waters subject to the ebb and flow of the tide, as well as adjacent bays, lakes or other normally standing waters, and extending to the outer boundaries of the jurisdiction and control of Canada.

Oil well means a well completed for the production of crude oil from at least one oil zone or reservoir.

Operating pressure means the containment pressure that characterizes the normal state of gas or liquid inside a particular process, pipeline, vessel or tank.

Pump means a device used to raise pressure, drive, or increase flow of liquid streams in closed or open conduits.

Pump seals means any seal on a pump drive shaft used to keep methane and/or carbon dioxide containing light liquids from escaping the inside of a pump case to the atmosphere.

Pump seal emissions means hydrocarbon gas released from the seal face between the pump internal chamber and the atmosphere.

Reciprocating compressor means a piece of equipment that increases the pressure of a gas stream by positive displacement, employing linear movement of a shaft driving a piston in a cylinder.

Reciprocating compressor rod packing means a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of the compressed gas stream that escapes to the atmosphere.

Re-condenser means heat exchangers that cool compressed boil-off gas to a temperature that will condense natural gas to a liquid.

Reservoir means a porous and permeable underground natural formation containing significant quantities of hydrocarbon liquids and/or gases.

Residue gas and residue gas compression mean, respectively, production lease natural gas from which gas liquid products and, in some cases, non-hydrocarbon components have been extracted such that it meets the specifications set by a pipeline transmission company, and/or a distribution company; and the compressors operated by the processing facility, whether inside the processing facility boundary fence or outside the fence-line, that deliver the residue gas from the processing facility to a transmission pipeline.

Sales oil means produced crude oil or condensate measured at the production lease automatic custody transfer (LACT) meter or custody transfer meter tank gauge.

Separator means a vessel in which streams of multiple phases are gravity separated into individual streams of single phase.

Sour natural gas means natural gas that contains significant concentrations of hydrogen sulphide and/or carbon dioxide that exceed the concentrations specified for commercially saleable natural gas delivered from transmission and distribution pipelines.

Sweet gas is natural gas with low concentrations of hydrogen sulphide (H_2S) and/or carbon dioxide (CO_2) that does not require (or has already had) acid gas treatment to meet pipeline corrosion-prevention specifications for transmission and distribution.

Transmission pipeline means high pressure cross country pipeline transporting saleable quality natural gas from production or natural gas processing to natural gas distribution pressure let-down, metering, regulating stations where the natural gas is typically odorized before delivery to customers.

Turbine meter means a flow meter in which a gas or liquid flow rate through the calibrated tube spins a turbine from which the spin rate is detected and calibrated to measure the fluid flow rate.

Vapour recovery system means any equipment located at the source of potential gas emissions to the atmosphere or to a flare, that is composed of piping, connections, and, if necessary, flow-inducing devices, and that is used for routing the gas back into the process as a product and/or fuel.

Vapourization unit means a process unit that performs controlled heat input to vapourize LNG to supply transmission and distribution pipelines or consumers with natural gas.

Vented emissions means the same as defined in the relevant greenhouse gas reporting regulation, including but not limited to process designed flow to the atmosphere through seals or vent pipes, equipment blowdown for maintenance, and direct venting of gas used to power equipment (such as pneumatic devices), but not including stationary combustion flue gas.

Well completions means a process that allows for the flow of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and test the reservoir flow characteristics, steps which may vent produced gas to the atmosphere via an open pit or tank. Well completion also involves connecting the well bore to the reservoir, which may include treating the formation or installing tubing, packer(s), or lifting equipment, steps that do not significantly vent natural gas to the atmosphere. This process may also include high-rate flowback of injected gas, water, oil, and proppant used to fracture or re-fracture and prop open new fractures in existing lower permeability gas reservoirs, steps that may vent large quantities of produced gas to the atmosphere.

Well workover means the process(es) of performing of one or more of a variety of remedial operations on producing petroleum and natural gas wells to try to increase production. This process also includes high-rate flowback of injected gas, water, oil, proppant and sand used to re-fracture and prop-open new fractures in existing low permeability gas reservoirs, steps that may vent large quantities of produced gas to the atmosphere.

Wellhead means the piping, casing, tubing and connected valves protruding above the Earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve. Wellhead equipment includes all equipment, permanent and portable, located on the improved land area (i.e. well pad) surrounding one or multiple wellheads.

Wet natural gas means natural gas in which water vapour exceeds the concentration specified for commercially saleable natural gas delivered from transmission and distribution pipelines. This input stream to a natural gas dehydrator is referred to as "wet gas".

Directions for the use of Tables 360-1 to 360-2

(a) Starting with 2013 calendar year emissions, for each component listed in the Tables 360-1 to 360-2 or otherwise required by the quantification method referencing Tables 360-1 and 360-2:

(i) If statistically valid facility specific emission factors for a component type are available or can safely or reasonably developed, they must be used.

(ii) If facility specific emissions factors for a component type are not available, an operator must use statistically valid company specific emission factors, if they can be safely or reasonably developed.

If statistically valid facility or company specific emission factors for a specific component type cannot be safely and reasonably developed, estimates in the default tables 360-1 to 360-2 may be used. Equipment or facilities that have low temporal utilization (e.g. equipment such as booster stations used only sporadically during a year) may continue to use the default tables.

(b) For 2011 and 2012 calendar year emissions:

(i) An operator may use the default factors specified below, company or facility-specific emissions factors (if such emission factors are available). If the default factors in Tables 360-1 to 360-2 are used, an explanation as to why company or facility specific emission factors are cannot be used must be provided to the jurisdiction.

(c) If a facility-specific emission factor has been used in a previous reporting year, it must continue to be used until updated. If a company-specific emission factor has been used in a previous reporting year, it must continue to be used until updated or a facility-specific emission factor is used in its place

(d) Any changes from facility-specific factors to company-specific or the defaults in Tables 360-1 to 360-2, or from company specific factors to the defaults in Tables 360-1 to 360-2 must be approved by the jurisdiction and substantiated by evidence that the new approach is more accurate for the facility or facilities in question.

(e) If an emission factor required by the quantification method referencing Tables 360-1 and 360-2 is not provided in the tables, emission factors from either the U.S. EPA 40 CFR Part 98.230 Tables W-1A or W-2 or the Clearstone Engineering Ltd.. *A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry*, Volume 5, September 2004 may be used (as converted for use in the relevant equation).

(f) Documentation on the method used to update the emission factors, input data, sampling methodology and other relevant information must be kept by the operator and provided to the jurisdiction or verifier upon request.

(g) All emission factors or data collection for emission factors must be developed using CAPP (CAPP) or Canadian Gas Association (CGA) standard methods, or other methods if CAPP or CGA methods are not available or applicable. Facility and company-specific emission factors must be updated at a minimum on a three year cycle, with the first update to the original facility and company-specific emission factors for the 2016 reporting period, at the latest.

(h) Updated emission factors can only be incorporated for reporting purposes at the start of a reporting period and not during a calendar year.

(i) The default emission factors provided in Tables 360-1 to 360-2 below are published emission factors for Canada as of the 2010 calendar year. The factors will be updated every 3-5 years based on new data, methods and statistically valid samples of the entire industry and developed in collaboration with industry groups.

Table 360-1. Additional Natural Gas Facility Average Emission Factors

Component – Service	Emission Factor, tonnes THC/component-hr
Valves - fuel gas	2.81E-06
Valves - light liquid	3.52E-06
Valves - gas/vapor - all	2.46E-06
Valves - gas/vapor - sour	1.16E-06
Valves - gas/vapor - sweet	2.81E-06
Connectors - fuel gas	8.18E-07
Connectors - light liquid	5.51E-07
Connectors - gas/vapor - all	7.06E-07
Connectors - gas/vapor - sour	1.36E-07
Connectors - gas/vapor - sweet	8.18E-07
Control valves - fuel gas	1.62E-05
Control valves - light liquid	1.77E-05
Control valves - gas/vapor - all	1.46E-05
Control valves - gas/vapor - sour	9.64E-06
Control valves - gas/vapor - sweet	1.62E-05
Pressure relief valves - fuel gas and gas/vapor	1.70E-05
Pressure relief valves - light liquid	5.39E-06
Pressure regulators - fuel gas and gas/vapor	8.11E-06
Pressure regulators - gas/vapor - sour	4.72E-08
Pressure regulators - gas/vapor - sweet	8.39E-06
Open ended lines - fuel gas	4.67E-04
Open ended lines - light liquid	1.83E-05
Open ended lines - gas/vapor - all	4.27E-04
Open ended lines - gas/vapor - sour	1.89E-04
Open ended lines - gas/vapor - sweet	4.67E-04
Chemical injection pumps - fuel gas and gas/vapor	1.62E-04

Compressor seals - fuel gas and gas/vapor	7.13E-04
Compressor starts - fuel gas	6.34E-06
Controllers - fuel gas and gas/vapor	2.38E-04
Pump seals - light liquid	2.32E-05

Footnotes and Sources:
[a] American Petroleum Institute. *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry*. August 2009. Table 6-21 (from Clearstone Engineering Ltd.. *A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry*, Volume 5, September 2004.)

Table 360-2. Additional Oil Facility Average Emission Factors

Component – Service	Emission Factor, tonnes THC/component-hr
Valves - fuel gas and gas/vapor	1.51E-06
Valves - heavy liquid	8.40E-09
Valves - light liquid	1.21E-06
Connectors - fuel gas and gas/vapor	2.46E-06
Connectors - heavy liquid	7.50E-09
Connectors - light liquid	1.90E-07
Control valves - fuel gas and gas/vapor	1.46E-05
Control valves - light liquid	1.75E-05
Pressure relief valves - fuel gas and gas/vapor	1.63E-05
Pressure relief valves - heavy liquid	3.20E-08
Pressure relief valves - light liquid	7.50E-05
Pressure regulators - fuel gas and gas/vapor	6.68E-06
Open ended lines - fuel gas and gas/vapor	3.08E-04
Open ended lines - light liquid	3.73E-06
Chemical injection pumps - fuel gas and gas/vapor	1.62E-04
Compressor seals - fuel gas and gas/vapor	8.05E-04
Compressor starts - fuel gas	6.34E-06
Controllers - fuel gas and gas/vapor	2.38E-04
Pump seals - heavy liquid	3.20E-08
Pump seals - light liquid	2.32E-05

Footnotes and Sources:
[a] American Petroleum Institute. *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry*. August 2009. Table 6-22 (from Clearstone Engineering Ltd.. *A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry*, Volume 5, September 2004.)

Table 360-3. Default Major Equipment Component Counts for Canada

(for further average component counts required by the methods in this quantification method, please refer to the Clearstone Engineering Ltd.. *A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry*, Volume 5, September 2004, as updated from time to time.)

MAJOR EQUIPMENT	SERVICE	Connectors	Pressure Relief Vales	Pump Seals	Valves	Open-Ended Lines	Compressor Seals	Control Valves	Pressure Regulators
ABSORPTION (LEAN OIL)	Gas/Vapour	200	4	0	82	0	0	0	0
ABSORPTION (LEAN OIL)	Light Liquid	46	0	1	21	0	0	0	0
ADSORPTION	Gas/Vapour	243	8	0	63	0	0	0	0
ADSORPTION	Light Liquid	0	0	0	2	0	0	0	0
AERIAL COOLER	Gas/Vapour	2937	0	0	19	0	0	0	0
BULLET	Gas/Vapour	39	1	0	15	0	0	0	0
BULLET	Light Liquid	60	1	0	27	0	0	0	0
CENTRIFUGAL COMPRESSOR	Gas/Vapour	495	1	0	32	4	2	0	0
CENTRIFUGAL COMPRESSOR	Light Liquid	11	0	0	5	0	0	0	0
COLD BED ABSORPTION	Gas/Vapour	134	1	0	31	0	0	0	0
COLD BED ABSORPTION	Light Liquid	12	0	0	7	0	0	0	0
DE-BUTANIZER	Gas/Vapour	177	6	0	79	0	0	0	0
DE-BUTANIZER	Light Liquid	208	0	2	80	0	0	0	0
DEEP GAS WELL (>1000 M)	Gas/Vapour	19	0	0	6	0	0	0	0
DEEP GAS WELL (>1000 M)	Light Liquid	1	0	0	0	0	0	0	0
DEEPCUT (WITH TURBO-EXPANDER)	Gas/Vapour	241	10	0	131	0	2	0	0
DEEPCUT (WITH TURBO-EXPANDER)	Light Liquid	386	0	2	121	0	0	0	0
DE-ETHANIZER	Gas/Vapour	177	6	0	79	0	0	0	0
DE-ETHANIZER	Light Liquid	208	0	2	80	0	0	0	0
DE-PROPANIZER	Gas/Vapour	177	6	0	79	0	0	0	0
DE-PROPANIZER	Light Liquid	208	0	2	80	0	0	0	0
DESICCANT	Gas/Vapour	100	1	0	24	0	0	0	0
DESICCANT	Light Liquid	14	0	0	7	0	0	0	0
FLARE KNOCK OUT DRUM	Gas/Vapour	26	0	0	3	0	0	0	0
FLARE KNOCK OUT DRUM	Light Liquid	20	0	0	1	0	0	0	0
FLOW LINE HEADER TIE-IN	Gas/Vapour	0	0	0	0	1	0	0	0
FLOW LINE HEADER TIE-IN	Heavy Liquid	10	0	0	3	0	0	0	0

MAJOR EQUIPMENT	SERVICE	Connectors	Pressure Relief Vales	Pump Seals	Valves	Open-Ended Lines	Compressor Seals	Control Valves	Pressure Regulators
FLOW LINE HEADER TIE-IN	Light Liquid	10	0	0	3	0	0	0	0
FLOWING OIL WELL	Heavy Liquid	57	0	0	14	0	0	0	0
FLOWING OIL WELL	Light Liquid	57	0	0	14	0	0	0	0
FRACTIONATION	Gas/Vapour	241	10	0	131	0	0	0	0
FRACTIONATION	Light Liquid	386	0	2	121	0	0	0	0
GAS BOOT	Gas/Vapour	37	0	0	2	0	0	0	0
GAS BOOT	Light Liquid	40	0	0	2	0	0	0	0
GAS INJECTION WELL	Gas/Vapour	19	0	0	6	0	0	0	0
GAS LINE HEADER TIE-IN	Gas/Vapour	10	0	0	3	1	0	0	0
GAS SWEETENING: AMINE/SULFINOL	Gas/Vapour	702	2	0	60	3	0	0	0
GAS SWEETENING: AMINE/SULFINOL	Light Liquid	3	0	1	1	0	0	0	0
GAS SWEETENING: IRON SPONGE	Gas/Vapour	134	1	0	31	0	0	0	0
GAS SWEETENING: IRON SPONGE	Heavy Liquid	0	0	0	7	0	0	0	0
GAS SWEETENING: IRON SPONGE	Light Liquid	12	0	0	7	0	0	0	0
GAS-FIRED UNIT HEATER	Fuel Gas	10	0	0	1	0	0	0	0
GLYCOL DEHYDRATOR	Gas/Vapour	100	1	0	24	0	0	0	0
GLYCOL DEHYDRATOR	Light Liquid	14	0	0	7	0	0	0	0
GROUP TREATER	Gas/Vapour	178	0	0	21	1	0	0	0
GROUP TREATER	Heavy Liquid	56	0	0	17	1	0	0	0
GROUP TREATER	Light Liquid	56	0	0	17	1	0	0	0
HEAT EXCHANGER - GAS	Gas/Vapour	13	0	0	7	0	0	0	0
HEAT EXCHANGER - LIQUID	Heavy Liquid	13	0	0	7	0	0	0	0
HEAT EXCHANGER - LIQUID	Light Liquid	13	0	0	7	0	0	0	0
HEAVY OIL WELL - PRIMARY	Heavy Liquid	22	0	0	9	0	0	0	0
HEAVY OIL WELL - THERMAL	Heavy Liquid	22	0	0	9	0	0	0	0
INCINERATOR	Gas/Vapour	10	0	0	1	0	0	0	0
INLET SEPARATOR	Gas/Vapour	66	0	0	11	0	0	0	0
INLET SEPARATOR	Heavy Liquid	41	0	0	11	0	0	0	0
INLET SEPARATOR	Light Liquid	41	0	0	11	0	0	0	0
JOULE-THOMSON REFRIGERATION	Gas/Vapour	79	0	0	19	0	0	0	0
JOULE-THOMSON REFRIGERATION	Light Liquid	41	0	0	11	0	0	0	0
LINE HEATER	Fuel Gas	145	0	0	10	0	0	0	0

MAJOR EQUIPMENT	SERVICE	Connectors	Pressure Relief Vales	Pump Seals	Valves	Open-Ended Lines	Compressor Seals	Control Valves	Pressure Regulators
LINE HEATER	Gas/Vapour	40	1	0	10	0	0	0	0
METERING	Gas/Vapour	70	2	0	24	0	0	0	0
MOLECULAR SIEVE	Gas/Vapour	100	1	0	24	0	0	0	0
MOLECULAR SIEVE	Light Liquid	14	0	0	7	0	0	0	0
OIL PUMP	Heavy Liquid	10	0	1	3	0	0	0	0
OIL PUMP	Light Liquid	10	0	1	3	0	0	0	0
PIG TRAP	Gas/Vapour	11	0	0	3	0	0	0	0
PIPELINE HEADER	Gas/Vapour	0	0	0	0	1	0	0	0
PIPELINE HEADER	Heavy Liquid	10	0	0	3	0	0	0	0
PIPELINE HEADER	Light Liquid	10	0	0	3	0	0	0	0
POP TANK	Heavy Liquid	24	0	1	10	0	0	0	0
POP TANK	Light Liquid	24	0	1	10	0	0	0	0
PROCESS BOILER	Fuel Gas	25	0	0	2	0	0	0	0
PRODUCTION TANK	Gas/Vapour	2	0	0	1	0	0	0	0
PRODUCTION TANK	Heavy Liquid	24	0	1	0	0	0	0	0
PRODUCTION TANK	Light Liquid	24	0	1	0	0	0	0	0
PUMP JACK	Heavy Liquid	57	0	1	14	0	0	0	0
PUMP JACK	Light Liquid	57	0	1	14	0	0	0	0
PUMPING OIL WELL	Heavy Liquid	57	0	1	14	0	0	0	0
PUMPING OIL WELL	Light Liquid	57	0	1	14	0	0	0	0
RECIPROCATING COMPRESSOR	Fuel Gas	145	0	0	6	0	0	0	0
RECIPROCATING COMPRESSOR	Gas/Vapour	275	0	0	20	4	2	0	0
RECIPROCATING COMPRESSOR	Light Liquid	2	0	0	1	0	0	0	0
REFRIGERATION	Gas/Vapour	170	2	0	65	0	2	0	0
REFRIGERATION	Light Liquid	31	0	2	13	0	0	0	0
REGULATOR STATION	Gas/Vapour	24	0	0	10	0	0	0	0
SALT BATH HEATER	Fuel Gas	25	0	0	2	0	0	0	0
SCREW COMP CS TO FLARE	Gas/Vapour	228	2	0	35	0	0	1	2
SCREW COMPRESSOR	Gas/Vapour	228	2	0	35	0	1	1	2
SHALLOW GAS WELL (<1000 M)	Gas/Vapour	10	0	0	3	0	0	0	0
STABILIZATION	Gas/Vapour	80	3	0	20	0	0	0	0
STABILIZATION	Light Liquid	247	0	1	77	0	0	0	0

MAJOR EQUIPMENT	SERVICE	Connectors	Pressure Relief Vales	Pump Seals	Valves	Open-Ended Lines	Compressor Seals	Control Valves	Pressure Regulators
SULPHUR RECOVERY	Gas/Vapour	100	0	0	10	0	0	0	0
TAIL GAS CLEANUP	Gas/Vapour	25	0	0	5	0	0	0	0
TANK FARM	Heavy Liquid	190	0	6	94	0	0	0	0
TANK FARM	Light Liquid	190	0	6	94	0	0	0	0
TANK HEATER	Fuel Gas	10	0	0	2	0	0	0	0
TANK HEATER	Heavy Liquid	2	0	0	0	0	0	0	0
TANK HEATER	Light Liquid	2	0	0	0	0	0	0	0
TEST SEPARATOR	Gas/Vapour	49	1	0	15	0	0	0	0
TEST SEPARATOR	Heavy Liquid	25	0	0	15	0	0	0	0
TEST SEPARATOR	Light Liquid	25	0	0	15	0	0	0	0
TEST TREATER	Gas/Vapour	178	1	0	21	1	0	0	0
TEST TREATER	Heavy Liquid	56	0	0	17	0	0	0	0
TEST TREATER	Light Liquid	56	0	0	17	0	0	0	0
TURBO EXPANDER	Gas/Vapour	123	6	0	48	0	2	0	0
TURBO EXPANDER	Light Liquid	9	0	0	2	0	0	0	0
UNIT HEATER	Fuel Gas	10	0	0	2	0	0	0	0
UNIT HEATER	Light Liquid	2	0	0	0	0	0	0	0
UTILITY BOILER	Fuel Gas	25	0	0	2	0	0	0	0
VAPOUR RECOVERY COMPRESSOR	Gas/Vapour	25	0	0	5	0	1	0	0
VAPOUR RECOVERY COMPRESSOR	Light Liquid	2	0	0	3	0	0	0	0
WATER PUMP	Light Liquid	5	0	1	2	0	0	0	0

Footnotes and Sources:
[a] Clearstone Engineering Ltd.. *A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry*, Volume 5, September 2004. Table 4.1,

TABLE 360-4 –DEFAULT EMISSION FACTORS FOR SPECIFIC FIELDS

Table 360-4 is currently being developed and is likely to be incorporated in WCI.360 in the future. In the interim, please refer to default emission factors for specific fields within the jurisdiction as posted by the regulator during the reporting year.

Western Climate Initiative

WCI Regional Emissions Trading Program Status Update

WCI Stakeholder Meeting
Hollywood, CA
April 13, 2011

WCI Regional Emissions Trading Program

- Comprehensive strategy to reduce regional greenhouse gas emissions and spur a clean-energy economy
- Detailed Program Design released July 2010

  http://westernclimateinitiative.org/the-wci-cap-and-trade-program/program-design

  - Provides a roadmap to inform Partners in their development of implementing regulations
  - Based on extensive analysis and stakeholder consultation

Program Benefits

- Reduces costly impacts that climate change will have on water resources, natural ecosystems, air quality, and environment-dependent industries like agriculture and tourism
- Provides incentives for clean-energy technologies
- Creates green jobs
- Increases energy security
- Protects public health

Progress Implementing the Program

- WCI Partner jurisdictions have made significant progress on key elements of a linked regional program, including:
  - Emissions reporting
  - Offset protocols
  - Infrastructure requirements
  - Regional administrative organization
- WCI Partner jurisdictions also continue to work closely with federal governments and other North American climate initiatives to promote national and international action and ensure coordination

Implementation Schedule

- The WCI Detailed Program Design accommodates alternative schedules for implementation
- As each jurisdiction assesses its options for moving forward, CA, BC, and QC are working towards a 2012 start date
- ON and MB will join after the program starts
- Additional jurisdictions will be able to join

Other Approaches to Climate Action

- All 11 WCI Partner jurisdictions continue to work together, and with states and provinces in other North American climate initiatives
- Portfolio approach to climate action
  - Includes a range of strategies and policies to grow the low-carbon, clean energy economy in North America
  - Information on next steps will be released in the coming months

Emissions Reporting

- WCI Partner jurisdictions have been phasing-in new reporting requirements
  - A rigorous reporting system and high-quality emissions data achieves environmental and economic objectives and supports program design
  - ON is still phasing-in reporting and so will join after 2012
- WCI is also working with federal counterparts to develop common systems
  - This would minimize duplication and reduce the reporting burden for industry

Offset Protocols

- WCI Partner jurisdictions are continuing to design an offset system that produces high-quality offsets
  - Goal is to ensure cost-effective compliance options through a broad range of emission reduction strategies
  - Final recommendations for the WCI offset definition and quality criteria were released in July 2010
  - Draft recommendations for the process of offset project approval will be released this week
- WCI Partner jurisdictions are also evaluating an initial set of protocols to meet the WCI quality criteria

Infrastructure – Tracking System

- WCI Partner jurisdictions are working to establish a compliance instrument tracking system
  - System needed to ensure accurate accounting of the issuance, holding, transfer, and retirement of emission allowances and offset credits
  - The system will be accessible, secure, and scalable and will meet the jurisdictions' transparency objectives through public reporting

Infrastructure – Auction Platform

- WCI Partner jurisdictions are working to define requirements for a platform to support a regionally coordinated auction
  - The platform will support a process to ensure fairness and transparency, promote price discovery, and maximize efficiency in the allowance market while being consistent with applicable state and provincial laws

Auction Design

- WCI Partner jurisdictions are finalizing recommendations on:
  - Setting a reserve price and purchase limit
  - Addressing currency exchange issues
  - Settling tied bids
  - Evaluating options for a non-competitive component of the auction and for consignment of allowances

Market Monitoring and Oversight

- WCI Partner jurisdictions are committed to ensuring a well-functioning allowance market
  - Comprehensive market oversight, including market monitoring, to ensure that market participants are protected from fraudulent activities
- Program design includes specific policies to ensure:
  - Fair and equal access to the market
  - Transparent operations
  - Timely public disclosure of information
  - Safeguards to prevent market manipulation

Coordinating Program Administration

- WCI Partner jurisdictions are considering setting up a regional administrative organization (RAO)
  - An RAO (like RGGI Inc.) is one way to support coordinated implementation and ensure integrity, efficiency, and consistency in the administration of the emissions trading program
  - WCI Partners are specifying the function and structure of a RAO for the WCI program

Next Steps

- Continue working together to complete design
- Finalize regulations
- Put in place administrative systems and infrastructure
- Review each jurisdiction's program to assess consistency and to facilitate linkage
- WCI will continue to provide stakeholders with periodic updates

Western Climate Initiative

Draft Recommendations
Offset System Process
(Offset Committee Task 1.3)
June 7, 2011

An efficient offset system, consistent across WCI Partner Jurisdictions, will help ensure an adequate supply of high-quality offsets.

The Western Climate Initiative (WCI) Offsets Committee today releases draft recommendations for the requirements and process of offset project review and approval and credit creation for the regional emissions trading program.

The WCI Design Recommendations (2008) recommended the establishment of a rigorous offset system to support the WCI cap-and-trade program. The Design for the WCI Regional Program (2010) recommended essential criteria for credible offsets and that standards and processes for approving offset projects be developed in an open and transparent manner in advance of the start of the cap-and-trade program. The draft recommendations in this paper support these objectives.

The draft recommendations identify the critical elements of offset project approval that WCI Partner Jurisdictions believe will lead to high-quality offset credits that can be exchangeable across the region. Consistent, transparent processes are expected to lower project development costs and support learning and sharing of experience among Partner Jurisdictions and offset project developers. Stakeholder engagement, third party involvement, and regulatory oversight combine to ensure the environmental integrity of the program.

The Draft Recommendations are available on the WCI website. The WCI Offsets Committee will hold a stakeholder conference call to present the draft recommendations on **Wednesday, June 15, 2011, from 12:30 – 2:00 p.m. Pacific Daylight Time**. To join the call dial **1-800-868-1837** and enter participant code **753491#.** A PowerPoint presentation will be posted to the WCI website at the time of the call. Written comments should be submitted here via the WCI website by **Friday, July 8, 2011**.

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1 Executive Summary

This paper is the fourth paper issued by the WCI Offsets Committee as part of its efforts to offer design recommendations for the WCI offset system to the WCI Partner jurisdictions. This paper describes the draft recommendations for the WCI offset system process steps. The three previous papers provided recommendations for the WCI offset definition and essential criteria.

In the WCI's workplan, this paper is part of the Offset Committee's Task 1.3 to identify the specific requirements for registration, validation, monitoring, quantification, reporting, verification, certification and issuance of offsets. For each of these steps, this paper presents draft recommendations which are summarized in Table 1.0 below and depicted in Figure 1.

As WCI Partner jurisdictions will recognize the offsets issued by other Partners, it is important for the Partner jurisdictions to have processes in their offset systems that ensure the rigor and interchangeability of offsets across the WCI Partner jurisdictions. These draft recommendations propose processes to help ensure the necessary level of rigor across WCI Partner jurisdictions. The WCI Partner jurisdictions recognize that Partner jurisdictions have labeled the steps with varying terms, and in some cases have combined steps in their proposed programs. These draft recommendations acknowledge that such variations that result in the same or greater level of rigor being achieved are acceptable.

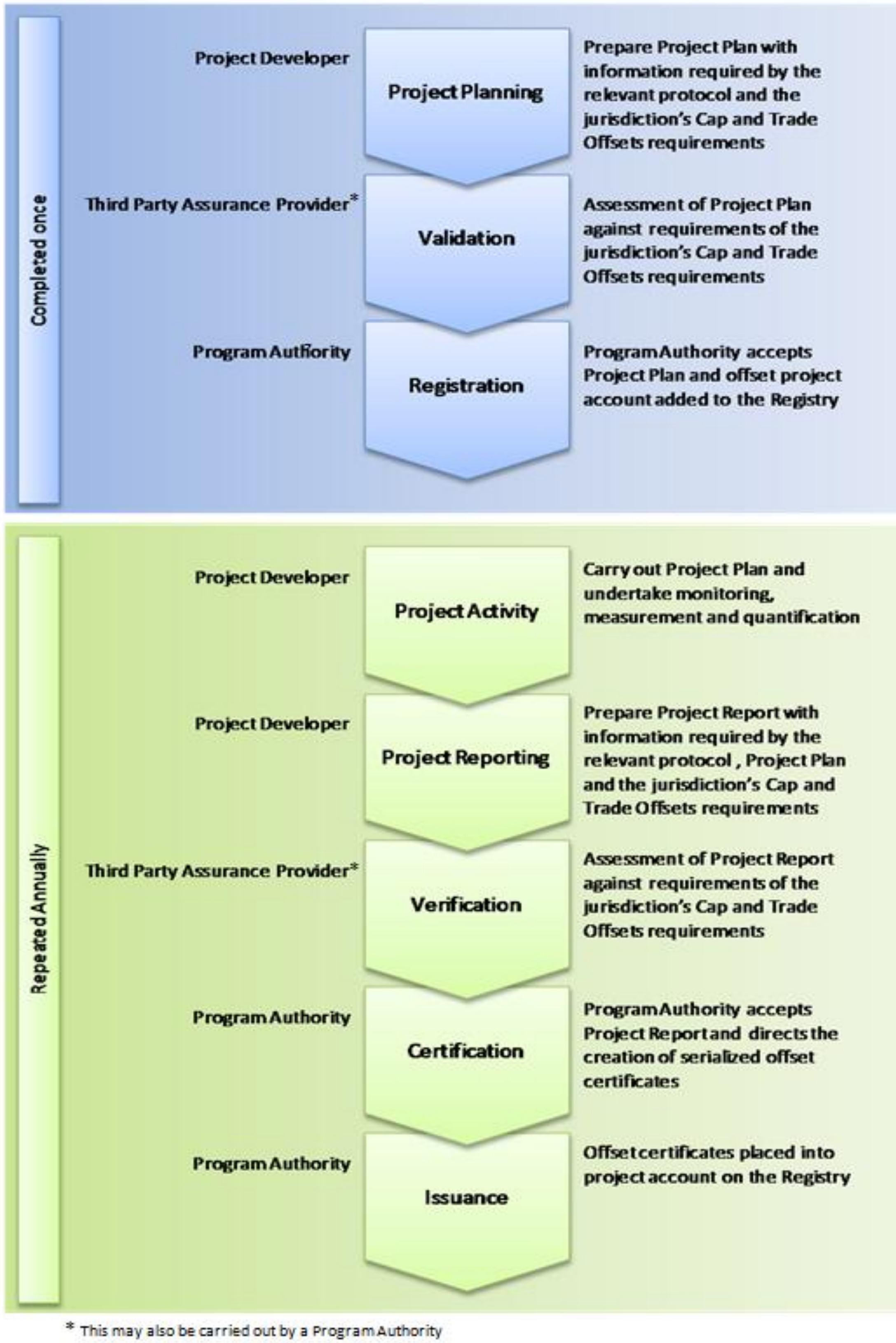

Figure 1. Recommended Western Climate Initiative offset system process flow

Table 1. Draft Recommendations

Section	Criteria	Draft Recommendation
3.1	Validation	Validation will initiate a relationship between the proposed project and the relevant authority. Each WCI Partner jurisdiction will be responsible for evaluating offset projects within its respective jurisdiction and may also evaluate and register offset projects in non-WCI jurisdictions throughout Canada, the United States and Mexico. Therefore, whether performed by a WCI Partner jurisdiction or a validation body, validation will be conducted with the expectation that the project will be considered under a specific jurisdiction's offset system. An offset project proponent initiates the process by submitting information on their proposed project required by the WCI Partner jurisdiction or an accredited third-party validation body to effectively perform their validation activities. The required information may be defined by the relevant protocol and may be in the form of a project plan providing basic contact information, describing the project, referring to the appropriate WCI protocol, baseline scenario (where appropriate) or performance standard, and identifying all project-specific monitoring requirements. The WCI Partner jurisdiction or the validation body will assess whether the project meets the requirements of the WCI offsets system and is in conformance with an appropriate protocol. The validation step must be completed prior to verification of the offset project's first project report. A project must be validated as part of each renewed crediting period. If validation is performed by an accredited third-party validation body, the validation body must issue a positive validation statement before the project can be registered. Subject to activity (validation/verification) and sectoral scope (project type) requirements, third-party validation bodies must conduct validation in accordance with ISO 14064-3 and must be accredited to ISO 14065 through (a) a program developed under ISO 17011 by an accreditation body that is a member of the International Accreditation Forum or (b) a program developed or authorized by a WCI Partner jurisdiction under the jurisdiction's required statutory or

		regulatory process that is at least as stringent as the process defined in ISO 17011.
3.2	Registration	Project registration requires the submission of information for each project to the responsible WCI Partner jurisdiction. The required information may be defined by the relevant protocol and may be in the form of a project plan. Registration information will be posted for public review and comment to provide transparency. The project developer must identify a potential offset project and determine if it is conformant to WCI offset criteria and an accepted WCI protocol. For aggregation of small projects, unless otherwise specified in the protocol, a single request for registration can be submitted for the entire aggregation although it must include the required information on each project. The Project Developer must implement the project per the information provided as part of registration. If the proponent changes any aspect of the project compared to the project plan at the time of registration, the change will need to be approved by the relevant WCI Partner jurisdiction and a revised project plan reflecting the change posted for public review. The WCI Offsets Committee is not recommending a preferred approach among the options presented above for Registration. WCI Partner jurisdictions will retain the flexibility to select the Registration approach most appropriate for their jurisdiction. However, for all WCI Partner jurisdictions, no offset certificates will be issued until the project is validated, registered and has verified emission reductions.
3.3	Monitoring and Quantification	Each offset project shall follow the monitoring and quantification requirements specified in the applicable protocol. Monitoring and quantification requirements for offsets will be harmonized, to the extent practicable, with WCI Mandatory Reporting Requirements.
3.4	Reporting	Reporting frequency will be annual unless otherwise specified in a recommended protocol. A WCI Partner jurisdiction will have two options for assigning the annual reporting date for a project:

		• the month and day of the project start date (as determined by the first day for which a reduction is claimed); or • a common calendar date for all projects each year. Reporting requirements will be harmonized, to the extent possible, with the WCI Mandatory Reporting Requirements. Aggregated small projects may submit a single report for the entire aggregation of projects, unless otherwise specified in protocol, although the report must include required information on each project’s reductions.
3.5	Verification	Emission reductions or removals must be verified by an accredited third-party verification body and submitted to the relevant WCI Partner jurisdiction prior to the issuance of offset certificates. Subject to activity (validation/verification) and sectoral scope (project type) requirements, verification bodies must be accredited to ISO 14065 through (a) a program developed under ISO 17011 by an accreditation body that is a member of the International Accreditation Forum or (b) a program developed or authorized by a WCI Partner jurisdiction under the jurisdiction’s required statutory or regulatory process that is at least as stringent as the process defined in ISO 17011. The verification must also be conducted in accordance with ISO 14064-3 to a reasonable level of assurance. A third party assurance provider which validated the registered project plan may not perform third-party verification of a project report for that project within the same crediting period. Verification statements will be posted publicly. Unless otherwise specified in protocol, for aggregation of small projects, a single verification report can be submitted for the entire aggregation, although it must include verification for each project’s reductions.
3.6	Certification	The certification step involves the WCI Partner jurisdiction or its agent/recognized body reviewing project documentation presented as evidence and accepting that evidence into the system through the assignment or creation of an offset certificate when they are satisfied all conditions of the Partner Jurisdiction have been or will be met. The committee

		recommends certification take place at the point of issuing an offset certificate, so that certificates are not issued prior to successful completion of certification.
3.7	Issuance	Following certification, the WCI Partner jurisdiction will proceed with offset issuance. The jurisdiction will complete the administrative steps of serializing the units and issuing to the appropriate account(s) in the tracking system. Issuance does not require the project proponent to submit any additional information nor require the WCI Partner jurisdiction to conduct any further review of the project.
3.8	Post-Issuance Activities	Project protocols and the offset systems of the WCI Partner jurisdictions will ensure permanence, including mechanisms that will replace offsets from sequestration projects lost to unintentional and intentional reversal. No draft recommendation is made at this time regarding the ability to revoke or require the replacement of offset certificates. Comment is solicited regarding three potential options for consideration: • Offset certificates are not revocable by any WCI Partner jurisdiction and the remedies for fraud and error include replacement. • Any offset certificate is revocable by the WCI Partner jurisdiction that issued it upon discovery of fraud or error. • WCI Partner Jurisdictions choose to issue, at their discretion, offset certificates that are either revocable or non-revocable. This option would support some jurisdictions issuing offset certificates that may be revoked, and others issuing offset certificates that may not be revoked. WCI Partner jurisdictions would appreciate comments on potential implications of these options for: offset supply; trading of offset certificates; program administration requirements; and environmental integrity.

2 Purpose and Background

The July 2010 Design for the WCI Regional Program includes provisions for a rigorous offset system. The primary role of the offset system is to reduce the compliance costs associated with the cap-and-trade program while maintaining the environmental integrity of the cap. The design of the offset system should encourage emission reductions, innovation, and technology development in sectors and at sources not covered by the cap-and-trade program.

The purpose of the WCI Offset Committee is to make recommendations to the WCI Partner jurisdictions on the design and operation of the offset system as part of the WCI cap-and-trade program. The committee divided its work into three tasks. Task 1 is recommendations for essential elements and infrastructure to create and operate the WCI offset system. Task 2 will provide recommendations for accepting offsets and allowances from other greenhouse gas trading programs. Task 3 is the review and recommendation of protocols for the WCI offset system.

This paper is part of the Offset Committee's Task 1 Essential Element work, specifically Task 1.3 to identify the specific requirements for registration, validation, monitoring, quantification, reporting, verification, certification and issuance of offsets. This paper presents draft recommendations for those elements. Since WCI Partner jurisdictions will recognize the offsets issued by other Partners, it is important for the Partner jurisdictions to have processes in their offset systems that ensure the rigor and interchangeability of offsets across the WCI Partner jurisdictions. These draft recommendations propose processes to ensure the necessary level of rigor across WCI Partner jurisdictions. Figure 1 identifies the process steps from project design and project implementation to project performance. The WCI Partner jurisdictions recognize that Partner jurisdictions have labeled the steps with varying terms, and in some cases have combined steps, in the processes proposed for their programs. While offering these draft recommendations, the WCI Partner jurisdictions acknowledge that such variations that result in the same or greater level of rigor being achieved are acceptable.

As part of their effort to design an offset system that encourages emission reductions from sources not covered by the cap-and-trade program, WCI Partner jurisdictions aim to facilitate participation of small projects by implementing a process that readily accommodates the aggregation of small projects. The draft recommendations for some process steps include specific elements related to the aggregation of small projects in order to streamline the process for these projects while ensuring the same high quality standards are met for all offset projects.

3 Process Options and Draft Recommendations

3.1 Validation

Validation is the assessment of a proposed offset project against the offset system requirements. Validation includes review and assessment of project information for conformance with system criteria, alignment with an appropriate protocol[1] and review of quantification methodologies, baselines, standards, calculations, assumptions, factors, forecasts and assertions. Validation is intended to provide the project developer and the WCI Partner jurisdiction with assurance that the project, when implemented, is likely to meet all of the WCI criteria and is likely result in emission reductions qualifying under the WCI offset system. More detailed information on the validation step can be found in ISO 14064-3.

3.1.1 Options

Validation could be conducted by staff of the WCI Partner jurisdiction registering the project, a commissioned service provider or an independent third party. Each option presents some key concerns for consideration:

- Would WCI Partner jurisdictions ensure a staff approach was adequately resourced, trained and experienced to ensure an efficient and effective review and validation process in each jurisdiction and would institutional capacity be consistent across the WCI region?
- Would a commissioned service provider be capable of maintaining independence and incorporating direction from all of the WCI Partner jurisdictions?
- Would there be adequate third party verifiers and at what potential cost to project developers?

Each option brings unique benefits that must be weighed against these considerations:

- A staff approach would allow direct regulatory control over the initial project review and approval step and would provide the project developer with comfort that the regulator will register their project once they pass the validation step.
- A commissioned service provider could provide a similar level of comfort to the WCI Partner jurisdiction while providing access to a pool of validation capacity that can be shaped to accommodate the changing level of demand for validation services.
- Third party validation provides less direct control to the WCI Partner jurisdiction while delivering the variable capacity of a commissioned service provider and requires the validator place their reputation on each validation service performed to ensure a high level of integrity and reliability in services provided.

[1] By "appropriate protocol," the WCI Offset Committee is referring to a protocol which has been recommended by the WCI Partners and which is appropriate to the project activity.

Validation could occur at any of a variety of times along the project cycle including prior to registration, at registration, before or concurrent with verification or at certification. Each option presents a different cost/benefit to the project developer and the WCI Partner jurisdiction. Earlier in the process may mean more up-front cost for the project developer with an accompanying increase in certainty of being accepted by the program. Later in the process aligns validation effort and cost with successful project activities and claims for offset, reducing up front cost and possibly lessening certainty for project developers.

Information required to complete the validation step could include contact and other project details, information about the project operation and expected emission reductions, protocol selection, baseline selection, applicability and project eligibility. The validation process could follow an established standard such as ISO 14064 part 3.

Validation could provide assurance that information has been reviewed for completeness and consistency, could go deeper to provide assurance the information is well founded in evidence and fact or could include a thorough review of all project documentation, testing of assumptions and field inspection of project assertions. Increasing levels of assurance usually require additional time and cost to achieve and provide increasing levels of comfort to the WCI Partner jurisdiction that the criteria for inclusion in the offset system are met.

3.1.2 Draft recommendation

As the first step in the process, validation will initiate a relationship between the proposed project and the relevant authority. Each WCI Partner jurisdiction will be responsible for evaluating offset projects within its respective jurisdiction and may also evaluate and register offset projects in non-WCI jurisdictions throughout Canada, the United States and Mexico.[2] Therefore, whether performed by a WCI Partner jurisdiction or a validation body, validation will be conducted with the expectation that the project will be considered under a specific jurisdiction's offset system.

An offset project proponent initiates the process by submitting information on their proposed project required by the WCI Partner jurisdiction or an accredited third-party validation body to effectively perform their validation activities. The required information may be defined by the relevant protocol[3] and may be in the form of a project plan providing basic contact information,

[2] The program design in one jurisdiction, New Mexico, does not include the implementation of an offset system to issue offset certificates. As part of linking, New Mexico could agree with another WCI Partner jurisdiction that the other jurisdiction will issue offset certificates for projects in New Mexico.

[3] The protocols included in California's cap-and-trade program refer to this information as "listing information."

describing the project, referring to the appropriate WCI protocol, baseline scenario (where appropriate) or performance standard, and identifying all project-specific monitoring requirements. The WCI Partner jurisdiction or the validation body will assess whether the project meets the requirements of the WCI offsets system and is in conformance with an appropriate protocol. The validation step must be completed prior to verification of the offset project's first project report. A project must be validated as part of each renewed crediting period. If validation is performed by an accredited third-party validation body, the validation body must issue a positive validation statement before the project can be registered. Subject to activity (validation/verification) and sectoral scope (project type) requirements, third-party validation bodies must conduct validation in accordance with ISO 14064-3 and must be accredited to ISO 14065 through (a) a program developed under ISO 17011 by an accreditation body that is a member of the International Accreditation Forum or (b) a program developed or authorized by a WCI Partner jurisdiction under the jurisdiction's required statutory or regulatory process that is at least as stringent as the process defined in ISO 17011.

3.1.3 Explanation of draft recommendation

This draft recommendation meets the WCI Offset System Essential Elements Final Recommendation (July 2010) that, "validation is a required review by an accredited independent third party of the WCI Partner jurisdiction to assess the likely result of reduction or sequestration from a proposed project that would use a WCI offset protocol."

Validation serves as the initial review of a proposed project. In order to ensure a complete and efficient verification of emission reductions, the draft recommendation proposes that validation be conducted prior to verification of the first project report for a given offset project. At the start of a new crediting period some project information reviewed as part of the validation process is unlikely to change. However, information regarding applicable regulatory requirements, as well as performance standard thresholds to assess additionality, may change over time. Each project must be validated prior to each crediting period to assure that the project meets the current requirements of the appropriate protocol. To the degree possible, the validation process for project renewal will be streamlined.

Information submitted on the proposed project will serve as the basis for the validation review. Submitted information will include identification and description of the project, an assertion of the projection's additionality, and copies of other legal documentation required for the project (e.g., permits, environmental impact assessment).

The draft recommendation does not require at the system-wide level site visits as part of the project review process for validation. The WCI Offsets Committee recognizes that requiring a site visit presents a potentially unnecessary cost to project developers, particularly given the

WCI Partners' preference for standardized offset protocols. However, if required for particular protocols, project types or technologies a site visit could be included as part of the validation process.

The accreditation requirement for third-party validators is designed to mirror as closely as possible the accreditation requirement for third-party verifiers providing services for mandatory reporting and offset projects.

Following a validation review, a third-party validator may issue a positive validation statement if they determine the project to be in conformance with offset system requirements and the appropriate protocol. As discussed later in this paper, a verifier would then verify a project against the validation statement.

3.2 Registration

The registration process is the mechanism for project developers to record offset project information with the WCI Partner jurisdiction evaluating the project. Project registration requires the submittal of forms and information on each project to the applicable WCI Partner jurisdiction to help ensure that projects meet the requirements of the offsets system. For the WCI Partner jurisdictions, a registration system for recording and managing project information will be especially important to ensure proper oversight for a regulatory compliance program and effective communication across multiple jurisdictions. Posting registration information for public review provides transparency to the offset system.

3.2.1 Options for Registration

The WCI Offsets Committee evaluated several approaches for project registration. Under all of the options considered, no offset certificates would be issued by a WCI Partner jurisdiction until the project is validated, registered, and has verified emission reductions. If validation is performed by an accredited third-party validation body, the validation body must issue a positive validation statement before the project can be registered. The options present different approaches for the timing for completing the validation, registration and verification step, but for all projects each step would be required.

Option A

- Project proponent submits registration information to the WCI Partner jurisdiction as specified in the appropriate protocol. The Partner jurisdiction reviews the information for consistency with eligibility criteria and completeness of information. The project would be considered "listed" in the program registry and not yet registered if the information is complete. The project would not be registered until a project is validated and a verified project report is submitted which demonstrates that real emissions reductions have occurred. This approach is similar to the process of the Climate Action Reserve.

Option B

- As part of validation step, the WCI Partner jurisdiction could have the project proponent submit detailed registration information as specified in the appropriate protocol. The WCI Partner jurisdiction or an accredited third-party assurance provider would undertake a detailed review of the information and assess the project against system requirements as part of a both the validation and registration process steps. Upon successful completion of the WCI Partner jurisdiction review, the project would be registered. This approach resembles the initial review and registration process under the RGGI program.

Option C

- Project proponents would wait to submit documentation for validation and registration until just prior to verification. A project proponent would not be required to submit any information until the first project report is due. At that time, a project would complete the validation, registration and verification steps in succession. Under this approach, validation and registration could occur after the project has already begun operation. This approach is similar to the process used by the Voluntary Carbon Standard.

Option D

- A hybrid approach informed by the approach best suited to a project type. The project developer is allowed to choose one of several approaches based on their experience and risk tolerance. If validation is performed by an accredited third-party validation body, the validation body must issue a positive validation statement before the project can be registered.

3.2.2 Draft recommendation

Project registration requires the submission of information for each project to the responsible WCI Partner jurisdiction. The required information may be defined by the relevant protocol and may be in the form of a project plan. Registration information will be posted for public review and comment to provide transparency.

The project developer must identify a potential offset project and determine if it is conformant to the jurisdiction’s offset criteria and the jurisdiction’s adopted protocol. For aggregation of small projects, unless otherwise specified in the protocol, a single request for registration can be submitted for the entire aggregation although it must include the required information on each project. The Project Developer must implement the project per the information provided as part of registration. If the proponent changes any aspect of the project compared to the project plan at the time of registration, the change will need to be approved by the relevant WCI Partner jurisdiction and a revised project plan reflecting the change posted for public review.

The WCI Offsets Committee is not recommending a preferred approach among the options presented above for Registration. WCI Partner jurisdictions will retain the flexibility to select the Registration approach most appropriate for their jurisdiction. However, for all WCI Partner jurisdictions, no offset certificates will be issued until the project is validated, registered and has verified emission reductions.

3.2.3 Explanation of draft recommendation

The WCI Offsets Committee recommends the priority for ensuring the integrity of offsets across the WCI Partner jurisdictions is for requirements to be consistently met and documented in all WCI Partner jurisdictions prior to the issuance of offset certificates. The timing of when requirements and process steps for registration, as well as with validation presented above, occur may vary based on circumstances specific to each WCI Partner jurisdiction.

3.3 Monitoring and Quantification

Monitoring is the process of collecting project activity data essential for quantifying GHG reductions or removals and also the process of validating assumptions used in quantification. Monitoring includes what project activities need to be measured, how often measurements should be taken, what methods are acceptable, what instrumentation should be used for data collection, how the data is stored and how data quality is maintained. Monitoring of an offset project is intended to allow for the complete and transparent quantification of GHG reductions or removals.

Essential elements of monitoring procedures and monitoring reports often include the following:

- GHG data and information for all sources and sinks to be monitored, including units of measurement.
- Source information for all data and information included.
- Monitoring methodology identified, including description of the approach used (e.g., estimation, modeling, measurement or calculation) and description of all relevant assumptions, constants, mathematical relationships and formulas.
- Measurement collection techniques identified including technical information regarding location and specifications of metering equipment, procedures for meter reading, calibration and maintenance, and length of measurement periods.
- Level of uncertainty associated with measurement and estimation of data.
- Roles and responsibilities for monitoring procedures.

- QA/QC measures including data management systems, procedures for managing poor quality or lost data and data archive procedures.

Quantification is the process of estimating emissions reductions achieved from project activity data collected through monitoring. Requirements for quantification will be included in offset protocols recommended by the WCI Partner jurisdictions. The process for developing recommended offset protocols, including quantification requirements, will be addressed through the work under Task 3 of the WCI Offset Committee.

3.3.1 Options for Monitoring and Quantification

Several options for developing monitoring requirements are available and different approaches reflect the desired level of standardization at the protocol and program levels.

Protocols may specify the monitoring requirements for all projects of a specific type using the same recommended protocol. Protocol monitoring requirements could include options that project proponents could choose from in order to best tailor the requirements to the individual project activity. Program-level requirements, in addition to protocol-specific requirements, could specify required elements of monitoring that would need to be incorporated into all protocols and/or projects.

Allowing alternative monitoring approaches provides flexibility to tailor monitoring requirements to individual project circumstances while maintaining the integrity of the system. This could be especially relevant to projects with pre-existing systems in place or for carbon sequestration projects where preferred measurement approaches may vary based on the project conditions.

3.3.2 Draft recommendation

Each offset project shall follow the monitoring and quantification requirements specified in the applicable protocol and offset system rules of the WCI Partner jurisdiction. Monitoring and quantification requirements for offsets will be harmonized, to the extent practicable, with WCI Mandatory Reporting Requirements.

3.3.3 Explanation of draft recommendation

Protocol-specific monitoring requirements will provide consistency across projects using the same protocol and allow WCI Partner jurisdictions to tailor monitoring requirements to each project type. Under this approach, monitoring guidance requirements will be included as part of each WCI recommended protocol for a given project type. Since waiting until verification to have the monitoring plan approved could increase risk to project developers, project proponents will be required to submit a monitoring plan as part of the validation review that demonstrates how the project will meet the monitoring guidance requirements of the WCI recommended protocol being used. During the reporting and verification process steps, submitted monitoring data will be reviewed to ensure it meets the procedures outlined in the approved monitoring plan.

Consistency of monitored data is important for quantification, reporting and verification. Requiring all project developers for each project type to follow the same monitoring requirements helps ensure the consistency of monitored data. However, under certain circumstances a WCI Partner jurisdiction may allow a project proponent to use an alternative monitoring approach or to propose alternative monitoring approaches with approval from WCI Partner jurisdictions. For a proponent to propose an alternative monitoring approach, the proponent must be unable to implement the monitoring approach in the protocol, and the proponent must propose an approach that will achieve a similar level of accuracy to the approach in the protocol.

3.4 Reporting

Reporting refers to the process of summarizing project monitoring data, quantifying the GHG reduction achieved in the applicable period according to the calculation methodology in the project plan, and documenting that information in a project report. Periodic reporting on the performance of GHG reduction projects is a step required by most offsets systems and a necessary step before offsets can be issued. The required content and level of detail required in project reports vary between systems and by project type. A complete project report in the WCI offset system might include the following components:

- Summarized monitoring data.
- Calculations supporting the GHG reductions achieved (in accordance with the quantification methodologies of the appropriate WCI protocol).
- Proponent's assertion of the GHG reduction.
- A signed verification statement.

The WCI Partner jurisdictions will establish overall reporting requirements to ensure adequate oversight of the offset system. These requirements are intended to serve the needs of project proponents, assurance providers, and ultimately the wider WCI market by establishing what information must be documented before an offset certificate may be issued. Clear reporting requirements should allow for reports to be submitted and verified without undue delay.

3.4.1 Options for Reporting

Within the WCI offset system it may be beneficial to define a minimum level of monitoring data detail that proponents must be provided in a project report. The minimum level could be to provide the total GHG emissions or removals for each source and sink within the project boundary. A further layer of detail could be to require, at the level of source and sink and/or in aggregate, project emissions and removals by type of greenhouse gas.

Quantification methodologies should be well established by protocol. The project report should identify the extent to which any missing data was replaced and how it was replaced.

Reporting templates may be established. Standardizing the template for reporting could facilitate the verification process through clear identification of basic data requirements and assertions that will be necessary for the assurance provider to assess the project report. In addition, establishing a reporting template could facilitate consistency between offset project reporting requirements and the essential requirements for WCI reporting.

Reporting is an ongoing activity in active offsets projects. It is a necessary step in having GHG reductions verified and recognized as offsets and also provides a level of review and oversight. A reasonable reporting frequency needs to be established which balances adequate review and oversight with the recognition that reporting represents a project cost due to the resources required to prepare and subsequently verify project reports. Based on the approved reporting frequency, the project proponent would submit a periodic report to the verification body, which will review and issue a verification statement. The final report, including the verification statement would be provided to the program authority for review.

3.4.2 Draft recommendation

Reporting frequency will be annual unless otherwise specified in a recommended protocol. A WCI Partner jurisdiction will have two options for assigning the annual reporting date for a project:

- the month and day of the project start date (as determined by the first day for which a reduction is claimed); or
- a common calendar date for all projects each year.

Reporting requirements will be harmonized, to the extent possible, with the WCI Mandatory Reporting Requirements. Aggregated small projects may submit a single report for the entire aggregation of projects, unless otherwise specified in protocol, although the report must include required information on each project's reductions.

3.4.3 Explanation of draft recommendation

The WCI Offsets Committee recommends annual reporting to ensure ongoing oversight of project activities. For particular project types (e.g., long-term sequestration projects), less frequent reporting may be appropriate.

The WCI Offsets Committee discussed the merits of having common or staggered reporting dates for offset projects. The advantage of the common date was that offsets reporting would thus be more similarly aligned with mandatory reporting which also has a common date. Staggered reporting dates according to a project's start date allow the workload placed on verifiers to be more constant throughout the year instead of focused in one quarter of the year. Staggered dates are also consistent with other notable offset mechanisms. The Offsets Committee believes that both approaches are valid and recommends that WCI Partner jurisdictions be allowed to follow either approach, as this should not adversely affect the rigor or fungibility of offsets across the WCI region.

Harmonization of reporting requirements with the WCI Mandatory Reporting Requirements and aggregation of small projects into a single reporting report, are recommendations aimed at reducing the administrative burden and improving efficiency for project developers.

3.5 Verification

Verification is the process of reviewing offset project information to ensure that claimed emissions reductions have been achieved in accordance with the appropriate offset protocol and project plan.

3.5.1 Options for Verification

At verification, the verification body will review project documents and facilities, and produce a verification report and statement, which includes the verification body's assessment of the proponent's GHG assertion. The verification report should contain the following types of information:

- Verification plan, verification objective, criteria, scope, materiality and schedules.
- Sampling plan which would include amount and type of evidence necessary to achieve the agreed level of assurance, methodologies for determining samples, risks of potential errors, omissions or misrepresentations.
- Assessment of the GHG information systems and controls for sources of potential errors, omissions and misrepresentations.
- Assessment of the GHG data and information.
- Assessment against the appropriate protocol and system requirements.
- Evaluation of the GHG assertion.
- Issuance of the verification statement which will describe: the level of assurance of the verification statement, the objective scope and criteria, whether the data supporting the GHG assertion was historical, and will provide the verifier's conclusion on the GHG assertion including any limitations.
- Site visits as required for review.

The verification report will be submitted with the project report to the WCI Partner jurisdiction for review and consideration for certification and issuance.

3.5.2 Draft recommendation

Emission reductions or removals must be verified by an accredited third-party verification body and submitted to the relevant WCI Partner jurisdiction prior to the issuance of offset certificates. Subject to activity (validation/verification) and sectoral scope (project type) requirements, verification bodies must be accredited to ISO 14065 through (a) a program developed under ISO 17011 by an accreditation body that is a member of the International Accreditation Forum or (b) a program developed or authorized by a WCI Partner jurisdiction under the jurisdiction's required statutory or regulatory process that is at least as stringent as the process defined in ISO 17011. The verification must also be conducted in accordance with ISO 14064-3 to a reasonable level of assurance. A third party assurance provider which validated the registered project plan may not perform third-party verification of a project report within the same crediting period. Verification statements will be posted publicly. Unless otherwise specified in protocol, for aggregation of small projects, a single verification report can be submitted for the entire aggregation, although it must include verification for each project's reductions.

3.5.3 Explanation of draft recommendation

The draft recommendation for the verification process steps is based on the final recommendation for verification established in the WCI Offsets System Essential Elements Final Recommendations Paper (July 2010). The final recommendation stated, "verifiers for WCI offsets will be independent third parties who have been accredited to a standard acceptable by the WCI Partner jurisdiction in which the project is registered." The process steps draft recommendation presents accreditation requirements for third-party verifiers. The recommended accreditation requirements, accreditation for entities verifying offsets are consistent with the WCI mandatory reporting recommendations requirements.

Since a third-party body may have a conflict of interest if it verifies a project which it also validated, the Offsets Committee recommends that a third-party which validated a project's project plan may not also verify a project's emissions reductions or removals for the crediting period covered by the validation. As validation is necessary for a renewed crediting period, an entity which validated a project for its first but not its second compliance period would be allowed to verify a project's reductions or removals during the second compliance period.

3.6 Certification

At some point in the creation of an offset compliance instrument a WCI Partner Jurisdiction has to "accept" that the documentation provided and reviewed indicates that the reduction upon which the offset certificate may be based is real, additional, permanent and verifiable. At this step in the process, the WCI Partner Jurisdiction must have the ability to enforce these requirements through its review of the documentation and its assessment of whether it supports a determination that the reduction is real, additional, permanent, and verifiable. By performing this step, other jurisdictions in a regional trading system would be assured that the offset and underlying project meet all of the offset criteria and would be able to accept the offset for compliance. It is not essential that the WCI Partner Jurisdiction perform all of the certification steps directly and may assign certain roles, tasks and decisions to a third party. The tasks or steps involved in certification can take place at different times in the offset cycle and may be separated for convenience or functional efficiency.

The successful completion of the certification step is expected to lead to the Partner jurisdiction creating a tradable unit with a unique serial number within the tracking system of the WCI Partner jurisdictions. A partner jurisdiction may choose not to issue offsets and would therefore not have a certification step in their offset process and may not have an offset process at all.

3.6.1 Options for Certification

Two options have been identified for certification: (1) certification could be performed following successful completion of the verification step and prior to issuance; or (2) certification could be conducted after issuance, for example, when the offset is used for compliance. Under both options, certification would involve review of project documentation.

One approach would be for a WCI Partner Jurisdiction to certify an offset following successful completion of verification and prior to issuing the certificate. Under this approach, the certificate will likely be treated in a similar fashion to an allowance by market actors and compliance entities in the trading system. As one component of the full process, this approach provides a measure of certainty regarding the acceptable nature of the offset for the market and the jurisdictions accepting the offset certificate for compliance. This approach requires the commitment of resources needed to process all requests for certification (with associated administrative costs) before a certificate is issued.

An alternative approach is to conduct certification after issuance of an offset certificate. In this case, the offset instrument would be created based on the results of the verification, enabling offset certificates to be issued more quickly. The offset could be traded before certification is performed. Under this option, certification could be triggered when an offset is used for compliance. At that time, the jurisdiction that issued the offset certificate would review the project documentation to determine whether it supports a determination that the reduction is real, additional, permanent, and verifiable. The resources required for certification would be driven by the rate at which offsets were used for compliance, rather than the rate at which they were created.

If offset certificates are issued prior to certification, there will be more uncertainty regarding the reliability of the offset certificates in circulation. Using a certificate for compliance that has not yet been certified could entail risks if there is a chance that a subsequent unsuccessful certification would lead to the disqualification of the offset certificate for compliance. Consequently, if WCI Partner jurisdictions use differing approaches to the timing of certification, some occurring before and some occurring after issuance, the reliability and value of the two groups of offset certificates may be viewed differently in the marketplace.

Additional uncertainty is also created for the regulatory authority that accepts for compliance an offset certificate that has not been certified. Following the use of the offset for compliance, the jurisdiction would need to wait for the issuing jurisdiction to complete its certification prior to knowing whether the offset met all the necessary criteria.

3.6.2 Draft recommendation

The certification step involves the WCI Partner jurisdiction or its agent/recognized body reviewing project documentation presented as evidence and accepting that evidence into the system through the assignment or creation of an offset certificate when they are satisfied all conditions of the Partner Jurisdiction have been or will be met. The committee recommends certification take place at the point of issuing an offset certificate, so that certificates are not issued prior to successful completion of certification.

3.6.3 Explanation of draft recommendation

The draft recommendation for the certification process is based on WCI Partner Jurisdictions preferring to avoid adding uncertainty to the reliability of offset certificates and preferring not to add complexity to compliance procedures for little or no benefit. Completing certification prior to issuance ensures that the full set of reviews and evaluations are conducted prior to the offset certificate being issued, so that the quality and reliability of the offset instrument are less uncertain. In making this recommendation the WCI Partner jurisdictions recognize that the full set of criteria and processes recommended for offset systems collectively contribute to the quality and reliability of offset certificates. Certification is identified as one component of the overall process at which a final evaluation ensures that the emission reduction on which the offset is based is real, additional, permanent, and verifiable.

3.7 Issuance

After an emissions reduction or removal has been verified and certified in accordance with all requirements and a project proponent has submitted all required reports, the WCI Partner jurisdiction will issue offsets in an amount equal to the reductions credited to the projects, with each issued offset representing one metric tonne CO_2e reduced or removed. Issued offsets will be assigned a unique serial number and issued to the proponent's registry account or a registry account designated by the proponent. For sequestration projects, some offsets may also be retained in a contingency account or buffer pool as required by WCI Partner jurisdictions.

The unique serial number allows each issued offset to be linked to all supporting documents for the offset project. It also allows tracking of an offset from issuance until retirement, enhancing transparency and assisting with any enforcement activities that may be required. Once issued and deposited in an account, offsets can be traded, sold, or used to meet a compliance obligation.

3.7.1 Options for Issuance

Two approaches to issuance have been evaluated for this recommendation:

A. Offsets are issued following certification of reductions or removals.

   If WCI Partner jurisdiction staff review project documentation during the certification process, it may be duplicative to require additional submittals or project review prior to issuance.

B. Project proponents must submit additional documentation to request issuance of offsets following certification of reductions or removal.

   Some programs, most notably the CDM, require project proponents to apply for credit issuance following certification. The application for issuance is accompanied by verification and monitoring documents. Each WCI Partner jurisdiction would then review all documents prior to credit issuance. Requiring a separate application for credit issuance could potentially give project proponents more control over the timing of credit issuance. In addition, requiring a separate application for issuance could provide an opportunity for public review and consultation between offset certification and issuance. Additional review prior to credit issuance is most suited to programs where certification is conducted by a third-party. If WCI Partner jurisdictions review projects during certification, requiring additional submittals and review prior to issuance will probably duplicate efforts and increase the burden on project proponents.

3.7.2 Draft recommendation

Following certification, the WCI Partner jurisdiction will proceed with offset certificate issuance. The jurisdiction will complete the administrative steps of serializing the units and issuing to the appropriate account(s) in the tracking system. Issuance does not require the project proponent to submit any additional information nor require the WCI Partner jurisdiction to conduct any further review of the project.

3.7.3 Explanation of draft recommendation

The comprehensive due diligence process recommended in this paper combines the rigor of direct WCI Partner jurisdiction oversight and accreditation with the efficient aspects of third-party service providers, allowing project developers the maximum flexibility in scheduling and arranging for assurance services and providing jurisdictions with maximum assurance and control. The issuance of an offset certificate culminates the due diligence cycle, delivering a high quality, reliable product into the marketplace.

3.8 Post-Issuance Activities

Following issuance of offset certificates, the ownership of the certificates will be tracked in the tracking system used by the WCI Partner jurisdictions. Offset certificates may be traded and used for compliance within the rules of the WCI Partner jurisdiction programs. Offset certificates could also be retired by their owners for reasons other than compliance if desired.

The offset criteria and processes recommended by the WCI Partner jurisdictions are designed to ensure that all offset certificates are based on well-documented emission reductions. Nevertheless, situations may arise that require action by regulatory authorities regarding specific offset certificates in order to maintain the environmental integrity of the offset system and as a consequence the cap-and-trade program.

It is well recognized that carbon sequestration projects (such as some forestry projects) are vulnerable to reversal in which carbon that was verified as sequestered is released into the atmosphere. To ensure that carbon sequestration achieves the level of permanence described in the offset criteria, protocols and the offset system must include procedures for addressing both unintentional and intentional project reversals. Following issuance, regulatory authorities that issue the offset must have the ability to enforce these procedures and requirements.

In addition to permanence risk, there is a risk that following issuance the basis for issuing an offset certificate for a specific project could be found to be fraudulent or in error. The recommended documentation and independent review requirements are designed to detect such conditions prior to issuance, so that post-issuance discovery of such conditions is expected to be rare. Nevertheless, procedures are required to respond to such circumstances when they arise.

3.8.1 Options for Post Issuance Activities

The approach to post-issuance activities has been divided into two parts for this recommendation, one part for project reversals and one part for fraud and error. For projects that have a risk of reversal the project protocol must be designed with features that provide a mechanism for ensuring permanence. Mechanisms may include, for example, a buffer pool of offsets that is used to replace reductions that are unintentionally reversed. For this approach to be effective, the regulatory authority must have the ability to require that the buffer pool be maintained in adequate quantity to address risks of unintentional reversal, must have the ability to detect when unintentional reversals occur, and must be able to access the pool when needed to replace the carbon lost to unintentional reversal. Through these procedures, the offset certificate that is in circulation (or that may have been used for compliance) remains in circulation and the reduction underlying the certificate is replaced by a reduction from the buffer pool.

Mechanisms for addressing intentional reversals may vary from those for unintentional reversals. The WCI Partner jurisdictions expect that an enforceable relationship between the regulatory authority and the project proponent will require that the project proponent provide a valid instrument to replace the reduction reversed through an intentional reversal.[4] The regulatory authority must have the ability to enforce this requirement. Through this procedure, the offset certificate that is in circulation (or that may have been used for compliance) remains in circulation and the reduction underlying the certificate is replaced with another valid instrument.

Although expected to be rare, fraud or error could affect the validity of an offset from any type of project. Information regarding potential fraud or error could become available in several ways, including from a third-party verifier hired to verify emission reductions at an ongoing project, from public comment, or from Partner jurisdiction audit. Regulatory authorities must have the resources to respond to such information and determine whether the new information changes the conclusion that the project meets the requirements for the offset system. If the regulatory agency finds that the project does not meet the requirements, it must take action to ensure that the environmental integrity of the offset system is maintained.

Two approaches have been identified for taking action.

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[4] The WCI Offset System Essential Elements Final Recommendation (July 2010) includes replacement as part of the criteria for permanence.

- The regulatory authority is expected to have the ability to enforce requirements placed on project proponents and verifiers. The regulatory authority could require that those entities replace the offsets. While the regulatory authority pursues its remedies with the responsible parties, the offset certificate that is in circulation (or that may have been used for compliance) remains in circulation and the reduction underlying the certificate is replaced by project proponents.

- The regulatory authority could revoke offsets in the tracking system, removing them from any account. If the offsets have been used for compliance, the entity that used the offsets would be required by the jurisdiction in which it submitted the offset for compliance to replace it. The owner of the offset that was revoked could choose to pursue those responsible for the error or fraud to remedy their loss. The regulatory authority could pursue cases of fraud, but would not seek recovery of the offset itself, as that would be left to the offset owner.

In both approaches, the regulatory authorities have the ability to pursue remedies from those responsible for the error or fraud. The first approach puts the responsibility of ensuring that the offset is replaced on the regulatory authority. The current owner has no exposure to the risks of fraud or error in this first approach. The second approach puts the risk on the offset owner. If fraud or error is found to undermine an offset, the offset certificate is revoked and the offset owner may seek a remedy from the responsible party.

Both approaches can also encounter situations in which the mechanisms or those responsible for replacing the offset are unable to replace an offset. For example, a project proponent may have inadequate resources to replace offsets as directed by regulatory authorities. Consequently, under both approaches the regulatory authorities issuing the offsets must be able to take responsibility to ensure the environmental integrity of the program when those required to replace offsets cannot be compelled to do so.

The value of taking the first approach is that it allows offset certificates to be traded without concern that the certificate may be revoked. Offset buyers would not need to assess the risk of fraud or error that could potentially lead to an offset certificate being revoked. To maintain the environmental integrity of the program, the regulatory authorities would need to have sufficient resources to obtain remedies from the responsible parties that include replacing the offsets. If the responsible parties are unable to replace the offsets, the responsibility falls to the issuing regulatory authority.

The value of taking the second approach is that it puts the risk of revocation on the market participants (buyers and sellers) who are able to manage the risk through pricing and contracting. Facing these risks, the buyers and sellers may conduct more due diligence on the offsets and offset suppliers. Mechanisms for spreading the risk, such as through insurance, may develop to provide low cost security to compliance entities. The cost of bearing the risk of fraud and error would be expected to be internalized into the prices for offset certificates. However, the environmental integrity of the program may be maintained more easily under the second approach because offsets that have not been used for compliance are removed from the system immediately: environmental integrity does not rely on being able to get project proponents to replace the offsets. If the revoked offsets have been used for compliance, burden for replacement falls to the compliance entity.

3.8.2 Draft recommendation

Project protocols and the offset systems of the WCI Partner jurisdictions will have mechanisms in place to ensure permanence, including provisions to address unintentional and intentional reversals.

The offset systems of the WCI Partner jurisdictions will establish rules which enable action to be taken where fraud or error has been discovered. The outcomes of such action will include maintaining the environmental integrity of the program by ensuring every certificate in the system is supported by an emission reduction that is real, additional, permanent and verifiable.

No draft recommendation is made at this time regarding the ability to revoke or require the replacement of offset certificates. Comment is solicited regarding three potential options for consideration:

- Offset certificates are not revocable by any WCI Partner jurisdiction and the remedies for fraud and error include replacement.
- Any offset certificate is revocable by the WCI Partner jurisdiction that issued it upon discovery of fraud or error.
- WCI Partner Jurisdictions choose to issue, at their discretion, offset certificates that are either revocable or non-revocable. This option would support some jurisdictions issuing offset certificates that may be revoked, and others issuing offset certificates that may not be revoked.

WCI Partner jurisdictions would appreciate comments on potential implications of these options for: offset supply; trading of offset certificates; program administration requirements; and environmental integrity.

3.8.3 Explanation of draft recommendation

The draft recommendation regarding unintentional and intentional reversals is designed to ensure that sequestration projects and the offset system have built-in mechanisms to ensure permanence. These mechanisms should be used to deliver the promised performance of the offset projects.

No draft recommendation is made at this time regarding the ability to revoke or require the replacement of offset certificates. Partner jurisdictions have received and are continuing to receive stakeholder comments on this topic.

4 Consultation

The WCI Offsets Committee will receive stakeholder comment on this paper and its recommendations before making its final recommendations to WCI Partner Jurisdictions for consideration. Written comments may be submitted here via the WCI website through Friday, July 8, 2011. The WCI Offsets Committee will also host a stakeholder call on Wednesday, June 15, 2011 from 12:30 – 2:00 p.m. Pacific Daylight Time. To join the call, dial 1-800-868-1837 toll free in the US and Canada (1-404-920-6440 outside the US and Canada) and enter participant code 753491#. A PowerPoint presentation will be posted to the WCI website at the time of the call.

June 20, 2011 Draft Recommendations, Offset System Process (Offset Committee Task 1.3)

List of Commenters

American Carbon Registry

Canadian Association of Petroleum Producers

CE2 Capital Partners

Cement Association of Canada

Coalition for Emission Reduction Policy

Ecoplans, Ltd.

Independent Energy Producers Association

International Emissions Trading Association

Lloyd, Simon

Ontario Power Generation

Power Workers' Union

Southern California Public Power Authority

Union of Concerned Scientists

Waste Manangement

Western Climate Initiative

Draft Recommendations Offset System Process

WCI Stakeholder Call

June 15, 2011

To join the call, dial **1-800-868-1837** toll free in the US and Canada (1-404-920-6440 outside the US and Canada) and enter participant code **753491#.**

Background

- The WCI's detailed Design for a Regional Program included recommended criteria for offsets
- Today, the Committee is introducing draft recommendations for the requirements and process of offsets project review and approval and credit creation for the regional emissions trading program
- The Committee is now examining options for the review and recommendation process for offset protocols

Offset System Process

- This paper identifies the specific requirements for validation, registration, monitoring, quantification, reporting, verification, certification and issuance of offsets
- The recommended process is designed to lead to high quality offset credits that can be exchangeable across the region
- The WCI Partner jurisdictions recognize that Partner jurisdictions have labeled the steps with varying terms, and in some cases have combined steps, in the processes proposed for their programs. While offering these draft recommendations, the WCI Partner jurisdictions acknowledge that such variations that result in the same or greater level of rigor being achieved are acceptable

Validation

- Will initiate a relationship between the proposed project and the relevant authority
- Project proponent submits project information for validation by Partner Jurisdiction or third-party validation body
- This must be completed prior to verification of the project's first project report

Registration

- Requires that submission of information for each project to the responsible Partner Jurisdictions
- Registration information will be posted for public review and comment to provide transparency
- The Project Developer must implement the project per the information provided as part of registration

Monitoring and Quantification

- Each offset project shall follow the monitoring and quantification requirements specified in the applicable protocol
- Monitoring and quantification requirements for offsets will be harmonized, to the extent practicable, with WCI Mandatory Reporting Requirements

Reporting

- Reporting frequency will be annual unless otherwise specified in a recommended protocol
- Partner Jurisdictions will have two options for assigning the annual reporting date for the project:
  - the month and day of the project start date; or
  - a common calendar date for all projects each year

Verification

- Emission reductions or removals must be verified by an accredited third-party verification body and submitted to the relevant WCI Partner jurisdiction prior to the issuance of offset certificates
- The verification must be conducted in accordance with ISO 14064-3 to a reasonable level of assurance
- Verification statements will be publicly posted

Certification

- Reviewing project documentation presented as evidence and accepting that evidence into the system through the assignment or creation of an offset certificate when all conditions of the Partner Jurisdiction have been met
- The committee recommends certification take place at the point of issuing an offset certificate, so that certificates are not issued prior to successful completion of certification

Issuance

- Offset issuance follows certification
- The jurisdiction will complete the administrative steps of serializing the units and issuing to the appropriate account(s) in the tracking system

Post-Issuance Activities

- Project protocols and the offset systems of the Partner jurisdictions will ensure permanence, including mechanisms that will replace offsets from sequestration projects lost to unintentional and intentional reversal
- There is no draft recommendation at this time regarding revocation of offset certifications; however there are three potential options:
  - Offset certificates are not revocable
  - Offset certificates are revocable
  - Offsets certificates are issued as either revocable or non-revocable as per the jurisdictions discretion

Next steps

- The WCI Offsets Committee will receive stakeholder comment on this paper and its recommendations before making its final recommendations to WCI Partner Jurisdictions for consideration.
- Written comments may be submitted via the WCI website through Friday, July 8, 2011.

Western Climate Initiative

Compliance Instrument Tracking System

Generic Business Requirements:

Actors, Processes, Interfaces, Reports and Non-functional Requirements

DRAFT Version 1.0

2011-Jun-27

*Note: This document is not a complete version of the Business Requirements as additional content refinement is still in progress.

Document Control

Version	Date	Update Description
1.0	2011-Jun-27	Original document

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Note: Business requirements discovery is on-going with WCI Partner jurisdictions.

This content is focused on the business processes that will become part of the Compliance Instrument Tracking System Service, required to support the administration of the cap and trade program.

Purpose

The purpose of the Compliance Instrument Tracking System Service (CITSS) Draft Business Requirements is to provide our stakeholders and the public with an overview of the work completed to date in defining business processes and design requirements for the administrative tracking system, CITSS, that will support the Western Climate Initiative (WCI) cap and trade program. This is not a request for proposals and will not be used to pre-qualify or screen vendors for a subsequent competitive bidding process, if any.

These requirements are 'generic' to indicate that they are tracking system requirements that are applicable to all participating jurisdictions and do not include jurisdiction-specific customizations or service requirements.

This document incorporates information contained in the Western Climate Initiative's "Design for the WCI Regional Program" published July, 2010, as well as other previously published WCI documents. It also incorporates publicly available information contained within the California Air Resources Board's May 24, 2010, Market Tracking System Request for Information (RFI) and discussions with representatives of other cap and trade programs.

Introduction

The WCI has designed business requirements for a common system service that could be applied across all participating WCI Partner jurisdictions. Although this system service may be common across the region, each participating jurisdiction will retain authority over its own covered sources and compliance instruments. Beyond the common functions, the form and service of CITSS is left to the discretion of the WCI Partner jurisdictions.

CITSS is an integral component in the administration of the WCI Partner jurisdictions' cap and trade programs. In particular, CITSS is the record of ownership of compliance instruments; will record information related to accounts; enable and record compliance instrument transfers; facilitate compliance verification; and support market oversight through the collection of relevant information.

In addition to the CITSS system service, there are requirements to interface with several other systems and services, to maintain the efficiency and integrity of the cap and trade program.

Background

The Western Climate Initiative (WCI) is a collaboration of seven US states (Arizona, California, Montana, New Mexico, Oregon, Utah, and Washington) and four Canadian provinces (British Columbia, Manitoba, Ontario, and Quebec) to reduce greenhouse gas emissions (GHG). Several WCI partner jurisdictions have signaled their intent to implement greenhouse gas cap and trade programs and link them to form a regional market for compliance instruments. Several WCI participating jurisdictions continue to work towards a 2012 start date for regional emissions trading. The WCI Partner jurisdictions also recognize that alternative schedules for implementation can be accommodated and will continue to encourage additional jurisdictions to join the program after 2012.

As the name implies, the program puts a cap on the total amount of GHG that can be emitted by covered sources under the program by issuing a limited number of emission allowances, or permits to emit one metric ton of carbon dioxide equivalent (CO_2e). Once the cap is set, the program will enable allowances to be allocated (directly, or available for purchase at auction), bought and sold, and banked for future use.

To reduce compliance costs and encourage emissions reductions, WCI Partner jurisdictions will issue credits for certified offset projects that induce a reduction or removal of CO_2e and meet all recommended offset criteria. Offset credits, each representing one metric ton of CO_2e, provide a flexible mechanism that reduces the cost of a cap and trade program by introducing a broader range of reduction opportunities, and incentivize emissions reductions in sectors such as forestry and agriculture that are not covered by the cap and trade program. Allowances and offset credits are collectively called "compliance instruments."

Sources subject to a jurisdiction's cap and trade requirements (covered sources) will be required to submit allowances and/or offset credits on a certain date to the jurisdiction in which they operate in a number equal to their emissions over a compliance period. Because the number of allowances in the program is fixed, the cap and trade approach provides a measure of environmental certainty about the total quantity of GHG emissions attributable to the covered sources.

To successfully administer a regional cap and trade program, the WCI Partner jurisdictions are working on the development of a number of information services. These services include: an offsets information system service, auction services, one or more databases for covered source emissions and a Compliance Instrument Tracking System Service (CITSS). The CITSS is the focus of this document.

WCI Cap and Trade Cycle

For a comprehensive description of the Western Climate Initiative cap and trade recommendations, please refer to the WCI website.

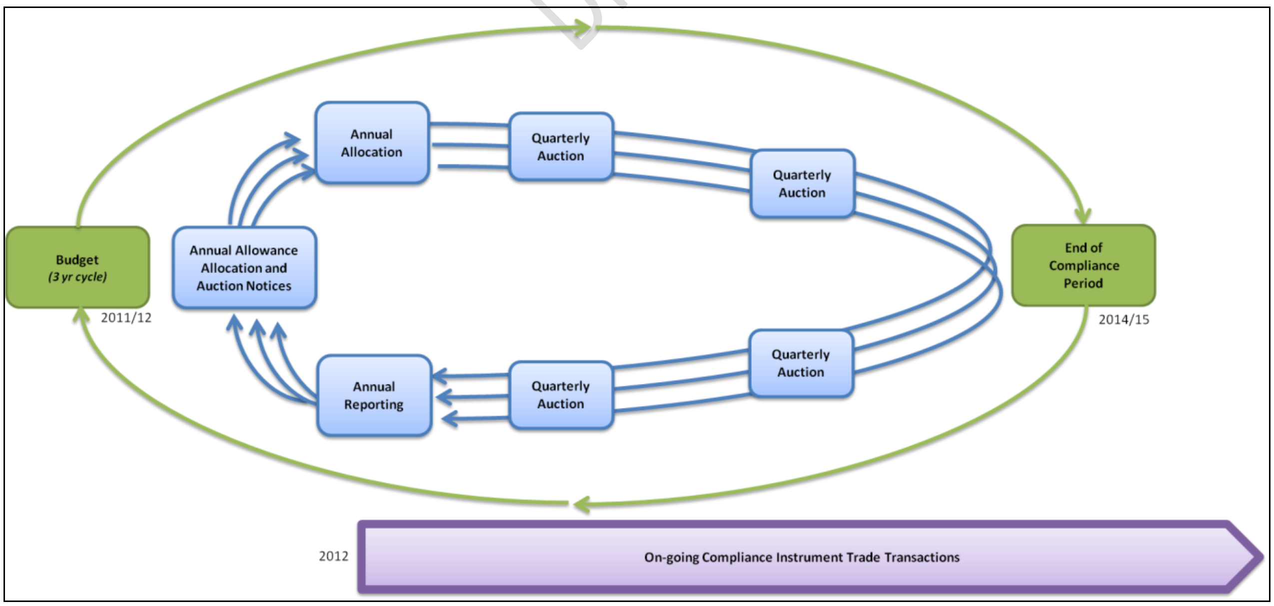
WCI Participating jurisdictions (states and provinces) will set budgets for greenhouse gas levels (emission allowance caps) for a given period. The goal is to lower emissions annually and to regulate compliance in successive three-year compliance periods.

Jurisdictions will control the amount of allowable emissions by issuing allowances in limited amounts. Each jurisdiction may, at its discretion, directly allocate a number of emission allowances to its covered sources (large greenhouse gas emitters) at or near the start of the compliance period and at other times during the compliance period as it sees fit. Jurisdictions will also hold regular auctions of allowances, expected to be quarterly.

Covered sources may meet their obligations by surrendering compliance instruments in the form of allowances and offset credits in amounts equal to their verified emissions for the three year compliance period. By a specified deadline following the end of the compliance period, those not having met their commitments will be subject to compliance enforcement.

In 2015, a subsequent three year compliance period commences.

Figure 1: Cap and trade three year cycle



CITSS Actors

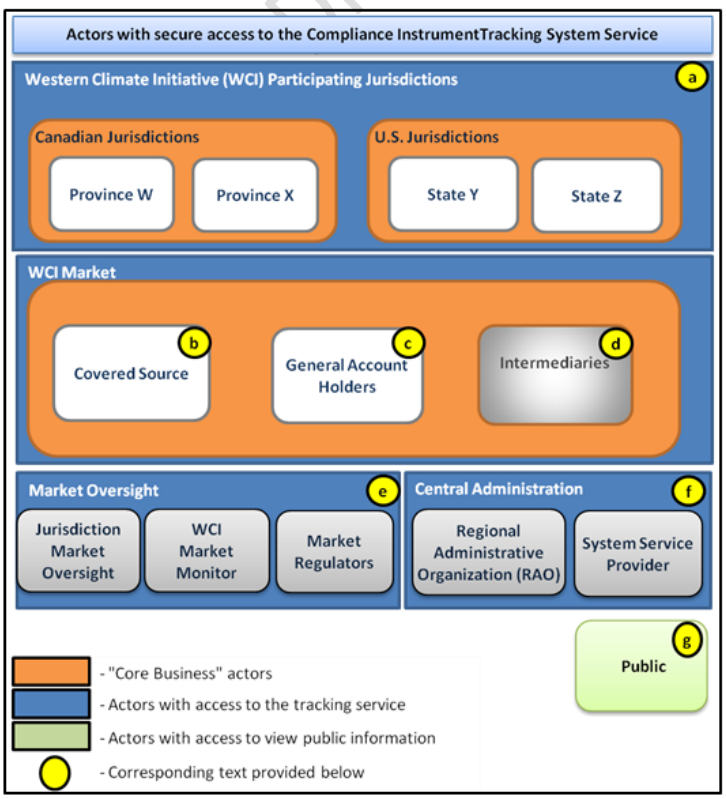
Participants in a cap and trade program include the following core actors who are actively involved in the issuance, acquisition, transfer and retirement of compliance instruments:

1. Participating jurisdictions (i.e., states and provinces)
2. Covered sources, including sources that emit greenhouse gases in a participating jurisdiction in excess of a threshold; sources voluntarily electing to opt into the program, as defined in their jurisdiction's regulations; first jurisdictional deliverers of electricity; and distributors of transportation fuels and residential and commercial fuels
3. Other general account holders, such as developers who undertake offset projects to reduce greenhouse gases and other market participants.

Other parties involved in the cap and trade system may have specific roles, such as providing market monitoring services or brokering trades in compliance instruments on behalf of clients. As an environmental program, the system must also have an element of transparency for the public.

Figure 2 is a conceptual depiction of the WCI cap and trade program actors. It is not meant to infer a hierarchy or tracking system account structure. Regardless of their access to the tracking system, all actors play significant roles in the success of the cap and trade program.

Figure 2: CITSS Actors



The following section provides a brief description of each of the proposed CITSS actors and lists its actions in the process. The descriptions in this document are clarifying descriptions for the purposes of system requirements. If any conflicts exist between definitions, the jurisdiction requirements take precedence.

a. Jurisdictions

Jurisdictions are participating states and provinces responsible for issuance of compliance instruments and general administration of the cap and trade program.

Jurisdiction:

- Defines its budget (sets emission caps) and issues allowances
- Approves the creation of compliance accounts and general accounts in its jurisdiction
- Allocates allowances to covered sources and other market participants, as defined by each jurisdiction
- Issues offset credits in respect of offset projects
- Coordinates auction timing with other jurisdictions and sets the quantity of allowances to be auctioned
- Retires compliance instruments at the end of each compliance period
- Has the authority to suspend all transfers in its jurisdiction (similar to halt in financial trading)

b. Covered Sources

Covered sources include: sources that emit greenhouse gases in a participating jurisdiction in excess of a threshold; sources voluntarily electing to opt into the program, as defined in their jurisdiction's regulations; first jurisdictional deliverers of electricity; and distributors of transportation fuels and residential and commercial fuels.

Covered entities are the legal entities that operate a business, a facility or an establishment that is covered by a jurisdiction's cap and trade law and regulations (covered sources). It has not yet been defined for all jurisdictions whether compliance will be assessed at the covered source or covered entity level. For simplicity, this requirements document has been written as having compliance accounts and compliance activities being the responsibility of the covered source. It may be necessary for CITSS to support compliance at either the covered source or covered entity level.

Covered Sources:

- Must register in CITSS for their business, facility or establishment that is covered by a jurisdiction's cap and trade law and regulations.
- Must report corporate affiliates that also have compliance instrument ownership interest.
- Must report any changes concerning the covered source, such as ownership, closure, corporate affiliation, and beneficial ownership in a timely manner, as specified by each Partner jurisdiction
- Must report covered emissions annually to the jurisdiction, which are imported into CITSS
- Must surrender allowances to their jurisdiction to meet their compliance obligations according to their jurisdictions' regulatory requirements and deadlines.
- May take any of the actions of a "general account holder" (section c. next page)

c. General Account Holders

An individual (natural person) or entity (including covered sources) that acquires, holds and trades compliance instruments in the market.

General Account Holders:

- Must register to open a general account, subject to authentication and approval by a jurisdiction
- May hold compliance instruments in the account
- May receive offset credits upon issuance by a jurisdiction
- May transfer compliance instruments between accounts
- Must declare beneficial ownership and corporate affiliations and changes to these in a timely manner, as specified by each Partner jurisdiction
- May transfer compliance instruments through an intermediary, such as a registered broker

d. Intermediaries

Intermediaries may include brokerage houses (registered brokers), banks, clearing houses, and market exchanges. All references to intermediaries and brokers are still under review.

- May hold compliance instruments on behalf of others, while maintaining records of beneficial ownership of the compliance instruments
- May hold compliance instruments on its own behalf as a "general account holder" (see section c.)

e. Market Monitors

Market monitoring is a key element of market oversight. Effective monitoring will contribute to market integrity through the deterrence and detection of fraud and manipulation. Market monitors support jurisdictions with investigation and enforcement matters. A market monitor:

- May view details of any transfer
- View all compliance instrument holdings and transfer activity of an account holder and its affiliates at any point in time (query or report)
- Review all transfers related to given compliance instruments

f. Central Administrator

The WCI partner jurisdictions may establish a central administrator either in the form of a regional administrative organization (RAO) and/or a system service provider, yet to be determined. The central administrator will be authorized to manage administrative tasks associated with the day-to-day operations across the regional cap and trade program. This is a role that would be defined and monitored by the partner jurisdictions, and would work to benefit the jurisdictions.

g. Public

The partner jurisdictions are committed to transparency. Public access to information is anticipated to include reports and basic queries of non-confidential information. All information access will be subject to legislation regarding privacy protection, and will be respectful of business-sensitive information.

CITSS Processes

The following sections describe the business processes designed to support compliance instrument tracking, as well as how CITSS will fit together with the other related systems.

Process sections 1 to 6 focus on the business (administrative) processes required to support the tracking of compliance instruments from issuance to retirement or cancellation, as depicted in the following overview diagram. Sections 7 and 8 of the document examine system interfaces and reports, while the last section (9) describes the known "non-functional" requirements. CITSS is expected to support the functionality described.

1. Accounts

For clarity, this document uses the term "user identification" or "user i.d." rather than "user account", to avoid confusion with accounts that hold compliance instruments.

CITSS User Identification

A user i.d. and role are needed for anyone to act upon or view any data in CITSS. A user i.d. is required for logging into the system and ties the access to an identifiable person, not to a position. A role defines the general access and authority in the system. A user may be assigned more than one role (for instance, a user may be an Authorized Account Representative on one account and be an Electronic Submission Agent on a different account).

System users that are not related to the jurisdiction will apply for user i.d.'s as part of the account creation process, as described later in this section[1]. Roles-based security will be defined by the jurisdiction for each user and will limit user access to data, as appropriate. More is written on this topic in the security section. These are the anticipated user roles required in CITSS:

At the jurisdiction level:

- **Jurisdiction Authority and Alternate**, who have sign-off authority in the jurisdiction
- **Jurisdiction Administrator**, who must be granted security access to jurisdiction functions and accounts by the Jurisdiction Authority(ies), which provides a separation of duties to suit the given jurisdiction
- **Jurisdiction Security Administrator** who will verify applications for new users of the tracking system

At the market participant and covered entity/covered source level:

- **Authorized Account Representative and Alternate Account Representative**
- **Electronic Submission Agent**

[1] System users may also be added to accounts after the accounts are created, and as approved by the jurisdiction.

At the market oversight and monitoring level:

- Market oversight system users **-** yet to be fully defined, anticipating the need to have a class that can query within a jurisdiction and some that may query data across WCI

At the system level:

- Possible regional administrative organization (RAO) administrators
- Service-operator roles with limited access to administrative or technical duties across all jurisdictions.

CITSS Accounts

Every account in CITSS must be opened through a participating jurisdiction. Each account that holds compliance instruments:

- Must name an Account Holder - a legal entity[2] ultimately responsible for the account
- Must name only one Authorized Account Representative and, optionally, one or more Alternate Authorized Account Representative - persons who will act in the account on behalf of the Account Holder and are the only managers of an account. In the case of accounts of a covered entity or a covered source, an Alternate Account Representative is mandatory.
- May optionally have one or more Electronic Submission Agents who are authorized to act in the account for specific purposes by the Authorized Account Representative(s). To authorize an Electronic Submission Agent, the Authorized Account Representatives must first submit a certificate of delegation to the appropriate jurisdiction.

The jurisdiction will decide whether to issue the CITSS user i.d.'s and compliance instrument accounts upon review of applications with certificate(s) of representation and all necessary information for authentication and security purposes.

1.1 Accounts for a Jurisdiction

1.1.1 Creating a new Jurisdiction in the system

On-boarding of new jurisdictions will require CITSS to create the initial foundation and access. This is a secure technical duty that will not be accessible to CITSS users at any level. When a jurisdiction is new to CITSS:

[2] Legal entities include government organizations, non-governmental organizations, corporate entities, and natural persons.

- A Jurisdiction Authority and Alternate Authority must be identified who will authorize and manage the accounts and system users in the jurisdiction.
- A Jurisdiction Security Administrator must be identified who will administer the creation of new users for authority approval.

1.1.2 Creating/Updating Jurisdiction Users

The Jurisdiction Authority and Security Administrator together must be able to update and remove all jurisdiction system users (authorities, administrators, and security administrators), appointing new users as jobs change. Each change will create an audit record in CITSS.

1.1.3 Creating/Updating Jurisdiction Compliance Instrument Accounts

The Jurisdiction Authorities must be able to create jurisdiction compliance instrument accounts according to their needs, including at minimum a jurisdiction general account, an issuance account, and a retirement account.

1.1.4 Jurisdiction Security

The Jurisdiction Authority and Alternate Authority will approve security access to the jurisdiction's compliance instrument accounts. This will be accomplished by defining roles and role access to system functions and accounts, and assigning users to the specific roles.

1.2 Accounts for Covered Sources

A source becomes "covered" under the cap and trade program as prescribed by a jurisdiction's regulations requiring mandatory compliance or when its entity[3] (operator) chooses to register it as part of the cap and trade program ("opt-in"), if this is permitted in their jurisdiction. Covered sources that are "opt-ins" will not be tracked differently in the system from covered sources with mandatory requirements. Once a source has been opted in, it will fall under the same rules and requirements as all other covered sources in the tracking system.

Prior to creating accounts related to a covered source, the jurisdiction must obtain the required information on the covered entity, the covered source, and the people who will be responsible

[3] A covered entity is a legal entity that operates a business, a facility or an establishment that is covered by a jurisdiction's cap and trade law and regulations.

for the related accounts in CITSS. The data collection will be done using an "account certificate of representation", as per the Design for the WCI Regional Program[4].

1.2.1 Processing an Account Certificate of Representation for a New Covered Source

1. A designated official from the covered entity will submit an account certificate of representation to create a new covered source presence in CITSS. The form will contain the following information[5]. :
   a) Covered Entity Data:
      - Legal and Operating names of the covered entity
      - Physical and mailing addresses
      - Telephone, facsimile numbers, cell phone, and email address
      - Web site address, if any
      - Contact name and position
      - Contact's direct telephone, facsimile, cell phone, and email address
      - Corporate Ownership (parent companies and subsidiaries) and Affiliation relationships (partnerships), including contact name and position, addresses, and full contact information, as above
      - Jurisdiction corporate number and other identifiers, as required by jurisdictions (multiple identifiers per entity)

   b) Covered Source Data must be provided for each covered source that is new to the system operated by the same covered entity:
      - Name of Covered Source
      - Type of source: NAICS / SCIAN code
      - Geographical location(s), which will dictate the relevant jurisdiction responsible and be used for reporting compliance by geographic area
        - Latitude and longitude of a specific location or
        - General area of a geographically dispersed operation
      - Covered Source Identifiers connecting it to the emissions database

   c) Certificate(s) of representation, as defined in the DPD, designating the Authorized Account Representative and Alternate Authorized Account Representative, and Electronic Submission Agents, if applicable

   d) Electronic signature confirming that the above information is complete and accurate (legal wording to be inserted). Paper signature and physical verification of documents may be needed to conduct the verification required (the method is still under review for parties outside all jurisdictions)

2. The relevant jurisdiction administrator will verify the accuracy of the covered entity, covered source, and prospective user information provided. It may ask for more information if required.

[4] http://westernclimateinitiative.org/the-wci-cap-and-trade-program/program-design

[5] There will likely be hardcopy submission requirements for verification of new CITSS users.

3. Once the documentation for each of the users has been reviewed and approved, the jurisdiction security administrator will generate an invitation to the prospective new users to create their CITSS user i.d.'s and passwords using a secure online form. Method subject to security standards.
4. The prospective users will complete a request for CITSS user i.d. form online with terms and conditions of use and communicate with the jurisdiction once their user i.d.'s have been confirmed to enable the completion of the account set up.
5. Once the users have been verified, the jurisdiction creates the covered source in the tracking system by entering:
    a. the covered entity (if it has not been registered in the system previously)
    b. the covered source tombstone data (i.e. identifying data, contacts, etc.),
    c. the covered source general and compliance accounts, and using the confirmed user i.d.'s, the Authorized Account Representatives and the Alternate Authorized Account Representative for the accounts.
6. The Authorized Account Representatives of the covered source accounts will provide access to Electronic Submission Agents, as applicable.

1.2.2 Updating the account of an existing covered source

Authorized Account Representatives of covered entity and covered source accounts may:

- Update basic covered entity/covered source contact information in CITSS, such as addresses, telephone numbers, email addresses, and web sites.
- Change the security access of Electronic Submission Agents in accounts over which they have authority.
- Notify the Jurisdiction of a change to any other secured data under their area of responsibility, such as their covered entity, covered source, Electronic Submission Agents, any other Authorized Account Representatives or themselves.
- Notify the jurisdiction of a change of corporate ownership (parent companies and subsidiaries) and affiliations.

Jurisdictions governing covered entity and covered source accounts may:

- Update data that is critical to the identification or classification of covered entities and covered sources (e.g., NAICS code, legal name, etc.).
- Change the ownership or structure of an account. There are many situations that may require a change of account ownership or restructuring of covered source accounts, such as sale of a facility or jurisdictional reassessment resulting in a merger with an adjacent or related covered source. The system needs to support the administrative records for these types of transactions, including providing linkages to past related accounts in the case of a transfer or split.
- Change the Authorized Account Representative or Electronic Submission Agents of a covered entity/covered source and any of the related core data.

- Update the records of association of a covered entity.

1.3 Accounts for General Account Holders (Market Participants)

This section deals with accounts for general account holders – individuals or entities who wish to open a general account not related to compliance.

Each account is opened in a single jurisdiction, and each system user obtains their user i.d. through a single jurisdiction. However, users may have roles in multiple accounts, and in more than one WCI jurisdiction (as Authorized Account Representative or Electronic Submission Agent) – for example, if their business or covered sources span the WCI region.

1.3.1 Creating new general account holder in the system

In order to register as a general account holder, an account certificate(s) of representation must be completed online in CITSS, with hard-copy identity documentation submitted to the jurisdiction for verification:

1. The individual (natural person) or designated official of an organization will use an online application form in CITSS to open an account by providing the following information, in general, with jurisdictional variances:

   a) Information on the general account holder:
      Account Holder information will be collected in two slightly different formats depending whether the applicant is an individual or an organization (may require separate versions of a form)

      Individual (data still subject to privacy impact assessment)
      - Legal and Common names
      - Identifying data (e.g., government issued id, etc)
      - Whether acting as a broker
      - Physical and mailing addresses
      - Telephone, facsimile numbers, cell phone, and email address
      - Employer, for conflict of interest
      - Any other relevant relationships (partnerships, holding positions in companies involved in WCIS cap and trade). For each affiliation, include full personal or organization contact information.

      Organization
      - Legal and Operating names of the organization responsible, as per jurisdiction's rules
      - Type of organization (e.g., NGO, Corporate, etc.)
      - Whether acting in the account as a broker
      - Organization physical and mailing addresses

- Organization telephone, facsimile numbers, cell phone, and email address
- Organization Web site address, if any
- Contact name and position
- Contact's direct telephone, facsimile, cell phone, and email address
- Corporate Ownership (parent companies and subsidiaries) and Affiliation relationships (partnerships), to be determined by the Market Oversight Committee

b) Certificate(s) of representation, as defined in the DPD, designating the Authorized Account Representative and Alternate Authorized Account Representative, and Electronic Submission Agents, if applicable

c) Electronic signature confirming that the above information is complete and accurate (legal wording to be inserted). Paper signature may also be required.

2. The relevant jurisdiction administrator or authority will verify the accuracy of the information provided, and ask for more information if required.
3. Once the documentation for each of the prospective users has been reviewed and approved, the jurisdiction security administrator will generate an invitation to the prospective new users to create their CITSS user i.d.'s and passwords using a secure online form (method subject to security standards).
4. The prospective users will complete a CITSS user i.d. request form online with terms and conditions of use. They must notify the jurisdiction of their user i.d. once it's been confirmed to enable the completion of the account set up.
5. Once the users are verified, the jurisdiction creates the general account in the tracking system and assigns the Authorized Account Representative(s) and Electronic Submission Agents, if applicable.

1.3.2 Updating an existing general account

Authorized Account Representatives of general accounts may:

- Update their own basic contact information, such as addresses, telephone numbers, email addresses, and web sites.
- Change the security access of Electronic Submission Agents in accounts over which they have authority.
- Notify the Jurisdiction of a change to any other secured data under their area of responsibility, Electronic Submission Agents, any other Authorized Account Representatives or themselves.
- Notify the jurisdiction of any change to Corporate Ownership (parent companies and subsidiaries) or Affiliation relationships.

Jurisdiction governing a general account holder may:

- Update data that is critical to the identification or classification of general account holders, Authorized Account Representatives, and Electronic Submission Agents.
- Change the ownership or structure of an account. There are many situations that may require a change of account ownership or restructuring of general accounts, such as sale of a company or jurisdictional reassessment resulting in a merger with or split from another general account. The system needs to support the proper administrative records for these types of transactions, including providing linkages to past related accounts in the case of a transfer or split.

1.4 Account Status, Restrictions, and Closure

Jurisdictions will have the authority to change the status of any of the jurisdiction-controlled accounts in CITSS. Account status can be open, suspended, inactive, or closed.

The jurisdictions may impose different types of suspensions on accounts, depending on the reason. In some cases the suspension is complete and the account is essentially frozen, allowing no activity by the account holder until the jurisdiction lifts the suspension and returns the account to “open”. In other cases, the jurisdiction may suspend the account to prevent the deposit of compliance instruments. For example, if an account has reached a threshold of compliance instruments, the jurisdiction may choose to suspend the account until the number of compliance instruments has been lowered to an acceptable level. Yet another type of account suspension may occur when a covered source is not in compliance. In this case, the jurisdiction may allow deposits into the account and limit transfers out to only specific accounts (e.g., the covered source may be permitted to deposit compliance instruments into its general account, but only transfer compliance instruments into its compliance account for the purpose of meeting a compliance obligation or an excess emissions obligation).

Accounts will be identified by the jurisdiction after a period of inactivity. To provide the jurisdictions with the flexibility to manage their own house-keeping, a report or query is required that will allow administrators to find accounts that have not be accessed for a period of time. The query or report would allow jurisdictions to request a listing of accounts with a period of inactivity longer than a specified timeframe, and ideally would allow the jurisdiction to choose to change their status to inactive. No process will be allowed from inactive accounts.

The jurisdiction may choose to close an account and an account holder may request that their account be closed. Compliance instruments in the account would be transferred out of the account before it is closed. Closed accounts cannot be re-opened, and no activity may be generated from a closed account

The system must allow the jurisdiction to include a comment, such as a reason, for changing the status of accounts.

1.5 Confidentiality of Data

The jurisdiction administrator may identify any data, including personal data, which CITSS must keep confidential; that information may only be accessible by specific users, such as the administrator and the relevant user. CITSS must have the ability to support field-level security, to provide the ability to restrict viewing sensitive data to specific roles.

2. Jurisdiction Budget

Each jurisdiction will provide a budget set out by calendar years, which are linked to compliance periods. The following table is intended to provide an example of the type of data that may be required for budgets. It is not intended to be a prescriptive design:

Jurisdiction - XX	**Period**	**Year**	**Number of Allowances**
Version: current	Compliance Period 1	2012	999,999,999
Effective Date: 2011-DEC-05		2013	999,999,999
Updated by: J. Doe		2014	999,999,999
Notes: Changed the xxx due to xx decision to ...	Compliance Period 2	2015	999,999,999
		2016	999,999,999
		2017	999,999,999
	Compliance Period 3	2018	999,999,999
		2019	999,999,999
		2020	999,999,999
	...	...	...

Entering budgets in CITSS will provide jurisdictions with control over the number of allowances that can be issued within a given year. This will mitigate potential administrative errors and maintain the integrity of the emissions cap. It is recommended that security for the entry of budgets be limited to the Jurisdiction Authority, with confirmation by an Alternate Jurisdiction Authority. The dual authority within a jurisdiction to change the budget is recommended as security control.

3. Issue Compliance Instruments

Compliance instruments are generated in the tracking system through a process termed "issuance". A compliance instrument is issued with a unique identifier that follows the WCI Compliance Instrument Serialization System (CISerS) (details in Section 3.4). This highly secure and controlled process requires a separation of duties between two CITSS users within a jurisdiction with the authority to a) enter a proposed compliance instrument issuance transaction, and b) approve the transaction.

3.1 Types of Compliance Instruments

At an upper level, all compliance instruments are classified either as allowances or offset credits. The tracking system must allow for the definition of new compliance instrument types in the future, such as compliance instruments from other approved cap and trade programs. Certain business rules are applicable based on the type of compliance instrument.

3.1.1 Allowances

Allowances are issued by jurisdictions as per the WCI Compliance Instrument Serialization System. Allowance issuance may not exceed the jurisdiction's budget.

3.1.2 Offset Credits

Compliance instruments created as a result of an offset project will also use the WCI Compliance Instrument Serialization System and will have a project code to allow the instrument to be referenced to its project. That code will enable the holder of the offset to identify the project and project type[6] for which it was issued.

3.2 Steps for Issuing Compliance Instruments

STEP 1. A Jurisdiction Administrator with the security privilege to do so will enter the proposed compliance instrument issuance, specifying the appropriate data depending on the type of instrument (see section 3.3) and the account(s) to which the compliance instruments will be deposited.

It may be beneficial to have all newly issued compliance instruments deposited initially into jurisdiction issuance accounts (separate accounts for allowances and offsets) for ease of consistent reporting across the region, and then transferred automatically to their ultimate destinations in the final stage of the issuance process. Note that jurisdictions are still considering their account requirements. It is up to the jurisdiction

[6] Projects will be categorized by the offset protocol used.

to decide their account structure and into which account issued compliance instruments are deposited.

Allowances

In the case of issuing new allowances, jurisdictions may use a distribution form, specifying the total number of allowances to issue and the intended method of distribution, such as:

a. Percentage or number of compliance instruments to auction

b. Percentage or number of compliance instruments to hold in reserve (e.g., for future allocation, auction or any other purpose, at the discretion of the jurisdiction)

c. Percentage or number of compliance instruments to transfer to other jurisdiction accounts, as determined by each jurisdiction.

d. Number to distribute to each account-holder (if known at the time of issuance).

e. Ability for jurisdiction to opt to issue to a single account (e.g., allowance issuance account) and transfer the issued allowances into other accounts as a separate system action.

Offsets

In the case of issuing new jurisdiction offsets, jurisdictions will complete an offset issuance form, specifying the total number of offset credits to issue, the offset project name and link to the offset information system, and the ultimate account in which to deposit the offset credits after issuance (usually that of the offset developer).

STEP 2. The system will present the Jurisdiction Administrator or Authority with a confirmation page, allowing them to verify the proposed issuance and distribution and change any items before continuing. The confirmation will result in a notice to a second Jurisdiction Authority (approver) for segregation of duties.

STEP 3. The second Jurisdiction Authority will receive a notice of the request for approval and can choose either to return the request to the Jurisdiction Administrator if it needs to be changed (prefer that this function include the ability for the authority to include a note why) or to approve the issuance.

STEP 4. On the final approval, the instruments will automatically be serialized and deposited into the jurisdiction issuance account, and from there will be transferred to any destination account(s). In the case of an offset project, it may go to a jurisdiction issuance account and then to the account of the offset developer.

STEP 5. Following the issuance of allowances, CITSS will enable the jurisdiction to report on compliance instrument issuance.

3.3 Compliance Instrument Serialization

When each compliance instrument is issued, it will be assigned an identification number by the system that is unique across the WCI region and cannot be re-used in the future.

The compliance instrument identification number will link the compliance instrument to a record of issuance, which will hold the following information associated with the origin of each compliance instrument:

a. Issuing jurisdiction
b. Vintage
c. Instrument Type, e.g.:
    i. Allowance
        a) WCI Allowance
        b) Early reduction allowance (ERA)
        c) Price containment reserve allowance
        d) Consignment allowance
        e) Recognized allowance from another cap and trade program
    ii. Offset credit
        a) WCI Offset
        b) Recognized offset from another cap and trade program
d. Offset project code (when offset credit)
e. Number of Compliance Instruments in the Issuance
f. Serial block start (first compliance instrument identifier in the series, as determined by CITSS)
g. Serial block end (last compliance instrument identifier in the series, as determined by CITSS)
h. Approving authority (user id)
i. Date and time of issuance

The potential number of compliance instruments that will be may reach the low billions over the next 20 years. Jurisdictions would prefer to restart the number portion of the serial code at zero annually, which would keep the number much smaller. However, conventional data standards require that the number should be unique throughout the years, regardless of other qualifiers.

4. Transfer Compliance Instruments

All transfers conducted within CITSS must conform to the jurisdictions' requirements when developed. This section outlines a general process by which compliance instruments will be transferred in CITSS.

There are several types of transfer transactions:

Transfers Initiated by Jurisdictions

Multiple Transfers by Jurisdictions

The system needs to support the entry of balanced, multiple entry transfers, for functions such as allowance allocations, auction results, and retirements. This type of entry serves to reduce data entry/accounting errors by incorporating a verification step that shows the total effect of the transfers prior to their approval and commitment to the database. On approval, each of the multiple entries will still represent a transfer between two accounts. Multiple transfers can be entered manually online or may be submitted through a batch interface. These are the most common jurisdiction examples of multiple transfers:

1. Distribution plan transfers (online transfer from jurisdiction account to multiple general accounts)
2. Auction result transfers (batch transfers from jurisdiction to multiple general accounts)
3. Retirement transfers (from multiple covered source compliance accounts to a jurisdiction retirement account)

Single Transfers by Jurisdictions

The most common data transfers will be single transfers with the transferor as the debit account and the acquirer as the credit account. Examples include:

4. Transfers between accounts held by the same jurisdiction
5. Transfers from jurisdiction accounts to general accounts (of covered sources, general account holders or other jurisdictions)

Transfers Initiated by General Account Holders

6. Transfers between general accounts held by the same account holder[7]
7. Transfers between general accounts held by different account holders
8. Transfers involving intermediaries[8]

[7] This may be necessary when an account holder has both a general account at a corporate level and a general account related to a covered source. The system needs to accommodate jurisdictions limiting account holders to one general 'non-covered source' account. The system also needs to be able to accommodate additional ownership in client/broker accounts.

Initiated by Covered Source Account Holders to meet Compliance Obligations

Covered Sources may also act as General Account Holders (see items 6-8 above). However, transfer type 9 is specific to accounts related to covered sources.

9. Transfers from covered source general account to covered source compliance account

Initiated by Account Holders for Voluntary Retirement

10. Transfers from any General Account to the Jurisdiction Retirement Account, for voluntary retirement purposes.

4.1 Jurisdiction Transfers

Jurisdictions have sole authority to transfer compliance instruments out of their own accounts, whether to another of their own jurisdiction accounts or to other accounts. Only users with the security to transfer compliance instruments out of an account may do so. The Jurisdiction Authority sets this privilege for jurisdiction accounts and may name any number of Jurisdiction Administrators. Jurisdiction Administrators may have variable access levels (e.g. view only access) to jurisdiction accounts as enabled by the Jurisdiction Authority.

Functions resulting in multiple transfers are highly secure and controlled processes, requiring a separation of duties between two jurisdiction system users; one user has the privilege to a) enter data or download a proposed multiple-transfer form, and the second user has the ability to b) approve the completed multiple-transfer form.

The Jurisdiction Administrator and Authority are both required to enter and approve any changes to high-level control transactions and multi-transfer forms, such as the budget plan or the allowance distribution plan. Jurisdictions will not have access to the budget or allowance distribution plan table of other jurisdictions. In the case of retirement transfers, the jurisdiction will decide on a date and time to run the retirement process (entered as a parameter in CITSS) and once the initial transfers are proposed, the Jurisdiction Authority will have an opportunity to review and accept the transfers.

Jurisdictions also have authority to enter and approve single transfers from jurisdiction accounts to general account holders, such as transferring issued offset credits.

[8] WCI may structure broker accounts such that the account holder is the owner and the broker is an electronic agent on the account or a trust account is created for every broker/client relationship.

4.2 General Account Holder Transfers

Content throughout this section is subject to final decision on market transfer protocol. The 'push' model would have the transfer completed by the transferor only; the 'push/pull' model requires initiation by the transferor and confirmation from the acquirer; and in the 'push, pull, match' model, both parties submit their sides of the transaction and a match happens in CITSS to confirm the completion. Until a final decision is made, the assumption in this document is that a "push" protocol will be used.

4.2.1 Transfers between two accounts held by the same General Account Holder

Compliance instrument transfers between two accounts that have the same account holder are considered administrative transfers and do not require a reported price[9].

4.2.2 Transfers between general accounts held by two different account holders

An assumption has been made that the transferring account holder will be solely responsible for reporting transfers between general account holders in CITSS (see above). Transfers between general accounts may require that price is reported[10].

4.2.3 Transfers involving intermediaries

For the purpose of this document, accounts will be structured such that the account holder is the owner of the compliance instruments held in the account, and that limited access may be provided to a broker (electronic submission agent) to act on his/her client's behalf.

4.2.4 Transfers Covered Sources use to meet their Compliance Obligations

Transfers from a covered source's general account to its compliance account are handled like any other transfer between accounts held by the same account holder (see 4.2.1). The only difference is the permanence of that action, because compliance instruments cannot be transferred back to the covered source general account.

[9] This applies if the accounts are held by single owners, but is difficult if accounts have multiple (beneficial) owners. The WCI is still investigating the structuring of brokerage accounts.

[10] Transfers between general accounts may require that price is reported.

4.3 Steps for Transferring Compliance Instruments

1. An account user with the security privilege to do so will enter the proposed compliance instrument transfer, specifying the transferring account that will be debited, the acquiring account and name (for verification), the type of compliance instrument, vintage, project i.d., when applicable, quantity of instruments to transfer, and price and currency, if applicable.

2. If the proposed transfer exceeds the amount of compliance instruments held in the transferor's account, CITSS will request a modification to the entry and not allow the transfer to proceed.

3. Depending on the approval process for the specific transfer, CITSS may require that the Alternate Account Representative of the transferring account and/or the Account Representative of the receiving account confirm the transaction. If this is the case, the system must present the Alternate Account Representative of the transferring account and/or the Account Representative of the receiving account with a notification and a confirmation page, allowing them to verify the proposed transfer or change any items before continuing. Completion of the confirmation may result in a notice to the user who initiated the transfer.

4. After all required approvals:

    a. There will be a final system check of any transfer rules prior to committing the transfer to the database, such as holding limits and accountability limits. If a limit is reached, a review, warning or error process will go into effect.

    b. If the transfer proceeds, the instruments will be debited from the transferring account and credited to the acquiring account. In addition to the transfer data defined in step 1, for audit purposes, the system will store the following audit data on the transfer record:

        - Date and time stamp of update
        - User i.d. of the user(s) who transferred or authorized the transfer from the transferring account
        - User i.d. of the person who confirmed the transfer from the acquiring account, if applicable.

5. Following the transfer of compliance instruments, any account representative who is directly affected by the transfer but was a passive participant will be notified by CITSS to

check their account for the change in balance. For example, in the “push” transfer model where the transferor initiates the transfer, the acquiring party would receive a notification.

4.4 Transfer Reversal

If a transfer is made in error, CITSS requires a transfer reversal to “undo” the transfer made in error. A transfer reversal links the ’correction’ transfer to the original transfer in error, and requests a reason for the reversal. A reference to the original transfer in error (A) will be stored in the transfer reversal log for (B), and vice versa for accounting and audit integrity.

For transfers between two account holders, the transfer must be proposed by one of the two original parties and approved by the other. The system function must clearly state that the action can only be used to reverse a transfer that was completed in error. Jurisdictions of both account holders will be notified of the transfer reversal in a daily activity summary and in any other reports that may be of interest to the market monitor.

Transfer reversals will be excluded from transfer volume statistics.

5. Compliance

All registered program participants must conform to their jurisdiction's requirements. This section outlines the compliance process as it will be facilitated by CITSS.

Key terms[11] for this section are:

- Annual verified emissions: The annual verified emissions of a given covered source. This figure is determined on a calendar year basis and is entered/imported from the jurisdiction's emissions database.

- Compliance obligation ('true-up value'): The sum of the annual verified emissions for all three calendar years within a compliance period.

5.1 The Compliance Obligation ('True-up") value

Each year, annual verified emissions per covered source are recorded in each jurisdiction's emissions database. The annual verified emissions per covered source will be imported into CITSS from the various jurisdiction emissions databases. The jurisdictions also need the ability to enter verified emissions manually in CITSS, without the import interface. The deadline of emissions entry varies by jurisdiction and will not be managed by CITSS. At its discretion, a jurisdiction can run an exception report to check if any of the verified emissions are missing for its covered sources for a given year or compliance period[12].

When the jurisdiction decides that its emissions data is complete for a compliance period, the jurisdiction has two options to identify the compliance obligation value: [Option A] enter the compliance obligation value manually or [Option B] initiate a function for CITSS to determine the compliance obligation value for each covered source by adding together its annual verified emissions for each year of the 3-year compliance period. The compliance obligation and annual verified emissions values for a given covered source will be standard data featured in the covered source account to enable covered sources and covered entities to clearly see the data that will constitute their compliance obligation at any time in the compliance period.

[11] Actual terms used by each jurisdiction may vary.

[12] A covered source will not have annual verified emissions submitted in CITSS for years prior to being "covered". If a source becomes covered part-way through a compliance period, there may be legitimate emissions data gaps at the start of the period.

CITSS will notify the covered source's account representative once the compliance obligation values have been recorded in CITSS. The notification[13] will advise the account representative to log in to CITSS for instructions on how to surrender their compliance instruments to meet the covered source compliance obligation by the compliance date. In addition to the notification, account representatives of covered source accounts will have the ability to view or query the compliance obligation value of the current, or previous compliance period(s).

5.2 Surrendering Compliance Instruments

To satisfy a compliance obligation, compliance instruments must be surrendered by the account representative of the covered source's compliance account in an amount equal to or greater than the compliance obligation by the deadline. The compliance deadline will be the set by the jurisdictions.

Account representatives may transfer compliance instruments into a covered source's compliance account at any time prior to the deadline. Once compliance instruments are in a compliance account, they cannot be transferred out by the covered source. Only the jurisdiction may approve the transfer of compliance instruments out of a covered source's compliance account.

There is no limit to the number of compliance instruments that can be transferred into a compliance account. Instruments held in compliance accounts are exempt from holding limits up to an amount equal to the emissions reported or estimated in a positive or qualified positive verification statement covering the previous annual verified emissions in a calendar year.

The jurisdictions are considering allowing the covered source account representative to choose to specify (flag) which of its compliance instruments it prefers to have the jurisdiction retire first. This functionality is still being discussed. Priority would only be considered in the case where a compliance account contains more compliance instruments than is needed for the impending obligation. On the compliance deadline, CITSS will automatically transfer compliance instruments from the covered source compliance account to the jurisdiction retirement account, based on the order outlined in section 5.3. The mix of compliance instruments retired will not exceed the maximum percentage of offset credits nor the overall compliance obligation value for a given covered source, and will not include future vintages.

[13] Notifications have two components 1) an email message sent to each account representative stating the type of notification and to log into CITSS for details, and 2) notification details in a secure notification area, available through secure sign-on to CITSS. Emails may not be used to transmit confidential data.

5.3 Retiring Compliance Instruments

Final retirement of compliance instruments occurs once the compliance instruments are transferred to the jurisdictions' retirement account.   Compliance instruments transferred to the retirement account are permanently removed from circulation (end of compliance instrument life-cycle).

At the compliance deadline, compliance instrument retirement will be initiated automatically by CITSS on behalf of each jurisdiction, transferring compliance instruments from covered source compliance accounts to the appropriate jurisdiction retirement accounts. Compliance instruments that are of a vintage within the compliance period or earlier will be retired in the following order[14]:

1. Offset credits flagged by the account representative, taking the oldest first and adhering to the maximum offset limit
2. Allowances instruments flagged by the account representative, taking the oldest first to the maximum of the remaining obligation.
3. Oldest offset credits **not** flagged by the account representative, to the maximum offset limit and remaining obligation
4. Oldest allowances **not** flagged by the account representative, to the maximum of the remaining obligation.

The covered source status will be updated to either "in compliance" or "out of compliance" depending whether it meets its compliance obligation. If there are more compliance instruments in the compliance account than required, the excess compliance instruments will remain in the compliance account.

[14] The order may be amended if policy changes. Recognised compliance instruments from other cap and trade programs are not included here. Further policy direction and refinement is needed for this instance, which is not anticipated in the first year(s) of the WCI regional cap and trade program operation.

A compliance report will be produced for each jurisdiction, based on selected compliance period:

Displaying and sorted by:

- compliance status
- covered entity
- covered source
- contact information for the covered source

Specifying:

- original compliance obligation
- number of compliance instruments retired (separated into offsets, allowances and total)
- excess emissions (described in section 5.4)
- excess emissions obligation (described in section 5.4)
- relevant balances in the covered source compliance account and general account

5.4 Non-Compliance (Excess Emissions)

For any covered source that has not met its compliance liability (has excess emissions[15]):

1. The status of the covered source and of the covered entity will be changed to “not in compliance”.
2. All accounts of the covered source and its covered entity may have their status updated to “suspended”, suspending the ability for the account representative to transfer compliance instruments to any other account than the compliance account.
3. CITSS will calculate the excess emissions obligation that the covered source must meet. The program design specifies that an excess emission obligation of three times the excess emissions (i.e. outstanding compliance obligation) must be applied to the covered source. The original outstanding compliance obligation is still required to be met by the covered source.
4. The Jurisdictions may transfer compliance instruments from the covered source’s or the covered entity’s accounts to the jurisdiction’s retirement account to cover the outstanding compliance obligation and excess emissions obligation[16]. Excess emissions obligations may be met with later vintages.

[15] “Excess emissions” is the difference between the compliance obligation and the number of compliance instruments retired.

[16] The DPD indicates that as a first course of action, the jurisdiction will deduct allowances, regardless of vintage, from the compliance account. It also indicates that offset credits will not be use (pre-supposes that the offset credit usage limit has been reached?)

5. If there are insufficient compliance instruments to meet the outstanding compliance obligation and the excess emissions obligation, the account representative of the covered source will have a period of time (i.e., 30 days) to meet its requirements.

CITSS must have the functionality to support a jurisdiction in taking any of the following administrative actions, at the jurisdiction's discretion:

- Appending notes/instructions/official document reference codes on specified accounts
- Transferring compliance instruments from the covered source's or covered entity's general account(s) into the covered source's compliance account (referred to as "deductions" in the DPD; recommend two jurisdiction e-signatures)
- Suspending the transfer out of compliance instruments from specified accounts
- Suspending the complete use of specified accounts

CITSS may also be required to hold information or notations appended to each account that will list the date and jurisdiction reference number of any previous compliance, verification or enforcement action by a jurisdiction.

5.6 Close the Compliance Period

At the end of the retirement process for a compliance period, any compliance instruments remaining in the covered source accounts can continue to be held for use in a future compliance period, regardless of vintage; they do not expire. This applies equally to compliance instruments in general accounts and compliance accounts.

Closing the compliance period is not a formal system process, but a time to produce reports of various types (to be determined), especially to summarize compliance and support reconciliation.

One suggested compliance report would summarize all retired compliance instruments at the jurisdiction level, listing the type of instrument, jurisdiction of origin, vintage, and in the case of offsets, project, with total amounts for each. This type of report will assist in reconciliation of compliance instruments across the WCI.

6. Voluntary Retirement and Cancellation of Compliance Instruments

Though mandatory compliance is the primary way in which compliance instruments will be removed from circulation, jurisdictions may also need to process voluntary retirements and may need to cancel / retire issued compliance instruments on infrequent occasions. It is important to distinguish between mandatory retirement, voluntary retirement and cancellation for administrative purposes (e.g., remedies offset invalidation, cancel excess compliance instruments). Each 'end of compliance instrument lifecycle' process has a distinct purpose, and this purpose needs to be documented to enable necessary reporting and reconciliation of issued and retired/cancelled compliance instruments. This section describes processes for ending compliance instrument circulation that are not related to compliance.

Action to permanently remove compliance instruments from circulation	Applicable to Account Types
Retirement - Mandatory	Covered Source
Retirement - Voluntary	General Market Participant
Cancellation for Administrative Purposes (e.g., administrative error or offset invalidation)	Jurisdiction

6.1 Voluntary Retirement of Compliance Instruments

Account holders may choose to retire compliance instruments voluntarily at any time. This is a different process than the retirement which occurs as part of the compliance process in that the retirement of units is not to meet a compliance obligation. The system must make the distinction very clear to avoid user confusion between selecting voluntary over mandatory retirement and vice versa.

Steps for voluntary retirement:

1. Account authorized representative selects a "Voluntary Retirement" transfer, specifying which compliance instruments to retire.
   a. It is recommended that the system interface provide a means to easily distinguish this function from regular transfers and from compliance-related retirements to minimize its selection by mistake, due to the final nature of this

function and the different outcomes between it and that of mandatory retirement (i.e. to meet a compliance obligation).

2. A confirmation page will be displayed, listing the compliance instruments to be retired, informing the authorized account representative that once the voluntary retirement has taken place, these compliance instruments will be taken out of circulation and cannot be returned and that as a voluntary retirement, the compliance instruments will not be used towards any compliance obligation.
3. Once confirmed, the compliance instruments will be transferred to the voluntary retirement account of the jurisdiction governing the account from which they are being transferred[17].
4. A notification of the transfer will be sent to the authorized account representative and to the jurisdiction.

Voluntary retirements may be reported as a separate class of data than compliance retirements and cancellations for reporting purposes.

6.2 Cancellation of Compliance Instruments for Administrative Purposes

Cancellations of compliance instruments for administrative purposes are likely to be for exceptional events. However, from an accounting and administrative perspective, it's important to have the ability to cancel compliance instruments appropriately. The following are examples where cancellation of compliance instruments may be required:

- Allowance over-issuance within budget - a jurisdiction has made an administrative error, issuing too many allowances.
- Reducing issued allowances and budget - a jurisdiction has either made an administrative error at the budget level or has chosen to reduce allowances in circulation.
- Offset invalidation - a jurisdiction may (a) reverse all or a portion of an offset project's issued offset credits or (b) the jurisdiction may cancel an equivalent number of compliance instruments to restore the environmental integrity of issued offset credits that are subject to invalidation.

Cancellations will be reported as a separate class of data than retirements, as cancellations are not accounted in compliance.

[17] Assumption that in Voluntary Retirement, account holders will not have a choice which jurisdiction will be the recipient of the voluntary retirement – it will go to the jurisdiction with authority over the account. This also assumes that the compliance instruments' jurisdiction of origin is irrelevant.

6.2.1 Allowance Over-Issuance within Budget (Budget Unaffected)

If a jurisdiction has made an error by issuing more allowances than it had planned for a single issuance but is still within its overall budget, the following steps are taken:

1. Jurisdiction administrator or authority verifies that the excess allowances are still in the jurisdiction's accounts.[18]

2. The jurisdiction authority selects a transfer that indicates this is a cancellation due to over-issuance and specifies which instruments to cancel and any further notes regarding the reason for cancellation.

3. A second jurisdiction authority will be notified of a requirement to complete a confirmation page, which lists the compliance instruments to be cancelled (including vintage), and notes that once the cancellation has taken place, these compliance instruments will be taken out of circulation permanently.

4. Upon second authority approval, the system will move the compliance instruments from the jurisdiction's general or issuance account to the jurisdiction's cancellation account with the recorded reason.

6.2.2 Reducing Issued Allowances and Budget (Budget Affected)

If a jurisdiction must reduce the budget and corresponding number of issued allowances in circulation:

1. Jurisdiction authority verifies that the jurisdiction holds the amount of available allowances to be reduced in the right vintage in either the issuance or general account as per the jurisdiction's design (i.e., not retired or cancelled, not pending for use in an auction or held in an account with a specific and defined purpose, such as an offset contingency account). If allowances are already in circulation, the jurisdiction may choose to reduce planned (future) issuances.

2. The jurisdiction administrator/authority proposes a reduction in the allowance budget for the given period, noting the reason. The appropriate amount of allowances of the right vintage is held for transfer to the cancellation account, pending approval.

3. A second jurisdiction administrator/authority will be notified of a requirement to complete a confirmation page, which lists the allowances to be cancelled, and notes that

[18] For control purposes, it may be best to always cancel from only one jurisdiction account, e.g., general or issuance.

once the cancellation has taken place, these allowances will be taken out of circulation permanently.

4. Upon authority approval, the system will move the allowances from the jurisdiction's account to the jurisdiction's cancellation account with the recorded reason and will record a new version of the budget.

6.2.3 Offset Invalidation/Reversals

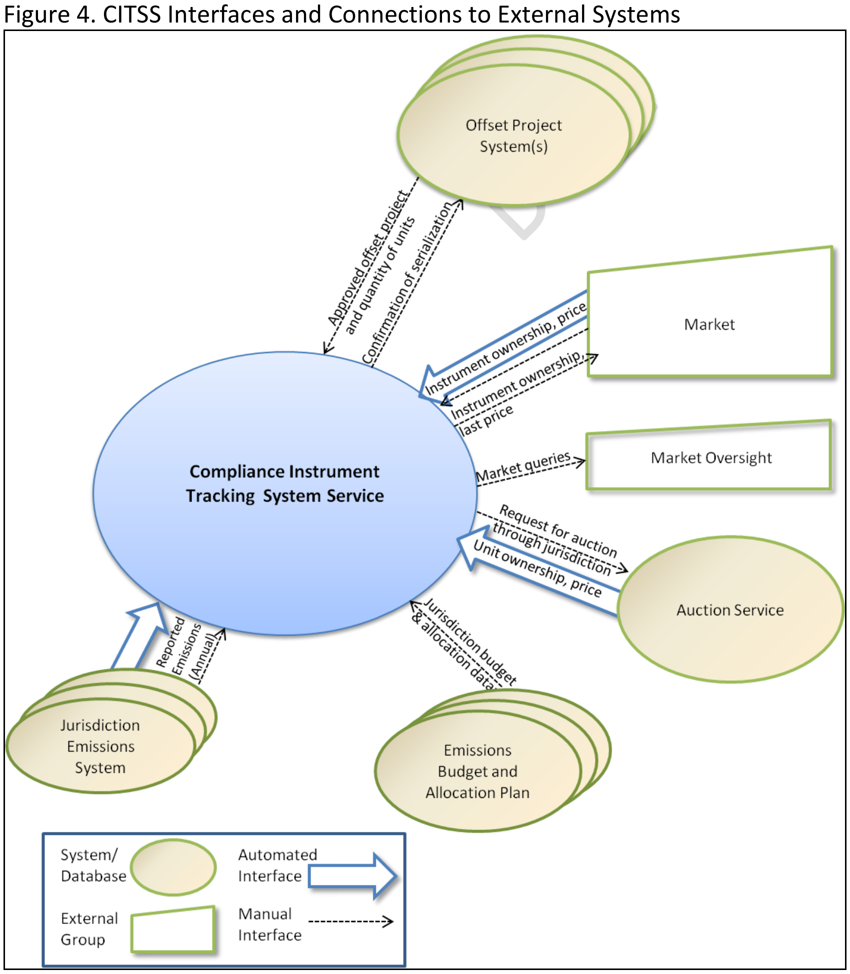
To support possible actions related to offset invalidation / reversals, CITSS must provide the capability of reporting all accounts holding offset credits from a particular offset project, including accounts that are closed or restricted (e.g. compliance accounts, retirement account of another jurisdiction, etc.). There must also be a means of extracting data to enable communication with the account holders.

7. Interfaces

Further to the processes defined in sections 1 to 6, this section provides a consolidated overview of the interface requirements of CITSS with respect to its connection to external systems. Export interfaces will be files generated in CITSS to send to other systems, while import interfaces will be files generated by external systems for input into CITSS. In some cases, the interface will not require a file – only that both systems share common key data to provide the ability to look up information (e.g., offset project number).

In the following diagram, CITSS is represented in blue and other related systems as ovals. Markets and Market Oversight have been included as external groups that may require automated interfaces but they are not defined systems. The arrows represent interfaces. Data best suited to be entered into CITSS through automated interfaces are identified by large blue arrows and data that can be entered manually or viewed by an external source without creating a file exchange are identified by black, dotted arrows. In some cases, like emissions reporting, both automated and manual interfaces are anticipated. Details of the interfaces follow in sub-sections 7.1 to 7.5.

Figure 4. CITSS Interfaces and Connections to External Systems



7.1 Auction Interfaces

Allowance auctions will be carried out through an auction service provider four times per year as coordinated among jurisdictions.

This section discusses, from the perspective of CITSS, the processes required to provide necessary data to support the auctions and to receive auction results data for input into CITSS. The auction service provider will receive data about registered bidders from the tracking system in a suitable and secure electronic format prior to the auction. The auction service provider will prepare and send post-auction results to the tracking system in a suitable and secure electronic format.

7.1.1 Process to Prepare for Auction and Auction Export Interface

The following CITSS-related process steps will be taken in preparation for an auction:

1. Jurisdictions will identify the number of allowances they intend to auction at a given time and transfer these into a separate account or as a separate entry in the jurisdiction auction account. (Note: This entry will be the control number used to verify the completeness of auction results imported back into CITSS via the results interface.)

2. In advance of the auction, prospective auction participants must qualify and indicate their intent to bid with the auction service provider. As part of auction qualification, prospective participants must provide their CITSS user i.d. and CITSS general account name and number to which their auction acquisitions will be deposited. Any party interested in participating in an auction that does not yet have a CITSS user i.d. and general account must first obtain them before their registration form may be submitted.

3. The auction service provider will require limited access to data in CITSS to:
   - Confirm that the prospective bidder exists in CITSS
   - Confirm that the account provided in the auction registration form either belongs to the applicant or that the applicant has authority to purchase allowances on the owner's behalf
   - Confirm that the general account provided is in good standing

Export Interface to Auction Service Provider

Selected bidder information from CITSS will be sent via export file to the auction service provider to support the auction (may include account numbers, purchase limits, etc.). This transfer of information will need to be consistent with jurisdictions' privacy and security requirements.

7.1.2 Process for Inputting Auction Results and Auction Import Interface

After the auction has been closed, auction results have been approved and payments have been processed, the following CITSS-related process steps will be taken to process the auction results and reflect the change of ownership of the allowances in CITSS:

1. The auction service provider will create encrypted auction results files for each jurisdiction.

2. The auction service provider will use a secure file transfer protocol to transmit the auction result data to the CITSS platform.

3. The import program will check the totals in the import file against the jurisdiction control amount for the auction.

4. The regular check of any holding limits will be conducted as part of the update.

5. For entries that meet all rules and any limits, CITSS will update individual accounts with the winning auction bids by transferring allowances to the general account designated by the winning bidder.

Import Results Interface from Auction Service Provider
The auction service provider will send a separate file to each jurisdiction with only its own auction results, listing for each winning bid, CITSS i.d., CITSS general account number, number of allowances purchased, price, and currency.

7.2 Offset Information System Interfaces

Service requirements for offset information system(s) are in development. An offset information system records integral offset project data and relevant documentation associated with an offset project: from validation and registration of a project to monitoring and quantification, reporting, verification, certification, and proposed issuance of offsets.

7.2.1 Input of Offset Project Data from the Offset Information System

It is anticipated that at the initial implementation of CITSS, input of information from the Offset Information System for the purpose of offset credit issuance will be managed manually through simple data entry. The anticipated volume of approved offset projects does not warrant an automated interface.

Once an offset project is certified by a jurisdiction in the Offset Information System, to receive issued offset credits the offset project developer must apply for a CITSS account (if it does not already have one), identifying account representatives, including CITSS user i.d.s, as per Section 1 - Accounts.

Once the offset project developer has specified an account for deposit, the CITSS administrator will issue serialized offset credits to the jurisdiction issuance account and transfer them to the offset project developer's account.

7.2.2 Enabling Look-ups on the Offset Information System

The issuance record will hold relevant project data in CITSS to enable a link with the Offset Project Information system. This will allow market participants to research offset project information associated with any issued offset credit.

Ideally, it would be "nice to have" the ability to mouse click on an offset project code in CITSS and to get a new browser instance with a public page for the project on the Offset Information System.

It is important to note that CITSS will only contain basic offset project information such as the unique project identification code – the Offset Information System contains the detailed information about offset project history, validation, verification etc.

7.3 Market Interface

While inbound data in the form of transfers of compliance instruments is a known requirement, market processes could take different forms such as over-the-counter transactions or transactions stemming from an exchange. CITSS must allow for batch entry of transfers from trusted market sources.

7.4 Market Oversight Access

In order to monitor the marketplace effectively, one or more market monitors may require direct online access, or request all relevant data from a jurisdiction(s). Some of this data will include confidential personal information and would therefore need to be handled according to jurisdictional privacy requirements. Market oversight will require an outbound interface (streaming, export or other form of file transfer) from CITSS as well as the ability for the monitor to perform queries.

7.5 Emissions Information System Interfaces

Each jurisdiction has an emissions reporting system or database used to record the annual reportable emissions of sources. Jurisdictions will use this data to determine which sources must be covered under the cap and trade program (‘covered sources’) based on the rules/regulations of the jurisdiction (e.g., sources above an emissions threshold are subject to the cap and trade regulation).

While the jurisdictions’ systems do not share a common data structure or platform, regional data standards are in place for measurement of emissions and key identifiers (e.g., industry codes), which makes data sharing possible with a regional system like CITSS.

At this time, there is no need for data transfers from CITSS to the emissions databases. However, there are two times that data from the emissions databases may be needed for reference in CITSS: (1) covered source account opening, (2) entry of annual verified emissions, and any changes (e.g., in the event of a revised verification).

7.5.1 Input of Covered Source data into CITSS

When a new covered source account is created in CITSS the basic ‘tombstone’ data identifying the covered source must be the same as that data in the jurisdiction emissions database. This may mean that a CITSS Jurisdiction Administrator needs to do a simple look up on the emissions database or refer to a report. Covered source data needs to be synchronized between the systems when changes occur to identifying data such as its operator, the operator’s representative, contact information, associations and affiliations.

Data to reference in emissions systems:

- Covered Source identifier (for entry into CITSS for future cross reference)
- Covered Entity identifier (for entry into CITSS for future cross-reference)
- Covered Entity legal name
- Covered Entity contact name, address, phone numbers, etc.
- Covered Entity associations (e.g. parent company, subsidiaries, etc.)
- Industry Code (NAICS)

7.5.2 Input of Emissions data into CITSS

The second interface from the emissions systems is required to enter annual verified into CITSS to ensure covered sources will cover their compliance obligation fully. While this can be accomplished through direct data entry into CITSS, an interface file to transfer (upload) emissions data into CITSS is preferred, both for security and accuracy.

Data required in the emissions interface file:

- Jurisdiction
- Period Ending (annual)

- Covered entity identifier
- Covered entity legal name
- Covered Source identifier
- Annual verified emissions (tCO2e)

8. Reports

Reports are needed to serve a number of purposes, from transactional and ad hoc administrative reports to management, public, and executive reports.

CITSS will need to deliver some reports on-screen, like notifications and confirmations, and other more traditional reports both on-screen and in pdf format. On-screen reports that are formatted as lists with columns should have a feature to allow sorting by clicking on most column headings.

It is expected that selected reports will have accompanying selection and parameter screens to allow the user to tailor the report request.

Reports listed in this section do not include extract files listed in the Interface section.

The reports listed here are not yet comprehensive. At this point, report planning is still at a conceptual stage and will be further developed with the final completion of requirements.

8.1 Administrative Reports and Notifications

Administrative reports are required to ensure the flow of day-to-day business. Most of these reports and notifications are referenced in the process sections of this document and are issued as part of a system function.

8.1.1 Jurisdiction Administrative Reports and Notifications

- Confirmation of Budget – a one-page summary of a jurisdiction's budget entry awaiting approval
- Confirmation of Issuance – a one-page confirmation of an issuance awaiting approval
- Confirmation of Allocation – a confirmation page of a jurisdiction's proposed allocations awaiting approval
- Confirmation of Compliance Results – a confirmation page of a jurisdiction's compliance results for a compliance period

8.1.2 Account Holder Reports and Notifications

- Notification of compliance instrument acquisition – sent to the acquiring account representative when the transferor completes the transfer
- Notification of compliance instrument transfer - would only be required if the completion of the transfer depends on confirmation from another party. If the model is "push" only, the transferor will receive confirmation on-screen as a result of his/her actions.

- Account summaries (ad hoc requests available to account representatives and electronic submission agents with access)
    - All acquisitions and transfers over a time period
    - Acquisitions over a time period
    - Transfers over a time period
        - To general accounts within portfolio (group of accounts)
        - To other account holders
        - Surrenders for compliance
        - Retirements from compliance accounts
        - Voluntary Retirements and Cancellations

8.2 Management Reports

Management reports are required so that a jurisdiction's work is managed effectively (assists in environmental compliance, work planning, financial and resource management, etc). Reports under this section would be generated exclusively for individual jurisdictions and would not be viewable by other CITSS users.

8.2.1 Work Flow and Management Reports

- Summarized balance of holdings of covered source and general participant accounts tied to a jurisdiction, with breakdown by type of compliance instrument (one page)
- Summary of transfers by compliance instrument type over a time period (one page).
- For any year / compliance period, allocations, annual emissions, true-up (compliance obligation) amount and compliance instruments surrendered for each compliance account or for all compliance accounts.
- Preliminary compliance status reports after true-up date and a final compliance status reports 30 day after the true-up date (including outstanding obligation and excess emissions obligation if applicable).
- Daily transaction summary for a period of time (e.g. option to select per day summary or daily average, reporting over a period of time [week , month, quarter, year], reporting daily volume and value by transfer type, with optional breakdown by user group [jurisdiction, covered source, general account holder])
- Number of new accounts created per day in a given time period.
- Summary of offset credit issuances in a given time period.
- Covered entity/general account holder listing of associations and affiliations.

8.2.2 Financial, Reconciliation and Audit Reports

- Jurisdiction compliance instrument summary at a point-in-time, with balances of each jurisdiction account (e.g. issuance, auction, reserve, holding, retirement, voluntary retirement, cancellation), and balance of jurisdiction allowances and offset credits in circulation (in accounts governed by jurisdiction and in accounts outside jurisdiction).
- Summary of origin of holdings in the jurisdiction accounts and jurisdiction governed accounts (i.e. which jurisdiction compliances instruments originated)
- Listing of covered entity/covered source accounts at a point in time (end of business day): balance, number of allowances, number of offset credits, number of transfers (credits, debits)
- Number of transfer reversals in a time period with summary of reasons.

8.3 Market Monitor Reports

Market monitoring reports are required to ensure that the independent market monitor has access to the information in CITSS. Reports under this section would be generated exclusively for the market monitor and would span every jurisdiction in CITSS. The information below is an example of the information CITSS would need to report to the market monitor. It is anticipated that additional information may be requested by the independent market monitor.

- Summarized balance of holdings of accounts
- Summary of transfers by compliance instrument type over a time period.
- Detailed and up-to-date information for each account in CITSS, including covered entity/general account holder information, current compliance instrument ownership, beneficial ownership information, and listing of associations and affiliation.
- Detailed transaction information for a period of time (e.g. option to select per day summary or daily average, reporting over a period of time [week , month, quarter, year]) which includes: counter-parties, daily volume, price, date and time-stamp,

8.3 Public Reports

Information released to the public in online reports is dependent on what information jurisdictions can publicly release, depending on jurisdiction privacy laws and privacy impact assessment. This is a preliminary list of proposed reports for consideration that may be posted publicly on the CITSS unsecured website.

- Allocation Plan and History of Changes (per jurisdiction and across WCI)
- Compliance Summary
- Accounts Search
    - Lists: Jurisdiction, account name, account type, account holder, authorized representative.
- Covered Source Search
    - Lists: Jurisdiction, account holder, covered source name and number, account type, NAICS code, compliance status, link to view compliance details of current and past compliance periods.

8.4 Executive/Business Intelligence

Additional reports may be required that would assist WCI jurisdictions in assessing operational or policy issues. An extract file may be needed to provide the foundation for an external business intelligence database, which would support WCI jurisdictions in policy planning and future directions.

9. Non-functional Requirements

This section focuses on the non-functional requirements of the Compliance Instruments Tracking System of the WCI cap and trade program, with particular attention to the user interface, technical, security, and financial service related requirements for CITSS.

9.1 User Interface

These basic user requirements are over-arching and must be kept in mind throughout the system design process.

9.1.1 Usability

The tracking system must be designed with its intended users in mind so that actions can be performed easily and without making errors. The tracking system must provide user-friendly interfaces for its customization and operation.

9.1.2 Multi-language

The tracking system must be fully multilingual and must be available at least in English and in French from the beginning. Support for other languages might be required later on.

9.2 Technical Requirements

9.2.1 Extensibility

9.2.1.1 Compatibility

The tracking system must be able to share data easily with various internal and external systems, particularly any required external databases, such as existing emissions reporting.

It is important to keep in mind that any “live” link between the CITSS and an external system may be expensive and take considerable time to implement; asynchronous transfers such as batch XML files imports tend to be simpler and cheaper to develop.

9.2.1.2 Customization

Within certain boundaries specified in the functional requirements document, the overall look and feel (skin) of the system and reports (wrapper), language, the

CITSS registration forms, the accounts naming scheme, and various transaction rule parameters must be customizable.

9.2.1.3 Flexibility

The tracking system shall be developed with possible future integration in mind, in particular with other cap-and-trade programs in Canada, the U.S. or the E.U.

9.3 Security Requirements

9.3.1 Standards Compliance

Critical systems such as CITSS are subject to security standards compliance. For example, any system dealing with credit card numbers is required to abide by the PCI-DSS standard (Payment Card Industry). Even though the tracking system will not deal directly with credit cards and money, it will be the record of ownership of compliance instruments, which have value. Strong security standards are required to prevent theft and illegal manipulation of the instruments and accounts.

Another widespread security standard, ISO 27001, describes thoroughly the best practices for the information security field. One can formally certify its information security management system against the ISO 27001 standard by commissioning an independent auditor to perform a fully documented audit on a regular basis.

If the WCI members prefer not to impose PCI-DSS compliance to the service provider of the tracking system because of its tight coupling with the credit cards industry, requiring the service provider to demonstrate ISO 27001 compliance with complete documentation disclosure could be a valuable alternative.

CITSS must also be designed considering relevant best practices and recent developments in tracking system operations to mitigate security risks. For example, CITSS design should consider the relevance of the "Proposal to change rules on EU ETS registry infrastructure" http://ec.europa.eu/clima/news/articles/news_2011050501_en.htm

Some questions related to this topic are:

- Is there government regulation in any of the WCI jurisdictions stating which standards must be followed for a sensitive financial information system?
- If not, what would be a minimum acceptable requirement for each jurisdiction?

9.3.2 Confidentiality

Confidentiality means to prevent the disclosure of information to unauthorized individuals or systems. For example, filling a tracking system application form on the Internet requires personal information to be transmitted from the user's computer to the CITSS servers. The system should enforce confidentiality by encrypting the user information during transmission, by limiting the places where it might appear (in databases, log files, backups, printed receipts, and so on), and by restricting access to the places where it is stored. If an unauthorized party obtains personal information in any way, a breach of confidentiality has occurred.

A thorough analysis of which information assets are considered personal or sensitive should be conducted to ensure confidentiality is properly addressed. Confidentiality is necessary (but not sufficient in itself) for maintaining the privacy of the people and corporations whose personal or confidential information is held in CITSS.

9.3.3 Integrity

Transaction integrity means that data cannot be modified undetectably. All system actions should be audit stamped with the user name and date of the action (transaction).

Data integrity in a quasi-financial system is achieved with accountability of the units of value, in this case, compliance instruments. It is important that every compliance instrument be serialized with a unique number that is traceable such that the status of the instrument is known and that it can only exist in one account at a time.

A jurisdiction should be able to prove ownership of specific instruments at any given time in the system's history through the CITSS data. It is critical (i.e., zero tolerance for errors) that at any given time, the system holds the right amount of instruments in the correct accounts.

9.3.4 Non-repudiation

Non-repudiation is a method by which the sender of data is provided with proof of delivery and the recipient is assured of the sender's identity, so that neither can later deny having processed the data. It is a way to avoid denial of transactions.

In law, non-repudiation implies one's intention to fulfill their obligations to a contract. It also implies that one party of a transaction cannot deny having received a transaction nor can the other party deny having sent a transaction.

Electronic commerce uses technology such as digital signatures and encryption to establish authenticity and non-repudiation.

For CITSS, here are a few examples of requirements that could lead to satisfactory non-repudiation:

- Strong user authentification mechanism in place. This likely means that more is required than the usual username/password strategy. Examples of potential strategies are multi-factor authentification, digital signatures and SecurIDs
- Strong encryption of all data transmitted over the network
- Pro-active “approval” of any transfer by both parties involved
- Complete logs of everything that occurs in the system
- Management and operational processes that guarantee the integrity and non-repudiation of the logs themselves.

9.3.5 Authentication

In computing, e-Business and information security it is necessary to ensure that the data, transactions, communications or documents (electronic or physical) are genuine. It is also important for authenticity to validate that both parties involved are who they claim they are.

9.3.6 Personal Information Protection[19]

Protection of personal information is a high priority for WCI Partner jurisdictions. CITSS will be designed to ensure information is managed in accordance with WCI Partner jurisdiction requirements and legislation.

[19] Please refer to a Canadian federal government document: “Guidance Document: Taking Privacy into Account Before Making Contracting Decisions” (http://www.tbs-sct.gc.ca/atip-aiprp/tpa-pcp/tpa-pcp01-eng.asp)

Western Climate Initiative

Draft Offset Protocol Review and Recommendation Process

July 14, 2011

The Western Climate Initiative (WCI) Partner Jurisdictions have recommended the establishment of a robust and transparent process to review and recommend offset protocols that meet the requirements for the regional emissions trading and offset program. This paper presents draft recommendations for the: 1) identification of candidate protocols, 2) evaluation of protocols by expert task teams, 3) public consultation on candidate protocols and 4) recommendation of candidate protocols for adoption by WCI Partner Jurisdictions.

The WCI Partner Jurisdictions will build on the extensive work of other individuals and organizations, sound science, and standard greenhouse gas accounting practices to revise and update existing protocols to meet the geographic, regulatory, technological and sectoral scope of the WCI regional emissions trading and offset program. WCI Partner Jurisdictions will consider protocols recommended by this WCI protocol review process for incorporation or inclusion in their state or provincial approaches to implement the regional emissions trading and offset program. Issues regarding intellectual rights related to existing protocols will be examined on a case-by-case basis.

The preference of the WCI Partner Jurisdictions is to recommend a single protocol for each project type and the WCI Partner Jurisdictions recognize this may not be feasible or practical in all applications.

The WCI Offsets Committee (Committee) will carry out the review and recommendation process based on the prioritization of project types and protocols determined by the WCI Partners.

Four main steps are recommended in the process to allow Partner Jurisdictions to demonstrate to the market and public that their process is rigorous and transparent.

1. Identification of a candidate protocol
2. Evaluation of a candidate protocol
3. Public consultation
4. Recommendation of a candidate protocol

1. Identification of a candidate protocol

In order to be considered for review, a candidate offset protocol must be nominated by a WCI Partner Jurisdiction. The WCI Partner Jurisdictions will establish a list of candidate protocols under review and scheduled for review, and make that list known to stakeholders. Partner Jurisdictions will agree on the scheduling of reviews and any additions to the established list of project types over time.

When jurisdictions nominate an additional candidate protocol, it will be added to the established list in a priority agreed by Partner Jurisdictions. When more than one candidate protocol for a project type is nominated they will be evaluated simultaneously. When there is more than one candidate protocol with different geographic coverage the committee may recommend multiple candidate protocols providing there is no overlapping geographic coverage and the methodologies (baseline, monitoring, quantification, additionality, etc…) are compatible. The Committee work will proceed on direction of the WCI Partner Jurisdictions and as time and resources allow.

2. Evaluation of candidate Protocol

After a candidate protocol is identified, it will be evaluated in regards to its alignment to the WCI design. A task team will be established consisting of relevant staff from each WCI Partner Jurisdiction. There will be an initial review of legislation and common practice in each Partner Jurisdiction to determine suitability of the protocol across the WCI region. At this step, WCI Partner Jurisdictions will assign whatever resources are required to complete the work.

At any point in the evaluation process the task team may consider seeking additional technical advice from expert advisors to inform the candidate protocol evaluation process and may develop white papers, hold webinars or workshops to seek broader stakeholder input on aspects of interest to the team or the WCI Partner Jurisdictions. A project manager will be assigned or hired for each candidate protocol evaluation process and the task team may draw on administrative support when necessary throughout the protocol evaluation process.

Once the task team is established they will evaluate the candidate protocol. The candidate protocol will initially be evaluated against the high level criteria in the WCI design:

- Definition of project scope
- Eligibility /additionality requirements
- GHG quantification method
- GHG emissions reduction method
- Monitoring and verification method
- Permanence
- Leakage

The candidate protocol will be further evaluated against the more detailed criteria recommended by the WCI Partner Jurisdictions within the high level criteria listed above. This two phase evaluation will be customized to the specific characteristics of each project type. This evaluation will deliver a gap analysis identifying where the candidate protocol aligns with WCI design and where it does not align.

At the end of the evaluation the task team will reach a consensus opinion based on the results of the work and the gap analysis and will make one of the following recommendations to WCI Partner Jurisdictions for consideration:

A. Recommend
   The task team can demonstrate that the candidate protocol meets all the requirements of the WCI design and that it can be applied in all WCI Partner Jurisdictions. The candidate protocol should Proceed with Public Consultation (Step 3).

B. Reject
   The task team cannot demonstrate that the protocol meets all the requirements of the WCI design and that it can be applied in all WCI Partner Jurisdictions. The candidate protocol should not proceed. Reasons for rejection may include:
   - not within the scope of the WCI offset system,
   - lack of necessary scientific or technical information,
   - unable to manage leakage or permanence,
   - Extremely low potential for offset creation,
   - There is already a recommended protocol of the same type.

C. Revise
   The task team can demonstrate that the candidate protocol could meet all the requirements of the WCI design and that it could be applied in all WCI Partner Jurisdictions with reasonable revision. The task team will identify the gaps in the protocol and propose how to resolve those gaps including resources required in a proposed work plan for revisions. This could include consolidating a number of protocols using the elements that best fit WCI design standards. The proposal will include a timeline and budget for resources required to complete the revisions. The task team will be as detailed as possible in describing the work that is required to produce a revised candidate protocol. The proposed workplan will be provided to the WCI Partner Jurisdictions for approval.

   After WCI Partner approval of the recommended approach to revise the protocol the task team will begin the revision process. The revision may include options papers, workshops, working groups, webinars or consultations on certain areas of the protocol. Consultations may include discussions with expert advisors, integration of public comment and stakeholder feedback. The result of this process will be a revised candidate protocol to WCI Partners for approval to move on to public consultation. The revised candidate protocol may include options in specific sections where an approach is not agreed upon by all WCI Partner Jurisdictions.

3. WCI Public Consultation

When WCI Partner Jurisdictions receive a recommended candidate protocol or revised candidate protocol, the WCI Partner Jurisdictions will post the document for public consultation. The candidate protocol will be posted to the WCI website and a joint WCI webinar will take place within 2 weeks of posting. There will be minimum 30 day consultation period where stakeholders may submit comments on the document. This public consultation will serve to provide input in the development of a WCI recommended Protocol and each WCI Partner Jurisdiction may carry out stakeholder engagement within their jurisdiction at any time during or after the WCI joint engagement process.

The task team will summarize stakeholder comments and integrate relevant proposed changes into a revised candidate protocol.

4. Recommendation of a candidate protocol

The WCI Partner Jurisdictions will review a revised candidate protocol incorporating stakeholder comments and will consider recommending it for use by WCI Partner Jurisdictions in the regional emissions trading and offsets program. The recommended protocol will be posted on the WCI website.

The recommended protocol will be available for adoption into the rules and regulations of individual WCI Partner Jurisdictions. Each WCI Partner Jurisdiction will follow its own procedures to incorporate the recommended protocol into its rules or regulations including the public comment process requirements of their own jurisdictions. Jurisdictions may need to make revisions to the recommended protocol to incorporate it into their respective rules or regulations and to maintain transparency, each WCI Partner Jurisdiction will keep other jurisdictions informed of revisions. As needed, WCI Partners will address concerns regarding revisions made by individual jurisdictions.

July 14, 2011 Draft Offset Protocol Review and Recommendation Process

List of Commenters

CE2 Capital Partners

Coalition for Emission Reduction Policy

International Emissions Trading Association

International Performance Assessment Center for Geologic Storage of CO2

Pacific Forest Trust

The Delphi Group

Union of Concerned Scientists

Verified Carbon Standard

Waste Management

Western Climate Initiative

DRAFT Offset Protocol Review and Recommendation Process

WCI Stakeholder Call

July 20, 2011

To join the call, dial **1-800-868-1837** toll free in the US and Canada (1-404-920-6440 outside the US and Canada) and enter participant code **753491#.**

DRAFT process

1. Identification of a candidate protocol
2. Evaluation of a candidate protocol
3. Public consultation
4. Recommendation of a candidate protocol

Identification of a candidate protocol

- Candidate protocol nominated by a WCI Partner Jurisdiction
- Candidate protocol added to established list of protocols in agreed priority
- Offsets Committee works through established list as time and resources allow

Identification of a candidate protocol

- When more than one candidate protocol is nominated they will be evaluated simultaneously
  - Offsets Committee may recommend multiple protocols providing there is no overlapping geographic coverage and the methodologies (baseline, monitoring, quantification, additionality, etc…) are compatible

Evaluation of a candidate protocol

- Offset Committee will establish a task team of WCI Partner Jurisdiction staff for each protocol
- Assign task team lead and project manager
- Carry out cross-jurisdictional regulatory analysis
- Review protocol against design criteria
  - may include options papers, workshops, webinars
- Consult expert advisors as necessary
- Provide recommendation to WCI Partner Jurisdictions

Evaluation of a candidate protocol

- Offset Committee may:
  - Recommend
    - candidate protocol moves forward to public consultation
  - Reject
    - candidate protocol does not move forward
  - Revise
    - task team proposes gap analysis and work plan
    - may propose options papers, workshops, webinars for specific candidate protocol components
    - revised candidate protocol moves forward to public consultation

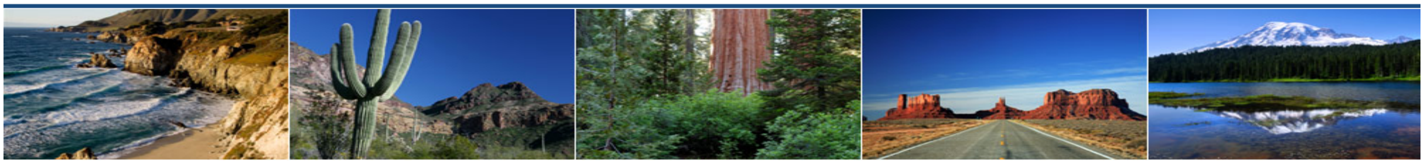
Public consultation

- WCI Partner Jurisdictions receive candidate or revised candidate protocol with recommendation to post for public consultation
- Public posting for minimum of 30 days
  - available on central website (WCI Partner Jurisdictions optional)
  - joint webinar (WCI Partner Jurisdictions may run simultaneous consultations)
- Summary of public comments
- Task team revises candidate protocol to reflect relevant comments

Recommendation of a candidate protocol

- WCI Partner Jurisdictions consider recommending revised candidate protocol for use by all WCI Partner Jurisdictions
- Protocol available on central website
  - WCI Partner Jurisdictions may post individually
- Recommended protocol considered for adoption into rules and regulations of WCI Partner Jurisdictions
- Individual WCI Partner Jurisdictions inform each other of any protocol modifications necessary during adoption into rules and regulations

Western Climate Initiative



Final Offset Protocol Review and Recommendation Process

December 19, 2011

An efficient offset system consistent across WCI Partner Jurisdictions will ensure an adequate supply of low cost, high quality offsets for the region.

The Partner jurisdictions of the Western Climate Initiative (WCI) today release the final process to review and recommend offset protocols for adoption by WCI Partner jurisdictions. Working together, the Partner jurisdictions that comprise the WCI have forged a comprehensive strategy to mitigate climate change that will spur investment in clean-energy technologies, create green jobs and reduce independence on import oil. When fully implemented, the plan will reduce GHG emissions to 15 percent below 2005 levels by 2020.

The Western Climate Initiative (WCI) Partner jurisdictions have recommended the establishment of a robust and transparent process to review and recommend offset protocols that meet the requirements for the regional emissions trading and offset program. This paper presents final recommendations for the: 1) identification of candidate protocols, 2) evaluation of protocols by expert task teams, 3) public consultation on candidate protocols and 4) recommendation of candidate protocols for adoption by WCI Partner jurisdictions.

The WCI Partner jurisdictions will build on the extensive work of other individuals and organizations, sound science, and standard greenhouse gas accounting practices to revise and update existing protocols to meet the geographic, regulatory, technological and sectoral scope of the WCI regional emissions trading and offset program. WCI Partner jurisdictions will consider protocols recommended by this WCI protocol review process for incorporation or inclusion in their state or provincial approaches to implement a regional emissions trading and offset program.

The preference of the WCI Partner jurisdictions is to recommend a single protocol for each project type and the WCI Partner Jurisdictions recognize this may not be feasible or practical in all applications. The WCI Offsets Committee will carry out the review and recommendation process based on the prioritization of project types and protocols determined by the WCI Partner jurisdictions. The four main steps recommended in the process allow Partner Jurisdictions to demonstrate to the market and public that their process is rigorous and transparent.

The final process reflects input from stakeholders and is available on the WCI website. There were no significant change to the content of the paper. There were small editorial changes throughout the document for clarity and Step 3 was revised for readability.

1. Identification of a candidate protocol

In order to be considered for review, a candidate offset protocol must be nominated by a WCI Partner jurisdiction. The WCI Partner jurisdictions will establish a list of candidate protocols under review and scheduled for review, and make that list known to stakeholders. WCI Partner jurisdictions will agree on the scheduling of reviews and any additions to the established list of project types over time.

When WCI Partner jurisdictions nominate an additional candidate protocol, it will be added to the established list in a priority agreed by WCI Partner jurisdictions. When more than one candidate protocol for a project type is nominated they will be evaluated simultaneously. When there is more than one candidate protocol with different geographic coverage, the committee may recommend multiple candidate protocols providing there is no overlapping geographic coverage and the methodologies (baseline, monitoring, quantification, additionality, etc.) are compatible. The WCI Offsets Committee work will proceed on direction of the WCI Partner jurisdictions and as time and resources allow.

2. Evaluation of candidate protocol

After a candidate protocol is identified, it will be evaluated in regards to its alignment to the WCI design. A task team will be established consisting of relevant staff from each WCI Partner jurisdiction. There will be an initial review of legislation and common practice in each WCI Partner jurisdiction to determine suitability of the protocol across the WCI region. At this step, WCI Partner jurisdictions will assign whatever resources are required to complete the work.

At any point in the evaluation process the task team may consider seeking additional technical advice from expert advisors to inform the candidate protocol evaluation process and may develop white papers and hold webinars or workshops to seek broader stakeholder input on aspects of interest to the team or the WCI Partner jurisdictions. A project manager will be assigned or hired by the WCI for each candidate protocol evaluation process and the task team will draw on administrative support when necessary throughout the protocol evaluation process. The task team lead, similar to the chair of the WCI Offsets Committee, will serve as the primary point of contact for providing input on the task team's work.

Once the task team is established, the candidate protocol will be evaluated. The candidate protocol will initially be evaluated against the WCI criteria as defined in the WCI *Offset System Essential Elements Final Recommendations Paper* and the WCI *Detailed Design*:

- Definition of project scope
- Eligibility/additionality requirements
- GHG quantification method
- GHG emissions reduction method
- Monitoring and verification method
- Permanence
- Leakage

The candidate protocol will be further evaluated against the more detailed criteria recommended by the WCI Partner jurisdictions within the high level criteria listed above. This two phase evaluation will be customized to the specific characteristics of each project type. This evaluation will deliver a gap analysis identifying where the candidate protocol aligns and does not align with WCI design.

At the end of the evaluation, the task team will reach a consensus opinion based on the results of the work and the gap analysis and **will make one of the following recommendations to WCI Partner** jurisdictions for consideration:

A. Recommend
   The task team concludes that the candidate protocol meets all the requirements of the WCI design and that it can be applied in all WCI Partner jurisdictions. The candidate protocol should proceed with public consultation (Step 3).

B. Reject
   The task team concludes that the protocol does not meet the requirements of the WCI design and/or that it is not appropriate for WCI Partner jurisdictions. The candidate protocol would not proceed further. Reasons for rejection may include:
   - not within the scope of the WCI offset system,
   - lack of necessary scientific or technical information,
   - unable to manage leakage or permanence,
   - extremely low potential for offset creation,
   - a protocol for the same project type already recommended.

C. Revise
   The task team concludes that the candidate protocol, with reasonable revision, could meet all the requirements of the WCI design and that it could be applied in all WCI Partner jurisdictions. The task team will identify the gaps in the protocol and propose how to resolve those gaps including resources required in a proposed work plan for revisions. This could include consolidating multiple protocols using the elements that best fit WCI design standards. The proposal will include a timeline and budget for resources required to complete the revision. The task team will be as detailed as possible in describing the work that is required to produce a revised candidate protocol. The proposed workplan will be provided to the WCI Partner jurisdictions for approval.

   After WCI Partner approval of the recommended approach to revise the protocol, the task team will begin the revision process. The revision may include options papers, workshops, working groups, webinars or consultations on certain areas of the protocol. Consultations may include discussions with expert advisors, integration of public comment and stakeholder feedback. The result of this process will be a revised candidate protocol to WCI Partner jurisdictions for approval to move on to public consultation. The revised candidate protocol may include options in specific sections where an approach is not agreed upon by all WCI Partner jurisdictions.

3. WCI public consultation

As noted above, as part of the task team's evaluation of the protocol, public input in the form of webinars and written comments may be sought during the evaluation and revision process. Following the evaluation of a candidate protocol (Step 2), once WCI Partner jurisdictions receive a recommended candidate protocol or revised candidate protocol, the WCI Partner jurisdictions will post the document for public consultation. The candidate protocol will be posted to the WCI website, and a WCI webinar will take place within two weeks of posting. There will be a minimum 30-day consultation period during which stakeholders may submit comments on the protocol. The task team will summarize stakeholder comments and may integrate relevant proposed changes into a revised candidate protocol. This WCI public consultation process wil help harmonize WCI recommended protocols that are subsequently adopted by WCI Partner jurisdictions by gathering input from stakeholders across the WCI Partner jurisdictions prior to recommendation of a protocol. WCI Partner jurisdictions may hold further public consultation as required as part of their process to adopt a recommended protocol into its rule or regulation.

4. Recommendation of a candidate protocol

The WCI Partner jurisdictions will review a revised candidate protocol incorporating stakeholder comments and will consider recommending it for use by WCI Partner jurisdictions in the regional emissions trading and offsets program. The recommended protocol will be posted on the WCI website.

The recommended protocol will be available for adoption into the rules and regulations of individual WCI Partner jurisdictions. Each WCI Partner jurisdiction will follow its own procedures to incorporate the recommended protocol into its rules or regulations including the public comment process requirements of their own jurisdictions. Jurisdictions may need to make revisions to the recommended protocol to incorporate it into their respective rules or regulations and to maintain transparency. Each WCI Partner jurisdiction will keep other jurisdictions informed of revisions. As needed, WCI Partners will address concerns regarding revisions made by individual jurisdictions.

A process will be developed for the revision and update of recommended protocols.

Western Climate Initiative

Final Essential Requirements of Mandatory Reporting

2011 Amendments for Harmonization of Reporting in Canadian Jurisdictions

December 21, 2011

Amended February 10, 2012 to include #7 in the list of errata changes

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1 Introduction

This document and the attachments provide an overview of the 2011 amendments made to WCI Final Essential Requirements of Mandatory Reporting for harmonization of reporting for Canadian jurisdictions (referred to as the 2011 Canadian ERs).

The WCI Essential Requirements for Mandatory Reporting (ERs) were first published on July 15, 2009 and then amended in 2010 to create U.S. (published November 12, 2010) and Canadian versions (published December 17, 2010). The 2010 amendments were a result of WCI partners being concerned that the existence of two different reporting systems in a WCI state could result in the imposition of duplicative or conflicting reporting obligations on facilities subject to both programs. The Partners therefore directed the WCI Reporting Committee to develop amended ERs that are harmonized with the EPA rule. The November 12, 2010 U.S. ERs took the form of a mark-up of the U.S. Environmental Protection Agency (EPA) rule showing the changes to the EPA program that are needed to support a cap-and-trade program.

To ensure consistency and harmonization with the U.S. ERs in Canadian Partner jurisdictions, on December 17, 2010, the WCI published the "Final Essential Requirements for Mandatory Reporting – Canadian Harmonization Version" (the "2010 Canadian ERs"). The 2010 Canadian ERs adopted consistent quantification methods for use in Canadian Partner jurisdictions for all source categories. Significant updates were made to a number of quantification sections and the two oil and gas methods were published for the first time.

Quantification methods for the oil and gas sector are evolving in the U.S. and some technical elements of the U.S. EPA November 8, 2010 Subpart W (Petroleum and Natural Gas Systems) publication were not reflected in the 2010 Canadian ERs. WCI's Reporting Committee has worked through 2011, with the help of technical experts, to develop cap and trade quality reporting requirements for sources covered by Subpart W for use in both Canadian and U.S. jurisdictions. In addition, WCI also retained a technical expert to refine the biomass emission factors.

Stakeholder comments on proposed changes to the ERs were sought by the WCI Partner jurisdictions using informal means. This included communications on technical issues about the methods, consultation with individual companies and consultation with industry groups.

The 2011 Canadian ERs make both minor amendments and broader harmonization updates to the two oil and gas quantification sections. No changes are made to the general provisions of the ERs. The updates replace specific sections or clauses of the 2010 Canadian ERs and have been designed to be adopted for use by Canadian jurisdictions at the earliest point feasible in the jurisdiction. For those jurisdictions with direct references to the WCI Canadian ERs, adoption would be for 2012 calendar year emissions, as reported in 2013.

Further work within WCI is expected in 2012 given that the U.S. EPA released a revised Subpart W on December 2, 2011. WCI plans to review the latest Subpart W revisions and may consult with stakeholders on further potential updates (though less extensive) to the two oil and gas quantification sections in 2012.

Further evaluation of "reporting only" sources within the scope of the methods in the ERs, particularly for specific oil and gas sources, will be occurring, along with analysis and incorporation of further changes needed to include such sources within a cap and trade system.

This document and the attachments provide an overview of the 2011 amendments made to WCI Final Essential Requirements of Mandatory Reporting for harmonization of reporting for Canadian jurisdictions. Only those quantification methods where there are significant changes are re-published in full in this package. Where only a few modifications were made to a method, errata changes made are listed in Section 5 below.

2 Harmonization Principles

2.1 For U.S. Jurisdictions

The harmonization principles for U.S. jurisdictions are outlined in the "Harmonization of Essential Requirements for Mandatory Reporting in U.S. Jurisdictions with EPA Mandatory Reporting Rule"[1].

2.2 For Canadian Jurisdictions

In developing harmonized ERs that modify the existing ERs for use in Canadian Partner jurisdictions, the WCI Reporting Committee adhered to the following principles:

1. A Canadian facility should apply the equivalent functions, equations, sampling protocols and measurement criteria as U.S. facilities subject to the U.S. version of the harmonized ERs. This means that the harmonized ERs will achieve the same level of reporting accuracy for Canadian and U.S. facilities, but the U.S. version may require more data elements to be reported to harmonize with the EPA rule.
2. The quantification methods included in the harmonized ERs must remain sufficiently reliable and accurate to be employed in a GHG cap-and-trade program.

[1] http://www.westernclimateinitiative.org/news-and-updates/125-harmonization-of-essential-requirements-for-mandatory-reporting-in-us-jurisdictions-with-epa-mandatory-reporting-rule

3. The WCI reporting system must remain suitable for use in Canadian Partner jurisdictions. For example, it must allow reporting in metric as well as English units and must where necessary include Canada-specific emission factors.
4. The harmonized ERs should facilitate harmonization with Canadian federal reporting. Some Canadian Partner jurisdictions are working with Environment Canada to develop a one-window reporting tool for provincial and national GHG reporting requirements.

WCI intends to follow the same principles with regard to future additions or amendments to the EPA rule, such as the recently finalized Subpart W for the oil and gas industry, and the recently proposed revisions to Subpart A (general provisions) and several source category subparts.[2] WCI will review each proposed revision to assess its suitability for cap-and-trade before incorporating it into the harmonized ERs.

3 Harmonization Approach

3.1 For U.S. Jurisdictions

The harmonization approach for U.S. jurisdictions is outlined in the "Harmonization of Essential Requirements for Mandatory Reporting in U.S. Jurisdictions with EPA Mandatory Reporting Rule"[3].

3.2 For Canadian Jurisdictions

For the Canadian jurisdictions, the key requirement is that the WCI reporting system as a whole require the use of comparable methodologies and produce comparable results for facilities of the same type, so that "a tonne is a tonne" in both the U.S. and Canada. For Canadian jurisdictions it is not nearly as important to avoid small differences between the ERs and the EPA rule as it is for the U.S. jurisdictions, where such differences could create a risk of inadvertent non-compliance.

Canadian Partners have developed Canadian ERs that can be applied within the provincial legal frameworks. U.S. states also work within their legal framework by referencing the EPA rules and making the specific amendments needed to ensure cap and trade quality data. This latest Canadian ERs conforms in substance with reporting requirements adopted by the US WCI Partners (e.g., California). In addition, the Canadian ERs facilitate harmonization with Environment Canada and the use of Canada-specific reporting metrics and factors.

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[2] Pre-publication version posted on July 20, 2010 at: http://www.epa.gov/climatechange/emissions/technical-corrections.html#revisions

[3] http://www.westernclimateinitiative.org/news-and-updates/125-harmonization-of-essential-requirements-for-mandatory-reporting-in-us-jurisdictions-with-epa-mandatory-reporting-rule

3.3 Verification

Consistent with the Design Recommendations for the WCI Regional Cap-and-Trade Program, the harmonized U.S. and Canadian ERs require third party verification of emission reports for entities and facilities with emissions equal to or greater than 25,000 tonnes CO_2e. No revisions to the verification rule are made in the 2011 amendments to the Canadian ERs.

The amount of data to be reported for Canadian jurisdictions has been keep at a reduced level compared to that which is required to be reported to the EPA. This reflects the WCI third party verification requirements for emissions reports instead of the reliance on internal verification.

3.4 Missing Data Procedures

The Canadian harmonized ERs incorporate the EPA missing data procedures. During initial implementation of the cap-and-trade program, however, the WCI intends to revisit this issue. The WCI is investigating how the EPA missing data procedures can be modified to be more consistent with the needs of a cap-and-trade program while adhering to the harmonization principles and intends to propose and implement the necessary modifications in time for the 2013 reporting year.

4 Summary of Changes to the Quantification Methods

The following table summarizes the changes to the quantification methods that the WCI is publishing for Canadian jurisdictions. The specific language for the amendments is made in Section 5 and the attached amended quantification methods.

Section	Change to WCI Rule	Rationale
WCI.023	Updates to CO2 equations and parameters	Clarification of biomass and solid waste reporting, other clarifications
WCI.024	Updates to CH4 and N20 equations, creation of new coal-specific equations.	Simplification and clarification of equations
WCI.025	Refinement to sampling, analysis and measurement procedures, including calibration.	Simplification and clarification

Section	Change to WCI Rule	Rationale
WCI.027	Updated biomass emission factors	Review of differences between various published biomass emission factors 2010 sample data.
WCI.020 / WCI.040 and WCI.210	Clarification of where to report black liquor emissions	Avoidance of double-counting
WCI.160 and WCI.240	Errata changes Addition of method for sampling waste-based fuels	Clarification Technical review
WCI.040 and WCI.090	Errata changes	Clarification
WCI.352 WCI.362	Clarified and updated application of different quantification methods Updated information to be reported	Clarification and updates Updates
WCI.353 WCI.363 (throughout)	Simplification of equations to most basic form	Simplification and clarification
WCI.353(a), (a.1), (b), (b.1) WCI.363(a), (a.1), (b), (b.1)	Split pneumatic devices to four categories Extended phase-in and clarified language for metering of high bleed devices and pumps Clarified reporting of compressor starters	Rule clarity Extension of phase-in, rule clarity Clarification
WCI.363(c)	Incorporated EPA 98.233(d) methods 1 and 2 and revised existing WCI equation	Addition of options, reduced error in main acid gas removal equation, harmonization within WCI.

Section	Change to WCI Rule	Rationale
WCI.363(f)	Incorporated EPA 98.233(g) methods	Harmonization within WCI
WCI.353 (c) WCI.363(g)	Updated equation to be consistent with EPA	Harmonization within WCI
WCI.353 (c.1) WCI.363 (g.1)	Added third party line hit method	Completeness of reporting
WCI.363 (h)	Removed limitation on choice of method	Ease of use
WCI.353 (m) WCI.363(h.1)	Added transmission storage tank method from EPA 98.233(k)	Harmonization within WCI / correction of oversight
WCI.353(e) WCI.363(l)	Identified wet and dry gas seals Allowed application of emission factor for units (in aggregate) <250 hp (WCI.363 only) Added detail of operating modes per EPA language	Clarification, harmonization within WCI Reduced burden for small compressors Harmonization within WCI
WCI.353(f) WCI.363(m)	Added control factor to account for seal gas used as fuel Allowed application of emission factor for units (in aggregate) <250 hp (WCI.363 only)	Accuracy Reduced burden for small compressors

Section	Change to WCI Rule	Rationale
WCI.353(g) and WCI.353(h) WCI.363(n) and WCI.363(o)	Cross-checked and corrected references to WCI.352 and WCI.362 sections for application of leak detection and population count methods Clarified requirements for leak detection at small compressor stations	Accuracy Harmonization within WCI, reduced burden
WCI.363(o)	Correct equation to account for THC factors and multiple service types	Technical correction
WCI.353(j)	Clarified use of known gas composition for transmission and distribution	Clarification, reduced burden
WCI.363(w)	Required use of actual compositions where known. Indicated that same methodology must be used in subsequent year	Accuracy, use of existing data Accuracy
WCI.357 WCI.367 Tables	Added table of pneumatic manufacturer average bleed rates Revised pneumatic emission factors Revised reference from Clearstone Methodology Manual Table 6 to Table 9	Reduced burden Harmonization within WCI Technical correction
WCI.356 WCI.366 Definitions	Revised use of “city gate station” to “metering-regulation station” Clarified split between custody transfer and non-custody transfer Other updates	Clarification and technical corrections

5 Errata Changes to Quantification Methods

The following is a list of the errata changes made to quantification methods other than WCI.020 (General Stationary Combustion), WCI.350 (Natural Gas Transmission and Distribution) and WCI.360 (Petroleum and Natural Gas Production and Natural Gas Processing in the Final Essential Requirements of Mandatory Reporting (for harmonization of reporting for Canadian jurisdictions). No changes are made to the general provisions (WCI.1 to WCI.9) as published by the WCI on July 15, 2009 and updated on December 17, 2010. Errata changes are effective immediately and are meant to clarify issues for 2011 calendar year reporting and into the future.

1. **Cement Manufacturing:** WCI.094(j) is amended by adding "**, and or material balances.**" at the end of the provision.
2. **Electricity Generation:** WCI.043(a)(1)(A) is modified to read "… the results of fuel sampling and analysis for the fuel heat value **or carbon content, as applicable,** from the fuel supplier…".
3. **Electricity Generation and Pulp and Paper Manufacturing**. The following note is placed at the top of the WCI.040 and WCI.210 quantification methods:

   "*Note: CO_2, CH_4, and N_2O emissions from spent/pulping liquor combusted to produce electricity in the process of pulp and paper manufacturing should be reported under WCI.210, starting with the 2011 reporting year. Additional reporting requirements that are present in the two quantification methods are maintained independent on the direction of where to report the emissions."*
4. **Lead Production and Zinc Production**: WCI.164(a)(4) and WCI.244(a)(4) are struck and replaced with the following:

   (4) For waste-based carbon-containing material, determine the carbon content by either:

   i. Operating the smelting furnace both with and without the waste-reducing agents while keeping the composition of other material introduced constant.

   A. To ensure representativeness of waste-based carbon containing material variability, the specific testing plan (e.g. number of test runs, other process variable to keep constant, timing of runs) for these trials must be approved by the jurisdiction.

   ii. By using the theoretical carbon content of the waste-based carbon containing material as derived using engineering estimation techniques.
5. **Lead Production**: WCI.164(a) is amended by adding the following:

   (5) A facility may use an appropriate analytical method for determining the carbon content of ore
6. **Lead Production and Zinc Production**: WCI.162(c) and WCI.242(c) are modified to read "… (tonnes C/tonne input material)"
7. Updates to the WCI.28 Tables are applicable starting with 2011 calendar year emissions as they correct emission factors that were in error or had substantive uncertainty.

§ WCI.20 GENERAL STATIONARY COMBUSTION

§ WCI.21 Source Category Definition

Stationary fuel combustion sources are devices that combust solid, liquid, or gaseous fuel generally for the purpose of producing electricity, generating steam or providing useful heat or energy for industrial, commercial, or institutional use; or reducing the volume of waste by removing combustible matter. Stationary fuel combustion sources are boilers, simple and combined cycle combustion turbines, engines, incinerators (including units that combust hazardous waste), process heaters, and any other stationary combustion device that is not specifically addressed under the methods for another source category. This source category does not include portable equipment, emergency generators, and emergency equipment (including emergency flares).

§ WCI.22 Greenhouse Gas Reporting Requirements

Note: CO_2, CH_4, and N_2O emissions from spent/pulping liquor combusted in the process of pulp and paper manufacturing should be reported under WCI.210, starting with the 2011 reporting year.

Except as noted in the previous paragraph, the emissions data report shall include the following information at the facility level:

(a) Annual greenhouse gas emissions in tonnes, reported as follows:

(1) Total CO_2 emissions for fossil fuels, reported by fuel type.

(2) Total CO_2 emissions for biomass, reported by fuel type.

(3) Total CH_4 emissions, reported by fuel type.

(4) Total N_2O emissions, reported by fuel type.

(b) Annual fuel consumption:

(1) For gases, report in units of standard cubic meters.

(2) For liquids, report in units of kilolitres.

(3) For non-biomass solids, report in units of tonnes.

(4) For biomass solid fuels, report in units of bone dry tonnes.

(c) Annual weighted average carbon content of each fuel, if used to compute CO_2 emissions.

(d) Annual weighted average high heat value of each fuel, if used to compute CO_2 emissions.

(e) Annual steam in kilograms, for units that burn biomass fuels or municipal solid waste and generate steam.

§ WCI.23 Calculation of CO_2 Emissions

For each fuel, calculate CO_2 mass emissions using one of the four calculation methodologies specified in this section, subject to the restrictions in WCI.23(e). If a fuel or fuels is not listed in all of Tables 20-1 through 20-7, or in Table C-1 or C-2 of U.S. EPA 40 CFR Part 98, Subpart C, then emissions from such fuels do not need to be reported so long as the sum of emissions from these fuels does not exceed 0.5% of total facility emissions. If the sum of emissions from these fuels exceeds 0.5% of total facility emissions, then report emissions from one or more of these fuels as needed so that the sum of emissions from the remaining unlisted fuels does not exceed 0.5% of total facility emissions.

(a) Calculation Methodology 1. Calculate the annual CO_2 mass emissions for each type of fuel by substituting a fuel-specific default CO_2 emission factor, a default high heat value, and the annual fuel consumption into Equation 20-1 or 20-1a:

$$CO_2 = Fuel \times HHV \times EF \times 0.001$$ **Equation 20-1**

$$CO_2 = Fuel \times EF_c \times 0.001$$ **Equation 20-1a**

Where:

CO_2 = Annual CO_2 mass emissions for the specific fuel type (tonnes).
Fuel = Mass or volume of fuel combusted per year (express mass in tonnes for solid fuel, volume in standard cubic meters for gaseous fuel, or volume in kilolitres for liquid fuel).
HHV = Default high heat value of the fuel, from Table 20-1 and 20-1a (GJ per tonne for solid fuel, GJ per kilolitre for liquid fuel, or GJ per cubic meter for gaseous fuel).
EF = Fuel-specific default CO_2 emission factor, from Tables 20-1a, 20-2, 20-3, 20-5, or 20-7, as applicable (kg CO_2/GJ).
EFc = Fuel-specific default CO_2 emission factor, from Tables 20-2 or 20-5 (kg CO_2 per tonne for solid fuel, kg CO_2 per kilolitre for liquid fuel, or kg CO_2 per cubic meter for gaseous fuel)
0.001 = Conversion factor from kilograms to tonnes.

(b) Calculation Methodology 2. Calculate the annual CO_2 mass emissions using a default fuel-specific CO_2 emission factor, a high heat value provided by the supplier or measured by the operator, using Equation 20-2, except for emissions from the combustion of biomass fuels, for which the operator may instead elect to use the method shown in Equation 20-3. For use of Calculation Methodology 2 for municipal solid waste, Equation 20-3 must be used.

(1) For any type of fuel for which an emission factor is provided in Tables 20-1a, 20-2, 20-3, 20-5, or 20-7, as applicable, except biomass fuels when the operator elects to use the method in WCI.23(b)(2), use Equation 20-2:

$$CO_2 = \sum_{p=1}^{n} Fuel_p \times HHV_p \times EF \times 0.001$$ **Equation 20-2**

Where:

CO_2	=	Annual CO_2 mass emissions for a specific fuel type (tonnes).
n	=	Number of required heat content measurements for the year as specified in WCI.25.
$Fuel_p$	=	Mass or volume of the fuel combusted during the measurement period *p* (express mass in tonnes for solid fuel, volume in standard cubic meters for gaseous fuel, or volume in kilolitres for liquid fuel).
HHV_p	=	High heat value of the fuel for the measurement period *p* (GJ per tonne for solid fuel, GJ per bone-dry tonne biomass solid fuel, GJ per kilolitre for liquid fuel, or GJ per cubic meter for gaseous fuel).
EF	=	Fuel-specific default CO_2 emission factor, from Tables 20-1a, 20-2, 20-3, 20-5, or 20-7, as applicable (kg CO_2/GJ).
0.001	=	Conversion factor from kilograms to tonnes.

(2) For units that combust municipal solid waste and produce steam, use Equation 20-3. Equation 20-3 of this section may also be used for any solid biomass fuel listed in Table 20-2 of this subpart provided that steam is generated by the unit.

$$CO_2 = Steam \times B \times EF \times 0.001$$ **Equation 20-3**

Where:

CO_2	=	Annual CO_2 mass emissions from biomass solid fuel or municipal solid waste combustion (tonnes).
Steam	=	Total mass of steam generated by biomass solid fuel or municipal solid waste combustion during the reporting year (tonnes steam).
B	=	Ratio of the boiler's design rated heat input capacity to its design rated steam output capacity (GJ/tonne steam).
EF	=	Default emission factor for biomass solid fuel or municipal solid waste, from Table 20-2 or Table 20-7, as applicable (kg CO_2/GJ),[1] Site-specific emission factor determined through measurements may be used if updated no less often than every third year as provided in WCI.25(a)(7)(B).
0.001	=	Conversion factor from kilograms to tonnes.

(c) Calculation Methodology 3. Calculate the annual CO_2 mass emissions for each fuel by using measurements of fuel carbon content or molar fraction (for gaseous fuels only), conducted by the operator or provided by the fuel supplier, and the quantity of fuel combusted.

(1) For a solid fuel, except for the combustion of municipal solid waste, use Equation 20-4 of this section:

$$CO_2 = \sum_{i=1}^{n} 3.664 \times Fuel_i \times CC_i$$ **Equation 20-4**

[1] The ER required development of a site-specific emission factor for MSW. For harmonization with Part 98, Subpart C, this requirement was deleted. However, jurisdictions may allow or require testing to develop a site-specific emission factor as an alternative to the default emission factors in Subpart C, Table C-1.

Where:

CO_2 = Annual CO_2 mass emissions from the combustion of the specific solid fuel (tonnes).
n = Number of carbon content determinations for the year.
$Fuel_i$ = Mass of the solid fuel combusted in measurement period *i* (tonnes).
CC_i = Carbon content of the solid fuel, from the fuel analysis results for measurement period *i* (percent by weight, expressed as a decimal fraction, e.g., 95% = 0.95).
3.664 = Ratio of molecular weights, CO_2 to carbon.

(2) For biomass fuels and municipal solid waste, which is combusted in units for producing steam, either use 20-5 or Equation 20-3 in WCI.23(b)(2) above. Equation 20-5 of this section may also be used for any solid biomass fuel listed in Table 20-2 provided that steam is generated by the unit.

$$CO_2 = Steam \times EF \times 0.001$$

Equation 20-5

Where:

CO_2 = Annual CO_2 mass emissions from biomass solid fuel or municipal solid waste combustion (tonnes).
Steam = Total mass of steam generated by biomass solid fuel or municipal solid waste combustion during the reporting year (tonnes steam).
EF = Measured emission factor for biomass solid fuel or municipal solid waste, as applicable (kg CO_2/tonne steam), adjusted no less often than every third year.
0.001 = Conversion factor from kilograms to tonnes.

(3) For a liquid fuel, use Equation 20-6 of this section:

$$CO_2 = \sum_{i=1}^{n} 3.664 \times Fuel_i \times CC_i$$

Equation 20-6

Where:

CO_2 = Annual CO_2 mass emissions from the combustion of the specific liquid fuel (tonnes).
n = Number of required carbon content determinations for the year, as specified in WCI.25.
$Fuel_i$ = Volume of the liquid fuel combusted in measurement period *i* (kilolitres).

CC_i	=	Carbon content of the liquid fuel, from the fuel analysis results for measurement period *i* (tonne C per kilolitre of fuel).
3.664	=	Ratio of molecular weights, CO_2 to carbon.

(4) For a gaseous fuel, use Equation 20-7 of this section:

$$CO_2 = \sum_{i=1}^{n} 3.664 \times Fuel_i \times CC_i \times 0.001 \qquad \textbf{Equation 20-7}$$

Where:

CO_2	=	Annual CO_2 mass emissions from combustion of the specific gaseous fuel (tonnes).
n	=	Number of required carbon content determinations for the year, as specified in WCI.25.
$Fuel_i$	=	Fuel combusted in period "i" (a day or month, as applicable) (volume of the gaseous fuel in Rm^3 at reference temperature and pressure conditions as used by the facility, or mass of the gaseous fuel in kg if a mass flow meter is used)
CC_i	=	Average carbon content of the gaseous fuel, from the fuel analysis results for the period *i* (day or month, as applicable) (kg C per Rm^3 or kg C per kg of fuel if a mass flow meter is used).
3.664	=	Ratio of molecular weights, CO_2 to carbon.
0.001	=	Conversion factor from kg to tonnes.

(d) Calculation Methodology 4. Calculate the annual CO_2 mass emissions from all fuels combusted in a unit, by using data from continuous emission monitoring systems (CEMS) as specified in (d)(1) through (d)(7). This methodology requires a CO_2 monitor and a flow monitoring subsystem except as otherwise provided in paragraph (d)(3) of this section. CEMS shall use methodologies provided in *Protocols And Performance Specifications For Continuous Monitoring Of Gaseous Emissions From Thermal Power Generation* (Report EPS 1/PG/7) (Revised December 2005) (or by other document that supersedes it).

(1) For a facility that operates CEMS in response to federal, state, provincial, or local regulation, use CO_2 or O_2 concentrations and flue gas flow measurements to determine hourly CO_2 mass emissions using methodologies provided in Report EPS 1/PG/7 (Revised December 2005) (or by other relevant document, if superseded).

(2) The operator shall report CO_2 emissions for the reporting year in tonnes based on the sum of hourly CO_2 mass emissions over the year, converted to tonnes.

(3) An oxygen (O_2) concentration monitor may be used in lieu of a CO_2 concentration monitor in a CEMS installed before January 1, 2012, to determine the hourly CO_2 concentrations, if the effluent gas stream monitored by the CEMS consists solely of combustion products (i.e., no process CO_2 emissions or CO_2 emissions from acid gas control are mixed with the combustion products) and if only the following fuels are

combusted in the unit: coal, petroleum coke, oil, natural gas, propane, butane, wood bark, or wood residue.

(A) If the unit combusts waste-derived fuels (as defined in the General Provisions and including municipal solid waste), emissions calculations shall not be based on O_2 concentrations.

(B) If the operator of a facility that combusts biomass fuels uses O_2 concentrations to calculate CO_2 concentrations, annual source testing must demonstrate that the calculated CO_2 concentrations, when compared to measured CO_2 concentrations, meet the Relative Accuracy Test Audit (RATA) requirements in *Protocols And Performance Specifications For Continuous Monitoring Of Gaseous Emissions From Thermal Power Generation* (Report EPS 1/PG/7 (Revised) December 2005) (or by other relevant document, if superseded).

(4) If both biomass fuel (including fuels that are partially biomass) and fossil fuel are combusted during the year, determine and report the biogenic CO_2 mass emissions separately, as described in paragraph (f) of this section.

(5) For any units for which CO_2 emissions are reported using CEMS data, the operator is relieved of the requirement to separately report process emissions from combustion emissions for that unit or to report emissions separately for different fossil fuels for that unit when only fossil fuels are co-fired. In this circumstance, operators shall still report fuel use by fuel type as otherwise required.

(6) If a facility is subject to requirements for continuous monitoring of gaseous emissions, and the operator chooses to add devices to an existing CEMS for the purpose of measuring CO_2 concentrations or flue gas flow, the operator shall select and operate the added devices pursuant to the appropriate requirements for the facility as applicable in Canada.

(7) If a facility does not have a CEMS and the operator chooses to add one in order to measure CO_2 concentrations, the operator shall select and operate the CEMS pursuant to the appropriate requirements or equivalent requirements as applicable in Canada. Operators who add CEMS under this paragraph are subject to the specifications in paragraphs (d)(1) through (d)(5), if applicable.

(e) Use of the Four CO_2 Calculation Methodologies. Use of the four CO_2 emissions calculation methodologies described in paragraphs (a) through (d) of this section is subject to the following requirements and restrictions:

(1) Calculation Methodology 1 (Equations 20-1 and 20-1a).

(A) May be used by a facility that is not subject to the verification requirements by regulation for any type of fuel for which a default high heat value (Table 20-1 and 20-1a) and a default CO_2 emission factor (Tables 20-1a, 20-2, 20-3, or 20-5, as applicable) is specified.

(B) May be used for a facility emitting at any level for the combustion of natural gas with a high heat value between 36.3 and 40.98 MJ per cubic meter, and for the combustion of any of the fuels listed in Table 20-1a.

(C) May be used for a facility emitting at any level from the combustion of municipal solid waste in a unit that does not generate steam.

(D) May be used for the combustion of biomass listed in Table 20-2 that is exempted from verification requirements by the jurisdiction, unless it is specifically addressed under the provisions for another source category (e.g., spent pulping liquor from pulp and paper facilities).

(E) May not be used at a facility emitting at any level from a fuel for which you routinely perform fuel sampling and analysis for the fuel's high heat value or can obtain the results (i.e. high heat value) of fuel sampling and analysis from the fuel supplier at the minimum frequency specified in WCI.25(a), or at a greater frequency. In such cases, Calculation Method 2, 3 or 4 shall be used for those fuels.

(2) Calculation Methodology 2 (Equations 20-2 and 20-3).

(A) Calculation Methodology 2 may not be used by a facility that is subject to the verification requirements by regulation, except as specified in paragraphs (e)(2)(B) through (E) of this section. Otherwise, Calculation Methodology 2 may be used for any type of fuel combusted for which a default CO_2 emission factor for the fuel is specified in Tables 20-1a, 20-2, 20-3, 20-5, or 20-7, as applicable.

(B) Calculation Methodology 2 may be used for the combustion of natural gas with a high heat value between 36.3 and 40.98 MJ per cubic meter at a facility emitting at any level. Notwithstanding the provisions in paragraph (e)(1) of this section, Calculation Methodology 2, 3, or 4 shall be used for combustion in any unit with a rated heat input capacity greater than 264 GJ/hr (250mmBtu/hr) and that has operated for more than 1,000 hours in any of the past three years, when the fuel is natural gas with a high heat value between 36.3 and 40.98 MJ per cubic meter.

(C) Calculation Methodology 2 may be used at a facility emitting at any level for the combustion of any of the fuels listed in Table 20-1a, and for biomass that has been determined by [the jurisdiction] not to be subject to a compliance obligation under the cap-and-trade program.

(D) Equation 20-3 may be used for the combustion of municipal solid waste only at facilities that are not subject to verification by regulation.

(E) Equation 20-2 may not be used for the combustion of municipal solid waste.

(3) Calculation Methodology 3 (Equations 20-4 through 20-7) may be used for the combustion of any type of fuel, except as specified in paragraph (e)(3)(A) through (E) of this section.

(A) Notwithstanding the provisions in paragraph (e)(1) and (e)(2) of this section, Calculation Methodology 3 or 4 must be used at a facility subject to verification for all combustion in any unit with a rated heat input capacity greater than 264 GJ/hr (250mmBtu/hr) and that has operated for more than 1,000 hours in any of the past three years, except when the fuel is natural gas with a high heat value between 36.3 and 40.98 MJ per cubic meter, the fuel is listed in Table 20-1a, or the fuel is biomass that has been determined by [the jurisdiction] not to be subject to a compliance obligation under the cap-and-trade program.

(B) Must be used for all other combustion at a facility subject to verification, except for combustion of fuels for which Calculation Methodology 1 or 2 is permitted, as described in paragraphs (e)(1) and (e)(2) of this section.

(C) May not be used when the use of Calculation Methodology 4 is required.

(D) Equation 20-4 may not be used for the calculation of emissions from combustion of municipal solid waste.

(E) Equation 20-5 may be used for the combustion of municipal solid waste at a facility emitting at any level; however, it must be used for the combustion of municipal solid waste if the facility is subject to verification by regulation, unless Calculation Methodology 4 is required.

(4) Calculation Methodology 4 may be used for a unit combusting any type of fuel. Notwithstanding the provisions in paragraphs (e)(1) through (3) of this section, Calculation Methodology 4 must be used for a combustion unit with a CEMS that is required by any federal, provincial, or local regulation and that includes both a stack gas volumetric flow rate monitor and a CO_2 concentration monitor.

(5) You may elect to use any applicable higher calculation methodology for one or more of the fuels combusted in a unit. For example, if a unit combusts natural gas and distillate fuel oil, you may elect to use Calculation Methodology 1 for natural gas and Calculation Methodology 2 for the fuel oil, even though Calculation Methodology 1 could have been used for both fuels. However, for units that use Calculation Methodology 4, CO_2 emissions from the combustion of all fuels shall be based solely on CEMS measurements.

(f) CO_2 emissions from combustion of mixtures of biomass or biomass fuel and fossil fuel. Use the procedures of this paragraph (f) to estimate biogenic CO_2 emissions from units that combust a combination of biomass and fossil fuels, including combustion of waste-derived fuels (e.g., municipal solid waste, tires, etc,) that are partially biomass.

(1) If CEMS are not used to measure CO_2 and the facility combusts biomass fuels that do not include waste-derived fuels (e.g., municipal solid waste and tires), use Calculation Methodology 1, 2, or 3, as applicable, to calculate the annual biogenic CO_2 mass emissions from the combustion of biomass fuels. Determine the mass of biomass combusted using either company records, or, for premixed fuels that contain biomass and fossil fuels (e.g., mixtures containing biodiesel), use best available information to determine the mass of biomass fuels and document the procedure.

(2) If a CEMS is used to measure CO_2 (or O_2 as a surrogate) and the facility combusts biomass fuels that do not include waste-derived fuels (as defined in the General Provisions), use Calculation Methodology 1, 2, or 3 to calculate the annual CO_2 mass emissions from the combustion of fossil fuels. Calculate biomass fuel emissions by subtracting the fossil fuel-related emissions from the total CO_2 emissions determined from the CEMS-based methodology.

(3) If the owner or operator that combusts fuels or fuel mixtures for which the biomass fraction is unknown or cannot be documented (e.g., municipal solid waste, tire-derived fuel, etc.), or if the owner or operator combusts a biomass fuel for which a CO_2

emission factor is not provided in Table 20-2, use the following to estimate biogenic CO_2 emissions:

(A) Use Calculation Methodology 1, 2, 3, or 4 to calculate the total annual CO_2 mass emissions, as applicable.

(B) Determine the biogenic portion of the CO_2 emissions using ASTM D6866-08 “Standard Test Methods for Determining the Biobased Content of Solid, Liquid, and Gaseous Samples Using Radiocarbon Analysis”, as specified in this paragraph. This procedure is not required for fuels that contain less than 5 percent biomass by weight or for waste-derived fuels that are less than 30 percent by weight of total fuels combusted in the year for which emissions are being reported, except where the operator wishes to report a biomass fuel fraction of CO_2 emissions.

(C) The operator shall conduct ASTM D6866-08 analysis on a representative fuel or exhaust gas sample at least every three months. The exhaust gas samples shall be collected over at least 24 consecutive hours following the standard practice specified by ASTM D7459-08 “Standard Practice for Collection of Integrated Samples for the Speciation of Biomass (Biogenic) and Fossil-Derived Carbon Dioxide Emitted from Stationary Emissions Sources.” If municipal solid waste is combusted, the ASTM D6866-08 analysis must be performed on the exhaust gas stream.

(D) The operator shall divide total CO_2 emissions between biomass fuel emissions and non-biomass fuel emissions using the average proportions of the samples analyzed for the year for which emissions are being reported.

(E) If there is a common fuel source to multiple units at the facility, the operator may elect to conduct ASTM D6866-06a testing for only one of the units sharing the common fuel source.

(4) If Equations 20-1 or 20-1a of this section is selected to calculate the annual biogenic mass emissions for wood, wood waste, or other solid biomass-derived fuel, Equation 20-8 of this section may be used to quantify biogenic fuel consumption, provided that all of the required input parameters are accurately quantified. Similar equations and calculation methodologies based on steam generation and boiler efficiency may be used, provided that they are documented.

$$\left(Fuel\right)_p = \frac{\left[H \times S\right] - \left(HI\right)_{nb}}{\left(HHV\right)_{bio} \times \left(Eff\right)_{bio}} \qquad \textbf{Equation 20-8}$$

Where:

$(Fuel)_p$	=	Quantity of biomass consumed during the measurement period *p* (tonnes/year or tonnes/month, as applicable).
H	=	Average enthalpy of the boiler steam for the measurement period (GJ/tonne).
S	=	Total boiler steam production for the measurement period (tonne/month or tonne/year, as applicable).

$(HI)_{nb}$ = Heat input from co-fired fossil fuels and non-biomass-derived fuels for the measurement period, based on company records of fuel usage and default or measured HHV values (GJ/month or GJ/year, as applicable).

$(HHV)_{bio}$ = Default or measured high heat value of the biomass fuel (GJ/tonne).

$(Eff)_{bio}$ = Efficiency of biomass-to-energy conversion, expressed as a decimal fraction.

(g) Calculation of CO_2 from sorbent.

(1) When a unit is a fluidized bed boiler, is equipped with a wet flue gas desulfurization system, or uses other acid gas emission controls with sorbent injection, use Equation 20-9 of this section to calculate the CO_2 emissions from the sorbent, if those CO_2 emissions are not monitored by CEMS:

$$CO_2 = S \times R \times \left(\frac{MW_{CO2}}{MW_S} \right)$$ **Equation 20-9**

Where:

CO_2 = CO_2 emitted from sorbent for the reporting year (tonnes).

S = Limestone or other sorbent used in the reporting year, from company records (tonnes).

R = 1.00, the calcium-to-sulphur stoichiometric ratio, or determined based on the actual absorbent used.

MW_{CO2} = Molecular weight of carbon dioxide.

MW_S = Molecular weight of sorbent.

(2) The annual CO_2 mass emissions for the unit shall be the sum of the CO_2 emissions from the combustion process and the CO_2 emissions from the sorbent.

§ WCI.24 Calculation of CH_4 and N_2O Emissions

Calculate the annual CH_4 and N_2O mass emissions from stationary fuel combustion sources using the procedures in paragraph (a), (b), or (c), as appropriate. You are not required to calculate the annual CH_4 and N_2O emissions for fuels that are not listed in Tables 20-2, 20-3, 20-4 and 20-6. However, you may use engineering estimates to calculate the annual CH_4 and N_2O emissions for fuels that are not listed in Tables 20-2, 20-3, 20-4 and 20-6.

(a) ***For fuel(s) other than coal***: If the High Heat Value (HHV) for fuels is not measured directly, use Equation 20-10 to calculate the emissions for each fuel type:

$$CH_4 \text{ or } N_2O = \sum_{i=1}^{n} Fuel_i \times HHV_{D\_i} \times EF_i \times 0.000001$$ **Equation 20-10**

(a.2) ***For coal***: If the emissions factors are not measured directly or provided by suppliers, use Equation 20-11 to calculate the emissions for each type of coal :

$$CH_4 \text{ or } N_2O = \sum_{i=1}^{n} Fuel_i \times EF_{c,i} \times 0.001 \qquad \textbf{Equation 20-11}$$

Where:

CH_4 or N_2O	=	Combustion emissions from specific fuel type (tonnes CH_4 or N_2O per year).
$Fuel_i$	=	Mass or volume of fuel type combusted during measurement period "i" (express mass in tonnes for solid fuel, volume in standard cubic meters for gaseous fuel, or volume in kilolitres for liquid fuel).
$HHV_{D,i}$	=	Default high heat value specified by fuel type during measurement period "i" provided in Table 20-1, (GJ per tonne for solid fuel, GJ per kilolitre for liquid fuel, or GJ per cubic meter for gaseous fuel).
EF_i	=	Default CH_4 or N_2O emission factor for each fuel type during measurement period "i" provided in Tables 20-2 or 20-4, as applicable, grams CH_4 or N_2O per GJ. The facility may also use equipment specific factors from U.S. EPA AP-42 for the specific equipment as appropriate.
$EF_{c,i}$	=	Default CH_4 or N_2O emission factor for each coal type during measurement period "i" provided in Table 20-6 (grams CH_4 or N_2O per kg of coal). The facility may also use equipment specific factors from U.S. EPA AP-42 for the specific equipment as appropriate.
0.000001	=	Factor to convert grams to tonnes in Equation 20-10 .
0.001	=	Factor to convert kg to tonne in Equation 20-11.

(b) ***For fuels other than coal:*** If the HHVs for fuels are measured directly or provided by suppliers then use Equation 20-12 to calculate the emissions for each type of fuels:

$$CH_4 \text{ or } N_2O = \sum_{i=1}^{n} Fuel_i \times HHV_{P,i} \times EF_i \times 0.000001 \qquad \textbf{Equation 20-12}$$

(b.2) ***For coal only:*** If the emission factors are measured directly or provided by suppliers then use Equation 20-13 to calculate the emissions for each coal type:

$$CH_4 \text{ or } N_2O = \sum_{i=1}^{n} Fuel_i \times EF_{c,i} \times 0.001 \qquad \textbf{Equation 20-13}$$

Where:

CH_4 or N_2O	=	Combustion emissions from specific fuel type (tonnes CH_4 or N_2O per year).
$Fuel_i$	=	Mass or volume of fuel type during measurement period "i" (express mass in tonnes for solid fuel, volume in standard cubic meters for gaseous fuel, or volume in kilolitres for liquid fuel).
$HHV_{P,i}$	=	High heat value of the specific fuel during measurement period "i" measured

directly or provided by supplier(s) (GJ per tonne for solid fuel, GJ per kilolitre for liquid fuel, or GJ per cubic meter for gaseous fuel).

EF_i = Default CH_4 or N_2O emission factor for fuel "i" other than coal or during measurement period "i" provided in Tables 20-2 or 20-4, as applicable, grams CH_4 or N_2O per GJ. The facility may also use equipment specific factors from U.S. EPA AP-42 for the specific equipment as appropriate.

$EF_{c,i}$ = CH_4 or N_2O emission factor for each coal type during measurement "i" measured directly or provided by supplier(s) (kg CH_4 or N_2O per tonne of coal).

0.000001 = Factor to convert grams to tonnes in Equation 20-12.

0.001 = Factor to convert kg to tonne in Equation 20-13.

(c) For biomass and municipal solid waste combustion where Equation 20-3 or -5 or 20-4 is used to calculate CO_2 emissions, use Equation 20-14 of this section to estimate CH_4 and N_2O emissions:

$$CH_4 \ or \ N_2O = Steam \times B \times EF \times 0.000001 \qquad \textbf{Equation 20-14}$$

Where:

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a biomass or municipal solid waste (tonnes).

Steam = Total mass of steam generated by biomass or municipal solid waste combustion during the reporting year (tonnes steam).

B = Ratio of the boiler's design rated heat input capacity to its design rated steam output (GJ/tonne steam).

EF = Fuel-specific emission factor for CH_4 or N_2O, from Tables 20-2, 20-4, 20-6, or 20-7 as applicable (grams per GJ).

0.000001 = Conversion factor from grams to tonnes.

(d) Use Equation 20-15 of this section for units that use Calculation Methodology 4 and for which heat input is monitored on a year round basis.

$$CH_4 \ or \ N_2O = (HI)_A \times EF \times 0.000001 \qquad \textbf{Equation 20-15}$$

Where:

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (tonnes).

$(HI)_A$ = Cumulative annual heat input from the fuel (GJ), derived from the electronic data reports or estimated from the best available information used for accounting purposes (e.g., fuel feed rate measurements, fuel heating values, engineering analysis, etc.). For coal cumulative mass of coal (kilograms)

		from the best available information (e.g., fuel feed rate measurements, cumulative heat input, fuel heating values, engineering analysis).
EF	=	Fuel-specific emission factor for CH_4 or N_2O, from Tables 20-2, 20-4, or 20-6, as applicable (grams per GJ or grams per kilogram for coal).
0.000001	=	Conversion factor from grams to tonnes.

(1) If only one type of fuel is combusted during normal operation, substitute the cumulative annual heat input from combustion of the fuel into Equation 20-15 of this section to calculate the annual CH_4 or N_2O emissions.

(2) If more than one type of fuel listed is combusted during normal operation, use Equation 20-15 of this section separately for each type of fuel.

(e) When multiple fuels are combusted during the reporting year, sum the fuel-specific results from Equations 20-10/ 20-11, 20-12/13 and 20-14 or 20-15 of this section (as applicable) to obtain the total annual CH_4 and N_2O emissions, in tonnes.

(f) The operator may elect to calculate CH_4 or N_2O emissions using source-specific emission factors derived from source tests conducted at least annually under the supervision of the regulator. Upon approval of a source test plan, the source test procedures in that plan shall be repeated in each future year to update the source specific emission factors annually.

(g) Use of the four CH_4 and N_2O Calculation Methodologies. Use of the four CH_4 and N_2O emissions calculation methodologies described in paragraphs (a) through (d) of this section is subject to the following requirements and restrictions:

(1) WCI.24(a) may not be used by a facility that is subject to the verification requirements of WCI.8, except for stationary combustion units that combust natural gas with a high heat value between 36.3 and 40.98 MJ per cubic meter. Otherwise, WCI.24(a) may be used for any type of fuel for which a default CH_4 or N_2O emission factor (Tables 20-2, 20-4, 20-6, and 20-7) and a default high heat value (Table 20-1 and 20-1a) is specified.

(2) WCI.24(b) may be used for a unit of any size combusting any type of fuel.

(3) WCI.24(c) may only be used for biomass or municipal solid waste combustion. WCI.24(c) must be used instead of WCI.24(a) for any unit combusting municipal solid waste that generates steam.

(3) (4) WCI.24(d) may be used for a unit of any size combusting any type of fuel, and must be used for any units for which Calculation Methodology 4 is used to estimate CO_2 emissions and heat input is monitored on a year round basis.

§ WCI.25 Sampling, Analysis, and Measurement Requirements

(a) Fuel Sampling Requirements. Fuel sampling must be conducted or fuel sampling results must be received from the fuel supplier at the minimum frequency specified in paragraphs (a)(1) through (a)(7) of this section, subject to the requirements of WCI.23(e) and WCI.24(g). All fuel samples shall be taken at a location in the fuel handling system that provides a representative of the fuel combusted.

(1) Once for each new fuel shipment or delivery for coal.

(2) Once for each new fuel shipment or delivery of fuels, or quarterly for each of the fuels listed in Table 20-1a (when required).

(3) Semiannually for natural gas (when required and except as noted in WCI.025(f) and (g)).

(4) Quarterly for liquid fuels and fossil fuel-derived gaseous fuels other than fuels listed in Table 20-1a (when Table 20-1a is used).

(5) Quarterly for gases derived from biomass including landfill gas and biogas from wastewater treatment or agricultural processes.

(6) For gaseous fuels other than natural gas, gases derived from biomass, and biogas, daily sampling and analysis to determine the carbon content and molecular weight of the fuel is required if the necessary equipment is in place to make these measurements. If the necessary equipment is not in place to make the measurements, weekly sampling and analysis shall be performed. If on-line instrumentation is to be used, the equipment necessary to perform daily sampling and analysis of carbon content and molecular weight must determine fuel carbon content accurate to ±5 percent.

(7) Monthly for solid fuels other than coal and waste-derived fuels (including municipal solid waste), as specified below:

(A) The monthly solid fuel sample shall be a composite sample of weekly samples.

(B) The solid fuel shall be sampled at a location after all fuel treatment operations but before fuel combustion, and the samples shall be representative of the fuel chemical and physical characteristics immediately prior to combustion.

(C) Each weekly sub-sample shall be collected at a time (day and hour) of the week when the fuel consumption rate is representative and unbiased.

(D) Four weekly samples (or a sample collected during each week of operation during the month) of equal mass shall be combined to form the monthly composite sample.

(E) The monthly composite sample shall be homogenized and well mixed prior to withdrawal of a sample for analysis.

(F) One in twelve composite samples shall be randomly selected for additional analysis of its discrete constituent samples. This information will be used to monitor the homogeneity of the composite.

(8) For biomass fuels and waste-derived fuels (including municipal solid waste), the following may apply in lieu of WCI.25(a)(5):

(A) If CO_2 emissions are calculated using Equation 20-3 in WCI.23(b)(2) or Equation 20-4 in WCI.23(c)(1), the fuel-specific high heat value or carbon content is determined annually. If CO_2 emissions are calculated using Equation 20-5 in WCI.23(c)(2) (biomass fuels and municipal solid waste only), the operator shall adjust the emission factor, in kg CO_2/GJ not less frequently than every third year, through a stack test measurement of CO_2 and use of the applicable ASME

Performance Test Code to determine heat input from all heat outputs, including the steam, flue gases, ash and losses.

(b) Fuel Consumption Monitoring Requirements.

(1) Facilities may determine fuel consumption on the basis of direct measurement or recorded fuel purchase or sales invoices measuring any stock change (measured in MJ, litres, million standard cubic meters, tonnes or bone dry tonnes) using Equation 20-16. For facilities that are covered by WCI.360 (Petroleum and Natural Gas Production and Gas Processing), an operator may calculate fuel consumption for gasoline, propane and diesel using Equation 20-16 without correcting for the difference in inventory at the beginning and end of the year or using Equation 20-16a

Fuel Consumption in the Report Year = Total Fuel Purchases – Total Fuel Sales + Amount Stored (or reading) at Beginning of Year – Amount Stored (or reading) at Year End

Equation 20-16

$$Fuel = \sum_{j=1}^{n} \frac{P_{rated\ j}}{\eta_j} \times \frac{LD_j}{HHV_j} \times OH_j \times 0.0036$$

Equation 20-16a

Where:

Fuel	= Annual theoretical volume of liquid fuel combusted by fired equipment *j* (m^3/year).
$P_{rated\ j}$	= Maximum rated power for fired equipment *j* (kW).
LD_j	= Load for fired equipment *j* (load fraction).
OH_j	= Annual operating hours for fired equipment *j* (hours/year).
η_j	= Thermal efficiency for fired equipment *j*.
HHV_j	= High heat value of the liquid fuel combusted by fired equipment *j* (GJ/m^3).
n	= quantity of fired equipment units,
0.0036	= conversion factor between kWh and GJ.

(2) Fuel consumption measured in MJ values shall be converted to the required metrics of mass or volume using heat content values that are either provided by the supplier, measured by the facility, or provided in Table 20-1.

(3) All fuel oil and gas flow meters (except for gas billing meters) shall be calibrated prior to the first year for which GHG emissions are reported under this rule, using calibration procedures specified by the flow meter manufacturer[2]. Fuel flow meters shall be recalibrated once every three years, upon replacement of a previously calibrated meter or at the minimum frequency specified by the manufacturer. For orifice, nozzle,

[2] California's requirements in s. 95103(k) are being considered.

and venturi flow meters, the calibration shall consists of in-situ calibration of the differential pressure (delta-P), total pressure, and temperature transmitters. For flow meters used for natural gas, the facilities may follow the requirements under the laws and regulation of Measurement Canada for electricity and gas. For clarity, this provision also applies to flow meters used in upstream oil and gas, and natural gas transmission and distribution applications.

(4) For fuel oil, tank drop measurements may also be used.

(5) Fuel flow meters that measure mass flow rates may be used for liquid fuels, provided that the fuel density is used to convert the readings to volumetric flow rates. The density shall be measured at the same frequency as the carbon content, using ASTM D1298-99 (Reapproved 2005) "Standard Test Method for Density, Relative Density (Specific Gravity), or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method."

(6) Facilities using Calculation Methods 1 or 2 for CO_2 emissions may use the following (Table 20-8) default density values for fuel oil, in lieu of using the ASTM method in paragraph (b)(5) of this section. These default densities may not be used for facilities using Calculation Method 3.

Table 20-8 Fuel Oil Default Density Values

Fuel Oil	No.1 Oil	No.2 Oil	No.6 Oil
Default Density, kg/litre	0.81	0.86	0.97

(c) Fuel Heat Content Monitoring Requirements. High heat values shall be based on the results of fuel sampling and analysis received from the fuel supplier or determined by the operator, using an applicable analytical method listed by regulation. For fuel heat content monitoring of natural gas, the facilities may follow the requirements under the laws and regulation of Measurement Canada for electricity and gas.

(1) For gases, use the most appropriate method published by a consensus-based standards organization, if such a method exists. Specific test procedures that may be required to be used include ASTM D1826 "Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter", ASTM D3588 "Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels", or ASTM D4891-, GPA Standard 2261 "Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography." If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used. The operator may alternatively elect to use on-line instrumentation that determines heating value accurate to within ±5.0 percent. Where existing on-line instrumentation provides only low heat value, the operator shall convert the low heat value to high heat value as follows:

$$HHV = LHV \times CF \qquad \textbf{Equation 20-17}$$

Where:

HHV	= fuel or fuel mixture high heat value (MJ/scm).
LHV	= fuel or fuel mixture low heat value (MJ/scm).
CF	= conversion factor.

For natural gas, a CF of 1.11 shall be used. For refinery fuel gas and mixtures of refinery fuel gas, a weekly average fuel system-specific CF shall be derived as follows:

(A) By concurrent LHV and HHV measurements determined by on-line instrumentation or laboratory analysis as part of the daily carbon content determination; or,

(B) By the HHV/LHV ratio obtained from the laboratory analysis of the daily samples.

(2) For middle distillates and oil, or liquid waste-derived fuels, use the most appropriate method published by consensus-based standards organization. Specific test procedures that may be required to use include ASTM D240 “Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter” or ASTM D4809 “Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method).” If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used.

(3) For solid biomass-derived fuels, use the most appropriate method published by a consensus-based standards organization. Specific test procedures that may be required to use include ASTM D5865 “Standard Test Method for Gross Calorific Value of Coal and Coke.” If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used.

(4) For waste-derived fuels, use the most appropriate method published by a consensus-based standards organization. Specific test procedures that may be required to use include ASTM D5865 and ASTM D5468 “Standard Test Method for Gross Calorific and Ash Value of Waste Materials.” Operators who combust waste-derived fuels that are not pure biomass fuels shall determine the biomass fuel portion of CO_2 emissions using the method specified in WCI.23(f), if applicable. If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used.

(5) Use Equation 20-18 to calculate the weighted annual average heat content of the fuel, if the measured heat content is used to calculate CO_2 emissions.

$$(HHV)_{annual} = \frac{\sum_{p=1}^{n} (HHV)_p \times (Fuel)_p}{\sum_{p=1}^{n} (Fuel)_p} \qquad \textbf{Equation 20-18}$$

Where:

$(HHV)_{annual}$ = Weighted annual average high heat value of the fuel (GJ per tonne for solid fuel, GJ per kilolitre for liquid fuel, or GJ per cubic meter for gaseous fuel).

$(HHV)_p$ = High heat value of the fuel, for measurement period *p* (GJ per tonne for solid fuel, GJ per kilolitre for liquid fuel, or GJ per cubic meter for gaseous fuel).

$(Fuel)_p$ = Mass or volume of the fuel combusted during measurement period *p* (express mass in tonnes for solid fuel, volume in standard cubic meters for gaseous fuel, or volume in kilolitres for liquid fuel).

n = Number of measurement periods in the year that fuel is burned in the unit.

(d) Fuel Carbon Content Monitoring Requirements. The determination of fuel carbon content and either molecular weight or molar fraction for gaseous fuels shall be based on the results of fuel sampling and analysis received from the fuel supplier or determined by the operator, using an applicable analytical method listed by regulation. For carbon content monitoring of natural gas, the facilities may follow the requirements under the laws and regulation of Measurement Canada for electricity and gas .

(1) For coal and coke, solid biomass fuels, and waste-derived fuels, use the most appropriate method published by a consensus-based standards organization. Specific test procedures that may be required to use include ASTM 5373“Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal”. If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used.

(2) For liquid fuels, use the most appropriate method published by a consensus-based standards organization. Specific test procedures that may be required to use include the following ASTM methods: For petroleum-based liquid fuels and liquid waste-derived fuels, use ASTM D5291“Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants,” ultimate analysis of oil or computations based on ASTM D3238, and either ASTM D2502“Standard Test Method for Estimation of Mean Relative Molecular Mass of Petroleum Oils From Viscosity Measurements” or ASTM D2503 “Standard Test Method for Relative Molecular Mass (Molecular Weight) of Hydrocarbons by Thermoelectric Measurement of Vapor Pressure.” If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used.

(3) For gaseous fuels, use the most appropriate method published by a consensus-based standards organization. Specific test procedures that may be required to used include use ASTM D1945 “Standard Test Method for Analysis of Natural Gas by Gas Chromatography” or ASTM D1946 “Standard Practice for Analysis of Reformed Gas by Gas Chromatography.” If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used.

(4) Use Equation 20-19 to calculate the weighted annual average carbon content of the fuel, if the measured carbon content is used to calculate CO_2 emissions.

$$(CC)_{annual} = \frac{\sum_{p=1}^{n} (CC)_p \times (Fuel)_p}{\sum_{p=1}^{n} (Fuel)_p} \qquad \textbf{Equation 20-19}$$

Where:

$(CC)_{annual}$ = Weighted annual average carbon content of the fuel (percent C by weight for solid fuel, tonne C per kilolitre for liquid fuel, or kg C per kg fuel for gaseous fuel).

$(CC)_p$ = Carbon content of the fuel, for measurement period *p* (percent C by weight for solid fuel, tonne C per kilolitre for liquid fuel, or kg C per kg fuel for gaseous fuel).

$(Fuel)_p$ = Mass or volume of the fuel combusted during measurement period *p* (express mass in tonnes for solid fuel, volume in standard cubic meters for gaseous fuel, or volume in kilolitres for liquid fuel).

n = Number of measurement periods in the years that fuel is burned in the unit.

(e) Fuel Analytical Data Capture. When the applicable emissions estimation methodologies in WCI.23 and WCI.24 require periodic collection of fuel analytical data for an emissions source, the operator shall demonstrate every reasonable effort to obtain a fuel analytical data capture rate of 100 percent for each report year.

(1) If the operator is unable to obtain fuel analytical data such that more than 20 percent of emissions from a source cannot be directly accounted for, the emissions from that source shall be considered unverifiable for the report year.

(2) If the fuel analytical data capture rate is at least 80 percent but less than 100 percent for any emissions source identified in WCI.23 and WCI.24, the operator shall use the methods in WCI.26(b) to substitute for the missing values for the period of missing data.

(f) Specific Requirements for Petroleum and Natural Gas Production and Gas Processing. For field or process gas combustion or general stationary combustion of natural gas within facilities covered by WCI.360, legislative or regulatory requirements, such as those required by the Petroleum and Natural Gas Act of British Columbia are sufficient for the points of measurement that are metered. For British Columbia, combustion sources specifically covered by the Petroleum and Natural Gas Act are to be metered, sampled and analyzed in the manner prescribed by the Act and its regulations, guidelines, and policies. Calibration for all meters used in emissions quantification (whether covered by legislative or regulatory requirements, or not) must be conducted annually, or at the minimum frequency specified by the manufacturer, if appropriate for emissions quantification. Combustion sources not specifically covered by the legislative or regulatory requirements must be measured according to the following requirements:

(1) For combustion emissions sources where meters are not required by legislation or regulation, a calculated shrinkage value is sufficient but must be assigned using engineering estimation techniques to the various sources, if required for reporting.

(2) For field, pipeline quality natural gas as defined in WCI.350, or process gas combustion emissions sources where metering is not required by law or regulation and shrinkage is not calculated, engineering estimation techniques that consolidate to common meter points such as that at the input to a processing plant used for financial purposes are sufficient. As required, fuel use must be allocated (using equipment specifications, operating hours, and flow rates) to specific emissions sources.

(3) For upstream sources, a meter is required at each installation or at a point where fuel use can be allocated to multiple combustion sources such that the aggregate of all combustion sources are metered.

All combustion estimates must be calculated in a manner that ensures that fugitive, flaring, and venting emissions as calculated under WCI.360 are uniquely reported and that no double-counting of emissions in one or more categories occurs.

Carbon content and molecular weight of the field or process gas determined annually by a facility following paragraphs (c)(1) and (d)(3) of this section for operational and regulatory purposes must be used as inputs to Equation 20-7. When this data is not available, the generic gas composition (as covered into the required format) provided in Table 360-4(or as provided by the jurisdiction) must be used by a company or operator for the specific gas field in question.

(g) Specific Requirements for Natural Gas Transmission and Distribution. Weights and Measures Act of Canada standards (or other appropriate standards if the Weights and Measures Act is not applicable) are deemed to be sufficiently rigorous for the sampling, analysis and measurement for the combustion of pipeline quality natural gas as defined in WCI.350 (including for derivation of standard gas composition) for facilities covered by WCI.350 – Natural Gas Transmission and Distribution. Calibration for all meters used in emissions quantification (whether covered by legislative or regulatory requirements, or not) must be conducted annually, or at the minimum frequency specified by the manufacturer, if appropriate for emissions quantification. If a required meter is not covered by the Weights and Measures Act, it must exist and meet the requirements of the applicable greenhouse gas reporting regulation for the jurisdiction.

§ WCI.26 Procedures for Estimating Missing Data.

Whenever a quality-assured value of a required parameter is unavailable (e.g., if a CEMS malfunctions during unit operation or if a required fuel sample is not taken), a substitute data value for the missing parameter shall be used in the calculations.

(a) For all units subject to the requirements of WCI.20 that monitor and report emissions using a CEMS, the missing data backfilling procedures in *Protocols And Performance Specifications For Continuous Monitoring Of Gaseous Emissions From Thermal Power Generation* (Report EPS 1/PG/7 (Revised) December 2005) (or by other relevant document, if superseded) shall be followed for CO_2 concentration, stack gas flow rate, fuel flow rate, high heat value, and fuel carbon content.

(b) For units that use Calculation Methodologies 1, 2, 3, or 4, perform missing data substitution as follows for each parameter:

(1) For each missing value of the high heat value, carbon content, or molecular weight of the fuel, substitute the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If the "after" value has not been obtained by the time that the GHG emissions must be calculated, you may use the "before" value for missing data substitution or the best available estimate of the parameter, based on all available process data (e.g., electrical load, steam production, operating hours). If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.

(2) For missing records of CO_2 concentration, stack gas flow rate, moisture percentage, fuel usage, and sorbent usage, the substitute data value shall be the best available estimate of that parameter, based on all available process data (e.g., electrical load, steam production, operating hours, etc.). You must document and retain records of the procedures used for all such estimates.

§ WCI.27 Definitions

Except as specified in this section, all terms used in this subpart have the same meaning given in the General Provisions.

Consensus based standards organizations include, but are not limited to, the following: ASTM International, the American Gas Association (AGA), the American Petroleum Institute (API), the Canadian Standards Association (CSA), the Gas Processors Association (GPA), the Gas Processors Suppliers Association (GPSA) , the American National Standards Institute (ANSI), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB).

Emergency generator means a stationary combustion device, such as a reciprocating internal combustion engine or turbine that serves solely as a secondary source of mechanical or electrical power whenever the primary energy supply is disrupted or discontinued during power outages or natural disasters that are beyond the control of the owner or operator of a facility. An emergency generator operates only during emergency situations, for training of personnel under simulated emergency conditions, as part of emergency demand response procedures, or for standard performance testing procedures as required by law or by the generator manufacturer. A generator that serves as a back-up power source under conditions of load shedding, peak shaving, power interruptions pursuant to an interruptible power service agreement, or scheduled facility maintenance shall not be considered an emergency generator.

Emergency equipment means any auxiliary fossil fuel-powered equipment, such as a fire pump, that is used only in emergency situations.

Portable means designed and capable of being carried or moved from one location to another. Indications of portability include but are not limited to wheels, skids, carrying handles, dolly, trailer, or platform. Equipment is not portable if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The equipment or a replacement resides at the same location for more than 12 consecutive months.

(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least two years, and operates at that facility for at least three months each year.

(4) The equipment is moved from one location to another in an attempt to circumvent the portable residence time requirements of this definition.

U.S. AP-42 means the Fifth Edition, Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources, U.S. EPA., as amended from time to time

§ WCI.28 Tables

Table 20-1: Default High Heat Value by Fuel Type

Liquid Fuels	**High Heat Value (GJ/kl)**
Asphalt & Road Oil	44.46
Aviation Gasoline	33.52
Diesel	38.3
Aviation Turbo Fuel	37.4
Kerosene	37.68
Propane	25.31
Ethane	17.22
Butane	28.44
Lubricants	39.16
Motor Gasoline – Off-Road	35
Light Fuel Oil	38.8
Residual Fuel Oil (No. 5 & No. 6)	42.5
Crude Oil	38.32
Naphtha	35.17
Petrochemical Feedstocks	35.17
Petroleum Coke – Refinery Use	46.35
Petroleum Coke – Upgrader Use	40.57
Ethanol (100%)	32.41
Biodiesel (100%)	35.67
Rendered Animal Fat	34.83
Vegetable Oil	33.44
Solid Fuels	**High Heat Value (GJ/tonne)**
Anthracite Coal	27.7
Bituminous Coal	26.33
Foreign Bituminous Coal	29.82
Sub-Bituminous Coal	19.15
Lignite	15
Coal Coke	28.83
Solid Wood Waste (at 0% moisture content)[3]	19.2[4]
Spent Pulping Liquor (at 0% moisture content)[3]	13.5[4]
Municipal Solid Waste	11.57
Tires	31.18
Agricultural By-products	8.6
Solid By-products	26.93
Gaseous Fuels	**High Heat Value (GJ/m^3)**
Natural Gas	0.038
Coke Oven Gas	0.01914
Still Gas – Refineries	0.03608
Still Gas – Upgraders	0.04324
Landfill Gas (methane fraction)	0.0359
Biogas (methane fraction)	0.0281

[1] The default high heat value for "propane" is only for the pure gas species. For the product commercially sold as propane, the value for liquefied petroleum gas in Table 20-1a should be used instead.

[3] HHV can be readily calculated for any moisture content as $HHV_{dry} = HHV_{wet} / (1 - percent\_moisture/100)$.
[4] A Review of Biomass Emissions Factors (2011). Clarity Works Ltd. Prepared for BC Ministry of Environment t.

Table 20-1a—Fuels for which Calculation Methodologies 1 or 2 may be used at a facility emitting at any level.

Fuel Type	Default High Heat Value	Default CO_2 Emission Factor
Petroleum Products	**GJ/kilolitre**	**kg CO_2/GJ**
Distillate Fuel Oil No. 1	38.78	69.37
Distillate Fuel Oil No. 2	38.50	70.05
Distillate Fuel Oil No. 4	40.73	71.07
Kerosene	37.68	67.25
Liquefied Petroleum Gases (LPG)	25.66	59.65
Propane (pure, not mixtures of LPGs)[1]	25.31	59.66
Propylene	25.39	62.46
Ethane	17.22	56.68
Ethylene	27.90	63.86
Isobutane	27.06	61.48
Isobutylene	28.73	64.16
Butane	28.44	60.83
Butylene	28.73	64.15
Natural Gasoline	30.69	63.29
Motor Gasoline	34.87	65.40
Aviation Gasoline	33.52	69.87
Kerosene-type Jet Fuel	37.66	68.40

[1] The default factors for "propane" are only for the pure gas species. For the product commercially sold as propane, the values for LPG should be used instead.

Table 20-2: Default Emission Factors by Fuel Type

Liquid Fuels	CO_2 Emission Factor (kg/l)	CO_2 Emission Factor (kg/GJ)	CH_4 Emission Factor (g/l)	CH_4 Emission Factor (g/GJ)	N_2O Emission Factor (g/l)	N_2O Emission Factor (g/GJ)
Aviation Gasoline	2.342	69.87	2.2	65.63	0.23	6.862
Diesel	2.663	69.53	0.133	3.473	0.4	10.44
Aviation Turbo Fuel	2.534	67.75	0.08	2.139	0.23	6.150
Kerosene						
- Electric Utilities	2.534	67.25	0.006	0.159	0.031	0.823
- Industrial	2.534	67.25	0.006	0.159	0.031	0.823
- Producer Consumption	2.534	67.25	0.006	0.159	0.031	0.823
- Forestry, Construction, and Commercial/Institutional	2.534	67.25	0.026	0.69	0.031	0.823
Propane						
- Residential	1.51	59.66	0.027	1.067	0.108	4.267
- All other uses	1.51	59.66	0.024	0.948	0.108	4.267

Ethane	0.976	56.68	N/A	N/A	N/A	N/A
Butane	1.73	60.83	0.024	0.844	0.108	3.797
Lubricants	1.41	36.01	N/A	N/A	N/A	N/A
Motor Gasoline – Off-Road	2.289	65.40	2.7	77.14	0.05	1.429
Light Fuel Oil						
- Electric Utilities	2.725	70.23	0.18	4.639	0.031	0.799
- Industrial	2.725	70.23	0.006	0.155	0.031	0.799
- Producer Consumption	2.643	68.12	0.006	0.155	0.031	0.799
- Forestry, Construction, and Commercial/Institutional	2.725	70.23	0.026	0.67	0.031	0.799
Residual Fuel Oil (No. 5 & No. 6)						
- Electric Utilities	3.124	73.51	0.034	0.800	0.064	1.506
- Industrial	3.124	73.51	0.12	2.824	0.064	1.506
- Producer Consumption	3.158	74.31	0.12	2.824	0.064	1.506
- Forestry, Construction, and Commercial/Institutional	3.124	73.51	0.057	1.341	0.064	1.820
Naphtha	0.625	17.77	N/A	N/A	N/A	N/A
Petrochemical Feedstocks	0.5	14.22	N/A	N/A	N/A	N/A
Petroleum Coke - Refinery Use	3.826	82.55	0.12	2.589	0.0265	0.572
Petroleum Coke - Upgrader Use	3.494	86.12	0.12	2.958	0.0231	0.569
Biomass	**CO_2 Emission Factor (kg/kg)**	**CO_2 Emission Factor (kg/GJ)**	**CH_4 Emission Factor (g/kg)**	**CH_4 Emission Factor (g/GJ)**	**N_2O Emission Factor (g/kg)**	**N_2O Emission Factor (g/GJ)**
Landfill Gas	2.989	54.63	0.6	1.0	0.06	0.1
Wood Waste (at 0% moisture content)	1.8[5]	93.7[5]	0.576	30[6]	0.077	4[6]
Spent Pulping Liquor (at 0% moisture content)	1.239	91.8[5]	0.039	2.9[7]	0.026	1.9[7]
Agricultural By-products	NA	112	NA	NA	NA	NA
Solid By-products	NA	100	NA	NA	NA	NA
Biogas (captured methane)	NA	49.4	NA	NA	NA	NA
Ethanol (100%)	NA	64.9	NA	NA	NA	NA
Biodiesel (100%)	NA	70	NA	NA	NA	NA
Rendered Animal Fat	NA	67.4	NA	NA	NA	NA
Vegetable Oil	NA	77.3	NA	NA	NA	NA
Other Solid Fuels	**CO_2 Emission Factor (kg/kg)**	**CO_2 Emission Factor (kg/GJ)**	**CH_4 Emission Factor (g/kg)**	**CH_4 Emission Factor (g/GJ)**	**N_2O Emission Factor (g/kg)**	**N_2O Emission Factor (g/GJ)**
Coal Coke	2.48	86.02	0.03	1.041	0.02	0.694
Tires	N/A	85	N/A	N/A	N/A	N/A

[5] A Review of Biomass Emissions Factors (2011). Clarity Works Ltd. Prepared for BC Ministry of Environment.
[6] US EPA (2009). U.S. Environmental Protection Agency. *Mandatory reporting of greenhouse gases, final rule*. Washington, DC, 2009.
[7] IPCC (2006). Intergovernmental Panel on Climate Change. 2006 *IPCC Guidelines for National Greenhouse Gas Inventories*. Japan, 2006.

Gaseous Fuels	CO_2 Emission Factor (kg/m^3)	CO_2 Emission Factor (kg/GJ)	CH_4 Emission Factor (g/m^3)	CH_4 Emission Factor (g/GJ)	N_2O Emission Factor (g/m^3)	N_2O Emission Factor (g/GJ)
Coke Oven Gas	1.6	83.60	0.037	1.933	0.035	1.829
Still Gas – Refineries	1.75	48.50	N/A	N/A	0.0222	0.615
Still Gas – Upgraders	2.14	49.49	N/A	N/A	0.0222	0.513

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007, unless otherwise stated

[1] Assumes 50% moisture content of wood waste

[2] Assumes 12% moisture content of wood waste

Table 20-3: Default Carbon Dioxide Emission Factors for Natural Gas by Province

	Marketable Gas (kg/m^3)	Marketable Gas (kg/GJ)	Non-Marketable Gas (kg/m^3)	Non-Marketable Gas (kg/GJ)
Quebec	1.878	49.01	Not occurring	Not occurring
Ontario	1.879	49.03	Not occurring	Not occurring
Manitoba	1.877	48.98	Not occurring	Not occurring
British Columbia	1.916	50.00	2.151	56.13

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007

Table 20-4: Default Methane and Nitrous Oxide Emission Factors for Natural Gas

	CH_4 (g/m^3)	CH_4 (g/GJ)	N_2O (g/m^3)	N_2O (g/GJ)
Electric Utilities	0.49	12.79	0.049	1.279
Industrial	0.037	0.966	0.033	0.861
Producer Consumption (Non-marketable)	6.5	169.6	0.06	1.566
Pipelines	1.9	49.58	0.05	1.305
Cement	0.037	0.966	0.034	0.887
Manufacturing Industries	0.037	0.966	0.033	0.861
Residential, Construction, Commercial/Institutional, Agriculture	0.037	0.966	0.035	0.913

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007

Table 20-5: Default Carbon Dioxide Emission Factors for Coal

	Emission Factor (kg CO_2/kg coal)	Emission Factor (kg CO_2/GJ)
Quebec		
- Canadian Bituminous	2.25	85.5
- U.S. Bituminous	2.34	88.9
- Anthracite	2.39	86.3
Ontario		
- Canadian Bituminous	2.25	85.5
- U.S. Bituminous	2.43	81.5
- Sub-bituminous	1.73	90.3

- Lignite	1.48	98.7
- Anthracite	2.39	86.3
Manitoba		
- Canadian Bituminous	2.25	85.5
- U.S. Bituminous	2.43	81.5
- Sub-bituminous	1.73	90.3
- Lignite	1.42	94.7
- Anthracite	2.39	86.3
British Columbia		
- Canadian Bituminous	2.07	78.6
- U.S. Bituminous	2.43	81.5
- Sub-bituminous	1.77	92.4

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007

Table 20-6: Default Methane and Nitrous Oxide Emission Factors for Coal

	CH_4 Emission Factor (g/kg)	N_2O Emission Factor (g/kg)
Electric Utilities	0.022	0.032
Industry and Heat and Steam Plants	0.03	0.02
Residential, Public Administration	4	0.02

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007

Table 20-7: Other Emission Factors

	CO_2 Emission Factor (kg/GJ)	CH_4 Emission Factor (g/GJ)	N_2O Emission Factor (g/GJ)
Municipal Solid Waste	85.6	30	4
Peat	103	1	1.5

Source: 2006 IPCC Guidelines for National Greenhouse Gas Inventories, except the CO_2 emission factor for municipal solid waste is from the U.S. EPA from table C-1 of 40 CFR 98 subpart C.

WCI has reviewed in detail results and analysis from Clarity Works on biomass emissions factors using 2010 data collected by British Columbia through the BC Reporting Regulation. Further data collection and analysis will be needed to refine the CH_4, and N_2O emission factor for pulping liquor and hog fuel, among other fuels.

Due to the timing of the release of amendments to the EPA Subpart W rule on December 2, 2011 and the potential need for the WCI to address harmonization questions with it, further consultation on WCI.350 and potential amendments to WCI.350 are scheduled to occur in 2012.

§ WCI.350 NATURAL GAS TRANSMISSION AND DISTRIBUTION

§ WCI.351 Source Category Definition

This source category consists of the following:

(a) *Onshore natural gas transmission compression.* Onshore natural gas transmission compression means any stationary combination of compressors that move natural gas at elevated pressure from production fields or natural gas processing facilities in transmission pipelines to natural gas distribution pipelines, into storage or at times directly to industrial customers or farms located along the pipeline route. In addition, transmission compressor station may include equipment for liquids separation, natural gas dehydration, and tanks for the storage of water and hydrocarbon liquids. Residue (sales) gas compression operated by natural gas processing facilities are included in the onshore natural gas processing segment and are excluded from this segment.

(b) *Underground natural gas storage.* Underground natural gas storage means subsurface storage, including depleted gas or oil reservoirs and salt dome caverns that store natural gas that has been transferred from its original location for the primary purpose of load balancing (the process of equalizing the receipt and delivery of natural gas); natural gas underground storage processes and operations (including compression, dehydration and flow measurement, and excluding transmission pipelines); and all the wellheads connected to the compression units located at the facility that inject and recover natural gas into and from the underground reservoirs.

(c) *Liquefied natural gas (LNG) storage.* LNG storage means onshore LNG storage vessels located above ground, equipment for liquefying natural gas, compressors to capture and re-liquefy boil-off-gas, re-condensers, and vapourization units for re-gasification of the liquefied natural gas.

(d) *LNG import and export equipment.* LNG import equipment means all onshore or offshore equipment that receives imported LNG via ocean transport, stores LNG, re-gasifies LNG, and delivers re-gasified natural gas to a natural gas transmission or distribution system. LNG export equipment means all onshore or offshore equipment that receives natural gas, liquefies natural gas, stores LNG, and transfers the LNG via ocean transportation to any location, including locations in Canada.

(e) *Natural gas distribution.* Natural gas distribution consists of all natural gas equipment downstream of the station yard inlet shut-off valves of natural gas transmission pipelines at stations where pressure reduction and/or measuring first occurs for eventual delivery of natural gas to consumers. Some natural gas distribution systems receive gas from gas batteries rather than from transmission pipelines and typically transport odourized natural gas.

(f) *Natural gas transmission pipelines.* Natural gas transmission pipelines means a high pressure pipeline (and associated equipment) transporting sellable quality natural gas from production or natural gas processing to natural gas distribution pressure let-down, metering and/or regulating stations before delivery to customers. In some cases natural gas is delivered directly from natural gas transmission pipelines to farms and industrial end users along the pipeline route.

§ WCI.352 Greenhouse Gas Reporting Requirements

Where greenhouse gases are not emitted from a specific emission source identified in paragraphs (a) to (h) below, then the reported emissions for the specific source shall be reported as zero or "not applicable".

In addition to the information required by regulation, the annual emissions data report for both each individual facility over 10,000 tonnes, and the aggregate of facilities less than 10,000 tonnes (or as otherwise specified by regulation), must contain the following information:

(a) CO_2 and CH_4 (and N_2O, if applicable) emissions (in tonnes) from each industry segment specified in paragraph (b) through (f) of this section and from stationary and portable combustion equipment identified in paragraphs (g) and (h) of the section.

(b) For onshore natural gas transmission compression and natural gas transmission pipelines, report CO_2, CH_4 and N_2Oemissions from the following sources:

(1) Compressor venting (from the following sources):

(i) Reciprocating compressors. *[WCI.353(f)]*

(ii) Centrifugal compressors. *[WCI.353(e)]*

(iii) Blowdown vent stacks . *[WCI.353(c)]*

(iv) Natural gas pneumatic continuous high-bleed devices. *[WCI.353(a)]*

(v) Natural gas pneumatic pumps. *[WCI.353(a.1)]*

(vi) Natural gas pneumatic continuous low-bleed device venting. *[WCI.353(b)]*

(vii) Natural gas pneumatic intermittent (low and high) bleed device (including compressor starters) venting. *[WCI.353(b.1])*

(viii) Other venting emission sources.* *[WCI.353(l)]*

(2) Compressor fugitive equipment leaks from valves, connectors, open ended lines, pressure relief valves and meters. *[WCI.353(g)] or [WCI.353(h)}, size dependent*

(3) Compressor station flaring. *[WCI.353(d)]*

(4) Compressor other fugitive emission sources.**[WCI.353(l)]*

(5) Above grade meters and regulators and associated equipment at custody transfer meter-regulating stations, including fugitive equipment leaks from connectors, block valves, control valves, pressure relief valves, orifice meters, regulators, and open ended lines. *[WCI.353(g)]*

(6) Above grade meters and regulators and associated equipment at non-custody transfer meter-regulating stations, including station equipment leaks. *[WCI.353(h)]*

(7) Pipeline flaring. *[WCI.353(d)]*

(8) Pipeline belowground meters and regulators and valve fugitives. *[WCI.353(h)]*

(9) Pipeline other fugitive emission sources not covered in (b)(5), (b)(6), (b)(7), (b)(8) or (b0(12) (including, but not limited to, farm taps <=700 kPa, pipe leaks, and customer meter sets).*, ** *[WCI.353(l)]*

(10) Pipeline other venting emission sources.**[WCI.353(l)]*

(11) Transmission storage tanks. *[WCI.353(m)]*

(12) Third party line hits. *[WCI.353(c.1)]*

(c) For underground natural gas storage, report CO_2, CH_4 and N_2O emissions from the following sources:

(1) Venting (from the following sources):

(i) Reciprocating compressors. *[WCI.353(f)]*

(ii) Centrifugal compressors. *[WCI.353(e)]*

(iii) Natural gas pneumatic continuous high-bleed devices. *[WCI.353(a)]*

(iv) Natural gas pneumatic pumps. *[WCI.353(a.1)]*

(v) Natural gas pneumatic continuous low-bleed device venting. *[WCI.353(b)]*

(vi) Natural gas pneumatic intermittent (low and high) bleed device (including compressor starters) venting. *[WCI.353(b.1])*

(vii) Other venting emission sources.* *[WCI.353(l)]*

(2) Fugitive equipment leaks from valves, connectors, open ended lines, pressure relief valves and meters. *[WCI.353(g)], [WCI.353(h)]*

(3) Flares. *[WCI.353(d)]*

(4) Other fugitive emission sources.* *[WCI.353(l)]*

(d) For LNG storage, report CO_2, CH_4 and N_2Oemissions from the following sources:

(1) Venting (from the following sources):

(i) Reciprocating compressors. *[WCI.353(f)]*

(ii) Centrifugal compressors. *[WCI.353(e)]*

(iii) Other venting emission sources.* *[WCI.353(l)]*

(2) Fugitive equipment leaks from valves, pump seals, connectors, vapour recovery compressors, and other equipment leak sources. *[WCI.353(g)], [WCI.353(h)]*

(3) Flares. *[WCI.353(d)]*

(4) Other fugitive emission sources.* *[WCI.353(l)]*

(e) LNG import and export equipment, report CO_2, CH_4 and N_2Oemissions from the following sources:

(1) Venting (from the following sources):

(i) Reciprocating compressors. *[WCI.353(f)]*

(ii) Centrifugal compressors. *[WCI.353(e)]*

(iii) Blowdown vent stacks (including third party line hits). *[WCI.353(c)]*

(iv) Other venting emission sources.* *[WCI.353(l)]*

(2) Fugitive equipment leaks from valves, pump seals, connectors, vapour recovery compressors, and other equipment leak sources. *[WCI.353(g)], [WCI.353(h)]*

(3) Flares. *[WCI.353(d)]*

(4) Other fugitive emission sources.**[WCI.353(l)]*

(f) For natural gas distribution, report CO_2, CH_4 and N_2O emissions from the following sources:

(1) Meters, regulators, and associated equipment at above grade custody transfer metering-regulating stations, including fugitive equipment leaks from connectors, block valves, control valves, pressure relief valves, orifice meters, regulators, and open- ended lines. *[WCI.353(g)]*

(2) Meters, regulators, and associated equipment at above grade non custody transfer metering-regulating stations, including fugitive equipment leaks from connectors, block valves, control valves, pressure relief valves, orifice meters, regulators, and open- ended lines. *[WCI.353(h)]*

(3) Equipment leaks from vaults at below grade metering-regulating stations. *[WCI.353(h)]*

(4) Meters, regulators, and associated equipment at above grade metering-regulating stations. *[WCI.353(h)]*

(5) Equipment leaks from vaults at below grade metering-regulating stations *[WCI.353(h)]*

(6) Pipeline main fugitive equipment leaks. *[WCI.353(h)]*

(7) Service line fugitive equipment leaks. *[WCI.353(h)]*

(8) Pipeline flaring. *[WCI.353(d)]*

(9) Flares. *[WCI.353(d)]*

(10) Third party line hits *[WCI.353(c.1)]*

(11) Other fugitive emission sources (including, but not limited to, farm taps, and customer meter sets).*, ** *[WCI.353(l)]*

(12) Venting (from the following sources):

(i) Natural gas pneumatic continuous high-bleed devices. *[WCI.353(a)]*

(ii) Natural gas pneumatic pumps. *[WCI.353(a.1)]*

(iii) Natural gas pneumatic continuous low-bleed device venting. *[WCI.353(b)]*

(iv) Natural gas pneumatic intermittent (low and high) bleed device (including compressor starters) venting. *[WCI.353(b.1]*

(v) Other venting emission sources.* *[WCI.353(l)]*

(g) Report CO_2, CH_4, and N_2O emissions from each stationary fuel combustion source type combusting field gas or process vent gas *[WCI.363(w)]* and fuels other than field gas or process vent gas. Report stationary combustion sources that combust fuels other than field gas or process vent gas using WCI.20 (General Stationary Combustion Sources) quantification methods. The reference to process vent gas is not intended to include vent gas that is sellable quality natural gas.

(h) Report CO_2, CH_4, and N_2O emissions from each portable equipment combustion source type combusting field gas or process vent gas *[WCI.363(w)]* and fuels other than field gas or process vent gas. Report portable equipment combustion sources that combust fuels other than field gas or process vent gas using WCI.20 (General Stationary Combustion Sources) quantification methods. . The reference to process vent gas is not intended to include vent gas that is sellable quality natural gas.

(i) Report data for each aggregated source type within paragraph (b) through (f) of this section as follows (for each individual facility or aggregate of facilities reported, as required by regulation):

(1) Where there is a choice of quantification method used for a source, the specific method(s) used and under what circumstances.

(2) Facility- and company-specific emission factors or emissions information, as appropriate, used in place of Tables 350-1 to 350-5.

(3) Count of natural gas pneumatic continuous high-bleed devices.

(4) Count of natural gas pneumatic continuous low-bleed devices.

(5) Count of natural gas pneumatic intermittent (low and high) bleed devices.

(6) Count of natural gas-driven pneumatic pumps.

(7) Count of third party line hits
   (i) Engineering distribution of number of line hits by volume of gas released by hit

(8) Total pipeline length.

(9) For each dehydrator unit report the following:
   (i) Glycol dehydrators:
      (A) The number of glycol dehydrators less than and greater than or equal to 11,328 Sm^3/day operated
   (ii) Desiccant dehydrators:
      (A) The number of desiccant dehydrators operated.

(10) For each compressor report the following:
   (i) Type of compressor whether reciprocating, centrifugal dry seal, or centrifugal wet seal.
   (ii) Compressor driver capacity in horsepower.
   (iii) Number of blowdowns per year.
   (iv) Operating mode(s) during the year (i.e., operating, not operating and pressurized or not operating and depressurized).
   (v) Number of compressor starts per year.

(11) For fugitive equipment leaks and population-count/emission-factor sources, using emission factors for estimating emissions in WCI.353(g) and (h), report the following:
   (i) Component count for each source type for which an emission factor is provided in Tables 350-1, 350-2 or 350-3, 350-4 or 350-5 in this document. Approximate counts may be used for provided for the 2011 and 2012 calendar years (reported in 2012 and 2013) in preparation for full component counts in the 2013 calendar year (reported in 2014). Current processing and instrumentation drawings (P&ID) may be used for the source of component counts for all years.
   (ii) Total counts of leaks found in leak detection surveys by type of leak source for which an emission factor is provided.

(12) For natural gas distribution, report the following, in addition to other requirements:
   (i) The number of custody transfer meter-regulating stations.
   (ii) The number of non-custody transfer meter-regulating stations.

(13) Identification (including geographic coordinates) of any facility that was above 1,000 tonnes of greenhouse gas emissions in the previous year that was:
   (i) Acquired during the reporting year;
   (ii) Sold, decommissioned, or shut-in during the reporting year;

and,
(iii) The greenhouse gas emissions for the facility in the previous year.
(iv) The purchaser or seller, as appropriate

** other venting emission or other fugitive sources not specificially listed are not required to be reported if a specific other venting or other fugitive source type is reasonably estimated to be below 0.5% of total operation emissions and total emissions not reported under this clause do not exceed 1% of total operation emissions (if an individual facility is part of a larger reporting operation, the 0.5% or 1% should be interpreted as 0.5% or 1% of the reporting operation emissions, otherwise interpret as 0.5% or 1% of the facility emissions). The applicable regulator may, upon request and provision of sufficient information, provide a list of sources believed to be below these thresholds for all operations for which reporting and verification would not be required.*

*** tubing systems less than one half inch diameter may be quantified using WCI.353(g) instead of WCI.353(h) if a leak detection survey captures them. If not covered by a leak detection survey, they must be quantified using WCI.353(h). Reporting must occur using the appropriate section of WCI.352, dependent upon industry segment and quantification method used.*

§ WCI.353 Calculation of Greenhouse Gas Emissions

If greenhouse gases are not emitted from one or more of the following emission sources, the reporter will not need to calculate emissions from the emission source(s) in question and reported emissions for the emission source(s) will be zero or "not applicable". Where a quantification method is not provided for a specific source (such as for other venting and other fugitive sources), industry inventory practices must be used to estimate emissions. For ambient conditions, reporters must use average atmospheric conditions or typical operating conditions as applicable to the respective monitoring methods in this section. In general, equations are presented at the most basic unit level and emissions must be summed, so that the total population of devices and/or events are included for the reporting facility or organization, as required by regulation. Nomenclature used in the equations is presented in Table 350-7.

(a) <u>Natural gas pneumatic continuous high-bleed device venting</u> Calculate emissions from a natural gas pneumatic continuous high-bleed flow control device venting using the method specified in paragraph (a)(1) below when the device is metered. By the start of the 2014 reporting year (January 1, 2014), natural gas consumption must be metered for 50 % of the operator's pneumatic high-bleed devices (the 50% calculation of metered devices may include devices that were operational on January 1, 2012 that are no longer operational as of January 1, 2014 due to phase out or not-operating). By the start of the 2015 reporting year (January 1, 2015), natural gas consumption must be metered for all of the operator's pneumatic high-bleed devices. If a transmission or distribution company has less than 25 high bleed pneumatic devices in a jurisdiction, then the method in paragraph (a)(2) may be used for all years. For the purposes of this reporting requirement, high-bleed devices are defined as all natural gas powered devices which continuously bleed at a rate greater than 0.17 m^3/hr. For unmetered devices the operator must use the method specified in paragraph (a)(2).

(1) The operator must calculate vented emissions for metered pneumatic high-bleed devices using the following equation:

$$E_s = Q_j$$

Equation 350-1

Where:

E_s	=	Annual natural gas volumetric emissions for pneumatic high-bleed devices where gas is metered (Sm^3/y).
Q_j	=	Natural gas consumption for meter *j* (Sm^3/y).

(2) The operator must calculate vented emissions for unmetered pneumatic high-bleed devices using the following equation:

$$E_s = EF_j \times t_j$$

Equation 350-2

Where:

E_s	=	Annual natural gas volumetric emissions for pneumatic high-bleed devices where gas is unmetered (Sm^3/y).
EF_j	=	Natural gas-driven pneumatic device, j, bleed rate volume as provided by the manufacturer or in Table 350-6 (Sm^3/h/device).
t_j	=	Total time that the pneumatic device, j, has been in service (i.e. the time that the gas flows to the device) through the reporting period (h).

(3) If manufacturer data for a specific device is not available, then use data for a similar device model, size and operational characteristics to estimate emissions. If data for a reasonably similar pump model size and operational characteristics cannot be obtained, use the factor in Table 350-1 for high-bleed pneumatic devices.

(4) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (j) and (k) of this section

(5) Provide the total number of continuous high-bleed natural gas pneumatic devices as follows:

(i) In 2012, you may count 50% of the devices for each type of facility and engineering estimates can be used to determine both the denominator to be used in the 50% calculation and to estimate the number of remaining devices.

(ii) In 2013, all continuous high-bleed natural gas pneumatic devices must be counted.

(iii) In 2014, and for calendar years thereafter, facilities must update the total count of continuous high-bleed pneumatic devices and adjust accordingly to reflect any modifications due to changes in equipment.

(a.1) Natural gas pneumatic pump venting. Calculate emissions from natural gas-driven pneumatic pump venting using the method specified in paragraph (a)(1) above when the pump is metered. By the start of the 2014 reporting year (January 1, 2014), natural gas consumption must be metered for 50 % of the operator's pneumatic pumps (the 50% calculation of metered devices may include devices that were operational on January 1, 2012 that are no longer operational as of January 1, 2014 due to phase out or not-operating). By the start of the 2015 reporting year (January 1, 2015), natural gas consumption must be metered for all of the operator's pneumatic pumps. For unmetered pumps the operator must use the methods preferentially specified in paragraph (a.1)(2). If a transmission or distribution company has less than 25 pneumatic pumps in a jurisdiction, then the method in paragraph (a.1)(2) may be used for all years Natural gas-driven pneumatic pumps covered in paragraph (d) (dehydrator vents) of this section do not have to report emissions under paragraph (a.1) of this section.

(1) The operator must calculate vented emissions for metered pneumatic pumps using Equation 350-1.

(2) The operator must calculate vented emissions for unmetered pneumatic pumps using Equation 350-3.

(i) Obtain from the manufacturer specific pump model natural gas emission (or manufacturer "gas consumption") per unit volume of liquid circulation rate at pump speeds and operating pressures. If manufacturer data for a specific pump is not available, then use data for a similar pump model, size and operational characteristics to estimate emissions.

(ii) Maintain a log of the amount of liquid pumped annually from individual pumps*.

(iii) Calculate the natural gas emissions for each pump using Equation 350-3.

$$E_s = EF_j \times Q_j$$

Equation 350-3

Where:

E_s = Annual natural gas volumetric emissions (Sm^3/y).

EF_j = Natural gas-driven pneumatic pump gas emission factor expressed in "emission per volume of liquid pumped at operating pressure" as provided by the manufacturer for pump *j* ($Sm^3/liter$).

Q_j = Volume of liquid pumped annually by pump *j* (liters/y).

(3) If manufacturer data for a specific pump, or reasonably similar pump model size and operational characteristics cannot be obtained; Equation 350-2 can be used with the

population emission factor for natural gas-driven pneumatic pumps provided in Tables 350-1 or 350-2.

(4) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (j) and (k) of this section

(5) Provide the total number of natural gas pneumatic pumps as follows:

(i) In 2012, you may count 50% of the devices for each type of facility and engineering estimates can be used to determine both the denominator to be used in the 50% calculation and to estimate the number of remaining pumps.

(ii) In 2013, all natural gas pneumatic pumps must be counted.

(iii) In 2014, and for calendar years thereafter, facilities must update the total count of pneumatic pumps and adjust accordingly to reflect any modifications due to changes in equipment.

** an engineering estimation approach may be used in 2012 to calculate the amount of liquid pumped annually from natural gas driven odourant injection pumps used in the distribution system, either in individual or in bulk*

(b) Natural gas pneumatic continuous low-bleed device venting. Calculate emissions from natural gas pneumatic continuous low-bleed device venting using Equation 350-4 of this section.

$$E_s = EF_j \times t_j$$

Equation 350-4

Where:

E_s	=	Annual natural gas volumetric emissions for pneumatic continuous low-bleed bleed devices (Sm^3/y).
EF_j	=	Population emission factor for natural gas-driven pneumatic continuous low-bleed device, *j*, as provided in Tables 350-1 and 350-2 ($Sm^3/h/device$).
t_j	=	Total time that the pneumatic device, *j*, has been in service (i.e. the time that the gas flows to the device) through the reporting period (h).

(1) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (j) and (k) of this section.

(2) Provide the total number of continuous low-bleed natural gas pneumatic devices of each type as follows:

(i) In 2012, you may count 50% of the devices for each type of facility and engineering estimates can be used to determine both the denominator to be used in the 50% calculation and to estimate the number of remaining devices.

(ii) In 2013, all continuous low-bleed natural gas pneumatic devices must be counted.

(iii) In 2014, and for calendar years thereafter, facilities must update the total count of continuous low-bleed natural gas pneumatic devices and adjust accordingly to reflect any modifications due to changes in equipment.

(b.1) Natural gas pneumatic intermittent (low and high) bleed device venting. Calculate emissions from natural gas pneumatic intermittent (low and high) bleed device venting as follows.

(1) The operator must calculate vented emissions for pneumatic intermittent (low and high) bleed devices used to maintain a process condition such as liquid level, pressure, delta-pressure or temperature using Equation 350-5:

$$E_s = EF_j \times t_j$$

Equation 350-5

Where:

E_s	=	Annual natural gas volumetric emissions for pneumatic intermittent (low and high) bleed devices (Sm^3/y).
EF_j	=	Emission factor for natural gas-driven pneumatic intermittent (low and high) bleed device, *j*, as provided in Table 350-1 or Table 350-6 (Sm^3/h/device).
t_j	=	Total time that the pneumatic device, *j*, has been in service (i.e. the time that the gas flows to the device) through the reporting period (h).

(2) The operator must calculate vented emissions for pneumatic intermittent (high) bleed devices, used to drive compressor starters, using Equation 350-6*:

$$E_s = EF_j \times t_j$$

Equation 350-6

Where:

E_s	=	Annual natural gas volumetric emissions for pneumatic intermittent (high) bleed devices (Sm^3/y).
EF_j	=	Emission factor for natural gas-driven pneumatic compressor starter, *j*, as provided by the manufacturer (Sm^3/min/device).
t_j	=	Total time that the pneumatic device, *j*, has been in service (i.e. the time that the gas flows to the device) through the reporting period (min).

(3) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (j) and (k) of this section.

(4) Provide the total number of intermittent (low and high) bleed natural gas pneumatic devices as follows:

(i) In 2012, you may count 50% of the devices for each type of facility and engineering estimates be used to determine both the denominator to be used in the 50% calculation and to estimate the number of remaining devices.

(ii) In 2013, all intermittent (low and high) bleed natural gas pneumatic devices must be counted.

(iii) In 2014, and for calendar years thereafter, facilities must update the total count of intermittent (low and high) bleed natural gas pneumatic devices and adjust accordingly to reflect any modifications due to changes in equipment.

** for 2012, the volume of gas per start provided by the manufacturer may be used in place of the EF_j and t_j variables*

(c) <u>Blowdown vent stacks</u>. Calculate blowdown vent stack emissions from depressurizing equipment to reduce system pressure for planned or emergency shutdowns or to take equipment out of service for maintenance (excluding depressurizing to a flare, over-pressure relief, operating pressure control venting and blowdown of non-GHG gases) as follows:

(1) Calculate the total physical volume (including, but not limited to, pipes, compressor case or cylinders, manifolds, suction and discharge bottles and vessels) between isolation valves determined by engineering estimates based on best available data.

(2) If the total physical volume between isolation valves is greater than or equal to 1.42 $m^{3,}$ retain logs of the number of blowdowns for each equipment system (including, but not limited to pipes, compressors and vessels). Physical volumes smaller than 1.42 $m^3$are exempt from reporting under paragraph (c) of this section

(3) Calculate the venting emissions for each equipment system j using Equation 350-7 of this section:

$$E_s = V_v\left[\frac{(273.15+T_s)(P_{a,1}-P_{a,2})}{(273.15+T_a)P_s}\right]$$

Equation 350-7

Where:

E_s = Natural gas venting volumetric emissions from blowdown of equipment system (Sm^3).

V_j = Total physical volume of blowdown equipment chambers (including, but not limited to, pipes, compressors and vessels) between isolation valves for the equipment system (m^3).

T_s = Temperature at standard conditions (ºC).

T_a = Temperature at actual conditions in the equipment system (^oC).

P_s = Absolute pressure at standard conditions (kPaa).

$P_{a,1}$ = Absolute pressure at actual conditions in the equipment system (kPaa) prior to depressurization.

$P_{a,2}$ = Absolute pressure at actual conditions in the equipment system after depressurization; 0 if equipment is purged using non-GHG gases (kPaa).

(4) Calculate both CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (j) and (k) of this section.

(5) Blowdowns that are directed to flares use the WCI.353(d) Flare stacks calculation method rather than WCI.353(c) Blowdown vent stacks calculation method.

(c.1) Third party line hits. Calculate emissions from third party line hits as follows:

(1) For each dig-in incident (i.e., line hit) which results in gas release ≥ 1.416 Sm^3, calculate volumetric flow rate prior to pipeline isolation for both catastrophic pipeline ruptures and pipeline puncture incidents using the appropriate methodology below[1]. For 2012, the methodology referenced in paragraph (iv) may be used in addition to those in paragraphs (i) and (ii).

(i) For catastrophic pipeline ruptures where the pipeline is severed use the following methodology:

$$Q_s = \frac{3.6x10^6 \times A}{\rho_s} \sqrt{\frac{K \times MW}{1000 \times R \times (273.15 + T_a)}} \times \frac{P_a \times M}{\left(1 + \frac{K-1}{2} M^2\right)^{\frac{K+1}{2(K-1)}}}$$

Equation 350-8

Where:

[1] Methodology Manual, Estimation of Air Emissions from the Canadian Natural Gas Transmission, Storage and Distribution System, Prepared for Canadian Energy Partnership for Environmental Innovation (CEPEI). Prepared by Clearstone Engineering Ltd. Calgary, Alberta, September 25, 2007. Chapter7, Third-Party Dig-Ins, page 117.

$$M = \sqrt{\frac{2\left[\left(\frac{P_a}{P_e}\right)^{\frac{K-1}{K}} - 1\right]}{K-1}} \text{, (for M} \leq 1\text{),}$$

Equation 350-9

M = 1, (for all other cases)

Where:

Q_s	=	natural gas venting volumetric flow rate (Sm^3/h)
A	=	cross-sectional flow area of the pipe (m^2, $A=\pi D^2/4000$)
D	=	inside diameter of the pipe (mm)
K	=	specific heat ratio of the gas (dimensionless – 1.299 for methane)
M	=	Mach number of the flow (m/s)
MW	=	molecular weight of the gas (kg/mole, 16.043 kg/mole for methane)
P_e	=	pressure at the damage point (local atmospheric pressure, kPaa)
P_a	=	pressure inside the pipe at supply (kPaa)) (usually taken at the point where the damaged main branches off a larger main). The supply pressure values should represent a stable supply pressure; however, it is important to account for the lower pressure which will occur because of the flow of gas from the break.
R	=	universal gas constant (8.3145 $kPam^3/kmol/K$)
T_a	=	temperature inside pipe at the supply (˚C)
ρ_s	=	gas density at standard conditions (kg/m^3) (0.6785 kg/m^3 for CH_4)

(ii) For pipeline punctures use the following methodology (for flows not choked):

$$Q_s = \frac{A_e}{\rho_s}\sqrt{\frac{2000 \cdot K}{K-1} P_a \rho_a \left[\left(\frac{P_{Atm}}{P_a}\right)^{2/K} - \left(\frac{P_{Atm}}{P_a}\right)^{(K+1)/K}\right]}$$

Equation 350-10

Where:

$$\left(\frac{P_{Atm}}{P_a}\right) \geq \left(\frac{P_{Atm}}{P_a}\right)_{choked} = \left(\frac{2}{K+1}\right)^{K/(K-1)} = 0.546 \qquad \text{(for methane)}$$

Equation 350-11

Where:

A_e	=	size of the hole in the pipe (m^2)
P_a	=	pressure inside the pipe at the puncture location (kPaa)
ρ_a	=	gas density inside the pipe at the puncture location (kg/m^3)
MW	=	molecular weight of the natural gas (16.043 for methane)
T_a	=	temperature inside the pipe (˚C)
$(P_{ATM}/P_a)_c$	=	0.546 - lower limit for choked flow

(iii) Check for choked flow

(A) If (P_{ATM}/P_a) is ≥0.546 flow is not choked and the reporter must use the equations in section (c.1)(ii) above.

(B) If (P_{ATM}/P_a) <0.546 flow is choked and A must be set to the cross sectional flow area of the pipe and the reporter must use the equations in section (c.1)(i) above.

(iv) For 2012 calendar year emissions, an operator may use other methods to calculate emissions published in the CEPEI Methodology Manual, or other industry standard reference sources.

(v) Calculate volumetric natural gas emissions by multiplying Q_s for each pipeline rupture and puncture by the total elapsed time from pipeline rupture or puncture until isolation and final bleed-down to atmospheric pressure.

(vi) Calculate GHG (CH_4 and CO_2 emissions) mass emissions using the methodologies in sections (j) and (j) of this section.

(d) Flare stacks. Calculate CO_2, CH_4, and N_2O emissions from a flare stack as follows:

(1) If there is a continuous flow measurement device on the flare, measured flow volumes can be used to calculate the flare gas emissions. If all of the flare gas is not measured by the existing flow measurement device, then the flow not measured can be estimated using engineering calculations based on best available data or company records. If there is not a continuous flow measurement device on the flare, a flow measuring device can be installed on the flare or use engineering calculations based on process knowledge, company records, and best available data.

(2) If there is a continuous gas composition analyzer on the gas stream to the flare, these compositions must be used in calculating emissions. If there is not a continuous gas composition analyzer on the gas stream to the flare, use the gas compositions for each stream of hydrocarbons going to the flare (must be determined using (j)(1) and (j)(2) of this section).

(3) Determine flare combustion efficiency from manufacturer. If not available, assume that flare combustion efficiency is 98 percent.

(4) Calculate GHG volumetric emissions at actual conditions using Equations 350-12, 350-13, 350-14, and 350-15 of this section.

$$E_{s,CH4}(noncombusted) = Q_s \times (1-\eta) \times Y_{CH4}$$ **Equation 350-12**

$$E_{s,CO2}(noncombusted) = Q_s \times Y_{CO2}$$ **Equation 350-13**

$$E_{s,CO2}(combusted) = \sum_i \eta \times Q_s \times Y_i \times n_i$$ **Equation 350-14**

$$E_{s,CO2}(total) = E_{s,CO2}(combusted) + E_{s,CO2}(noncombusted)$$ **Equation 350-15**

Where:

$E_{s,CH4}$ (noncombusted)	=	Contribution of annual noncombusted volumetric CH_4 emissions from flare stack (Sm^3).
$E_{s,CO2}$ (noncombusted)	=	Contribution of annual volumetric CO_2 emissions from CO_2 in the inlet gas passing through the flare noncombusted (Sm^3).
$E_{s,CO2}$ (combusted)	=	Contribution of annual volumetric CO_2 emissions from combustion from flare stack (Sm^3).
Q_s	=	Volume of natural gas sent to flare during the year (Sm^3).
η	=	Fraction of natural gas combusted by flare (default combustion efficiency is 0.98). For gas sent to an unlit flare, η is zero.
Y_{CH4}	=	Mole fraction of CH_4 in gas to the flare.
Y_{CO2}	=	Mole fraction of CO_2 in gas to the flare.
Y_i	=	Mole fraction of hydrocarbon constituents *i* (i.e., methane, ethane, propane, butane, pentanes, hexanes and pentanes plus) in natural gas to the flare.
n_i	=	Number of carbon atoms in the hydrocarbon constituent *i*; 1 for methane, 2 for ethane, 3 for propane, 4 for butane, 5 for pentanes, 6 for hexanes and 7 for pentanes plus) in natural gas to the flare.

(5) Calculate both CH_4 and CO_2 mass emissions from volumetric CH_4 and CO_2 emissions using the calculation in paragraph (k) of this section.

(6) Calculate N_2O emissions using Equation 350-16.

$$E_{N2O} = Q_s \times HHV \times EF \times 0.001$$

Equation 350-16

Where:

E_{N2O}	=	Annual N_2O mass emissions from flaring (tonnes/y).
Q_s	=	Volume of gas combusted by the flare in the reporting period (Sm^3/y).
HHV	=	High heat value of the flared gas from paragraph (d)(2)
EF	=	N_2O emission factor. Use 9.52×10^{-5} kg N_2O/GJ.
0.001	=	Conversion factor from kilograms to tonnes.

(7) To avoid double-counting, this emissions source excludes any emissions calculated under other emissions sources in this section. Where gas to be flared is manifolded from multiple sources in WCI.353 to a common flare, report all flaring emissions under WCI.353(d).

(e) Centrifugal compressor venting. Calculate emissions from centrifugal compressor vents as follows.

(1) The operator must calculate CO_2, and CH_4, and N_2O (when flared) emissions from both wet seal and dry seal centrifugal compressor vents (including wet seal oil degasing) for all compressors using a temporary or permanent flow measurement meter such as, but not limited to, a vane anemometer according to methods set forth in WCI.354(b).

(2) Estimate annual emissions using flow meter measurement using Equation 350-17 of this section.

$$E_{s,i} = \sum_{m} Q_{s,m} \times t_m \times Y_{i,m} \times (1 - CF)$$

Equation 350-17

Where:

$E_{s,i}$ = Annual GHG *i* (either CH_4 or CO_2) volumetric emissions from all measured compressor venting modes(Sm^3).

$Q_{s,m}$ = Measured volumetric gas emissions during operating mode *m* described in paragraph (e)(4) of this section (Sm^3/h).

t_m = Total time the compressor is in operating mode *m* during the calendar year (h)

Y_i = Mole fraction of GHG *i* in the degassing vent gas; use the appropriate gas compositions in paragraph (j)(2) of this section.

CF = Fraction of centrifugal compressor vent gas sent to vapour recovery or fuel gas or other beneficial use as determined by keeping logs of the number of operating hours for the vapour recovery system and the amount of vent gas that is directed to the fuel gas system. An engineering estimation approach may be used for the CF parameter for 2012 emissions reporting.

(3) An engineering estimate approach based on similar equipment specifications and operating conditions may be used to determine the $Q_{s,m}$ variable in place of actual measured values for centrifugal compressors that are operated for no more than 200 hours in a calendar year and used for peaking purposes in place of metered gas emissions if an applicable meter is not present on the compressor.

(4) Conduct an annual measurement for each compressor in the mode in which it is found during the annual measurement. Measure emissions from (including emissions manifolded to common vents) unit isolation-valve vents and blowdown-valve vents.

(i) Operating or standby-pressurized mode, blowdown vent leakage through the blowdown vent stack.

(ii) Operating mode.

(iii) Not operating, depressurized mode, unit isolation-valve leakage through the blowdown vent stack, without blind flanges.

(A) For the not operating, depressurized mode, each compressor must be measured at least once in any three consecutive calendar years if this mode is not found in the annual measurement. If a compressor is not operated and has blind flanges in place throughout the 3 year period, measurement is not required in this mode. If the compressor is in standby depressurized mode without blind flanges in place and is not operated throughout the 3 year period, it must be measured in the standby depressurized mode.

(5) Calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (k) of this section.

(6) Calculate emissions from degassing vent vapours to flares as follows:

(i) Use the degassing vent vapour volume and gas composition as determined in paragraphs (e)(1) through (3) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (d) of this section to determine degassing vent vapour emissions from the flare.

(7) Emissions from dry seal centrifugal compressor vents, blow down valve leakage and unit isolation valve leakage to open ended vented lines must use methods outlined in EPA Subpart W 98.233(o)

(f) Reciprocating compressor venting. Calculate annual CH_4 and CO_2 emissions from all reciprocating compressor vents as follows. Where venting emissions are sent to a common flare, calculate emissions using WCI.353(d).

(1) Estimate annual emissions using the flow measurement in (f)(2) or (f)(3) below and Equation 350-18.

$$E_{s,i} = \sum_{m} Q_{s,m} \times t_m \times Y_i \times (1 - CF)$$

Equation 350-18

Where:

$E_{s,i}$ = Annual volumetric emissions of GHG *i* (either CH_4 or CO_2)from all measured compressor venting modes (Sm^3/y).

$Q_{s,m}$ = Measured volumetric gas emissions during operating mode *m* described in paragraph (f)(4) (Sm^3/h)..

t_m = Total time the compressor is in operating mode *m* during the calendar year (h).

Y_i = Mole fraction of GHG *i* in the vent gas; use the appropriate gas compositions in paragraph (j)(2) of this section.

CF = Fraction of reciprocating compressor vent gas sent to vapour recovery or fuel gas or other beneficial use as determined by keeping logs of the number of operating hours for the vapour recovery system and the amount of vent gas that is directed to the fuel gas system. An engineering estimation approach may be used for the CF parameter for 2012 emissions reporting.

(2) If the reciprocating rod packing and blowdown vent is connected to an open-ended vent line then use one of the following two methods to calculate emissions.

(i) Measure emissions from all vents (including emissions manifolded to common vents) including rod packing, unit isolation valves, and blowdown vents using either calibrated bagging or High-flow Sampler according to methods set forth in WCI.354(c) and (d).

(ii) Use a temporary meter such as a vane anemometer or a permanent meter such as an orifice meter to measure emissions from all vents (including emissions manifolded to a common vent) including rod packing vents, unit isolation valves, and blowdown valves according to methods set forth in WCI.354(b). If you do not have a permanent flow meter, you may install a port for insertion of a temporary meter or a permanent flow meter on the vents. For through-valve leakage to open-ended vents, such as unit isolation valves on not-operating, depressurized compressors and blowdown valves on pressurized compressors, you may use an acoustic detection device according to methods set forth in WCI.354(a).

(3) If the rod packing case is not equipped with a vent line use the following method to estimate emissions:

(i) Use the methods described in WCI.354(a) to conduct a progressive leak detection of fugitive equipment leaks from the packing case into an open distance piece, or from the compressor crank case breather cap or vent with a closed distance piece.

(ii) Measure emissions using a High-flow Sampler, or calibrated bag, or appropriate meter according to methods set forth in WCI.354(b), (c), or (d).

(4) Conduct an annual measurement for each compressor in the mode in which it is found during the annual measurement. Measure emissions from (including emissions manifolded to common vents) reciprocating rod-packing vents, unit isolation-valve vents, and blowdown-valve vents.

(i) Operating or standby-pressurized mode, blowdown vent leakage through the blowdown vent stack.

(ii) Operating mode, reciprocating rod-packing emissions.

(iii) Not operating, depressurized mode, unit isolation-valve leakage through the blowdown vent stack, without blind flanges.

(A) For the not operating, depressurized mode, each compressor must be measured at least once in any three consecutive calendar years if this mode is not found in the annual measurement. If a compressor is not operated and has blind flanges in place throughout the 3 year period, measurement is not required in this mode. If the compressor is in standby depressurized mode without blind flanges in place and is not operated throughout the 3 year period, it must be measured in the standby depressurized mode

(5) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in paragraphs (j) and (k) of this section.

(6) Determine if the reciprocating compressor vent vapors are sent to a vapor recovery system.

(i) Adjust the emissions estimated in paragraphs (f)(1) of this section downward by the magnitude of emissions recovered using a vapor recovery system as determined by engineering estimate based on best available data.

(ii) An engineering estimate approach based on similar equipment specifications and operating conditions or manufacturer's data may be used to determine the $Q_{s,m}$ variable in place of actual measured values for reciprocating compressors that are are operated for no more than 200 hours in a calendar year .

(g) Leak detection and leaker emission factors. Existing legislative or regulatory requirements (described in WCI.354(a)(0.1)) or progressive sampling methods (described in WCI.354(a)(0.2)) must be used to conduct a leak detection survey of fugitive equipment leaks from all sources listed in WCI.352(b)(2) (where total emissions for a compressor station are 10,000 tonnes CO_2e or greater), (b)(5), (c)(2), (d)(2), (e)(2), and (f)(1). This paragraph (g) applies to emissions sources in streams with gas containing greater than 10 percent CH_4 plus CO_2 by weight. Emissions sources in streams with gas containing less than 10 percent CH_4 plus CO_2 by weight need to be reported instead under paragraph (l) of this section. **

If fugitive equipment leaks are detected for sources listed in this paragraph, calculate equipment leak emissions per source per reporting facility using Equation 350-19 (for volumetric emission factor [Sm^3/h/component]) or Equation 350-20 (for mass emission factors [t/h/component]) of this section, as appropriate, for each source with fugitive equipment leaks.

$$E_i = EF_s \times Y_i \times t \times \rho_{s,i} \times 0.001$$

Equation 350-19

$$E_{s,i} = EF_s \times Y_i \times t$$

Equation 350-20

Where:

$E_{s,i}$	=	Annual total mass emissions of GHG *i* (CH_4 or CO_2) from each fugitive equipment leak source (tonnes/year).
EF_s	=	Leaker emission factor for specific sources listed in Table 350-1 through Table 350-5 of this section or facility/company-specific emission factors* used in place of Tables 350-1 to 350-5 (Sm^3/component/year for Equation 350-19 and tonnes/ component/year for Equation 350-20).
Y_i	=	For volumetric emissions in Equation 350-19, use 1 for CH_4 and 1.1×10^{-2} for CO_2. For mass emissions in Equation 350-20, use mass fractions of CH_4 and CO_2 from each unit of a distribution or transmission company within a

		jurisdiction that has similar gas composition or the 2007 Canadian Energy Partnership for Environmental Innovation (CEPEI) Methodology Manual.[2]
t	=	Total time the component was found leaking and operational, in hours. If one leak detection survey is conducted, assume the component was leaking from the start of the year until the leak was repaired and then zero for the remainder of the year. If the leak was not repaired, assume the component was leaking for the entire year. If multiple leak detection surveys are conducted, assume that the component found to be leaking has been leaking since the last survey during which it was determined to be not leaking, or the beginning of the calendar year. For the last leak detection survey in the calendar year, assume that all leaking components continue to leak until the end of the calendar year or until the component was repaired and then zero until the end of the year.
$\rho_{s,i}$	=	Density of GHG *i* (1.861 kg/m^3 for CO_2 and 0.678 kg/m^3 for CH_4 at standard conditions of 15 ºC and 1 atmosphere).
0.001	=	Conversion factor from kilograms to tonnes.

(1) Onshore natural gas transmission compression facilities shall use the appropriate default leaker emission factors listed in Table 350-1 of this section for fugitive equipment leaks detected from connectors, valves, pressure relief valves, meters, and open ended lines.

(2) Underground natural gas storage facilities for storage stations shall use the appropriate default leaker emission factors listed in Table 350-2 of this section for fugitive equipment leaks detected from connectors, valves, pressure relief valves, meters, and open-ended lines.

(3) LNG storage facilities shall use the appropriate default leaker emission factors listed in Table 350-3 of this section for fugitive equipment leaks detected from valves, pump seals, connectors, and other equipment.

(4) LNG import and export facilities shall use the appropriate default leaker emission factors listed in Table 350-4 of this section for fugitive equipment leaks detected from valves; pump seals; connectors; and other.

(5) Natural gas distribution facilities for above ground meters and regulators at custody transfer meter-regulating stations shall use the appropriate default leaker emission factors listed in Table 350-5 of this section for fugitive equipment leaks detected from connectors, block valves, control valves, pressure relief valves, orifice meters, regulators, and open ended lines.

** component-specific emission factors may equal leak rates quantified, following WCI.354(c) or (d), during leak detection surveys.*

[2] Clearstone Engineering Ltd. *Methodology Manual: Estimation of Air Emissions from the Canadian Natural Gas Transmission, Storage and Distribution System.* Prepared for Canadian Energy Partnership for Environmental Innovation (CEPEI). 2007

*** tubing systems less than one half inch diameter may be quantified using WCI.353(g) instead of WCI.353(h) if a leak detection survey captures them. If not covered by a leak detection survey, they must be quantified using WCI.353(h). Reporting must occur using the appropriate section of WCI.352, dependent upon industry segment and quantification method used.*

(h) Population count and emission factors. This paragraph applies to emissions sources listed in WCI.352 (b)(2) (where total emissions for a compressor station are less than 10,000 tonnes CO_2e), b(6), b(8), (c)(2), (d)(2), (e)(2), (f)(2), (f)(3), (f)(4), (f)(5), (f)(6) and (f)(7) on streams with gas containing greater than 10 percent CH_4 plus CO_2 by weight. Emissions sources in streams with gas containing less than 10 percent CH_4 plus CO_2 by weight do not need to be reported. **

Calculate emissions from all sources listed in this paragraph using Equation 350-21 (for volumetric emission factor [m^3/h/component]) or Equation 350-22 (for mass emission factors [kg/h/component]) of this section, as appropriate.

$$E_i = N \times EF_s \times Y_i \times t \times \rho_{s,i} \times 0.001$$

Equation 350-21

$$E_i = N \times EF_s \times X_i \times t \times 0.001$$

Equation 350-22

Where:

E_i	=	Annual total mass emissions of GHG *i* (CH_4 or CO_2) from each fugitive source (tonnes/year).
$E_{s,i}$	=	Annual total volumetric emissions of GHG *i* (CH_4 or CO_2) from each fugitive source (Sm^3/year).
N	=	Total number of this type of emission source at the facility. Per WCI.352(i)(11), average component counts by major equipment pieces from the 2007 Canadian Energy Partnership for Environmental Innovation Methodology Manual (or other relevant Canadian Gas Association and/or Canadian Association of Petroleum Producers documentation) may be used for 2011 and 2012 calendar year emissions as appropriate for operations and required by (h)(1) through (h)(4), below. For 2013 calendar year emissions and onwards component counts for individual facilities must be used. If facility or company-specific major equipment count data that meet or exceed the quality of the relevant CGA default count data are available, they must be used in its place. Current processing and instrumentation drawings (P&ID) may be used for the source of component (or major equipment) counts for all years.

EF_s	=	Population emission factor for specific sources listed in Table 350-1 through Table 350-5 of this section (Sm^3/component/hour for Equation 350-21 and tonnes/component/hour for Equation 350-22). EF for custody transfer meter-regulating stations is determined in Equation 350-23. Direction on the use of Tables 350-1 through 350-5, provided prior to the tables, must be followed and indicates that if facility specific emission factors are available these facility specific emission factors must be used*.
Y_i	=	For volumetric emissions in Equation 350-21, use 1 for CH_4 and 1.1×10^{-2} for CO_2.
X_i	=	For mass emissions in Equation 350-22, use mass fractions of CH_4 and CO_2 from operation/facility-specific data or the 2007 Canadian Energy Partnership for Environmental Innovation Methodology Manual.
t	=	Total time the specific source associated with the fugitive equipment leak was operational in the reporting year (hours).
$P_{s,i}$	=	Density of GHG *i* (1.861 kg/m^3 for CO_2 and 0.678 kg/m^3 for CH_4 at standard conditions of 15 ºC and 1 atmosphere).
0.001	=	Conversion factor from kilograms to tonnes.

(1) Underground natural gas storage facilities for storage wellheads shall use the appropriate default population emission factors listed in Table 350-2 of this section for fugitive equipment leaks from connectors, valves, pressure relief valves, and open-ended lines.

(2) LNG storage facilities shall use the appropriate default population emission factors listed in Table 350-3 of this section for fugitive equipment leaks from vapour recovery compressors.

(3) LNG import and export facilities shall use the appropriate default population emission factor listed in Table 350-4 of this section for fugitive equipment leaks from vapour recovery compressors.

(4) Natural gas distribution facilities shall use the appropriate emission factors as described in paragraph (h)(4) of this section.

(i) Below grade metering-regulating stations; distribution mains; and distribution services, shall use the appropriate default population emission factors listed in Table 350-5 of this section.

(ii) Above grade meters and regulators at meter-regulating stations not at custody transfer as listed WCI.352(f)2), must use the total volumetric GHG emissions at standard conditions for all equipment leak sources calculated in paragraph (g)(5) of this section to develop facility emission factors using Equation 350-23 of this section. The calculated facility emission factor from Equation 350-23 of this section shall be used in Equations 350-15 and 350-16 of this section.

$$EF_{s,i} = \sum \frac{E_{s,i}}{N \times 8760}$$ **Equation 350-23**

Where:

$EF_{s,i}$	=	Facility emission factor for a meter/regulator run at above grade metering-regulating for GHG_i (Sm^3/year).
$E_{s,i}$	=	Annual volumetric GHG emissions, CO_2 or CH_4 from all equipment leak sources at all above-grade, custody-transfer, metering-regulating stations, from paragraph (g) of this section (Sm^3).
N	=	Total number of meter/regulator runs at all custody-transfer, metering-regulating stations.
8760	=	Conversion to hourly emissions

(iii) To ensure proper calculation of emissions from buried pipeline-main and service line equipment leaks, Equations 350-21 and 350-22 and their inputs may be modified as necessary to meet 2007 Canadian Energy Partnership for Environmental Innovation Methodology Manual standards. For example, the length of the installed underground pipeline used in place of count and company-specific leak data and CEPEI manual equations is permitted.

** facility -specific emission factors may equal leak rates quantified, following WCI.354(c) or (d), during leak detection surveys or those emission factors calculated for the purposes of WCI.357 – Directions for the use of Tables 350-1 to 350-5.*
*** tubing systems less than one half inch diameter may be quantified using WCI.353(g) instead of WCI.353(h) if a leak detection survey captures them. If not covered by a leak detection survey, they must be quantified using WCI.353(h). Reporting must occur using the appropriate section of WCI.352, dependent upon industry segment and quantification method used.*

(i) Volumetric emissions. Calculate volumetric emissions at standard conditions as specified in paragraphs (i)(1) or (2) , with actual pressure and temperature of this section determined by engineering estimate based on best available data unless otherwise specified.

(1) Calculate natural gas volumetric emissions at standard conditions by converting actual temperature and pressure to standard temperature and pressure (15 ºC and 1 atmosphere in Canada) using Equation 350-24 of this section.

$$E_s = \frac{E_a \times (273.15 + T_s) \times P_a}{(273.15 + T_a) \times P_s}$$

Equation 350-24

Where:

E_s	=	Natural gas volumetric emissions at standard temperature and pressure (STP) conditions (Sm^3).

E_a = Natural gas volumetric emissions at actual conditions (m^3).
T_s = Temperature at standard conditions (^oC).
T_a = Temperature at actual emission conditions (^oC).P_s = Absolute pressure at standard conditions (kPa).
P_a = Absolute pressure at actual conditions (kPa).

(2) Calculate GHG volumetric emissions at standard conditions by converting actual temperature and pressure of GHG emissions to standard temperature and pressure using Equation 350-25 this section.

$$E_{s,i} = \frac{E_{a,i} \times (273.15 + T_s) \times P_a}{(273.15 + T_a) \times P_s}$$

Equation 350-25

Where:

$E_{s,i}$ = GHG *i* volumetric emissions at standard temperature and pressure (STP) conditions (Sm^3).
$E_{a,i}$ = GHG *i* volumetric emissions at actual conditions (m^3).
T_s = Temperature at standard conditions. (^oC).
T_a = Temperature at actual emission conditions. (^oC).
P_s = Absolute pressure at standard conditions (kPa).
P_a = Absolute pressure at actual conditions (kPa).

(j) GHG volumetric emissions. If the GHG volumetric emissions at actual conditions are known, follow the method in (j)(2) to calculate their emissions at standard conditions. If the GHG volumetric emissions are not yet known, then follow the methods below to calculate GHG volumetric emissions at standard conditions as specified in paragraphs (j)(1) and (2) of this section determined by engineering estimate based on best available data unless otherwise specified.

(1) Estimate CH_4 and CO_2 emissions from natural gas emissions using Equation 350-26 of this section.

$$E_{s,i} = E_s \times Y_i$$

Equation 350-26

Where:

$E_{s,i}$ = GHG *i* (either CH_4 or CO_2) volumetric emissions at standard conditions.
$E_{s,}$ = Natural gas volumetric emissions at standard conditions.
Y_i = Mole fraction of GHG *i* in the natural gas.

(2) For Equation 350-26 of this section, the mole fraction, Y_i, shall be the annual average mole fraction for each unit of a natural gas distribution, natural gas transmission, LNG storage, LNG import or export, or underground natural gas storage company within a jurisdiction that has similar gas composition as sampled within the current (required if available) or previous (if current data not available) reporting period, using the methods set forth in WCI.354(b), and specified in paragraphs (j)(2)(i) through (v) of this section.

(i) GHG mole fraction in transmission pipeline natural gas that passes through the facility for onshore natural gas transmission compression facilities.

(ii) GHG mole fraction in natural gas stored in underground natural gas storage facilities.

(iii) GHG mole fraction in natural gas stored in LNG storage facilities.

(iv) GHG mole fraction in natural gas stored in LNG import and export facilities.

(v) GHG mole fraction in local distribution pipeline natural gas that passes through the facility for natural gas distribution facilities.

(k) GHG mass emissions. Calculate GHG mass emissions in tonnes of carbon dioxide equivalent by converting the GHG volumetric emissions at standard conditions into mass emissions using Equation 350-27 of this section.

$$E_i = E_{s,i} \times \rho_{s,i} \times GWP_i \times 0.001$$

Equation 350-27

Where:

E_i = GHG *i* (either CH_4, CO_2, or N_20) mass emissions (tonnes CO_2e).

$E_{s,i}$ = GHG *i* (either CH_4, CO_2 or N_2O) volumetric emissions (Sm^3).

$\rho_{s,i}$ = Density of GHG *i* (1.861 kg/m^3 for CO_2 and 0.678 kg/m^3 for CH_4 at standard conditions of T_s = 15°C and P_s = 101.325 kPa).

$$= \frac{P_s \times MW_i}{R_u \times (T_s + 273.15)}$$

GWP_i = Global warming potential of GHG *i*, (1 for CO_2 and 21 for CH_4, and 310 for N_2O).

MW_i = Molecular weight for GHG_i taken from the 12th edition of the Gas Processors Suppliers Association Engineering Data Book (kg/kmole).

R_u = Universal gas constant (8.31434 kJ/kmole K)

0.001 = Conversion factor from kilograms to tonnes.

(l) Other venting or fugitive emissions. All venting or fugitive emissions not covered by quantification methods in WCI.353 must be calculated by methodologies consistent with those presented here, in the 2007 Canadian Energy Partnership for Environmental Innovation Methodology Manual[3] (as amended from time to time), or in other relevant Canadian Gas Association documentation.

(m) Transmission storage tanks. For condensate storage tanks, either water or hydrocarbon, without vapour recovery or thermal control devices in onshore natural gas transmission compression facilities calculate CH_4, CO_2 and N_2O (when flared) annual emissions from compressor scrubber dump valve leakage as follows. For 2012, other methodologies may be used to quantify emissions from transmission storage tanks in addition to those outlined below.

(1) Monitor the tank vapour vent stack annually for emissions using an optical gas imaging instrument according to methods set forth in WCI.354(a)(1) or by directly measuring the tank vent using a flow meter, calibrated bag, or High-flow Sampler according to methods in WCI.354(b) through (d) for a duration of 5 minutes. Or you may annually monitor leakage through compressor scrubber dump valve(s) into the tank using an acoustic leak detection device according to methods set forth in WCI.354(a)(4).

(2) If the tank vapours are continuous for 5 minutes, or the acoustic leak detection device detects a leak, then use one of the following two methods in paragraph (m)(2) of this section to quantify annual emissions:
(i) Use a meter, such as a turbine meter, calibrated bag, or High-flow Sampler to estimate tank vapour volumes according to methods set forth in WCI.354(b) through (d). If you do not have a continuous flow measurement device, you may install a flow measuring device on the tank vapour vent stack. If the vent is directly measured for five minutes under paragraph (m)(1) of this section to detect continuous leakage, this serves as the measurement.
(ii) Use an acoustic leak detection device on each scrubber dump valve connected to the tank according to the method set forth in WCI.354(a)(4).
(iii) Use the appropriate gas composition in paragraph (j) of this section.

(3) If the leaking dump valve(s) is fixed following leak detection, the annual emissions shall be calculated from the beginning of the calendar year to the time the valve(s) is repaired.

(4) Calculate annual emissions from storage tanks to flares as follows:
(i) Use the storage tank emissions volume and gas composition as determined in paragraphs (m)(1) through (m)(3) of this section.
(ii) Use the calculation methodology of flare stacks in paragraph (d) of this section to determine storage tank emissions sent to a flare.

[3] Clearstone Engineering Ltd. *Methodology Manual: Estimation of Air Emissions from the Canadian Natural Gas Transmission, Storage and Distribution System.* Prepared for Canadian Energy Partnership for Environmental Innovation (CEPEI). 2007.

§ WCI.354 Sampling, Analysis, and Measurement Requirements

Instruments used for sampling, analysis and measurement must be operated and calibrated according to legislative, manufacturer's, or other written specifications or requirements. All sampling, analysis and measurement must be conducted only by, or under the direct supervision of appropriately certified personnel or individuals with demonstrated understanding and experience in the application (and principles related) of the specific sampling, analysis and measurement technique in use.

(a) Leak Detection

(0.1) If a documented leak detection or integrity management standard or requirement that is required by legislation or regulation such as CSA Z662-07 Oil & Gas Pipeline Systems or similar standard Canadian Gas Association methodologies (as amended from time to time) is used, the documented standard or requirement must be followed – including service schedules for different components and/or facilities - with reporting as required for input to the calculation methods herein. A minimum of 12 months and a maximum of 36 months is allowed between surveys.

(0.2) If there is no such legal requirement (as specified in paragraph (a)(0.1) of this section), then progressive sampling is required using one of the methods outlined below in combination with best industry practices for use of the method– including service schedules for different components - to determine the count of leaks (and time leaking) required in WCI.353(f), (g), and (h), as applicable. Progressive sampling means establishing a statistically valid baseline sample of leaks under normal operating conditions for the 2011 and 2012 calendar years, with subsequent sampling determined based on random or spot-sampling, modeling, detection or measurement of leaks under normal operating conditions. A minimum of 18 months and a maximum of 36 months is allowed between surveys. This interval is determined based on whether there are indications of leaks. If a leak is found and immediately repaired, the existing schedule may be maintained.

Leak detection for fugitive equipment leaks must be performed for all identified equipment in operation or on standby mode.

(1) Optical gas imaging instrument. Use an optical gas imaging instrument for fugitive equipment leaks detection in accordance with 40 CFR part 60, subpart A, §60.18(i)(1) and (2) *Alternative work practice for monitoring equipment leaks* (or per relevant standard in Canada). In addition, the optical gas imaging instrument must be operated to image the source types required by this proposed reporting rule in accordance with the instrument manufacturer's operating parameters. The optical gas imaging instrument must comply with the following requirements:

(i) Provide the operator with an image of the potential leak points for each piece of equipment at both the detection sensitivity level and within the distance used in the daily instrument inspection described in the relevant best practices. The detection sensitivity level depends upon the frequency at which leak monitoring is to be performed.

(ii) Provide a date and time stamp for video records of every monitoring event.

(2) Bubble tests.

(3) Portable organic vapour analyzer. Use a portable organic vapour analyzer in accordance with US EPA Method 21 or as outlined in standard Canadian Gas Association methodologies or the CAPP Best Management Practices for Fugitive Emissions

(4) Other methods as outlined in standard Canadian Gas Association methodologies or the CAPP Best Management Practices for Fugitive Emissions (as amended from time to time) may be used as necessary for operational circumstances. Other methods that are deemed to be technically sound based on an engineering assessment may also be used as necessary for operational circumstances provided that sufficient documentation as to the method used, results on tests, and the methods reliability and accuracy is maintained and updated at regular intervals.

(b) All flow meters, composition analyzers and pressure gauges that are used to provide data for the GHG emissions calculations shall use appropriate QA/QC procedures, including measurement methods, maintenance practices, and calibration methods, prior to the first reporting year and in each subsequent reporting year according to the an appropriate standard published by a consensus standards organization such as Canadian Standards Association (CSA), Canadian Gas Association, Canadian Energy Pipeline Association (CEPA), ASTM International, American National Standards Institute (ANSI), the relevant provincial or national oil and gas regulator, Measurement Canada, American Society of Mechanical Engineers (ASME), and North American Energy Standards Board (NAESB). If no appropriate standard exists from the organizations listed above, one from the Canadian Association of Petroleum Producers (CAPP), American Petroleum Institute (API) may be used. If a consensus based standard is not available, industry standard practices such as manufacturer instructions must be used.

(c) Use calibrated bags (also known as vent bags) only where the emissions are at near-atmospheric pressures and hydrogen sulphide levels are such that it is safe to handle and can capture all the emissions, below the maximum temperature specified by the vent bag manufacturer, and the entire emissions volume can be encompassed for measurement.

(1) Hold the bag in place enclosing the emissions source to capture the entire emissions and record the time required for completely filling the bag. If the bag inflates in less than one second, assume one second inflation time.

(2) Perform three measurements of the time required to fill the bag, report the emissions as the average of the three readings.

(3) Correct the natural gas volumetric emissions to standard conditions using the calculations in WCI.353(i).

(4) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in WCI.353(j) and (k).

(d) Use a High-flow Sampler to measure emissions within the capacity of the instrument.

(1) Calibrate the instrument at 2.5 percent methane with 97.5 percent air and 100 percent CH_4 by using calibrated gas samples and by following manufacturer's instructions for calibration.

(2) A technician following (and competent to follow) manufacturer's instructions shall conduct measurements, including equipment manufacturer operating procedures and measurement methodologies relevant to using a High-flow Sampler, positioning the instrument for complete capture of the fugitive equipment leaks without creating backpressure on the source.

(3) If the High-flow Sampler, along with all attachments available from the manufacturer, is not able to capture all the emissions from the source then you shall use anti-static wraps or other aids to capture all emissions without violating operating requirements as provided in the instrument manufacturer's manual.

(4) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in WCI.353(j) and (k).

§ WCI.355 Procedures for Estimating Missing Data

A complete record of all estimated and/or measured parameters used in the GHG emissions calculations is required. If data are lost or an error occurs during annual emissions estimation or measurements, the estimation or measurement activity for those sources must be repeated as soon as possible, including in the subsequent reporting year if missing data are not discovered until after December 31 of the reporting year, until valid data for reporting is obtained. Data developed and/or collected in a subsequent reporting year to substitute for missing data cannot be used for that subsequent year's emissions estimation. Where missing data procedures are used for the previous year, at least 30 days must separate emissions estimation or measurements for the previous year and emissions estimation or measurements for the current year of data collection. For missing data that are continuously monitored or measured (for example flow meters), or for missing temperature and pressure data, the reporter may use best available data for use in emissions determinations. The reporter must record and report the basis for the best available data in these cases.

§ WCI.356 Definitions

Blowdown vent stack emissions mean natural gas and/or CO_2 released due to maintenance and/or blowdown operations including compressor blowdown and emergency shut-down (ESD) system testing.

Calibrated bag means a flexible, non-elastic, anti-static bag of a calibrated volume that can be affixed to a emitting source such that the emissions inflate the bag to its calibrated volume.

Centrifugal compressor means any equipment that increases the pressure of a process natural gas or CO_2 by centrifugal action, employing rotating movement of the driven shaft.

Centrifugal compressor dry seals mean a series of rings around the compressor shaft where it exits the compressor case that operates mechanically under the opposing forces to prevent natural gas or CO_2 from escaping to the atmosphere.

Centrifugal compressor dry seals emissions mean natural gas or CO_2 released from a dry seal vent pipe and/or the seal face around the rotating shaft where it exits one or both ends of the compressor case.

Centrifugal compressor wet seal degassing venting emissions mean emissions that occur when the high-pressure oil barriers for centrifugal compressors are depressurized to release absorbed natural gas or CO_2. High-pressure oil is used as a barrier against escaping gas in centrifugal compressor shafts. Very little gas escapes through the oil barrier, but under high pressure, considerably more gas is absorbed by the oil. The seal oil is purged of the absorbed gas (using heaters, flash tanks, and degassing techniques) and recirculated. The separated gas is commonly vented to the atmosphere.

Component means each metal to metal joint or seal of non-welded connection separated by a compression gasket, screwed thread (with or without thread sealing compound), metal to metal compression, or fluid barrier through which natural gas or liquid can escape to the atmosphere.

Compressor means any machine for raising the pressure of a natural gas by drawing in low pressure natural gas and discharging significantly higher pressure natural gas.

Continuous bleed means a continuous flow of pneumatic supply gas to the process measurement device (e.g. level control, temperature control, pressure control) where the supply gas pressure is modulated by the process condition, and then flows to the valve controller where the signal is compared with the process set-point to adjust gas pressure in the valve actuator.

Custody-transfer means the transfer of product from one gas company to another gas company, excluding transfers between companies who have same parent company.

De-methanizer means the natural gas processing unit that separates methane-rich residue gas from the heavier hydrocarbons (e.g., ethane, propane, butane, pentane-plus) in feed natural gas stream.

Equipment leak detection means the process of identifying emissions from equipment, components, and other point sources.

Engineering estimation, for the purposes of WCI.350 and WCI.360 means an estimate of emissions based on engineering principles applied to measured and/or approximated physical parameters such as dimensions of containment, actual pressures, actual temperatures, and compositions.

External combustion means fired combustion in which the flame and products of combustion are separated from contact with the process fluid to which the energy is delivered. Process fluids may be air, hot water, or hydrocarbons. External combustion equipment may include fired heaters, industrial boilers, and commercial and domestic combustion units.

Farm taps mean pressure regulation stations that deliver gas directly from transmission pipelines to generally rural customers.

Field gas means natural gas extracted from a production well prior to its entering the first stage of processing, such as dehydration.

Flare, for the purposes of WCI.350, means a combustion device, whether at ground level or elevated, that uses an open or closed flame to combust waste gases without energy recovery.

Flare combustion efficiency means the fraction of natural gas, on a volume or mole basis, that is combusted at the flare burner tip.

Fugitive emissions means the unintended or incidental emissions of greenhouse gases from the transmission, processing, storage, use or transportation of fossil fuels, greenhouse gases, or other.

Fugitive equipment leak means the those fugitive emissions which could not reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening.

Gas conditions mean the actual temperature, volume, and pressure of a gas sample.

High-bleed pneumatic devices means automated continuous bleed control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream which is regulated by the process condition flows to a valve actuator controller where it vents (bleeds) to the atmosphere at a rate in excess of 0.17 standard cubic meters per hour.

Intermittent-bleed pneumatic devices mean automated flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. These are snap-acting or throttling devices that discharge the full volume of the actuator intermittently when control action is necessary, but does not bleed continuously.

Internal combustion means the combustion of a fuel that occurs with an oxidizer (usually air) in a combustion chamber. In an internal combustion engine the expansion of the high-temperature and –pressure gases produced by combustion applies direct force to a component of the engine, such as pistons, turbine blades, or a nozzle. This force moves the component over a distance, generating useful mechanical energy. Internal combustion equipment may include gasoline and diesel industrial engines, natural gas-fired reciprocating engines, and gas turbines.

Liquefied natural gas (LNG) means natural gas (primarily methane) that has been liquefied by reducing its temperature to -162 degrees Celsius at atmospheric pressure.

LNG boiloff gas means natural gas in the gaseous phase that vents from LNG storage tanks due to ambient heat leakage through the tank insulation and heat energy dissipated in the LNG by internal pumps.

Low-bleed pneumatic devices mean automated control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream which is regulated by the process condition flows to a valve actuator controller where it vents (bleeds) to the atmosphere at a rate equal to or less than 0.17 standard cubic meters per hour.

Meter-regulating station means a station that meters the flowrate, regulates the pressure, or both, of natural gas in a natural gas distribution facility. This does not include customer meters, customer regulators, or farm taps.

Natural gas driven pneumatic pump means a pump that uses pressurized natural gas to move a piston or diaphragm, which pumps liquids on the opposite side of the piston or diaphragm.

Operating pressure means the containment pressure that characterizes the normal state of gas or liquid inside a particular process, pipeline, vessel or tank.

Pipeline quality natural gas means natural gas having a high heat value equal to or greater than 36.3 MJ/m^3 or less than 40.98 MJ/m^3, and which is at least ninety percent methane by volume, and which is less than five percent carbon dioxide by volume.

Portable means the same as defined in WCI.361(a)(2), as applicable to natural gas transmission and distribution operations

Pump means a device used to raise pressure, drive, or increase flow of liquid streams in closed or open conduits.

Pump seals means any seal on a pump drive shaft used to keep methane and/or carbon dioxide containing light liquids from escaping the inside of a pump case to the atmosphere.

Pump seal emissions means hydrocarbon gas released from the seal face between the pump internal chamber and the atmosphere.

Reciprocating compressor means a piece of equipment that increases the pressure of a gas stream by positive displacement, employing linear movement of a shaft driving a piston in a cylinder.

Reciprocating compressor rod packing means a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of the compressed gas stream that escapes to the atmosphere.

Re-condenser means heat exchangers that cool compressed boil-off gas to a temperature that will condense natural gas to a liquid.

Reservoir means a porous and permeable underground natural formation containing significant quantities of hydrocarbon liquids and/or gases.

Transmission pipeline means high-pressure cross-country pipeline transporting saleable quality natural gas from production or natural gas processing to natural gas distribution pressure let-down, metering, regulating stations where the natural gas is typically odorized before delivery to customers.

Third party line hit means damages to gas pipelines and surface facilities resulting from natural causes or third party incidents. Natural causes include corrosion, abrasion, rock damage, frost heaving or settling. Third party damages may include hits on surface facilities and dig-ins. Specific examples of dig-ins include grader/dozer/scraper excavation, demolition/breakout, general agriculture, driving bars/stakes/posts/anchors, backhoe/trackhoe excavation, ditch shaping, snow removal, landscaping/tree planting, hand excavation, bobcat/loader excavation, saw cutting, cable/pipe plowing, vertical augering/drilling, trencher excavation, blasting/vibrosis, deep tillage, horizontal augering/boring, and other such anthropogenic ground disturbances.

Vapour recovery system means any equipment located at the source of potential gas emissions to the atmosphere or to a flare, that is composed of piping, connections, and, if necessary, flow-inducing devices, and that is used for routing the gas back into the process as a product and/or fuel.

Vapourization unit means a process unit that performs controlled heat input to vapourize LNG to supply transmission and distribution pipelines or consumers with natural gas.

Vented emissions means the same as defined in the relevant greenhouse gas reporting regulation, including process designed flow to the atmosphere through seals or vent pipes, equipment blowdown for maintenance, and direct venting of gas used to power equipment (such as pneumatic devices), but not including stationary combustion flue gas.

§ WCI.357 Tables

Directions for the use of Tables 350-1 to 350-5

(a) Starting with 2014 calendar year emissions, for each component listed in the Tables 350-1 to 350-5, or otherwise required by the quantification method referencing Tables 350-1 and 350-2:

(1) If statistically valid facility-specific emission factors for a component type are available or can be safely or reasonably developed they must be used

(2) If facility-specific emissions factors for a component type are not available, an operator must use statistically valid company specific emission factors if they can be safely or reasonably developed.

(3) If statistically valid facility or company-specific emission factors for a specific component type cannot be safely and reasonably developed, estimates in the default Tables 350-1 to 350-5 may be used. Equipment or facilities that have low temporal utilization (e.g. equipment such as some booster stations used only sporadically during a year) may continue to use the default tables.

(b) For 2011, 2012 and 2013 calendar year emissions,

(1) An operator may use the default factors specified below, company or facility-specific emissions factors (if such emission factors are available). If the default factors in Tables 350-1 to 350-5 are used, an explanation as to why company or facility-specific emission factors cannot be used must be provided to the jurisdiction.

(c) If a facility-specific emission factor has been used in a previous reporting year, it must continue to be used until updated. If a company-specific emission factor has been used in a previous reporting year, it must continue to be used until updated or a facility-specific emission factor is used in its place

(d) Any changes from facility-specific factors to company-specific or table factors, or from company-specific factors to the defaults in Tables 350-1 to 350-5 must be approved by the jurisdiction and substantiated by proof that the new approach is more accurate for the facility or facilities in question

(e) If an emission factor required by the quantification method referencing Tables 350-1 through 350-5 is not provided in the tables, emission factors from either the U.S. EPA 40 CFR Part 98.230 Tables W-3 through W-7 or the 2007 Canadian Gas Association Methodology Manual may be used (as converted for use in the relevant equation).

(f) Documentation on the method used to update the emission factors, input data, sampling methodology and other relevant information must be kept by the operator and provided to the jurisdiction or verifier upon request

(g) All emission factors or data collection for emission factors must be developed using Canadian Gas Association (CGA) standard methods, or other methods if CGA methods are not available or applicable. Facility and company-specific emission factors must be updated at a minimum on a three year cycle, with the first update to the original facility and company-specific emission factors for the 2016 reporting period, at the latest.

(h) Updated emission factors can only be incorporated for reporting purposes at the start of a reporting period and not during a calendar year.

(i) The default emission factors provided in Tables 350-1 to 350-5 below are industry average emission factors for Canada as of the 2010 calendar year. The factors will be updated every 3-5 years based on new data, methods and statistically valid samples of the entire industry and developed in collaboration with industry groups.

TABLE 350-1 –DEFAULT EMISSION FACTORS FOR TRANSMISSION

Transmission	Emission Factor (tonnes/hour/component) Direct conversion of EF's in CGA Manual[4] Table 9 (kg to tonnes)
Leaker Emission Factors - All Components, Gas Service	
Connector	4.848E-5
Block valve	1.275E-4
Control valve	8.205E-5
Compressor blowdown valve	5.691E-3
Pressure relief valve	5.177E-4
Orifice meter	2.076E-4
Other meter	3.493E-7
Regulator	1.125E-4
Open-ended line	1.580E-4
Population Emission Factors - Other Components, Gas Service	**Emission Factor (Sm^3/hour/component) Direct conversion of EF's in EPA Subpart W Tables W1-A and W-3 (scf to Sm^3)**
Low-bleed pneumatic device vents	5.07 E-2
High continuous bleed pneumatic device vents	5.69 E-1
Intermittent (low and high) bleed pneumatic device vents	5.69 E-1
Pneumatic Pumps	3.766 E-1

* The distribution emission factors in Table 350-5 should be used for equipment in odourized service and the transmission factors in Table 350-1 should be used for equipment in unodourized service, regardless of the actual classification or functionality of the facility

[4] Clearstone Engineering Ltd. *Methodology Manual: Estimation of Air Emissions from the Canadian Natural Gas Transmission, Storage and Distribution System*. Prepared for Canadian Energy Partnership for Environmental Innovation (CEPEI). 2007. As these emission factors are updated from time to time, the intention is to incorporate such updates here as well as permit use of the most recent values published.

TABLE 350-2 –DEFAULT METHANE EMISSION FACTORS FOR UNDERGROUND STORAGE*

Underground Storage	Emission Factor (Sm^3/hour/component) Direct conversion of EF's in EPA Subpart W Table W-4 (scf to Sm^3)
Leaker Emission Factors - Storage Station, Gas Service	
Valve[1]	4.268 E-1
Connector	1.60 E-1
Open-ended line	4.967 E-1
Pressure relief valve	1.140
Meter	5.560 E-1
Population Emission Factors - Storage Wellheads, Gas Service	
Connector	2.8 E-4
Valve	2.8 E-3
Pressure relief valve	4.8 E-3
Open-ended line	8.5 E-4
Population Emission Factors - Other Components, Gas Service	
Low-bleed pneumatic device vents	5.07 E-2
High continuous bleed pneumatic device vents	5.69 E-1
Intermittent (low and high) bleed pneumatic device vents	5.69 E-1

*Emission factors are conversions of those contained in the U.S. EPA Subpart W Table W-4.

[1] Valves include control valves, block valves and regulator valves

TABLE 350-3 –DEFAULT METHANE EMISSION FACTORS FOR LIQUEFIED NATURAL GAS (LNG) STORAGE*

LNG Storage	Emission Factor (Sm^3/hour/component) Direct conversion of EF's in EPA Subpart W Table W-5 (scf to Sm^3)
Leaker Emission Factors - LNG Storage Components, LNG Service	
Valve	3.43 E-2
Pump seal	1.15 E-1
Connector	9.9 E-3
Other[1]	5.10 E-2
Population Emission Factors - LNG Storage Compressor, Gas Service	
Vapour Recovery Compressor	1.20 E-1

[1] The "other" equipment type should be applied for any equipment type other than connectors, pumps, or valves.

* Emission factors are conversions of those contained in the U.S. EPA Subpart W Table W-5.

TABLE 350-4–DEFAULT METHANE EMISSION FACTORS FOR LNG TERMINALS*

LNG Terminals	Emission Factor (Sm^3/hour/component) Direct conversion of EF's in EPA Subpart W Table W-6 (scf to Sm^3)
Leaker Emission Factors - LNG Terminals Components, LNG Service	
Valve	3.43 E -2
Pump seal	1.15 E-1
Connector	9.9 E-3
Other	5.10 E-2
Population Emission Factors - LNG Terminals Compressor, Gas Service	
Vapour recovery compressor	1.20 E-1

*Emission factors are conversions of those contained in the U.S. EPA Subpart W Table W-6.

TABLE 350-5 –DEFAULT EMISSION FACTORS FOR DISTRIBUTION

Distribution	Emission Factor** (tonnes/hour/component) Direct conversion of EF's in CGA Manual[5] Table 9 (kg to tonnes)
Leaker Emission Factors - Above Grade M&R Stations Components, Gas Service	
Connector	0.6875 E-3
Block valve	1.410 E-2
Control valve	7.881 E-2
Pressure relief valve	3.524 E-2
Orifice meter	8.091 E-3
Regulator	2.849 E-2
Open-ended line	1.216 E-1
Population Emission Factors - Below Grade M&R Stations Components, Gas Service[1]	**Emission Factor (Sm^3/hour/component) Direct conversion of EF's in EPA Subpart W Table W-7 (scf to Sm^3)**
Below grade M&R station, inlet pressure > 300 psig	3.74 E-2
Below grade M&R station, inlet pressure 100 to 300 psig	5.7 E-3
Below grade M&R station, inlet pressure < 100 psig	2.8 E-3

[5] Clearstone Engineering Ltd. *Methodology Manual: Estimation of Air Emissions from the Canadian Natural Gas Transmission, Storage and Distribution System.* Prepared for Canadian Energy Partnership for Environmental Innovation (CEPEI). 2007. As these emission factors are updated from time to time, the intention is to incorporate such updates here.

Population Emission Factors - Distribution Mains, Gas Service[2]*	Emission Factor (Sm^3/hour/component) Direct conversion of Leak Rates in CGA Forms 4.2.1-3 to 6 (scf to Sm^3) except where noted
Unprotected steel	1.83 E-1
Protected steel	7.22 E-2
Plastic	7.76 E-2
Cast iron*	7.836 E-1
Population Emission Factors - Distribution Services, Gas Service*	**Emission Factor (Sm^3/hour/component) Direct conversion of Leak Rates in CGA Forms 4.2.1-7 to 10 (scf to Sm^3) except where noted**
Unprotected steel	7.08 E-2
Protected steel	3.23 E-2
Plastic	1.04 E-2
Copper	2.7 E-2

[1] Emission Factor is in units of "Sm^3/hour/station"
[2] Emission Factor is in units of "Sm^3/hour/service"

*Emission factors are conversions of those contained in the U.S. EPA Subpart W Table W-7.

** the distribution emission factors in Table 350-5 should be used for equipment in odourized service and the transmission factors in Table 350-1 should be used for equipment in unodourized service, regardless of the actual classification or functionality of the facility

Table 350-6. Average manufacturer bleed rates for pneumatic controllers, positioner, transmitters and transducers.

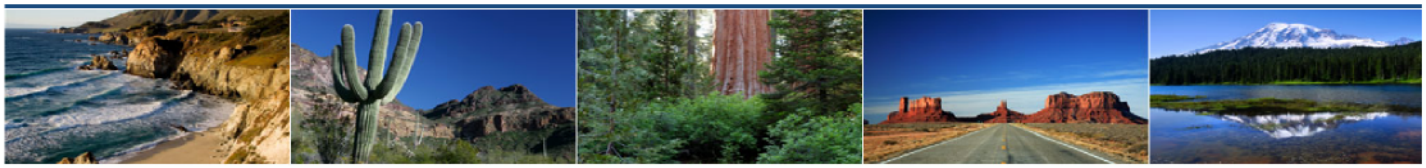
Description	Manufacturer	Model	Operating Condition	Manufacturer Rate (m^3/h)[4]
Liquid level controller	Bristol Babcock	Series 5453-Model 624-II	Continuous	0.0850
Liquid level controller	Fisher	2100	Continuous	0.0283
Liquid level controller	Fisher	2500	Continuous	1.1893
Liquid level controller	Fisher	2660	Continuous	0.0283
Liquid level controller	Fisher	2680	Continuous	0.0283
Liquid level controller	Fisher	2900	Continuous	0.6513
Liquid level controller	Fisher	L2	Continuous	0.0425
Liquid level controller	Invalco	AE-155	Continuous	1.5008
Liquid level controller	Invalco	CT Series	Continuous	1.1327
Liquid level controller	Norriseal	1001 (A) 'Envirosave'	Intermittent	0.0000
Liquid level controller	Norriseal	1001 (A) snap	Intermittent	0.0057
Liquid level controller	Norriseal	1001 (A) throttle	Intermittent	0.0002
Liquid level controller	Wellmark	2001 (snap)	Intermittent	0.0057
Liquid level controller	Wellmark	2001 (throttling)	Intermittent	0.0002
Positioner	Becker	EFP-2.0	Intermittent	0.0000
Positioner	Becker	HPP-5	Continuous	0.1416
Positioner	Fisher	3582	Continuous	0.4531
Positioner	Fisher	3590	Continuous	0.8495
Positioner	Fisher	3660	Continuous	0.1982
Positioner	Fisher	3661	Continuous	0.2959
Positioner	Fisher	3582i	Continuous	0.5833
Positioner	Fisher	3610J	Continuous	0.4531
Positioner	Fisher	3620J	Continuous	0.7532
Positioner	Fisher	DVC 5000	Continuous	0.2832
Positioner	Fisher	DVC 6000	Continuous	0.3964
Positioner	Fisher	Fieldview Digital	Continuous	0.8920
Positioner	Masoneilan	7400	Continuous	1.0477
Positioner	Masoneilan	4600B Series	Continuous	0.6796
Positioner	Masoneilan	4700B Series	Continuous	0.6796
Positioner	Masoneilan	4700E	Continuous	0.6796
Positioner	Masoneilan	SV	Continuous	0.1133
Positioner	Moore Products	73N-B	Continuous	1.0194
Positioner	Moore Products	750P	Continuous	1.1893
Positioner	PMV	D5 Digital	Continuous	0.0283
Positioner	Sampson	3780 Digital	Continuous	0.0283
Positioner	VCR	VP700 PtoP	Continuous	0.0283
Pressure controller	Ametek	Series 40	Continuous	0.1699
Pressure controller	Becker	HPP-SB	Intermittent	0.0000
Pressure controller	Becker	VRP-B-CH	Continuous	0.1416
Pressure controller	Becker	VRP-SB	Intermittent	0.0000
Pressure controller	Becker	VRP-SB Gap Controller	Intermittent	0.0000
Pressure controller	Becker	VRP-SB-CH	Intermittent	0.0000
Pressure controller	Becker	VRP-SB-PID Controller	Intermittent	0.0000

Description	Manufacturer	Model	Operating Condition	Manufacturer Rate (m^3/h)[4]
Pressure controller	Bristol Babcock	Series 5453-Model 10F	Continuous	0.0850
Pressure controller	Bristol Babcock	Series 5455-Model 624-III	Continuous	0.0708
Pressure controller	CSV	4150	Continuous	0.6853
Pressure controller	CSV	4160	Continuous	0.6853
Pressure controller	Dyna-Flow	4000	Continuous	0.6853
Pressure controller	Fisher	2506	Continuous	0.6853
Pressure controller	Fisher	2516	Continuous	0.6853
Pressure controller	Fisher	4150	Continuous	0.7362
Pressure controller	Fisher	4160	Continuous	0.7362
Pressure controller	Fisher	4194	Continuous	0.1203
Pressure controller	Fisher	4195	Continuous	0.1203
Pressure controller	Fisher	4660	Continuous	0.1416
Pressure controller	Fisher	4100 (large orifice)	Continuous	1.4158
Pressure controller	Fisher	4100 (small orifice)	Continuous	0.4248
Pressure controller	Fisher	C1	Continuous	0.1472
Pressure controller	Fisher	DVC 6010	Continuous	0.0878
Pressure controller	Foxboro	43AP	Continuous	0.5097
Pressure controller	ITT Barton	338	Continuous	0.1699
Pressure controller	ITT Barton	358	Continuous	0.0510
Pressure controller	ITT Barton	359	Continuous	0.0510
Pressure controller	ITT Barton	335P	Continuous	0.1699
Pressure controller	ITT Barton	335P	Continuous	0.1699
Transducer	Bristol Babcock	9110-00A	Continuous	0.0119
Transducer	Bristol Babcock	Series 502 A/D	Continuous	0.1671
Transducer	Fairchild	TXI 7800	Continuous	0.2407
Transducer	Fisher	546	Continuous	0.8495
Transducer	Fisher	646	Continuous	0.2209
Transducer	Fisher	846	Continuous	0.3398
Transducer	Fisher	i2P-100	Continuous	0.2832
Transmitter	Bristol Babcock	Series 5457-70F	Continuous	0.0850
Transmitter	ITT Barton	273A	Continuous	0.0850
Transmitter	ITT Barton	274A	Continuous	0.0850
Transmitter	ITT Barton	284B	Continuous	0.0850
Transmitter	ITT Barton	285B	Continuous	0.0850

Footnotes and Sources:
[1] Canadian Association of Petroleum Producers. *Fuel Gas Best Management Practices: Efficient Use of Fuel Gas in Pneumatic Instruments*. Module 3, CETAC West, Calgary, AB. 2008 Appendix B converted to metric units.
[2] United States Environmental Protection Agency. *Lessons Learned from Natural Gas STAR Partners: Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry.* Washington, DC. 2006. Appendix A converted to metric units.
[3] Various manufacturer specification publications.
[4] Factors equal to zero indicate that the device does not vent gas.

Table 350-7. Nomenclature (subscripts, variables and their descriptions)

Variable Name	Description
A	Variable – Area
a	Subscript – Actual condition for temperature and pressure
CF	Variable – Control factor (fractional)
D	Variable – Diameter
E	Variable – Greenhouse Gas release rate
e	Subscript – exit point
EF	Variable – Emission factor
GOR	Variable – Gas to oil ratio
GWP	Variable – Global warming potential
HHV	Variable – Higher (gross) heating value
i	Subscript - Chemical compound
j	Subscript - Individual device, equipment, meter or well
K	Variable – Specific heat ratio for gases
k	Subscript - Service type (e.g., fuel gas, process gas, liquid, etc)
L	Variable - Length
l	Subscript - Individual equipment components
M	Variable – Mach number
MW	Variable – Molecular weight
m	Subscript – Operating mode
N	Variable – Count of devices, equipment, meters, wells, events, etc.
n	Variable – Number of carbon atoms in a molecule of a specified substance.
P	Variable – Pressure
R	Variable – Universal Gas Constant
s	Subscript – Standard condition for temperature (15 ^{o}C) and pressure (101.325 kPa)
t	Variable – Time duration of event
T	Variable – Temperature (°C)
Q	Variable – Volumetric flow rate
V	Variable - Volume
X	Variable - Mass fraction
Y	Variable - Mole fraction
ρ	Variable - density
□	Variable – efficiency (fractional)



Due to the timing of the release of amendments to the EPA Subpart W rule on December 2, 2011 and the potential need for the WCI to address harmonization questions with it, further consultation on WCI.360 and potential amendments to WCI.360 are scheduled to occur in 2012.

§WCI.360 PETROLEUM AND NATURAL GAS PRODUCTION AND GAS PROCESSING

§ WCI.361 Source Category Definition

(a) This source category consists of the following:

(1) *Offshore petroleum and natural gas production.* Offshore petroleum and natural gas production is any platform structure, affixed temporarily or permanently to offshore submerged lands, that houses equipment to extract hydrocarbons from the ocean or lake floor and that processes and/or transfers such hydrocarbons to storage, transport vessels, or onshore. In addition, offshore production includes secondary platform structures connected to the platform structure via walkways, storage tanks associated with the platform structure and floating production and storage offloading equipment (FPSO). This source category does not include reporting of emissions from offshore drilling and exploration that is not conducted on production platforms.

(2) *Onshore petroleum and natural gas production.* Onshore petroleum and natural gas production equipment means all structures associated with wells (including but not limited to compressors, generators, or storage facilities), piping (including but not limited to flowlines or intra-facility gathering lines), and portable non-self-propelled equipment (including but not limited to well drilling and completion equipment, workover equipment, gravity separation equipment, auxiliary non-transportation-related equipment, and leased, rented or contracted equipment) used in the production, extraction, recovery, lifting, stabilization, separation or treating of petroleum and/or natural gas (including condensate). This also includes associated storage or measurement and all systems engaged in gathering produced gas from multiple wells, all EOR operations using CO_2, and all petroleum and natural gas production located on islands, artificial islands or structures connected by a causeway to land, an island, or artificial island.

(3) *Onshore natural gas processing.* Natural gas processing plants separates and/or recovers natural gas liquids (NGLs) and/or other non-methane gases and liquids from a stream of produced natural gas to meet onshore natural gas transmission pipeline quality specifications through equipment performing one or more of the following processes: oil and condensate removal, separation of natural gas liquids, sulphur and carbon dioxide removal, fractionation of NGLs, or other processes, and also the capture of CO_2

separated from natural gas streams for delivery outside the facility. In addition, field gathering and/or boosting stations that gather and process natural gas from multiple wellheads, and compress and transport natural gas (including but not limited to flowlines or intra-facility gathering lines or compressors) as feed to the natural gas processing plants may be considered a part of the processing plant if emissions are not calculated under onshore petroleum and natural gas production. Gathering and boosting stations that send the natural gas to an onshore natural gas transmission compression facility, or natural gas distribution facility, or to an end user are also considered within onshore natural gas processing for the purposes of emissions calculation. All residue gas compression equipment operated by a processing plant, whether inside or outside the processing plant fence, are considered part of the natural gas processing plant.

(b) This source category does not include natural gas transmission and distribution (i.e., onshore natural gas transmission compression, underground natural gas storage, liquefied natural gas (LNG) storage, LNG import and export equipment, and natural gas distribution). These are included in WCI.350 (Natural Gas Transmission and Distribution).

§ WCI.362 Greenhouse Gas Reporting Requirements

Where greenhouse gases are not emitted from a specific emission source identified in paragraphs (a) to (f), below then the reported emissions for the specific source shall be reported as zero or "not applicable".

In addition to the information required by regulation, the annual emissions data report, for both each individual facility over 10,000 tonnes and the aggregate of facilities less than 10,000 tonnes (or as otherwise specified by regulation), must contain the following information:

(a) CO_2 and CH_4 (and N_2O, if applicable) emissions (in tonnes) from each industry segment specified in paragraph (b) through (d) of this section and from stationary and portable combustion equipment identified in paragraphs (e) and (f) of the section.

(b) For offshore petroleum and natural gas production, report CO_2, CH_4, and N_2O emissions from equipment leaks, vented emission, and flare emission source types as identified in the data collection and emissions estimation study conducted by BOEMRE in compliance with 30 CFR 250.302 through 304. Offshore platforms do not need to report portable emissions. *[WCI.363(p), reserved]*

(c) For onshore petroleum and natural gas production, report CO_2 and CH_4 (and N_2O, if applicable) emissions from the following source types:

(1) Natural gas pneumatic continuous high-bleed device venting. *[WCI.363(a)]*

(2) Natural gas-driven pneumatic pump venting. *[WCI.363(a.1)]*

(3) Natural gas pneumatic continuous low-bleed device venting. *[WCI.363(b)]*

(4) Natural gas pneumatic intermittent (low and high) bleed device venting. *[WCI.363(b.1)]*

(5) Acid gas removal venting or incineration process. *[WCI.363(c)]*

(6) Dehydrator vents. *[WCI.363(d)]*

(7) Well venting for liquids unloading. *[WCI.363(e)]*

(8) Gas well venting during well completions or workovers. *[WCI.363(f)]*

(9) Blowdown vent stacks. *[WCI.363(g)]*

(10) Third party line hits. *[WCI.363(g.1)]*

(11) Onshore production and processing storage tanks. *[WCI.363(h)]*

(12) Transmission storage tanks *[WCI.363(h.1)]*

(13) Well testing venting and flaring. *[WCI.363(i)]*

(14) Associated gas venting and flaring. *[WCI.363(j)]*

(15) Flare stacks. *[WCI.363(k)]*

(16) Centrifugal compressor venting. *[WCI.363(l)]*

(17) Reciprocating compressor venting. *[WCI.363(m)]*

(18) Gathering pipeline fugitive equipment leaks. *[WCI.363(o) or WCI.363(x) for emission sources not covered by WCI.363(o)]*

(19) Fugitive equipment leaks from valves, connectors, open ended lines, pressure relief valves, pumps, flanges, and other fugitive equipment leak sources (such as instruments, loading arms, stuffing boxes, compressor seals, dump lever arms, and breather caps). *[WCI.363(o]*

(20) EOR injection pump blowdown. *[WCI.363(t)]*

(21) Hydrocarbon liquids dissolved CO_2 from flashing [Reserved]. *[WCI.363(u)]*

(22) Produced water dissolved CO_2 [Reserved]. *[WCI.363(v)]*

(23) Coal bed methane produced water emissions [Reserved]. *[WCI.363(v)]*

(24) Other venting emission sources.* *[WCI.363(x)]*

(25) Other fugitive emission sources.**[WCI.363(x)]*

(d) For onshore natural gas processing, report CO_2 and CH_4 (and N_2O, if applicable) emissions from the following sources:

(1) Acid gas removal venting or incineration. *[WCI.363(c)]*

(2) Dehydrator vents. *[WCI.363(d)]*

(3) Blowdown vent stacks. *[WCI.363(g)]*

(4) Storage tanks. *[WCI.363(h)]*

(5) Flare stacks. *[WCI.363(k)]*

(6) Centrifugal compressor venting. *[WCI.363(l)]*

(7) Reciprocating compressor venting. *[WCI.363(m)]*

(8) Gathering pipeline fugitive equipment leaks. *[WCI.363(o)] or [WCI.363(x)] for emission sources not covered by [WCI.363(o)]*

(9) Fugitive equipment leaks from: valves, connectors, open ended lines, pressure relief valves and meters. *[WCI.363(n)]*

(10) Other fugitive emission sources (including reciprocating compressor rod packing fugitives, centrifugal compressor dry and wet seals, etc).* *[WCI.363(x)]*

(11) Other venting emission sources.* *[WCI.363(x)]*

(e) Report CO_2, CH_4, and N_2O emissions from each stationary fuel combustion source type combusting field gas or process vent gas *[WCI.363(w)]* and fuels other than field gas or process vent gas. Report stationary combustion sources that combust fuels other than field gas or process vent gas using WCI.20 (General Stationary Combustion Sources) quantification methods. The reference to process vent gas is not intended to include vent gas that is sellable quality natural gas. **

(f) Report CO_2, CH_4, and N_2O emissions from each portable equipment combustion source type combusting field gas or process vent gas *[WCI.363(w)]* and fuels other than field gas or process vent gas. Report portable equipment combustion sources that combust fuels other than field gas or process vent gas using WCI.20 (General Stationary Combustion Sources) quantification methods. The reference to process vent gas is not intended to include vent gas that is sellable quality natural gas. **

(g) Report data for each aggregated source type within paragraph (b) through (d) of this section as follows (for each individual facility or aggregate of facilities reported, as required by regulation):

(1) Where there is a choice of quantification method used for a source, the specific method(s) used and under what circumstances.

(2) Facility and company-specific emission factors or emissions information, as appropriate, used in place of Tables 360-1 and 360-2.

(3) Count of natural gas pneumatic continuous high-bleed devices.

(4) Count of natural gas pneumatic continuous low-bleed devices.

(5) Count of natural gas intermittent (low and high) bleed devices.

(6) Count of natural gas-driven pneumatic pumps.

(7) Total throughput of acid gas removal units.

(8) For each dehydrator unit report the following:
  (i) Glycol dehydrators:

    (A) The number of glycol dehydrators with throughput less than 11,328 Sm^3/day operated, and

    (B) The number of glycol dehydrators with throughput greater than or equal to 11,328 Sm^3/day operated.

  (ii) Desiccant dehydrators:
    (A) The number of desiccant dehydrators operated.

(9) Count of wells vented to the atmosphere for liquids unloading.

(10) Count of third party line hits

  (i) Engineering distribution of number of line hits by volume of gas released by hit

(11) Count of wells venting during well completions:
  (i) The number of conventional completions.
  (ii) The number of completions employing hydraulic fracturing.

(12) Count of wells venting during well workovers:
  (i) The number well workovers involving well venting to the atmosphere.

(13) For each compressor report the following:
  (i) Type of compressor whether reciprocating, centrifugal dry seal, or centrifugal wet seal (for all compressors).
  (ii) Compressor driver capacity in horsepower (where the total horsepower (as aggregated) for the facility has rated power greater than or equal to 250 hp).
  (iii) Number of blowdowns per year (where the total horsepower (as aggregated) for the facility has rated power greater than or equal to 250 hp).
  (iv) Operating mode(s) (i.e., operating, not operating and pressurized or not operating and depressurized) during the year (where the total horsepower (as aggregated) for the facility has rated power greater than or equal to 250 hp).
  (v) Number of compressor starts per year.

(14) Number of EOR injection pump blowdowns per year.

(15) Count of wells tested in the reporting period.

(16) Count of wells venting or flaring associated natural gas in the reporting period.

(17) Count of wells being unloaded for liquids in the reporting year.

(18) Count of wells completed (worked over) in the reporting year.

(19) For fugitive equipment leaks and population-count/emission-factor sources, using emission factors for estimating emissions in WCI.363(n) and (o), report the following:
   (i) Major equipment (for 2011 and 2012 calendar year reporting) or component (for 2013 calendar year reporting and onwards) counts for which an emission factor is provided in Tables 360-1, 360-2 or 360-3 in this document. Default counts provided may be used for the 2011 and 2012 calendar years (reported in 2012 and 2013 in preparation for full component counts in the 2013 calendar year (reported in 2014). Current processing and instrumentation drawings (P&ID) may be used for the source of component (or major equipment) counts for all years.
   (ii) Total counts of fugitive equipment leaks found in leak detection surveys by type of leak source for which an emission factor is provided.

(20) Barrels of oil equivalent throughput/processed as determined by engineering estimate based on best available data.

(21) Identification (including geographic coordinates) of any facility that had 1,000 tonnes or greater of greenhouse gas emissions in the previous year that was:
   (i) Acquired during the reporting year;
   (ii) Sold, decommissioned or shut-in during the reporting year; and,
   (iii) The greenhouse gas emissions for the facility in the previous year.
   (iv) The purchaser or seller, as appropriate

** Other venting emission or other fugitive sources not specifically listed are not required to be reported if a specific other venting or other fugitive source type is reasonably estimated to be below 0.5% of total operation emissions, and total emissions not reported under this clause do not exceed 1% of total operation emissions (if an individual facility is part of a larger reporting operation, the 0.5% or 1% should be interpreted as 0.5% or 1% of the reporting operation emissions, otherwise interpret as 0.5% or 1% of the facility emissions). The applicable regulator may, upon request and provision of sufficient information, provide a list of sources believed to be below these thresholds for all operations for which reporting and verification would not be required.*

*** Portable equipment is portable fuel combustion equipment that cannot move on roadways under its own power and drive train, and that are located at an onshore production facility. Stationary or portable equipment include the following equipment which are integral to the extraction, processing or movement of oil or natural gas: well drilling and completion* *equipment, workover equipment, natural gas dehydrators, natural gas compressors, electrical generators, steam boilers, and process heater.s*

§ WCI.363 Calculating GHG Emissions

If greenhouse gases are not emitted from one or more of the following emission sources, the reporter will not need to calculate emissions from the emission source(s) in question and reported emissions for the emission source(s) will be zero or “not applicable”. Where a quantification method is not provided for a specific source (such as for other venting and other fugitive sources), industry inventory practices must be used to estimate emissions. For ambient conditions, reporters must use average atmospheric conditions or typical operating conditions as applicable to the respective monitoring methods in this section. In general, equations are presented at the most basic unit level and emissions must be summed, so that the total population of devices and/or events are included for the reporting facility or organization, as required by regulation. Nomenclature used in the equations is presented in Table 360-7.

(a) Natural gas pneumatic continuous high-bleed device venting Calculate emissions from a natural gas pneumatic continuous high-bleed flow control device venting using the method specified in paragraph (a)(1) below when the device is metered. By the start of the 2014 reporting year (January 1, 2014), natural gas consumption must be metered for 50 % of the operator’s pneumatic high-bleed devices (the 50% calculation of metered devices may include devices that were operational on January 1, 2012 that are no longer operational as of January 1, 2014 due to phase out or not-operating). By the start of the 2015 reporting year (January 1, 2015), natural gas consumption must be metered for all of the operator’s pneumatic high-bleed devices. For the purposes of this reporting requirement, high-bleed devices are defined as all natural gas powered devices which continuously bleed at a rate greater than 0.17 m^3/hr . For unmetered devices the operator must use the method specified in paragraph (a)(2).

(1) The operator must calculate vented emissions for metered pneumatic high-bleed devices using the following equation:

$$E_s = Q_j$$

Equation 360-1

Where:

E_s = Annual natural gas volumetric emissions for pneumatic high-bleed devices and pneumatic pumps where gas is metered (Sm^3/y).

Q_j = Natural gas consumption for meter *j* (Sm^3/y).

(2) The operator must calculate vented emissions for unmetered pneumatic high-bleed devices using the following equation:

$$E_s = EF_j \times t_j$$

Equation 360-2

Where:

E_s	=	Annual natural gas volumetric emissions for pneumatic high-bleed devices where gas is unmetered (Sm^3/y).
EF_j	=	Natural gas-driven pneumatic device, j, bleed rate volume as provided by the manufacturer or in Table 360-6 (Sm^3/h/device).
t_j	=	Total time that the pneumatic device, j, has been in service the (i.e. the time that gas flows to the device) through the reporting period (h).

(3) If manufacturer data for a specific device is not available, then use data for a similar device model, size and operational characteristics to estimate emissions. If data for a reasonably similar pump model size and operational characteristics cannot be obtained, use the factor in Table 360-5 for high-bleed pneumatic devices

(4) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (r) and (s) of this section

(5) Provide the total number of continuous high-bleed natural gas pneumatic devices as follows:

(i) In 2012, you may count 50% of the devices for each type of facility and engineering estimates can be used to determine both the denominator to be used in the 50% calculation and to estimate the number of remaining devices.

(ii) In 2013, all continuous high-bleed natural gas pneumatic devices must be counted.

(iii) In 2014, and for calendar years thereafter, facilities must update the total count of continuous high-bleed pneumatic devices and adjust accordingly to reflect any modifications due to changes in equipment.

(a.1) <u>Natural gas pneumatic pump venting.</u> Calculate emissions from natural gas-driven pneumatic pump venting using the method specified in paragraph (a)(1) above when the pump is metered. By the start of the 2014 reporting year (January 1, 2014), natural gas consumption must be metered for 50 % of the operator's pneumatic pumps (the 50% calculation of metered devices may include devices that were operational on January 1, 2012 that are no longer operational as of January 1, 2014 due to phase out or not-operating). By the start of the 2015 reporting year (January 1, 2015), natural gas consumption must be metered for all of the operator's pneumatic pumps. For unmetered pumps the operator must use the methods preferentially specified in paragraph (a.1)(2). Natural gas-driven pneumatic pumps covered in paragraph (d) (dehydrator vents) of this section do not have to report emissions under paragraph (a.1) of this section.

(1) The operator must calculate vented emissions for metered pneumatic pumps using Equation 360-1.

(2) The operator must calculate vented emissions for unmetered pneumatic pumps using Equation 360-3.

(i) Obtain from the manufacturer specific pump model natural gas emission (or manufacturer "gas consumption") per unit volume of liquid circulation rate at pump speeds and operating pressures. If manufacturer data for a specific pump is not available, then use data for a similar pump model, size and operational characteristics to estimate emissions.

(ii) Maintain a log of the amount of liquid pumped annually from individual pumps.

(iii) Calculate the natural gas emissions for each pump using Equation 360-3.

$$E_s = EF_j \times Q_j$$

Equation 360-3

Where:

E_s	=	Annual natural gas volumetric emissions (Sm^3/y).
EF_j	=	Natural gas-driven pneumatic pump gas emission factor expressed in "emission per volume of liquid pumped at operating pressure" as provided by the manufacturer for pump *j* (Sm^3/liter).
Q_j	=	Volume of liquid pumped annually by pump *j* (liters/y).

(3) If manufacturer data for a specific pump, or reasonably similar pump model size and operational characteristics cannot be obtained; Equation 360-2 can be used with the population emission factor for natural gas-driven pneumatic pumps provided in Table 360-5.

(4) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (r) and (s) of this section

(5) Provide the total number of natural gas pneumatic pumps as follows:

(i) In 2012, you may count 50% of the devices for each type of facility and engineering estimates can be used to determine both the denominator to be used in the 50% calculation and to estimate the number of remaining pumps.

(ii) In 2013, all natural gas pneumatic pumps must be counted.

(iii) In 2014, and for calendar years thereafter, facilities must update the total count of pneumatic pumps and adjust accordingly to reflect any modifications due to changes in equipment.

(b) Natural gas pneumatic continuous low-bleed device venting. Calculate emissions from natural gas pneumatic continuous low-bleed device venting using Equation 360-4 of this section.

$$E_s = EF_j \times t_j$$

Equation 360-4

Where:

E_s = Annual natural gas volumetric emissions for pneumatic continuous low-bleed devices (Sm^3/y).

EF_j = Population emission factor for natural gas-driven pneumatic continuous low-bleed device, *j*, as provided in Table 360-5 ($Sm^3/h/device$).

t_j = Total time that the pneumatic device, *j*, has been in service (i.e. the time that the gas flows to the device) through the reporting period (h).

(1) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (r) and (s) of this section.

(2) Provide the total number of continuous low-bleed natural gas pneumatic devices of each type as follows:

(i) In 2012, you may count 50% of the devices for each type of facility and engineering estimates can be used to determine both the denominator to be used in the 50% calculation and to estimate the number of remaining devices.

(ii) In 2013, all continuous low-bleed natural gas pneumatic devices must be counted.

(iii) In 2014, and for calendar years thereafter, facilities must update the total count of continuous low-bleed natural gas pneumatic devices and adjust accordingly to reflect any modifications due to changes in equipment.

(b.1) <u>Natural gas pneumatic intermittent (low and high) bleed device venting.</u> Calculate emissions from natural gas pneumatic intermittent (low and high) bleed device venting as follows.

(1) The operator must calculate vented emissions for pneumatic intermittent (low and high) bleed devices used to maintain a process condition such as liquid level, pressure, delta-pressure or temperature using Equation 360-5:

$$E_s = EF_j \times t_j$$

Equation 360-5

Where:

E_s = Annual natural gas volumetric emissions for pneumatic intermittent (low and high) bleed devices (Sm^3/y).

EF_j = Emission factor for natural gas-driven pneumatic intermittent (low and high) bleed device, *j*, as provided in Table 360-6 ($Sm^3/h/device$). If manufacturer data for a specific device is not available, then use data for a similar device model, size and operational characteristics to estimate emissions. If data for a reasonably similar intermittent bleed device size and operational characteristics cannot be obtained, use the factor in Table 360-5 for intermittent bleed pneumatic devices.

t_j = Total time that the pneumatic device, *j*, has been in service (i.e. the time that the gas flows to the device) through the reporting period (h).

(2) The operator must calculate vented emissions for pneumatic intermittent (high) bleed devices, used to drive compressor starters, using Equation 360-6*:

$$E_s = EF_j \times t_j$$

Equation 360-6

Where:

E_s = Annual natural gas volumetric emissions for pneumatic intermittent (high) bleed devices (Sm^3/y).

EF_j = Emission factor for natural gas-driven pneumatic compressor starter, *j*, as provided by the manufacturer (Sm^3/min/device).

t_j = Total time that the pneumatic device, *j*, has been in service (i.e. the time that the gas flows to the device) through the reporting period (min).

(3) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (r) and (s) of this section.

(4) Provide the total number of intermittent (low and high) bleed natural gas pneumatic devices as follows:

(i) In 2012, you may count 50% of the devices for each type of facility and engineering estimates can be used to determine both the denominator to be used in the 50% calculation and to estimate the number of remaining devices.

(ii) In 2013, all intermittent (low and high) bleed natural gas pneumatic devices must be counted.

(iii) In 2014, and for calendar years thereafter, facilities must update the total count of intermittent (low and high) bleed natural gas pneumatic devices and adjust accordingly to reflect any modifications due to changes in equipment.

** for 2012, the volume of gas per start provided by the manufacturer may be used in place of the* EF_j *and* t_j *variables*

(c) Acid gas removal (AGR) venting or incineration process. Except for AGRs where the acid gases are re-injected into the oil/gas field or manifolded to a common flare stack, calculate CO_2 emissions only (not CH_4) for AGR (including but not limited to processes such as amine, membrane, molecular sieve or other absorbents and adsorbents) using any of the calculation methodologies described in this section, as applicable.

(1) Calculation Methodology 1. If you operate and maintain a CEMS on the AGR vent or incinerator stack that has both a CO_2 concentration analyzer and volumetric flow rate meter CO_2 emissions under this subpart must be calculated by following Calculation Methodology 4 and all associated calculation, quality assurance, reporting, and recordkeeping requirements for Calculation Methodology 4 in WCI.20 (General Stationary Combustion). If a CO_2 concentration analyzer and volumetric flow rate meter are not available, a CO_2 concentration analyzer and a volumetric flow rate meter that comply with all of the requirements specified for the Calculation Methodology 4 in WCI.20 (General Stationary Combustion) may be installed.

(2) Calculation Methodology 2. If CEMS is not available but a vent meter is available, use the CO_2 composition and annual volume of vent gas to calculate emissions using Equation 360-7.

$$E_{CO2} = Q \times Y_{CO2}$$

Equation 360-7

Where:

E_{CO2}	=	Annual volumetric CO_2 emissions (Sm^3/y).
Q	=	Metered total annual volume of acid gas flow out of the AGR unit (Sm^3/y) as determined in paragraph (c)(5) of this section.
Y_{CO2}	=	Mole fraction of CO_2 in acid gas out of the AGR unit as determined in paragraph (c)(6) of this section.

(3) Calculation Methodology 3. If CEMS or a vent meter is not available, the inlet gas flow rate of the acid gas removal unit may be used to calculate emissions for CO_2 using Equation 360-8.

$$E_{CO2} = \frac{Q_{in} \times \left[Y_{CO2\_in} \times \left(1 - Y_{H2S\_spec}\right) - Y_{CO2\_out} \times \left(1 - Y_{H2S\_in}\right) \right]}{\left(1 - Y_{H2S\_spec} - Y_{CO2\_out}\right)}$$

Equation 360-8

Where:

E_{CO2}	=	Annual volumetric CO_2 emissions (Sm^3/y).
Q_{in}	=	Metered total annual volume of natural gas flow into the AGR unit (Sm^3/y) as determined in paragraph (c)(5) of this section.

Y_{CO2_in} = Mole fraction of CO_2 in natural gas into the AGR unit as determined in paragraph (c)(6) of this section.

Y_{CO2_out} = Mole fraction of CO_2 in natural gas out of the AGR unit as determined in paragraph (c)(6) of this section.

Y_{H2S_spec} = Mole fraction of H_2S in the natural gas out of the AGR unit as defined by the performance specification of the AGR.

Y_{H2S_in} = Mole fraction of H_2S in natural gas into the AGR unit as determined in paragraph (c)(6) of this section.

(4) Record the gas flow rate, referenced to standard conditions, of the inlet and outlet natural gas or acid gas stream of an AGR unit using a meter according to methods set forth in WCI.364(b).

(5) If a continuous gas analyzer is installed on the inlet gas stream, then the continuous gas analyzer results must be used. If a continuous gas analyzer is not available, either install a continuous gas analyzer or take monthly gas samples from the inlet gas stream to determine Y_{CO2_in} according to methods set forth in WCI.364(b).

(6) Determine volume fraction of CO_2 content in natural gas or acid gas out of the AGR units using one of the methods specified in paragraph (c)(6) of this section.

(i) If a continuous gas analyzer is installed on the outlet gas stream, then the continuous gas analyzer results must be used. If a continuous gas analyzer is not available, you may install a continuous gas analyzer.

(ii) If a continuous gas analyzer is not available or installed, monthly gas samples must be taken from the outlet gas stream to determine Y_{CO2} according to methods set forth in WCI.364(b).

(7) Determine volume fraction of H_2S content in natural gas or acid gas into the AGR units using continuous gas analyzer data (if available), or other known or commonly accepted method (if continuous gas analyzer data is not available.

(8) Mass CO_2 emissions shall be calculated from volumetric CO_2 emissions using calculations in paragraph (s) of this section.

(d) Dehydrator vents. For dehydrator vents, calculate annual mass CH_4, CO_2 and N_2O (when flared) emissions as follows:

(1) Calculate annual mass emissions from dehydrator vents using a simulation software package of similar accuracy to GRI-GLYCalc Version 4.0 or AspenTech HYSYS®, that uses the Peng-Robinson equation of state to calculate the equilibrium coefficient, speciates CH_4 and CO_2 emissions from dehydrators, and has provisions to include regenerator control devises, a separator flash tank, stripping gas and a gas injection

pump or gas assist pump. A minimum of the following parameters must be used for characterizing emissions from dehydrators:

(i) Feed natural gas flow rate.
(ii) Feed natural gas water content.
(iii) Outlet natural gas water content.
(iv) Absorbent circulation pump type (natural gas pneumatic/air pneumatic/electric).
(v) Absorbent circulation rate.
(vi) Absorbent type: including, but not limited to, triethylene glycol (TEG), diethylene glycol (DEG) or ethylene glycol (EG).
(vii) Use of stripping gas.
(viii) Use of flash tank separator (and disposition of recovered gas).
(ix) Hours operated.
(x) Wet natural gas temperature and pressure.
(xi) Wet natural gas composition. Determine this parameter by selecting one of the methods described under paragraph (d)(1)(xi) of this section.
   (A) Use the wet natural gas composition as defined in paragraph (r)(2)(i) of this section.
   (B) If wet natural gas composition cannot be determined using paragraph (r)(2)(i) of this section, select a representative analysis.
   (C) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice as specified in WCI.364(b) to sample and analyze wet natural gas composition.
   (D) If only composition data for dry natural gas is available, assume the wet natural gas is saturated.

(2) Determine if dehydrator unit has vapor recovery. Adjust the emissions estimated in paragraphs (d)(1) or (d)(4) of this section downward by the magnitude of emissions captured.

(3) Calculate annual emissions from dehydrator vents to flares or regenerator fire-box/fire tubes as follows:
   (i) Use the dehydrator vent stack volume and gas composition as determined in paragraph (d)(1) of this section.
   (ii) Use the calculation methodology of flare stacks in paragraph (k) of this section to determine dehydrator vent emissions from the flare or regenerator combustion gas vent.

(4) Dehydrators that use desiccant shall calculate emissions from the amount of gas vented from the vessel every time it is depressurized for the desiccant refilling process using Equation 360-10.

$$E_s = \left(\frac{H \times D^2 \times \pi \times P_2 \times \%G \times 365}{4 \times P_1 \times t} \right) \Big/ 100$$

Equation 360-10

Where:

E_s = Annual natural gas volumetric emissions (Sm^3/y).
H = Height of the dehydrator vessel (m).
D = Inside diameter of the vessel (m).
P_1 = Atmospheric pressure (kPa).
P_2 = Pressure of the gas (kPa).
π = pi (3.14).
%G = Percent of packed vessel volume that is gas.
365 = Conversion from days to years.
t = Time between refilling (days) (365/t represent the refilling times during the reporting year).
100 = Conversion of %G to fraction.

(5) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (r) and (s) of this section.

(e) Well venting for liquids unloading. The CO_2 and CH_4 emissions for well venting for liquids unloading shall be determined using one of the following calculation methodologies:

(1) Calculation Methodology 1. For one representative well of each unique well tubing diameter grouping, pressure grouping and producing horizon/formation combination in each gas producing field where gas wells are vented to the atmosphere to expel liquids accumulated in the tubing, a recording flow meter shall be installed on the vent line used to vent gas from the well (e.g. on the vent line off the wellhead separator or atmospheric storage tank) according to the methods set forth in the WCI.364(b). Calculate emission from well venting for liquids unloading using Equation 360-11.

$$E_a = Q_j \times t_j$$

Equation 360-11

Where:

E_a = Annual natural gas volumetric emissions from well *j* at actual conditions (m^3/y).
t_j = Cumulative amount of time in hours of venting from well *j* during the reporting period (h).
Q_j = Average flow rate of the measured well venting for the duration of the liquids unloading, under actual conditions as determined in paragraph (e)(1)(i) of this section (m^3/h).

(i) Determine the well vent average flow rate as specified under paragraph (e)(1)(i) of this section.

(A) The average flow rate per hour of venting is calculated for each unique tubing diameter grouping and pressure grouping in each producing horizon/formation combination in each producing field by dividing the recorded total flow by the recorded time (in hours) for a single liquid unloading with venting to the atmosphere.

(B) This average flow rate is applied to all wells in the same pressure grouping that have the same tubing diameter grouping, for the number of hours in the calendar year of venting these wells.

(C) A new average flow rate is calculated every other calendar year (if necessary) for each reporting field and horizon combination starting the first calendar year of data collection. For a new producing reporting field and horizon combination, an average flow rate is calculated beginning in the first year of production.

(ii) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (q) of this section.

(2) Calculation Methodology 2. Calculate emissions from each well venting to the atmosphere for liquids unloading with plunger lift assist using Equation 360-12.

$$E_{a,n} = \left(\left[7.854 \times 10^{-5}\right] \times D_t^{\,2} \times WD \times \left[\frac{P_{sales}}{101.325}\right] \times N_V \right) + \left(Q_{sfr} \times \left[t_{open} - 0.5\right] \times Z \right)$$ **Equation 360-12**

Where:

E_a	=	Annual natural gas volumetric emissions at actual conditions (m^3/y).
7.854×10^{-5}	=	$(\pi/4)/(10000)$
D_t	=	Tubing diameter (cm).
WD	=	Tubing depth to plunger bumper (meters).
P_{sales}	=	Sales line pressure (kPa-gage).
N_V	=	Number of vents per year.
Q_{sfr}	=	Average sales flow rate of gas well at actual conditions (m^3/h).
t_{open}	=	Hours that the well was left open to the atmosphere during unloading.
0.5	=	Hours for average well to blowdown tubing volume at sales line pressure.
Z	=	If t_{open} is less than 0.5 then Z is equal to 0. If t_{open} is greater than or equal to 0.5 then Z is equal to 1.

(i) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (q) of this section.

(4) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (r) and (s) of this section.

(f) Gas well venting during well completions and workovers. Calculate emissions from gas conventional or unconventional (from hydraulic fracturing) well venting during well completions and workovers using one of the following methods. Sum all events to determine total annual venting that occurred in the reporting year. For 2012 calendar year emissions reporting, in addition to WCI.363(f)(1) and (2), methods published in the December 17, 2010 version of this document may be used for quantifying emissions from gas well venting during well completions and workovers.

(1) Calculation Methodology 1.

(i) The operator must measure total gas flow with a recording flow meter (analog or digital) installed in the vent line.

(ii) The operator must correct total gas volume vented for the volume of CO_2 or N_2 injected and the volume of gas recovered into a sales lines as follows:

$$E_a = V_M - V_{CO2,N2} - V_{SG}$$

Equation 360-13

Where:

E_a = Natural gas emissions during the well completion or workover at actual conditions (m^3).
V_M = Volume of vented gas measured during well completion or workover (m^3).
$V_{CO2,N2}$ = Volume of CO_2 or N_2 injected during well completion or workover (m^3).
V_{SG} = Volume of natural gas recovered into a sales pipeline (m^3).

(iii) All gas volumes must be corrected to standard temperature and pressure using methods in paragraph (q) of this section.

(iv) The operator must calculate CO_2 and CH_4 mass emissions from gas venting using the methods found in paragraphs (r) and (s) of this section.

(2) Calculation Methodology 2.

(i) The operator must make a series of measurements of upstream pressure (P_1) and downstream pressure (P_2) across a choke installed in the vent line and upstream gas temperature according to methods in section WCI.364(b) during each well completion and well workover where venting occurs. The operator must record this data at a time interval (e.g., every five minutes) suitable to accurately describe both sonic and subsonic flow regimes. Sonic flow is defined as the flow regime where $P_2/P_1 \leq 0.542$. Subsonic flow is defined as the flow regime where $P_2/P_1 > 0.542$. The operator must then calculate flow rate for both sonic and subsonic flow regimes using the following equations:

A. Sonic flow regime.

1. The operator must calculate the average flow rate during sonic flow conditions as follows:

$$Q_{S,avg} = 3600 \times A \times \sqrt{187.08 \times T_u}$$

Equation 360-14

Where:

$Q_{S,avg}$	=	Average flow rate of natural gas during sonic flow conditions (m^3/h).
3600	=	Conversion factor from m^3/second to m^3/hour.
A	=	Cross sectional area of the orifice (m^2).
187.08	=	Constant with units of $m^2/(sec^2 * K)$
T_u	=	Upstream gas temperature (degrees Kelvin).

2. The operator must calculate total natural gas volume vented during sonic flow conditions as follows:

$$V_S = Q_{S,avg} \times t_S$$

Equation 360-15

Where:

V_s	=	Volume of gas vented during sonic flow conditions (m^3)
t_S	=	Duration of venting during sonic flow conditions (h).The operator must correct Q_S to standard conditions using the methodology in paragraph (q) of this section

B. Subsonic flow regime.

1. The operator must calculate the instantaneous gas flow rate during subsonic flow conditions as follows:

$$Q_{SS,inst} = 3600 \times A \times \sqrt{3430 \times T_u \left[\left(P_2 / P_1 \right)^{1.515} - \left(P_2 / P_1 \right)^{1.758} \right]}$$

Equation 360-16

Where:

$Q_{SS,inst}$	=	Instantaneous flow rate of natural gas at time t_{inst} during subsonic flow conditions (m^3/h).
3600	=	Conversion factor from m^3/second to m^3/hour.
A	=	Cross sectional area of the orifice (m^2).
3430	=	Constant with units of $m^2/(sec^2 * K)$

T_u = Upstream gas temperature (degrees Kelvin).
P_2 = Downstream pressure (kPa)
P_1 = Upstream pressure (kPa)

2. The operator must determine total gas volume vented during subsonic flow conditions (Vss) as the total volume under the curve of a plot of $Q_{ss,inst}$ and time (t_{inst}) for the time period during which the well was flowing during subsonic conditions.

3. The operator must correct V_{SS} to standard conditions using the methodology in paragraph (q) of this section

(ii) The operator must sum the vented volumes during sonic and subsonic flow and adjust emissions for the volume of CO_2 or N_2 injected and the volume of gas recovered into a sales line as follows:

$$E_s = V_S + V_{SS} - V_{CO2,N2} - V_{SG}$$

Equation 360-17

Where:
E_s = Natural gas emissions during the well completion or workover (Sm^3).
V_S = Volume of gas vented during sonic flow conditions (Sm^3)
V_{SS} = Volume of gas vented during subsonic flow conditions (Sm^3)
$V_{CO2,N2}$ = Volume of CO_2 or N_2 injected during well completion or workover (Sm^3).
V_{SG} = Volume of natural gas recovered into a sales pipeline (Sm^3).

(iii) The operator must calculate CO_2 and CH_4 mass emissions from gas venting using the methods found in paragraphs (r) and (s) of this section.

(3) Calculate annual emissions from gas well venting during well completions and workovers to flares as follows:
(i) Use the gas well venting volume during well completions and workovers as determined in paragraph (f)(1) or (f)(2) of this section.
(ii) Use the calculation methodology of flare stacks in paragraph (k) of this section to determine gas well venting during well completions and workovers emissions from the flare.

(g) Blowdown vent stacks. Calculate blowdown vent stack emissions from depressurizing equipment to reduce system pressure for planned or emergency shutdowns or to take equipment out of service for maintenance (excluding depressurizing to a flare, over-pressure relief, operating pressure control venting and blowdown of non-GHG gases; desiccant dehydrator blowdown venting before reloading is covered in paragraph (d)(4) of this section) as follows:

(1) Calculate the total physical volume (including, but not limited to, pipe, compressor case or cylinders, manifolds, suction and discharge bottles and vessels) between isolation valves determined by engineering estimates based on best available data.

(2) If the total physical volume between isolation valves is greater than or equal to 1.42 Sm^3, retain logs of the number of blowdowns for each equipment system (including, but not limited to pipes, compressors and vessels). Physical volumes smaller than 1.42 m^3 are exempt from reporting under paragraph (g) of this section.

(3) Calculate the venting emissions for each equipment type using Equation 360-18.

$$E_s = V_v \left[\frac{(273.15 + T_s)(P_{a,1} - P_{a,2})}{(273.15 + T_a)P_s} \right]$$

Equation 360-18

Where:

E_s	=	Natural gas venting volumetric emissions from blowdown of an equipment system (Sm^3).
V_v	=	Total physical volume of blowdown equipment chambers (including, but not limited to, yard piping, pipelines, compressors and vessels) between isolation valves for the equipment system (m^3).
T_s	=	Temperature at standard conditions (ºC).
T_a	=	Temperature at actual conditions in the equipment system (°C).
P_s	=	Absolute pressure at standard conditions (kPaa).
$P_{a,1}$	=	Absolute pressure at actual conditions in the equipment system prior to depressurization (kPaa).
$P_{a,2}$	=	Absolute pressure at actual conditions in the equipment system after depressurization; 0 if equipment is purged using non-GHG gases (kPaa).

(4) Calculate both CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (r) and (s) of this section.

(5) Blowdowns that are directed to flares use the WCI.363(k) Flare stacks calculation method rather than WCI.363(g) Blowdown vent stacks calculation method.

(g.1) Third party line hits. Calculate emissions from third party line hits as follows:

(1) For each dig-in incident (i.e., line hit) which results in gas release ≥ 1.416 Sm^3, calculate volumetric flow rate prior to pipeline isolation for both catastrophic pipeline

ruptures and pipeline puncture incidents using the appropriate methodology below[1]. For 2012, the methodology in paragraph (iv) may be used in addition to those in paragraphs (i) and (ii).

(i) For catastrophic pipeline ruptures where the pipeline is severed use the following methodology:

$$Q_s = \frac{3.6x10^6 \times A}{\rho_s} \sqrt{\frac{K \times MW}{1000 \times R \times (273.15 + T_a)}} \times \frac{P_a \times M}{\left(1 + \frac{K-1}{2} M^2\right)^{\frac{K+1}{2(K-1)}}}$$

Equation 360-19

Where:

$$M = \sqrt{\frac{2\left[\left(\frac{P_a}{P_e}\right)^{\frac{K-1}{K}} - 1\right]}{K-1}} \text{ , (for M} \leq 1\text{),}$$

Equation 360-20

M = 1, (for all other cases)

Where:

Q_s	=	natural gas venting volumetric flow rate (Sm^3/h)
A	=	cross-sectional flow area of the pipe (m^2, $A=\pi D^2/4000$)
D	=	inside diameter of the pipe (mm)
K	=	specific heat ratio of the gas (dimensionless – 1.299 for methane)
M	=	Mach number of the flow (m/s)
MW	=	molecular weight of the gas (kg/mole, 16.043 kg/mole for methane)
P_e	=	pressure at the damage point (local atmospheric pressure, kPaa)
P_a	=	pressure inside the pipe at supply (kPaa)) (usually taken at the point where the damaged main branches off a larger main). The supply pressure values should represent a stable supply pressure; however, it is important to account for the lower pressure which will occur because of the flow of gas from the break.
R	=	universal gas constant (8.3145 $kPam^3/kmol/K$)
T_a	=	temperature inside pipe at the supply (˚C)
ρ_s	=	gas density at standard conditions (kg/m^3) (0.6785 kg/m^3 for CH_4)

[1] Methodology Manual, Estimation of Air Emissions from the Canadian Natural Gas Transmission, Storage and Distribution System, Prepared for Canadian Energy Partnership for Environmental Innovation (CEPEI). Prepared by Clearstone Engineering Ltd. Calgary, Alberta, September 25, 2007. Chapter7, Third-Party Dig-Ins, page 117.

(ii) For pipeline punctures use the following methodology (for flows not choked):

$$Q_s = \frac{A_e}{\rho_s}\sqrt{\frac{2000 \cdot K}{K-1} P_a \rho_a \left[\left(\frac{P_{Atm}}{P_a}\right)^{2/K} - \left(\frac{P_{Atm}}{P_a}\right)^{(K+1)/K}\right]}$$

Equation 360-21

Where:

$$\left(\frac{P_{Atm}}{P_a}\right) \geq \left(\frac{P_{Atm}}{P_a}\right)_{choked} = \left(\frac{2}{K+1}\right)^{K/(K-1)} = 0.546 \qquad \text{(for methane)}$$

Equation 360-22

Where:

A_e	=	size of the hole in the pipe (m^2)
P_a	=	pressure inside the pipe at the puncture location (kPaa)
ρ_a	=	gas density inside the pipe at the puncture location (kg/m^3)
MW	=	molecular weight of the natural gas (16.043 for methane)
T_a	=	temperature inside the pipe (˚C)
$(P_{ATM}/P_a)_c$	=	0.546 - lower limit for choked flow

(iii) Check for choked flow

(A) If (P_{ATM}/P_a) is $\geq$0.546 flow is not choked and the reporter must use the equations in section (g.1)(ii) above.

(B) If (P_{ATM}/P_a) <0.546 flow is choked and A must be set to the cross sectional flow area of the pipe and the reporter must use the equations in section (g.1)(i) above.

(iv) For 2012 calendar year emissions, an operator may use other methods to calculate emissions published in the CEPEI Methodology Manual, or other industry standard reference sources.

(v) Calculate volumetric natural gas emissions by multiplying Q_s for each pipeline rupture and puncture by the total elapsed time from pipeline rupture or puncture until isolation and final bleed-down to atmospheric pressure.

(vi) Calculate GHG (CH_4 and CO_2 emissions) mass emissions using the methodologies in sections (r) and (s) of this section.

(h) Onshore production and processing storage tanks. For emissions from atmospheric pressure fixed roof storage tanks receiving hydrocarbon produced liquids from onshore petroleum and natural gas production facilities and onshore natural gas processing facilities, calculate annual CH_4, CO_2 (and N_20, when flared) emissions as specified in either paragraphs (h)(1) or (h)(2). For atmospheric storage tanks vented to flares, use the calculation methodology for flare stacks in paragraph (k) of this section. Storage tanks equipped with vapour recovery units (VRU) are exempt from the requirements of this paragraph. For 2012 calendar year emissions reporting, Equation 360-12, as published in the December 17, 2010 version of this document, may also be used for quantifying emissions from onshore production and processing storage tanks.

(1) Calculate CH_4 and CO_2 flashing emissions using Equation 360-23.

$$E_i = GOR \times Q_o \times Y_i \times \rho_i \times 0.001$$

Equation 360-23

Where:

E_i	=	Annual emissions of greenhouse gas *i* (CO_2 or CH_4) (tonnes/y).
GOR	=	Gas Oil Ratio (Sm^3 gas/m^3 oil) measured following WCI.364(f).
Q_o	=	Oil production rate (m^3/y).
ρ_i		Density of GHG i (1.861 kg/m^3 for CO_2 and 0.678 kg.m^3 for CH_4 at standard conditions of 101.325 kPa and 15 ^oC).
Y_i	=	Mole fraction of greenhouse gas *i* (CO_2 or CH_4) in tank vapour.
0.001	=	Conversion factor (tonnes/kg).

(2) Calculate CH_4 and CO_2 flashing emissions using the latest software package for E&P Tank. A minimum of the following parameters must be used to characterize emissions from liquid transfer to atmospheric pressure storage tanks.
(i) Separator oil composition.
(ii) Separator temperature.
(iii) Separator pressure.
(iv) Sales oil API gravity.
(v) Sales oil production rate.
(vi) Sales oil Reid vapour pressure.
(vii) Ambient air temperature.
(viii) Ambient air pressure.

(h.1) Transmission storage tanks. For condensate storage tanks, either water or hydrocarbon, without vapour recovery or thermal control devices in onshore natural gas production and processing facilities calculate CH_4, CO_2 and N_2O (when flared) annual emissions from compressor scrubber dump valve leakage as follows. For 2012, other methodologies may be used to quantify emissions from transmission storage tanks in addition to those outlined below.

(1) Monitor the tank vapour vent stack annually for emissions using an optical gas imaging instrument according to methods set forth in WCI.364(a)(1) or by directly measuring the tank vent using a flow meter, calibrated bag, or High-flow Sampler according to methods in WCI.364(b) through (d) for a duration of 5 minutes. Or you may annually monitor leakage through compressor scrubber dump valve(s) into the tank using an acoustic leak detection device according to methods set forth in WCI.364(a)(4).

(2) If the tank vapours are continuous for 5 minutes, or the acoustic leak detection device detects a leak, then use one of the following two methods in paragraph (h.1)(2) of this section to quantify annual emissions:

(i) Use a meter, such as a turbine meter, calibrated bag, or High-flow Sampler to estimate tank vapour volumes according to methods set forth in WCI.364(b) through (d). If you do not have a continuous flow measurement device, you may install a flow measuring device on the tank vapour vent stack. If the vent is directly measured for five minutes under paragraph (h.1)(1) of this section to detect continuous leakage, this serves as the measurement.

(ii) Use an acoustic leak detection device on each scrubber dump valve connected to the tank according to the method set forth in WCI.364(a)(4).

(iii) Use the appropriate gas composition in paragraph (r) of this section.

(3) If the leaking dump valve(s) is fixed following leak detection, the annual emissions shall be calculated from the beginning of the calendar year to the time the valve(s) is repaired.

(4) Calculate annual emissions from storage tanks to flares as follows:

(i) Use the storage tank emissions volume and gas composition as determined in paragraphs (h.1)(1) through (h.1)(3) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (k) of this section to determine storage tank emissions sent to a flare.

(i) Well testing venting and flaring. Calculate CH_4, CO_2, and N_2O (when flared) well testing venting and flaring emissions as follows.

(1) Determine the gas to oil ratio (GOR) of the hydrocarbon production from each well tested.

(2) If GOR cannot be determined from your available data, then use one of the two procedures in paragraph (i)(2) of this section to determine GOR and follow paragraph (3). Otherwise follow paragraph (4).:

(i) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists.

(ii) Or you may use an industry standard practice as described in WCI.364(b).

(3) Calculation Methodology 1. Estimate venting emissions using Equation 360-24.

$$E_a = GOR \times Q_o \times t$$

Equation 360-24

Where:

E_a = Annual volumetric natural gas emissions from well testing at actual conditions (m^3/y).
GOR = Gas to oil ratio; oil here refers to hydrocarbon liquids produced of all API gravities (m^3 gas/m^3 oil).
Q_o = Flow rate for the well being tested (m^3 oil/h).
t = Total hours during the year the well is tested (h).

(4) Calculation Methodology 2. In cases where very little hydrocarbon liquids are produced and the GOR approaches infinity, estimate emissions using Equation 360-25. A recording flow meter shall be installed on the vent (or flare) line used to vent gas from the well (e.g. on the vent line off the well-test separator) according to the methods set forth in the WCI.364(b).

$$E_a = Q_g \times t$$

Equation 360-25

Where:

E_a = Annual natural gas volumetric emissions at actual conditions (m^3/y).
t = Total hours during the year the well is tested (h).
Q_g = Average flow rate of the measured well venting for the duration of the test at actual conditions (m^3 gas/h).

(5) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (q) of this section.

(6) Calculate both CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (r) and (s) of this section.

(7) Calculate emissions from well testing to flares as follows:
(i) Use the well testing emissions volume as determined in paragraphs (i)(1) through (4) of this section.
(ii) Use the calculation methodology of flare stacks in paragraph (k) of this section to determine well testing gas composition and emissions from the flare.

(j) Associated gas venting and flaring. Calculate associated gas venting and flaring emissions not in conjunction with well testing (refer to section (i): Well testing venting and flaring) as follows.

(1) Determine the GOR of the hydrocarbon production from each well whose associated natural gas is vented or flared. If GOR from each well is not available, the GOR from a cluster of wells in the same field shall be used.

(2) If GOR cannot be determined from your available data, then use one of the two procedures in paragraph (j)(2) of this section to determine GOR:

(i) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists.
(ii) Or you may use an industry standard practice as described in WCI.364(b).

(3) Estimate venting emissions using the Equation 360-26.

$$E_a = GOR \times Q_o$$

Equation 360-26

Where:

E_a = Annual volumetric natural gas emissions from associated gas venting at actual conditions (m^3/y).
GOR = Gas to oil ratio; oil here refers to hydrocarbon liquids produced of all API gravities (m^3 gas/m^3 oil).
Q_o = Total volume of oil produced for the calendar year during which associated gas was flared or vented (m^3 oil/y)..

(4) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (q) of this section.

(5) Calculate both CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (r) and (s) of this section.

(6) Calculate emissions from associated natural gas to flares as follows:
(i) Use the associated natural gas volume as determined in paragraph (j)(1) through (4) of this section.
(ii) Use the calculation methodology of flare stacks in paragraph (k) of this section to determine associated gas composition and emissions from the flare.

(k) Flare stacks. Calculate CO_2, CH_4, and N_2O emissions from a flare stack as follows.

(1) If there is a continuous flow measurement device on the flare, measured flow volumes must be used to calculate the flare gas emissions. If all of the flare gas is not measured by the existing flow measurement device, then the flow not measured can be estimated using engineering calculations based on best available data or company records. If there is not a continuous flow measurement device on the flare, a flow measuring device can be installed on the flare or engineering calculations based on process knowledge, company records, and best available data.

(2) If there is a continuous gas composition analyzer on the gas stream to the flare, these compositions must be used in calculating emissions. If there is not a continuous gas composition analyzer on the gas stream to the flare, the appropriate gas compositions for each stream of hydrocarbons going to the flare must be used as follows:
(i) For onshore natural gas production, determine natural gas composition using (r)(2)(i) of this section.
(ii) For onshore natural gas processing, when the stream going to flare is natural gas, use the GHG mole percent in feed natural gas for all streams upstream of the de-

methanizer or dew point control and GHG mole percent in facility specific residue gas to transmission pipeline systems for all emissions sources downstream of the de-methanizer overhead or dew point control for onshore natural gas processing facilities. For onshore natural gas processing plants that solely fractionate a liquid stream, use the GHG mole percent in feed natural gas liquid for all streams.

(iii) For any applicable industry segment, when the stream going to the flare is a hydrocarbon product stream, such as ethane, butane, pentane-plus, and mixed light hydrocarbons then a representative composition from the source for the stream determined by engineering calculation based on process knowledge and best available data may be used.

(3) Determine flare combustion efficiency from manufacturer. If not available, assume that flare combustion efficiency is 98 percent.

(4) Calculate GHG volumetric emissions at actual conditions using Equations 360-27, 360-28, 360-29, and 360-30.

$$E_{s,CH4}(noncombusted) = Q_s \times (1-\eta) \times Y_{CH4}$$ **Equation 360-27**

$$E_{s,CO2}(noncombusted) = Q_s \times Y_{CO2}$$ **Equation 360-28**

$$E_{s,CO2}(combusted) = \sum_i \eta \times Q_s \times Y_i \times n_i$$ **Equation 360-29**

$$E_{s,CO2}(total) = E_{s,CO2}(combusted) + E_{s,CO2}(noncombusted)$$ **Equation 360-30**

Where:

$E_{s,CH4}$ (noncombusted)	=	Contribution of annual noncombusted volumetric CH_4 emissions from flare stack (Sm^3).
$E_{s,CO2}$ (noncombusted)	=	Contribution of annual volumetric CO_2 emissions from CO_2 in the inlet gas passing through the flare noncombusted (Sm^3).
$E_{s,CO2}$ (combusted)	=	Contribution of annual CO_2 emissions from combustion from flare stack under ambient conditions (Sm^3).
Q_s	=	Volume of natural gas sent to flare during the year (Sm^3).
η	=	Fraction of natural gas combusted by flare (default combustion efficiency is 0.98). For gas sent to an unlit flare, η is zero.
Y_{CH4}	=	Mole fraction of CH_4 in gas to the flare.
Y_{CO2}	=	Mole fraction of CO_2 in gas to the flare.
Y_i	=	Mole fraction of hydrocarbon constituents *i* (i.e., methane, ethane, propane, butane, pentanes, hexanes and pentanes plus) in natural gas to the flare.
n_i	=	Number of carbon atoms in the hydrocarbon constituent i (i.e., 1 for methane, 2 for ethane, 3 for propane, 4 for butane, 5 for

pentanes, 6 for hexanes and 7 for pentanes plus) in natural gas to the flare.

(5) Calculate both CH_4 and CO_2 mass emissions from volumetric CH_4 and CO_2 emissions using calculation in paragraph (s) of this section.

(6) Calculate N_2O emissions using Equation 360-31.

$$E_{N2O} = Q_s \times HHV \times EF \times 0.001$$

Equation 360-31

Where:

E_{N2O}	=	Annual N_2O mass emissions from flaring (tonnes/y).
Q_s	=	Volume of gas combusted by the flare in the reporting period (Sm^3/y).
HHV	=	High heat value of the flared gas from paragraph (k)(2).
EF	=	N_2O emission factor. Use 9.52×10^{-5} kg N_2O/GJ.
0.001	=	Conversion factor from kilograms to tonnes.

(7) To avoid double-counting, this emissions source excludes any emissions calculated under other emissions sources in WCI.363. Where gas to be flared is manifolded from multiple sources in WCI.363 to a common flare, report all flaring emissions under WCI.363(k).

(l) Centrifugal compressor venting. Calculate emissions from centrifugal compressor venting as follows.

(1) The operator must calculate CO_2, and CH_4, and N_2O (when flared) emissions from both wet seal and dry seal centrifugal compressor vents (including wet seal oil degasing) where the aggregate rated power for the sum of compressors at the facility is 186.4 kW or greater using a temporary or permanent flow measurement meter such as, but not limited to, a vane anemometer according to methods set forth in WCI.364(b).

(2) Estimate annual emissions using flow meter measurement using Equation 360-32.

$$E_{s,i} = \sum_m Q_{s,m} \times t_m \times Y_i \times (1 - CF)$$

Equation 360-32

Where:

$E_{s,i}$	=	Annual volumetric emissions of GHG *i* (either CH_4 or CO_2) from all measured compressor venting modes (Sm^3/y).

$Q_{s,m}$	=	Measured volumetric gas emissions during operating mode *m* described in paragraph (l)(4) of this section (Sm^3/h).
t_m	=	Total time the compressor is in operating mode *m* during the calendar year (h).
Y_i	=	Mole fraction of GHG *i* in the vent gas; use the appropriate gas compositions in paragraph (r)(2) of this section.
CF	=	Fraction of centrifugal compressor vent gas sent to vapour recovery or fuel gas or other beneficial use as determined by keeping logs of the number of operating hours for the vapour recovery system and the amount of vent gas that is directed to the fuel gas system. An engineering estimation approach may be used for the CF parameter for 2012 emissions reporting.

(3) An engineering estimate approach based on similar equipment specifications and operating conditions may be used to determine the $Q_{s,m}$ variable in place of actual measured values for centrifugal compressors that are operated for no more than 200 hours in a calendar year and used for peaking purposes in place of metered gas emissions if an applicable meter is not present on the compressor.

(4) Conduct an annual measurement for each compressor in the mode in which it is found during the annual measurement. Measure emissions from (including emissions manifolded to common vents), unit isolation-valve vents, and blowdown-valve vents.

(i) Operating or standby-pressurized mode, blowdown vent leakage through the blowdown vent stack.

(ii) Operating mode.

(iii) Not operating, depressurized mode, unit isolation-valve leakage through the blowdown vent stack, without blind flanges.

(A) For the not operating, depressurized mode, each compressor must be measured at least once in any three consecutive calendar years if this mode is not found in the annual measurement. If a compressor is not operated and has blind flanges in place throughout the 3 year period, measurement is not required in this mode. If the compressor is in standby depressurized mode without blind flanges in place and is not operated throughout the 3 year period, it must be measured in the standby depressurized mode

(5) The operator must calculate CO_2, and CH_4, and N_2O (when flared) emissions from both wet seal and dry seal centrifugal compressor vents (including wet seal oil degassing) for all compressors where the aggregate rated power for the sum of compressors at the facility is less than 186.4 kW (250 hp) using Equation 360-33.

$$E_{s,i} = Count \times EF_i$$

Equation 360-33

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from centrifugal compressors (m^3/year).

Count = Total number of centrifugal compressors less than 186.4 kW.

EF_i = Emission factor for GHG *i* (either CH_4 or O_2). Use 339,573.2 Sm^3/year per compressor for CH_4 and 14,974.7 Sm^3/year per compressor for CO_2 at 15 °C and 1 atmosphere, or as adjusted for different reference temperatures using ideal gas law.

(6) Calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (s) of this section.

(7) Calculate emissions from degassing vent vapours to flares as follows:

(i) Use the degassing vent vapour volume and gas composition as determined in paragraphs (l)(1) through (3) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (k) of this section to determine degassing vent vapour emissions from the flare.

(m) Reciprocating compressor venting. Calculate annual CH_4 and CO_2 emissions from all reciprocating compressor vents as follows, except as specified in paragraph (m)(7) . Where venting emissions are sent to a common flare, calculate emissions using WCI.363(k).

(1) Estimate annual emissions using the flow measurement in (m)(2) or (m)(3) below and Equation 360-34.

$$E_{s,i} = \sum_{m} Q_{s,m} \times t_m \times Y_i \times (1 - CF)$$

Equation 360-34

Where:

$E_{s,i}$, = Annual volumetric emissions of GHG *i* (either CH_4 or CO_2) from all measured compressor venting modes (Sm^3/y).

$Q_{s,m}$ = Measured volumetric gas emissions during operating mode *m* described in paragraph (m)(4) (Sm^3/h).

t_m = Total time the compressor is in operating mode *m* during the calendar year (h).

Y_i = Mole fraction of GHG *i* in the vent gas; use the appropriate gas compositions in paragraph (r)(2) of this section.

CF = Fraction of reciprocating compressor vent gas sent to vapour recovery or fuel gas or other beneficial use as determined by keeping logs of the number of operating hours for the vapour recovery system and the amount of vent gas that is directed to the fuel gas system. An engineering estimation approach may be used for the CF parameter for 2012 emissions reporting.

(2) If the reciprocating rod packing and blowdown vent is connected to an open-ended vent line then use one of the following two methods to calculate emissions**.**

(i) Measure emissions from all vents (including emissions manifolded to common vents) including rod packing, unit isolation valves, and blowdown vents using either calibrated bagging or High-flow Sampler according to methods set forth in WCI.364(c) and (d).

(ii) Use a temporary meter such as a vane anemometer or a permanent meter such as an orifice meter to measure emissions from all vents (including emissions manifolded to a common vent) including rod packing vents, unit isolation valves, and blowdown valves according to methods set forth in WCI.364(b). If you do not have a permanent flow meter, you may install a port for insertion of a temporary meter or a permanent flow meter on the vents. For through-valve leakage to open ended vents, such as unit isolation valves on not operating, depressurized compressors and blowdown valves on pressurized compressors, you may use an acoustic detection device according to methods set forth in WCI.364(a).

(3) If the rod packing case is not equipped with a vent line use the following method to estimate emissions:

(i) Use the methods described in WCI.364(a) to conduct a progressive leak detection of fugitive equipment leaks from the packing case into an open distance piece, or from the compressor crank case breather cap or vent with a closed distance piece.

(ii) Measure emissions using a High-flow Sampler, or calibrated bag, or appropriate meter according to methods set forth in WCI.364(b), (c), or (d).

(4) Conduct an annual measurement for each compressor in the mode in which it is found during the annual measurement, except as specified in paragraph (m)(7) of this section. Measure emissions from (including emissions manifolded to common vents) reciprocating rod-packing vents, unit isolation-valve vents, and blowdown-valve vents.

(i) Operating or standby-pressurized mode, blowdown vent leakage through the blowdown vent stack.

(ii) Operating mode, reciprocating rod-packing emissions.

(iii) Not operating, depressurized mode, unit isolation-valve leakage through the blowdown vent stack, without blind flanges.

(A) For the not operating, depressurized mode, each compressor must be measured at least once in any three consecutive calendar years if this mode is not found in the annual measurement. If a compressor is not operated and has blind flanges in place throughout the 3 year period, measurement is not required in this mode. If the compressor is in standby depressurized mode without blind flanges in place and is not operated throughout the 3 year period, it must be measured in the standby depressurized mode

(5) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in paragraphs (r) and (s) of this section.

(6) Determine if the reciprocating compressor vent vapors are sent to a vapor recovery system.

(i) Adjust the emissions estimated in paragraphs (f)(1) of this section downward by the magnitude of emissions recovered using a vapor recovery system as determined by engineering estimate based on best available data.

(ii) An engineering estimate approach based on similar equipment specifications and operating conditions or manufacturer's data may be used to determine the $Q_{s,m}$ variable in place of actual measured values for reciprocating compressors that are operated for no more than 200 hours in a calendar year

(7) Onshore petroleum and natural gas production may calculate emissions from reciprocating compressors where the aggregate rated power for the sum of compressors at the facility is less than 186.4 kW (250 hp) as follows using Equation 360-35:

$$E_{s,i} = Count \times EF_i$$

Equation 360-35

Where:

$E_{s,i}$	=	Annual total volumetric GHG emissions at standard conditions from reciprocating compressors (m^3/year).
Count	=	Total number of reciprocating compressors considered under (m)(7) for the reporter.
EF_i	=	Emission factor for GHG *i* (either CH_4 or O_2). Use 268.0 Sm^3/year per compressor for CH_4 and 14.9 Sm^3/year per compressor for CO_2 at 15 °C and 1 atmosphere, or as adjusted for different reference temperatures using ideal gas law.

(n) Leak detection and leaker emission factors. Existing legislative or regulatory requirements (described in WCI.364(a)(0.1) or progressive sampling methods (described in WCI.364(a)(0.2)) must be used to conduct a leak detection survey of fugitive equipment leaks from all sources listed in §WCI.362(d)(9). This paragraph (n) applies to emissions sources in streams with gas containing greater than 10 percent CH_4 plus CO_2 by weight. Emissions sources in streams with gas containing less than 10 percent CH_4 plus CO_2 by weight need to be reported instead under paragraph (x) of this section. **

If fugitive equipment leaks are detected for sources listed in this paragraph, calculate equipment leak emissions per source per reporting facility using Equation 360-36 for each source with fugitive equipment leaks.

$$E_{s,i} = EF_{s,l} \times Y_i \times t_1$$

Equation 360-36

Where:

$E_{s,i}$	=	Annual total volumetric emissions of GHG *i* (either CH_4 or CO_2), from each fugitive equipment leak source (Sm^3/y).
$EF_{s,l}$	=	Leaker volumetric emission factor for specific component, *l*, listed in 40 CFR Part 98 Table W-2, relevant Canadian Association of Petroleum Producers (CAPP) methodology manuals, if available or facility/company-specific emission factors* used (as converted for use in Equation 360-36).
Y_i	=	For onshore natural gas processing facilities, mole fraction of GHG *i* (either CH_4 or CO_2) in the total hydrocarbon of the feed natural gas.
t_l	=	Total time the component, *l*, was found leaking and operational (hours). If one leak detection survey is conducted, assume the component was leaking from the start of the year until the leak was repaired and then zero for the remainder of the year. If the leak was not repaired, assume the component was leaking for the entire year. If multiple leak detection surveys are conducted, assume that the component found to be leaking has been leaking since the last survey during which it was determined to be not leaking, or the beginning of the calendar year. For the last leak detection survey in the calendar year, assume that all leaking components continue to leak until the end of the calendar year or until the component was repaired and then zero until the end of the year.

(1) Calculate GHG mass emissions in carbon dioxide equivalent at standard conditions using calculations in paragraph (s) of this section.

(2) Onshore natural gas processing facilities shall use the appropriate default volumetric leaker emission factors listed in 40 CFR Part 98 Table W-2 (as converted to metric) or relevant Canadian Association of Petroleum Producer methodology manuals, if available for fugitive equipment leaks detected from valves; connectors; open ended lines; pressure relief valves; and meters.

** component-specific emission factors may equal leak rates quantified, following WCI.364(c) or (d), during leak detection surveys.*

*** tubing systems less than one half inch diameter may be quantified using WCI.363(n), instead of WCI.363(x) if a leak detection survey captures them. If not covered by a leak detection survey, they must be quantified using WCI.363(x). Reporting must occur using the appropriate section of WCI.362, dependent upon quantification method used.*

(o) <u>Population count and emission factors</u>. This paragraph applies to emissions sources listed in §WCI.362 (c)(16), (c)(17) and (d)(8) on streams with gas containing greater than 10 percent CH_4 plus CO_2 by weight. Emissions sources in streams with gas containing less than 10 percent CH_4 plus CO_2 by weight do not need to be reported. **

(1) Calculate emissions from all sources listed in this paragraph using Equation 360-37 except for emissions from underground gathering pipelines that are calculated in paragraph (2).

$$E_i = \sum_k \sum_l \left(N_{k,l} \times \frac{EF_{k,l}}{THC_k} \times X_{i,k} \right) \times t$$

Equation 360-37

Where:

E_i	=	Annual total mass emissions of GHG *i* (CH_4 or CO_2) at standard conditions from each major equipment or component count fugitive source at the facility (tonnes/year).
$N_{k,l}$	=	Number of components in service *k* and component type *l*. Per WCI.362(g)(19) average component counts by major equipment pieces for Canada from Table 360-3 may be used for 2011 and 2012 calendar year emissions as appropriate and can be in Gas/Vapour, Fuel Gas and Liquid service. For 2013 calendar year emissions and onwards component counts for individual facilities must be used. If facility or company specific major equipment count data that meet or exceed the quality of the relevant default count data are available, they must be used instead. Current processing and instrumentation drawings (P&ID) may be used for the source of component (or major equipment) counts for all years
$EF_{k,l}$	=	Population mass emission factor for components in service *k* and component type *l* listed in Table 360-1 or Table 360-2. The direction on the use of Tables 360-1 and 360-2 provided prior to these tables must be followed and indicates that if facility specific emission factors are available these facility specific emission factors must be used* (tonnes total hydrocarbon (THC) / component / h).
THC_k	=	Mass fraction of total hydrocarbons in service *k*.
$X_{i,k}$	=	Mass fraction of GHG *i* (CH_4 or CO_2) in service *k*.
t	=	Total time the specific source associated with the fugitive equipment leak was operational in the reporting year (h).

(2) Calculate emissions from underground gathering pipelines using Equation 360-38.

$$E_{s,i} = EF_{s,i} \times L \times t$$

Equation 360-38

Where:

$E_{s,i}$	=	Annual total volumetric emissions of GHG *i* (either CH_4 or CO_2), from an underground gathering pipeline (Sm^3/y).
$EF_{s,i}$	=	Volumetric emission factors equal to 2.66×10^{-5} t CH_4/km/h and 3.63×10^{-6} t CO_2/km/h for pipeline leaks plus the portion of methane emitted from

underground leaks that is oxidized to form carbon dioxide and equal to 2.72 x 10^{-6} t CO_2/km/h. These factors are published in Table 6-4 of the American Petroleum Institute (API) 2009 Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry.

L = Length of the underground gathering pipeline (km)

t = Total time the underground gathering pipeline was operational in the reporting year (h).

(3) Onshore petroleum and natural gas production facilities shall use the appropriate default population emission factors listed in Table 360-1 or 360-2 for fugitive equipment leaks from valves, connectors, open ended lines, pressure relief valves, pump, flanges, and other equipment. Where facilities conduct EOR operations the emissions factors listed in Table 360-1 or Table 360-2 shall be used to estimate all streams of gases, including the recycle CO_2 stream. The component count can be determined using either of the methodologies described in this paragraph (o)(1). The same methodology must be used for the entire calendar year..

(i) *Component Count Methodology 1*. For all onshore petroleum and natural gas production operations in the facility perform the following activities:

(A) Count all major equipment listed in Table 360-3 of this section.

(B) Multiply major equipment counts by the average component counts in Gas/Vapour, Fuel Gas and Liquid service listed in Table 360-3 of this section for onshore natural gas production and onshore oil production, respectively. Use the appropriate total hydrocarbon (THC) factor in Table 360-1 or Table 360-2 of this section or from CAPP methodology manuals, if the appropriate factor is not provided in Tables 360-1 or 360-2.

(ii) *Component Count Methodology 2*. Count each component individually for the facility. Use the appropriate factor Table 360-1 or Table 360-2 of this section or from CAPP methodology manuals, if the appropriate factor is not provided in Tables 360-1 or 360-2.

** facility/company-specific emission factors may equal leak rates quantified, following WCI.364(c) or (d), during leak detection surveys or those emission factors calculated for the purposes of WCI.367 – Directions for the use of Tables 360-1 and 360-2.*

*** tubing systems less than one half inch diameter may be quantified using WCI.363(n), instead of WCI.363(x) if a leak detection survey captures them. If not covered by a leak detection survey, they must be quantified using WCI.363(x). Reporting must occur using the appropriate section of WCI.362, dependent upon quantification method used.*

(p) <u>Offshore petroleum and natural gas production facilities in both provincial and federal waters.</u>
[reserved]

(q) Volumetric emissions. Calculate volumetric emissions at standard conditions as specified in paragraphs (q)(1) or (2), with actual pressure and temperature determined by engineering estimate based on best available data unless otherwise specified.

(1) Calculate natural gas volumetric emissions at standard conditions by converting the actual temperature and pressure to standard temperature and pressure (15 ºC and 1 atmosphere in Canada) using Equation 360-39 of this section.

$$E_s = \frac{E_a \times (273.15 + T_s) \times P_a}{(273.15 + T_a) \times P_s}$$

Equation 360-39

Where:

E_s	=	Natural gas volumetric emissions at standard temperature and pressure (STP) conditions (Sm^3).
E_a	=	Natural gas volumetric emissions at actual conditions (m^3).
T_s	=	Temperature at standard conditions (^oC).
T_a	=	Temperature at actual emission conditions (^oC).
P_s	=	Absolute pressure at standard conditions (kPa).
P_a	=	Absolute pressure at actual conditions (kPa).

(2) Calculate GHG volumetric emissions at standard conditions by converting actual temperature and pressure of GHG emissions to standard temperature and pressure using Equation 360-40.

$$E_{s,i} = \frac{E_{a,i} \times (273.15 + T_s) \times P_a}{(273.15 + T_a) \times P_s}$$

Equation 360-40

Where:

$E_{s,i}$	=	GHG *i* volumetric emissions at standard temperature and pressure (STP) conditions (Sm^3).
$E_{a,i}$	=	GHG *i* volumetric emissions at actual conditions (m^3).
T_s	=	Temperature at standard conditions (^oC).
T_a	=	Temperature at actual emission conditions (^oC).
P_s	=	Absolute pressure at standard conditions (kPa).
P_a	=	Absolute pressure at actual conditions (kPa).

(r) GHG volumetric emissions. If the GHG volumetric emissions at actual conditions are known, follow the method in (q)(2) to calculate their emissions at standard conditions. If the GHG volumetric emissions are not yet known, then follow the methods below to calculate

GHG volumetric emissions at standard conditions as specified in paragraphs (r)(1) and (2) of this section determined by engineering estimate based on best available data unless otherwise specified.

(1) Estimate CH_4 and CO_2 emissions from natural gas emissions using Equation 360-41.

$$E_{s,i} = E_s \times Y_i$$

Equation 360-41

Where:

$E_{s,i}$	=	GHG *i* (CH_4 or CO_2) volumetric emissions at standard conditions.
E_s	=	Natural gas volumetric emissions at standard conditions.
Y_i	=	Mole fraction of GHG *i* in the natural gas.

(2) For Equation 360-41 of this section, the mole fraction, Y_i, shall be the annual average mole fraction for each facility, as specified in paragraphs (r)(2)(i) and (ii) of this section.

(i) GHG mole fraction in produced natural gas for onshore petroleum and natural gas production facilities. If you have a continuous gas composition analyzer for produced natural gas, you must use an annual average of these values in calculating emissions. If you do not have a continuous gas composition analyzer, then use an annual average of the known composition (in required order of preference) for the (i) facility; or (ii) company for the specific field sampled within the current (required if available) or previous (if current data not available) reporting period, using the methods set forth in WCI.364(b). Alternatively, if this information is not available, the composition for the specific field from Table 360-4.

(ii) (a) GHG mole fraction in feed natural gas for all emissions sources upstream of the de-methanizer or dew point control and (b) GHG mole fraction in facility specific residue gas to transmission pipeline systems for all emissions sources downstream of the de-methanizer overhead or dew point control for onshore natural gas processing facilities. For onshore natural gas processing plants that solely fractionate a liquid stream, use the GHG mole percent in feed natural gas liquid for all streams. If you have a continuous gas composition analyzer on feed natural gas, you must use an annual average of these values to determine the mole fraction in calculating emissions. If you do not have a continuous gas composition analyzer, then use an annual average of the known composition (in required order of preference) for the (i) facility; or (ii) company for the specific field must be used as taken according to methods set forth in WCI.364(b). If such information is not available, then the composition for the specific field can be referenced from Table 360-4.

(s) <u>GHG mass emissions</u>. Calculate GHG mass emissions in tonnes of carbon dioxide equivalent by converting the GHG volumetric emissions at standard conditions into mass emissions using Equation 360-42.

$$E_i = E_{s,i} \times \rho_{s,i} \times GWP_i \times 0.001$$

Equation 360-42

Where:

E_i = GHG *i* (either CH_4,, CO_2 ,or, N_20 mass emissions (tonnes CO_2e).
$E_{s,i}$ = GHG *i* (either CH_4, CO_2,or, N_20) volumetric emissions (Sm^3).
$\rho_{s,i}$ = Density of GHG *i*, (1.861 kg/m^3 for CO_2 and 0.678 kg/m^3 for CH_4 at standard conditions of $T_s = 15^oC$ and P_s = 101.325 kPa)

$$= \frac{P_s \times MW_i}{R_u \times (T_s + 273.15)}$$

GWP_i = Global warming potential of GHG *i* (1 for CO_2 and 21 for CH_4, and 310 for N_2O).
MW_i = Molecular weight for GHG_i taken from the 12th edition of the Gas Processors Suppliers Association Engineering Data Book (kg/kmole).
R_u = Universal gas constant (8.31434 kJ/kmole K)
0.001 = Conversion factor from kilograms to tonnes.

(t) <u>EOR injection pump blowdown</u>. Calculate pump blowdown emissions as follows:

(1) Calculate the total volume in cubic meters (including, but not limited to, pipelines, manifolds and vessels) between isolation valves.

(2) Retain logs of the number of blowdowns per reporting period.

(3) Calculate the total annual venting emissions using Equation 360-43.

$$E_i = N \times V_v \times \rho_c \times X_i \times 0.001$$

Equation 360-43

Where:

E_i = Annual EOR injection gas venting mass emissions at critical conditions *c* from blowdowns (tonnes/y).
N = Number of blowdowns for the equipment in reporting year.
V_v = Total physical volume of blowdown equipment chambers (including, but not limited to, pipelines, manifolds and vessels) between isolation valves (m^3).
ρ_c = Density of critical phase EOR injection gas (kg/m^3). Use an appropriate standard method published by a consensus-based standards organization if such

a method exists or otherwise an industry standard to determine density of super critical EOR injection gas.

X_i = Mass fraction of GHG_i in critical phase injection gas.

0.001 = Conversion factor from kilograms to tonnes.

(u) Hydrocarbon liquids dissolved CO_2 from flashing [Reserved]

(v) Produced water dissolved CO_2 / Coal bed methane produced water emissions [Reserved]

(w) Field gas or process vent gas combustion. For combustion units that combust field gas or process vent gas or any blend of field gas and process vent gas, you must comply with following requirements:

(1) Measure the higher heating value of the field gas or process vent gas annually.

(i) Calculate the CO_2 and CH_4 emissions using either the Tier 3 or Tier 4 methodology in WCI.20 (General Stationary Combustion Sources). Sampling, analysis and measurement requirements (including for gas composition) required for WCI.360 in WCI.025(f) apply in place of those indicated for Equation 20-7, or

(ii) When measurement data is not available and if the measured higher heating value is equal to or greater than 36.3 MJ/m^3 and less than 40.98 MJ/m^3, then calculate the CO_2, CH_4, and N_2O emissions using the methods in WCI.20 (General Stationary Combustion Sources) following the methods required for pipeline quality natural gas.

(2) Maintain the WCI.20 (General Stationary Combustion Sources) methodology, required by paragraph (1) of this section, for subsequent reporting years.

(x) Other venting or fugitive emissions. All venting or fugitive emissions not covered by quantification methods in WCI.363 must be calculated by methodologies consistent with those presented here, the 2009 API Compendium[2], or other similar resource documents.

§ WCI.364 Sampling, Analysis, and Measurement Requirements

Instruments used for sampling, analysis and measurement must be operated and calibrated according to legislative, manufacturer's, or other written specifications or requirements. All sampling, analysis and measurement must be conducted only by, or under the direct supervision

[2] American Petroleum Institute. *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry*. August 2009. Table 6-22 (from Clearstone Engineering Ltd.. *A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry*, Volume 5, September 2004.)

of appropriately certified personnel or individuals with demonstrated understanding and experience in the application (and principles related) of the specific sampling, analysis and measurement technique in use.

(a) Leak Detection

(0.1) If a documented leak detection or integrity management standard or requirement that is required by legislation or regulation such as CSA Z662-07 Oil & Gas Pipeline Systems or the CAPP Best Management Practices for Fugitive Emissions or similar standard CAPP Methodologies (as amended from time to time) is used, the documented standard or requirement must be followed – including service schedules for different components and/or facilities - with reporting as required for input to the calculation methods herein. A minimum of 12 months and a maximum of 36 months is allowed between surveys.

(0.2) If there is no such legal requirement (as specified in paragraph (a)(0.1) of this section), then progressive sampling is required using one of the methods outlined below in combination with best industry practices for use of the method– including service schedules for different components - to determine the count of leaks (and time leaking) required in WCI.363(m), (n), and (o), as applicable. Progressive sampling means establishing a statistically valid baseline sample of leaks under normal operating conditions for the 2011 and 2012 calendar years, with subsequent sampling determined based on random or spot-sampling modeling, detection or measurement of leaks under normal operating conditions. A minimum of 18 months and a maximum of 36 months is allowed between surveys. This interval is determined based on whether there are indications of leaks. If a leak is found and immediately repaired, the existing schedule may be maintained.

Leak detection for fugitive equipment leaks must be performed for all identified equipment in operation or on standby mode.

(1) Optical gas imaging instrument. Use an optical gas imaging instrument for fugitive equipment leaks detection in accordance with 40 CFR part 60, subpart A, §60.18(i)(1) and (2) *Alternative work practice for monitoring equipment leaks* (or per relevant standard in Canada). In addition, the optical gas imaging instrument must be operated to image the source types required by this proposed reporting rule in accordance with the instrument manufacturer's operating parameters. The optical gas imaging instrument must comply with the following requirements:

(i) Provide the operator with an image of the potential leak points for each piece of equipment at both the detection sensitivity level and within the distance used in the daily instrument inspection described in the relevant best practices. The detection sensitivity level depends upon the frequency at which leak monitoring is to be performed.

(ii) Provide a date and time stamp for video records of every monitoring event.

(2) Bubble tests

(3) Portable organic vapour analyzer. Use a portable organic vapour analyzer in accordance with US EPA Method 21 or as outlined in the CAPP Best Management Practices for Fugitive Emissions

(4) Other methods as outlined in the CAPP Best Management Practices for Fugitive Emissions or similar standard CAPP Methodologies (as amended from time to time) may be used as necessary for operational circumstances. Other methods that are deemed to be technically sound based on an engineering assessment may also be used as necessary provided that sufficient documentation as to the method used, test results, and the methods reliability, and accuracy is maintained and updated at regular intervals.

(b) All flow meters, composition analyzers and pressure gauges that are used to provide data for the GHG emissions calculations shall use appropriate QA/QC procedures, including measurement methods, maintenance practices, and calibration methods, prior to the first reporting year and in each subsequent reporting year according to an appropriate standard published by a consensus standards organization such as ASTM International, Canadian Standards Association (CSA), American National Standards Institute (ANSI), the relevant provincial or national oil and gas regulator, Measurement Canada, American Society of Mechanical Engineers (ASME), and North American Energy Standards Board (NAESB) , If no appropriate standard exists from the organizations listed above, one from the Canadian Association of Petroleum Producers (CAPP), Canadian Gas Association (CGA) or American Petroleum Institute (API) may be used. If a consensus based standard is not available, industry standard practices such as manufacturer instructions must be used.

(c) Use calibrated bags (also known as vent bags) only where the emissions are at near-atmospheric pressures and hydrogen sulphide levels are such that it is safe to handle and can capture all the emissions, below the maximum temperature specified by the vent bag manufacturer, and the entire emissions volume can be encompassed for measurement.

(1) Hold the bag in place enclosing the emissions source to capture the entire emissions and record the time required for completely filling the bag. If the bag inflates in less than one second, assume one second inflation time.

(2) Perform three measurements of the time required to fill the bag, report the emissions as the average of the three readings.

(3) Correct the natural gas volumetric emissions to standard conditions using the calculations in WCI.363(q).

(4) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in WCI.363(r) and (s).

(d) Use a High-flow Sampler to measure emissions within the capacity of the instrument.

(1) Calibrate the instrument at 2.5 percent methane with 97.5 percent air and 100 percent CH_4 by using calibrated gas samples and by following manufacturer's instructions for calibration.

(2) A technician following (and competent to follow) manufacturer's instructions shall conduct measurements, including equipment manufacturer operating procedures and measurement methodologies relevant to using a High-flow Sampler, including, positioning the instrument for complete capture of the fugitive equipment leaks without creating backpressure on the source.

(3) If the High-flow Sampler, along with all attachments available from the manufacturer, is not able to capture all the emissions from the source, then anti-static wraps or other aids must be used to capture all emissions without violating operating requirements as provided in the instrument manufacturer's manual.

(4) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in WCI.363(r) and (s).

(e) Peng Robinson Equation of State means the equation of state defined by Equation 360-44 of this section.

$$p = \frac{RT}{V_m - b} - \frac{a\alpha}{V_m^2 + 2bV_m - b^2}$$ **Equation 360-44**

Where:

p = Absolute pressure.
R = Universal gas constant.
T = Absolute temperature.
V_m = Molar volume.

$$a = \frac{0.45724 R^2 T_c^2}{p_c}$$

$$b = \frac{0.7780 R T_c}{p_c}$$

$$\alpha = \left(1 + \left(0.37464 + 1.54226\omega - 0.26992\omega^2\right)\left(1 - \sqrt{\frac{T}{T_c}}\right)\right)^2$$

Where:
ω = Acentric factor of the species.

T_c = Critical temperature.
P_c = Critical pressure.

(f) Onshore Production and Processing Storage Tanks.

(1) A pressurized sample of produced liquids shall be collected from the separator at a location upstream of the storage tank. This point would typically be at the final separation device before produced oil transitions from separator outlet pressure to atmospheric pressure and enters a production storage tank. This may require the installation of a sampling valve at the appropriate location. Sampling protocol specific to the collection of separator liquid can be found in the following publications:

(i) Appendix C Sampling Protocol section (page 33) of the *E&P TANK Version 2.0 User's Manual*.

(ii) Wyoming Department of Environmental Quality Air Quality Division guidance document *Oil and Gas Production Facilities, Chapter 6, Section 2 Permitting Guidance (revised August 2001), Appendix D Sampling and Analysis of Hydrocarbon Liquids and Natural Gas.*

(iii) Gas Processors Association (GPA) Standard 2174-93, *Obtaining Liquid Hydrocarbon Samples for Analysis by Gas Chromatography*.

(2) The sample collection pressure shall be determined at the time of collection and again prior to processing in the laboratory to insure that sample integrity has been maintained. Liquid temperature should also be determined and recorded at the time of collection.

(3) Sampling and laboratory based determination of the gas to oil ratio GOR shall be conducted at prescribed intervals and at a time when operational parameters of the storage tank battery are representative and consistent with normal operating conditions. Sampling shall be annual for oil production rates between 1.75 and 15.9 m^3/day, semi-annual for oil production rates between15.9 and 79.5 m^3/day, and quarterly for oil production rates greater than 79.5 m^3/day.

(4) An additional sample shall be collected and analyzed if:

(i) The oil production rate at the storage tank battery changes more than 20 percent for time periods in excess of one week (e.g., in cases where a well or wells feeding the storage tank battery stop or start production).

(ii) The separator operating pressures change by more than 10 percent.

(5) The volume (barrels) of liquid produced during the sampling interval shall be determined using a calibrated liquid meter or industry standard method to an accuracy of ±5%.

§ WCI.365 *Procedures for Estimating Missing Data*

A complete record of all estimated and/or measured parameters used in the GHG emissions calculations is required. If data are lost or an error occurs during annual emissions estimation or measurements, the estimation or measurement activity for those sources must be repeated as soon as possible, including in the subsequent reporting year if missing data are not discovered until after December 31 of the reporting year, until valid data for reporting is obtained. Data developed and/or collected in a subsequent reporting year to substitute for missing data cannot be used for that subsequent year's emissions estimation. Where missing data procedures are used for the previous year, at least 30 days must separate emissions estimation or measurements for the previous year and emissions estimation or measurements for the current year of data collection. For missing data that are continuously monitored or measured (for example flow meters), or for missing temperature and pressure data, the reporter may use best available data for use in emissions determinations. The reporter must record and report the basis for the best available data in these cases.

§ WCI.366 Definitions

Absorbent circulation pump means a pump commonly powered by natural gas pressure that circulates the absorbent liquid between the absorbent regenerator and natural gas contactor.

Acid gas means hydrogen sulphide (H_2S) and carbon dioxide (CO_2) contaminants that are separated from sour natural gas by an acid gas removal unit.

Acid gas removal (AGR) unit means a process unit that separates hydrogen sulphide and/or carbon dioxide from sour natural gas using liquid or solid absorbents or membrane separators.

Acid gas removal vent stack emissions mean the acid gas separated from the acid gas absorbing medium (e.g., an amine solution) and released with methane and other light hydrocarbons to the atmosphere or a flare.

Blowdown vent stack emissions mean natural gas and/or CO_2 released due to maintenance and/or blowdown operations including compressor blowdown and emergency shut-down (ESD) system testing.

Calibrated bag means a flexible, non-elastic, anti-static bag of a calibrated volume that can be affixed to a emitting source such that the emissions inflate the bag to its calibrated volume.

Centrifugal compressor means any equipment that increases the pressure of a process natural gas or CO_2 by centrifugal action, employing rotating movement of the driven shaft.

Centrifugal compressor dry seals mean a series of rings around the compressor shaft where it exits the compressor case that operates mechanically under the opposing forces to prevent natural gas or CO_2 from escaping to the atmosphere.

Centrifugal compressor dry seals emissions mean natural gas or CO_2 released from a dry seal vent pipe and/or the seal face around the rotating shaft where it exits one or both ends of the compressor case.

Centrifugal compressor venting emissions means emissions that occur when the high-pressure oil barriers for centrifugal compressors are depressurized to release absorbed natural gas or CO_2. High-pressure oil is used as a barrier against escaping gas in centrifugal compressor shafts. Very little gas escapes through the oil barrier, but under high pressure, considerably more gas is absorbed by the oil. The seal oil is purged of the absorbed gas (using heaters, flash tanks, and degassing techniques) and recirculated. The separated gas is commonly vented to the atmosphere.

Coal bed methane (CBM) means natural gas which is extracted from underground coal deposits or "beds."

Component means each metal to metal joint or seal of non-welded connection separated by a compression gasket, screwed thread (with or without thread sealing compound), metal to metal compression, or fluid barrier through which natural gas or liquid can escape to the atmosphere.

Compressor means any machine for raising the pressure of natural gas or CO_2 by drawing in low pressure natural gas or CO_2 and discharging significantly higher pressure natural gas or CO_2.

Condensate means hydrocarbon and other liquid separated from natural gas that condenses due to changes in the temperature, pressure, or both, and remains liquid at storage conditions..

Continuous bleed means a continuous flow of pneumatic supply gas to the process measurement device (e.g. level control, temperature control, pressure control) where the supply gas pressure is modulated by the process condition, and then flows to the valve controller where the signal is compared with the process set-point to adjust gas pressure in the valve actuator

Dehydrator means a device in which a liquid absorbent (including desiccant, ethylene glycol, diethylene glycol, or triethylene glycol) directly contacts a natural gas stream to absorb water vapor.

Dehydrator vent emissions means natural gas and CO_2 released from a natural gas dehydrator system absorbent (typically glycol) reboiler or regenerator, including stripping natural gas and motive natural gas used in absorbent circulation pumps.

De-methanizer means the natural gas processing unit that separates methane rich residue gas from the heavier hydrocarbons (e.g., ethane, propane, butane, pentane-plus) in feed natural gas stream.

Desiccant means a material used in solid-bed dehydrators to remove water from raw natural gas by adsorption. Desiccants include activated alumina, pelletized calcium chloride, lithium chloride and granular silica gel material. Wet natural gas is passed through a bed of the granular or pelletized solid adsorbent in these dehydrators. As the wet gas contacts the surface of the particles of desiccant material, water is adsorbed on the surface of these desiccant particles. Passing through the entire desiccant bed, almost all of the water is adsorbed onto the desiccant material, leaving the dry gas to exit the contactor.

E&P Tank means the most current version of an exploration and production field tank emissions equilibrium program that estimates flashing, working and standing losses of hydrocarbons, including methane, from produced crude oil and gas condensate. Equal or successors to E&P Tank Version 2.0 for Windows Software. Copyright (C) 1996-1999 by The American Petroleum Institute and The Gas Research Institute.

Engineering estimation, for the purposes of WCI.350 and WCI.360 means an estimate of emissions based on engineering principles applied to measured and/or approximated physical parameters such as dimensions of containment, actual pressures, actual temperatures, and compositions.

Enhanced oil recovery (EOR) means the use of certain methods such as water flooding or gas injection into existing wells to increase the recovery of crude oil from a reservoir. In the context of this rule, EOR applies to injection of critical phase carbon dioxide into a crude oil reservoir to enhance the recovery of oil.

Equipment leak detection means the process of identifying emissions from equipment, components, and other point sources.

External combustion means fired combustion in which the flame and products of combustion are separated from contact with the process fluid to which the energy is delivered. Process fluids may be air, hot water, or hydrocarbons. External combustion equipment may include fired heaters, industrial boilers, and commercial and domestic combustion units.

Farm taps means pressure regulation stations that deliver gas directly from transmission pipelines to generally rural customers.

Field means the surface area underlaid or appearing to be underlaid by one or more pools, and the subsurface regions vertically beneath that surface area;

Field gas means natural gas extracted from a production well prior to its entering the first stage of processing, such as dehydration.

Flare, for the purposes of WCI.360, means a combustion device, whether at ground level or elevated, that uses an open or closed flame to combust waste gases without energy recovery.

Flare combustion efficiency means the fraction of natural gas, on a volume or mole basis, that is combusted at the flare burner tip.

Fugitive emissions means the unintended or incidental emissions of greenhouse gases from the transmission, processing, storage, use or transportation of fossil fuels, greenhouse gases, or other.

Fugitive equipment leak means those fugitive emissions which could not reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening.

Gas conditions mean the actual temperature, volume, and pressure of a gas sample.

Gas gathering/booster stations mean centralized stations where produced natural gas from individual wells is co-mingled, compressed for transport to processing plants, transmission and distribution systems, and other gathering/booster stations which co-mingle gas from multiple production gathering/booster stations. Such stations may include gas dehydration, gravity separation of liquids (both hydrocarbon and water), pipeline pig launchers and receivers, and gas powered pneumatic devices.

Gas to oil ratio (GOR) means the ratio of the volume of gas at standard temperature and pressure that is produced from a volume of oil when depressurized to standard temperature and pressure.

Gas well means a well completed for production of natural gas from one or more gas zones or reservoirs. Such wells contain no completions for the production of crude oil.

High-bleed pneumatic devices mean automated control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream which is regulated by the process condition flows to a valve actuator controller where it vents (bleeds) to the atmosphere at a rate in excess of 0.17 standard cubic meters per hour .

Intermittent-bleed pneumatic devices mean automated flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. These are snap-acting or throttling devices that discharge the full volume of the actuator intermittently when control action is necessary, but does not bleed continuously.

Internal combustion means the combustion of a fuel that occurs with an oxidizer (usually air) in a combustion chamber. In an internal combustion engine the expansion of the high-temperature and –pressure gases produced by combustion applies direct force to a component of the engine, such as pistons, turbine blades, or a nozzle. This force moves the component over a distance, generating useful mechanical energy. Internal combustion equipment may include gasoline and diesel industrial engines, natural gas-fired reciprocating engines, and gas turbines.

Liquefied natural gas (LNG) means natural gas (primarily methane) that has been liquefied by reducing its temperature to -162 degrees Celsius at atmospheric pressure.

LNG boiloff gas means natural gas in the gaseous phase that vents from LNG storage tanks due to ambient heat leakage through the tank insulation and heat energy dissipated in the LNG by internal pumps.

Low-bleed pneumatic devices mean automated control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream which is regulated by the process condition flows to a valve actuator controller where it vents (bleeds) to the atmosphere at a rate equal to or less than 0.17 standard cubic meters per hour.

Natural gas-driven pneumatic pump means a pump that uses pressurized natural gas to move a piston or diaphragm, which pumps liquids on the opposite side of the piston or diaphragm.

Offshore means seaward of the terrestrial borders of Canada, including waters subject to the ebb and flow of the tide, as well as adjacent bays, lakes or other normally standing waters, and extending to the outer boundaries of the jurisdiction and control of Canada.

Oil well means a well completed for the production of crude oil from at least one oil zone or reservoir.

Operating pressure means the containment pressure that characterizes the normal state of gas or liquid inside a particular process, pipeline, vessel or tank.

Pressure groupings are defined as follows: less than or equal to 25 psig; greater than 25 psig and less than or equal to 60 psig; greater than 60 psig and less than or equal to 110 psig; greater than 110 psig and less than or equal to 200 psig; and greater than 200 psig.

Pump means a device used to raise pressure, drive, or increase flow of liquid streams in closed or open conduits.

Pump seals mean any seal on a pump drive shaft used to keep methane and/or carbon dioxide containing light liquids from escaping the inside of a pump case to the atmosphere.

Pump seal emissions mean hydrocarbon gas released from the seal face between the pump internal chamber and the atmosphere.

Reciprocating compressor means a piece of equipment that increases the pressure of a gas stream by positive displacement, employing linear movement of a shaft driving a piston in a cylinder.

Reciprocating compressor rod packing means a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of the compressed gas stream that escapes to the atmosphere.

Re-condenser means heat exchangers that cool compressed boil-off gas to a temperature that will condense natural gas to a liquid.

Reservoir means a porous and permeable underground natural formation containing significant quantities of hydrocarbon liquids and/or gases.

Residue gas and residue gas compression mean, respectively, production lease natural gas from which gas liquid products and, in some cases, non-hydrocarbon components have been extracted such that it meets the specifications set by a pipeline transmission company, and/or a distribution company; and the compressors operated by the processing facility, whether inside the processing facility boundary fence or outside the fence-line, that deliver the residue gas from the processing facility to a transmission pipeline.

Sales oil means produced crude oil or condensate measured at the production lease automatic custody transfer (LACT) meter or custody transfer meter tank gauge.

Separator means a vessel in which streams of multiple phases are gravity separated into individual streams of single phase.

Sour natural gas means natural gas that contains significant concentrations of hydrogen sulphide and/or carbon dioxide that exceed the concentrations specified for commercially saleable natural gas delivered from transmission and distribution pipelines.

Sweet gas means natural gas with low concentrations of hydrogen sulphide (H_2S) and/or carbon dioxide (CO_2) that does not require (or has already had) acid gas treatment to meet pipeline corrosion-prevention specifications for transmission and distribution.

Third party line hit means damages to gas pipelines and surface facilities resulting from natural causes or third party incidents. Natural causes include corrosion, abrasion, rock damage, frost heaving or settling. Third party damages may include hits on surface facilities and dig-ins. Specific examples of dig-ins include grader/dozer/scraper excavation, demolition/breakout, general agriculture, driving bars/stakes/posts/anchors, backhoe/trackhoe excavation, ditch shaping, snow removal, landscaping/tree planting, hand excavation, bobcat/loader excavation, saw cutting, cable/pipe plowing, vertical augering/drilling, trencher excavation, blasting/vibrosis, deep tillage, horizontal augering/boring, and other such anthropogenic ground disturbances.

Transmission pipeline means high pressure cross country pipeline transporting saleable quality natural gas from production or natural gas processing to natural gas distribution pressure let-down, metering, regulating stations where the natural gas is typically odorized before delivery to customers.

Tubing diameter groupings are defined as follows: less than or equal to 1 inch; greater than 1 inch and less than 2 inch; and greater than or equal to 2 inch.

Tubing systems mean piping equal to or less than one half inch diameter as per nominal pipe size

Turbine meter means a flow meter in which a gas or liquid flow rate through the calibrated tube spins a turbine from which the spin rate is detected and calibrated to measure the fluid flow rate.

Vapour recovery system means any equipment located at the source of potential gas emissions to the atmosphere or to a flare, that is composed of piping, connections, and, if necessary, flow-inducing devices, and that is used for routing the gas back into the process as a product and/or fuel.

Vapourization unit means a process unit that performs controlled heat input to vapourize LNG to supply transmission and distribution pipelines or consumers with natural gas.

Vented emissions means the same as defined in the relevant greenhouse gas reporting regulation, including but not limited to process designed flow to the atmosphere through seals or vent pipes, equipment blowdown for maintenance, and direct venting of gas used to power equipment (such as pneumatic devices), but not including stationary combustion flue gas.

Well completion means a process that allows for the flow of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and test the reservoir flow characteristics, steps that may vent produced gas to the atmosphere via an open pit or tank. Well completion also involves connecting the well bore to the reservoir, which may include treating the formation or installing tubing, packer(s), or lifting equipment, steps that do not significantly vent natural gas to the atmosphere. This process may also include high-rate flowback of injected gas, water, oil, and proppant used to fracture or re-fracture and prop open new fractures in existing lower permeability gas reservoirs, steps that may vent large quantities of produced gas to the atmosphere.

Well testing venting and flaring means venting and/or flaring of natural gas at the time the production rate of a well is determined (i.e. the well testing) through a choke (an orifice restriction). If well testing is conducted immediately after well completion or workover, then it is considered part of well completion or workover.

Well workover means the process(es) of performing of one or more of a variety of remedial operations on producing petroleum and natural gas wells to try to increase production. This process also includes high-rate flowback of injected gas, water, oil, proppant and sand used to re-fracture and prop-open new fractures in existing low permeability gas reservoirs, steps that may vent large quantities of produced gas to the atmosphere.

Wellhead means the piping, casing, tubing and connected valves protruding above the Earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve. Wellhead equipment includes all equipment, permanent and portable, located on the improved land area (i.e. well pad) surrounding one or multiple wellheads.

Wet natural gas means natural gas in which water vapour exceeds the concentration specified for commercially saleable natural gas delivered from transmission and distribution pipelines. This input stream to a natural gas dehydrator is referred to as "wet gas".

§ WCI.367 Tables

Directions for the use of Tables 360-1 to 360-2

(a) Starting with 2014 calendar year emissions, for each component listed in the Tables 360-1 to 360-2 or otherwise required by the quantification method referencing Tables 360-1 and 360-2:

(1) If statistically valid facility specific emission factors for a component type are available or can safely or reasonably developed, they must be used.

(2) If facility specific emissions factors for a component type are not available, an operator must use statistically valid company specific emission factors, if they can be safely or reasonably developed.

(3) If statistically valid facility or company specific emission factors for a specific component type cannot be safely and reasonably developed, estimates in the default Tables 360-1 to 360-2 may be used. Equipment or facilities that have low temporal utilization (e.g. equipment such as booster stations used only sporadically during a year) may continue to use the default tables.

(b) For 2011, 2012 and 2013 calendar year emissions:

(1) An operator may use the default factors specified below, company or facility-specific emissions factors (if such emission factors are available). If the default factors in Tables 360-1 to 360-2 are used, an explanation as to why company or facility specific emission factors are cannot be used must be provided to the jurisdiction.

(c) If a facility-specific emission factor has been used in a previous reporting year, it must continue to be used until updated. If a company-specific emission factor has been used in a previous reporting year, it must continue to be used until updated or a facility-specific emission factor is used in its place

(d) Any changes from facility-specific factors to company-specific or the defaults in Tables 360-1 to 360-2, or from company specific factors to the defaults in Tables 360-1 to 360-2 must be approved by the jurisdiction and substantiated by evidence that the new approach is more accurate for the facility or facilities in question.

(e) If an emission factor required by the quantification method referencing Tables 360-1 and 360-2 is not provided in the tables, emission factors from either the U.S. EPA 40 CFR Part 98.230 Tables W-1A or W-2 or the Clearstone Engineering Ltd.. *A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry*, Volume 5, September 2004 may be used (as converted for use in the relevant equation).

(f) Documentation on the method used to update the emission factors, input data, sampling methodology and other relevant information must be kept by the operator and provided to the jurisdiction or verifier upon request.

(g) All emission factors or data collection for emission factors must be developed using CAPP (CAPP) or Canadian Gas Association (CGA) standard methods, or other methods if CAPP or CGA methods are not available or applicable. Facility and company-specific emission factors must be updated at a minimum on a three year cycle, with the first update to the original facility and company-specific emission factors for the 2016 reporting period, at the latest.

(h) Updated emission factors can only be incorporated for reporting purposes at the start of a reporting period and not during a calendar year.

The default emission factors provided in Tables 360-1 to 360-2 below are published emission factors for Canada as of the 2010 calendar year. The factors will be updated every 3-5 years based on new data, methods and statistically valid samples of the entire industry and developed in collaboration with industry groups.

Table 360-1. Additional Natural Gas Facility Average Emission Factors

Component – Service	Emission Factor, tonnes THC/component-hr
Valves - fuel gas	2.81E-06
Valves - light liquid	3.52E-06
Valves - gas/vapor - all	2.46E-06
Valves - gas/vapor - sour	1.16E-06
Valves - gas/vapor - sweet	2.81E-06
Connectors - fuel gas	8.18E-07
Connectors - light liquid	5.51E-07
Connectors - gas/vapor - all	7.06E-07
Connectors - gas/vapor - sour	1.36E-07
Connectors - gas/vapor - sweet	8.18E-07
Control valves - fuel gas	1.62E-05
Control valves - light liquid	1.77E-05
Control valves - gas/vapor - all	1.46E-05
Control valves - gas/vapor - sour	9.64E-06
Control valves - gas/vapor - sweet	1.62E-05
Pressure relief valves - fuel gas and gas/vapor	1.70E-05
Pressure relief valves - light liquid	5.39E-06
Pressure regulators - fuel gas and gas/vapor	8.11E-06
Pressure regulators - gas/vapor - sour	4.72E-08

Pressure regulators - gas/vapor - sweet	8.39E-06
Open ended lines - fuel gas	4.67E-04
Open ended lines - light liquid	1.83E-05
Open ended lines - gas/vapor - all	4.27E-04
Open ended lines - gas/vapor - sour	1.89E-04
Open ended lines - gas/vapor - sweet	4.67E-04
Pump seals - light liquid	2.32E-05

Footnotes and Sources:
[a] American Petroleum Institute. *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industr*y. August 2009. Table 6-21 (from Clearstone Engineering Ltd.. *A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry*, Volume 5, September 2004.)

Table 360-2. Additional Oil Facility Average Emission Factors

Component – Service	**Emission Factor, tonnes THC/component-hr**
Valves - fuel gas and gas/vapor	1.51E-06
Valves - heavy liquid	8.40E-09
Valves - light liquid	1.21E-06
Connectors - fuel gas and gas/vapor	2.46E-06
Connectors - heavy liquid	7.50E-09
Connectors - light liquid	1.90E-07
Control valves - fuel gas and gas/vapor	1.46E-05
Control valves - light liquid	1.75E-05
Pressure relief valves - fuel gas and gas/vapor	1.63E-05
Pressure relief valves - heavy liquid	3.20E-08
Pressure relief valves - light liquid	7.50E-05
Pressure regulators - fuel gas and gas/vapor	6.68E-06
Open ended lines - fuel gas and gas/vapor	3.08E-04
Open ended lines - light liquid	3.73E-06
Pump seals - heavy liquid	3.20E-08
Pump seals - light liquid	2.32E-05

Footnotes and Sources:
[a] American Petroleum Institute. *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industr*y. August 2009. Table 6-22 (from Clearstone Engineering Ltd.. *A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry*, Volume 5, September 2004.)

Directions for the use of Table 360-3

(a) Major equipment listed in Tables 360-3 includes components located between the first flange of the process identified and the last flange before the next process.

(b) When delineation between major equipment is not possible, individual component counts should be completed.

Table 360-3. Default Major Equipment Component Counts for Canada

(for further average component counts required by the methods in this quantification method, please refer to the Clearstone Engineering Ltd.. *A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry*, Volume 5, September 2004, as updated from time to time.)

MAJOR EQUIPMENT	SERVICE	Connectors	Pressure Relief Vales	Pump Seals	Valves	Open-Ended Lines	Compressor Seals	Control Valves	Pressure Regulators
ABSORPTION (LEAN OIL)	Gas/Vapour	200	4	0	82	0	0	0	0
ABSORPTION (LEAN OIL)	Light Liquid	46	0	1	21	0	0	0	0
ADSORPTION	Gas/Vapour	243	8	0	63	0	0	0	0
ADSORPTION	Light Liquid	0	0	0	2	0	0	0	0
AERIAL COOLER	Gas/Vapour	2937	0	0	19	0	0	0	0
BULLET	Gas/Vapour	39	1	0	15	0	0	0	0
BULLET	Light Liquid	60	1	0	27	0	0	0	0
CENTRIFUGAL COMPRESSOR	Gas/Vapour	495	1	0	32	4	2	0	0
CENTRIFUGAL COMPRESSOR	Light Liquid	11	0	0	5	0	0	0	0
COLD BED ABSORPTION	Gas/Vapour	134	1	0	31	0	0	0	0
COLD BED ABSORPTION	Light Liquid	12	0	0	7	0	0	0	0
DE-BUTANIZER	Gas/Vapour	177	6	0	79	0	0	0	0
DE-BUTANIZER	Light Liquid	208	0	2	80	0	0	0	0
DEEP GAS WELL (>1000 M)	Gas/Vapour	19	0	0	6	0	0	0	0
DEEP GAS WELL (>1000 M)	Light Liquid	1	0	0	0	0	0	0	0
DEEPCUT (WITH TURBO-EXPANDER)	Gas/Vapour	241	10	0	131	0	2	0	0
DEEPCUT (WITH TURBO-EXPANDER)	Light Liquid	386	0	2	121	0	0	0	0
DE-ETHANIZER	Gas/Vapour	177	6	0	79	0	0	0	0
DE-ETHANIZER	Light Liquid	208	0	2	80	0	0	0	0
DE-PROPANIZER	Gas/Vapour	177	6	0	79	0	0	0	0
DE-PROPANIZER	Light Liquid	208	0	2	80	0	0	0	0
DESICCANT	Gas/Vapour	100	1	0	24	0	0	0	0
DESICCANT	Light Liquid	14	0	0	7	0	0	0	0
FLARE KNOCK OUT DRUM	Gas/Vapour	26	0	0	3	0	0	0	0
FLARE KNOCK OUT DRUM	Light Liquid	20	0	0	1	0	0	0	0
FLOW LINE HEADER TIE-IN	Gas/Vapour	0	0	0	0	1	0	0	0
FLOW LINE HEADER TIE-IN	Heavy Liquid	10	0	0	3	0	0	0	0

MAJOR EQUIPMENT	SERVICE	Connectors	Pressure Relief Vales	Pump Seals	Valves	Open-Ended Lines	Compressor Seals	Control Valves	Pressure Regulators
FLOW LINE HEADER TIE-IN	Light Liquid	10	0	0	3	0	0	0	0
FLOWING OIL WELL	Heavy Liquid	57	0	0	14	0	0	0	0
FLOWING OIL WELL	Light Liquid	57	0	0	14	0	0	0	0
FRACTIONATION	Gas/Vapour	241	10	0	131	0	0	0	0
FRACTIONATION	Light Liquid	386	0	2	121	0	0	0	0
GAS BOOT	Gas/Vapour	37	0	0	2	0	0	0	0
GAS BOOT	Light Liquid	40	0	0	2	0	0	0	0
GAS INJECTION WELL	Gas/Vapour	19	0	0	6	0	0	0	0
GAS LINE HEADER TIE-IN	Gas/Vapour	10	0	0	3	1	0	0	0
GAS SWEETENING: AMINE/SULFINOL	Gas/Vapour	702	2	0	60	3	0	0	0
GAS SWEETENING: AMINE/SULFINOL	Light Liquid	3	0	1	1	0	0	0	0
GAS SWEETENING: IRON SPONGE	Gas/Vapour	134	1	0	31	0	0	0	0
GAS SWEETENING: IRON SPONGE	Heavy Liquid	0	0	0	7	0	0	0	0
GAS SWEETENING: IRON SPONGE	Light Liquid	12	0	0	7	0	0	0	0
GAS-FIRED UNIT HEATER	Fuel Gas	10	0	0	1	0	0	0	0
GLYCOL DEHYDRATOR	Gas/Vapour	100	1	0	24	0	0	0	0
GLYCOL DEHYDRATOR	Light Liquid	14	0	0	7	0	0	0	0
GROUP TREATER	Gas/Vapour	178	0	0	21	1	0	0	0
GROUP TREATER	Heavy Liquid	56	0	0	17	1	0	0	0
GROUP TREATER	Light Liquid	56	0	0	17	1	0	0	0
HEAT EXCHANGER - GAS	Gas/Vapour	13	0	0	7	0	0	0	0
HEAT EXCHANGER - LIQUID	Heavy Liquid	13	0	0	7	0	0	0	0
HEAT EXCHANGER - LIQUID	Light Liquid	13	0	0	7	0	0	0	0
HEAVY OIL WELL - PRIMARY	Heavy Liquid	22	0	0	9	0	0	0	0
HEAVY OIL WELL - THERMAL	Heavy Liquid	22	0	0	9	0	0	0	0
INCINERATOR	Gas/Vapour	10	0	0	1	0	0	0	0
INLET SEPARATOR	Gas/Vapour	66	0	0	11	0	0	0	0
INLET SEPARATOR	Heavy Liquid	41	0	0	11	0	0	0	0
INLET SEPARATOR	Light Liquid	41	0	0	11	0	0	0	0
JOULE-THOMSON REFRIGERATION	Gas/Vapour	79	0	0	19	0	0	0	0
JOULE-THOMSON REFRIGERATION	Light Liquid	41	0	0	11	0	0	0	0
LINE HEATER	Fuel Gas	145	0	0	10	0	0	0	0

MAJOR EQUIPMENT	SERVICE	Connectors	Pressure Relief Vales	Pump Seals	Valves	Open-Ended Lines	Compressor Seals	Control Valves	Pressure Regulators
LINE HEATER	Gas/Vapour	40	1	0	10	0	0	0	0
METERING	Gas/Vapour	70	2	0	24	0	0	0	0
MOLECULAR SIEVE	Gas/Vapour	100	1	0	24	0	0	0	0
MOLECULAR SIEVE	Light Liquid	14	0	0	7	0	0	0	0
OIL PUMP	Heavy Liquid	10	0	1	3	0	0	0	0
OIL PUMP	Light Liquid	10	0	1	3	0	0	0	0
PIG TRAP	Gas/Vapour	11	0	0	3	0	0	0	0
PIPELINE HEADER	Gas/Vapour	0	0	0	0	1	0	0	0
PIPELINE HEADER	Heavy Liquid	10	0	0	3	0	0	0	0
PIPELINE HEADER	Light Liquid	10	0	0	3	0	0	0	0
POP TANK	Heavy Liquid	24	0	1	10	0	0	0	0
POP TANK	Light Liquid	24	0	1	10	0	0	0	0
PROCESS BOILER	Fuel Gas	25	0	0	2	0	0	0	0
PRODUCTION TANK	Gas/Vapour	2	0	0	1	0	0	0	0
PRODUCTION TANK	Heavy Liquid	24	0	1	0	0	0	0	0
PRODUCTION TANK	Light Liquid	24	0	1	0	0	0	0	0
PUMP JACK	Heavy Liquid	57	0	1	14	0	0	0	0
PUMP JACK	Light Liquid	57	0	1	14	0	0	0	0
PUMPING OIL WELL	Heavy Liquid	57	0	1	14	0	0	0	0
PUMPING OIL WELL	Light Liquid	57	0	1	14	0	0	0	0
RECIPROCATING COMPRESSOR	Fuel Gas	145	0	0	6	0	0	0	0
RECIPROCATING COMPRESSOR	Gas/Vapour	275	0	0	20	4	2	0	0
RECIPROCATING COMPRESSOR	Light Liquid	2	0	0	1	0	0	0	0
REFRIGERATION	Gas/Vapour	170	2	0	65	0	2	0	0
REFRIGERATION	Light Liquid	31	0	2	13	0	0	0	0
REGULATOR STATION	Gas/Vapour	24	0	0	10	0	0	0	0
SALT BATH HEATER	Fuel Gas	25	0	0	2	0	0	0	0
SCREW COMP CS TO FLARE	Gas/Vapour	228	2	0	35	0	0	1	2
SCREW COMPRESSOR	Gas/Vapour	228	2	0	35	0	1	1	2
SHALLOW GAS WELL (<1000 M)	Gas/Vapour	10	0	0	3	0	0	0	0
STABILIZATION	Gas/Vapour	80	3	0	20	0	0	0	0
STABILIZATION	Light Liquid	247	0	1	77	0	0	0	0

MAJOR EQUIPMENT	SERVICE	Connectors	Pressure Relief Vales	Pump Seals	Valves	Open-Ended Lines	Compressor Seals	Control Valves	Pressure Regulators
SULPHUR RECOVERY	Gas/Vapour	100	0	0	10	0	0	0	0
TAIL GAS CLEANUP	Gas/Vapour	25	0	0	5	0	0	0	0
TANK FARM	Heavy Liquid	190	0	6	94	0	0	0	0
TANK FARM	Light Liquid	190	0	6	94	0	0	0	0
TANK HEATER	Fuel Gas	10	0	0	2	0	0	0	0
TANK HEATER	Heavy Liquid	2	0	0	0	0	0	0	0
TANK HEATER	Light Liquid	2	0	0	0	0	0	0	0
TEST SEPARATOR	Gas/Vapour	49	1	0	15	0	0	0	0
TEST SEPARATOR	Heavy Liquid	25	0	0	15	0	0	0	0
TEST SEPARATOR	Light Liquid	25	0	0	15	0	0	0	0
TEST TREATER	Gas/Vapour	178	1	0	21	1	0	0	0
TEST TREATER	Heavy Liquid	56	0	0	17	0	0	0	0
TEST TREATER	Light Liquid	56	0	0	17	0	0	0	0
TURBO EXPANDER	Gas/Vapour	123	6	0	48	0	2	0	0
TURBO EXPANDER	Light Liquid	9	0	0	2	0	0	0	0
UNIT HEATER	Fuel Gas	10	0	0	2	0	0	0	0
UNIT HEATER	Light Liquid	2	0	0	0	0	0	0	0
UTILITY BOILER	Fuel Gas	25	0	0	2	0	0	0	0
VAPOUR RECOVERY COMPRESSOR	Gas/Vapour	25	0	0	5	0	1	0	0
VAPOUR RECOVERY COMPRESSOR	Light Liquid	2	0	0	3	0	0	0	0
WATER PUMP	Light Liquid	5	0	1	2	0	0	0	0

Footnotes and Sources:
[a] Clearstone Engineering Ltd.. *A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry*, Volume 5, September 2004. Table 4.1,

TABLE 360-4 –DEFAULT GAS COMPOSITIONS FOR SPECIFIC FIELDS

Table 360-4 is currently being developed and is likely to be incorporated in WCI.360 in the future. In the interim, please refer to default gas compositions for specific fields within the jurisdiction as posted by the regulator during or immediately after the reporting year.

Table 360-5. Additional Natural Gas-driven Pneumatic Device Average Emission Factors

Pneumatic device type	**Emission Factor, standard m^3/hour/device**
High Continuous Bleed Pneumatic Device Vents	1.3620
Intermittent-bleed Pneumatic Device Vents	0.4927
Low Continuous Bleed Pneumatic Device Vents	0.0510
Pneumatic pumps	0.3766

Footnotes and Sources:
[a] United States Environmental Protection Agency. *Mandatory Reporting of Greenhouse Gases: Petroleum and Natural Gas Systems(40 CFR Part 98 Subpart W).* September 2011. Table W-1A converted to metric units.

Table 360-6. Average manufacturer bleed rates for pneumatic controllers, positioner, transmitters and transducers.

Description	Manufacturer	Model	Operating Condition	Manufacturer Rate (Sm^3/h) [4]
Liquid level controller	Bristol Babcock	Series 5453-Model 624-II	Continuous	0.0850
Liquid level controller	Fisher	2100	Continuous	0.0283
Liquid level controller	Fisher	2500	Continuous	1.1893
Liquid level controller	Fisher	2660	Continuous	0.0283
Liquid level controller	Fisher	2680	Continuous	0.0283
Liquid level controller	Fisher	2900	Continuous	0.6513
Liquid level controller	Fisher	L2	Continuous	0.0425
Liquid level controller	Invalco	AE-155	Continuous	1.5008
Liquid level controller	Invalco	CT Series	Continuous	1.1327
Liquid level controller	Norriseal	1001 (A) 'Envirosave'	Intermittent	0.0000
Liquid level controller	Norriseal	1001 (A) snap	Intermittent	0.0057
Liquid level controller	Norriseal	1001 (A) throttle	Intermittent	0.0002
Liquid level controller	Wellmark	2001 (snap)	Intermittent	0.0057
Liquid level controller	Wellmark	2001 (throttling)	Intermittent	0.0002
Positioner	Becker	EFP-2.0	Intermittent	0.0000
Positioner	Becker	HPP-5	Continuous	0.1416
Positioner	Fisher	3582	Continuous	0.4531
Positioner	Fisher	3590	Continuous	0.8495
Positioner	Fisher	3660	Continuous	0.1982
Positioner	Fisher	3661	Continuous	0.2959
Positioner	Fisher	3582i	Continuous	0.5833
Positioner	Fisher	3610J	Continuous	0.4531
Positioner	Fisher	3620J	Continuous	0.7532
Positioner	Fisher	DVC 5000	Continuous	0.2832
Positioner	Fisher	DVC 6000	Continuous	0.3964
Positioner	Fisher	Fieldview Digital	Continuous	0.8920
Positioner	Masoneilan	7400	Continuous	1.0477
Positioner	Masoneilan	4600B Series	Continuous	0.6796
Positioner	Masoneilan	4700B Series	Continuous	0.6796
Positioner	Masoneilan	4700E	Continuous	0.6796
Positioner	Masoneilan	SV	Continuous	0.1133
Positioner	Moore Products	73N-B	Continuous	1.0194
Positioner	Moore Products	750P	Continuous	1.1893
Positioner	PMV	D5 Digital	Continuous	0.0283
Positioner	Sampson	3780 Digital	Continuous	0.0283
Positioner	VCR	VP700 PtoP	Continuous	0.0283
Pressure controller	Ametek	Series 40	Continuous	0.1699
Pressure controller	Becker	HPP-SB	Intermittent	0.0000
Pressure controller	Becker	VRP-B-CH	Continuous	0.1416
Pressure controller	Becker	VRP-SB	Intermittent	0.0000
Pressure controller	Becker	VRP-SB Gap Controller	Intermittent	0.0000
Pressure controller	Becker	VRP-SB-CH	Intermittent	0.0000

Description	Manufacturer	Model	Operating Condition	Manufacturer Rate (Sm^3/h) [4]
Pressure controller	Becker	VRP-SB-PID Controller	Intermittent	0.0000
Pressure controller	Bristol Babcock	Series 5453-Model 10F	Continuous	0.0850
Pressure controller	Bristol Babcock	Series 5455-Model 624-III	Continuous	0.0708
Pressure controller	CSV	4150	Continuous	0.6853
Pressure controller	CSV	4160	Continuous	0.6853
Pressure controller	Dyna-Flow	4000	Continuous	0.6853
Pressure controller	Fisher	2506	Continuous	0.6853
Pressure controller	Fisher	2516	Continuous	0.6853
Pressure controller	Fisher	4150	Continuous	0.7362
Pressure controller	Fisher	4160	Continuous	0.7362
Pressure controller	Fisher	4194	Continuous	0.1203
Pressure controller	Fisher	4195	Continuous	0.1203
Pressure controller	Fisher	4660	Continuous	0.1416
Pressure controller	Fisher	4100 (large orifice)	Continuous	1.4158
Pressure controller	Fisher	4100 (small orifice)	Continuous	0.4248
Pressure controller	Fisher	C1	Continuous	0.1472
Pressure controller	Fisher	DVC 6010	Continuous	0.0878
Pressure controller	Foxboro	43AP	Continuous	0.5097
Pressure controller	ITT Barton	338	Continuous	0.1699
Pressure controller	ITT Barton	358	Continuous	0.0510
Pressure controller	ITT Barton	359	Continuous	0.0510
Pressure controller	ITT Barton	335P	Continuous	0.1699
Pressure controller	ITT Barton	335P	Continuous	0.1699
Transducer	Bristol Babcock	9110-00A	Continuous	0.0119
Transducer	Bristol Babcock	Series 502 A/D	Continuous	0.1671
Transducer	Fairchild	TXI 7800	Continuous	0.2407
Transducer	Fisher	546	Continuous	0.8495
Transducer	Fisher	646	Continuous	0.2209
Transducer	Fisher	846	Continuous	0.3398
Transducer	Fisher	i2P-100	Continuous	0.2832
Transmitter	Bristol Babcock	Series 5457-70F	Continuous	0.0850
Transmitter	ITT Barton	273A	Continuous	0.0850
Transmitter	ITT Barton	274A	Continuous	0.0850
Transmitter	ITT Barton	284B	Continuous	0.0850
Transmitter	ITT Barton	285B	Continuous	0.0850

Footnotes and Sources:
[1] Canadian Association of Petroleum Producers. *Fuel Gas Best Management Practices: Efficient Use of Fuel Gas in Pneumatic Instruments*. Module 3, CETAC West, Calgary, AB. 2008 Appendix B converted to metric units.
[2] United States Environmental Protection Agency. *Lessons Learned from Natural Gas STAR Partners: Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry.* Washington, DC. 2006. Appendix A converted to metric units.
[3] Various manufacturer specification publications.
[4] Factors equal to zero indicate that the device does not vent gas.

Table 360-7. Nomenclature (subscripts, variables and their descriptions)

Variable Name	Description
A	Variable – Area
a	Subscript – Actual condition for temperature and pressure
CF	Variable – Control factor (fractional)
D	Variable – Diameter
E	Variable – Greenhouse Gas release rate
e	Subscript – exit point
EF	Variable – Emission factor
GOR	Variable – Gas to oil ratio
GWP	Variable – Global warming potential
HHV	Variable – Higher (gross) heating value
i	Subscript - Chemical compound
j	Subscript - Individual device, equipment, meter or well
K	Variable – Specific heat ratio for gases
k	Subscript - Service type (e.g., fuel gas, process gas, liquid, etc)
L	Variable - Length
l	Subscript - Individual equipment components
M	Variable – Mach number
MW	Variable – Molecular weight
m	Subscript – Operating mode
N	Variable – Count of devices, equipment, meters, wells, events, etc.
n	Variable – Number of carbon atoms in a molecule of a specified substance.
P	Variable – Pressure
R	Variable – Universal Gas Constant
s	Subscript – Standard condition for temperature (15 ^{o}C) and pressure (101.325 kPa)
t	Variable – Time duration of event
T	Variable – Temperature (°C)
Q	Variable – Volumetric flow rate
V	Variable - Volume
X	Variable - Mass fraction
Y	Variable - Mole fraction
ρ	Variable - density
□	Variable – efficiency (fractional)

WCI Emissions Trading Program Update

San Francisco, CA

January 12, 2012

WCI Emissions Trading Program

- Comprehensive strategy to reduce greenhouse gas emissions and spur a clean-energy economy
- Benefits include:
  - Reducing costly impacts climate change will have on water resources, natural ecosystems, air quality, & environment-dependent industries like agriculture and tourism
  - Providing incentives for clean-energy technologies
  - Creating green jobs
  - Increasing energy security
  - Protecting public health

Recent Accomplishments

- Detailed Program Design released July 2010
- California rules for C&T and offsets approved December 2011
- Québec rule for C&T approved December 2011
- Offset Protocol Review and Recommendation Process released December 2011
- Further harmonization of Canadian emission reporting requirements released December 2011

Recent Accomplishments

- WCI, Inc. incorporated November 2011
  - WCI, Inc. provides administrative and technical services to support the implementation of state and provincial greenhouse gas emissions trading programs
  - WCI continues to exist as a collaboration of governments interested in implementing market-based mechanisms for reducing economy-wide GHG emissions
  - These organizations continue to include jurisdictions actively pursuing a C&T program. This streamlines the process of developing the program while allowing other jurisdictions to join when ready.

Regional Administration

The creation of WCI, Inc. will allow participating jurisdictions to implement their programs efficiently and consistently to create a regional carbon market

- Services will include:
  - Management of a compliance instrument tracking system
  - Administration of allowance auctions
  - Coordination of market monitoring and oversight
- Next steps
  - Hire executive director and staff

Market Development

Proper market design, infrastructure, and oversight reduce compliance cost and ensure fair treatment of market participants

- Next steps
  - Execute contracts for support services for auction and reserve sales and market monitoring
  - WCI, Inc. to release RFP for compliance instrument tracking system service (CITSS) operation
  - Allow covered entities and others to register with CITSS

Offsets

A rigorous offset system is key to producing high-quality offsets that can be exchanged across Partner jurisdictions

- Next steps
  - Finalize process for issuing offsets
  - Develop offset protocols to meet WCI program criteria

Emissions Reporting

A rigorous reporting system and high-quality emissions data are important for achieving environmental and economic objectives

- Next steps
  - Harmonization with final EPA oil and gas methods, while maintaining C&T quality data
  - Maintain harmonization among Partner reporting requirements

Linking

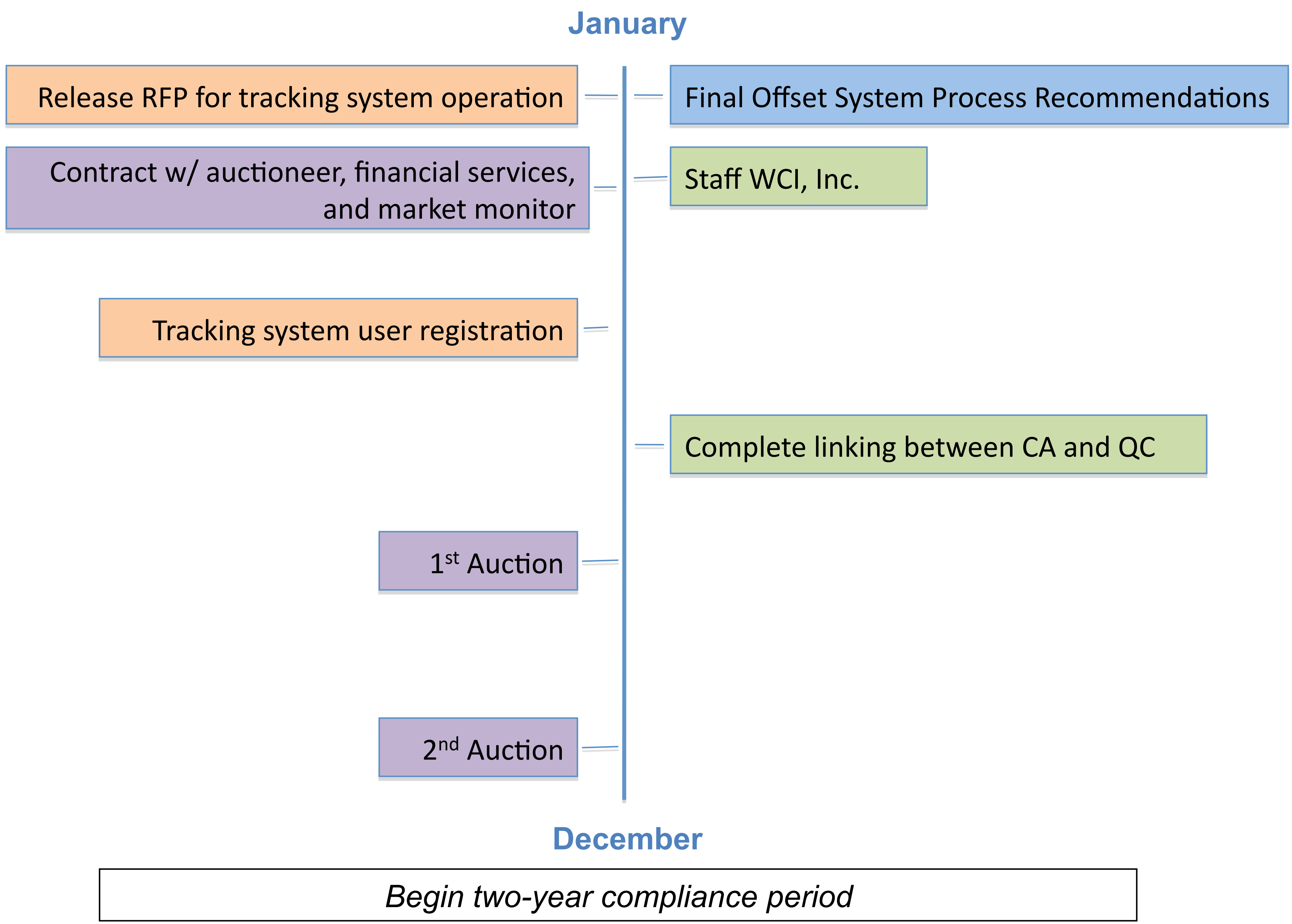
The full value of the regional program will be realized as Partner jurisdictions complete bilateral linking, recognizing each others' allowances and offsets for compliance purposes

- Next steps
  - Review jurisdictions' programs to assess consistency
  - Complete and update regulations as necessary

Outreach

- Provide stakeholders with periodic updates
- Continue working closely with federal governments and other climate initiatives to ensure coordination and promote national and international action

2012 Implementation Timeline



Western Climate Initiative

Final Recommendations
Offset System Process

(Offset Committee Task 1.3)
February 22, 2012

An efficient offset system, consistent across WCI Partner jurisdictions, will help ensure an adequate supply of high-quality offsets.

The Western Climate Initiative (WCI) Partner jurisdictions today release final recommendations for the requirements and process of offset project review, approval, and certificate creation for the regional emissions trading program.

The WCI Design Recommendations (2008) recommended the establishment of a rigorous offset system to support the cap-and-trade programs established by WCI Partner jurisdictions. The Design for the WCI Regional Program (2010) recommended essential criteria for high-quality offsets and that standards and processes for approving offset projects be developed in an open and transparent manner in advance of the start of the cap-and-trade program. The final recommendations in this paper support these objectives.

The final recommendations identify the critical elements of offset project approval that WCI Partner jurisdictions believe will lead to high-quality offset certificates that can be exchangeable across the region. Consistent, transparent processes are expected to lower project development costs and support learning and sharing of experience among Partner jurisdictions and offset project developers. Stakeholder engagement, third party involvement, and regulatory oversight combine to ensure the environmental integrity of the program.

The final recommendations reflect input from stakeholders. All stakeholder comments are available on the WCI website.

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1 Executive Summary

This paper is issued by the WCI Offsets Committee as part of its efforts to offer design recommendations for the WCI offset system to the WCI Partner jurisdictions. This paper describes the final recommendations for the WCI offset system process steps. Previous papers provided recommendations for the WCI offset definition and essential criteria.

In the WCI's workplan, this paper is part of the Offset Committee's Task 1.3 to identify the specific requirements for registration, validation, monitoring, quantification, reporting, verification, certification and issuance of offset certificates. For each of these steps, this paper presents final recommendations which are summarized in Table 1.0 below and depicted in Figure 1.

As WCI Partner jurisdictions will recognize the offset certificates issued by other Partner jurisdictions, it is important for the Partner jurisdictions to have processes in their offset systems that ensure the rigor and interchangeability of offset certificates across the WCI Partner jurisdictions. These final recommendations propose processes to help ensure the necessary level of rigor across WCI Partner jurisdictions.

The WCI Partner jurisdictions recognize that Partner jurisdictions have labeled the steps with varying terms, and in some cases have combined steps in their proposed programs. These final recommendations acknowledge that such variations, which result in the same or greater level of rigor being achieved, are acceptable.

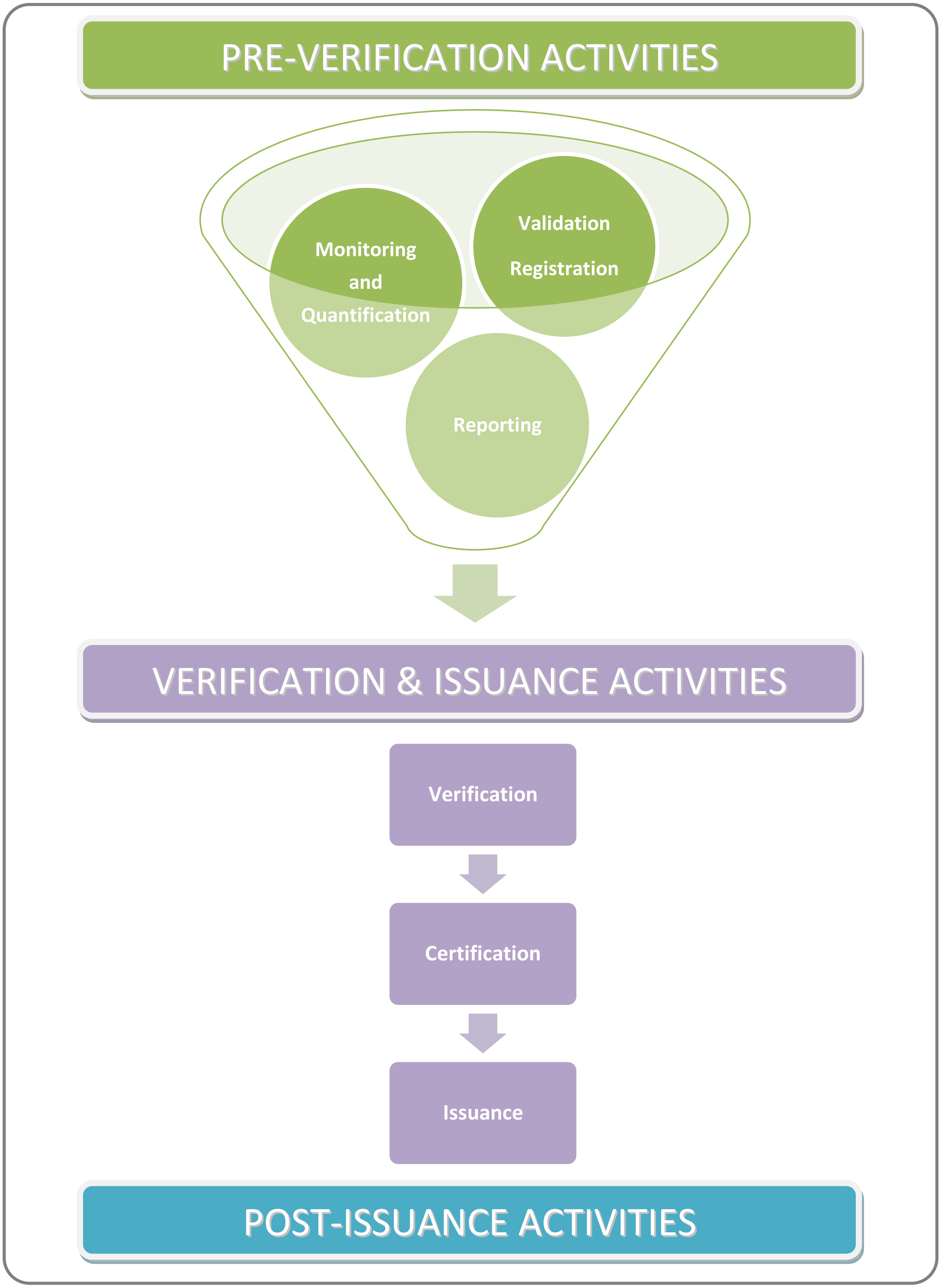

Figure 1. Recommended Western Climate Initiative offset system process flow

Table 1. Summary of Final Recommendations.

Group	Criteria	Summary of Final Recommendation
Pre-verification Activities	Validation	Validation is intended to provide the project developer and the WCI Partner jurisdiction with assurance that the project, when implemented, is likely to meet all of the WCI criteria and is likely to result in emission reductions qualifying under the WCI offset system. Each WCI Partner jurisdiction will be responsible for evaluating offset projects within its respective jurisdiction and may also evaluate and record offset projects in non-WCI jurisdictions throughout Canada, the United States and Mexico. Therefore, whether performed by a WCI Partner jurisdiction or a validation body, validation will be conducted with the expectation that the project will be considered under a specific jurisdiction's offset system. An offset project proponent initiates the process by submitting information on their proposed project required by the WCI Partner jurisdiction or an accredited third-party validation body to effectively perform their validation activities. The required information may be defined by the appropriate protocol (i.e. the WCI recommended protocol adopted by jurisdictions) and may be in the form of a project plan providing basic contact information, describing the project, referring to the appropriate protocol baseline scenario (where appropriate) or performance standard, and identifying all project-specific monitoring requirements. The WCI Partner jurisdiction or the validation body will assess whether the project meets the relevant jurisdiction's requirements and is in conformance with an appropriate protocol. The validation step must be completed prior to verification of the offset project's first project report. A project must be validated as part of each renewed crediting period. Subject to activity (validation/verification) and sectoral scope (project type) requirements, third-party validation bodies must conduct validation in accordance with ISO 14064-3 and must be accredited to ISO 14065 through (a) a program developed under ISO 17011 by an accreditation body that is a member of the International Accreditation Forum or (b) a program developed or authorized by a WCI Partner jurisdiction under the jurisdiction's required statutory or regulatory process that is at least as stringent as the process defined in ISO 17011.

Pre-verification Activities	Registration	Project registration requires the submission of information for each project to the responsible WCI Partner jurisdiction. The required information may be defined by the appropriate protocol and may be in the form of a project plan. Registration information will be posted for public review and comment to provide transparency. For a potential offset project, the project developer will follow an appropriate protocol as adopted by a WCI Partner jurisdiction. For aggregation of small projects, a single request for registration may be submitted for the entire aggregation. The request for registration must include the required information on each small project. The project developer must implement the project per the information provided as part of registration. If the proponent changes any aspect of the project compared to the project plan at the time of registration, the change will need to be approved by the relevant WCI Partner jurisdiction and a revised project plan reflecting the change(s) posted for public review. WCI Partner jurisdictions will endeavor to adopt protocol content that is as similar as possible to that recommended by WCI Partner jurisdictions. The committee recommends that WCI Partner jurisdictions retain the flexibility to select the registration approach most appropriate for their jurisdiction. However, for all WCI Partner jurisdictions, no offset certificates will be issued until the project is validated, registered and has verified emission reductions.
	Monitoring and Quantification	Each offset project shall follow the monitoring and quantification requirements specified in the appropriate protocol. Monitoring and quantification requirements for offset projects will be harmonized, to the extent practicable, with Reporting Requirements recommended by the WCI for facilities and sources covered by emission caps.

	Reporting	Reporting frequency will be annual unless otherwise specified in the appropriate protocol. A WCI Partner jurisdiction will have two options for assigning the annual reporting date for a project: • the month and day of the project start date (as determined by the first day for which a reduction is claimed); or • a common calendar date for all projects each year. Reporting requirements will be harmonized, to the extent possible, with the Reporting Requirements recommended by the WCI for covered sources. Aggregated small projects may submit a single report for the entire aggregation of projects, although the report must include required information on each project's reductions.
All pre-verification steps must be completed before moving on to VERIFICATION.		
Verification & Issuance Activities	**All steps in this section must be completed in order: VERIFICATION, then CERTIFICATION, then ISSUANCE.**	
	Verification	Emission reductions or removals must be verified by an accredited third-party verification body and submitted to the relevant WCI Partner jurisdiction prior to the issuance of offset certificates. Subject to activity (validation/verification) and sectoral scope (project type) requirements, verification bodies must be accredited to ISO 14065 through (a) a program developed under ISO 17011 by an accreditation body that is a member of the International Accreditation Forum or (b) a program developed or authorized by a WCI Partner jurisdiction under the jurisdiction's required statutory or regulatory process that is at least as stringent as the process defined in ISO 17011. The verification must also be conducted in accordance with ISO 14064-3 to a reasonable level of assurance. A third party verifier that validated the project plan may not perform third-party verification of a project report for that project within the same crediting period. Verification statements will be posted publicly. For aggregation of small projects, a single verification report can be submitted for the entire aggregation, although it must include verification for each project's reductions.
	Certification	The certification step involves the WCI Partner jurisdiction or its agent/recognized body reviewing project documentation presented as evidence and accepting that evidence into the system through the assignment or creation of an offset certificate when it is satisfied all conditions of the WCI Partner jurisdiction have been or will be met. The committee recommends certification take place before issuance of offset certificates, so that certificates are not issued prior to successful completion of certification.

	Issuance	Following certification, the WCI Partner jurisdiction will proceed with the issuance of offset certificates. The jurisdiction will complete the administrative steps necessary to serialize the units. Issuance does not require the project proponent to submit any additional information nor require the WCI Partner jurisdiction to conduct any further review of the project.
Post-issuance Activities	Project Reversals, Fraud and Error	Offset project protocols and the offset systems of the WCI Partner jurisdictions will have mechanisms in place to ensure permanence, including provisions to address unintentional and intentional reversals. The offset systems of the WCI Partner jurisdictions will establish rules that enable action to be taken where fraud or error has been discovered. The outcomes of such action will include maintaining the environmental integrity of the program by ensuring every certificate in the system is supported by an emission reduction that is real, additional, permanent and verifiable. WCI Partner jurisdictions may choose to issue, at their discretion, offset certificates that are either revocable or non-revocable. This option would support some jurisdictions issuing offset certificates that may be revoked, and others issuing offset certificates that may not be revoked. Partner jurisdictions should have the ability to manage both revocable and non-revocable offset certificates.

2 Purpose and Background

The July 2010 Design for the WCI Regional Program includes provisions for a rigorous offset system. The primary role of the offset system is to reduce the compliance costs associated with the cap-and-trade program while maintaining the environmental integrity of the cap. The design of the offset system should encourage emission reductions, innovation, and technology development in sectors and at sources not covered by the cap-and-trade program. WCI Partners will only consider non-covered sources on a limited and case-by-case basis.

The purpose of the WCI Offsets Committee is to make recommendations to the WCI Partner jurisdictions on the design and operation of the offset system as part of the WCI cap-and-trade program. The committee divided its work into three tasks. Task 1 is to make recommendations for essential elements and infrastructure to create and operate the WCI offset system. Task 2 is to make recommendations for accepting offset certificates and allowances from other greenhouse gas trading programs. Task 3 is to make recommendations for the review and recommendation of protocols for the WCI offset system. This paper uses the term "appropriate protocol" to mean recommended by WCI Partner jurisdictions and adopted into the rules and regulations of Partner jurisdictions.

This paper is part of the Offsets Committee's Task 1 Essential Elements work, specifically Task 1.3, to identify the specific requirements for pre-verification activities (registration, validation, monitoring, quantification, reporting), verification, certification, issuance and post-issuance activities. This paper presents final recommendations for those elements. Since WCI Partner jurisdictions will recognize the offset certificates issued by other Partners, it is important for the Partner jurisdictions to have processes in their offset systems that ensure the rigor and interchangeability of offset certificates across the WCI Partner jurisdictions.

These final recommendations propose processes to ensure the necessary level of rigor across WCI Partner jurisdictions. Figure 1 identifies the process steps for an offset project. The WCI Partner jurisdictions recognize that Partner jurisdictions have labeled the steps with varying terms, and in some cases have combined steps, in the processes proposed for their programs. While offering these final recommendations, the WCI Partner jurisdictions acknowledge that such variations that result in the same or greater level of rigor being achieved are acceptable.

As part of their effort to design an offset system that encourages emission reductions from sources not covered by the cap-and-trade program, WCI Partner jurisdictions aim to facilitate participation of small projects by implementing a process that readily accommodates the aggregation of small projects. The final recommendations for some process steps include specific elements related to the aggregation of small projects in order to streamline the process for these projects while ensuring the same high quality standards are met for all offset projects.

Information collected during the offset system process will be made publicly available by the WCI Partner jurisdictions. WCI Partner jurisdictions will make information public consistent with public records and protection of privacy laws and policies in the respective jurisdiction. WCI Partner jurisdictions maintain that the process for approving offset projects be conducted in an open and transparent manner.

3 Process Options and Final Recommendations

PRE-VERIFICATION ACTIVITIES

Validation

Validation is the assessment of a proposed offset project against the offset system requirements. Validation includes review and assessment of project information for conformance with system criteria; alignment with an appropriate protocol; and review of quantification methodologies, baselines, standards, calculations, assumptions, factors, forecasts and assertions. More detailed information on the validation step can be found in ISO 14064-3.

Final Recommendation

Validation is intended to provide the project developer and the WCI Partner jurisdiction with assurance that the project, when implemented, is likely to meet all of the WCI criteria and is likely to result in emission reductions qualifying under the WCI offset system. Each WCI Partner jurisdiction will be responsible for evaluating offset projects within its respective jurisdiction and may also evaluate and register offset projects in non-WCI jurisdictions throughout Canada, the United States and Mexico.[1] Therefore, whether performed by a WCI Partner jurisdiction or a validation body, validation will be conducted with the expectation that the project will be considered under a specific jurisdiction's offset system.

An offset project proponent initiates the validation process by submitting information on their proposed project required by the WCI Partner jurisdiction or an accredited third-party validation body to effectively perform their validation activities. The required information may be defined by the appropriate protocol[2] and may be in the form of a project plan providing basic contact information, describing the project, referring to the appropriate protocol (i.e. the

[1] There is some possibility that a WCI Partner jurisdiction may choose not to administer its own offset system. In that case, it may be necessary for offset projects in that jurisdiction to have another WCI Partner jurisdiction(s) issuing offset certificates for projects in that jurisdiction. It is not the intent of the WCI Partner jurisdictions to prevent offset projects from occurring in a jurisdiction that may lack the resources to effectively administer its own offset system.

[2] The protocols included in California’s cap-and-trade program refer to this information as "listing information."

WCI recommended protocol adopted by jurisdictions), baseline scenario (where appropriate) or performance standard, and identifying all project-specific monitoring requirements. The WCI Partner jurisdiction or the validation body will assess whether the project meets the relevant jurisdiction's requirements WCI offset system requirements as adopted by WCI Partner jurisdictions and is in conformance with an appropriate protocol.

The validation step must be completed prior to verification of the offset project's first project report. A project must be validated as part of each renewed crediting period. If validation is performed by an accredited third-party validation body, the validation body must issue a positive validation statement before the project can be registered. Subject to activity (validation/verification) and sectoral scope (project type) requirements, third-party validation bodies must conduct validation in accordance with ISO 14064-3 and must be accredited to ISO 14065 through (a) a program developed under ISO 17011 by an accreditation body that is a member of the International Accreditation Forum or (b) a program developed or authorized by a WCI Partner jurisdiction under the jurisdiction's required statutory or regulatory process that is at least as stringent as the process defined in ISO 17011.

Explanation of Final Recommendation

This final recommendation meets the WCI Offset System Essential Elements Final Recommendation (July 2010) that "validation is a required review by an accredited independent third party of the WCI Partner jurisdiction to assess the likely result of reduction or sequestration from a proposed project that would use a WCI offset protocol."

In order to ensure a complete and efficient verification of emission reductions, the final recommendation proposes that validation be conducted prior to verification of the first project report for a given offset project. Each project must be validated prior to each crediting period to assure that the project meets the current requirements of the appropriate protocol. To the degree possible, the validation process for project renewal will be streamlined. At the start of a new crediting period some project information reviewed as part of the validation process is unlikely to change. However, information regarding applicable regulatory requirements, as well as performance standard thresholds to assess additionality, may change over time.

Information submitted on the proposed project will serve as the basis for the validation review. Submitted information will include identification and description of the project, an assertion of the projection's additionality, and copies of other legal documentation required for the project (e.g., permits, environmental impact assessment).

The final recommendation does not require site visits as part of the project review process for validation. The WCI Offsets Committee recognizes that requiring a site visit presents a potentially unnecessary cost to project developers, particularly given the WCI Partners' preference for standardized offset protocols. However, if required for particular protocols, project types or technologies a site visit could be included as part of the validation process.

The accreditation requirement for third-party validators is designed to mirror as closely as possible the accreditation requirement for third-party verifiers providing services for mandatory reporting and offset projects. Following a validation review, a third-party validator may only issue a positive validation statement if they determine the project to be in conformance with offset system requirements and the appropriate protocol. As discussed later in this paper, a verifier would then verify a project against the validated project plan and the appropriate protocol.

Registration

The registration process is the mechanism for project developers to record offset project information with the WCI Partner jurisdiction evaluating the project. Project registration requires the submittal of forms and information on each project to the applicable WCI Partner jurisdiction to help ensure that projects meet the requirements of the offset system. For the WCI Partner jurisdictions, a registration system for recording and managing project information will be especially important to ensure proper oversight for a regulatory compliance program and effective communication across multiple jurisdictions. Posting registration information for public review provides transparency to the offset system.

Final Recommendation

Project registration requires the submission of information for each project to the responsible WCI Partner jurisdiction. The required information may be defined by the appropriate protocol and may be in the form of a project plan.

For a potential offset project, the project developer will follow an appropriate WCI protocol as adopted by a WCI Partner jurisdiction. For aggregation of small projects, a single request for registration can be submitted for the entire aggregation, although it must include the required information on each project. The project developer must implement the project in accordance with the information provided as part of registration. If the proponent changes any aspect of the project compared to the project plan at the time of registration, the change will need to be approved by the relevant WCI Partner jurisdiction and a revised project plan reflecting the change must be posted for public review.

The committee recommends that WCI Partner jurisdictions retain the flexibility to select the registration approach most appropriate for their jurisdiction. However, for all WCI Partner jurisdictions, no offset certificates will be issued until the project has completed the pre-verification activities and has verified emissions reductions. In order to ensure against double-counting and prevent the issuance of offset certificates from the same project under multiple registries, offset projects cannot be registered in more than one registry.

If the project was previously registered under a different offset program registry, it must be deregistered from all other registries before being registered in a WCI Partner jurisdiction. The emission reductions and removals from the project for which offset certificate issuance by a WCI Partner jurisdiction may be requested must not have already been retired, canceled, used to meet a surrender obligation, used to meet a voluntary commitment, or used to meet any GHG requirement in any voluntary or regulatory system. Also, the emission reductions and removals must:

- have a legal owner;
- meet the relevant jurisdiction's requirements, including being in conformance with an appropriate protocol (i.e., the WCI recommended protocol adopted by the jurisdiction); and
- have all the documentation required by the appropriate protocol to ensure that the emission reductions and removals meet the program requirements.

Prior to issuing offset certificates for emission reductions and removals from a project that was previously registered in another registry, all instruments representing those emission reductions and removals in any other programs must be retired to avoid double crediting.

Explanation of Final Recommendation

The WCI Offsets Committee recommends the priority for ensuring the integrity of offset certificates across the WCI Partner jurisdictions is for requirements to be consistently met and documented in all WCI Partner jurisdictions prior to the issuance of offset certificates. Pre-verification activities are completed before verification and the timing and order of steps within pre-verification activities may vary based on circumstances specific to each WCI Partner jurisdiction.

Monitoring and Quantification

Monitoring is the process of collecting project activity data essential for quantifying greenhouse gas (GHG) reductions or removals and also the process of confirming assumptions used in quantification. Monitoring includes determining what project activities need to be measured, how often measurements should be taken, what methods are acceptable, what instrumentation should be used for data collection, how the data is stored and how data quality is maintained. Monitoring of an offset project is intended to allow for the complete and transparent quantification of GHG reductions or removals.

Essential elements of monitoring procedures and monitoring reports often include the following:

- GHG data and information for all sources and sinks to be monitored, including units of measurement.
- Source information for all data and information included.
- Monitoring methodology identified, including description of the approach used (e.g., estimation, modeling, measurement or calculation) and description of all relevant assumptions, constants, mathematical relationships and formulas.
- Measurement collection techniques identified including technical information regarding location and specifications of metering equipment, procedures for meter reading, calibration and maintenance, and length of measurement periods.
- Level of uncertainty associated with measurement and estimation of data.
- Roles and responsibilities for monitoring procedures.
- Quality assurance/quality control measures including data management systems, procedures for managing poor quality or lost data and data archive procedures.

Quantification is the process of estimating emissions reductions achieved from project activity data collected through monitoring. Requirements for quantification will be included in offset protocols recommended by the WCI Partner jurisdictions. The process for developing appropriate protocols recommended by the WCI Partner jurisdictions, including quantification requirements, will be addressed through the work under Task 3 of the WCI Offset Committee.

Final Recommendation

Each offset project shall follow the monitoring and quantification requirements specified in the appropriate protocol and offset system rules of the WCI Partner jurisdiction. Monitoring and quantification requirements for offset projects will be harmonized, to the extent practicable, with reporting requirements recommended by the WCI for facilities and sources covered by emission caps.

Explanation of Final Recommendation

Protocol-specific monitoring requirements will provide consistency across projects using the same appropriate protocol and allow WCI Partner jurisdictions to tailor monitoring requirements to each project type. Under this approach, monitoring requirements will be included as part of each appropriate protocol for a given project type. Since waiting until verification to have the monitoring plan approved could increase risk to project developers, project proponents will be required to submit a plan to meet monitoring requirements as part of the validation review that demonstrates how the project will meet the monitoring requirements of the appropriate protocol being used. During the reporting and verification process steps, submitted monitoring data will be reviewed to ensure it meets the procedures outlined in the approved plan.

Consistency of monitored data is important for quantification, reporting and verification. Requiring all project developers for each project type to follow the same monitoring requirements helps ensure the consistency of monitored data. However, under certain circumstances a WCI Partner jurisdiction may allow a project proponent to use an alternative monitoring approach or to propose alternative monitoring approaches with approval from WCI Partner jurisdictions. For a proponent to propose an alternative monitoring approach, the proponent must be unable to implement the monitoring approach in the appropriate protocol, and the proponent must propose an approach that will achieve a similar level of accuracy to the approach in the appropriate protocol.

Reporting

Reporting refers to the process of summarizing project monitoring data, quantifying the GHG reduction achieved in the applicable period according to the calculation methodology in the project plan, and documenting that information in a project report. Periodic reporting on the performance of GHG reduction projects is a step required by most offsets systems and a necessary step before offset certificates can be issued. The required content and level of detail required in project reports vary between systems and by project type. A complete project report in the WCI offset system might include the following components:

- Summarized monitoring data
- Calculations supporting the GHG reductions achieved (in accordance with the quantification methodologies of the appropriate protocol)
- Proponent's assertion of the GHG reduction.
- A signed verification statement.

The WCI Partner jurisdictions will establish overall reporting requirements to ensure adequate oversight of the offset system. These requirements are intended to serve the needs of project proponents, assurance providers, and ultimately the wider WCI market by establishing what information must be documented before an offset certificate may be issued. Clear reporting requirements should allow for reports to be submitted and verified without undue delay.

Final Recommendation

Reporting frequency will be annual unless otherwise specified in an appropriate protocol. A WCI Partner jurisdiction will have two options for assigning the annual reporting date for a project:

- the month and day of the project start date (as determined by the first day for which a reduction is claimed); or
- a common calendar date for all projects each year.

Reporting requirements will be harmonized, to the extent possible, with the reporting requirements recommended by the WCI for covered sources. Aggregated small projects may submit a single report for the entire aggregation of projects, although the report must include required information on each project's reductions.

Explanation of Final Recommendation

The WCI Offsets Committee recommends annual reporting to ensure ongoing oversight of project activities. For particular project types (e.g., long-term sequestration projects), less frequent reporting may be appropriate.

The WCI Offsets Committee discussed the merits of having common or staggered reporting dates for offset projects. The advantage of the common date was that offset project reporting would thus be more similarly aligned with mandatory reporting which also has a common date. Staggered reporting dates according to a project's start date allow the workload placed on verifiers and jurisdiction staff to be more constant throughout the year instead of focused in one quarter of the year. Staggered dates are also consistent with other notable offset systems. The Offsets Committee believes that both approaches are valid and recommends that WCI Partner jurisdictions follow either approach, as this should not adversely affect the rigor or fungibility of offset certificates across the WCI region.

Harmonization of reporting requirements with the WCI Mandatory Reporting Requirements and aggregation of small projects into a single reporting report, are recommendations aimed at reducing the administrative burden and improving efficiency for project developers.

All pre-verification steps must be completed before moving on to VERIFICATION & ISSUANCE ACTIVITIES.

VERIFICATION & ISSUANCE ACTIVITIES

All steps in this section must be completed in order:
VERIFICATION, then CERTIFICATION, then ISSUANCE.

Verification

Verification is the process of reviewing offset project information to ensure that claimed emissions reductions have been achieved in accordance with the appropriate protocol and project plan.

Final Recommendation

Emission reductions or removals must be verified by an accredited third-party verification body and submitted to the relevant WCI Partner jurisdiction prior to the issuance of offset certificates. Subject to activity (validation/verification) and sectoral scope (project type) requirements, verification bodies must be accredited to ISO 14065 through (a) a program developed under ISO 17011 by an accreditation body that is a member of the International Accreditation Forum or (b) a program developed or authorized by a WCI Partner jurisdiction under the jurisdiction's required statutory or regulatory process that is at least as stringent as the process defined in ISO 17011. The verification must also be conducted in accordance with ISO 14064-3 to a reasonable level of assurance. The verification must also be conducted in accordance with ISO 14064-3 to a reasonable level of assurance.

A third party assurance provider which validated the registered project plan may not perform third-party verification of a project report for a minimum of the next five verifications. WCI Partners may consider changing the minimum requirement if it is found that additional verifiers are not available. Any staff member of a verification team may not perform verification services for the same project for more than six consecutive years. Any verification staff that previously performed six years of verification services for the project may only again perform verification services for the project: 1) after the project has been verified by another verification team; and 2) at least 3 years after the verification staff last provided verification services for the project.

Explanation of Final Recommendation

The final recommendation for the verification process steps is based on the final recommendation for verification established in the WCI Offsets System Essential Elements Final Recommendations Paper (July 2010). The final recommendation stated, "verifiers for WCI offsets will be independent third parties who have been accredited to a standard acceptable by the WCI Partner jurisdiction in which the project is registered." The process steps final recommendation presents accreditation requirements for third-party verifiers. The recommended accreditation requirements, accreditation for entities verifying offset projects are consistent with the requirements recommended for mandatory reporting by covered sources. A site visit is required for the first project verification, and as stated in the protocol thereafter.

Certification

At some point in the creation of an offset compliance instrument a WCI Partner jurisdiction has to “accept” that the documentation provided and reviewed indicates that the reduction upon which the offset certificate may be based is real, additional, permanent and verifiable. At this step in the process, the WCI Partner jurisdiction must have the ability to enforce these requirements through its review of the documentation and its assessment of whether it supports a determination that the reduction is real, additional, permanent, and verifiable. By performing this step, other jurisdictions in a regional trading system would be assured that the resulting offset certificate and underlying project meet all of the offset criteria and would be able to accept the offset certificate for compliance.

It is not essential that the WCI Partner jurisdiction perform all of the certification steps directly and may assign certain roles, tasks and decisions to a third party. The tasks or steps involved in certification can take place at different times in the offset cycle and may be separated for convenience or functional efficiency. The successful completion of the certification step is expected to lead to the Partner jurisdiction issuing a tradable unit with a unique serial number within the tracking system of the WCI Partner jurisdictions.

Final Recommendation

The certification step involves the WCI Partner jurisdiction or its agent/recognized body reviewing project documentation presented as evidence and accepting that evidence into the system through the assignment or creation of an offset certificate when they are satisfied all conditions of the Partner jurisdiction have been or will be met. The committee recommends certification take place before issuing an offset certificate, so that certificates are not issued prior to successful completion of certification.

Explanation of Final Recommendation

The final recommendation for the certification process is based on WCI Partner jurisdictions preferring to avoid adding uncertainty to the reliability of offset certificates and preferring not to add complexity to compliance procedures for little or no benefit. Completing certification prior to issuance ensures that the full set of reviews and evaluations are conducted prior to the offset certificate being issued, so that the quality and reliability of the offset instrument are less uncertain. In making this recommendation the WCI Partner jurisdictions recognize that the full set of criteria and processes recommended for offset systems collectively contribute to the quality and reliability of offset certificates. Certification is identified as one component of the overall process at which a final evaluation ensures that the emission reduction on which the offset certificate is based is real, additional, permanent, and verifiable.

Issuance

After an emissions reduction or removal has been verified and certified in accordance with all requirements and a project proponent has submitted all required reports, the WCI Partner jurisdiction will issue offset certificates in a number equal to the reductions credited to the projects, with each issued offset certificate representing one metric tonne CO_2e reduced or removed. Issued offset certificates will be assigned unique serial numbers and issued to the proponent's registry account or a registry account designated by the proponent. For sequestration projects, some offset certificates may also be retained in a contingency account or buffer pool as required by WCI Partner jurisdictions.

The unique serial number allows each issued offset certificate to be linked to all supporting documents for the offset project. It also allows tracking of an offset certificate from issuance until retirement, enhancing transparency and assisting with any enforcement activities that may be required. Once issued and deposited in an account, offsets certificates can be traded voluntarily retired, or used to meet a compliance obligation.

Final Recommendation

Following certification, the WCI Partner jurisdiction will proceed with offset certificate issuance. The jurisdiction will complete the administrative steps necessary to serialize the units. Issuance does not require the project proponent to submit any additional information nor require the WCI Partner jurisdiction to conduct any further review of the project.

Explanation of Final Recommendation

The comprehensive due diligence process recommended in this paper combines the rigor of direct WCI Partner jurisdiction oversight and accreditation with the efficient aspects of third-party service providers, allowing project developers the maximum flexibility in scheduling and arranging for assurance services and providing jurisdictions with maximum assurance and control. The issuance of an offset certificate culminates the due diligence cycle, delivering a high quality, reliable product into the marketplace.

POST-ISSUANCE ACTIVITIES

Project Reversals, Fraud and Error

Following issuance of offset certificates, the ownership of the certificates will be tracked in the tracking system used by the WCI Partner jurisdictions. Offset certificates may be traded and used for compliance within the rules of the WCI Partner jurisdiction programs. Offset certificates could also be retired by their owners for reasons other than compliance if desired.

The offset criteria and processes recommended by the WCI Partner jurisdictions are designed to ensure that all offset certificates are based on well-documented emission reductions. Nevertheless, situations may arise that require action by regulatory authorities regarding specific offset certificates in order to maintain the environmental integrity of the offset system and as a consequence the cap-and-trade program.

It is well recognized that carbon sequestration projects (such as some forestry projects) are vulnerable to reversal in which carbon that was verified as sequestered is released into the atmosphere. To ensure that carbon sequestration achieves the level of permanence described in the offset criteria, appropriate protocols and the offset system must include procedures for addressing both unintentional and intentional project reversals. Following issuance, regulatory authorities that issue the offset certificates must have the ability to enforce these procedures and requirements.

In addition to permanence risk, there is a risk that following issuance the basis for issuing an offset certificate for a specific project could be found to be fraudulent or in error. The recommended documentation and independent review requirements are designed to detect such conditions prior to issuance, so that post-issuance discovery of such conditions is expected to be rare. Nevertheless, procedures are required to respond to such circumstances when they arise.

Final Recommendation

Appropriate project protocols and the offset systems of the WCI Partner jurisdictions will have mechanisms in place to ensure permanence, including provisions to address unintentional and intentional reversals.

The offset systems of the WCI Partner jurisdictions will establish rules which enable action to be taken where fraud or error has been discovered. The outcomes of such action will include maintaining the environmental integrity of the program by ensuring every certificate in the system is supported by an emission reduction that is real, additional, permanent and verifiable.

WCI Partner jurisdictions may choose to issue, at their discretion, offset certificates that are either revocable or non-revocable. This option supports some jurisdictions issuing offset certificates that may be revoked, and others issuing offset certificates that may not be revoked. All WCI Partner jurisdictions should have the ability to manage both revocable and non-revocable offset certificates.

Explanation of Final Recommendation

The final recommendation regarding unintentional and intentional reversals is designed to ensure that sequestration projects and the offset system have built-in mechanisms to ensure permanence. These mechanisms should be used to deliver the promised performance of the offset projects.

The approach to post-issuance activities has been divided into two parts for this recommendation, one part for project reversals and one part for fraud and error. For projects that have a risk of reversal the appropriate project protocol must be designed with features that provide a mechanism for ensuring permanence. Mechanisms may include, for example, a buffer pool of offset certificates that is used to replace reductions that are unintentionally reversed. For this approach to be effective, the regulatory authority must have the ability to require that the buffer pool be maintained in adequate quantity to address risks of unintentional reversal, must have the ability to detect when unintentional reversals occur, and must be able to access the pool when needed, to replace the carbon lost to unintentional reversal. Through these procedures, the offset certificate that is in circulation (or that may have been used for compliance) remains in circulation and the reduction underlying the certificate is replaced by a reduction from the buffer pool.

Mechanisms for addressing intentional reversals may vary from those for unintentional reversals. The WCI Partner jurisdictions expect that an enforceable relationship between the regulatory authority and the project proponent will require that the project proponent provide a valid instrument to replace the reduction reversed through an intentional reversal. The regulatory authority must have the ability to enforce this requirement. Through this procedure, the offset certificate that is in circulation (or that may have been used for compliance) remains in circulation and the reduction underlying the certificate is replaced with another valid instrument.

Although expected to be rare, fraud or error could affect the validity of an offset certificate from any type of project. Information regarding potential fraud or error could become available in several ways, including from a third-party verifier hired to verify emission reductions at an ongoing project, from public comment, or from Partner jurisdiction audit. Regulatory authorities must have the resources to respond to such information and determine whether the new information changes the conclusion that the project meets the requirements for the offset system. If the regulatory agency finds that the project does not meet the requirements, it must take action to ensure that the environmental integrity of the offset system is maintained.

Two approaches have been identified for taking action:

- The regulatory authority is expected to have the ability to enforce requirements placed on project proponents and verifiers. The regulatory authority could require that those entities replace the offset certificates. While the regulatory authority pursues its remedies with the responsible parties, the offset certificate that is in circulation (or that may have been used for compliance) remains in circulation and the reduction underlying the certificate is replaced by project proponents.

- The regulatory authority could revoke offset certificates in the tracking system, removing them from any account. If the offset certificates have been used for compliance, the entity that used the offset certificate would be required by the jurisdiction in which it submitted the offset certificate for compliance to replace it. The owner of the offset certificate that was revoked could choose to pursue those responsible for the error or fraud to remedy their loss. The regulatory authority could pursue cases of fraud, but may not seek replacement of the offset certificate itself, as that would be left to the offset certificate owner.

In both approaches, the regulatory authorities have the ability to pursue remedies from those responsible for the error or fraud. The first approach puts the responsibility of ensuring that the offset certificate is replaced on the regulatory authority. The current owner has no exposure to the risks of fraud or error in this first approach. The second approach puts the risk on the offset certificate owner. If fraud or error is found to undermine an offset certificate, the offset certificate is revoked and the offset certificate owner may seek a remedy from the responsible party.

Both approaches can also encounter situations in which the mechanisms or those responsible for replacing the offset certificate are unable to replace it. For example, a project proponent may have inadequate resources to replace offset certificates as directed by regulatory authorities. Consequently, under both approaches the regulatory authorities issuing the offsets must be able to take responsibility to ensure the environmental integrity of the program when those required to replace offset certificates cannot be compelled to do so.

4 Conclusion

This paper describes the final recommendations for the WCI offset system process steps, including specific requirements for registration, validation, monitoring, quantification, reporting, verification, certification and issuance of offset certificates. The Final Recommendations reflect input provided by stakeholders via the WCI website and webinar. This Final Recommendations paper is the final deliverable for Task 1 of the WCI Offset Committee's work. The Final Recommendations are made available on the WCI website and the WCI Offsets Committee will hold a stakeholder conference call to present the final recommendations.

Western Climate Initiative

Final Recommendations
Offset System Process

WCI Stakeholder Call

March 2, 2012

To join the call, dial: **1-800-868-1837** toll free in the U.S. and Canada (1-404-920-6440 outside the U.S. and Canada) and enter code: **753491#**.

Document Release

- Final recommendations for the requirements and process of offsets project review and approval; and credit creation for the implementation of state and provincial greenhouse gas emissions trading programs
- Draft recommendations released June 15, 2011.
- Culmination of work since WCI released Design for WCI Regional Program in July 2010

Offset System Process

- This paper identifies the specific requirements for registration, validation, monitoring, quantification, reporting, verification, certification and issuance of offsets
- This process helps ensure that rigor and interchangeability of offsets across WCI Partner Jurisdictions is possible

Grouped Activities

1. Pre-Verification Activities (in any order)
   - Validation
   - Registration
   - Monitoring & Quantification
   - Reporting
2. Verification & Issuance (in this order)
   - Verification
   - Certification
   - Issuance
3. Post-Issuance Activities

Validation

- Is intended to provide the project developer and the WCI Partner jurisdiction with assurance that the project, when implemented, is likely to meet all of the WCI criteria and is likely to result in emission reductions qualifying under the WCI offset system
- This must be completed prior to verification of the project's first project report

Registration

- Requires submission of information for each project to the responsible Partner Jurisdictions
- Registration information will be posted for public review and comment to provide transparency
- The project developer must implement the project per the information provided as part of registration

Monitoring and Quantification

- Each offset project shall follow the monitoring and quantification requirements specified in the applicable protocol
- Monitoring and quantification requirements for offsets will be harmonized, to the extent practicable, with WCI Mandatory Reporting Requirements

Reporting

- Reporting frequency will be annual unless otherwise specified in a recommended protocol
- Partner jurisdictions will have two options for assigning the annual reporting date for the project:
  - the month and day of the project start date; or
  - a common calendar date for all projects each year

Verification

- Emission reductions or removals must be verified by an accredited third-party verification body and submitted to the relevant WCI Partner jurisdiction prior to the issuance of offset certificates
- The verification must be conducted in accordance with ISO 14064-3 to a reasonable level of assurance
- Verification statements will be publicly posted

Certification

- Reviewing project documentation presented as evidence and accepting that evidence into the system through the assignment or creation of an offset certificate when all conditions of the Partner Jurisdiction have been met
- Certification takes place at the point of issuing an offset certificate, so that certificates are not issued prior to successful completion of certification

Issuance

- Following certification is offset issuance
- The jurisdiction will complete the administrative steps to serialize the units

Post-Issuance Activities

- Project protocols and the offset systems of the Partner jurisdictions will ensure permanence, including mechanisms that will replace offsets from sequestration projects lost to unintentional and intentional reversal
- WCI Partner jurisdictions may choose to issue, at their discretion, offset certificates that are either revocable or non-revocable and Partner jurisdictions should have the ability to manage both revocable and non-revocable offset certificates.